California Environmental Protection Agency
Air Resources Board

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

PROPOSED RE-ADOPTION OF THE LOW CARBON FUEL STANDARD

Industrial Strategies Division
Transportation Fuels Branch
Oil & Gas and GHG Mitigation Branch

December 2014

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State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

PROPOSED RE-ADOPTION OF THE LOW CARBON FUEL STANDARD REGULATION

Date of Release: **January 2, 2015**
Scheduled for Consideration: **February 19, 2015**

State of California
AIR RESOURCES BOARD

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Air Resources Board

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Glossary

List of Acronyms and Abbreviations

AEZ-EF	Agro-Ecological Zone Emissions Factor
ANL	Argonne National Laboratory
ARB or Board	California Air Resources Board
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
CBI	Confidential Business Information
CEQA	California Environmental Quality Act
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO_2, CO_2e	Carbon Dioxide, Carbon Dioxide Equivalent
DGE	Diesel Gallon Equivalent
EER	Energy Economy Ratio
EIA	United States Energy Information Administration
EO	Executive Officer
EWG	Electricity Workgroup
EV	Electric Vehicle
gCO_2e/MJ	Grams of CO_2 Equivalent per Megajoule
GGE	Gasoline Gallon Equivalent
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GTAP	Global Trade Analysis Project
GWP	Global Warming Potential
iLUC	Indirect Land Use Change
IPCC	Intergovernmental Panel on Climate Change
ISOR	Initial Statement of Reasons
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuel Standard
LRT-CBTS	LCFS Reporting Tool and Credit Bank & Transfer System
MJ	Megajoule
$MMTCO_2e$	Million Metric Tons of CO_2 Equivalent
$MTCO_2e$	Metric Ton of CO_2 Equivalent
NREL	United States National Renewable Energy Laboratory
PTD	Product Transfer Document
RFS2	United States Renewable Fuels Standard 2
U.S. DOE	United States Department of Energy
U.S. DOT	United States Department of Transportation
U.S. EPA	United States Environmental Protection Agency
UN FAO	United Nations Food and Agriculture Organization
USDA	United States Department of Agriculture

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Staff Report: Initial Statement of Reasons for Proposed Re-Adoption of the Low Carbon Fuel Standard Regulation

PUBLIC HEARING TO CONSIDER THE PROPOSED RE-ADOPTION OF THE LOW CARBON FUEL STANDARD REGULATION

Date of Release: **January 2, 2015**
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Purpose of Proposed Rulemaking

In this rulemaking, the Air Resources Board (Board/ARB) staff is proposing to re-adopt the Low Carbon Fuel Standard (LCFS) regulation and to include updates and revisions compared to the previous regulation. The Board approved the original LCFS regulation in April 2009 as a discrete early action measure under the California Global Warming Solutions Act of 2006 (AB 32). In addition, the Board subsequently approved amendments to the LCFS in December 2011, which have been implemented since January 1, 2013.

On July 15, 2013, the State of California Court of Appeal issued its opinion in POET, LLC v. California Air Resources Board (2013) 218 Cal.App.4th 681. The court held that the LCFS adopted in 2009 and implemented in 2010 (referred to as 2010 LCFS) would remain in effect and that ARB could continue to implement and enforce the 2013 regulatory standards while taking steps to remedy California Environmental Quality Act (CEQA) and Administrative Procedure Act (APA) issues identified in the decision.

To address the Court ruling, ARB will bring a new LCFS regulation to the Board for consideration in February 2015. The proposed LCFS regulation will contain revisions to the 2010 LCFS as well as new provisions designed to foster investments in the production of the low-CI fuels, offer additional flexibility to regulated parties, update critical technical information, simplify and streamline program operations, and enhance enforcement.

Although post-2020 goals for the LCFS are not part of this proposed rulemaking, continuing these policies beyond 2020 will ensure that fuel carbon intensity continues to decline and that low-carbon alternatives to petroleum are available in sufficient quantities in the long term. Achieving California's mid and long-term greenhouse gas and air quality goals will require a renewable portfolio of transportation fuels—including electricity and hydrogen—well beyond the current policy trajectories. Accordingly, ARB, in a future rulemaking, will consider extending the LCFS with more aggressive targets for 2030.

Overview

In 2013, Californians used 14.2 billion gallons of gasoline and 3.8 billion gallons of diesel fuel. These traditional fuels will continue to play a role in supporting California's transportation needs for many years to come. At the same time, the production, transport, and use of traditional fuels are responsible for nearly half of the state's greenhouse gas (GHG) emissions; 80 percent of total emissions of oxides of nitrogen (NO_X); and 95 percent of diesel particulate matter (PM) emissions. The primary goal of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in

California by at least ten percent by 2020 from a 2010 baseline, thereby reducing GHG emissions, among other benefits.

The LCFS is a key part of a comprehensive set of programs in California to reduce GHG emissions and other smog-forming and toxic air pollutants from the transportation sector by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options. All of these programs, including the LCFS, are in turn a part of California's overall effort to reduce GHG emissions. The LCFS is designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable alternatives.

The LCFS standards are expressed in terms of the "carbon intensity" (CI) of gasoline and diesel fuel and their substitutes. Although GHG emissions from the use of fuels are primarily carbon dioxide (CO_2), other GHG emissions associated with the complete life cycle of fuels can also include methane, nitrous oxide (N_2O), and other GHG contributors. The overall GHG contribution from all of the steps of the life cycle—production, transport, and use—is divided by the fuel's energy content (in megajoules). Thus, carbon intensity is expressed in terms of grams of CO_2 equivalent per megajoule (gCO_2e/MJ).

The LCFS is designed to encourage the use of cleaner low-carbon fuels in California, encourage the production of those fuels, and, therefore, reduce GHG emissions. The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced.

The LCFS is based on the principle that each fuel has "life cycle" GHG emissions that include CO_2, N_2O, and other GHG contributors. This life cycle assessment (LCA) examines the GHG emissions associated with the production, transportation, and use of a given fuel. The LCA includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels. Subjecting this life cycle GHG rating to a declining standard for the transportation fuel pool in California would result in a decrease in the total life cycle GHG emissions from fuels used in California.

The current LCFS regulation, which staff is proposing to replace in its entirety with a new LCFS regulation, is working as designed and intended. To date, nearly 160 active entities have registered for reporting in the LCFS Reporting Tool (LRT), and since the regulation went into effect, regulated parties have successfully operated under the LCFS program. Furthermore, fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensity, an effect the LCFS regulation is expressly designed to encourage. This is reflected in the large number of applications submitted under the "Method 2A/2B" process. The Method 2A/2B process allows fuel producers to apply for carbon intensity values for their fuels that are lower than the default values found in the LCFS Lookup Tables. To date, more than 230 individual new or modified fuel pathways with substantially lower carbon intensities have been certified. Almost 170 biofuel facilities are registered under the LCFS as supplying low-carbon fuels to California.

Cumulatively through the end of the second quarter of 2014, reporting parties have generated a total of 8.7 million metric tons of LCFS credits and 5.2 million metric tons of deficits, for a net total of 3.5 million metric tons of “excess” credits. Regulated parties as a whole continue to over-comply with the regulation, banking significant excess credits that can be used for future compliance.

Summary of Proposal

Re-adoption of LCFS

As stated above, ARB staff is proposing that the Board re-adopt the LCFS, replacing the current LCFS regulation in its entirety. The proposed LCFS regulation will maintain the basic framework of the current LCFS regulation, including: declining carbon intensity targets; use of life cycle analyses; inclusion of indirect land use change effects; quarterly and annual reporting requirements; and credit generation and trading.

2016 through 2020 Compliance Curves

ARB staff is proposing to retain the existing requirement of reducing the average carbon intensity of California transportation fuels by at least ten percent by 2020. This requirement would apply to both the gasoline standard and the diesel standard. However, staff is proposing to modify interim requirements compared to those adopted in the original LCFS for the years 2016 through 2019. Table ES-1 presents a comparison of the current and proposed percent reduction requirements.

Table ES-1. Comparison of Previous and Proposed Percent Reduction Requirements

Year	Current Reduction Percent	Proposed Reduction Percent
2016	3.5 percent	2.0 percent
2017	5.0 percent	3.5 percent
2018	6.5 percent	5.0 percent
2019	8.0 percent	7.5 percent
2020 onwards	10.0 percent	10.0 percent

ARB staff completed an analysis of the ability of parties regulated by the LCFS to obtain sufficient credits from lower-CI fuels to comply with a ten percent standard by 2020 and to sustain that compliance through 2025. As part of the analysis, staff developed an estimate of the mix of fuels that is expected to be available for use by parties subject to the LCFS. This mix was then used to evaluate the feasibility of alternative compliance curves that achieve a ten percent LCFS reduction goal in 2020.

Cost Containment Provision

The Board directed staff in Resolution 11-39 to incorporate a cost containment provision for providing alternative means to comply with the LCFS standards. The analysis that informed the proposed compliance curves was based on an informed expectation that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. Nonetheless, the LCFS can be enhanced by a cost containment provision that allows regulated parties to achieve compliance under a credit shortfall scenario. A cost containment provision that allows regulated parties to achieve compliance at a pre-determined maximum price will prevent a low-probability, but potentially high-impact, credit shortfall that would make future compliance more expensive than anticipated, and will, thus, protect regulated parties and consumers from fuel price spikes.

Staff proposes the creation of a year-end “credit clearance” process to provide additional compliance options if the LCFS credit market gets tight; to increase market certainty regarding maximum compliance costs; to strengthen incentives to invest in and produce low-CI fuels; and to reduce the probability of credit shortfalls and price spikes. Under this process, regulated parties would be allowed to carry over deficits to the next compliance period, provided that they purchase their pro-rata share of all credits made available for sale during a year-end credit clearance market. This ensures that regulated parties can achieve compliance under all possible credit supply outcomes.

Staff is proposing that the cost containment threshold for 2016 be set at $200 per metric ton of carbon dioxide-equivalent ($MTCO_2e$) and adjusted annually using a Consumer Price Index deflator to keep pace with inflation and remain at a constant price, in real terms. Staff is further proposing that any compliance debt (in $MTCO_2e$) that is carried over into the next compliance year after the annual credit clearance process has been completed be assessed a five percent interest on that debt until such time that the debt is paid off. Furthermore, all deferred deficits must be repaid within five years. These provisions will encourage regulated parties to erase any compliance debts that they may accrue as soon as possible.

Obtaining and Using Fuel Pathways

Based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff in Resolutions 09-31 and 11-39 to consider revisions to the regulation in a number of specific areas, including the approval of additional fuel pathways. Additionally, staff conducted internal reviews of lessons learned and has been assessing what has changed since the initial implementation of the LCFS. It is evident that evaluating fuel pathways is very resource-intensive. Furthermore, stakeholders have expressed concerns that many of the Method 2 pathways in the Lookup Table and on the Method 2 web site are not available for wider use by regulated parties.

To address these issues with fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier. If a Tier 1 fuel is produced using an innovative method, such as the use of low-CI process energy sources, it would move into the second tier. The Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator that computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI. Tier 2 applicants may use one of three methods to obtain a fuel pathway: Tier 2 Lookup Tables, Method 2A, or Method 2B.

The process of obtaining a fuel pathway CI will be further simplified by automating most aspects of the application process. Under that process, all applicants, regardless of Tier, will initiate the application process by completing an LCFS New Pathway Request Form (NPRF). The NPRF is an interactive, web-based form that will be available on the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS) web site. Once the NPRF has been approved, the applicant may begin uploading the required application materials, including version 2 of the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model (CA-GREET) calculations, through the secure LRT-CBTS web interface. Once the fuel pathway has been certified, an automated application process will be available through the LRT-CBTS for obtaining fuel transport mode demonstration approval.

<u>Revised Indirect Land Use Change Values</u>

Carbon intensities are calculated under the LCFS on a full life cycle basis. This means that the CI value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. The CA-GREET model accounts only for such direct effects. In addition to these direct effects, some fuel production processes generate GHGs indirectly, via intermediate market mechanisms. To date, ARB staff has identified an indirect effect that has a measurable impact on GHG emissions: land use change. A land use change effect occurs when demand for a crop-based biofuel brings non-agricultural lands into production. When new land is converted, such conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change (iLUC) impact of increased biofuel production. For the LCFS, iLUC emissions are attributable to biofuels produced from crops.

Based on published work by academics and researchers studying land use change, ARB staff concluded that the land use impacts of crop-based biofuels are significant, and must be included in LCFS fuel carbon intensities. To exclude them would assume that there is zero impact resulting from the production of biofuels and would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and by not accounting for the GHG emissions from land use change, would jeopardize the achievement of a ten percent reduction in fuel carbon intensity by

2020. For the LCFS, staff has identified fuels derived from waste-feedstocks as having zero or small iLUC emissions (or other indirect emissions).

The Board, in Resolution 9-31, directed staff to convene an Expert Work Group to refine and improve iLUC values and return to the Board with those revised values. This rulemaking includes proposed iLUC values pursuant to the Board's direction.

For the current regulatory process, staff has completed iLUC analysis for six biofuels. Table ES-2 provides a summary of the proposed iLUC values.

Table ES-2. Summary of iLUC Values

Biofuel	iLUC (gCO_2/MJ)
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soy Biodiesel	29.1
Canola Biodiesel	14.5
Sorghum Ethanol	19.4
Palm Biodiesel	71.4

Low-Complexity/Low-Energy-Use Refinery Provisions

On December 16, 2011, the Board directed the Executive Officer in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address the lower energy inherently embedded into the transportation fuels from refineries that use simple processes to refine transportation fuels.

Staff investigated two metrics to define a low-complexity/low-energy-use refinery: the Nelson Complexity Index and the total energy use of the refinery. This Nelson Complexity Index is a measure of how simple or complex a refinery is by adding the various process units in the refinery, using their relative complexity values as compared to a distillation unit. Since the LCFS deals with transportation fuels only, the Nelson Complexity Index was modified to exclude lube oil and asphalt capacity. The total energy use of the refinery would include the direct consumption of fuels, as well as imported and exported electricity and thermal energy. Staff is proposing that a refinery must have a modified Nelson Complexity score of five or less and that the annual energy usage would have to be five million MMBtu or less. Each refinery would have to comply with both parts of the metric to be considered a low-complexity/low-energy-use refinery.

Staff investigated the difference in transportation fuel carbon intensity between low-complexity/low-energy-use refineries and the remaining refineries. Staff is proposing to credit the low-complexity/low-energy-use refineries 5 gCO_2e/MJ for both

California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and CARB diesel. Instead of lowering the carbon intensity values for the CARBOB and CARB diesel produced by these refineries—as is done with biofuel production facilities—the credit will be handled in the Reporting Tool to maintain the fungibility of these fuels in the fuels market. All credits generated under this provision must be used by the refinery that generated them and may not be sold to other regulated parties.

Staff is proposing to add reporting requirements for low-complexity/low-energy-use refineries. They are:

- The volume of CARBOB and CARB diesel refined from crude oil;
- The volume of CARBOB and CARB diesel refined from intermediates, including transmix; and
- The volume of CARBOB and CARB diesel purchased for blending.

Refinery-Specific Crude Oil Incremental Deficit Accounting

In December 2011, the Board approved amendments to the LCFS that included using a California Average Crude Oil approach to “hold the line” on the average CI of the crudes that California refineries are processing. Using crudes that have higher CIs over time will erode the efficacy of the LCFS. For the California Average Crude Oil approach, ARB set a baseline average carbon intensity for all of the crudes processed in California refineries in 2010 and then calculated subsequent years’ crude slates to compare with the baseline. If the average crude CI in any subsequent rolling three-year period exceeds the 2010 baseline average CI, all of the refineries are assessed an incremental deficit for which they must compensate by acquiring additional low-CI fuels or LCFS credits. The California Average Crude Oil approach applies to the refining industry as a whole. At the same Board hearing, the Board, in Resolution 11-39, also directed the Executive Officer to evaluate and propose, as appropriate, an option for individual regulated parties to have their incremental deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of crude oils, intermediate products, and finished fuels.

Smaller refineries can be affected by potential California Average incremental deficits generated by the larger refineries, but, because of their low crude throughputs, they cannot affect the California Crude Average carbon intensity. Therefore, staff is proposing to allow low-complexity/low-energy-use refineries to opt out of the California Average Crude Provision in the current LCFS regulation and instead have their crude oil incremental deficit calculated on a refinery-specific basis. The large, complex refineries will continue to operate under the California Average crude oil provision.

The small refineries have been able to provide field-specific volumes for California produced crude supplied to their refineries, and, therefore, staff can readily determine refinery-specific crude carbon intensities. The large refineries report volumes of

California crudes using generic marketing and pipeline names. Because staff does not have information on which fields make up each generic marketing or pipeline name, accurate refinery-specific accounting of crude production emissions is not currently possible for these large refineries. Staff will continue to evaluate the option for refinery-specific incremental deficit accounting for large refineries, but foresees significant challenges in implementing this approach.

The low-complexity/low-energy-use refineries will be allowed a one- time, irreversible opportunity to opt for refinery-specific accounting. A participating refinery will have a refinery-specific incremental deficit assessed if its refinery Annual Crude Carbon Intensity exceeds its refinery 2010 Baseline Crude Carbon Intensity. A participating refinery will also be required to work with staff to properly characterize all crudes supplied to the refinery, including the requirement to report field names and volumes for all California-produced crude that is supplied to the refinery. Refinery-specific accounting will only apply to those volumes of CARBOB and diesel fuel derived from crude oil supplied to the refinery.

Revised Annual Crude Average CI Calculation

The Annual Crude Average CI is a volume-weighted average of crude CI values supplied to California refineries. The crude CI values are those listed in the LCFS regulation, while the crude volumes are those reported by refineries as part of annual compliance reporting. The crude lookup table lists field-specific CI values for crudes produced in and offshore of California. Regulated parties, however, are often supplied California crude in pipelines carrying crude blended from many fields. Because neither staff nor the regulated parties have data that maps crude oil volumes from California fields to pipeline blends, it is not possible to match reported California crude names with CI values from the lookup table.

Instead of using California crude names and volumes reported by refineries, staff proposes, in calculating the Annual Crude Average CI value, that volume contributions for California State fields will be based on oil production data from the California Department of Conservation, and volume contributions for California Federal Offshore fields will be based on oil production data from the Bureau of Safety and Environmental Enforcement.

Data that maps crude oil volumes from fields to pipeline blends is not available, and therefore, it is not possible to as accurately estimate CI values for California pipeline blends as for fields. Assuming all crude produced in California is refined in California, it makes no difference if one calculates a volume-weighted average CI using field production volumes and field CIs or using pipeline blend volumes and pipeline blend CIs. However, since field CI values can be more accurately estimated than pipeline blend CIs, staff is proposing to use field production volumes and CIs for California crude in calculating the Annual Crude Average CI value.

Innovative Technologies for Crude Oil Production

The Board adopted the innovative crude provision as part of the 2011 LCFS amendments. The intent of the provision is to promote the development and implementation of innovative crude oil production methods that reduce GHG emissions. Allowable methods are carbon capture and sequestration (CCS) and solar steam generation. The crude oil producer must apply to the Executive Officer for approval of both the method and the carbon intensity reduction associated with the method. Refineries that purchase the innovative crude generate credits proportional to the carbon intensity reduction achieved by the method. To date, no application has been submitted under this provision, and discussions with stakeholders have revealed several issues.

Staff proposes the following revisions in order to better promote the development and implementation of innovative crude oil production methods:

- The *producer* of the innovative crude may opt in as a regulated party and earn LCFS credits based on the volume of crude supplied to California refineries;

- The 1.0 g/MJ minimum threshold for carbon intensity reduction would be reduced to 0.1 g/MJ. Innovative projects not meeting the 0.1 g/MJ threshold may also be approved if they reduce annual emissions by 5,000 $MTCO_2e$ or more;

- Simplified, default credit calculations for solar-based steam generation and solar-or wind-based power generation would be incorporated into the regulation language; and

- Solar and wind electrical power generation and solar heat generation would be added to the allowable innovative methods. All are in keeping with the intent of the regulation to promote the development and implementation of sustainable fuel sources.

Staff proposes the following revisions to better align the treatment of CCS under the LCFS with the Cap & Trade program:

- CCS as an innovative method would be limited to those instances where the carbon capture occurs onsite at the crude oil production facilities; and

- Credit generation for CCS projects would only be allowed through the use of a Board-approved quantification methodology, including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative crude production method.

Revisions to Oil Production Greenhouse Gas Emissions Estimator (OPGEE) and Updates to the Crude Lookup Table

In 2011, the Board approved OPGEEv1.0 as the model to be used to estimate the carbon intensity for crude recovery and transport of crude to the refinery. During and following the 2011 LCFS amendment process, several stakeholders suggested improvements to the OPGEE model. ARB staff and model developers at Stanford University also discovered areas in which the model could be improved. Moreover, staff is updating the CA-GREET model to a more recent version of GREET published by Argonne National Laboratory (GREET1 2013). Because OPGEE uses GREET to provide many emission factors, life cycle inventory data, and fuel cycle emissions values, staff determined that OPGEE should be updated to be consistent with GREET1 2013 as well.

Staff is also proposing that the revised OPGEEv1.1 be the specific model version to be used for generation of carbon intensity values for crude oil production and transport to California refineries. The OPGEE model version 1.1 will be incorporated in the regulation by reference. Staff is proposing that future revisions of OPGEE occur no more frequently than every three years and that they may be approved through an Executive Officer Hearing.

Because the revisions to the OPGEE model affect the carbon intensity estimates for crude oil production and transport, staff is also proposing revised carbon intensity values for the crudes listed in the Crude Lookup Table, including the 2010 Baseline Crude Average carbon intensity. Proposed revisions to the Crude Lookup Table will include both updated carbon intensity values for listed crudes and expansion of the table to include carbon intensity values for all crudes supplied to California refineries from 2010 to 2013, as well as additional crudes of interest to California refiners.

Credit for GHG Emissions Reductions at Refineries

Staff is proposing to allow refineries to generate credits for investments at the refinery that reduce GHG emissions. This proposed revision is consistent with a proper life cycle analysis, which is a key element of the LCFS.

In the current CA-GREET model, the refinery portion of the life cycle of CARBOB and CARB diesel has fixed values. Treating the refineries the same does not incent GHG reductions—and associated toxic and criteria pollutant emission reductions—at the refinery. To be more consistent with the full life cycle analysis, staff is proposing to allow refineries to generate credits for refinery modifications that are either capital investments or that produce CARBOB or diesel fuel that is partially derived from renewable feedstocks. However, if the proposed projects increase emissions from associated toxic and criteria air pollutants, they would be ineligible for credits under this provision.

For market fungibility purposes, the CI for CARBOB and CARB diesel will remain the same, instead of reducing the CI of the fuels produced—as is done with biofuel production facilities. ARB will issue credits to recognize GHG emission reductions at the refineries.

Staff is proposing that refineries would be eligible to receive credit under this provision for GHG reduction investments that occur in 2015 and beyond and result in a CI reduction of 0.1 gCO_2e/MJ or more for CARBOB or CARB diesel.

Enhancements to Reporting and Recordkeeping Requirements

The term PTD (Product Transfer Document) is defined loosely in the current regulation, and referred to in the current LCFS variously as a singular item and elsewhere as a collection of documents, including Bills of Lading (BOL), invoice, contracts, meter ticket, rail inventory sheet, Renewable Fuels Standard (RFS2) product transfer documents, etc. Collectively, the PTDs authenticate the transfer of ownership of a fuel from the transferor to the transferee. The regulation defines the data to be reported from these various documents in multiple sections of the regulation. Perhaps due to confusion regarding these documents, counterparties to a series of transactions have reported different information to ARB regarding the same transactions. The parties and ARB have had to devote additional resources toward reconciling conflicting reports.

Staff proposes consolidating the following important reporting parameters in the PTD for improved recordkeeping:

- Transfer Information
  - Date of title transfer. For aggregated transactions, the quarter end date.
  - Transferor company name, address and contact information
  - Transferee company name, address and contact information
  - A statement identifying whether the LCFS Obligation is retained by transferor or passed to the transferee
- Fuel Information
  - Fuel Pathway Code (FPC) (synonymous with Pathway Identifier) and Carbon Intensity
  - Volume (gallons or other unit amounts as appropriate)
- Fuel Production Facility Information. Alternative Fuel Production Company ID and Facility ID as registered with RFS2 program and/or LCFS program. If an alternative fuel production facility is not registered with either the federal RFS2 or

LCFS, the administrator of the LRT-CBTS will provide appropriate IDs for use on PTDs.

- A notice to the buyer as follows where fuel is sold without obligation:

  "This transportation fuel has been reported to the ARB LCFS Program by <*Insert name of Reporting Party holding LCFS obligation*> for intended use in California. Any export of this fuel from California by any subsequent owner or supplier must be reported to the ARB LCFS Program (www.arb.ca.gov/lcfsrt). Contact the ARB LCFS Administrator for assistance with reporting exported volumes (lrtadmin@arb.ca.gov)."

To improve the traceability of fuels to the fuel source, as well as to confirm the obligation "endpoint" in the transfer of LCFS regulated fuels, staff is proposing to require LCFS reporting by all entities in the chain of custody that held obligation for a fuel. This includes initial regulated parties, as well as those that acquired the LCFS obligation from upstream entities. Such entities are collectively referred to as "reporting parties" in the proposed regulation. Furthermore, all transaction types associated with the obligation transfer are to be reported. This includes reporting transaction where fuel is "Sold without Obligation Transfer" and where it is "Purchased without Obligation Transfer." The reported transactions are to include the identification of the business partners in these transactions.

The current LCFS requires records to be retained for three years. Given the time lag involved in developing and processing pathway applications and subsequent reporting and credit transactions, it is likely that reporting issues may need to be resolved for transactions that occurred more than three years ago; therefore, pertinent information contained in documents associated with those transactions must be maintained. Staff proposes to increase the record retention requirements of the LCFS Program to five years from the current three-year retention requirement.

Regulated parties have indicated that the 60-day period for compiling and reconciling their quarterly data in preparation for submittal is not sufficient to ensure the 100 percent accuracy in reporting that ARB requires. The result is that there are currently more post-submittal correction requests made by regulated parties than would be necessary if more time was provided for reporting parties to thoroughly complete the reconciliation of volumes, reporting of FPCs, and obligation transfer with their business partners. The regulatory language would be changed to provide a "45/45 Schedule." This revised schedule would provide a 45-day period for all reporting parties to upload their quarterly data in the LRT-CBTS. The second 45-day period would be for reporting parties to reconcile their reporting with that of their business partners prior to their official quarterly report submittal. As a result, the deadlines for all quarterly reports would be extended by one month. The annual reporting deadline would remain April 30th.

There is a need to have a standardized process for converting volumes of compressed natural gas (CNG) and liquefied compressed natural gas (L-CNG) dispensed in gallons to volumes in standard cubic feet (scf); therefore, staff is proposing that an equation for converting volumes of CNG and L-CNG be specified in the regulation, which will incorporate standard conversion factors from GREET for converting pounds of CNG and L-CNG to standard cubic feet for reporting purposes.

There is a need to clearly define the requirements for reporting parties when requesting to have a previously submitted report reopened for purposes of making corrective edits; therefore, staff is proposing a requirement that the reporting party submit an Unlock Report Request Form online in the LRT-CBTS. This form would be accompanied by a letter on letterhead from someone authorized to represent the reporting party with justification for the report corrections and a description of the specific corrections that are to be made to the reopened report.

Exported fuels that at one time had an associated obligation need to be more thoroughly tracked in the LRT-CBTS, so they are not exported outside California without the export being reported. This will ensure that credits and deficits associated with these exported fuels can be eliminated. Staff is proposing that a notice would be provided by the transferor of the fuel within the PTD where the fuel obligation is not transferred to inform the buyer that a fuel has been reported to the California LCFS Program as intended for use in California, and any export of that fuel from California by any subsequent owner or supplier must be reported back to ARB. The original transferor would be required to report this in the LRT-CBTS.

Enhancements to LCFS Credit Provisions

Staff is proposing to require use of the online LRT-CBTS for initiating and completing all credit transfers. Although the current regulatory text does not explicitly require use of the online system, it has become the *de facto* standard for recording credit transfers. The proposal would formalize this requirement and specify the current online system as the repository for all LCFS credit transactions, as well as quarterly and annual reports. Further, a hierarchy for retiring credits is being provided.

Additionally, staff proposes to clarify that there will not be retroactive credit generation except in very narrow circumstances that include some situations, but not all, where review of a pathway application or Fuel Transport Mode demonstration has been delayed by ARB rather than the applicant.

Other proposed revisions would stipulate that all LCFS credits are to be calculated in the LRT-CBTS, thus aligning the regulation with current practices. The provisions for designating credits as “pending” for lack of fuel transport mode demonstration purposes will be included for handling these credits.

LRT-CBTS: Requirements to Establish an Account

The LRT-CBTS currently has only a few data requirements to create a user profile and establish a user account in the secure online system. Some entities have registered in the system because they mistakenly thought that the LCFS regulation applies. Under current LCFS provisions, staff has limited means to deactivate a user account when data are not reported. Staff proposes a mandatory registration process that will clearly identify an entity's authorized users, as well as screen entities that do not need accounts.

The proposal requires that each registering entity assign a primary and secondary account administrator to manage its account at the time of registration. The account administrators are responsible for submitting all reports and credit transactions for their organization. They would have the capability to view the entire organizational profile. The administrators can designate other users to upload and review data for quarterly reports, but such designated users cannot submit the reports, a function belonging to only the account administrators. Account administrators may also designate other company users to facilitate credit transfers or allow brokers to transact credits on behalf of their organization. Credits can reside only in an organization's account; brokers simply aid in the credit exchange. The enhanced process for establishing an account would be available for use in the LRT-CBTS when the regulation goes into effect. Many of the entities that are currently reporting into LRT-CBTS would be able to continue using their accounts, but they would need to provide any missing user profile information within 90 days of the regulation's effective date.

Additional Electricity Provisions

The current regulation allows regulated parties to generate credits for electricity used in on-road vehicles only. The Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing credits for non-road, electricity-based transportation sources, including mass transit. As a result, staff has worked with stakeholders to develop a proposal to make electricity used in fixed guideway transit systems and electric forklifts eligible to generate credits.

In considering potential off-road categories to add to the regulation, staff identified fixed guideway transit systems and electric forklifts as categories of electric transportation that use significant and quantifiable electricity for transportation. Transit agencies report the electricity used for propulsion of fixed guideway systems annually to the National Transit Database, and electricity used to charge forklifts can be estimated with available data. Providing an opportunity for credit generation for use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce the carbon intensity of the transportation fuel pool in California, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels.

Electric forklifts, including motorized hand trucks, have taken a larger market share nationwide than internal combustion engine (ICE) forklifts powered by gasoline, propane, CNG, or diesel fuel in recent years. An increase in electric forklift use coupled with a decrease in ICE forklift is expected to result in decreased GHG emissions and contribute to meeting the goals of the LCFS program.

To date, many EV drivers have elected not to install dedicated EV meters at their residences. The current LCFS regulation allows electricity providers for residential EV charging to use an estimation method, subject to Executive Officer approval, to approximate residential EV charging electricity until January 1, 2015, when direct metering is required. A proposed revision to be included in the new LCFS regulation would remove the direct-metering requirement and allow estimation after January 1, 2015.

Energy Economy Ratio (EER) values for fixed guideway and forklift electricity have not previously existed in the LCFS regulation. Including values in the regulation for these sources of electricity is necessary for the calculation of generated credits. Staff is proposing to bifurcate the EER values for heavy-duty electric vehicles into two separate EER values, one for heavy-duty trucks and one for buses. Staff is proposing to include the current value of 2.7 for trucks due to the lack of available efficiency data for these vehicles. Staff is also proposing to include an EER value of 4.2 for electric buses, based on drive cycle testing in a controlled setting.

The current regulation requires regulated parties for residential and public EV charging to include public accounting of the number of credits generated, sold, and banked in annual compliance reporting. Public credit accounting is not required of regulated parties of other fuels and is unnecessary for electricity. Staff proposes to remove this requirement.

Enforcement-Related Provisions

Current provisions authorizing the Executive Officer to assign, hold, or reverse credits in various situations are scattered through various parts of the regulation, making it difficult to navigate the related provisions. Staff proposes language that explicitly empowers the Executive Officer to suspend, revoke, or restrict an LRT-CBTS account when violations have occurred or are being investigated. Such provisions could be used, for example, to prevent transactions involving credits subject to investigation regarding their authenticity.

A second enforcement-related issue with the current LCFS is the non-specific enforcement provisions. Given the existing per-day penalty statutes in Health and Safety Code (H&S) sections 43025 et seq., the current LCFS is not well-suited to address violations based on year-end deficits. The H&S provides for daily penalties for each violation, up to maximums that vary for strict liability, negligence, and intentional violations. While those provisions should work well for some LCFS violations, such as submitting a late or inaccurate report, a per-day approach is an awkward tool with which to address substantive deficit violations on an annual basis. For example, a party that reported transactions resulting in a net deficit of 40 metric tons of CO_2e at the end of a given compliance year would have the same number of violations (365) as a party that ended the same year with 40,000 deficits.

Where a party violates the LCFS by failing to match each deficit with a credit by the end of a compliance period, staff is proposing to define each net deficit as a separate violation. That approach, authorized by H&S section 38580, subdivision (b)(3), allows the punishment to fit the crime. Such an approach allows courts to more fairly differentiate between the small- and large-volume fuel suppliers regulated under the LCFS. Under California law, the maximum penalty is presumed to apply absent a showing by the violator that mitigating circumstances make a lesser amount appropriate. *People ex rel State Air Resources Board v. Wilmshurst* (1999) 68 Cal.App.4th 1332. The applicable statute for fuels violations makes a violator strictly liable for a penalty of up to $35,000. As the presumptive penalty, $35,000 is a large consequence for lacking one credit, the value of which is determined by supply and demand in the LCFS market, but which, for cost containment purposes, is proposed to be capped at $200. For that reason, along with defining violations in terms of deficits, staff is proposing to set the presumptive per-deficit penalty at a maximum of $1,000.

While regulated parties should already understand that violations of LCFS provisions are already subject to per-day penalties, the proposed regulation expressly underscores that inaccurate, incomplete, or late reports constitute a violation for each and every day that the report remains inaccurate, incomplete, or late.

Regulated Party Miscellaneous Updates

Diesel is both a finished fuel and a blendstock and, as such, the compliance obligation may be retained or passed along by the producer or importer of the fuel. However, there are cases where downstream parties who purchase "at or below the rack" (i.e., non-bulk transfers) are receiving the obligation with knowledge as it would be stated on the Product Transfer Document. These downstream entities could be retail outlets and end users and would likely not have the means to comply with the regulation. Staff is proposing that the diesel obligation transfer to only occur "above the rack." This provision would align with the current gasoline provision where end users and retail outlets could not receive an obligation.

Liquefied natural gas (LNG) can be brought to a CNG dispensing station where it is then converted back to CNG before being dispensed into the vehicle for use. (The LNG-to-CNG natural gas is referred to as L-CNG.) The current regulation does not clearly identify the regulated party for such situations. Under the current regulation, the initial regulated party for LNG is the provider of the LNG to the dispensing station, whereas the initial regulated party for CNG is the owner of the dispensing equipment. Staff is proposing a definition for L-CNG and that the regulated party for L-CNG fuel be aligned with LNG, where the initial regulated party is the owner of the LNG when it is delivered to a CNG station.

Potential Impacts of the Proposal

Environmental Impacts

As mentioned, on July 15, 2013, the State of California Court of Appeal, Fifth Appellate District (Court) issued its opinion in *POET, LLC v. California Air Resources Board* (2013) 218 Cal.App.4th 681 (POET vs. ARB). The Court left the LCFS in place, holding that ARB could continue to implement and enforce the 2013 regulatory standards while it worked to re-adopt the LCFS to address the CEQA and APA issues associated with the original adoption of the regulation.

The Court held that a proposal to address potentially significant impacts of nitrogen oxides (NO_X) associated with biodiesel use through a future rulemaking constituted improperly deferred mitigation. The proposed regulation on the commercialization of alternative diesel fuels (ADF) includes in-use requirements and fuel specifications for biodiesel that would, among other things, ensure that the proposed LCFS regulation would not result in increased NO_X emissions compared to current conditions and ensure that past increases in NO_X emissions from biodiesel in comparison to ARB decrease in following years. The proposed ADF regulation would also establish a regulatory process for other emerging diesel fuel substitutes to enter the commercial market in California, while managing and minimizing environmental and public health impacts and preserving the emissions benefits derived from ARB vehicle and fuel regulations.

To address the Court's 2013 ruling and achieve the State's objectives with the two regulations, ARB staff is proposing that the Board take the following actions in 2015: adopt the proposed ADF regulation; set aside adoption of the original LCFS regulation; and re-adopt the proposed LCFS regulation (including revisions to the original regulation). The proposed LCFS regulation and the proposed ADF regulation are analyzed in a Draft Environmental Analysis (EA) to meet CEQA requirements under ARB's certified regulatory program. The Draft EA is located in Appendix D.

The proposed LCFS and ADF regulations will be considered by the Board in separate proceedings. However, the two regulations are being analyzed as one project under CEQA because they are interrelated in two important ways: 1) the proposed ADF regulation defines specifications for biodiesel, which is among the low-carbon fuels that LCFS encourages, and 2) compliance responses by fuel producers and suppliers would be influenced concurrently by both regulations. Assessing them together captures the compliance responses, which are the physical actions reasonably expected to occur in response to the proposed regulatory action, without regard to whether they are attributable to the LCFS, ADF, or a combination of the two proposed regulations. This approach is consistent with CEQA's requirement that an agency consider the whole of an action when it assesses a project's environmental effects, even if the project consists of separate approvals.

The existing LCFS regulation, established in previous rulemakings, defines the current requirements for the CI of fuels in California. CEQA states the baseline for determining the significance of environmental impacts will normally be the existing conditions at the time the environmental review is initiated. Therefore, significance determinations reflected in the Draft EA are based on a comparison of the potential environmental consequences of the proposed regulations with the existing regulatory setting and physical conditions in 2014.

In combination with other state and federal GHG-reduction programs (the state Advanced Clean Cars and Pavley Vehicle Standards programs; the U.S. Environmental Protection Agency's Renewable Fuel Standard 2 and Corporate Average Fuel Economy programs), implementation of the proposed LCFS and ADF regulations is anticipated to result in environmental benefits that include an estimated reduction in GHG emissions of more than 60 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) from transportation fuels used in California from 2016 through 2020. On its own, the LCFS is estimated to reduce transportation-related GHG emissions by 35 MMT during those years.

The proposed LCFS regulation includes annual CI compliance requirements that have been revised from the existing regulation. The required reduction in the CI of the transportation fuel pool would be expected to result in annual GHG emissions reductions as shown in Table ES-3.

Table ES-3: Projected LCFS GHG Emissions Reductions

	2016	2017	2018	2019	2020
$MMTCO_2e$	6.0	8.8	11.6	16.2	20.7

For the purpose of determining whether the proposed regulations have a potential adverse effect on the environment, ARB evaluated the potential physical changes to the environment resulting from a reasonable foreseeable compliance scenario for the proposed LCFS regulation. Approval and implementation of the proposed LCFS regulation would result in re-adoption of an LCFS with the revisions described above. The environmental effects of the proposed LCFS regulation would, therefore, build upon the compliance responses of the existing LCFS regulation. In many instances, compliance responses associated with the proposed LCFS regulation would be a variation of actions that are already occurring.

Implementation of the proposed LCFS is anticipated to provide incentives for various projects, including: processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. The proposed regulations could also incent minor expansions to existing operations, such as collection of natural gas from landfills, dairies, and wastewater treatment plants; modifications to crude production facilities (onsite solar, wind, heat, and/or steam generation electricity); and installation of energy management systems at refineries. In addition, LCFS credits could be generated through development of CCS facilities and operation of expanded fixed guideway systems.

Because the authority to determine project-level impacts and required project-level mitigation lies with land use and/or permitting agencies for individual projects, and the programmatic level of analysis associated with the Draft EA does not attempt to address project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation that may ultimately by implemented.

Consequently, while impacts could be reduced to a less-than-significant level by land use and/or permitting agency conditions of approval, the Draft EA takes the conservative approach in its post-mitigation significance conclusions and discloses, for CEQA compliance purposes, that impacts from the development of new facilities or modification of existing facilities associated with reasonably foreseeable compliance responses to the proposed LCFS regulations could be potentially significant and unavoidable.

The Draft EA also states that the proposed regulations could result in less than significant or no impacts to mineral resources, population and housing, public services, and recreation; and potentially significant and unavoidable adverse impacts to aesthetics, agriculture resources, biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, transportation and traffic, and utilities, and short-term construction-related air quality impacts primarily related to the construction projects and minor expansions to existing operations that are reasonably foreseeable as a result of the proposed regulations.

Potential Economic Impacts

The LCFS has a range of potential economic impacts. They include direct costs to regulated parties, which are described below, and a broader set of macroeconomic impacts across California's economy. For example, the LCFS supports the growth of businesses and industries in California and elsewhere that are supplying lower carbon fuels, including renewable natural gas, advanced biofuels and others. It will also likely reduce compliance costs under California's Cap-and-Trade program for regulated entities that are subject to both regulations.

Additionally, the LCFS will help reduce costs associated with petroleum dependency in California, and the health and the climate change impacts of petroleum use in California's transportation sector. These benefits are not quantified in this analysis, but some studies suggest they are significant, potentially several times greater in magnitude than the direct economic costs to regulated parties.

Cost to Regulated Parties

The proposed LCFS is a fuel-neutral, performance-based regulation that allows regulated parties to find the most cost-effective approaches to compliance. In choosing a least-cost compliance strategy, regulated parties can generate credits by blending low-CI fuels with hydrocarbon blendstocks or purchase credits from the open market, or both. They can over-comply with annual LCFS standards—especially in the early years of the program—and generate "excess" credits that can be banked and used for compliance needs in later years, when the LCFS standards are more stringent.

The direct costs of the proposed LCFS can be calculated as the difference in the cost of producing the volumes of low-CI fuels required for compliance with the regulation and the cost of producing the fuels that would have been consumed without the proposed regulation. Some of these costs may be estimated from available studies, but much of this cost data is confidential business information, especially for nascent technologies just entering the commercial market. Therefore, to gauge a range of potential costs, staff analyzed three cases, based on current credit prices of $25, historical 2012-2013 average prices of $57, and a higher assumed price of $100.

Using these cases and the annual deficits anticipated to be generated by the proposed compliance curve as shown in Table ES-3, staff estimated a range of potential direct compliance costs (Table ES-4).

Table ES-4. Potential Range of Direct Costs of Compliance (million $)

LCFS Credit Price	2016	2017	2018	2019	2020
$25 (current price)	$150	$221	$291	$406	$517
$57 ('12-'13 average)	$343	$504	$663	$925	$1,178
$100	$601	$885	$1,163	$1,622	$2,066

*All credits are assumed to be sold at the same price.

Cost to Businesses and Individuals

Given the anticipated transportation fuel demand during this period, the maximum cost-per-gallon impacts are estimated based on the assumption that all costs to the regulated parties are passed onto customers. This assumption may be conservative because under competitive market conditions, some companies may not entirely pass on costs of compliance to their customers. Table ES-5 illustrates the maximum per-gallon price impact using these assumptions.

Table ES-5. Range of Estimated Fuel Price Impacts

Credit Price	Fuel	2016	2017	2018	2019	2020
$25	Gasoline	$0.009	$0.013	$0.017	$0.024	$0.030
	Diesel	$0.007	$0.012	$0.017	$0.026	$0.035
$57	Gasoline	$0.021	$0.030	$0.039	$0.054	$0.068
	Diesel	$0.016	$0.027	$0.039	$0.059	$0.079
$100	Gasoline	$ 0.036	$ 0.052	$ 0.068	$ 0.094	$ 0.120
	Diesel	$ 0.028	$ 0.048	$ 0.069	$ 0.104	$ 0.139

* All credits are assumed to be sold at the same price

The potential impact of the LCFS to businesses and individuals depends on how much of any compliance costs regulated parties pass onto them, and how much transportation fuel those businesses and individuals use. Businesses such as delivery services and taxis would be more impacted than businesses that use less fuel.

As an illustrative example, if a small business has a gasoline vehicle fleet that travels 100,000 miles annually and achieves an average fuel mileage of 25 miles per gallon, that business would consume 4,000 gallons of fuel in a year. Based on the values in Table ES-5, the cost impact might range from $52-208 in 2017 and $120-480 in 2020. An individual driving 12,000 miles with an average fuel economy of 30 miles per gallon would consume 400 gallons per year and potentially experience increased fuel costs of $5-21 in 2017 and $12-48 in 2020.

Businesses and individuals can reduce—and have reduced—their transportation expenses by purchasing or leasing more efficient or alternative-fueled vehicles that operate on less expensive fuels, such as electricity and natural gas. As the price of these vehicles continues to decrease, there will be greater opportunities for reduced transportation expenses. In fact, ARB estimates that per-capita fuel costs in California will decrease by up to several hundred dollars from current levels by 2020.

Fiscal Impacts on State and Local Governments

As with the impacts on businesses and individuals, the LCFS could potentially impact the fuel expenditures by state and local agencies. The illustrative examples for fuel cost impacts on businesses and individuals describe a range of potential impacts of state and local government fleets, as well.

On the other hand, because of the increase in price of petroleum diesel, gasoline, and their alternatives due to the conservatively assumed full-pass through of the theoretical credit price (in this example, $100), there would be increases in the local revenue collected from sales tax. While the magnitude of the increase depends on the credit price and varies depending upon the tax rate in the locality, ARB estimates a total change of $4 million in 2016 to $15 million in 2020. These results vary greatly depending on the local tax rate, the consumption patterns of consumers in these areas, the realized credit price, and the amount of the credit price that is passed on to consumers.

Similarly, there would be increases in the State revenue collected from sales tax. ARB estimates a total increase in state revenues of $11 million in 2016 and up to about $42 million in 2020. These results vary greatly depending on the realized credit price and the amount of the credit price that is passed on to consumers. Additionally, excise taxes are reduced due to reductions in diesel consumed amounting to a reduction in excise taxes of $7 million in 2016 and $2 million in 2020. Overall, the impact to the State budget, based on the theoretical compliance scenario is an increase of $4 million in 2016 and $40 million in 2020. (See Table ES-6 below.)

Table ES-6: Impacts on State and Local Tax Revenue (Millions 2014$)

	2016	2017	2018	2019	2020
State					
Total Change for State (Excise)	-7	-5	-4	-3	-2
Total Change for State (Sales)	11	17	23	33	42
Local					
Total Change for Local (Sales)	4	6	8	12	15

Macroeconomic Analysis

For a major regulation proposed on or after January 1, 2014, a standardized regulatory impact analysis (SRIA) is required. (A major regulation is one "that will have an economic impact on California business enterprises and individuals in an amount exceeding fifty million dollars ($50,000,000), as estimated by the agency." (Govt. Code Section 11342.548). The LCFS proposal was determined to be a major regulation because the direct cost of compliance exceeds $50 million in all years analyzed, 2016 through 2020; therefore, ARB prepared a SRIA and submitted it to the Department of Finance in October 2014.

As with the Environmental Assessment, the macroeconomic impact analysis considers both the re-adoption of the LCFS and the adoption of the ADF regulation. Macroeconomic impacts are modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. ARB used the REMI PI+ model for this analysis—a one-region, 160-sector model that has been modified by the Department of Finance to include California-specific data for population, demographics, and employment.

The macroeconomic impacts of the LCFS and ADF proposed regulations are negligible, considering the size and diversity of California's economy. In the $100/MT credit price case, ARB estimates the LCFS and ADF proposals will have a combined impact of reducing the growth in California's Gross State Product by less than 0.06 percent annually from 2016 through 2020. As modeled, the LCFS/ADF proposal will have very small impacts on employment growth from 2016 through 2023, reducing annual growth rates by 0.01 percent to 0.07 percent. At lower credit prices, any negative macroeconomic impacts would be even smaller.

I. INTRODUCTION AND BACKGROUND

In this chapter, the Air Resources Board (ARB/Board) staff provides a brief overview of the Low Carbon Fuel Standard (LCFS), information on the implementation of the LCFS program, and the specific purpose for its re-adoption with proposed revisions.

The Board approved the LCFS regulation in 2009 as a discrete early action measure under the California Global Warming Solutions Act of 2006 (AB 32). The goal of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in California by at least ten percent by 2020 from a 2010 baseline, thereby reducing greenhouse gas emissions, among other benefits discussed below. ARB approved revisions to the LCFS in December 2011, which became effective on November 26, 2012, and were implemented by ARB on January 1, 2013.

On July 15, 2013, the State of California Court of Appeal, Fifth Appellate District (Court) issued its opinion in POET, LLC versus California Air Resources Board (2013) 218 Cal.App.4th 681, resulting in a stay of the LCFS. The Court held that the LCFS adopted in 2009 and implemented in 2010 (referred to as 2010 LCFS) would remain in effect and that ARB could continue to implement and enforce the 2013 regulatory standards while taking steps to remedy California Environmental Quality Act (CEQA) and Administrative Procedure Act (APA) issues as required in the ruling.

To address the court ruling, ARB will bring a revised LCFS regulation to the Board for consideration in February 2015. The proposed LCFS regulation will contain revisions to the 2010 LCFS as well as new provisions designed to foster investments in the production of the low-CI fuels, offer additional flexibility to regulated parties, update critical technical information, simplify and streamline program operations, and enhance enforcement.

Additional information on the LCFS regulation and its underlying principles can be found in the 2009 staff report[1] prepared for the adoption of the LCFS regulation and in the 2011 staff report[2] prepared for amendments of the LCFS regulation.

A. Overview of the LCFS Regulation

Transportation fuels play a key role in California's economic success, as well as the lifestyle of its residents. In 2013, Californians used 14.2 billion gallons of gasoline and 2.7 billion gallons of diesel fuel. These traditional fuels will continue to play a role in supporting California's transportation needs for many years to come. At the same time, the production, transport, and use of traditional fuels are responsible for nearly half of the state's greenhouse gas emissions. The LCFS is a key part of a comprehensive set

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[1] See Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard." March 5 (2009), and Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard Volume II." March 5 (2009)

[2] See Staff Report: Initial Statement of Reasons: Proposed Amendments to the Low Carbon Fuel Standard." October 26 (2011)

of programs in California to reduce GHG emissions and other smog-forming and toxic air pollutants by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options.[3] The LCFS is designed to decrease the carbon intensity of California's transportation pool and provide an increasing range of low-carbon and renewable alternatives.

On April 23, 2009, the Board approved the LCFS for adoption, aiming to reduce GHG emissions by achieving a ten percent reduction in the carbon intensity of transportation fuels used in California by 2020. Carbon intensity (CI) is a measure of the GHG emissions associated with the various production, distribution, and consumption steps in the "life cycle" of a transportation fuel. The regulation became effective on January 12, 2010, with additional provisions becoming effective on April 15, 2010. The first year of the program, 2010, was a reporting year, and the actual implementation of the carbon intensity requirements and compliance schedules began on January 1, 2011.

Providers of transportation fuels (referred to as regulated parties) must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period. They must report all fuels provided and track the fuels' carbon intensity through a system of "credits" and "deficits." Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that amount of credits it earns (or otherwise acquires from another party) is equal to, or greater than, the deficits it has incurred. Credits and deficits are generally determined based on the amount of fuel sold, the carbon intensity of the fuel, and the efficiency by which a vehicle converts the fuel into useable energy. The calculated metric is tons of GHG emissions. This determination is made for each year between 2011 and 2020. Credits may be banked and traded within the LCFS market to meet obligations.

The LCFS standards are expressed in terms of the "carbon intensity" of gasoline and diesel fuel and their substitutes. Although primarily carbon dioxide (CO_2), GHG emissions from each step can also include methane, nitrous oxide (N_2O), and other GHG contributors. The overall GHG contribution from all steps is divided by the fuel's energy content (in megajoules). Thus, carbon intensity is expressed in terms of grams of CO_2 equivalent per megajoule (gCO_2e/MJ).

The LCFS is designed to encourage the use of low-carbon fuels in California, to encourage the production of those fuels in California and elsewhere, and, therefore, to reduce GHG emissions. The LCFS is performance-based and fuel neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced.

[3] See First Update to The Climate Change Scoping Plan, Building on the Framework" (2014) Pursuant to AB 32, The California Global Warming Solutions Act of 2006.

The LCFS is based on the principle that each fuel has "life cycle" GHG emissions that include CO_2, N_2O, and other GHG contributors. This life cycle assessment (LCA) examines the GHG emissions associated with the production, transportation, and use of a given fuel. The LCA includes direct emissions associated with producing, transporting, and using the fuels, as well as significant indirect effects on GHG emissions, such as changes in land use for some biofuels. Subjecting this life cycle GHG rating to a declining standard for the transportation fuel pool in California would result in a decrease in the total life cycle GHG emissions from fuels used in California.

A more complete description of how the LCFS regulation is designed to work, as well as its underlying scientific and economic principles, can be found in the initial and final statements of reasons for the original rulemaking.[4]

On December 15, 2011, the Board approved amendments to the LCFS. The regulatory amendments became effective on November 26, 2012, and were implemented by ARB on January 1, 2013.[5] The amendments addressed several aspects of the regulation, including: crude oil provisions, reporting requirements, credit trading, regulated parties, opt-in and opt-out provisions, definitions, and other clarifying language. The basic structure of the program and the compliance schedule remained unchanged.

B. Implementation Status of the LCFS Program

Since the Board approved the LCFS in April 2009 and approved amendments in December 2011, staff has continued to collaborate with stakeholders to help enhance the implementation of the program.

Since 2010, the LCFS has mandated that all regulated parties report required data on a quarterly and annual basis. To facilitate the electronic reporting of vast amounts of transactional data, staff developed the LCFS Reporting Tool (LRT) for reporting fuel volumes and other data. The LRT has been operational since early 2010 and has been used by regulated parties in its full production mode since December 2010. The LRT is accessible for electronic reporting by all regulated parties.[6] Because the LRT has been the only means regulated parties have used for LCFS reporting, it became the *de facto* method for electronic reporting and became a requirement to report during the 2011 amendments. Since then, staff developed the Credit Bank & Transfer System (CBTS) to move from the paper-based credit transfers used before the electronic system.

The LCFS is working as designed and intended. To date, more than 155 active entities have registered for reporting in the LRT, and since the regulation went into effect, regulated parties have successfully operated under the LCFS program. Furthermore,

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[4] See Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard." March 5 (2009); Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard Volume II." March 5 (2009); and Final Statement of Reasons for Rulemaking, Including Summary of Public Comments and Agency Responses." December (2009)
[5] Title 17, California Code of Regulations (CCR), sections 95480-95490.
[6] ARB, Low Carbon Fuel Standard Reporting Tool and Credit Bank & Transfer System

fuel producers are innovating and achieving material reductions in their fuel pathways' carbon intensity, an effect the LCFS regulation is expressly designed to encourage, which is reflected in the large number of applications submitted under the "Method 2A/2B" process. The Method 2A/2B process allows fuel producers to apply for carbon intensity values for their fuels that are lower than the default values found in the LCFS Lookup Tables. To date, 233 individual new or modified fuel pathways with substantially lower carbon intensities have been certified. Almost 170 biofuel facilities are registered under the LCFS as supplying low carbon fuels to California.

Cumulatively through the end of the second quarter of 2014, reporting parties have generated a total of about 8.7 million metric tons of LCFS credits and 5.2 million metric tons of deficits, for a net total of about 3.5 million metric tons of "excess" credits. Regulated parties as a whole continue to over-comply with the regulation, providing significant excess credits that can be used for future compliance. Additional summaries of quarterly data[7] and credit trading activity reports[8] may be found on the LCFS web site.

Credits have been generated from ethanol (60 percent), renewable diesel (15 percent), biodiesel (13 percent), natural gas (ten percent), and electricity (two percent). About 200 million gallons of renewable diesel and biodiesel and 150 million diesel gallon equivalent (DGE) of compressed natural gas (CNG) and liquefied natural gas (LNG) were brought into California for fuel use. Additionally, renewable natural gas has quadrupled in growth, and there has been 200 million gallons per year of low-CI ethanol.

Approximately 440 LCFS credits transactions were recorded through June 2014. The LCFS credit prices, which started at $10 to $15 per metric ton of carbon dioxide equivalent ($MTCO_2e$), have risen to $50 to $85 per $MTCO_2e$, but have declined to as low as $27 per $MTCO_2e$ as the 2013 LCFS compliance curves have been temporarily frozen in place by a California Court of Appeal decision. (See below.) A healthy LCFS program depends on having a robust credit market that has clarity, certainty, transparency, and accountability—one that instills confidence in its participants.

The successful implementation of California's LCFS program has generated interest in adopting LCFS programs in other jurisdictions. British Columbia has an LCFS program, and Oregon and Washington are pursuing LCFS programs. In the October 2013 Pacific Coast Collaborative (PCC) Pacific Coast Action Plan on Climate and Energy, British Columbia, Washington, Oregon, and California committed to work together to build an integrated West Coast market for low carbon fuels. The PCC is an example of recent progress towards harmonization of California's LCFS with similar programs in other states and jurisdictions. At the federal level, Congress adopted a renewable fuels standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA). As ARB developed the LCFS regulation, staff worked with the United States Environmental Protection Agency

[7] See Low Carbon Fuel Standard Reporting Tool Webpage: Quarterly Summaries.
[8] See Low Carbon Fuel Standard Reporting Tool Credit Webpage: Trading Activity Reports

(U.S. EPA) in an effort to harmonize the respective fuel programs in a number of critical areas, such as the inclusion of indirect impacts associated with land use changes. Harmonizing fuel programs between state, federal, and foreign jurisdictions is useful to ensure the optimum reduction of CI and associated GHG emissions. Similar program frameworks reduce the possibility of fuel shuffling across different jurisdictions, and they reduce the administrative burden for both regulated parties and regulatory agencies. The concept of harmonizing specific aspects of the LCFS program with other low carbon fuel standard programs has, therefore, been of interest for staff since the inception of the program.

C. Specific Purpose for the Proposed Re-Adoption

On July 15, 2013, the State of California Court of Appeal issued its opinion in *POET, LLC versus California Air Resources Board* (2013) 218 Cal.App.4th 681. The Court of Appeal held that the LCFS would remain in effect and that ARB can continue to implement and enforce the 2013 regulatory standards while it takes steps to cure the CEQA and the APA issues associated with the original adoption of the regulation. To address the ruling and provide lasting market certainty, ARB staff is proposing that the Board re-adopt the LCFS regulation. Additionally, ARB staff is proposing a suite of updates and revisions compared to the current regulation to provide a stronger signal for investments in, and production of, the cleanest fuels, offer additional flexibility, update critical technical information, and provide for improved efficiency and enforcement of the regulation.

It has been nearly five years since the Board's original action, and the core principles and policies of the LCFS regulation remain valid. The basic framework of the current LCFS, including the use of life cycle analysis, the LCFS credit market, and the LCFS Reporting Tool, among other aspects, are working and will continue. Therefore, this Initial Statement of Reason (ISOR) builds on the comprehensive and extensive work that was done in support of the original 2009 LCFS rulemaking[9] and the 2011 LCFS amendments.[10]

The primary objectives of the proposed revisions and updates compared to the current regulation are to clarify, streamline, and enhance certain provisions of the regulation. The proposed revisions include post-2015 compliance curves, a cost containment provision, updates to the indirect land use change (iLUC) values, additional electricity provisions, low-complexity/low-energy-use refinery provisions, refinery credits for GHG emission-reduction projects, a refinery-specific crude oil incremental deficit option,

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[9] See Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard." March 5 (2009); Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard Volume II." March 5 (2009); and Final Statement of Reasons for Rulemaking, Including Summary of Public Comments and Agency Responses." December (2009), all of which are incorporated herein by reference.

[10] See Staff Report: Initial Statement of Reasons: Proposed Amendments to the Low Carbon Fuel Standard." October 26 2011, and Final Statement of Reasons, Amendments to the Low Carbon Fuel Standard Including Summary of Public Comments and Agency Responses." October 2012, all of which are incorporated herein by reference.

revised credits for innovative technologies used in crude oil production, a streamlined fuel pathway process, more well-defined enforcement provisions, and other clarifying language. A summary description of each of the proposed updates and revisions is provided in Chapter III, Description of Proposed Regulation.

There are several additional factors driving the staff's proposed updates and revisions compared to the current regulation. First, based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff in Resolutions 09-31 and 11-39 to consider revisions to the regulation in a number of specific areas. These include updates to the electricity provisions, developing low-energy-use refinery provisions, evaluating a refinery-specific incremental deficit option, revising the approval of additional fuel pathways, and updating the Oil Production Greenhouse Gas Emissions Estimator (OPGEE). Second, staff solicited and encouraged feedback from regulated parties and other stakeholders throughout the implementation of the LCFS. This feedback directly informed the staff's refinements contained in this proposal, such as incentives for petroleum refinery modernization projects, updates to the iLUC values, proposal to include a cost containment provision, and issue refinery credits for GHG emission-reduction projects. Finally, staff conducted internal reviews of lessons learned since implementation began. For example, these reviews led to the proposal to enhance enforcement provisions, credit trading provisions, and reporting and recordkeeping requirements.

With the above drivers, staff identified specific areas of the regulation for clarification and improvements. These proposed improvements are expected to improve implementation of the LCFS program. Beyond this proposal, staff will continue to implement and enforce the LCFS program, monitoring its effectiveness, and will consider additional improvements for future iterations of the LCFS regulation, such as post-2020 compliance standards and sustainability provisions.

II. SUMMARY OF PROPOSAL

ARB staff is proposing to re-adopt the LCFS regulation and include updates and revisions to the current regulation. In this chapter, ARB staff provides a description of issues the proposed updates and revisions are intending to address, proposed solutions to these issues, and a brief rationale supporting the proposed solutions.

The objective of the (re-)proposed LCFS regulation is to reduce the carbon intensity of transportation fuels in the California market by at least ten percent from a 2010 baseline by 2020. Over and above other state and federal GHG-reduction programs, this CI reduction is expected to reduce the greenhouse gas emissions from the state's transportation sector by about 35 million metric tons (MMT) between 2016 and 2020, and support the development of a diversity of cleaner fuels with other attendant co-benefits. It is also expected to achieve other important benefits as well, including greater diversification of the state's fuel portfolio, provide consumers with more clean fuel choices, thereby increasing competition, greater innovation and development of cleaner fuels, and support for California's ongoing efforts to improve ambient air quality. The reductions in CI by 2020 are expected to account for about 20 percent of the total GHG emission reductions needed to meet the Assembly Bill (AB) 32 mandate of reducing California's GHG emissions to 1990 levels by 2020 and are also expected to set the stage for greater changes in the state's transportation fuel portfolio in subsequent years.

As noted, the primary objectives of the proposed updates and revisions compared to the current regulation are to clarify, streamline, and enhance certain provisions of the regulation. Staff developed these proposed revisions to support the overall purpose of the LCFS.

A. Re-Adoption of the LCFS

Description of the Problem

In 2010, an ethanol producer and a local consultant sued ARB in state court to invalidate the LCFS, alleging a variety of legal claims under CEQA and APA. A lower court ruled in favor of ARB; however, in 2013, the California Fifth District Court of Appeal ruled that ARB had failed to comply with certain requirements of CEQA and APA. The court allowed the LCFS to remain in effect and be enforceable at the 2013 regulatory standards while ARB cures the procedural defects associated with the regulation's original adoption. In essence, the Board has been ordered either to repeal or to re-adopt the LCFS. If the Board does not adopt the (re-)proposed regulation, the goals of the original LCFS regulation will not be met.

Proposed Solution

To address the Court of Appeal ruling and provide lasting market certainty, staff will propose that the Board re-adopt the LCFS regulation, which include updates and revisions to the current regulation, at the February 2015 Board hearing. At the same Board hearing, staff will also propose that the Board adopt the Alternative Diesel Fuel (ADF) regulation. The ADF regulation will mitigate any potentially significant nitrogen oxides (NO_X) impacts resulting from the increased use of biodiesel to comply with the LCFS. Finally, staff will prepare a complete rulemaking record and an environmental analysis for the Board to consider and approve.

Rationale Supporting the Proposed Solution

By re-adopting the LCFS regulation, along with the proposed ADF regulation, ARB will be able to fully address the court ruling and provide lasting market certainty. The primary goal of the LCFS to reduce the CI of transportation fuels by ten percent by 2020—and the attendant co-benefits—will be preserved.

B. Modification to Compliance Curves for Gasoline and Diesel Standards

Description of the Problem

The centerpiece of the LCFS regulation is the requirement to reduce the average carbon intensity of transportation fuels by ten percent by 2020. The compliance curves for gasoline and diesel define how this CI reduction must proceed.

As part of the re-consideration of the LCFS, ARB staff preformed an extensive re-evaluation of the ability to achieve the ten percent goal in light of the many changes that affect the LCFS. These include changes in the expected demand for transportation fuels and low CI fuel availability, improved methods to estimate the carbon intensity of most fuels governed by the LCFS, experience gained over the first three years of implementation of the LCFS, slower than anticipated implementation of the federal Renewable Fuel Standard, and the more rapid penetration of natural gas and electricity as transportation fuel. Collectively, these factors need to be analyzed in both the setting of the LCFS goal for 2020 and in the design of the trajectory to that goal.

Proposed Solution

ARB staff is proposing to retain the ten percent CI reduction requirement in 2020. However, based on the re-evaluation performed as part of this rulemaking, staff is proposing to establish somewhat less stringent interim requirements (compared to those adopted in the original LCFS) for the years 2016 through 2019. Table II-1 presents a comparison of the current and proposed percent reduction requirements.

Table II-1. Comparison of Previous and Proposed Percent Reduction Requirements

Year	Current LCFS Reduction Percent	Proposed LCFS Reduction Percent
2016	3.5 percent	2.0 percent
2017	5.0 percent	3.5 percent
2018	6.5 percent	5.0 percent
2019	8.0 percent	7.5 percent
2020 onwards	10.0 percent	10.0 percent

Rationale Supporting the Proposed Solution

ARB staff completed an analysis of the ability of parties regulated by the LCFS to obtain sufficient credits from lower CI fuels to comply with a ten percent standard by 2020 and to sustain that compliance beyond 2020. (See Appendix B for details.) The analysis period covers ten years from 2016 through 2025. In light of an anticipated statewide GHG 2030 target that is significantly lower than the AB 32 goal for 2020, it is expected that ARB will revisit the LCFS standard before 2020 to establish greater reductions targets for the 2021 through 2030 period.

This analysis focuses on the path to 2020, as well as compliance with a ten percent requirement in the 2020 and beyond period to ensure that the LCFS is sustainable. As part of the analysis, staff developed an estimate of the mix of fuels that is expected to be available for use by parties subject to the LCFS. This mix was then used to evaluate the feasibility of alternative compliance curves that achieve a ten percent LCFS reduction goal in 2020. This analysis evaluated three compliance curve options:

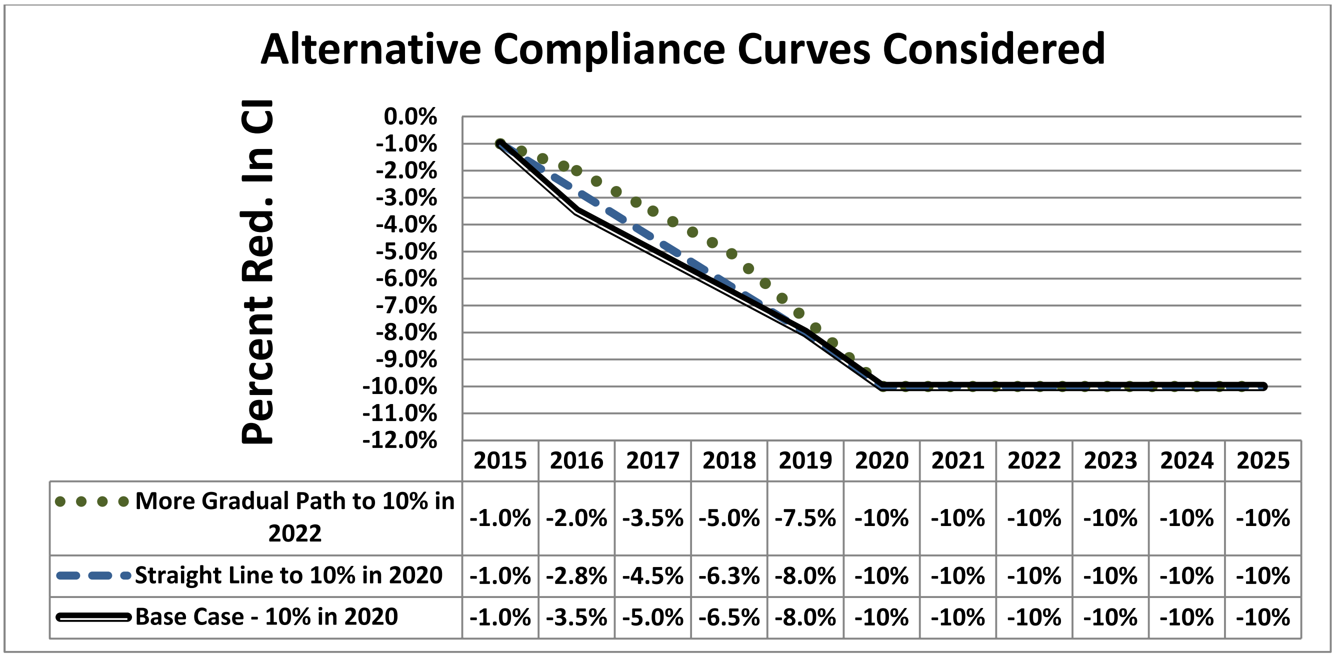
- Option 1: retain the percent reductions in the existing rule,
- Option 2: use a straight line approach to go from one percent in 2015 to ten percent in 2020, and
- Option 3: develop a more gradual path from one percent in 2015 to ten percent in 2020.

Table II-2 below provides the percent reductions for the three cases.

Table II-2. Comparison of Compliance Options Analyzed

Year	Original Reduction Percent	Straight Line Reduction Percent	Gradual Reduction Percent
2016	3.5 percent	2.75 percent	2.0 percent
2017	5.0 percent	4.5 percent	3.5 percent
2018	6.5 percent	6.25 percent	5.0 percent
2019	8.0 percent	8.0 percent	7.5 percent
2020+	10.0 percent	10.0 percent	10.0 percent

Figure II-1. Alternative Post-2015 Compliance Curves Considered



Each option produces sufficient credits to enable compliance through 2019, and Options 2 and 3 show sufficient credits availability through 2020. By 2022 all options produced annual reductions in excess of the ten percent reduction requirement. Option 3, the less stringent path, achieved 88 percent of the GHG reductions of the original compliance schedule, while Option 2 maintained 96 percent of the benefits of Option 1.

None of the options were adequate to produce annual credits adequate to offset annual deficit creation in every year. Options 1, 2, and 3 reached this point starting in 2017, 2018, and 2019, respectively. Therefore, regardless of the option chosen, compliance with a ten percent standard in 2020 required banked credits be built up in the early years (as has happened as the LCFS standard was frozen at one percent) and then used to supplement annual credit production until 2022. Since credits do not expire, they can be banked by regulated parties, giving them the option to over-comply in the early years of the program. This will enable them to have banked credits to use in the later years. The program allows this strategy by setting modest reduction targets in the early years, and then increasing the requirements in later years. Only the Option 3, the gradual path, compliance curve provides sufficient credits to allow compliance by all parties throughout 2020 and beyond. Option 3 creates the most robust supply of credits to sustain a liquid and competitive credit market.

For the reasons listed above, staff has proposed that Option 3 be the basis for the LCFS compliance curve.

C. Cost Containment Provision

Description of the Problem

The LCFS requires that regulated parties (fuel providers) meet the annual carbon intensity standards. The LCFS contains numerous design features that provide regulated parties with flexibility regarding their compliance strategy and that contain the cost of the program. Because the program is performance-based, it allows regulated parties to choose from a mix of strategies that achieve compliance in the most cost-effective and reliable manner. The mix includes: investing in production of low-CI fuels to self-generate credits; purchasing low-CI fuels for blending with traditional hydrocarbon fuels; purchasing credits from other regulated parties; and banking credits for use in future years. Regulated parties can determine the most economical path to compliance by choosing one, or a combination of, the above strategies.

In addition to its performance-standard design enabling regulated parties to seek their own least-cost, compliance strategies, the LCFS credit provisions incorporates a variety of other features that increase the ways regulated parties can achieve compliance using credits.

- First, credits do not have an expiration date, so they can be banked by regulated parties. This gives regulated parties the option to over-comply in the early years of the regulation so that they would have banked credits to use in later years. The program enables this strategy by setting modest reduction targets in the early years, then increasing the requirements in later years.

- Second, credits are fungible across the gasoline and diesel sectors. For example, if a regulated party makes both gasoline and diesel, it can use credits generated by over-complying with the diesel standard (e.g., by blending its petroleum diesel fuel with lower carbon renewable diesel or biodiesel) and apply those credits towards its gasoline deficit, or vice versa.

- Third, as noted above, credits can be bought and sold on the credit market, allowing regulated parties to meet their obligations with credits purchased from other regulated parties who have credits available for sale.

Even with multiple existing design features to contain costs and to provide regulated parties with flexibility to achieve compliance, some amount of uncertainty will always exist regarding the future supplies of low-CI fuels and the availability and price of LCFS credits. As credits and deficits are generated by regulated parties selling transportation fuels in the California market, the quantity of deficits and credits available each year is determined by the actions of regulated parties, not by the Executive Officer. The Executive Officer can, however, act to reduce future uncertainty, and increase confidence in the ability of the market to deliver sufficient quantities of low carbon fuels.

Staff analysis regarding the availability of low-CI fuels indicates that there will be sufficient credits available through 2020 from existing low-CI fuel technologies and promising low-CI fuels on the horizon. Nonetheless, the LCFS can be enhanced by a cost containment provision that allows regulated parties to achieve compliance under a credit shortfall scenario. A cost containment provision that allows regulated parties to achieve compliance at a pre-determined maximum price will prevent a low-probability, but high-impact, credit shortfall that would make future compliance more expensive than anticipated, and will, thus, protect regulated parties and consumers from a price spike.[11,12] (Institute of Transportation Studies University of California Davis, et. al., 2012) (Rubin & Leiby, 2011)

Proposed Solution

To provide additional compliance options if the LCFS credit market gets tight, increase market certainty regarding maximum compliance costs, strengthen incentives to invest in and produce low-CI fuels, and reduce the probability of credit shortfalls and price spikes, staff proposes the creation of a year-end credit clearance process. Under the credit clearance process, regulated parties would be allowed to carry over deficits to the next compliance period, provided that they purchase their pro rata share of all credits made available for sale during a year-end credit clearance market. This ensures that regulated parties can achieve compliance under all possible credit supply outcomes. The credit clearance process specified in Section 95485 of the proposed regulation would occur annually, and is described in Chapter III, Section I: Demonstrating Compliance.

Annual Credit Clearance Process:

- On the first Monday of April, the Executive Officer will issue a call for credits to be pledged into the year-end clearance market. Any credits pledged must be sold at

[11] National Low Carbon Fuel Standard: Policy Design Recommendations, ITS, UC Davis (2012)
[12] Rubin, Jonathan, and Paul N. Leiby. "Tradable credits system design and cost savings for a national low carbon fuel standard for road transport."

or below the pre-established maximum price. The Executive Officer will specify the year's pre-established maximum credit price in the call for credits.

- By April 30th, regulated parties that have elected to pledge credits for sale into the credit clearance market will inform the Executive Officer of their decision to participate in the Clearance Market and the quantity of credits they are pledging for sale.

- On May 15th, the Executive Officer will announce whether a Clearance Market will occur for a given compliance year. A Clearance Market will occur if at least one regulated party is required to participate in the Clearance Market to meet its compliance obligation, and if there are credits pledged for sale into the Clearance Market. A Clearance Market will not occur if at least one of two conditions are met:

    - The Executive Officer will determine a Clearance Market will not be held for that compliance year if no regulated parties are required to participate in the Clearance Market to meet their compliance obligation, regardless of whether there are credits pledged for sale into the Clearance Market.

    - The Executive Officer will determine a Clearance Market will not be held for that compliance year if there are no credits pledged for sale into the Clearance Market. If no credits are pledged for sale into the Clearance Market, the Executive Officer will consider the regulated parties that were required to participate in the Clearance Market to meet their compliance obligation in compliance for that year, provided they agree to carry over the entire deficit balance as an Accumulated Deficit. Accumulated Deficits must be re-paid in five years.

- On June 1st, if a clearance market will be held, the Executive Officer will publish: the name of each regulated entity that is participating in the Clearance Market; whether they are participating as a credit seller or purchaser; and the number of credits they have pledged, or their pro-rata credit obligation.

- From July 1st through July 31st, if the Executive Officer has determined the Clearance Market will occur, the Clearance Market will operate.

- By August 31st, Regulated Parties that purchased credits in the Clearance Market to meet their compliance obligation will submit to the Executive Officer an updated year-end compliance report that accounts for the acquisition and retirement of their pro-rata share of Clearance Market credits, and for all deficits carried over as accumulated deficits.

Rationale Supporting the Proposed Solution

A cost containment provision will enhance the market's functionality by providing regulated parties with increased certainty regarding the feasibility and cost of compliance, and by sending stronger market signals to encourage investment in low-CI fuels. Specifically, the credit clearance process will:

- Ensure that annual compliance can be achieved under all possible fuel supply scenarios. The credit clearance process would enable regulated parties to comply even if a shortage of credits renders them unable to meet their annual compliance obligation.

- Contain compliance costs and cap credit prices. By implementing a strong and transparent price cap for LCFS credits, the cost containment threshold price allows regulated parties to achieve compliance at a predetermined maximum price, and will protect regulated parties and consumers from the possibility of a low-probability but high-impact price spike driven by a tight supply of low-CI fuels or LCFS credits. Without a strong and transparent price cap in the LCFS market, a shortage of credits or low-CI fuels risks uncapped spikes in credit prices, as regulated parties bid up the price of credits in an effort to purchase enough credit to achieve compliance.

  Implementing a maximum price for credits through the year-end clearance market will contain costs in the market year-round, even in the event of a credit shortage: regulated parties with a compliance obligation can purchase credits to satisfy their compliance obligation at a maximum cost containment threshold price in the year-end market, and will therefore have little incentive to purchase credits at any point in the year at a price above the cost containment threshold price.

- Reduce market volatility. By limiting the potential increases in credit prices, the cost containment threshold price will minimize volatility during periods of market stress. Establishing clear, transparent rules for smooth market function under periods of strain caused by tight credit supplies will help to sustain an orderly market and reduce speculation regarding how the LCFS credit market might be managed in times of market stress. Implementing clear, predictable provisions to handle any credit shortage or price spike actually reduces the risk that the market prices will reach the ceiling.

- Incent additional investment in low-CI fuels. By addressing regulated parties' concerns about potential future supply shortages, the credit clearance market will improve market durability and investor confidence. The cost containment provision reduces two sources of market uncertainty that affect investments in low-CI fuels: price uncertainty and regulatory uncertainty.

- The cost containment threshold price will reduce price uncertainty by specifying a maximum credit price. By capping credit prices at a specified threshold, the clearance provision increases regulated parties' certainty regarding their maximum cost of compliance, which will facilitate long-term business planning.

- By providing a clear path for compliance even in years of credit shortage, the cost containment provision reduces regulatory uncertainty. Investors are aware that credit price spikes can destabilize the credit and fuel markets. Significant market instability could cause lawmakers to amend the LCFS in an effort to restore stability. The prospect of such intervention creates uncertainty and reduces the available of funds to developers of new low-CI fuels. By taking positive steps to prevent destabilizing price spikes, the cost containment provision will enhance market certainty and increase the pool of available investment dollars.

The credit clearance process provides a set of rules governing LCFS credit transactions in the event of a credit shortage, and addresses concerns regarding how the market would operate in periods of tight credit supply. Transparent rules governing market operations in times of tight supplies will increase investor confidence because they can predict how the market will react if stressed.

- Significantly reduce the likelihood that credit and fuel shortages will occur. The cost containment threshold provision allows low-CI fuel producers and investors to more confidently assess the market value for low-CI fuels and credits. By increasing confidence in the durability of the market and reducing uncertainty regarding the long-term market value for low-CI fuels, the cost containment provision will stimulate investments in low-carbon fuels. The result will be greater availability of low-CI fuels, and a reduced likelihood that the cost containment measure described in this section would ever be required.

D. Obtaining and Using Fuel Pathways

Description of the Problem

Based on stakeholder comments received in both the original 2009 rulemaking and the 2011 amendments, the Board directed staff in Resolutions 09-31 and 11-39 to consider revisions to the regulation in a number of specific areas, including the approval of additional fuel pathways. Additionally, staff conducted internal reviews of lessons learned and has been assessing what has changed since the initial implementation of the LCFS. It is evident that evaluating fuel pathways is very resource-intensive. Furthermore, stakeholders have expressed concerns that many of the Method 2 pathways in the Lookup Table and on the Method 2 web site are not available for wider use by regulated parties.

A related issue is that only fuels consumed in California must comply with the LCFS. It is essential, therefore, that fuel pathway certifications are only issued for fuels that are actually transported to and sold in California. It is particularly important that transactions involving low-CI fuels that are not transported to California do not get reported in the LRT-CBTS system. If this were to occur, fuels not sold in California could earn and sell LCFS credits.

Proposed Solution

In response to those considerations, and to better incent innovation, staff proposes to restructure the fuel certification and registration functions and integrate review of the fuel transport mode demonstrations with fuel pathway certifications. After a carbon-intensity (CI) value is certified for a fuel pathway, sellers of that fuel in California will not be able to generate credits under the LCFS until the regulated party reporting that fuel has submitted evidence regarding the physical delivery of that fuel to California and that submittal has been approved by the Executive Officer.

For fuel pathway certifications, staff is proposing a two-tiered system in which conventionally produced first-generation fuels, such as starch- and sugar-based ethanol, would fall into the first tier. Next-generation fuels, such as cellulosic alcohols, would fall into the second tier. If a Tier 1 fuel is produced using an innovative method, such as the use of low-CI process energy sources, it would move into the second tier.

The Tier 1 process simplifies and expedites the certification process by providing applicants with a streamlined CI calculator. That calculator computes pathway CIs using a base set of input parameters needed to determine a Tier 1 pathway CI.

Tier 2 applicants may use one of three methods to obtain a fuel pathway: Tier 2 Lookup Tables, Method 2A, or Method 2B. To use the Lookup Tables, applicants select, subject to Executive Officer approval, a pathway from the LCFS Lookup Tables found in Chapter III, Section L.

Under Methods 2A and 2B, fuel providers apply to the Executive Officer for new, producer-specific fuel pathways. Method 2A is used when a proposed pathway consists of a modified version of an existing “reference” pathway. Method 2A can only be used if the following two conditions are met:

- Proposed Method 2A pathways with CIs greater than 20 gCO_2e/MJ must have CIs that are 5.5 percent lower than the CIs of their reference pathways. Proposed pathways with CIs of 20 gCO_2e/MJ or less must have CIs that are at least one gCO_2e/MJ lower than the CIs of their reference pathways.

- The applicant is capable of providing (and intends to provide) more than ten million gasoline gallon equivalents of transportation fuel annually under the proposed Method 2A pathway.

Method 2B is reserved for entirely new fuels or fuel production processes. By definition, no previously certified pathway can serve as a reference pathway for a Method 2B fuel. The applicant is, therefore, responsible for providing and substantiating all input used to calculate the pathway CI.

The process of obtaining a fuel pathway CI will be further simplified by automating most aspects of the application process. Under that process, all applicants, regardless of Tier, will initiate the application process by completing an LCFS New Pathway Request Form (NPRF). The NPRF is an interactive, web-based form that will be available on the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS) web site. Once the NPRF has been approved (with modifications, if required by the Executive Officer), the applicant may begin uploading the required application materials, including version 2.0 of the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model (CA-GREET) calculations, through the secure LRT-CBTS web interface. Submission requirements are specified in Chapter III, Section L. Once the fuel pathway has been certified, an automated application process will be available through the LRT-CBTS for obtaining fuel transport mode demonstration approval.

Rationale Supporting the Proposed Solution

The improvements described in this section will streamline and expedite the fuel pathway certification process in the following specific ways:

- Provide first-generation Tier 1 pathway applicants a simpler and more direct route to pathway certification; expediting the Tier 1 process gives staff more time to focus on next-generation Tier 2 fuel technologies;

- Consolidate and organize, via an automatic application process, an inefficient two-step process that required manual processing of electronic files submitted via email and file transfer protocol (FTP). The new process also consolidates the existing certification and registration processes;

- Move to CA-GREET 2.0, based on GREET1 2013; and

- Integrate the fuel transport mode approval process with the fuel pathway certification process through the LRT-CBTS. The fuel transport mode demonstration process occurs after pathway certification—usually when reportable fuel shipments begin under the newly certified pathway.

E. Revised Indirect Land Use Change Values

Description of the Problem

As discussed under life cycle analysis using CA-GREET, carbon intensities are calculated under the LCFS on a full life cycle basis. This means that the CI value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. The CA-GREET model accounts only for such direct effects. In addition to these direct effects, some fuel production processes generate GHGs *indirectly*, via intermediate market mechanisms. To date, ARB staff has identified an indirect effect that has a measurable impact on GHG emissions: land use change. A land use change effect is initially triggered when an increase in the demand for a crop-based biofuel begins to drive up prices for the necessary feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop. Supplies of the displaced food and feed commodities subsequently decline, leading to higher prices for those commodities. Some of the options for farmers to take advantage of these higher commodity prices are to increase yields, switch to growing crops with higher returns, and to bring non-agricultural lands into production. When new land is converted, such conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change (iLUC) impact of increased biofuel production. For the LCFS, iLUC emissions are attributable to biofuels produced from crops.

Based on published work by academics and researchers studying land use change, ARB staff concluded that the land use impacts of crop-based biofuels are significant, and must be included in LCFS fuel carbon intensities. To exclude them would assume that there is zero impact resulting from the production of biofuels and would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and by not accounting for the GHG emissions from land use change, would jeopardize the achievement of a ten percent reduction in fuel carbon intensity by 2020. For the LCFS, staff has identified fuels derived from waste-feedstocks as having zero or small iLUC emissions (or other indirect emissions). The ultimate goal of the LCFS program is to incent the production and use of second-generation low CI fuels including fuels derived from waste feedstocks.[13]

The Board, in Resolution 9-31, directed staff to convene an Expert Work Group to refine and improve iLUC values and return to the Board with those revised values. This rulemaking includes proposed iLUC values pursuant to the Board's direction.

Proposed Solution

The land use change effects of a large expansion in biofuel production would occur both domestically and internationally. A sufficiently large increase in biofuel demand in the U.S. would cause non-agricultural land to be converted to crop land both in the U.S. and in countries with agricultural trade relations with the U.S., and as a result of land conversion will generate GHG emissions. As part of the LCFS regulation drafted in 2009, staff, in consultation with UCB selected the Global Trade Analysis Project (GTAP) model for iLUC analysis. The GTAP is a computable general equilibrium (CGE) model developed and supported by researchers at Purdue University. The GTAP has a global scope, is publicly available, and has a long history of use in modeling complex international economic effects.

[13] This was not a consideration in the SRIA analysis

Based on stakeholder comments received post 2009 rulemaking and recommendations by the Expert Working Group (established per Board directive 9-31), staff considered refinements to the iLUC analysis in a number of specific areas. Working with Purdue University, staff implemented changes to the structure of the GTAP-BIO model, refined operational parameters, included updates to account for real-world effects and harmonized iLUC analysis for all biofuels. Three new biofuels were added to the database to allow for estimating iLUC emissions for these biofuels. To refine carbon emission factors, staff, with assistance from UCB, University of California, Davis, and University of Wisconsin, developed a carbon emissions model called the Agro-Ecological Zone-Emissions Factor (AEZ-EF) model. This model estimates carbon emissions release when land is converted from one type to another. The new approach[14] uses land conversion estimates from the GTAP-BIO in combination with the AEZ-EF model to calculate iLUC emissions.

Rationale Supporting the Proposed Solution

ARB staff selected the GTAP-BIO model to estimate land use change for biofuels. The GTAP-BIO is relatively mature, having been frequently tested on large-scale economic and policy issues. The model includes 111 world regions, and each region contains data tables that describe every national economy in that region, as well as all significant intra- and inter-regional trade relationships. The data for this model are contributed and maintained by more than 6,000 local experts. The GTAP-BIO model allowed for the flexibility of modeling land-use change by adding data on 18 worldwide Agro-Ecological Zones. It allowed for the inclusion of the major types of land cover across the world. All the sectors of the global economy could be considered when estimating impacts from the production of biofuels. Based primarily on its global scope, public availability and its long history of use in modeling complex international economic effects, ARB staff determined the GTAP-BIO was most suitable for use in estimating the land use change impacts of crop based biofuels that will be regulated under the LCFS. The AEZ-EF model used IPCC greenhouse gas inventory methods and default values, augmented with more detailed and recent data where available. It represents the current state-of-the-art for emission factors from various types of land conversions across the globe. The refinements and modifications made to both the GTAP-BIO and AEZ-EF models make them the best tools currently available to estimate iLUC emissions from biofuels.

Staff will continue to review literature and other published reports that address progress in the science of iLUC emissions and make necessary updates in future models.

[14] The iLUC analysis in 2009 used carbon emission factors embedded within the GTAP-BIO model. These factors were the same for a given region. In the current analysis, carbon emission factors are disaggregated by region and AEZ. The GTAP-BIO model has 19 regions and 18 AEZs.

F. Low-Complexity/Low-Energy-Use Refinery Provisions

Description of the Problem

On December 16, 2011, the Board directed staff in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address the lower energy inherently embedded into the transportation fuels from refineries that use simple processes to refine transportation fuels.

Proposed Solution

Staff investigated two metrics to define a low-complexity/low-energy-use refinery. The first metric was the Nelson Complexity Index. This index is a measure of how simple or complex a refinery is by adding up the various process units in the refinery, using their relative complexity values as compared to a distillation unit. Since the LCFS deals with transportation fuels only, the Nelson Complexity Index was modified to exclude lube oil and asphalt capacity. The second metric was the total energy use of the refinery. This would include the direct consumption of fuels, as well as imported and exported electricity and thermal energy. Staff is proposing that a refinery must have a modified Nelson Complexity score of five or less and that the annual energy usage would have to be five million MMBtu or less. Each refinery would have to comply with both parts of the metric to be considered a low-complexity- and low-energy-use refinery.

Staff investigated the difference in transportation fuel carbon intensity between low-complexity/low-energy-use refineries and the remaining refineries. Staff is proposing to credit the low-complexity/low-energy-use refineries 5 gCO_2e/MJ for both California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) and CARB diesel. The credit will be handled in the Reporting Tool to maintain the fungibility of the fuels. All credits generated under this provision must be used by the refinery that generated them and may not be sold to other regulated parties.

Staff is proposing to add reporting requirements for low-complexity/low-energy-use refineries. They are:

- The volume of CARBOB and CARB diesel refined from crude oil;
- The volume of CARBOB and CARB diesel refined from intermediates, including transmix; and
- The volume of CARBOB and CARB diesel purchased for blending.

Rationale Supporting the Proposed Solution

Staff investigated the actual carbon intensity of the gasoline and diesel produced by low-complexity/low-energy-use refineries using GHG emissions and transportation fuel production data from 2011 to 2012. The low-complexity/low-energy-use refinery carbon intensity for CARBOB is 5.53 gCO_2e/MJ below the carbon intensity of the complex refineries. Similarly, the low-complexity/low-energy-use refinery carbon intensity for CARB diesel is 4.79 gCO_2e/MJ below the complex refineries' carbon intensity for diesel. Therefore, for simplicity, staff is proposing that these refineries be credited with 5 gCO2e/MJ for CARBOB and CARB diesel.

G. Refinery-Specific Crude Oil Incremental Deficit Accounting

Description of the Problem

In December 2011, the Board approved amendments to the LCFS that included using a California Average Crude Oil approach to "hold the line" on the average CI of the crudes that California refineries are processing. Using crudes that have higher CIs over time will erode the efficacy of the LCFS. For the California Average Crude Oil approach, ARB set a baseline average carbon intensity for all of the crudes processed in California refineries in 2010 and then calculates subsequent years' crude slates to compare with the baseline. If the average crude CI in any subsequent rolling three-year period exceeds the 2010 baseline average CI, all of the refineries are assessed an incremental deficit for which they must compensate by acquiring additional low-CI fuels or LCFS credits. The California Average Crude Oil approach applies to the refining industry as a whole. At the same Board hearing, the Board, in Resolution 11-39, also directed the Executive Officer to evaluate and propose, as appropriate, an option for individual regulated parties to have their incremental deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of crude oils, intermediate products, and finished fuels.

Proposed Solution

Staff is proposing to allow low-complexity/low-energy-use refineries to opt out of the California Average Crude Provision in the current LCFS regulation and instead have their crude oil incremental deficit calculated on a refinery-specific basis. The large, complex refineries will continue to operate under the California Average crude oil provision, and staff will continue to evaluate the feasibility of allowing larger, more complex refineries to opt for refinery-specific accounting as well.

The low-complexity/low-energy-use refineries will be allowed a one- time, irreversible opportunity to opt for refinery-specific accounting. A participating refinery will have a refinery-specific incremental deficit assessed if its refinery Annual Crude Carbon Intensity exceeds its refinery 2010 Baseline Crude Carbon Intensity. A participating refinery will also be required to work with staff to properly characterize all crudes supplied to the refinery, including the requirement to report field names and volumes for all California-produced crude that is supplied to the refinery. Refinery-specific accounting will only apply to those volumes of CARBOB and diesel fuel derived from crude oil supplied to the refinery. The volumes of CARBOB and diesel derived from imported blendstocks, refinery intermediates, or finished fuels purchased from another refinery will continue to be subject to the California average incremental deficit accounting.

Rationale Supporting the Proposed Solution

Smaller refineries can be affected by potential California Average incremental deficits generated by the larger refineries, but, because of their low crude throughputs, they cannot affect the California Crude Average carbon intensity. Therefore, staff is proposing to allow low-complexity/low-energy-use refineries to opt out of the California Average Crude Provision in the current LCFS regulation and instead have their crude oil incremental deficit calculated on a refinery-specific basis. The large, complex refineries will continue to operate under the California Average crude oil provision. Because imported blendstocks, refinery intermediates, and finished fuels supplied to the low-complexity/low-energy-use refineries are likely derived from crude that is processed by the larger California refineries, the volumes of CARBOB and diesel derived from imported blendstocks, refinery intermediates, or finished fuels will continue to be subject to the California average incremental deficit calculation. This requirement maintains proper emissions accounting if crude to the larger refineries becomes more carbon intensive over time.

Staff will continue to evaluate the option for refinery-specific incremental deficit accounting for large refineries, but foresees significant challenges in implementing this approach.

Accurate determination of refinery-specific crude oil carbon intensity values requires detailed information on the supply of California-produced crude oil to each refinery. Staff's modeling of California produced crude using OPGEE is by necessity at the field level, as crude recovery data in California is only available at the field level. Data that maps crude oil volumes from fields to pipeline blends is not available. The small refineries have been able to provide field-specific volumes for California-produced crude supplied to their refineries, and, therefore, staff can readily determine refinery-specific crude carbon intensities. The large refineries report volumes of California crudes using generic marketing and pipeline names (e.g., San Joaquin Valley [SJV] heavy, SJV light, Line 63, Kettleman-Los Medanos [KLM], Norwalk). Because staff does not have information on which fields make up each generic marketing or pipeline name, accurate refinery-specific accounting of crude production emissions is not currently possible for these large refineries.

H. Annual Crude Average CI Calculation

Description of the Problem

The Annual Crude Average CI is a volume-weighted average of crude CI values supplied to California refineries. The crude CI values are those listed in Table 8 of the regulation while the crude volumes are those reported by refineries as part of annual compliance reporting. The crude lookup table lists field-specific CI values for crudes produced in and offshore of California. Regulated parties, however, are often supplied California crude in pipelines carrying crude blended from many fields. Because neither staff nor the regulated parties have data that maps crude oil volumes from California fields to pipeline blends, it is not possible to match reported California crude names with CI values from the lookup table.

Proposed Solution

Instead of using California crude names and volumes reported by refineries, staff proposes, in calculating the Annual Crude Average CI value, that volume contributions for California State fields will be based on oil production data from the California Department of Conservation and volume contributions for California Federal Offshore fields will be based on oil production data from the Bureau of Safety and Environmental Enforcement.

Rationale Supporting the Proposed Solution

It is staff's belief that all crude produced in and offshore California is supplied to California refineries. This belief is supported by data showing that the total volume of California crude reported by refineries in 2012 and 2013 very closely matches the total volume of California production reported by oil field operators. Staff's modeling of California produced crude using OPGEE is more accurately accomplished at the field level, as detailed crude recovery data in California is available at the field level. Data that maps crude oil volumes from fields to pipeline blends is not available, and therefore it is not possible to as accurately estimate CI values for California pipeline blends as for fields. Assuming all crude produced in California is refined in California, it makes no difference if one calculates a volume-weighted average CI using field production volumes and field CIs or using pipeline blend volumes and pipeline blend CIs. However, since field CI values can be more accurately estimated than pipeline blend CIs, staff is proposing to use field production volumes and CIs for California crude in calculating the Annual Crude Average CI value.

Staff will continue to validate the assumption that all crude produced in California is refined in California by checking the total California crude volume reported by refineries against the total production volume reported by producers. If it becomes clearly evident that California crude is being exported, staff will reduce the production volumes used in the Annual Crude Average CI calculation to account for the exported crude.

I. Innovative Technologies for Crude Oil Production

Description of the Problem

The Board adopted the innovative crude provision, section 95489(d), as part of the 2011 LCFS amendments. The intent of the provision is to promote the development and implementation of innovative crude oil production methods that reduce GHG emissions. Allowable methods are carbon capture and sequestration (CCS) and solar steam generation. The crude oil producer must apply to the Executive Officer for approval of both the method and the carbon intensity reduction associated with the method. Refineries that purchase the innovative crude generate credits proportional to the carbon intensity reduction achieved by the method. To date, no application has been submitted under this provision, and discussions with stakeholders have revealed several issues. First, a financial disconnect exists between the crude oil producer who incurs the risk associated with installing the innovative production method and the refiner who receives the financial gain (i.e., LCFS credit) from purchasing the innovative crude. Second, the minimum threshold requirement for carbon intensity reduction precludes the approval of pilot-scale projects that currently provide too small of an emissions reduction when spread over the energy content of crude oil associated with a field or crude blend. Third, the application process is too cumbersome for relatively straightforward innovative methods, such as solar-based steam generation. Fourth, the list of allowable innovative methods is too restrictive.

Staff also determined that treatment of CCS under the LCFS should be better aligned with the treatment under the Cap-and-Trade (C&T) program for consistency. Under C&T, the emission reduction benefits of CCS are effectively allocated to the facility where capture occurs. Also under C&T, credit generation for CCS projects will only be allowed after ARB has in place an approved quantification methodology for monitoring, reporting, verification, and permanence requirements associated with the carbon storage method.

Proposed Solution

Staff proposes the following revisions in order to better promote the development and implementation of innovative crude oil production methods:

- The producer of the innovative crude may opt in as an LCFS regulated party and earn LCFS credit based on the volume of crude supplied to California refineries;

- The 1.0 g/MJ minimum threshold for carbon intensity reduction would be reduced to 0.1 g/MJ. Innovative projects not meeting the 0.1 g/MJ threshold may also be approved if they reduce annual emissions by 5,000 $MTCO_2e$ or more;

- Simplified, default credit calculations for solar-based steam generation and solar-or wind-based power generation would be incorporated into the regulation language. See Appendix G for details on default credit calculations; and

- Solar and wind electrical power generation and solar heat generation would be added to the allowable innovative methods. All are in keeping with the intent of the regulation to promote the development and implementation of sustainable fuel sources.

Staff proposes the following revisions to better align the treatment of CCS under the LCFS with the C&T program:

- CCS as an innovative method would be limited to those instances where the carbon capture occurs onsite at the crude oil production facilities; and

- Credit generation for CCS projects would only be allowed through the use of a Board-approved quantification methodology, including monitoring, reporting, verification, and permanence requirements associated with the carbon storage method being proposed for the innovative crude production method.

Staff also considered including biomass-based steam, heat, and electricity production as innovative methods, but decided against doing so for the following reasons. First, combustion of waste biomass results in production of criteria pollutants and toxics in excess of natural gas combustion, which would likely be the fuel source being displaced for newly-built steam generators or power plants. Second, waste biomass is not generated as part of the life cycle of crude oil production, and, therefore, including waste biomass as an innovative method may simply incent shuffling of biomass being used for other purposes, such as alternative fuel production or electricity production under the renewable portfolio standard. Third, the innovative crude provision applies to crude produced anywhere in the world, as long as it is supplied to California. It would be very difficult to monitor and enforce sources of biomass to ensure that only waste biomass is used, especially given that a concise definition of waste biomass has not been developed. Finally, greenhouse gas emissions generated during gathering, transport and processing of waste biomass, as well as other potential issues of concern, such as soil carbon loss and land use change pressure, result in an emissions intensity greater than that of more sustainable and innovative options for heat and electricity generation at oil fields, such as solar or wind power.

Rationale Supporting the Proposed Solution

The innovative crude provision has the potential to generate significant environmental benefits both inside and outside of California. Widespread adoption of innovative methods by crude oil producers that supply California refineries can lead to significant reductions in both greenhouse gas and criteria pollutant emissions. As an example, if solar energy were employed to produce 30 percent of the steam used for thermal enhanced oil recovery in California, estimated benefits include annual GHG emissions reduction of 4.2 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) and total criteria pollutant reduction of more than 1,000 tons per year. Similar environmental benefits could be achieved by out-of-state oil producers that supply oil to California refineries. Although no applications have been submitted for the innovative crude provision to date, staff believes that proposed revisions to the provision will increase incentives for oil producers to adopt these innovative methods.

J. Revisions to Oil Production Greenhouse Gas Emissions Estimator (OPGEE) and Updates to the Crude Lookup Table 8

Description of the Problem

The Board adopted OPGEEv1.0 as the model to be used to estimate the carbon intensity for crude recovery and transport of crude to the refinery. During and following the 2011 LCFS amendment process, several stakeholders suggested corrections and improvements to the OPGEE model. ARB staff and model developers at Stanford University also discovered areas in which the model could be improved.

Moreover, staff is proposing to update the CA-GREET model to a more recent version of GREET published by Argonne National Laboratory (GREET1 2013). Because OPGEE uses GREET to provide many emission factors, life cycle inventory data, and fuel cycle emissions values, staff determined that OPGEE should be updated to be consistent with GREET1 2013 as well.

Proposed Solution

In response to stakeholder feedback on OPGEEv1.0 and early draft versions of OPGEEv1.1, staff worked with Professor Adam Brandt of Stanford University to make revisions to the OPGEE. These revisions are listed in Appendix G of the OPGEE User Guide and Technical Documentation.[15] Staff is proposing that the revised OPGEEv1.1 be the specific model version to be used for generation of carbon intensity values for crude oil production and transport to California refineries. The OPGEE model version 1.1 will be incorporated in the regulation by reference. Staff is also proposing that future revisions of OPGEE occur no more frequently than every three years and that they may be approved through an Executive Officer Hearing.

Because the revisions to the OPGEE model affect the carbon intensity estimates for crude oil production and transport, staff is also proposing revised carbon intensity values for the crudes listed in the Crude Lookup Table (see Appendix H), including the 2010 Baseline Crude Average carbon intensity. Proposed revisions to the Crude Lookup Table will include both updated carbon intensity values for listed crudes and expansion of the table to include carbon intensity values for all crudes supplied to California refineries from 2010 to 2013, as well as additional crudes of interest to California refiners. This expanded Lookup Table will list carbon intensity values for over 100 internationally and nationally marketed crudes and nearly 200 California oil fields. The Crude Lookup Table will also include a single default carbon intensity value to be used in the event a refinery purchases a crude not listed in the table. This default carbon intensity will be equal to the 2010 Baseline Crude Average carbon intensity and will be used until the crude carbon intensity is included in the table as part of a subsequent update.

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[15] El-Houjeiri, H.M., Vafi, K., Duffy, J., McNally, S., and A.R. Brandt, Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model Version 1.1 Draft D, User Guide and Technical Documentation, October 1, 2014.

Rationale Supporting the Proposed Solution

OPGEEv1.1 provided to staff by Professor Adam Brandt of Stanford University is superior to OPGEEv1.0 in several respects. In general, the revisions improve usability of OPGEE with the bulk assessment tool, add functionality and more accurate modeling of various production options, clarify and model in detail important sources of emissions that were treated simply before (e.g., associated gas flaring), improve accounting of venting and fugitive emissions, and improve model equations or life cycle inventory data.

Because the revisions to the OPGEE model affect the carbon intensity estimates for crude oil production and transport, staff is also proposing revised carbon intensity values for the crudes listed in the Crude Lookup Table, including the 2010 Baseline Crude Average carbon intensity. Revising all crude carbon intensity estimates using the new model version is required in order to ensure consistent treatment of all crudes and to ensure accurate calculation of a potential incremental deficit for petroleum-based fuels.

K. GHG Emissions Reductions at Refineries

Description of the Problem

Biofuel producers who reduce their GHG emissions are rewarded with lower carbon intensity values for their fuels. Petroleum refineries have no such provision in the current LCFS regulation. Staff is proposing to allow refineries to generate credits for investments at the refinery that reduce GHG emissions. This proposed revision is consistent with a proper life cycle analysis, which is a key element of the LCFS.

Proposed Solution

In the current CA-GREET model, the refinery portion of the life cycle of CARBOB and CARB diesel has fixed values. Treating the refineries the same does not incent GHG reductions—and associated toxic and criteria pollutant emission reductions—at the refinery. To be more consistent with the full life cycle analysis, staff is proposing to allow refineries to generate credits for investments that reduce GHG emissions at the refinery. If the proposed projects increase emissions from associated toxic and criteria air pollutants, they would be ineligible for credits under this provision.

For market fungibility purposes, the CI for CARBOB and CARB diesel will remain the same, instead of reducing the CI of the fuels produced—as is done with biofuel production facilities. ARB will issue credits to recognize GHG emission reductions at the refineries.

Staff is proposing that refineries would be eligible to receive credit under this provision upon project approval. No project will be eligible unless it begins in 2015 or later, and results in a CI reduction of 0.1 gCO_2e/MJ or more for CARBOB or CARB diesel.

Rationale Supporting the Proposed Solution

Reductions in GHG emissions from petroleum refineries should be recognized through a proper life cycle analysis, as is done for biofuel facilities. Furthermore, the LCFS credits earned through the implementation of GHG emission reduction projects may make such projects more cost-effective than they otherwise would have been without the credits.

Staff analyzed data provided to ARB through the Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation (Energy Audit) (ARB, 3). The regulation required operators of California's largest industrial facilities to conduct a one-time energy efficiency assessment and identify GHG reduction projects that could be implemented within the border of the facility. The Energy Audit identified over 400 efficiency improvements at 12 refineries that overall would account for nearly 2.8 $MMTCO_2e$ GHG reductions, as well as 2.5 tons per day (tpd) NO_X and 0.6 tpd particulate matter (PM) reductions.

Almost 80 percent of identified GHG reduction projects were completed prior to the Energy Audit, leaving about 100 reduction projects that had not. The remaining projects that had not been implemented represent about 0.6 $MMTCO_2e$, 1.5 tpd NO_X, and 0.3 tpd PM potential reductions. If implemented, these GHG reduction projects would result in CI reductions for CARBOB and CARB diesel of 0.01 gCO_2e/MJ to 3.11 gCO_2e/MJ per project. The majority of these refinery reduction projects range from 0.1 gCO_2e/MJ to 1.0 gCO_2e/MJ.

L. Enhancements to Reporting and Recordkeeping Requirements

Description of the Problem

The term PTD (Product Transfer Document) is defined loosely, and referred to in the current LCFS variously as a singular item and elsewhere as a collection of documents including Bills of Lading (BOL), invoice, contracts, meter ticket, rail inventory sheet, Renewable Fuels Standard product transfer documents, etc. Collectively, the PTDs authenticate the transfer of ownership of a fuel from the transferor to the transferee. The regulation defines the data to be reported from these various documents in multiple sections of the regulation. Perhaps due to confusion regarding these documents, counterparties to a series of transactions have reported different information to ARB regarding the same transactions. The parties and ARB have had to devote additional resources toward reconciling conflicting reports.

Proposed Solution

Staff proposes consolidating the following important reporting parameters in the PTD for improved recordkeeping:

- Transfer Information
    - Date of title transfer. For aggregated transactions, the quarter end date.
    - Transferor company name, address and contact information
    - Transferee company name, address and contact information
    - A statement identifying whether the LCFS Obligation is retained by transferor or passed to the transferee
- Fuel Information
    - Fuel Pathway Code (FPC) (synonymous with Pathway Identifier) and Carbon Intensity
    - Volume (gallons or other unit amounts as appropriate)
- Fuel Production Facility Information

    Alternative Fuel Production Company ID and Facility ID as registered with RFS2 program and/or LCFS program. If an alternative fuel production facility is not registered with either the federal Renewable Fuel Standard (RFS2) or LCFS, the administrator of the LCFS Reporting Tool-Credit Bank & Transfer System (LRT-CBTS) will provide appropriate IDs for use on PTDs.
- A notice to the buyer as follows where fuel is sold without obligation:

    "This transportation fuel has been reported to the ARB LCFS Program by <*Insert name of Reporting Party holding LCFS obligation*> for intended use in California. Any export of this fuel from California by any subsequent owner or supplier must be reported to the ARB LCFS Program (www.arb.ca.gov/lcfsrt). Contact the ARB LCFS Administrator for assistance with reporting exported volumes (lrtadmin@arb.ca.gov)."

To improve the traceability of fuels to the fuel source, as well as to confirm the obligation "endpoint" in the transfer of LCFS regulated fuels, staff is proposing to require LCFS reporting by all entities in the chain of custody that held obligation for a fuel. This includes initial regulated parties, as well as those that acquired the LCFS obligation from upstream entities. Such entities are collectively referred to as reporting parties in the proposed regulation. Furthermore, all transaction types associated with the obligation transfer are to be reported. This includes reporting transaction where fuel is "Sold without Obligation Transfer" and where it is "Purchased without Obligation Transfer." The reported transactions are to include the identification of the business partners in these transactions. Additionally, staff is proposing to have all obligated LCFS transportation fuels (e.g., fuels that meet California fuel standards and were reported to claim credits in the program) be reported upon export in the LRT-CBTS.

Description of the Problem

The inclusion of the Opt-In provision has resulted in a significant increase in the number of parties registering for the LRT-CBTS. The registration process needs to gather company information more efficiently and effectively from parties that choose to opt in and better track when parties decide to opt out.

Proposed Solution

The Opt-In/Opt-Out provisions of the regulation are proposed to be revised to require that the initial registration form captures information ARB needs for the company that is opting in. Other related modifications will streamline the processing of "opt-outs" which would be implemented online.

Description of the Problem

The current LCFS requires records to be retained for three years. Given the time lag involved in developing and processing pathway applications and subsequent reporting and credit transactions, it is likely that reporting issues may need to be resolved for transactions that occurred more than three years ago; therefore, pertinent information contained in documents associated with those transactions must be maintained.

Proposed Solution

Staff proposes to increase the record retention requirements of the LCFS Program to five years from the current three-year retention requirement.

Description of the Problem

Regulated parties have indicated that the 60-day period for compiling and reconciling their quarterly data in preparation for submittal is not sufficient to ensure the 100 percent accuracy in reporting that ARB requires. The result is that there are currently more post-submittal correction requests made by regulated parties than would be necessary if more time was provided for reporting parties to thoroughly complete the reconciliation of volumes, reporting of FPCs and obligation transfer with their business partners.

Proposed Solution

The regulatory language would be changed to provide a “45/45 Schedule.” This revised schedule would provide a 45-day period for all reporting parties to upload their quarterly data in the LRT-CBTS. The second 45-day period would be for reporting parties to reconcile their reporting with that of their business partners prior to their official quarterly report submittal. As a result, the deadlines for all quarterly reports would be extended by one month. The annual reporting deadline would remain April 30th.

Description of the Problem

There is a need to have a standardized process for converting volumes of CNG and liquefied compressed natural gas (L-CNG) dispensed in gallons to volumes in standard cubic feet (scf).

Proposed Solution

An equation for converting volumes of CNG and L-CNG is proposed to be specified in the regulation, which will incorporate standard conversion factors from GREET for converting pounds of CNG and L-CNG to scf for reporting purposes.

Description of the Problem

There is a need to clearly define the requirements for reporting parties when requesting to have a previously submitted report reopened for purposes of making corrective edits.

Proposed Solution

The proposed solution is to require that the reporting party submit an Unlock Report Request Form online in the LRT-CBTS. This form would be accompanied by a letter on letterhead from the reporting party with justification for the report corrections and a description of the specific corrections that are to be made to the reopened report.

Description of the Problem

Exported fuels that at one time had an associated obligation need to be more thoroughly tracked in the LRT-CBTS, so they are not exported outside California while having an obligation which never gets reported. This will ensure that credits and deficits associated with these exported fuels are correctly reassigned to the appropriate reporting party.

Proposed Solution

A notice would be provided by the transferor of the fuel where the fuel obligation is not transferred to inform the buyer that a fuel has been reported to the California LCFS Program as intended for use in California, and any export of that fuel from California by any subsequent owner or supplier must be reported back to ARB. The original transferor would be required to report this in the LRT-CBTS.

Rationale Supporting the Proposed Solutions

The PTD will be required to include all the necessary information to track the obligation transfer and the fuel source of production, as well as other critical parameters. Clarifying and standardizing exactly what needs to be reported on a PTD should minimize both the current confusion and the time required for reconciling reports among business partners.

Complete chain of custody reporting by all entities in the supply chain of a fuel including reporting transactions where fuel is “Sold without Obligation Transfer” and where it is “Purchased without Obligation Transfer” will significantly improve the traceability of fuels to the fuel source, as well as to confirm the obligation “endpoint” in the transfer of LCFS regulated fuels.

Reporting export fuel transactions will make it much easier to account for and track fuel that has generated LCFS credits and then subsequently moved out of the state.

Revised Opt-In/Opt-Out protocols, utilizing the LRT-CBTS, will result in faster processing times. The LRT-CBTS will be able to ensure that a regulated party has at least a zero credit balance or better prior to exiting the LCFS program.

A five-year record retention period will provide additional time needed to fully review and audit reported data for enforcement of the LCFS.

With the extension of report submittal to 90 days after the end of each quarter, the accuracy of reporting is expected to improve considerably and the need for corrections after report submittal should be reduced significantly. There should be minimal impact regarding the implementation of the LCFS with this proposed change.

Defining an equation for converting CNG/L-CNG from gallons to scf will set a standard in the regulation for reporting of these volumes.

Correct reporting of exported fuel transactions will make it much easier to account for and track fuel that has generated LCFS credits and subsequently exported out of the state.

M. Enhancements to LCFS Credit Provisions

Description of the Problem

Although the current regulatory text does not explicitly require use of the online LRT-CBTS, it has become the *de facto* standard for recording credit transfers and should be defined as the official repository required for all LCFS credit transfers. The hierarchy for retiring credits should be clearly defined so that reporting parties are aware of the ordering currently used for retiring credits in the LRT-CBTS. The regulation currently contains only one reference to the issuance of credits retroactively under specified circumstances. Requests from regulated parties have shown that the reference has been misunderstood.

Proposed Solution

Staff is proposing to require use of the online LRT-CBTS for initiating and completing all credit transfers. Although the current regulatory text does not explicitly require use of the online system, it has become the *de facto* standard for recording credit transfers. The proposal would formalize this requirement and specify the current online system as the repository for all LCFS credit transactions, as well as quarterly and annual reports. The proposal sets out a timeline for credit sellers and buyers to follow so as to execute trades and have the Executive Officer approve and record them in LRT-CBTS. Further, a hierarchy for retiring credits is being provided. The proposed retirement hierarchy would continue to retire carry back credits first, followed by any credits purchased, and lastly the credits that have been generated.

Additionally, staff proposes to clarify that there will not be retroactive credit generation except in very narrow circumstances that include some situations, but not all, where review of a pathway application or Fuel Transport Mode demonstration has been delayed by ARB rather than the applicant.

Other proposed revisions would stipulate that all LCFS credits are to be calculated in the LRT-CBTS, thus aligning the regulation with current practices. The provisions for designating credits as “pending” for lack of fuel transport mode demonstration purposes will be included for handling these credits.

Rationale Supporting the Proposed Solution

The proposed changes are focused on providing clarification and consolidating various requirements for ease of finding them within the regulation. The LRT-CBTS is identified as the designated means for transferring credits. The proposed timelines for executing and recording credit transfers will support a more transparent credit market. A defined credit retirement hierarchy provides transparency to the reporting parties.

N. LRT-CBTS: Requirements to Establish an Account

Description of the Problem

Although the LRT has become the *de facto* means of recording credit transactions, its use has not been mandated. During the LCFS’s first few years, the LRT has been enhanced to include the credit trading and banking system, Given the volume and value of LCFS credit transactions in the LRT-CBTS, additional security measures are needed. Likewise, the roles and responsibilities of LRT-CBTS users need to be clearly established so that ARB staff knows whom to contact in the event of questions or problems.

The LRT-CBTS currently has only a few data requirements to create a user profile and establish a user account in the secure online system. Some entities have registered in the system because they mistakenly think that the LCFS regulation applies. Under current LCFS provisions, staff has limited means to deactivate a user account when data are not reported.

Proposed Solution

Staff proposes a mandatory registration process that will clearly identify an entity's authorized users, as well as screen entities that do not need accounts.

The proposal requires that each registering entity assign a primary and secondary account administrator to manage its account at the time of registration. The account administrators are responsible for submitting all reports and credit transactions for their organization. They would have the capability to view the entire organizational profile. The administrators can designate other users to upload and review data for quarterly reports, but such designated users cannot submit the reports, a function belonging to only the account administrators. Account administrators may also designate other company users to facilitate credit transfers or allow brokers to transact credits on behalf of their organization. Credits can reside only in an organization's account; brokers simply aid in the credit exchange. The enhanced process for establishing an account would be available for use in the LRT-CBTS when the regulation goes into effect. Many of the entities that are currently reporting into LRT-CBTS would be able to continue using their accounts, but they would need to provide any missing user profile information within 90 days of the regulation's effective date.

Rationale for the Proposed Solution

The proposed requirements to create an LRT-CBTS user account are only a modest change from actual practice, but would become readily enforceable. Having clearly-defined user roles, fulfilled by persons who have provided the requisite information, will enhance LRT-CBTS security. To the extent fraudulent activity can be prevented or failing that, prosecuted, adds to the integrity and stability of the overall LCFS program. The proposed registration process will also allow ARB to screen out unnecessary registrants.

O. Electricity Provisions

Off–Road Categories for Credit Generation

Description of the Problem

The current regulation allows regulated parties to generate credits for electricity used in on-road vehicles only. The Board directed staff in Resolutions 09-31 and 11-39 to evaluate the feasibility of issuing credits for non-road, electricity-based transportation sources, including mass transit. As a result, staff has worked with stakeholders to develop a proposal to make electricity used in fixed guideway transit systems and electric forklifts eligible to generate credits.

Proposed Solution and Supporting Rationale

In considering potential off-road categories to add to the regulation, staff selected fixed guideway transit systems and electric forklifts as categories of electric transportation that use significant and quantifiable electricity for transportation. Transit agencies report the electricity used for propulsion of fixed guideway systems annually to the National Transit Database, and electricity used to charge forklifts can be estimated with available data. Providing an opportunity for credit generation for use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce the carbon intensity of the transportation fuel pool in California, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels.

Electric forklifts, including motorized hand trucks, have taken a larger market share nationwide than internal combustion engine (ICE) forklifts powered by gasoline, propane, CNG, or diesel fuel in recent years (Industrial Truck Association 2013). An increase in electric forklift use coupled with a decrease in ICE forklift is expected to result in decreased GHG emissions and contribute to meeting the goals of the LCFS program.

Modification of Requirement for All Electricity Reported for Residential Electric Vehicle (EV) Charging be Metered

Description of the Problem

To date, many EV drivers have elected not to install dedicated EV meters at their residences. Therefore, a revised provision has been included in the proposed regulation to allow electricity providers for residential EV charging to, upon Executive Officer approval, use an estimation method to approximate residential EV charging electricity after January 1, 2015. The current regulation allows an approved estimation method to be used only through the end of 2014.

The estimation method currently being used by some utilities is based on all available directly metered data in each utility's service territory, the California Vehicle Rebate Project database, and California Department of Motor Vehicles registration data. The number of credits generated through an estimation method is not expected to differ significantly from the number of credits generated solely through the reporting of metered data (if all EV drivers employed dedicated metering to measure their charging electricity).

Proposed Solution and Supporting Rationale

Staff is proposing to modify the requirement that all reporting of electricity used in residential EV charging after January 1, 2015, be based on direct metering. The modification would allow for an approved electricity estimation method to be used, where metered data was not available, after July 1, 2015. The number of credits generated through an estimation method is not expected to differ significantly from the number of credits that would be generated solely through the reporting of metered data (if all EV drivers employed dedicated metering to measure their charging electricity).

<u>Modifications to Energy Economy Ratios (EER) for Electricity</u>

Description of the Problem

EER values for fixed guideway and forklift electricity have not previously existed in the LCFS regulation. Including values in the regulation for these sources of electricity is necessary for the calculation of generated credits.

Proposed Solution and Supporting Rationale

The current regulation includes an EER of 2.7 for heavy-duty, off-road electric vehicles. This value is based on the EER published by TIAX LLC in its February 2007 report to the California Energy Commission (CEC) titled "Full Fuel Cycle Assessment: Tank to Wheels Emissions and Energy Consumption."[16] The report was published pursuant to the requirements of California AB 1007. Performance testing and operational data are now available to calculate an EER that will more accurately reflect the fuel economy of electric buses currently in use in California. Staff is proposing to bifurcate the EER values for heavy-duty electric vehicles into two separate EER values, one for heavy-duty trucks and one for buses. Staff is proposing to include the current value of 2.7 for trucks due to the lack of available efficiency data for these vehicles. Staff is also proposing to include an EER value of 4.2 for electric buses, based on drive cycle testing in a controlled setting.

[16] TIAX LLC "Full Fuel Cycle Assessment"

Requirement to Report Credit Information in Electricity Annual Reporting

Description of the Problem

The current regulation requires regulated parties for residential and public EV charging to include public accounting of the number of credits generated, sold, and banked in annual compliance reporting. Public credit accounting is not required of regulated parties of other fuels and is unnecessary for electricity.

Proposed Solution and Supporting Rationale

Staff proposes to remove the requirement for regulated parties for residential and public EV charging to include a public accounting of the number of credits generated, sold, and banked in annual compliance reporting. Public credit accounting is not required of regulated parties of other fuels and is unnecessary for electricity.

P. Enforcement-Related Provisions

Description of the Problem

Current provisions authorizing the Executive Officer to assign, hold, or reverse credits in various situations are scattered through various parts of the regulation, making it difficult to navigate the related provisions.

Proposed Solution

Staff proposes language that explicitly empowers the Executive Officer to suspend, revoke, or restrict an LRT-CBTS account when violations have occurred or are being investigated. Such provisions could be used, for example, to prevent transactions involving credits subject to investigation regarding their authenticity.

Description of the Problem

A second enforcement-related issue with the current LCFS is the non-specific enforcement provisions. Given the existing per-day penalty statutes in Health and Safety Code (H&S) section 43025 et seq., the current LCFS is not well-suited to address violations based on year-end deficits. The H&S provides for daily penalties for each violation, up to maximums that vary for strict liability, negligence, and intentional violations. While those provisions should work well for some LCFS violations, such as submitting a late or inaccurate report, a per-day approach is an awkward tool with which to address substantive deficit violations on an annual basis. For example, a party that reported transactions resulting in a net deficit of 40 metric tons of CO_2e at the end of a given compliance year would have the same number of violations (365) as a party that ended the same year with 40,000 deficits.

Proposed Solution

Where a party violates the LCFS by failing to match each deficit with a credit by the end of a compliance period, staff is proposing to define each net deficit as a separate violation. That approach, authorized by H&S section 38580, subdivision (b)(3), allows the punishment to fit the crime. Such an approach allows courts to more fairly differentiate between the small- and large-volume fuel suppliers regulated under the LCFS. Under California law, the maximum penalty is presumed to apply absent a showing by the violator that mitigating circumstances make a lesser amount appropriate. *People ex rel State Air Resources Board v. Wilmshurst* (1999) 68 Cal.App.4th 1332. The applicable statute for fuels violations makes a violator strictly liable for a penalty of up to $35,000. As the presumptive penalty, $35,000 is a large consequence for lacking one credit, the value of which is determined by supply and demand in the LCFS market, but which, for cost containment purposes, is proposed to be capped at $200. For that reason, along with defining violations in terms of deficits, staff is proposing to set the presumptive per-deficit penalty at a maximum of $1,000.

While regulated parties should already understand that violations of LCFS provisions are already subject to per-day penalties, the proposed regulation expressly underscores that inaccurate, incomplete, or late reports constitute a violation for each and every day that the report remains inaccurate, incomplete, or late.

Rationale Supporting the Proposed Solutions

Clearly empowering the Executive Officer to take practical action to suspend an account or otherwise prevent improper credit transactions will strengthen the LCFS credit market and the program overall. The provisions defining violations are meant to provide clear notice to regulated parties regarding potential penalties. Defining certain violations on a per-credit basis allows ARB to seek, and a court to impose, penalties that are proportionate. As always, enforcement provisions should allow for remedies that are fair, consistent, and effective at deterring and remedying violations.

Q. Regulated Party Miscellaneous Updates

Description of the Problem

Diesel is both a finished fuel and a blendstock and, as such, the compliance obligation may be retained or passed along by the producer or importer of the fuel. However, there are cases where downstream parties who purchase “below the rack” (i.e., non-bulk transfers) are receiving the obligation with knowledge as it would be stated on the Product Transfer Document. These downstream entities could be retail outlets and end users and would likely not have the means to comply with the regulation.

Proposed Solution

A provision has been proposed in the regulation that would limit the diesel obligation transfer to only occur “above the rack.”

Rationale Supporting the Proposed Solution

This provision would align with the current gasoline provision where end users and retail outlets could not receive an obligation. The obligation would stay above the rack where the wholesale purchaser of the fuel has the capability to blend biomass-based diesel fuels to offset diesel deficits.

Description of the Problem

Liquefied natural gas (LNG) can be brought to a compressed natural gas (CNG) dispensing station where it is then converted back to CNG before being dispensed into the vehicle for use. (The LNG-to-CNG natural gas is referred to as L-CNG.) The current regulation does not clearly identify the regulated party for such situations. Under the current regulation, the initial regulated party for LNG is the provider of the LNG to the dispensing station, whereas the initial regulated party for CNG is the owner of the dispensing equipment.

Proposed Solution

A definition for L-CNG as LNG that is re-gasified and dispensed as CNG is proposed to be added to the regulation. The regulated party for L-CNG fuel is proposed to be aligned with LNG, where the initial regulated party is the owner of the LNG when it is delivered to a CNG station.

Rationale Supporting the Proposed Solution

A clear identification of regulated party for L-CNG fuel will avoid confusion between various entities in the supply chain of that fuel. Aligning the regulated party designation with LNG will ensure that the entity who is investing the greatest capital to bring the fuel to California is first in line to generate credits.

R. Severability.

Description of the Problem

Absent a severability provision, it is possible that a court would find one discrete portion of the LCFS to be invalid yet feel obligated to invalidate the entire LCFS.

Proposed Solution

Because it is not staff's intent that the entire regulation be invalidated in the event one provision is deemed illegal, staff proposes adding a severability provision to clarify that intent.

Rationale Supporting the Proposed Solution

This provision is necessary because it ensures that if one provision is ruled to be illegal, the remaining provisions can remain in effect, protecting the environment as well as investor expectations.

III. DESCRIPTION OF PROPOSED REGULATION

This chapter is a plain English discussion of the key requirements of the proposed LCFS regulation, including updates and revisions compared to the current regulation. The chapter follows the structure of the proposed regulation and provides an explanation of each major requirement of the proposal. This chapter is intended to satisfy the requirements of Government Code section 11346.2, which requires that a non-controlling "plain English" summary of the regulation be made available to the public. All section references are to the LCFS regulation (Cal. Code Regs., tit.17, §§ 95480-95496), unless otherwise noted.

A. Purpose of the Proposed Regulation

The re-proposed regulation would meet the goals of the current regulation in place by reducing the carbon intensity of transportation fuels used in California by at least ten percent by 2020 from a 2010 baseline; reducing carbon intensity is expected to reduce greenhouse gas emissions and support the development of a diversity of cleaner fuels with other attendant co-benefits. Carbon intensity is a measure of the direct and other GHG emissions associated with each of the steps in the full fuel-cycle of a transportation fuel, divided by the fuel's energy content. Thus, carbon intensity is typically expressed in terms of grams of CO_2 equivalent per megajoule (gCO_2e/MJ).

The LCFS achieves a ten percent reduction in average carbon intensity by starting specified providers of transportation fuels (referred to as "regulated parties") at an initial level and incrementally lowering the allowable carbon intensity for transportation fuels used in California in each subsequent year. A regulated party's overall carbon intensity for its pool of transportation fuels would then need to meet each year's specified carbon intensity level. Regulated parties can meet these annual carbon intensity levels with any combination of fuels they produce or supply and with LCFS credits banked in previous years or acquired from other regulated parties.

As indicated, the LCFS is based on a system whereby credits, which are generated from fuels with lower carbon intensity than the annual carbon intensity standards, balance the deficits that result from the sale of fuels in California that have higher carbon intensity than the annual carbon intensity standards. A regulated party would meet the carbon intensity requirements if the amount of credits at the end of the year is equal to, or greater, than the deficits. Credits and deficits are determined based on the amount of fuel sold, the carbon intensity of the fuel, and the efficiency by which a powertrain converts the fuel into usable energy. Credits may be retained and traded by regulated parties within the LCFS market to meet their obligations. LCFS credits never expire; therefore, unused credits may be carried forward to meet compliance obligation in future years.

Under the LCFS, a regulated party's compliance with the annual carbon intensity requirements is based on end-of-year credit/deficit balancing for each year. Technically, the LCFS went into effect in 2010, but the first year of the program was a reporting year only, which allowed both the regulated parties and ARB program staff to acclimate to the LCFS rule's intricacies and to identify any programmatic changes that may be needed as the program is implemented.

A key function of the LCFS is to incent the use of lower-carbon intensity alternative fuels (i.e., fuels that are not conventional gasoline or diesel fuel). Alternative fuels include, but are not limited to, biofuels such as ethanol, biodiesel, and renewable diesel fuel; compressed or liquefied natural gas, both from petroleum or from biomass sources; hydrogen; and electricity. Each of these fuels will have carbon intensity values associated with a life cycle analysis that will ultimately include other effects, including effects from land use changes, if any.

B. Definitions and Acronyms

Staff has defined key terms that are used throughout the regulation to provide clarity and avoid confusing terminology that may be used in a different context in other regulations or settings. There are a number of definitions within the regulation to facilitate implementation of the LCFS program. Some key definitions are as follows:

"Transportation fuel" means any fuel used or intended for use as a motor vehicle fuel or for transportation purposes in a non-vehicular source.

"Blendstock" means a component that is either used alone or is blended with another component(s) to produce a finished fuel used in a motor vehicle. Each blendstock corresponds to a fuel pathway in the CA-GREET. A blendstock that is used directly as a transportation fuel in a vehicle is considered a finished fuel.

"Carbon intensity" means the amount of life cycle greenhouse gas emissions, per unit of energy of fuel delivered, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ).

"Credits" and "deficits" are the measures used for determining a regulated party's compliance with average carbon intensity requirements in the proposal. Credits and deficits are denominated in units of metric tons of carbon dioxide equivalent and are calculated in accordance with the specified procedures.

"Finished fuel" means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.

"Life cycle greenhouse gas emissions" means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Executive Officer, related to the full fuel life cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

“Regulated party” means a person who must meet the average carbon intensity requirements specified in the proposal.

“Reporting Party” means any entity who, pursuant to section 95483 or 95483.1 is the initial regulated party, or a person to whom the compliance obligation has been transferred directly or indirectly from the initial regulated party.

“Product Transfer Document (PTD)” means a document that authenticates the transfer of ownership of fuel from a regulated party to the recipient of the fuel. A PTD is created by a regulated party to contain information collectively supplied by other fuel transaction documents, including Bills of Lading, invoices, contracts, meter tickets, rail inventory sheets, Renewable Fuels Standard product transfer documents, etc.

C. Fuels Subject to Regulation

Staff has listed the fuels that are subject to the regulatory provisions because they do not meet the compliance standard for 2020 and, therefore, can generate both credits and deficits over the timeframe of the LCFS. Also included is a list of fuels that are available to meet the 2020 compliance standard and how parties may elect to opt into the LCFS program to generate credits for those fuels. Lastly, a provision has been included that excludes certain applications, such as interstate locomotives and military vehicles. The proposal exempts any alternative fuel that is not biomass-based or renewable biomass-based and for which the aggregated volume by all parties for that fuel is less than 420 million megajoules per year (3.6 million gasoline gallon equivalent per year). This is intended to exempt research fuels entering the market or very-low-volume niche fuels. In addition to the low-volume exemption, the proposal does not apply to regulated parties providing liquefied petroleum gas (LPG or propane) as it does not play a significant role as a transportation fuel in the California market.

D. Regulated Parties

(1) Regulated Parties for Gasoline and Diesel

For gasoline and diesel fuel (i.e., “conventional” transportation fuels), crude oil is produced from the ground and then transported to a refinery where it is processed into various refinery products, including material that eventually goes into gasoline and diesel fuels. California refineries produce CARBOB, which is transported through pipelines, blended with ethanol at distribution terminals, and distributed to retail outlets as finished gasoline.

The California Reformulated Gasoline (CaRFG3) regulations describe the standards applicable to all gasoline produced or imported into California.[17] Imported gasoline must be CaRFG3-compliant. Enforcement can be conducted anywhere in the distribution system. CaRFG3 provides standards that can be enforced through quantitative analysis. Fuel quality can be tested, and compliance can be easily determined. For the LCFS regulation, however, the definition of regulated parties must

[17] Title 13, California Code of Regulations, section 2260 et seq.

also take into consideration the availability of carbon intensity data and the extent to which the data are verifiable.

Currently, seven large oil companies supply over 90 percent of the gasoline sold in California. Producers and importers are already subject to CaRFG3 regulations and are considered the regulated parties for the federal RFS2.

Thus, for gasoline, diesel, and other liquid blendstocks (including oxygenates and biodiesel) the regulated party is the producer or importer of the fuel or blendstock, or certain recipients, as specified in the regulation. Upon transfer of title to the fuel, the obligation to maintain compliance with the LCFS regulation may flow from the transferor to the recipient (i.e., the transferee). For example, the compliance obligation would flow from the regulated party to the recipient if the recipient were another producer or importer. However, the parties may enter into a contract for the transferor to retain the compliance obligation (along with the credits and deficits for the transferred fuel). In cases where the obligation is transferred, the transferor must provide the transferee a product transfer document containing pertinent information for LCFS reporting by both parties.

(2) Regulated Party for Liquid Alternative Fuels Not Blended with Gasoline or Diesel Fuel

Because liquid alternative fuels are likely to have CIs lower than the compliance standard, staff has developed provisions that state the regulated party is the producer or importer of the fuel.

(3) Regulated Party for Blends of Liquid Alternative Fuels and Gasoline or Diesel Fuel

Because liquid alternative fuels are likely to have CIs lower than the compliance standard, staff has developed provisions for the transfer of the obligation with the default action being that the obligation would remain with the fuel unless otherwise stated clearly on a product transfer document. This is intended to allow the credits that are generated by the fuel to be used to offset the deficits of the fuel that is being blended with it.

(4) Regulated Parties for Natural Gas

(a) Fossil CNG

The general production and distribution path for most fossil CNG is as follows: natural gas, after extraction from the production well, may be treated to bring it up to gas pipeline specifications at a processing plant. The gas is then sent through the transmission system to the “city gate,” where it is decompressed and odorized. The gas is then sent to the fueling station via the low-pressure distribution system.

Staff proposes to denote the first initial regulated party to be the entity that has invested the greatest capital to supply the natural gas fuel to California and convey it into the transportation fuel pool.

In most fossil CNG cases, the regulated party would be the local utility company. However, if the gas is purchased from an energy service provider (ESP) or other entity that owns the fuel dispensing equipment, the ESP or the dispensing equipment owner will be the regulated party since title to the gas would belong to them, and they are providing the gas for transportation use. In this case, the local utility company is serving only as a conduit for the gas to be transported at the behest of these entities. The ESP or the owner of dispensing equipment is providing the gas for transportation use is responsible for the gas quality, and, therefore, it should be the regulated party in such cases.

(b) Fossil LNG and Fossil L-CNG

For fossil-based LNG as a transportation fuel, production methods and fuel providers can vary. At present, LNG for motor vehicle fuel use is derived via two main routes. These are liquefaction of pipeline natural gas, which may be used directly at the source of liquefaction or involve truck transport of the LNG to a separate end-user, and the liquefaction and direct use of bio-methane derived from landfill gas and anaerobic digestion.

Staff proposes that the regulated party for fossil LNG be the person or entity that owns the title to the LNG when it is transferred to the fuel dispensing equipment in California. This would keep in line with the idea that the entity investing the greatest amount of capital into providing the transportation fuel would be granted the first opportunity to generate credits.

In some instances, LNG is re-gasified and dispensed as CNG. Staff proposes that the regulated party designation for L-CNG is aligned with LNG.

(c) Biomethane

For biomethane-derived fuels, such as bio-CNG, bio-LNG, and bio-L-CNG, it is important to provide regulated party status to the entity that has invested the greatest capital, which is the producer of fuel. This will allow those producers to retain the ability to generate credits for such fuels, even if the biomethane is blended with fossil-based natural gas. However, the upstream biomethane producers should work with downstream entities in the supply chain of biomethane, like the liquefaction facility and CNG dispensing station owners to ensure appropriate documentation to prove that the biomethane was used for fueling California vehicles.

(5) Regulated Parties for Electricity

Electric Vehicle (EV) Charging in Single- and Multi-family Residences

The LCFS regulation designates electric utilities as the regulated parties for EV charging in single- and multi-family residences. Several requirements that must be met before utilities can receive credit for residential charging. Utilities must:

1. Use all credit proceeds as direct benefits for current EV customers.

2. Provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid.

3. Educate the public on the benefits of EV transportation through outreach efforts.

4. Include in annual reporting a summary of efforts to meet requirements 1, 2, and 3, as well as an accounting of the number of EVs known to be operating in the service territory.

EV Charging through Public Charging Equipment

The LCFS regulation designates non-utility Electric Vehicle Service Providers (EVSPs) and electric utilities as the regulated parties for transportation fuel supplied through public charging equipment that they have installed. For the LCFS regulation, a non-utility EVSP is defined as the entity that installs the EV-charging equipment, or has had an agent install the equipment, and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment. The contract must be valid during the corresponding reporting period. For a utility to qualify as the regulated party for public access charging, the utility would also need to have a similar contract valid during the reporting period.

EV Fleet Operators

Under the LCFS regulation, a company operating a fleet of three or more EVs may opt into the regulation to become a regulated party, while the utility is eligible to be the regulated party for fuel supplied to fleets of less than three EVs. If the fleet operator chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with Executive Officer approval. To receive credit for fuel supplied to an EV fleet, regulated parties must annually report an accounting of the number of EVs in the fleet.

EV Charging through Private Charging Equipment

Employers who offer on-site EV charging equipment for their employees may opt into the LCFS to generate credits. If the employer chooses not to become a regulated party, the electric utility operating in the service territory where the fleet vehicles are charged can become eligible to be the regulated party with Executive Officer approval. Requirements for regulated parties for employee EV charging include:

1. Educate employees on the benefits of EV transportation.

2. Annually report on the efforts of (1), as well as an accounting of the number of EVs known to be charging at the business.

<u>Proposed Off–Road Categories for Credit Generation</u>

In considering potential off-road categories to add to the regulation, staff concluded that fixed guideway transit systems and electric forklifts should be included as categories of electric transportation that qualify to generate credits because they use significant and quantifiable electricity for transportation.

(a) Fixed Guideway Systems

For the purposes of the LCFS regulation, a fixed guideway system is a system of public transit electric vehicles that can operate only on its own guideway (directly operated, or DO) constructed specifically for that purpose, such as light rail, heavy rail, cable car, street car, and trolley bus. In California, these systems can provide lower carbon transportation for millions of passenger trips (American Public Transportation Association Transit Ridership Report 2014).[18] Providing an opportunity for credit generation for use of electricity as a transportation fuel supports the overall purpose of the LCFS to reduce the carbon intensity of the transportation fuel pool in California, reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low carbon fuels.

Staff proposes that transit agencies operating fixed guideway systems are eligible to opt into the LCFS program to generate credits for electricity used to propel fixed guideway systems. There are six transit agencies in the state reporting electricity use for transit propulsion in fixed guideway systems annually to the National Transit Database (National Transit Database, Federal Transit Association 2012).[19] Staff further proposes to allow Electrical Distribution Utilities (EDUs) to be regulated parties for electricity used for propulsion in fixed guideway systems in their service area if the transit agency is unable or unwilling to participate in the program. Staff is proposing that ARB Executive Officer approval is required for an EDU to generate credits for fixed guideway systems.

In the LCFS program, the credit calculation includes a value to represent the efficiency of a transit system compared to the efficiency of the mode of transport riders would have taken if the system was not available. This value, the EER, is often in units of fuel energy per distance traveled (MJ/mile). To determine EERs for electric vehicles, light-duty vehicles are compared to light-duty conventional vehicles, and heavy-duty vehicles are compared to heavy-duty diesel buses. Because fixed guideway systems

[18] APTA Transit Ridership Report
[19] National Transit Database, 2012 Table 17 Energy Consumption

are capable of carrying a greater number of passengers than light-duty vehicles or buses, the number of passengers using the system per mile traveled is a more appropriate comparison. Therefore, EERs for fixed guideway systems calculated for the LCFS program are as follows:

$$EER = \frac{energy\ (MJ)/(total\ passengers)(total\ miles\ traveled)_{urban\ diesel\ bus}}{energy(MJ)/(total\ passengers)(total\ miles\ traveled)_{fixed\ guideway\ system}} \qquad \text{Eq. 1}$$

This method accounts for the fact that transit cars operating with a full load of passengers are more efficient, in general, than transit cars that carry few passengers.

Staff determined EER values for transit systems compared to both a passenger car and a diesel transit bus. Transit surveys suggest that approximately one-third of passengers would have otherwise taken their trip using a car and one-third would have taken a bus (the remaining one-third gave a variety of answers, including not taking the trip, carpooling, or unknown) (Bay Area Rapid Transit 2012).[20] There is little difference between making the efficiency comparison to a vehicle or to a bus, and staff chose to compare the energy use of the fixed guideway system to the energy use of a diesel bus.

To calculate EER values, energy used for propulsion was obtained from the National Transit Database, and ridership data was obtained from the American Public Transportation Association Ridership Report.

EER values can vary significantly between different types of fixed guideway systems in California (light rail, heavy rail, trolley bus). For this reason, staff is proposing to use an average EER value for each system type. Under the proposal, cable cars and street cars will use the EER designated for trolley buses.

Because the displacement of diesel fuel cannot be entirely attributed to the LCFS for the transit lines that were also operating in 2010, staff proposes to use a modified credit formula that does not give credit for diesel fuel displacement. The modified credit formula is:

$$Credits\ (MTCO_2e) = \left(CI_{standard} - CI_{reported}\right)\ x\ E_{propulsion}\ x\ C \qquad \text{Eq. 2}$$

where:

$CI_{standard}$ is the carbon intensity requirement of diesel fuel for a given year;

$CI_{reported}$ is the adjusted carbon intensity value of electricity, in gCO_2e/MJ, calculated as per section 95486(b)(3)(B);

$E_{propulsion}$ is the total amount of energy used for fixed guideway transit propulsion, in MJ; and

[20] BART 2012 Customer Satisfaction Survey

$$C = 1.0x10^{-6}\frac{MTCO_2e}{gCO_2e}$$

For credits associated with future fixed guideway system expansion that includes extension to existing track, staff proposes to use the credit formula in section 95486(b)(3), which provides for diesel displacement credit.

Staff estimates that during the 2015 to 2020 timeframe, total credit generation for fixed guideway transportation could potentially be as high as one million credits ($MTCO_2e$) if all regulated parties opted into the program and reported all electricity used for propulsion. Based on an estimated credit value range of $40 to $100, these credits could be valued at $40 million to $100 million. If all fixed guideway transportation credits were generated and all credits were sold to satisfy program obligations, the impact on the LCFS program could be one percent of the cumulative program GHG reductions for both the gasoline and diesel standards.

(b) Electric Forklifts

Electric forklifts, including motorized hand trucks, have taken a larger market share nationwide than ICE forklifts powered by gasoline, propane, compressed natural gas, or diesel fuel in recent years (Industrial Truck Association 2013).[21] Based on population, staff estimates the number of Class 1, 2, and 3 electric forklifts delivered to California in 2013 was approximately 12,800 (Industrial Truck Association 2013, U.S. Census Bureau 2014[22]). An increase in electric forklift use coupled with a decrease in ICE forklift is expected to result in decreased GHG emissions and contribute to meeting the goals of the LCFS program.

Staff proposes that EDUs are designated as eligible to opt into the LCFS program to generate credits for electricity used to charge forklifts. Some EDUs have opted into the program and are currently reporting for on-road EVs.

For electric forklifts to be included in the regulation, a method to approximate the amount of electricity used to power them must be developed. Many electric forklifts are charged without the use of a dedicated meter to measure electricity use. Forklift fleet operators often charge batteries used in multiple equipment types using the same charging equipment and meter. In addition, tracking metered data for thousands of forklifts would likely be cost-prohibitive. For these reasons, staff proposes to estimate the amount of electricity used to charge electric forklifts in each utility service area. The number of forklifts used in California and the amount of electricity used by the fleet can be estimated using national shipment data, battery size, assumed annual operating hours and load factor. Further, each utility's share can be approximated based on their share of the state's non-residential (business/commercial) accounts.

[21] ITA 2014, United States Factory Shipments Through 2013
[22] U.S. Census Bureau "Annual Estimates of the Resident Population"

Because the displacement of diesel fuel cannot be attributed entirely to the LCFS for the forklifts that were already operating in 2010, staff proposes to use a modified credit formula that does not give credit for diesel fuel displacement. The modified credit formula is:

$$Credits\ (MTCO_2e) = \left(CI_{standard} - CI_{reported}\right)\ x\ E_{propulsion}\ x\ C \qquad \text{Eq. 3}$$

where:

$CI_{standard}$ is the carbon intensity requirement of diesel fuel for a given year;

$CI_{reported}$ is the adjusted carbon intensity value of electricity, in gCO_2e/MJ, calculated as per Section 95486(b)(3)(B);

$E_{propulsion}$ is the total amount of energy used for electric forklifts, in MJ; and

$$C = 1.0x10^{-6}\frac{MTCO_2e}{gCO_2e}$$

The efficiency of electric forklifts was analyzed in a report published by the Electric Power Research Institute (EPRI).[23] Staff proposes to use the EER value of 3.8 for electric forklifts based on the report.

Staff estimates that during the 2015 to 2020 timeframe, total credit generation for electric forklifts could potentially be as high as 245,000 credits ($MTCO_2e$) if all regulated parties opted into the program and reported all electricity used for forklifts. Based on an estimated credit value range of $40 to $100, these credits could be valued at $10 million to $25 million. If all electric forklift credits were generated and all credits were sold to satisfy program obligations, the impact on the LCFS program could be 0.3 percent of the total program GHG reductions for both gasoline and diesel standards.

Proposed Modification of Universal Metering Requirement for Residential EV Charging

Staff is proposing to modify the requirement that all reporting of electricity used in residential EV charging after January 1, 2015, be based on direct metering. The modification would allow for an approved electricity estimation method to be used, where metered data was not available, after January 1, 2015. To date, many EV drivers have elected not to install dedicated EV metering at their residences. Therefore, a provision has been included in the regulation to allow regulated parties for residential electricity to, upon Executive Officer approval, use an estimation method to approximate residential EV charging electricity.

The estimation method currently being used by some utilities is based on all available directly metered data in each utility's service territory, the California Vehicle Rebate

[23] EPRI, Energy Efficiency and Performance Testing for Non-Road Electric Vehicles

Project database,[24] and California Department of Motor Vehicles registration data. The number of credits generated through an estimation method is not expected to differ significantly from the number of credits that would be generated solely through the reporting of metered data (if all EV drivers employed dedicated metering to measure their charging electricity).

Proposed Removal of Requirement to Report EV Credit Information in Annual Reporting

Staff proposes to remove the requirement for regulated parties for residential and public EV charging to include a public accounting of the number of credits generated, sold, and banked in annual compliance reporting. Public credit accounting is not required of regulated parties of other fuels and is unnecessary for electricity.

(6) Regulated Parties for Hydrogen or a Hydrogen Blend

Because hydrogen already meets the standard for 2020 in the LCFS program, it is considered an opt-in fuel. As such, regulated parties for hydrogen may participate in the program to generate credits. For hydrogen as a transportation fuel, the party who owns the finished fuel at the time it is created, consisting of hydrogen or a hydrogen blend, is eligible to generate credits. Regulated party status can be transferred.

The proposed provisions for hydrogen have been revised to more clearly reflect the fact that hydrogen is an opt-in fuel and not obligated to meet the standard.

E. Opt-In Parties

The LCFS program has fuels that currently meet the 2020 compliance standard. As such, staff determined that provisions would be needed to allow parties that were producing or importing these fuels to opt into, as well as opt out of the program. These provisions determine who is eligible to be an opt-in party and how they would fall under the jurisdiction of the program. The next section explains the process for opting into the LCFS program and setting up an LRT-CBTS account for reporting purposes.

Staff also developed provisions for how an opt-in party can opt out of the program if they find the program does not suit their needs or they are no longer conducting business related to fuel delivery to the California transportation fuel pool.

F. Proposed Revisions to Establishing an LCFS Reporting Tool Account

The LRT was initially deployed in 2010 to support LCFS implementation. This tool was initially envisioned to house fuel transaction data; it now also encompasses the LCFS credit banking and trading system, hence the name LRT-CBTS. This later addition incorporated the LCFS credit trades made between regulated parties, a key compliance strategy.

[24] CVRP database, Clean Vehicle Rebate Project Rebate Statistics

With the incorporation of the credit banking and trading system within the LRT, additional “gate-keeping" and security restrictions are needed. The proposed requirements to create an LRT-CBTS user account are meant, in part, to screen out unnecessary accounts. The requirements are similar to what is currently in use with the additional requirement that all registering organizations must state how they qualify for an account and make various disclosure attestations. ARB staff has worked closely with stakeholders during the development of this reporting tool and will continue to do so as the tool is augmented to updated user profile to include primary and secondary account administrators. Account administrators may also designate other company users to facilitate credit transfers or allow brokers to transact credits on behalf of their organization.

H. Average Carbon Intensity Requirements

Since the court ruled that the LCFS would remain in effect and be enforceable at the 2013 regulatory standards while ARB cures the procedural defects associated with the regulation’s original adoption, staff developed an illustrative compliance scenario and evaluated potential compliance curves relative to 2013. ARB used a step-by-step approach to determine the feasibility of complying with an LCFS CI reduction goal of ten percent by 2020. (See Appendix B for additional details.) The demand for California transportation fuel is based on an estimate of how total energy demand for fuels will change from a 2013 baseline. The 2013 baseline was derived from data reported in the LCFS Reporting Tool (LRT). ARB combined estimates for fuels typically used by light-duty vehicles (gasoline, ethanol, and electricity) to create an estimate of the fuel energy subject to the LCFS gasoline standard. Similarly, ARB assumed that the remaining fuels (CARB diesel, biodiesel, renewable diesel, and natural gas) were subject to the LCFS diesel standard.

Note that in light of an anticipated statewide GHG 2030 target that is significantly lower than the AB 32 goal for 2020, it is expected that ARB will revisit the LCFS standard before 2020 to establish greater reductions targets for the 2021 through 2030 period.

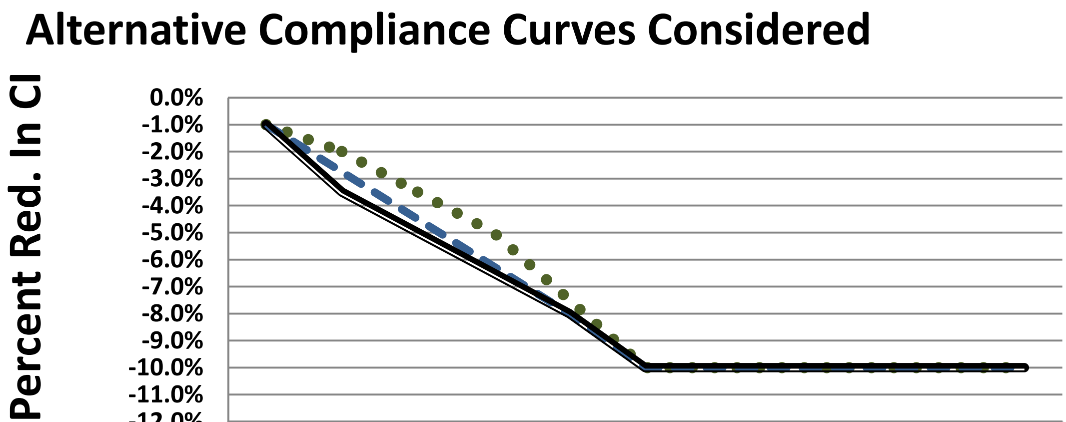
Using the information described in Appendix B, staff designed a illustrative estimate of the mix of fuels that could be used pursuant to the LCFS. This mix was then used to evaluate several compliance curves that target reaching a ten percent LCFS reduction goal in 2020. This analysis was performed for three different trajectories that staff believe best bound the available options. These were:

- Option 1: Use the percent reductions in the existing rule to define standards for 2016 to 2020,

- Option 2: Use a straight line to go from one percent standard in 2015 to ten percent in 2020, and

- Option 3: Use a more gradual approach from a one percent standard in 2015 to ten percent in 2020.

Figure III-1. Alternative Post-2015 Compliance Curves Considered



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
More Gradual Path to 10% in 2022	-1.0%	-2.0%	-3.5%	-5.0%	-7.5%	-10%	-10%	-10%	-10%	-10%	-10%
Straight Line to 10% in 2020	-1.0%	-2.8%	-4.5%	-6.3%	-8.0%	-10%	-10%	-10%	-10%	-10%	-10%
Base Case - 10% in 2020	-1.0%	-3.5%	-5.0%	-6.5%	-8.0%	-10%	-10%	-10%	-10%	-10%	-10%

Each option produces sufficient credits to enable compliance through 2019, and Options 2 and 3 show sufficient credits availability through 2020. By 2022, all options show annual reductions in excess of the ten percent reduction requirement.

Annual credit production in all scenarios is less than needed to offset annual deficit creation in a three- to five-year period around 2020. Therefore, compliance requires that substantial amounts of banked credits be used starting as early as 2017. However, due to the difference in banked credits achieved in the three approaches, only the Option 3, gradual path, compliance curve provides sufficient credits to allow compliance by all parties throughout 2020 in the 2025 period.

ARB staff believes it is necessary to maintain a significant quantity of credits, well above the total that is needed for compliance (a situation that relies on all excess credits being available for transfer to others). In addition to current year compliance, a supply of extra credits is equally important to producing a liquid and competitive credit market. With the fuel mix used in the illustrative scenarios, only Option 3 provides this buffer. For this reason, Option 3 is being proposed as the revised compliance curve. Table III-1 shows the carbon intensity values of gasoline and gasoline-substitutes, and diesel and diesel-substitutes from 2011 to 2020. This table includes the 2011 and 2012 CI-reduction targets required by the original LCFS regulation; the 2013 CI-reduction targets associated with the 2011 LCFS amendments; the 2014 and 2015 CI-reduction targets as they were frozen in place by a court order at 2013 levels; and the proposed post-2015 CI-reduction targets to achieve a ten percent CI reduction in 2020 from a 2010 adjusted baseline.

Table III-1. LCFS Compliance Schedules

Year	*Average Carbon Intensity for Gasoline and Fuels Substituting Gasoline (gCO_2e/MJ)*	*Average Carbon Intensity for Diesel and Fuels Substituting Diesel (gCO_2e/MJ)*
2010	Reporting Only	
2011	95.61	94.47
2012	95.37	94.24
2013	97.96	97.05
2014	97.96	97.05
2015	97.96	97.05
2016	97.20	100.76
2017	95.71	99.22
2018	94.22	97.68
2019	91.74	95.11
2020 and subsequent years	89.26	92.54

I. Demonstrating Compliance

Section 95485 of the proposed regulation specifies that a regulated party must possess and retire qualifying credits[25] equal to its deficits (as defined by its compliance obligation) by the time the regulated party submits its annual compliance report. The term “Credit Balance” is used in the proposed regulation to determine the total number of credits in a regulated party’s credit account. This is the maximum number of credits that can be retired for compliance. The credit balance for a regulated party is maintained in an accounting credit balance ledger in the LRT-CBTS, which stores and displays the credits and deficits generated, credits carried over from year to year, credits acquired, credits sold or exported, credits on hold, as well as the amount of credits to be retired. A regulated party’s compliance obligation is defined as the sum of all deficits a regulated party generates in the current compliance period. Specific conditions under which a deficit carryover to the next compliance period is allowed without penalty are also specified in this section.

[25] Qualifying credits must have been generated by a regulated party prior to the end of an annual compliance period.

The credit balance is computed per Equation 4:

$$CreditBalance = \left(Credits^{Gen} + Credits^{Acquired} + Credits^{CarriedOver}\right) \\ -\left(Credits^{Retired} + Credits^{Sold} + Credits^{OnHold} + Credits^{Exported}\right) \quad \text{Eq. 4}$$

where:

$Credits^{Gen}$ are the total credits generated as calculated in the LRT-CBTS according to Equation 6 of this report;

$Credits^{Acquired}$ are the credits purchased or otherwise acquired in the current compliance period;

$Credits^{CarriedOver}$ are the credits carried over from the previous compliance period;

$Credits^{Retired}$ are credits forfeited to offset a compliance obligation (a “deficit”) within the LCFS for the previous compliance period(s) at the time of annual report submittal;

$Credits^{Sold}$ are the credits sold/transferred during the compliance period;

$Credits^{OnHold}$ are the credits placed on hold due to enforcement/administrative action. While on hold these credits cannot be used for meeting an annual compliance obligation; and

$Credits^{Exported}$ are the credits exported to programs outside the LCFS for the compliance period.

The Compliance Obligation is computed per Equation 5:

$$ComplianceObligation = \left(Deficits^{Generated} + Deficits^{CarriedOver}\right) \quad \text{Eq. 5}$$

where:

$Deficits^{Generated}$ are the total deficits generated as calculated in the LRT-CBTS according to Equation 7 in Section J of this Chapter; and

$Deficits^{CarriedOver}$ are the total deficits carried over from one compliance period to the next when the compliance status of the reporting party is other than “Deficit-In Violation” and not deferred pursuant to section 95485(c) of the regulation.

For a compliance period, depending on the current credit balance, the compliance obligation and the previous compliance status, the resulting compliance status of a reporting party will be one of three below.

(1) Non-Negative LCFS Credit Balance

If a regulated party has acquired or generated enough LCFS credits such that the $CreditBalance$ is greater or equal to zero for a given compliance period after offsetting the entire $ComplianceObligation$, the regulated party has demonstrated compliance with the LCFS fuel carbon intensity requirements. The full $CreditBalance$ for a given compliance period may be rolled over to the next compliance period as $Credits^{CarriedOver}$ if there is no outstanding $ComplianceObligation$.

(2) Insufficient Credits ("Deficit but No Violation" Status)

If a regulated party has not generated,acquired, or carried over sufficient LCFS credits to retire and offset the entire $ComplianceObligation$ for the given compliance period, they may be able to be considered in compliance for that year via the proposed year-end clearance market. The Executive Officer will consider a regulated party with an unmet compliance obligation to be in compliance for that year if it participates in the LCFS credit clearance market, provided the following conditions are met:

- The regulated party acquires in the credit clearance market and retires the number of credits specified as their pro-rata obligation, by July 31st.

- If, after acquiring and retiring their pro-rata share of credits, the regulated party retains a compliance deficit, that regulated party must generate, transfer, or acquire the credits needed to meet the carried-over deficit balance plus interest, and retire these credits to the Executive Officer.

- To buy or sell credits in the credit clearance market, regulated party must purchase, transfer, and/or sell any credits in the clearance market at or below that year's pre-determined cap price.

To qualify for compliance via the credit clearance market, the regulated party must meet all of the following conditions:

- The regulated party must first retire for compliance all of the credits currently in its possession, including all carry-back credits acquired for the prior year.

- The regulated party must have unmet compliance obligations for the prior year after retiring all credits.

Regulated parties required to purchase credits in the Clearance Market must:

- Ensure that all carry-back credits are reflected in that regulated party's current credit balance;

- Retire for compliance purposes the regulated party's entire current credit balance, including the carry-back credits;

- Purchase no more than their pro-rata share of credits from the credit clearance market; and

- Purchase their pro-rata share of credits available in the clearance market at or below that year's cap price.

- Clearance market credits can be used for the purpose of meeting the regulated party's compliance obligation only from an immediate prior year.

<u>Pledging Credits for Sale into the Clearance Market</u>

The Executive Officer shall issue to all regulated parties a call for credits to be pledged for sale in the Clearance Market on the first Monday of April of each year. In the call for credits, the Executive Officer will inform regulated parties of that year's Maximum Price for Credits ($200 plus inflation). Regulated parties pledging credits for sale into the Clearance Market must report to the Executive Officer the quantity of any credits they are pledging for sale in their Annual Reports, due April 30th. Only regulated parties that have achieved compliance for the prior year, and that do not have an unmet compliance obligation for the compliance year, can pledge credits for sale into the Clearance Market.

By pledging credits for sale in the Clearance Market, regulated parties agree to the following provisions:

- Sell or transfer credits at or below a pre-established maximum price,

- Accept any offer to buy pledged credits at that year's maximum price,

- Withhold pledged credits from sale on the regular LCFS credit market until July 31st,

- The Executive Officer will announce whether a Clearance Market will occur on or before June 1st of each year, and

- If the Executive Officer announces that a Clearance Market will not be held that year, parties who have pledged credits to the Clearance Market may thereafter sell or transfer those credits in the ongoing credit market.

<u>Operation of the Clearance Market</u>

The Executive Officer will announce whether a Clearance Market will occur for a given compliance year on or by June 1st. A Clearance Market will occur if one or more parties failed to meet its annual compliance obligation under section 95485(a) and one or more parties has pledged credits for sale in the Clearance Market. If those two conditions do not occur, the Executive Officer will determine a Clearance Market will not be held for that compliance year.

By June 1, the Executive Officer will post on the ARB web site the following:

- The names of any parties obligated to purchase in the Credit Clearance Market; and

- The names of parties that have pledged credits into the Credit Clearance Market.

If the Executive Officer has determined the Clearance Market will occur, the Clearance Market will operate from June 1st through July 31st. Regulated Parties that purchased credits in the Clearance Market to meet their compliance obligation will submit to the Executive Officer an updated year-end compliance report by August 31st that accounts for the acquisition and retirement of their pro-rata share of Clearance Market credits, and for all deficits carried over as accumulated deficits.

<u>Calculation of the Pro-Rata Share of Clearance Market Credits</u>

On or by June 1st, the Executive Officer will inform each regulated party obligated to purchase in the Clearance Market of its pro-rata share of the credits pledged. The pro-rata shares of credits pledged will be calculated by the following formula:

> *Party A's pro-rata share = [(party A's unmet obligation) / (total number of unmet obligations from all regulated parties)] * (total number of credits pledged for sale into the Clearance Market)*

<u>Calculation of the Maximum Clearance Market Credit Price</u>

The maximum price for credits acquired, purchased, or transferred via the Credit Clearance Market shall be set by the following formula:

- \$200 per credit ($MTCO_2e$) in 2016.

- This price shall be adjusted in subsequent years by a Consumer Price Index deflator in all years subsequent to 2016 to keep pace with inflation and remain at a constant price, in real terms.

- The CPI deflator shall be the rate of inflation as measured by the most recently available twelve months of the Consumer Price Index for All Urban Consumers, as published by the U.S. Bureau of Labor Statistics.

<u>Calculation of Interest Applied to Accumulated Deficits</u>

If, after purchasing and retiring its pro-rata share of credits, a regulated party retains an unmet compliance obligation, that regulated party shall roll any remaining unmet deficits from that compliance year over into an Accumulated Deficit account, which account will be charged interest. On January 1st of each year, interest will be applied annually to all deficits in a regulated party's accumulated deficits account that are greater than one year old. Interest will be applied in terms of additional deficits at a rate of five percent annually, becoming an enforceable part of the party's obligation under the LCFS.

(3) Insufficient Credits ("Deficit and In Violation" Status)

If a regulated party fails to meet its annual compliance obligation under section 95485(a) and, for years in which a Credit Clearance Market is held, fails to purchase its pro-rata share of pledged credits, then the regulated party is considered to be in violation of the LCFS and subject to the penalties and enforcement actions authorized by law.

J. Generating and Calculating Credits and Deficits

The LCFS is structured much like an emissions reduction trading program in which credits are awarded based on the performance of fuels that exceed a regulatory standard. The LCFS recognizes a flexible combination of fuel-vehicle systems and awards credits to the fuel provider if the carbon intensity values of the fuels provided are below those of the corresponding gasoline or diesel standards. Credits are banked indefinitely until they are sold and transferred, exported to other programs, or retired for compliance purposes.

The method for calculating the credits and deficits generated is defined in the proposed regulation. The number of credits generated (or the deficits incurred) by a regulated party directly affects the overall credit/deficit balance used for the determination of compliance for a regulated party. For each compliance period, based on quarterly reports submitted by regulated parties, the LRT-CBTS calculates the number of credits and deficits generated for the amount of fuel supplied as either a gasoline or diesel fuel replacement. The total credits and deficits generated under the gasoline and diesel standard are respectively summed over all the fuels and blendstocks supplied by the regulated party. All credit and deficit totals are reported in units of metric tons of CO_2 equivalent. The equations 6 and 7 illustrate the summation credit and deficit calculations.

$$Credits^{Gen}(MT) = \sum_{i}^{n} Credits_i^{gasoline} + \sum_{i}^{n} Credits_i^{diesel} \qquad \text{Eq. 6}$$

$$Deficits^{Gen}(MT) = \sum_{i}^{n} Deficits_i^{gasoline} + \sum_{i}^{n} Deficits_i^{diesel} \qquad \text{Eq. 7}$$

where:

$Credits^{Gen}$ represents the total credits (a zero or positive value);

$Deficits^{Gen}$ represents the total deficits (a negative value);

i is the fuel or blendstock index; and

n is the total number of fuels and blendstocks provided by the regulated party in a compliance period.

For each applicable fuel under the LCFS, the credit and deficit determination is a result of the overall performance of the fuel. The performance is tied to the carbon intensity value and the extent that the fuel displaces a conventional fuel, such as gasoline or diesel. The equation 8 illustrates the calculation.

$$(Credits\ of\ Deficits)^{XD}(MT) = (CI^{XD}_{standard} - CI^{XD}_{reported}) \times E^{XD}_{displaced} \times C \qquad \text{Eq. 8}$$

where:

$(Credits\ of\ Deficits)^{XD}(MT)$ is the amount of LCFS credits generated (a zero or positive value), or deficits incurred (a negative value), in metric tons of CO_2 equivalent, by a finished fuel or blendstock under the gasoline standard (XD = “gasoline”) or diesel standard (XD = “diesel”);

C is the constant factor used to convert credits to units of metric tons and has the value of:

$$C = 1.0 \times 10^{-6}\frac{(MT)}{(gCO_2e)}$$

$CI^{XD}_{standard}$ is the carbon intensity of the gasoline or diesel LCFS standard for a given year. It is important to note that the number of credits generated depends on the extent to which the carbon intensity value of a fuel is below that of the standard.

For each alternative fuel, the number of credits/deficits generated is also determined by the amount of conventional gasoline or diesel fuel that is displaced, identified by the parameter $E^{XD}_{displaced}$. The amount of conventional energy displaced is determined using a fuel displacement factor called the EER, which compares the fuel economy of an alternative fuel vehicle to that of a conventional gasoline vehicle. The carbon intensity of an alternative fuel is adjusted by the EER value of the alternative fuel vehicle. The more energy efficient fuels contribute to vehicles being able to travel more miles per unit of energy into the vehicle. This results in less fuel consumption and CO_2 emissions. Thereby, the carbon intensity is dependent on both the emissions per unit of energy consumed and the fuel economy of the vehicle type.

For each fuel or blendstock:

$$CI^{XD}_{reported} = \frac{CI_i}{EER^{XD}} \quad \text{(Eq. 9)} \qquad \text{and} \qquad E^{XD}_{displaced} = E_i \times EER^{XD}_i \quad \text{(Eq. 10)}$$

where:

$CI_{reported}^{XD}$ is the <u>adjusted</u> carbon intensity value reported for credit determination, in gCO_2e/MJ;

CI_i is the <u>unadjusted</u> carbon intensity value, in gCO_2e/MJ, determined by a CA-GREET pathway or a custom pathway and incorporates a land-use modifier (if applicable);

$E_{displaced}^{XD}$ is the total amount of gasoline (XD = "gasoline") or diesel (XD = "diesel") fuel energy displaced, in MJ, by the use of an alternative fuel;

E_i is the energy of the fuel or blendstock, in MJ, determined from the energy density conversion factors in Table III-2.

EER_i is the dimensionless EER relative to gasoline (XD = "gasoline") or diesel fuel (XD = "diesel") as listed in Table III-3. For a vehicle-fuel combination not listed in Table III-2, EER_i^{XD}= 1 is used.

For fixed guideway systems and forklifts:

$$E_{displaced}^{XD} = E_i \qquad \text{Eq. 11}$$

where:

E_i is the energy of the fuel used to propel fixed guideway systems and electric forklifts. For fixed guideway system expansion beyond 2010, the formula for displaced energy in section 95485(a)(3)(C) may be used with Executive Officer approval.

Table III-2. Energy Densities of LCFS Fuels and Blendstocks.

Fuel (units)	***Energy Density***
CARBOB (gal)	119.53 (MJ/gal)
CaRFG (gal)	115.63 (MJ/gal)
Diesel fuel (gal)	134.47 (MJ/gal)
CNG (scf)	0.98 (MJ/scf)
LNG (gal)	78.83 (MJ/gal)
Electricity (KWh)	3.60 (MJ/KWh)
Hydrogen (kg)	120.00 (MJ/kg)
Denatured Ethanol (gal)	81.51 (MJ/gal)

Fuel (units)	Energy Density
FAME Biodiesel (gal)	126.13 (MJ/gal)
Renewable Diesel (gal)	129.65 (MJ/gal)

Table III-3. EER Values for Fuels Used in Light- and Medium-Duty, and Heavy-Duty Applications.

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		***Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)***	
Fuel/Vehicle Combination	***EER Values Relative to Gasoline***	***Fuel/Vehicle Combination***	***EER Values Relative to Diesel***
Gasoline (incl. E6 and E10) or E85 (and other ethanol blends)	1.0	Diesel fuel or Biomass-based diesel blends	1.0
CNG/ICEV	1.0	CNG or LNG (Spark-Ignition Engines)	0.9
		CNG or LNG (Compression-Ignition Engines)	1.0
Electricity/BEV, or PHEV	3.4	Electricity/BEV, or PHEV* Truck	2.7
		Electricity/BEV or PHEV* Bus	4.2
		Electricity/Fixed-Guideway, Heavy Rail	4.6
		Electricity/Fixed-Guideway, Light Rail	3.3
		Electricity/Trolley Bus, Cable Car, Street Car	3.1
		Electricity/Forklifts	3.8
H_2/FCV	2.5	H_2/FCV	1.9

*BEV = battery electric vehicle, PHEV= plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle.

K. Credit Transactions

The proposal allows for the use of GHG credits generated only inside the LCFS program to be used in the LCFS program. This is to ensure that GHG reduction improvements occur in the LCFS transportation fuel pool. The proposed regulation allows for the exporting of credits to other GHG programs, subject to the requirements of those programs. Such flexibility may incentivize the development of innovative low-carbon fuel technologies within the LCFS.

One element of the proposal facilitating cost reduction is the creation of a market for low-carbon-intensity credits. Under a market-based system, regulated parties are able to buy and sell credits. To make credits available in the marketplace, regulated parties will be able to bank credits indefinitely until they are retired to meet a compliance obligation or they are sold and transferred to another regulated party. To keep LCFS credit transactions simple and to ensure there are an adequate number of credits in the program, the LCFS proposal will require third-party entities (e.g., credit brokers) to act only on behalf of a reporting party for a credit transfer. They will not be allowed to purchase, sell, hold, and/or retire LCFS credits.

The proposal does not differentiate one credit from another by associating identification numbers with them. As a result, LCFS credits will be completely fungible in terms of transferability and retirement. Under the LCFS, all credits will be treated the same, regardless of which fuel generated credits. Reporting parties will not need to selectively identify which specific credits are to be retired by identification number and/or fuel type, etc.

Credits will be “retired” as needed to meet a compliance obligation that may exist at the time the annual reports are submitted. The LRT-CBTS will determine whether there are enough credits to completely offset the compliance obligation of each regulated party. Credits may also be retired for other reasons, such as to cover assigned incremental deficits. The LRT-CBTS will track such credits separately from those retired to offset deficits.

ARB developed the LRT-CBTS to handle the credit retirement as an automated process. A default credit retirement hierarchy programmed into the LRT-CBTS will be utilized to retire credits. The order of retirement, referred to as the default “Credit Retirement Hierarchy,” has been developed for the LRT-CBTS and implemented as follows: 1) Carryback Credits (retired first); 2) Credits Acquired (retired second), 3) Credits Generated (retired last). For both 2) and 3), the retirement of credits will be on a “first acquired/generated, first retired” basis.

L. Obtaining and Using Fuel Pathways

(1) Summary

This Section describes the methods used to determine direct fuel pathway carbon intensity (CI) values under the LCFS. Fuel CIs are fundamental to the reporting and compliance determination provisions of the LCFS. A fuel pathway CI consists of the sum of the greenhouse gases emitted throughout the production and use life cycle of the fuel, expressed on a per-unit-of-fuel-energy basis. It is denominated in units of grams of carbon dioxide equivalent emissions per mega joule of fuel energy (gCO_2e/MJ).

Carbon intensity is calculated using life cycle analysis (LCA). LCA is an analytical method for estimating the aggregate quantity of greenhouse gases emitted during a full fuel life cycle. In general, the CI includes the direct effects of producing and using the fuel, as well as "indirect" effects that may be associated with the fuel.

The direct effects typically include feedstock generation or extraction, feedstock conversion to finished fuel or fuel blendstock, distribution, storage, delivery, and final use of the finished fuel by the end user. An LCFS CI expresses the combined atmospheric heat-trapping effect of five GHGs: CO_2, CH_4, N_2O, VOC and CO. Because these gases are not equivalent in terms of their ability to trap atmospheric heat, they are standardized to the heat-trapping capability of CO_2. This standardization process is described in more detail below.

Some categories of GHG emissions are not captured by the LCA methodology described in this chapter. Indirect emissions, such as those generated by indirect land use change, are estimated separately and added to the direct CIs calculated in keeping with the approach described below. The estimation of indirect effects under the LCFS is described in Section M of this Chapter.

Full fuel pathway CIs, including all direct and indirect components, are adjusted to account for relative vehicle power train efficiencies when fuel transactions are reported in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS). The LRT-CBTS system is described in section F of this report. This adjustment is accomplished using energy-economy ratios (EERs). An EER is defined as the ratio of the miles traveled per unit energy input for a fuel of interest to the miles traveled per unit energy for a reference fuel. Each EER is specific to one fuel-vehicle combination. The derivation and use of EERs are described in section J of this chapter.

This section also describes the "Evidence of Fuel Transport Mode" provision which establishes procedures for obtaining fuel transport mode demonstration approval–a prerequisite for LCFS credit generation. In the existing LCFS regulation, this provision is referred to as "Evidence of Physical Pathway." Staff is proposing to rename this provision to avoid confusion over the use of the term "pathway" which is also used in fuel pathways for CI determination. The requirements under the proposed regulation for this provision are largely unchanged from the existing regulation with the exception of a few clarifications.

(2) Direct Effects Analysis

(a) Fuel Pathways

Determining the carbon intensity of a particular fuel requires that each step in the production and use of that fuel be fully characterized. These steps comprise the direct effects associated with a fuel pathway. The production of ethanol from corn, for example, involves many steps, each of which contributes to corn ethanol's ultimate carbon intensity value. Those steps include:

- Production of agricultural chemicals
- Agriculture
    - Use of transportation fuels in farm equipment and vehicles
    - Amounts and types of fertilizers, pesticides, and herbicides applied
    - Irrigation practices
    - Crop yields
- Feedstock transport
- Fuel production
    - Type of fuel production process (technology, process efficiency, etc.)
    - Sources of the thermal and electrical energy used in the production process
- Displacement of other products by fuel production co-products (e.g. distiller's grains, which displace corn in livestock feed markets)
- Transport and distribution of the finished fuel
- Combustion of the fuel in vehicles.

Once each step in the pathway is fully characterized, the carbon intensity of each step is calculated and the results summed to generate the fuel's total direct carbon intensity. Emissions associated with indirect effects, if any, are added to the direct effects subtotal to obtain the total pathway CI.

(b) Calculating the Carbon Intensity of LCFS Fuel Pathways

The goal of the fuel LCAs performed under the LCFS is to identify and quantify all material and energy flows in a fuel's life cycle, to calculate the GHG emissions associated with those flows, and to sum those emissions subtotals into a single cumulative well-to-wheels CI value. The analytical framework used to conduct LCFS LCAs is described in a set of ISO standards falling in the 14000 series[26].

LCFS fuel pathway CIs must, to the extent possible, be calculated using the proposed version 2.0 of the California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model. As described below, fuel pathways are grouped into either Tier 1 or Tier 2 under the LCFS. Slightly different versions of the model are used to

[26] The International Organization for Standardization (ISO). Environmental Management, Life Cycle Assessment Series (Standards 14040, 14044, 14047, 14048, 14049,).

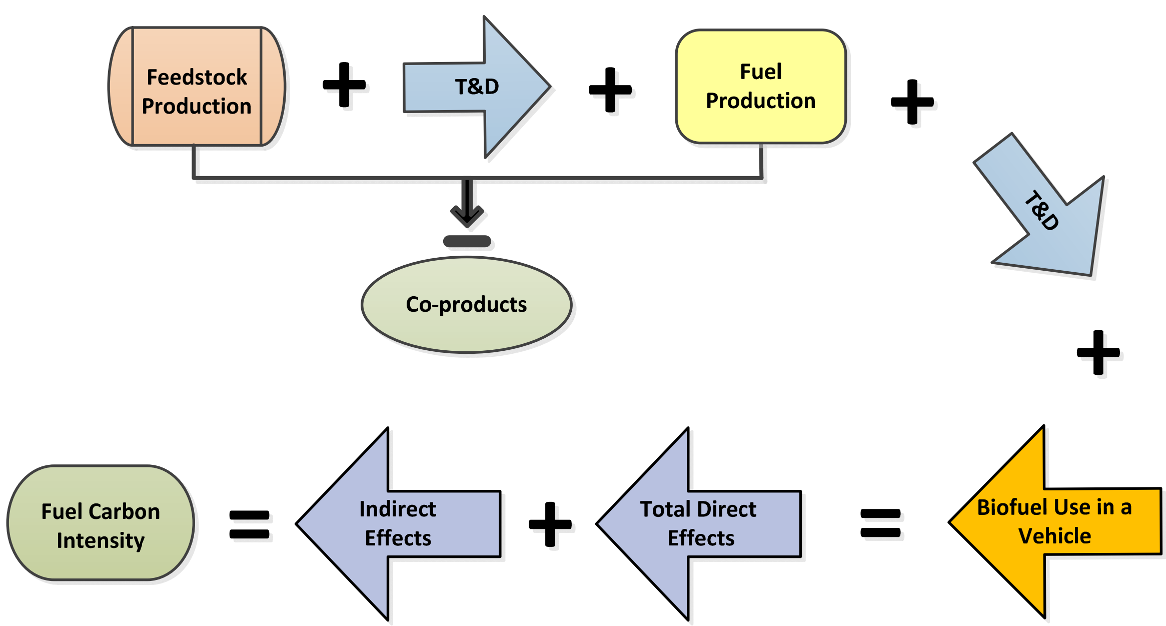
calculate Tier 1 and 2 CIs. The Tier 1 version is called CA-GREET2.0-T1, while the Tier 2 version is called CA-GREET2.0-T2.[27] Since these versions contain the same data tables (they differ only in how CIs are calculated), they are collectively referred to herein as "CA-GREET 2.0."

As depicted in Figure III-2, the direct GHG emissions from a fuel pathway are calculated in CA-GREET 2.0 as the sum of the GHG emissions from the following sequence of processes:

- Feedstock production (e.g., production of crude for gasoline and diesel, or digester biogas for biomethane)
- Feedstock transport, storage, and distribution (T&D)
- Fuel production (e.g., gasoline refining, renewable diesel production)
- Production of co-products
- Finished fuel T&D, and
- Fuel use in a vehicle.

The final pathway CI consists of the sum of the CA-GREET 2.0 result and any indirect emissions associated with the pathway. Indirect emissions are discussed in Section M of this Chapter.

Figure III-2. Generalized Fuel Life Cycle Analysis Schematic



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[27] CA-GREET 2.0 is available for download from http://www.arb.ca.gov/fuels/lcfs/software.htm.

The LCA phases shown in Figure III-2 are typically aggregated into two main stages. The first includes the series of steps that culminate in the dispensing of the finished fuel into a vehicle's fuel tank, battery, or other storage device. The second stage includes the conversion of the stored fuel energy into motive power.[28] A final LCFS well-to-wheels CI is expressed in terms of emissions per unit of fuel energy.

The basis of all fuel pathway CIs under the LCFS is the life cycle inventory (LCI) data contained in the CA-GREET 2.0 spreadsheet. LCI data quantifies the relevant energy, material, and waste flows into and out of the fuel production system. Emission factors and process efficiencies are also used to calculate CIs. Examples of the LCI, emissions, and efficiency data found in CA-GREET 2.0 follow:

- *Agricultural Feedstock Production*

    - Argonne National Laboratory (ANL) describes the material and energy flows used in the six cellulosic pathways included in its GREET1 2013[29] model in a 75-page document entitled "Material And Energy Flows In The Production Of Cellulosic Feedstocks For Biofuels For The GREET[tm] Model"[30]. This document draws on multiple peer-reviewed journal articles, data from the U.S. Department of Agriculture (USDA), the U.S. Department of Energy (U.S. DOE), the National Renewable Energy Laboratory (NREL), the U.S. Environmental Protection Agency (U.S. EPA), and other sources.

    - ANL provided background details on its updated LCA of sorghum ethanol in a 2013 paper entitled "Life-cycle energy use and greenhouse gas emissions of production of bioethanol from sorghum in the United States"[31]. This paper draws on information from a wide variety of sources, including the USDA, the United Nations Food and Agriculture Organization, the U.S. EPA, and other peer-reviewed literature.

    - The USDA's Economic Research Service reported the results of a 1996 survey of sorghum producers[32]. This report contained information on fertilizer, farm chemical, and on-farm fuel use.

- *Fuel Production*

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[28] These two stages are often referred to as Well-to-Tank and Tank-to-Wheels. The Well-to-Tank analysis includes all steps from recovery or production of the feedstock, to the blending and transport of the finished fuel to the retail service station for distribution to the vehicle tank. The Tank-to-Wheels analysis includes the use of the fuel in an automobile. The WTT and TTW are combined to create a complete Well-To-Wheels (WTW) analysis of a transportation fuel.
[29] Systems Assessment Section, Center for Transportation Research, Argonne National Laboratory, 2013. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET 1 2013).
[30] Material and Energy Flows in the Production of Cellulosic Feedstocks for Biofuels for the GREET™ Model. ANL/ESD-13/9.
[31] Life-cycle energy use and greenhouse gas emissions of production of bioethanol from sorghum in the United States. Biotechnology for Biofuels 6:141.
[32] Farm Business Economic Indicator Updates: Costs of Production, FBEI 97-1, February, 1997.

- The NREL reported on its simulation of the process of converting corn stover to ethanol through dilute-acid pretreatment, enzymatic saccharification, and co-fermentation[33]. NREL's simulation was conducted using the Aspen Plus process modeling software.

- The U.S. EPA published the results of simulations of the energy needed to produce ethanol from sorghum as part of a formal rulemaking under 40 CFR Part 80[34]. These simulations were carried out by the USDA, and drew on prior simulations of the corn ethanol production process. All simulations were carried out using Aspen process modeling software.

- The energy requirements of producing ethanol from sugar cane were drawn in part from an article by Seabra et al. entitled "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use"[35].

- *Feedstock and Fuel Transport*

  ANL describes the updates it has made to the transportation LCI data in the GREET model in a 2013 paper[36]. Revisions to the energy intensity and emissions associated with locomotives, pipelines, heavy-duty trucks, ocean-going vessels, and barges are presented. The updates are based on information from the U.S. Department of Transportation (U.S. DOT), the U.S. Energy Information Administration (U.S. EIA), the U.S. EPA, Journal articles, and other sources.

- *Emission Factors*

  - The U.S. EPA's Clearinghouse for Inventories and Emission Factors (Air CHIEF) CD ROM[37]. The Air CHIEF CD contains emission factors and software tools designed to assist with the estimation of emissions from a wide variety of stationary and point sources. It contains Volume I of the Agency's Compilation of Air Pollutant Emission Factors (AP-42), and the latest National Emission Inventory documentation for criteria and hazardous air pollutants.

  - ANL's "Updated Emission Factors of Air Pollutants from Vehicle Operations in GREET™ Using MOVES"[38]. This report documents ANL's approach to updating gasoline and diesel vehicle emission factors to account for changes in engine technology and fuel specifications; deterioration of emission control

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[33] Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol. Technical Report NREL/TP-5100-47764.
[34] Supplemental Determination for Renewable Fuels Produced Under the Final RFS2 Program From Grain Sorghum. 40 CFR Part 80. EPA–HQ–OAR–2011–0542; FRL–9760–2. Federal Register.
[35] Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use. Biofuels, Bioproducts, and Biorefing 5(5):519-532.
[36] Update to Transportation Parameters in GREET™.
[37] Emission Factor and Inventory Group. 2005. Clearinghouse for Inventories and Emission Factors (Air CHIEF)
[38] Updated Emission Factors of Air Pollutants from Vehicle Operations in GREET™ Using MOVES.

devices with vehicle age; implementation of emission control inspection and maintenance programs; and the adoption of advanced emission control technologies, such as second-generation onboard diagnostics (OBD II), selective catalytic reduction, diesel particulate filters, and diesel oxidation catalysts. To best capture the effects of these factors, ANL used the U.S. Environmental Protection Agency's latest mobile-source emission factor model, the Motor Vehicle Emission Simulator (MOVES). Previously, vehicular emission factors were estimated using the U.S. EPA's MOBILE6.2 and the California Air Resources Board's EMFAC models.

- The 2010 baseline tailpipe emission factors for CARBOB, CaRFG, and ultra-low sulfur diesel (ULSD) in the model are from the following sources. CO_2 emissions for these fuels were calculated based on the carbon content, assuming complete combustion to CO_2, and corrected for carbon emitted as CH_4.

  - CH_4 and N_2O tailpipe emission factors for gasoline-powered light- and heavy-duty vehicles were derived from ARB's GHG Emission Inventory[39]

  - CH_4 and N_2O tailpipe emission factors for light- and heavy-duty diesel vehicles are also from ARB's GHG Emission Inventory[40]

- Tailpipe emission factors for CNG-powered light- and heavy-duty trucks are from the U.S. EPA's Emission Inventory[41]

- Tailpipe emission factors for LNG-powered heavy-duty LNG trucks are from U.S. EPA Emission Inventory[42]

- The guidelines issued by the Intergovernmental Panel on Climate Change (IPCC) on performing national greenhouse gas inventories[43]. These guidelines provide detailed instructions on the preparation of national GHG inventories, as well as GHG emission factors that can be used in the preparation of those inventories. The CA-GREET 2.0 model utilizes many of these factors (e.g., N_2O emissions from agriculture).

- Emissions from the generation of grid electricity are calculated using electrical generation energy mixes (e.g., natural gas, coal, wind, etc.) from the U.S. EPA's Emissions and Generation Resource Integrated Database (eGRID)[44]. CA-GREET 2.0 uses energy mixes from the 26 eGRID subregions.

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[39] California's 2000-2012 Greenhouse Gas Emissions Inventory Technical Support Document. State of California Air Resources Board. Air Quality Planning and Science Division

[40] Ibid

[41] Emission Factors for Greenhouse Gas Inventories

[42] Ibid

[43] 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Intergovernmental Panel on Climate Change.

[44] Emissions and Generation Resource Integrated Database (eGRID); Ninth Edition, Version 1.0: 2010 data.

In order to calculate a single aggregate carbon intensity value for all greenhouse gas emissions occurring throughout the WTW life cycle, the atmospheric heat trapping potential of all greenhouse gases must be expressed in standardized additive units. Under the LCFS, all greenhouse gas species other than CO_2 are converted to CO_2 equivalent (CO_2e) values. These conversions are accomplished using global warming potential (GWP) indices developed by the IPCC[45]. CH_4 and N_2O are converted to a CO_2-equivalent basis using IPCC GWP values for inclusion in the total pathway carbon intensity. The IPCC GWP indices function as multipliers: CH_4 emissions, for example, are multiplied by 25. The 2007 IPCC GHG CO_2e values for the GHG emissions included in LCFS fuel pathways are 1 for CO_2, 25 for CH_4, and 298 for N_2O.

CA-GREET 2.0 assumes that VOC and CO are converted to CO_2 in the atmosphere. It therefore includes these pollutants in the total CO_2 value using ratios of the appropriate molecular weights. The ratio of the molecular weight of carbon to the molecular weight of CO_2 is 12/44 = 0.273. The CO_2e values of VOCs and CO are, therefore, 0.85/0.273 = 3.12, and 0.43/0.273 = 1.57, respectively.

CA-GREET 2.0 is a modified version of GREET1 2013[46]. Michael Wang and his team at ANL developed GREET1 2013. The software platform for both models is Microsoft Excel. The process of converting ANL's model to a California-specific version consisted primarily of adding the necessary California-specific LCI data and emission factors. A comprehensive list of revisions is maintained on the CA-GREET 2.0 web site (http://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm). Among those revisions are the following:

- Crude oil recovery efficiency was modified to reflect the values specific to the average crude used in California, including crude that is both produced in, and imported into, the State;

- Tailpipe CH_4 and N_2O emission factors were adapted for California vehicles where available, in light of the fact that California has stricter vehicle emissions standards than were assumed in developing GREET1 2013;

- The U.S. EPA's eGRID[47] was the source of the grid electricity generation energy mixes used in CA-GREET 2.0. An electrical energy generation mix is the mix of energy sources (e.g., natural gas, coal, hydroelectric dams, etc.) used to generate the electricity provided to an electrical grid.

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[45] Climate Change 2007: The Physical Science Basis," Technical Summary, .Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

[46] Low Carbon Fuel Standard Computation Modeling Software

[47] Emissions and Generation Resource Integrated Database (eGRID); Ninth Edition, Version 1.0: 2010 data.

(c) Tier 1 and Tier 2 Fuels

Proposed section 95488 provides for the establishment of fuel pathways for two categories of transportation fuels. The first—"Tier 1"—includes conventionally produced, first-generation fuels, and the second—"Tier 2"—includes fuels produced using emerging technologies and/or innovative production methods such as low-CI sources of process energy. In general, Tier 1 fuels are produced using mature production technologies and have been in use under the LCFS for at least three years. Tier 2 fuels have been in full commercial production for a relatively short period of time, and are relatively new to the LCFS.

Tier 1 fuels include:

- Starch- and sugar-based ethanol,
- Biodiesel produced from conventional feedstocks (including but not limited to plant oils, tallow and related animal wastes, and used cooking oil),
- Renewable diesel produced from conventional feedstocks (including but not limited to plant oils, tallow and related animal wastes, and used cooking oil),
- Natural gas, and
- Biomethane from landfill gas.

Tier 2 fuels include:

- Cellulosic alcohols;
- Biomethane from sources other than landfill gas;
- Hydrogen;
- Electricity, whether from dedicated, low CI energy sources, or (as discussed below) from the public grid;
- Drop-in fuels (renewable hydrocarbons, except for renewable diesel[48]);
- Tier 1 fuels produced using one or more innovative production methods.

The innovative production methods that could move a Tier 1 fuel into the Tier 2 category include:

[48] Renewable diesel is an established fuel that has been in production since before the implementation of the LCFS began.

- Use of one or more low-CI process energy sources. Innovative, low-CI energy sources include the following:
    - o Low-CI biomass, such as organic agricultural or municipal wastes;
    - o Renewable electricity from a dedicated (non-grid) form of generation, such as wind turbines and photovoltaic arrays;
- Use of unconventional feedstocks such as algal oil;
- Carbon capture and sequestration; and
- Production process innovations that improve production efficiency such that GHGs emitted per mega joule of fuel energy produced is significantly reduced.

For a low-CI process energy source to qualify as an innovative method (and move a fuel pathway into the second Tier), energy from that source must be directly consumed in the production process. No indirect accounting mechanisms, such as the use of renewable energy certificates, can be used to reduce an energy source's CI.

The use of grid electricity as a transportation fuel is not an emerging "next-generation" technology. Grid electricity is included in Tier 2 in order to enable opt-in electricity providers to use the pathway for grid electricity found in the Tier 2 Lookup Tables (Tables III-4 and III-5, below). Because that CI has already been calculated and certified, applicants should not have to calculate it on their own as part of a Tier 1 application.

Staff developed separate application processes for Tier 1 and 2 to expedite the processing of Tier 1 pathway applications. Having processed numerous applications for first-generation pathways during the initial five years of LCFS implementation, staff is very familiar with Tier 1 fuels. Figure III-3 summarizes the Tier 1 and Tier 2 application processes in the form of a flow diagram

<u>First Step</u>

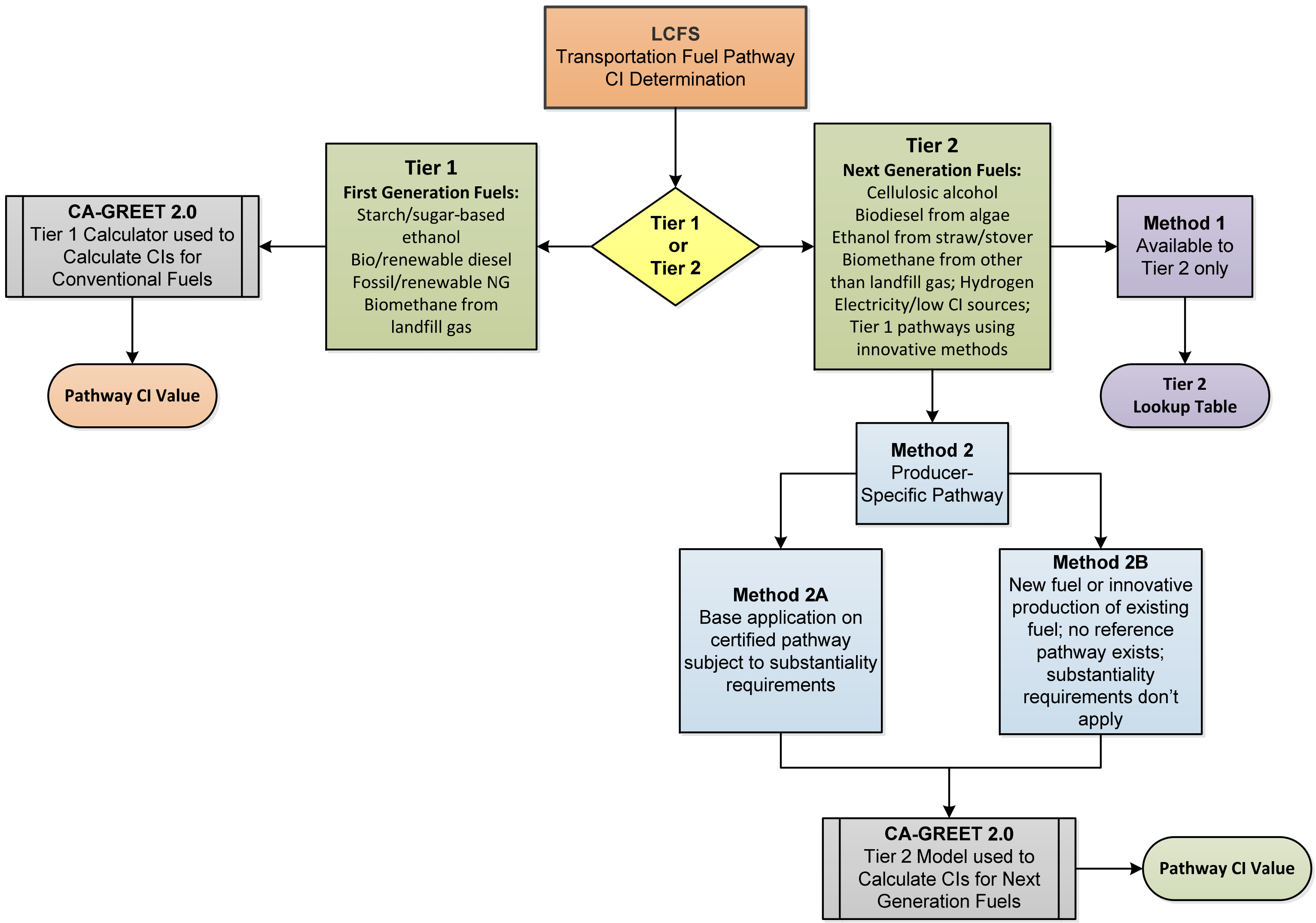
The process of applying for an LCFS pathway is set forth in Section 95488 of the LCFS regulation. All applicants, regardless of the Tier or Method into which their pathways fall, would initiate the application process by completing an LCFS New Pathway Request Form (NPRF). The NPRF is a secure, interactive, web-based form available on the LRT-CBTS web site[49]. Once the NPRF is submitted, an inactive record for the proposed pathway is created in the LRT-CBTS system. If and when the proposed pathway is certified, that record is activated.

The NPRF asks the applicant to provide information about the proposed pathway and the fuel producer, and to declare whether the proposed pathway falls under the Tier 1 or

[49] LCFS Reporting Tool web site

Tier 2 provisions of the LCFS regulation. If Tier 2 is selected, the applicant is asked to further declare whether the proposed pathway would fall into the Tier 2 Lookup Table, Method 2A, or Method 2B category. The Executive Officer will evaluate the applicant's declarations in light of the information provided in the NPRF and either approve them, or reclassify the proposed pathway. Once the Executive Officer's findings have been conveyed to the applicant, the application process may proceed.

Figure III-3. Tier 1 and Tier 2 Fuel Pathway Flow Diagram



Tier 1

The Tier 1 process builds upon staff's familiarity with Tier 1 fuels by providing applicants with a more direct route to pathway certification. In addition to providing applicants with a simplified and accelerated route to pathway certification, the Tier 1 process provides staff with more time to focus on the challenges of evaluating Tier 2 applications.

Proposed pathways may be classified into Tier 1 in one of two ways.

- The applicant declares in the NPRF submitted for the proposed pathways that they fall into Tier 1, and the Executive Officer approves of that declaration; or

- The Executive Officer overrides a Tier 2 Lookup Table, Method 2A, or Method 2B declaration and places the proposed pathways into Tier 1.

In either of these two cases, applicants in Tier 1 calculate their pathway CIs using the Tier 1 version of CA-GREET 2.0 (CA-GREET2.0-T1), and submit the results to the Executive Officer in the form of a copy of the calculator showing the proposed CI and the inputs used to obtain it. The model computes pathway CIs using only the base set of input parameters that determine a Tier 1 pathway CI. That base set includes:[50]

- Electrical energy generation mixes for the feedstock and fuel production phases. An electrical energy generation mix is the mix of energy sources (e.g., natural gas, coal, hydroelectric dams, etc.) used to generate the electricity provided to an electrical grid.

-
- Feedstock and fuel production thermal energy sources (natural gas, coal, biomethane, etc.).

- Feedstock and fuel production chemical use

- Fuel production energy use.

- Fuel yield.

- Feedstock and fuel transport modes and distances.

- Co-product yields.

In support of the inputs used to calculate that CI, the applicant submits energy consumption invoices covering a period of two full years, a copy of the independent,

[50] feedstock phase inputs except those associated with agriculture may be input into the Tier 1 calculator. Pending the development of an LCFS agricultural auditing and certification program, agricultural inputs are invariant.

third-party engineering report provided to the U.S. Environmental Protection Agency under the under the Renewable Fuel Standard 2 program, and a letter attesting to veracity of the information provided. These materials may be securely uploaded through the LRT-CBTS web site. An original, signed copy of the attestation letter must also be sent to the Executive Officer. If the Executive Officer is able to verify and confirm the results obtained by the applicant, the resulting direct CI will be added to the indirect effects value, if any, associated with the fuel pathway. The result becomes the applicant's certified Tier 1 pathway CI. Upon certification, the inactive LRT-CBTS record created for the pathway upon submission of the NPRF will be revised, if necessary, and activated.

Tier 2

Tier 2 applicants may obtain a new fuel pathway using the Tier 2 Lookup Tables, Method 2A, or Method 2B. Section 95488(c)(4)(F) of the LCFS regulation contains one Lookup Table for gasoline and gasoline substitute fuels, and another for diesel and diesel substitute fuels. Both tables are included, as Tables III-4 and III-5, in this chapter. In order to obtain a Lookup Table pathway, an applicant selects, subject to Executive Officer approval, a pathway from one of the two Lookup Tables. The Executive Officer will approve the use of a pathway from the Lookup Tables only when the correspondence between the applicant's actual fuel pathway and the selected Lookup Table pathway is sufficiently close. At a minimum, they must closely correspond in the following areas:

- Feedstock used to produce the fuel
- Feedstock and fuel production technology
- Feedstock and Fuel Transport modes and distances
- Types and amounts of thermal and electrical energy used to produce both the feedstock and the fuel
- Pathway CI: the CI of the applicant's actual production pathway must be lower than or equal to the CI of the Lookup Table pathway for which the applicant is applying.

Table III-4. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline[1]

Fuel	Pathway Identifier	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
			Direct Emissions	Land Use or Other Indirect Effect	Total
CARBOB	CBOB001	CARBOB - based on the average crude oil supplied to California refineries and average California refinery efficiencies	100.58	0	100.58
Compressed Natural Gas	CNG005	Biomethane produced from the high-solids (greater than 15 percent total solids) anaerobic digestion of food and green wastes: compressed in CA	-34.70	0	-34.70
	CNG020	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	7.80	0	7.80
	CNG021	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	30.98	0	30.98
Electricity	ELC002	Grid electricity	105.62	0	105.62
Hydrogen	HYGN001	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	152.48	0	152.48
	HYGN002	Liquid H2 from central reforming of NG	144.95	0	144.95
	HYGN003	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	105.91	0	105.91
	HYGN004	Compressed H2 from on-site reforming of NG	105.65	0	105.65
	HYGN005	Compressed H2 from on-site reforming with renewable feedstocks	81.92	0	81.92

[1]The numbers appearing in this table are adjusted by EER at the LRT-CBTS reporting stage. These pathways are available to Tier 2 applicants.

Table III-5. Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel[1]

Fuel	Pathway Identifier	Pathway Description	Carbon Intensity Values (gCO2e/MJ)		
			Direct Emissions	Land Use or Other Indirect Effect	Total
Diesel	ULSD001	ULSD - based on the average crude oil supplied to California refineries and average California refinery efficiencies	102.82	0	102.82
Compressed Natural Gas	CNG005	Biomethane produced from the high-solids (greater than 15 percent total solids) anaerobic digestion of food and green wastes; compressed in CA	-34.70	0	-34.70
	CNG020	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	7.80	0	7.80
	CNG021	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	30.98	0	30.98
Electricity	ELC002	Grid electricity	105.62	0	105.62
Hydrogen	HYGN001	Compressed H_2 from central reforming of NG (includes liquefaction and re-gasification steps)	152.48	0	152.48
	HYGN002	Liquid H_2 from central reforming of NG	144.95	0	144.95
	HYGN003	Compressed H_2 from central reforming of NG (no liquefaction and re-gasification steps)	105.91	0	105.91
	HYGN004	Compressed H_2 from on-site reforming of NG	105.65	0	105.65
	HYGN005	Compressed H_2 from on-site reforming with renewable feedstocks	81.92	0	81.92

[1]The numbers appearing in this table are adjusted by EER at the LRT reporting stage. These pathways are available to Tier 2 applicants.

Proposed pathways may be classified into the Tier 2 Lookup Table category in one of two ways.

- The applicant declares in the NPRF submitted for the proposed pathways that they fall into the Tier 2 Lookup Table category, and the Executive Officer approves of that declaration; or

- The Executive Officer overrides a Tier 1 or Tier 2 Method 2A or 2B declaration and places the proposed pathways into the Tier 2 Lookup Table category.

In either of these cases, applicants in the Tier 2 Lookup Table category submit energy consumption invoices covering a period of two full years, a copy of the independent, third-party engineering report provided to the U.S. EPA under the RFS2 program, and a letter attesting to veracity of the information provided. These materials may be securely uploaded through the LRT-CBTS web site. An original, signed copy of the attestation letter must also be sent to the Executive Officer. If the Executive Officer confirms that the information submitted adequately supports the Tier 2 Lookup Table pathway identified in the application, the resulting pathway CI becomes the applicant's certified Tier 2 Lookup Table CI. Upon certification, the inactive LRT-CBTS record created for the pathway upon submission of the NPRF will be revised, if necessary, and activated.

Under Tier 2, Methods 2A and 2B, fuel providers can apply to the Executive Officer for a new, producer-specific, fuel pathway. Method 2A is reserved for applicants whose proposed pathways consist of modified versions of existing certified pathways. The existing pathway which was modified to create the Method 2A pathway is referred to as the "reference" pathway. Method 2A is only available to applicants who can demonstrate that the pathways they propose satisfy the two substantiality requirements specified in the LCFS regulation (section 95488(d)(4)(F)2.):

- Proposed Method 2A pathways with CIs greater than 20 gCO_2e/MJ must have CIs that are 5.5 percent lower than the CIs of their reference pathways. Proposed pathways with CIs of 20 gCO_2e/MJ or less must have CIs that are at least one gCO_2e/MJ lower than the CIs of their reference pathways.

- The applicant is capable of providing (and intends to provide) more than ten million gasoline gallon equivalents (1.156×10^9 megajoules) of transportation fuel annually under the proposed Method 2A pathway.

Method 2B is reserved for entirely new fuels or fuel production processes. By definition, no previously certified pathway can serve as a reference pathway for a Method 2B fuel. As a result, the first of the two substantiality requirements listed above do not apply to Method 2B applications. So as to better incentivize the development of innovative low-carbon fuels, the second substantiality requirement (that ten million gasoline gallon equivalents of fuel be supplied annually) is also waived for Method 2B applications.

Method 2B is also available to fuels that would qualify for Method 2A pathways, except that their CIs are higher than the CIs of their reference pathways. An example of such a fuel is conventional renewable diesel produced from tallow in Asia. The existence of certified tallow-based renewable diesel pathways would indicate that the proposed pathway would fall under the Method 2A provisions of the LCFS regulation. However, due to differences in the distance the finished fuel must be shipped and in the mix of fuels used to generate electricity for the local grid, this Asian renewable diesel would have a higher CI than the potential reference pathways available to it. The LCFS accommodates fuels like this one—fuels that would fall under Method 2A except that their CIs are higher than the CIs of their reference pathways—by defining them as Method 2B pathways. Although they can be developed like Method 2A pathways, they are not subject to the requirement that their CIs be lower than the CIs of their reference pathways (as described above).

Tier 2 applicants seeking a pathway under either Method 2A or 2B will use the CA-GREET2.0-T2 version of the model. The interface in the CA-GREET2.0-T2 model links users to fuel- and feedstock-specific data tables throughout the model. With the exception of upstream agricultural inputs and grid electricity energy mixes, applicants must provide producer-specific inputs for all unit operations. Aside from agricultural inputs and grid electricity mixes, existing input values available in CA-GREET2.0-T2 may not be used without Executive Officer approval. Producer-specific Input parameter choices must be adequately documented. In order to certify a Method 2 pathway, the Executive Officer must be able to verify all CA-GREET2.0-T2 inputs, and to replicate the pathway CI calculated by the applicant.

Proposed pathways may be classified into the Tier 2, Method 2A or 2B categories in one of two ways.

- The applicant declares in the NPRF submitted for the proposed pathways that they fall into one of these categories, and the Executive Officer approves of that declaration; or

- The Executive Officer overrides a Tier 1 or Tier 2 Lookup Table declaration and places the proposed pathways into the Tier 2, Methods 2A or 2B categories.

In either of these cases, applicants in the Tier 2, Methods 2A or 2B categories submit the following in support of their proposed pathways:

- A life cycle analysis report describing the full fuel life cycle, and describing in detail the calculation of the fuel pathway CI.

- Energy consumption invoices covering a period of two full years.

- The geographical coordinates of fuel production facility. Geographical coordinates can be reported either as the longitude and latitude or as Universal Transverse Mercator coordinates.

- A copy of the CA-GREET2.0-T2spreadsheet prepared for the life cycle analysis of the proposed fuel pathway.

- One or more process flow diagrams that, singly or collectively, depict the complete fuel production process.

- All applicable air pollution control permits issued by the local air pollution control jurisdiction.

- A copy of the independent, third-party engineering report provided to the U.S. EPA under the under the RFS2 program.

- Copies of the federal RFS2 Fuel Producer Co-products Report as required under 40 CFR parts 80.1451(b)(1)(ii)(M) through (N). The reports shall cover the same time period as do the energy receipts submitted in support of the application.

- Audited statements or reports showing annual finished fuel sales. The statements shall cover the same time period as do the energy receipts submitted in support of the application.

- A letter attesting to veracity of the information provided and declaring that the information submitted accurately represents the long-term, steady state operation of the fuel production process described in the application packet. The letter must also attest that no products, co-products, by-products, or wastes undergo additional processing, such as drying or clean-up, once they leave the production facility, except as described and quantified in the pathway CI and in the life cycle analysis report.

These materials may be securely uploaded through the LRT-CBTS web site. If the Executive Officer is able to verify and confirm the results obtained by the applicant, the resulting direct CI will be added to the indirect effects value, if any, associated with the fuel pathway. The result becomes the applicant's certified Tier 2, Method 2A or 2B pathway CI. Upon certification, the inactive LRT-CBTS record created for the pathway upon submission of the NPRF will be revised, if necessary, and activated.

If the proposed regulation order is adopted by the Board, it will take effect when over 200 fuel pathways certified under the previous regulation order are active in the LRT-CBTS system. Because the CIs associated with those pathways were calculated using CA-GREET 1.8b, most will not be comparable with the CIs of similar pathways calculated using CA-GREET 2.0. In order to insure that all fuels sold under all certified pathways compete fairly in the California marketplace, all pathway CIs must be calculated using the same model. For this reason, the proposed regulation requires all pathways certified under the current regulation to be recertified with CIs calculated using CA-GREET 2.0. Recertification must occur within one year of the effective date of the proposed regulation. Since the proposed regulation is expected to take effect on

January 1, 2016, holders of pathways with CA-GREET-1.8b-based CIs will have until Jaunuary 1, 2017 to recertify those pathways. Pathways that are not recertified during this one-year grace period will be de-activated in the LRT-CBTS system.

(3) Evidence of Fuel Transport Mode

To ensure that low carbon transportation fuels that are produced outside of California are actually used in the State, regulated parties are required to provide evidence regarding the physical transport mode for fuels that are reported to generate credits. For each fuel for which a regulated party claims credits under the LCFS, this would involve a four-part showing:

- A one-time demonstration that there exists a physical mode by which the fuel is expected to arrive in California. This includes any applicable combination of truck delivery routes, rail tanker lines, gas/liquid pipelines, and any other fuel distribution routes that, taken together, accurately account for the fuel's movement from the generator of the fuel, through intermediate entities, to the fuel blender, provider, or importer in California;

- Written evidence, by contract or similar evidence, showing that a specific amount of a particular transportation fuel with known carbon intensity was introduced into the fuel transport mode as directed by the regulated party;

- Written evidence, by contract or similar evidence, showing that an equal amount of that transportation fuel was removed from the fuel transport mode by the regulated party for use as a transportation fuel in California; and

- An update to the initial fuel transport mode demonstration whenever there are modifications to the initially demonstrated transportation mode.

Sellers of an imported fuel in California cannot generate credits under the LCFS until the regulated party reporting that fuel has submitted evidence of a fuel transport mode as described above for that fuel, and that submittal has been approved by the Executive Officer. To ensure credits are generated in a timely manner, regulated parties are required to submit the evidence for fuel transport mode within 30 days of the first import of a fuel to California. An update to the initial fuel transport mode demonstration is also required to be submitted within 30 days of the change.

M. Indirect Land Use Change

As discussed earlier, carbon intensities are calculated under the LCFS on a full life cycle basis. This means that the carbon intensity value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. In addition to these direct effects, some fuel production processes generate GHGs *indirectly*, via intermediate market mechanisms. Stakeholders participating in the LCFS process have suggested that most or all transportation fuels generate varying levels of indirect GHG emissions. To date, however, ARB staff has only identified one indirect effect that has a measurable impact on GHG emissions: land use change effects. A land use change effect is initially triggered when an increase in the demand for a crop-based biofuel begins to drive up prices for the necessary feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop. Supplies of the displaced food and feed commodities subsequently decline, leading to higher prices for those commodities. Some of the options for many farmers to take advantage of these higher commodity prices are to take measures to increase yields, switch to growing crops with higher returns, and to bring non-agricultural lands into production. When new land is converted, such conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions constitute the "indirect" land use change (iLUC) impact of increased biofuel production.

Based on research and published work, most of the land use change impacts result from the diversion of food crops to producing biofuels. During the regulatory process (i.e., workshops and meetings with stakeholders) leading up to the 2009 LCFS Board Hearing, the magnitude of this impact was discussed and also questioned by renewable fuel advocates. Land use change is driven by multiple factors, some of them not related to the production of biofuels. Because the tools for estimating land use change were few and relatively new when the regulation was originally adopted in 2009, biofuel producers argued that land use change impacts should be excluded from carbon intensity values, pending the development of better estimation techniques. Based on its work with land use change academics and researchers, however, ARB staff concluded that the land use impacts of crop-based biofuels were significant, and must be included in LCFS fuel carbon intensities. To exclude them would assume that there is zero impact resulting from the production of biofuels and would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and by not accounting for the GHG emissions from land use change, would jeopardize the achievement of a ten percent reduction in fuel carbon intensity by 2020. Details of ARB's estimated land use change impacts of biofuel crop production for the 2009 regulation is provided in the ISOR from 2009[51].

Since 2009, there have been numerous peer-reviewed publications, dissertations, and other scientific literature, that have focused on various aspects of indirect land use changes related to biofuels. Staff has reviewed published articles, contracted with academics, and consulted with experts, all of which have led to significant improvements to the GHG modeling methodologies and analysis completed in 2009. Complete details of the updates and results from the current analysis are presented in Appendix I.

[51] See Staff Report: Initial Statement of Reasons: Proposed Regulation to Implement the Low Carbon Fuel Standard." March 5 (2009)

(1) Overview

Increasing worldwide demand for biofuels will stimulate a corresponding increase in the price and demand for the crops used to produce those fuels. To meet that demand, farmers can:

- Grow more biofuel feedstock crops on existing crop land by reducing or eliminating crop rotations, fallow periods, and other practices which improve soil conditions;
- Convert existing agricultural lands from food to fuel crop production;
- Convert lands in non-agricultural uses to fuel crop production; or
- Take steps to increase yields beyond that which would otherwise occur.

Land use change effects occur when the acreage of agricultural production is expanded to support increased biofuel production. Lands in both agricultural and non-agricultural uses may be converted to the cultivation of biofuel crops. Some land use change impacts are indirect or secondary. When biofuel crops are grown on acreage formerly devoted to food and livestock feed production, supplies of the affected food and feed commodities are reduced. These reduced supplies lead to increased prices, which, in turn, stimulate the conversion of non-agricultural lands to agricultural uses. The land conversions may occur both domestically and internationally as trading partners attempt to make up for reduced imports from the United States. The land use change will result in increased GHG emissions from the release of carbon sequestered in soils and land cover vegetation. These emissions constitute the land use change impact of increased biofuel production.

Not all biofuels have been linked to indirect land use change impacts. Biofuels produced by using waste products as feedstocks will have insignificant land use effects. The use of corn stover as a feedstock for cellulosic ethanol production, for example, is not likely to produce a land use change effect. Feedstocks such as native grasses grown on land that is not suitable for agricultural production are unlikely to cause land use change impacts. Waste stream feedstocks such yellow grease, waste cooking oils and municipal solid waste, are also unlikely to lead to land use change impacts. Staff has identified feedstocks that have no measurable land use change impacts and is constantly reviewing additional feedstocks that may have minimal land use change impacts.

(2) Results of iLUC Analysis

For the current regulatory process, staff has completed iLUC analysis for six biofuels and they include:

- Corn Ethanol

- Sugarcane Ethanol
- Soy Biodiesel
- Canola Biodiesel (also Rapeseed Biodiesel)
- Sorghum Ethanol
- Palm Biodiesel

Table III-6 provides a summary of the iLUC values.

Table III-6. Comparison of iLUC Values from Scenario Runs and MCS

Biofuel	Average from Scenario run (gCO_2/MJ)	Mean from Uncertainty Analysis (gCO_2/MJ)
Corn Ethanol	19.8	21.8
Sugarcane Ethanol	11.8	14.1
Soy Biodiesel	29.1	27.4
Canola Biodiesel	14.5	13.2
Sorghum Ethanol	19.4	22.8
Palm Biodiesel	71.4	72.5

N. Provisions for Petroleum-Based Fuels

(1) General

Section N describes the calculation of deficits for regulated parties that produce gasoline and diesel for consumption in California. The section also describes opportunities for crude oil producers and refineries to generate LCFS credits for projects that reduce greenhouse gas emissions associated with producing and refining crude oil into gasoline and diesel fuels. Finally, the section describes special provisions available only to small refineries.

(2) Deficit Calculation for CARBOB or Diesel Fuel

The base deficit for petroleum-based fuels is proportional to the difference between the carbon intensity of the petroleum-based fuel and the carbon intensity of the compliance target for the given year. As the compliance target carbon intensity decreases each year, the base deficit for petroleum-based fuels increases. The base deficit is, therefore, the primary driver of the regulation and requires the producers of petroleum-based fuels to either purchase more credits from alternative fuel producers or purchase and blend more/lower-carbon intensity biofuels as the compliance target decreases.

The incremental deficit accounts for any increases to the carbon intensity for crude oils supplied to California refineries as compared to the crude oils supplied in the baseline year, 2010. As part of the 2011 LCFS amendment process, the Board approved the California Average crude oil provision. Under the California Average provision, all California refineries are treated as a single "average" refinery with regard to the carbon intensity for crude oil. Each year, staff calculates the Annual Average carbon intensity for crude oil supplied to California refineries during the given year. This Annual Average crude carbon intensity is then compared to the 2010 Baseline Average carbon intensity, which is the average carbon intensity for crudes supplied to California refineries during 2010. If the Annual Average carbon intensity increases relative to the 2010 Baseline Average, then all regulated parties for petroleum-based fuels are assessed an incremental deficit reflecting the difference between the Annual Average and the 2010 Baseline Average.

(3) Addition of Incremental Deficits that Result from Increases in the Carbon-Intensity of Crude Oil to a Regulated Party's Compliance Obligation

This section specifies the process by which the Executive Officer must calculate the Annual Crude Average carbon intensity, present the calculation for public comment, and ultimately approve the carbon intensity value. The section also describes the process by which incremental deficits are added to the regulated party's compliance obligation.

(4) Credit for Purchasing Crudes Using Innovative Methods

The innovative crude provision was adopted as part of the 2011 LCFS amendments. The intent of the provision is to promote the development and implementation of innovative crude oil production methods that reduce GHG emissions. As currently designed, the only allowable methods are carbon capture and sequestration (CCS) and solar steam generation for thermal-enhanced oil recovery and the method must achieve a minimum carbon intensity reduction of 1 g/MJ to qualify for the credit. The crude oil producer must apply to the Executive Officer for approval of both the method and the carbon intensity reduction associated with the method. Refineries that purchase the innovative crude generate LCFS credits proportional to the carbon intensity reduction achieved by the method. To date, no application for an innovative method has been submitted.

Staff is proposing several improvements to the provision that may help promote the use of innovative methods. First, staff is proposing to allow the crude producer to opt-in as a regulated party and receive the LCFS credit for implementing the innovative production method. This revision more closely aligns the benefits with the risks of implementing the method. Second, staff is proposing to expand the list of eligible innovative methods to include heat generation using solar power and electricity generation using solar or wind power. These innovative methods are in keeping with the intent of the regulation to promote the development and implementation of sustainable fuel sources. Thirdly, staff is proposing to standardize and simplify the application and credit calculation process for three innovative methods: solar steam generation, solar electricity, and wind electricity. The calculation of emissions reduction from these methods is relatively straight-forward and does not warrant the more rigorous application process. Lastly, staff is proposing to reduce the minimum threshold for carbon intensity reduction to allow for sustainable electricity and smaller, pilot-scale steam or CCS projects to qualify.

Finally, staff is proposing to include two revisions restricting the use of CCS as an innovative crude oil production method. These revisions will help align the treatment of CCS under the innovative crude provision with the treatment under the Cap-and-Trade (C&T) program. Under the C&T program, the emission reduction credit for CCS projects is effectively allocated to the facility where carbon capture occurs. In order to be consistent with this allocation methodology, staff is proposing that CCS projects will only qualify for innovative crude provision credit if the carbon capture occurs onsite at the oil production facility. The C&T program has also delayed credit generation for CCS projects until after ARB has in place an approved quantification methodology for monitoring, reporting, verification, and permanence requirements associated with the carbon storage method. Staff proposes to adopt the same restriction for CCS credit generation.

The most common method of sequestration being considered for carbon capture projects in the United States is through carbon dioxide enhanced oil recovery (CO_2 EOR). Sources of anthropogenic carbon include natural gas, ethanol, synthesis gas, and electrical power production. Therefore, carbon capture with CO_2 EOR projects often involve the production of two fuels, the fuel produced at the capture facility and the crude oil produced using CO_2 EOR. Under the LCFS, the GHG emissions benefits of capture and sequestration for these projects can either be allocated to the fuel produced at the capture facility (i.e. Method 2 pathway application), the oil produced using CO_2 EOR (i.e. innovative crude method provision), or partially allocated to both. Staff has decided that emissions benefits of CCS projects are best allocated to the capture facility as this allocation is consistent with:

(a) Treatment of CCS under the Cap and Trade, the proposed LCFS refinery investment provision, as well as the U.S. EPA's proposed GHG regulations on new power plants. Under all of these programs, credit for emissions reduction due to CCS is allocated to the capture facility.

(b) The goals of the LCFS, which include reducing the CI of fuels in the transportation sector and promoting the development and use of alternative fuels. By allocating to the capture facility, the capture and sequestration of CO_2 emitted during the production of alternative fuels such as ethanol and hydrogen is promoted as these alternative fuels may be eligible for a much lower CI through the LCFS method 2 application process.

(c) The fact that CO_2 EOR is not innovative, as it has been used for decades. However, capturing CO_2 from a steam generator at the oil production facility or from a methane reformer at a bitumen upgrader is considered to be innovative.

Therefore, under the innovative crude provision, staff is proposing that carbon capture must occur onsite at the crude production facility in order for the oil producer to receive innovative crude method credit. Oil producers that simply inject CO_2 that has been captured elsewhere are not eligible for innovative method credit.

(5) Low-Complexity/Low-Energy-Use Refinery

On December 16, 2011, the Board directed staff in Resolution 11-39 to consider provisions to the LCFS to address low-energy-use refining processes. This Resolution language was meant to address the concerns to account for the lower energy inherently embedded into their transportation fuels from refineries that use simple processes to refine transportation fuels to account for the lower energy inherently embedded into their fuels.

ARB staff investigated the complexity of each California refinery using the Nelson Complexity Score, as well as the total energy use of each refinery.

(a) Modified Nelson Complexity Score

The Nelson Complexity Score was first developed in 1960 by W. L. Nelson. It is a metric that compares the cost of a process unit as compared to a primary distillation unit. It also provides insight into refinery complexity, as well as replacement costs of installed process units. The relative capacity of each unit as compared to the distillation unit is used to calculate the overall complexity of the refinery (Nelson, 1). For example, one barrel of crude is sent through the distillation unit, but only a fraction of that barrel is sent through the subsequent "downstream" processing units. Each fraction is multiplied by the complexity index for each process unit and then summed. That sum is the complexity of the refinery.

The complexity of California refineries was calculated using the 2010 World Wide Refining Survey (OGJ, 2). This survey included updated Nelson Complexity factors, as well as process unit capacities. Since the LCFS deals with transportation fuels, the Nelson Complexity Score was modified to exclude asphalt and lube oil production. Equation 12 shows the calculation for the modified Nelson Complexity Score. Table III-7 contains all the indices.

$$Modified\ Nelson\ Complexity\ Score\ = \sum_i^n (index_i)\left(\frac{Capacity_i}{Capacity_{dist}}\right) \qquad \text{Eq. 12}$$

where:

$index_i$ is the 2012 Nelson Complexity Index listed in Table III-7;

$Capacity_i$ is the capacity of each unit listed in Table III-7;

$Capacity_{dist}$ is the capacity of distillation unit;

i is the process unit; and

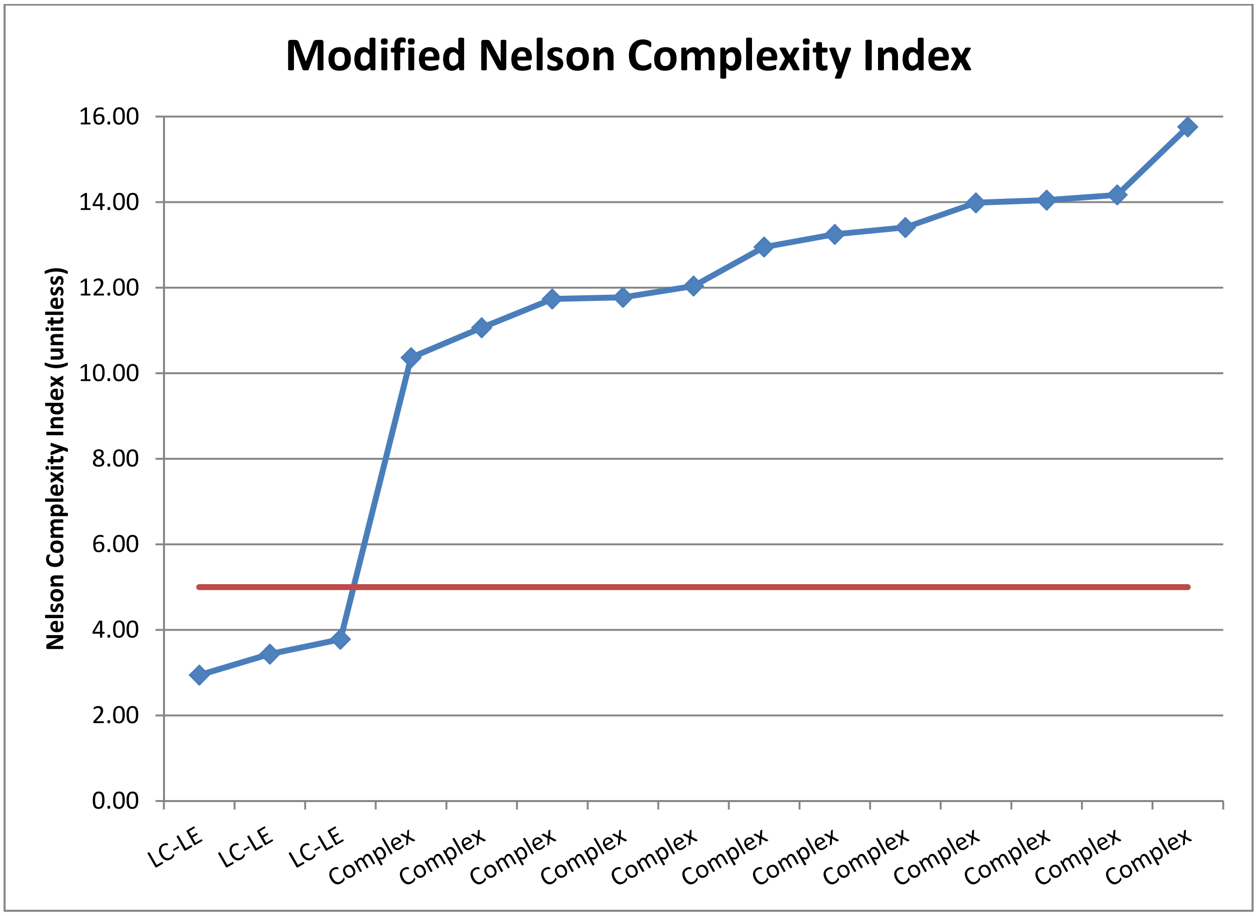
n is the total number of process units.

Table III-7. Nelson Complexity Indices.

Process Unit	***Index Value***
Vacuum Distillation	1.30
Thermal Processes	2.75
Delayed and Fluid Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining/Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00
Aromatics	20.00
Isomerization	3.00
Oxygenates	10.00
Hydrogen	1.00
Sulfur Extraction	240.00

Figure III-4 shows the modified Nelson Complexity Score for each refinery supplying transportation fuel to California. Three refineries have modified Nelson Complexity Scores between 2 and 4 and twelve refineries have modified Nelson Complexity Scores between 10 and 16. Figure III-4 illustrates a very clean break between "simple" refineries and "complex" refineries. Staff is proposing that a modified Nelson Complexity Score of 5 or less constitutes a low-complexity refinery.

Figure III-4. Modified Nelson Complexity Scores



(b) Total Energy Use

The total energy use of each refinery supplying transportation fuel to California was calculated using direct combustion, imported electricity and steam, and exported electricity and steam reported in the Mandatory Reporting Regulation. Equation 13 illustrates the calculation to determine each refinery's total annual energy use.

$$Energy\ Use\ (MMBtu/year) = fuel\ use + electricity + thermal \qquad \text{Eq. 13}$$

where:

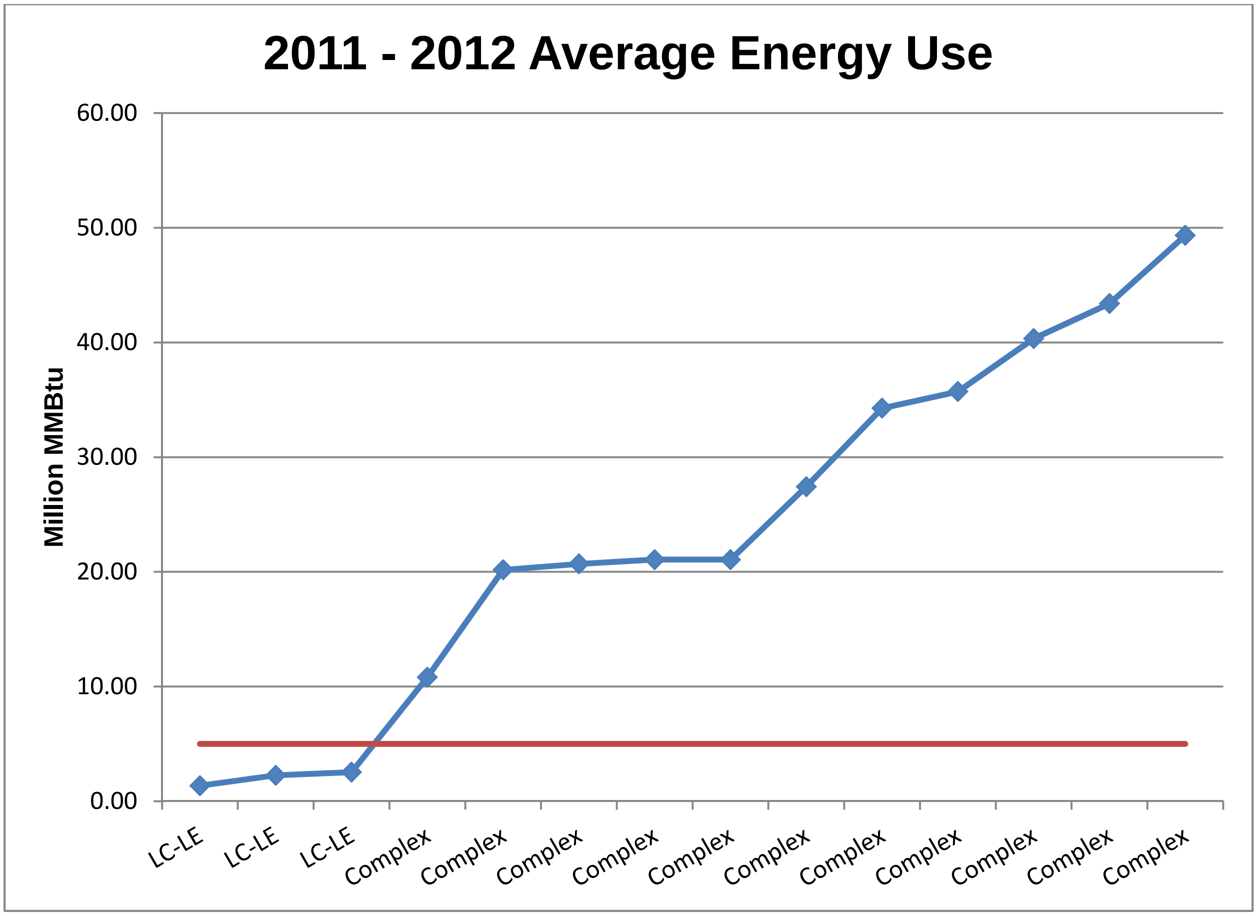
$fuel\ use$ is MMBtu of all fuel combusted per year;

$electricity$ is the imported electricity minus exported electricity per year converted to MMBtu by using 3.142 MMBtu/MWh; and

$thermal$ is the imported thermal energy minus exported thermal energy per year in MMBtu.

Two years of energy use data (2011 through 2012) were used to compute an average of the annual energy used by each refinery. Figure III-5 shows the annual energy use of each refinery supplying transportation fuel to California. This graph shows that three refineries use less than 5 million MMBtu of energy per year, one refinery uses about 11 million MMBtu of energy per year, and the remaining refineries use greater than 20 million MMBtu of energy per year. The three refineries that are below 5 million MMBtu of energy use per year are closely grouped and are the same refineries that are low-complexity refineries. Staff is proposing that a refinery must use 5 million MMBtu or less of energy to be a low-energy-use refinery.

Figure III-5. Total Annual Energy Use



(c) Proposed Revisions

Staff investigated the actual carbon intensity of the gasoline and diesel produced by low-complexity/low-energy-use refineries using data from 2011 to 2012. Equation 14 apportions emissions from each refinery on a volume basis.

$$CO_2e\ emissions\ (metric\ tons)_i = \left(\frac{Volume_i}{Volume_{total}}\right)(CO_2e\ emissions\ (metric\ tons)_{total}) \qquad \text{Eq. 14}$$

where:

$CO_2e\ emissions\ (metric\ tons)_i$ is the amount of emissions apportioned to each product i output of refinery;

$CO_2e\ emissions\ (metric\ tons)_{total}$ is the total emissions;

$Volume_i$ is the volume of individual product output in barrels (bbl); and

$Volume_{total}$ is the total volume of output product in barrels (bbl).

Each product was converted to total energy content using the Equation 15.

$$Energy\ Content\ (MJ)_i = (Volume_i)\left(energy\ content\ \left(\frac{MJ}{gal}\right)\right)\left(42\ \left(\frac{gal}{bbl}\right)\right) \qquad \text{Eq. 15}$$

where:

$Energy\ Content\ (MJ)_i$ is the total energy for each product output;

$Volume_i$ is the volume of individual product output in barrels (bbl); and

$energy\ content\ \left(\frac{MJ}{gal}\right)$ is the total energy content for each type of product.

Lastly, the total apportioned emissions for each product was divided by the total energy content for the volume of product produced. This renders the gCO_2e/MJ for each product.

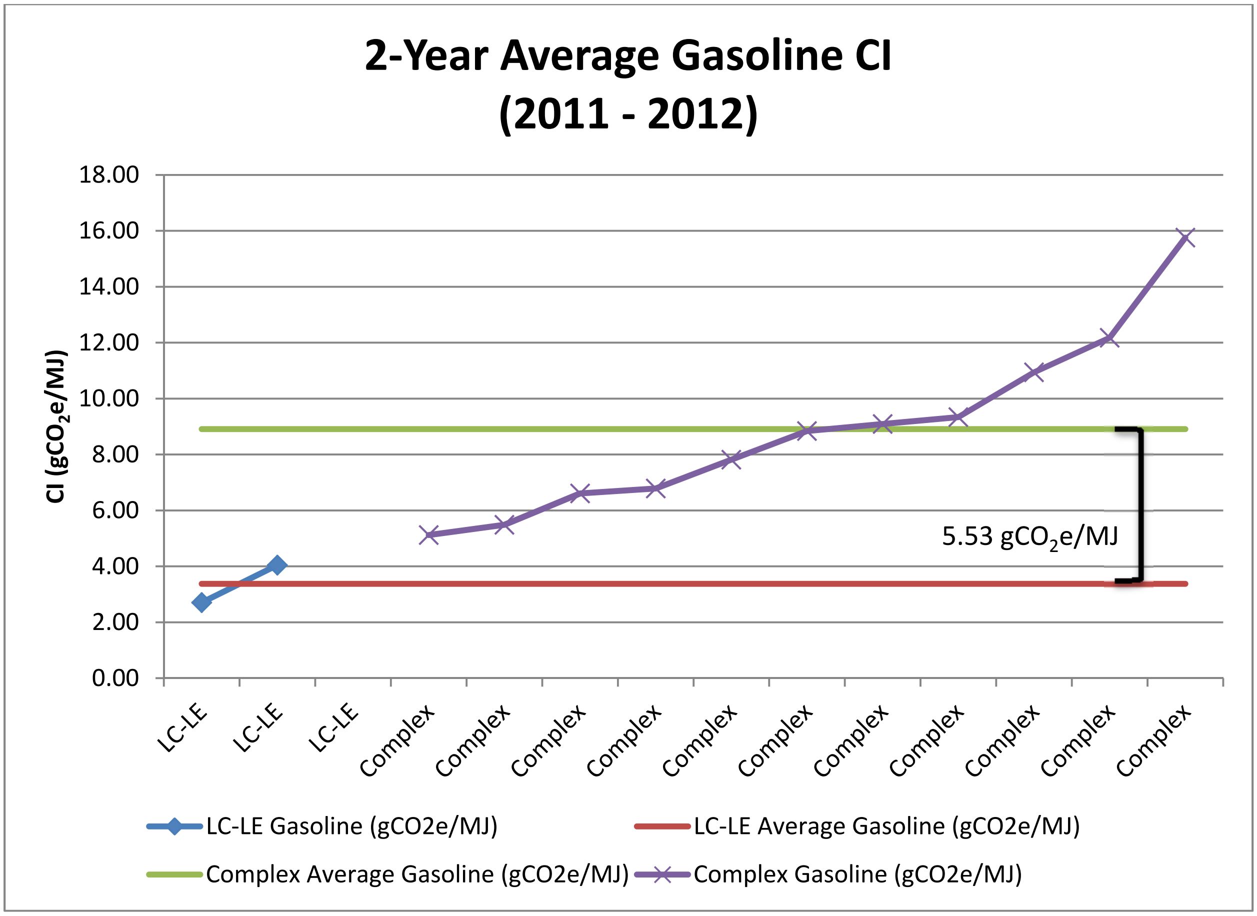
$$Emissions\ \left({}^{gCO_2e}/_{MJ}\right) = \left[\frac{CO_2e\ emissions\ (metric\ tons)_i}{Energy\ Content\ (MJ)_i}\right]\left(\frac{10^6\ g}{metric\ tons}\right) \qquad \text{Eq. 16}$$

Table III-8. Gasoline and Diesel Refinery Carbon Intensities

	CA-GREET (gCO_2e/MJ)	***Low-Complexity/Low-Energy-Use Refineries (gCO_2e/MJ)***	***Complex Refineries (gCO_2e/MJ)***
Gasoline	13.94	3.37	8.90
Diesel	15.33	3.15	7.94

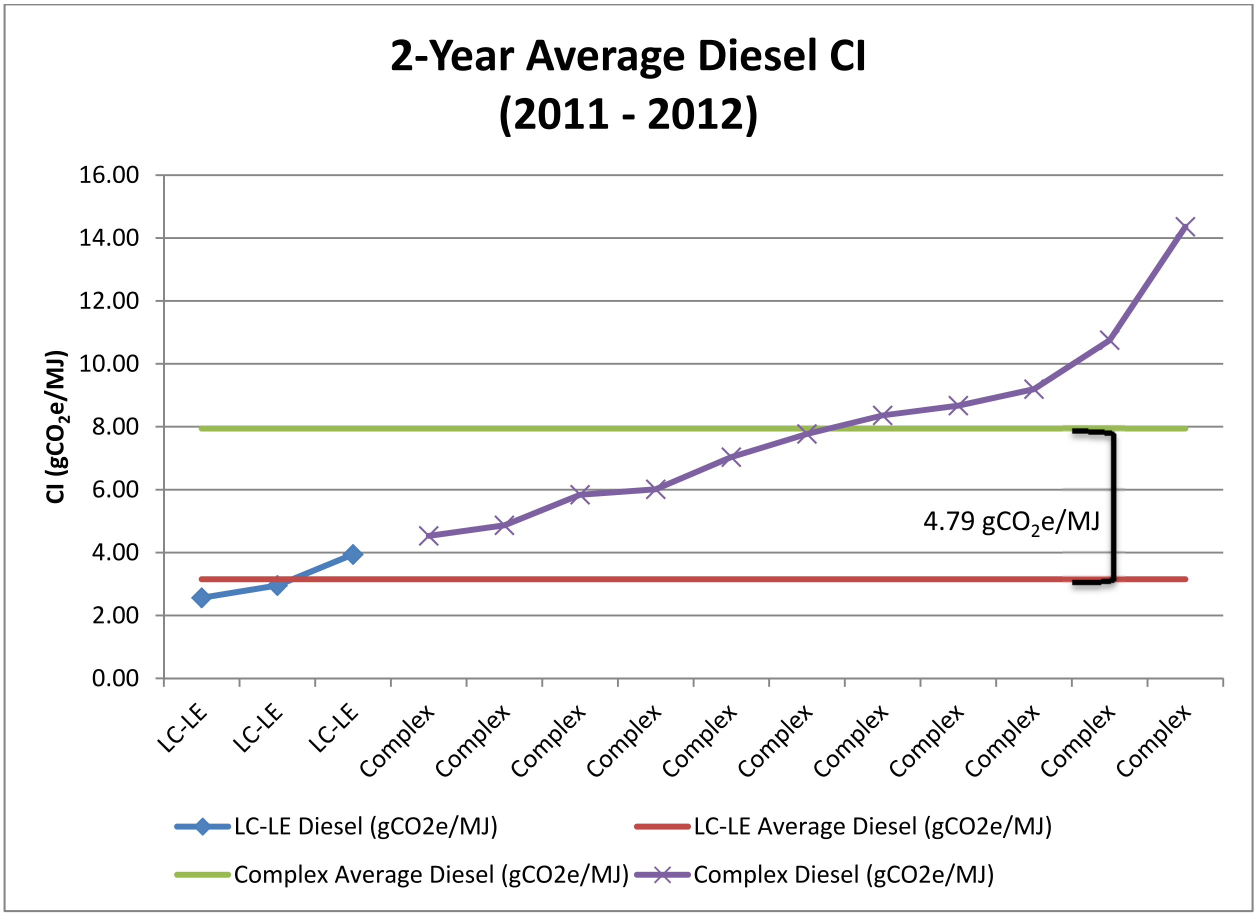
Table III-8 lists the average carbon intensity values for gasoline and diesel for California's refineries that produce transportation fuel. These values are based on data required to be submitted by the Mandatory Reporting Rule; they are not used for determining the carbon intensity of CARBOB and CARB diesel. The average gasoline carbon intensity for the low-complexity/low-energy-use refineries is 3.37 gCO_2e/MJ. The average gasoline carbon intensity for the remaining refineries is 8.90 gCO_2e/MJ. The low-complexity/low-energy-use refinery carbon intensity is 5.53 gCO_2e/MJ below the carbon intensity of the complex refineries. Figure III-6 shows the average CI for gasoline for all refineries. One of the low-complexity/low-energy-use refineries does not produce gasoline and so is not shown on the graph.

Figure III-6. Average Gasoline CI



The average diesel carbon intensity for the low-complexity/low-energy-use refineries is 3.15 gCO_2e/MJ. The average diesel carbon intensity for the remaining refineries is 7.94 gCO_2e/MJ. The low-complexity/low-energy-use refinery carbon intensity is 4.79 gCO_2e/MJ below the complex refineries' carbon intensity for diesel. Figure III-7 shows the average CI for diesel for all refineries.

Figure III-7. Average Diesel CI



Staff is proposing to credit the low-complexity/low-energy-use refineries 5 gCO_2e/MJ for CARBOB and CARB diesel. The credit will be handled in the Reporting Tool to maintain the fungibility of the fuels. All credits generated under this provision must be used by the refinery that generated them and may not be sold.

Staff is proposing to add reporting requirements for low-complexity/low-energy-use refineries. They are:

- The volume of CARBOB and CARB diesel refined from crude oil;
- The volume of CARBOB and CARB diesel refined from intermediates, including transmix; and
- The volume of CARBOB and CARB diesel purchased for blending.

(6) Refinery Investment Credit

Staff is proposing to modify the LCFS regulation to allow refineries to generate credits for GHG reduction projects implemented within the border of the refinery.

(a) Available Reductions

In the current CA-GREET model, the refinery portion of the life cycle of CARBOB and CARB diesel has fixed values. Treating all refineries the same does not incent GHG reductions, and consequently, associated toxic and criteria pollutant reductions, at the refinery. To be more consistent with the full life cycle analysis, staff is proposing to allow refineries to generate credits for investments at the refinery that reduce GHG emissions.

Staff analyzed data provided to ARB through the Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation (Energy Audit) (ARB, 3). The regulation required operators of California's largest industrial facilities to conduct a one-time energy efficiency assessment and identify GHG reduction projects that could be implemented within the border of the facility. Only facilities with total GHG emissions of 0.5 $MMTCO_2e$ or more were subject to the assessment. The Energy Audit identified over 400 efficiency improvements at 12 refineries that overall would account for nearly 2.8 $MMTCO_2e$ GHG reductions, as well as 2.5 tons per day (tpd) NO_X and 0.6 tpd particulate matter (PM) reductions.

Almost 80 percent of identified GHG reduction projects were completed prior to the Energy Audit, leaving about 100 reduction projects that had not. The remaining projects that had not been implemented represent about 0.6 $MMTCO_2e$, 1.5 tpd NO_X, and 0.3 tpd PM potential reductions.

The above GHG reduction projects would result in CI reductions for CARBOB and CARB diesel of 0.01 gCO_2e/MJ to 3.11 gCO_2e/MJ per project. The majority of these refinery reduction projects range from 0.1 gCO_2e/MJ to 1.0 gCO_2e/MJ.

(b) Proposed Revisions

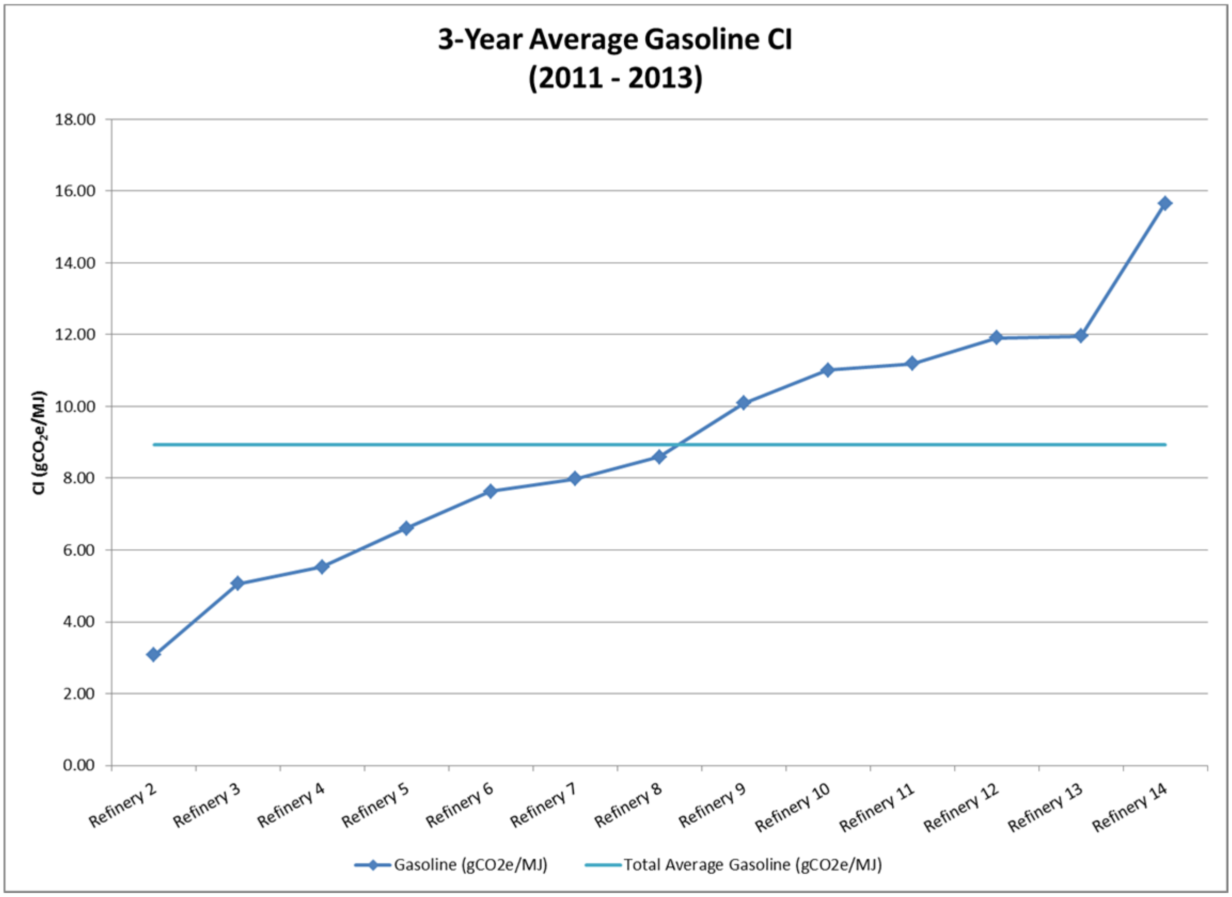
Staff investigated the actual carbon intensity of the gasoline and diesel produced by refineries using data from 2011 to 2013 and Equations 14 through 16, above.

Table III-9. Gasoline and Diesel Refinery Carbon Intensities

	CA-GREET (gCO_2e/MJ)	***Industry Average (gCO_2e/MJ)***
Gasoline	13.94	8.95
Diesel	15.33	7.61

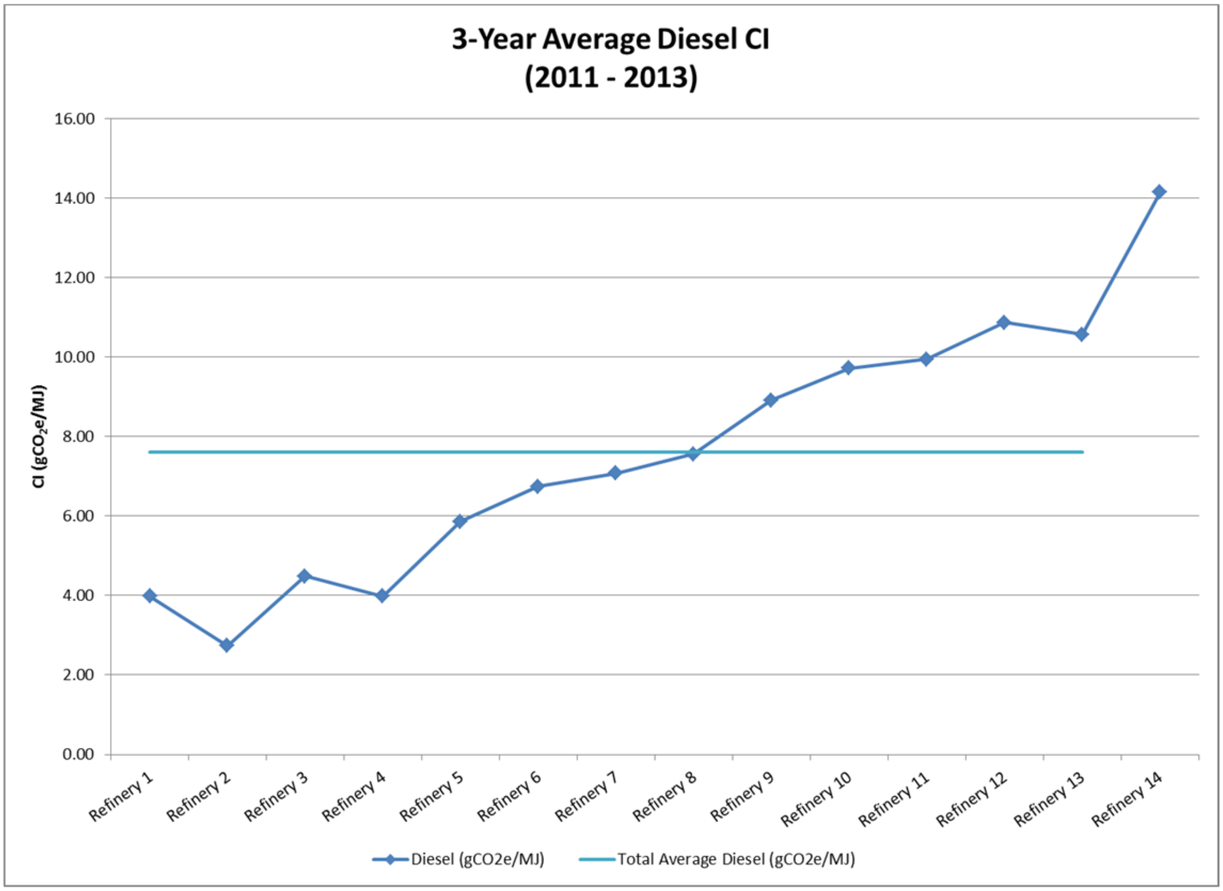
Table III-9 lists the average carbon intensity for gasoline and diesel for all refineries. The average gasoline carbon intensity is 8.95 gCO_2e/MJ. Figure III-8 shows the average CI for gasoline for all refineries.

Figure III-8. Industry Average Gasoline CI



The average diesel carbon intensity for all refineries is 7.61 gCO_2e/MJ. Figure III-9 shows the average CI for diesel for all refineries.

Figure III-9. Average Diesel CI



Staff is proposing to allow refineries to receive credit for GHG reduction projects performed within the boundary of the refinery. The refinery would submit a project plan to ARB for approval. Staff is proposing that all projects must meet a CI reduction threshold of 0.1 gCO_2e/MJ and that the project application must be submitted in 2015 or later. Staff recognizes that some refineries have invested in efficiency measures while others have not yet. To provide more of an equitable playing field, and to preserve simplicity as much as possible, staff is proposing that CARBOB and diesel CIs that are above the industry average will receive half of the calculated CI reduction, and CARBOB and diesel CIs that are below the industry average will receive the full calculated CI reduction. Staff is also proposing that the GHG reduction project must be a capital investment or use a renewable feedstock in a refinery process that does not increase emissions of criteria or toxic pollutants from the refinery itself. Furthermore, the project cannot merely move emissions increases off-site.

O. Requirements for Multimedia Evaluation

(1) Statutory Requirements

Senate Bill 529, enacted in 1999 and set forth in H&S section 43830.8 ("the statute"),[52] generally prohibits ARB from adopting a regulation establishing a specification for motor vehicle fuel unless the regulation and a multimedia evaluation conducted by affected State agencies is subject to a review and approval by the California Environmental Policy Council (CEPC). (Stats. 1999, ch. 813; SB 529, Bowen.) Pursuant to Public Resources Code section 71017(b), the CEPC was established as a seven-member body comprised of the Secretary for Environmental Protection; the Chairpersons of the ARB, State Water Resources Control Board, and Department of Resources Recycling and Recovery; and the Directors of the Office of Environmental Health Hazard Assessment, the Department of Toxic Substances Control, and the Department of Pesticide Regulation. Key components of the evaluation process are the identification and evaluation of significant adverse impacts on public health or the environment and the use of best available scientific data.

"Multimedia evaluation" means the identification and evaluation of any significant adverse impact on public health or the environment, including air, water, or soil, that may result from the production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications. (Health & Saf. Code, §43830.8(b).)

The statute generally provides that ARB may adopt a regulation establishing a motor vehicle fuel specification without undergoing the prescribed multimedia evaluation process if the CEPC, following an initial evaluation of the proposed regulation, finds that the regulation will not have significant adverse impacts on public health or the environment.

(2) Applicability of H&S Section 43830.8 to the LCFS Regulation

The provisions in H&S section 43830.8 are relatively straightforward for a fuel regulation that unquestionably constitutes a fuel specification. However, before the substantive requirements of the statute can be discussed, we first need to address an important threshold question in this case: Does the statute apply to the LCFS regulation itself, or does it apply only to subsequent ARB rulemakings establishing new or amended motor vehicle fuel specifications to implement the LCFS program?

(a) H&S Section 43830.8 Applies to ARB Adoption of Regulations that Establish Specifications for a Motor Vehicle Fuel

By its terms, the statute clearly focuses on prohibiting ARB from adopting regulations that establish specifications for motor vehicle fuels unless the regulation has been subjected to a multimedia evaluation as specified. Presumably, this is to avoid, among

[52] All statutory references in this chapter are to H&S §43830.8 unless otherwise noted.

other things, requiring ARB to conduct a multimedia evaluation for rule amendments that are merely technical in nature and have no substantive effect on motor vehicle fuel specifications. Another possibility is that the Legislature did not want to require a multimedia evaluation whenever ARB adopted fuel *use* requirements, which affect the use of a fuel and operation of equipment using that fuel, rather than affecting the fuel itself.[53] A third possibility is that the Legislature did not want to require multimedia evaluations for emissions averaging or similar regulatory schemes for which an enforceable goal is set but the exact methods for achieving that goal are not specified by the regulation (i.e., through motor vehicle fuel specifications).

Further, the Legislature presumably used the term “specification,” rather than more broad terms such as “standard” or “requirement,” to express an intent to focus on those regulations in which ARB is proposing to dictate what is added (or prohibited from being added) into a motor vehicle fuel. This would be consistent with the legislative history of SB 529, which was promulgated after fuel producers began to use methyl tert-butyl ether (MTBE) in gasoline in the 1990s to meet ARB oxygenate requirements. The Legislature enacted SB 529 after MTBE was subsequently shown to leak out of underground storage tanks unexpectedly into aquifers.

With these considerations in mind, the next questions that follow are, “What is a motor vehicle fuel specification?” and “Is the LCFS a regulation that establishes a fuel specification for motor vehicle fuels?”

(b) The LCFS Regulation Does Not Establish a Specification for Motor Vehicle Fuels

For purposes of this discussion, the primary LCFS requirement of interest is the requirement for regulated parties to reduce their average carbon intensity by ten percent.[54] This ten percent reduction in overall carbon intensity would cover the party’s overall motor vehicle fuel pool, including all fuels subject to the LCFS, as well as any credits/deficits from over-compliance and under-compliance with the requirement in a given compliance period.

Unfortunately, the statute provides no explicit definition for “specification.” However, there is evidence indicating that the Legislature intended the term “specification” as a reference to the permissible ingredients that comprise a fuel (i.e., the fuel’s “composition”). In H&S section 43018, a statute last amended nine years before SB 529 was enacted, the Legislature mandated that ARB:

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[53] An example is the California requirement for locomotives and commercial harbor craft to use California ultralow sulfur diesel. 13 CCR §2299 and 17 CCR §93116.

[54] That is, the regulated party’s carbon intensity must be no greater than the carbon intensity (CI) for gasoline or diesel as the CI for those fuels are reduced by ten percent between 2010 and 2020 in accordance with the proposed regulation’s compliance schedule (the gasoline CI applies generally for light-duty vehicles and the diesel CI for heavy-duty vehicles).

> "adopt standards and regulations which will result in the most cost-effective combination of control measures on all classes of motor vehicles and *motor vehicle fuel*, including, but not limited to, all of the following:…(4) *[s]pecification* of vehicular fuel *composition*…" [emphasis added].

H&S section 43018(c)(4) [Added Stats. 1988, ch. 1568; amended Stats. 1989, ch. 559; amended Stats. 1990, ch. 932].

In this context, the Legislature seems to use the term "specification" as a subset of motor vehicle "standards," "regulations," and "measures." Thus, one can reasonably presume that, in the context of motor vehicle fuels, the Legislature intended the term "specification" to be an ARB mandate on a vehicular fuel's permissible composition, rather than on the production process for the fuel.

This view of the legislative intent is further supported when one looks at the common usage for the term "specification" in the area of motor vehicle fuels. To this end, we first discuss the general characteristics of a specification and then look at several examples of existing ARB specifications. From these examples, it is possible to glean whether the Legislature intended for a regulation like the LCFS to trigger the multimedia evaluation requirement.

The American Heritage (4th Ed.) dictionary (73) defines "specification" as follows:

> "*A detailed, exact statement of particulars, especially a statement prescribing materials, dimensions, and quality of work for something to be built, installed, or manufactured.*"

This suggests that a specification is prescriptive in nature, i.e., telling the reader that material X is required in Y amount. A useful analogy is a typical cooking recipe, in which not only are the ingredients specified, but also their relative quantities. Motor vehicle fuel specifications, like cooking recipes, also specify what materials are permitted to be in a legal motor vehicle fuel and the relative quantities of those materials.

There are numerous examples of motor vehicle fuel specifications that were in existence at the time SB 529 was enacted. For instance, California's diesel regulation in 1999 applied specifications that limited aromatic hydrocarbons to ten volume percent and 500 parts per million (ppm) sulfur in diesel.[55] Another example is the California regulation establishing specifications for E85 (gasoline with 85 volume percent ethanol), which is presented in Table III-10.

[55] 13 CCR §2282(a)(1)(A) and §2281(a)(1), respectively. The 500 ppm sulfur limit was reduced for most applications to 15 ppm beginning in June 2006. *Id*. at §2282(a)(2).

Table III-10. Select Specifications for E85 Fuel Ethanol

Specification	Value	Test Method
Ethanol	79 vol. % (min.)	ASTM D 3545-90
Other Alcohols	2 vol. % (max.)	ASTM 4815-89
Hydrocarbons + aliphatic ethers	15-21 vol. %	ASTM D 4815-89, and then subtract concentration of alcohols, ethers and water from 100 to obtain percent hydrocarbons
Acidity as acetic acid	0.007 mass % (max.)	ASTM D 1613-85
Total chlorine as chloride	0.0004 mass % (max.)	ASTM D 3120-87 modified for the det. of organic chlorides, and ASTM D 2988-86
Copper	0.07 mg/l (max.)	ASTM D 1688-90 as modified in ASTM D 4806-88

Source: CCR, title 13, section 2292.4 (adopted by ARB in 1992); footnotes omitted.

A third, more current example is the CaRFG3 regulation is presented in Table III-11.

Table III-11. Select Current Specifications for CaRFG3

Property	Flat Limits	Averaging Limits	Cap Limits
Reid Vapor Pressure, psi, max	7.00 or 6.90	--	6.40 – 7.20
Benzene vol%, max	0.80	0.70	1.10
Sulfur, ppmw, max	20	15	20
Aromatic HC, vol%, max	25.0	22.0	35.0
Olefins, vol% max	6.0	4.0	10.0
Oxygen, wt%	1.8 to 2.2	--	1.8 - 3.5 0 – 3.5
T50 (temp. at 50% distilled) °F, max	213	203	220
T90 (temp. at 90% distilled) °F, max	305	295	330

Source: CCR, title 13, sections 2260 et seq.; footnotes omitted.

Of course, motor vehicle fuel specifications are not cooking recipes, as they entail highly technical properties and measurements for the affected fuels. But like a cooking recipe, all the above examples of existing fuel specifications share a common characteristic—the specifications contained in the requirements are quantifiable and measurable chemical or physical properties that are intrinsic to the final fuel itself, not how it is produced. In other words, one can take a sample of diesel and measure its sulfur and aromatic content to see if it meets the specified limits on those properties. Similarly, a sample of gasoline can be analyzed in a laboratory for its Reid vapor pressure or sulfur content. To determine compliance with the specifications for these fuels, it is irrelevant to ask how these fuels were made—the only question is whether the finished product has the desired physical and chemical properties.

In contrast, it is as important, or even more important, to know *how* a fuel or blendstock was made under the LCFS regulation than knowing the fuel's actual constituents. The LCFS requires a regulated party to achieve a specified performance reduction in its motor vehicle fuel pool's overall carbon intensity. This is the sum of all carbon intensities associated with all steps required to produce, distribute, market, and use the party's fuel, plus any credits purchased, generated, or used by the party. As such, a regulated party's carbon intensity cannot be directly measured in a sample of gasoline, diesel, or any other fuel. Simply put, one cannot take a gallon of gasoline and measure its carbon intensity in a laboratory like one would for determining the fuel's boiling point.

Rather, a fuel's carbon intensity is inferred from the various steps taken to produce that fuel and the relative impacts to climate change associated with each step (vis-à-vis the steps' carbon intensity), as well as accounting for any credits used, generated, or traded by the regulated party. Thus, the relevant question for the LCFS is exactly the opposite of the above examples of actual fuel specifications: Exactly how was the product made, since the process for producing and distributing the product is what affects the product's carbon intensity?

To further illustrate, a gallon of ethanol made from corn grown and processed in the Midwest will, under a microscope or other analytical device, look identical in every material way to a gallon of ethanol processed from sugar cane grown in Brazil. Both samples of ethanol will have the same boiling point, the same molecular composition, the same lower and upper limits of flammability—in other words, both will have identical physical and chemical properties because both products consist of 100 percent ethanol. On the other hand, the corn ethanol made from the Midwest will have different carbon intensity than the sugar cane ethanol from Brazil. Thus, the relevant inquiry with carbon intensity is not so much what is contained in a fuel, but how that fuel was made, distributed and used.

An additional complication is that a regulated party's carbon intensity is not only reflective of its fuels' carbon intensities, but also whether any credits that are used or traded are also reflected in the party's overall carbon intensity. Thus, from the above example, even if the corn ethanol and sugar ethanol were to have identical carbon intensity, one regulated party using corn ethanol would almost certainly have a different overall carbon intensity than another party with sugar ethanol, simply because each party would have different rates of credit generation and usage.

The above considerations strongly suggest that the LCFS regulation, unlike other existing California regulations, does not establish prescriptive[56] fuel specifications. Instead, the nature of the LCFS regulation points to a rule that is much more akin to a performance[57] requirement, one that establishes an enforceable goal but does not dictate the process for how to achieve compliance with that goal. As such, ARB staff believes the LCFS regulation, by itself, does not establish motor vehicle fuel

[56] "Prescriptive standard" means a regulation that specifies the sole means of compliance with a performance standard by specific actions, measurements, or other quantifiable means. (Gov. Code §11342.590.)
[57] "Performance standard" means a regulation that describes an objective with the criteria stated for achieving the objective. (Gov. Code §11342.570.)

specifications; therefore, the LCFS rule should not be subject to the multimedia evaluation requirement.

(c) The LCFS Regulation Does Not Affect Existing Fuel Specifications

It is important to note that, by its terms, the LCFS regulation does not modify any other existing State or federal specifications for motor vehicle fuels. Section 95482 of the proposed regulation includes a saving clause providing, in pertinent part, that:

> "*Nothing in this LCFS regulation (17 CCR §95480 et seq.) may be construed to amend, repeal, modify, or change in any way the California Reformulated Gasoline regulations (CaRFG, 13 CCR §2260 et seq.), the California Diesel Fuel regulations (13 CCR §2281-2285 and 17 CCR §93114), or any other applicable State or federal requirements. Any person, including but not limited to the regulated party as that term is defined in the LCFS regulation, subject to the LCFS regulation or other State and federal regulations shall be responsible for ensuring compliance with all applicable LCFS requirements and other State and federal requirements, including but not limited to the CaRFG requirements and obtaining any necessary approvals, exemptions, or orders from either the State or federal government.*"

This provision was included to reflect staff's intent that the LCFS regulation, by itself, neither establishes a fuel specification nor amends any other State or federal requirements that apply to the affected fuels, including other requirements that constitute fuel specifications.

This provision also reflects staff's understanding of what will likely occur to gasoline and diesel under the LCFS regulation. To comply with the LCFS regulation, it is unlikely that fuel producers will change the composition and makeup of gasoline and diesel since these are relatively mature technologies that still would need to meet applicable State and federal specifications. Instead, fuel producers are likely to choose less carbon-intensive blendstocks, such as cellulosic ethanol, to help meet their LCFS obligations.

(d) There are Practical Difficulties in Conducting a Multimedia Evaluation for the LCFS Rulemaking

Even if, for the sake of argument, one were to conclude that the LCFS rule itself somehow triggers the multimedia evaluation requirement, conducting such an evaluation for the overall rule would make it practically very difficult, if not impossible, to conduct such an evaluation. Because the LCFS establishes a performance-based requirement (see above) rather than a prescriptive standard, it is very difficult for ARB to predict with certainty how regulated parties will comply with the LCFS requirement. For instance, there has been substantial mention of the use of genetically-engineered algae to provide feedstock for making renewable diesel or other lower carbon intensity fuels. However, such technology is, at best, in its infancy, and no meaningful discussion of the pathways (and, by extension, the associated carbon intensity) can be made until the technology is better developed and ARB has adopted fuel specifications for such fuels.

Given these difficulties, the best that ARB staff can provide at this time is the "functional equivalent" of a multimedia evaluation. Such an equivalent can, to the extent feasible, identify and evaluate the potential adverse impacts on public health or the environment that may result from the production, use, or disposal of motor vehicle fuels that are likely to be used to meet the LCFS requirements. As fuels are developed and produced to comply with the LCFS, ARB can adopt new specifications or amend existing specifications for such fuels as needed. At that time, ARB staff plan to conduct new multimedia evaluations pursuant to H&S section 43830.8.

(3) Applicability of H&S Section 43830.8 to Post-LCFS Regulations Establishing Vehicular Fuel Specifications

Based on the above discussion, ARB staff believes that the LCFS regulation itself does not establish motor vehicle fuel specifications that trigger the multimedia evaluation requirement. However, it is clear that post-LCFS rules adopted by ARB would certainly require multimedia evaluations to the extent such rules establish new fuel specifications or modify existing ones. The LCFS regulation incorporates this principle as a pre-sale prohibition applied to fuels that are subject to an ARB specification that is modified or adopted after adoption of the LCFS regulation.[58] In such cases, regulated parties would be prohibited from selling the affected fuels in California to comply with the LCFS requirements until a multimedia evaluation is approved for those fuels pursuant to H&S section 43830.8.

Fuels that would not be subject to this pre-sale prohibition include the following (until such time as ARB adopts a new specification or modifies the existing specification for these fuels):

- Those fuels that were "grandfathered" in before July 1, 2000, pursuant to H&S section 43830.8(h), or have not had their specifications amended since SB 529 was enacted. These include CaRFG, diesel, E85, E10, CNG;

- Those fuels for which there are no existing ARB specifications but are permitted for sale in California pursuant to regulations promulgated by the Division of Measurement Standards. This includes biodiesel and renewable diesel; and

[58] See proposed LCFS regulation section 95487(a).

- Those fuels for which the California Environmental Policy Council has determined no significant adverse impacts would result from the Board's adoption of a fuel specification (under H&S section 43830.8(i)).

For the 2015 rulemaking calendar, ARB staff is currently planning to propose new motor vehicle specifications for biodiesel as part of the proposed ADF regulation. Staff may also propose rulemakings for E85, CNG and LNG by 2016. To the extent those rulemakings establish new specifications, multimedia evaluations may be needed pursuant to H&S section 43830.8.

To comply with the requirements for multimedia evaluations that is applicable to the Low Carbon Fuel Standard:

- Staff recognizes that a full and comprehensive multimedia evaluation, in accordance with H&S section 43830.8, is neither required nor practical to conduct for the LCFS rulemaking itself;

- Nevertheless, to implement the "spirit" of H&S section 43830.8, staff intends to conduct the functional equivalent of a multimedia evaluation for the LCFS rulemaking to the extent feasible;

- Staff will conduct full multimedia evaluations, pursuant to H&S section 43830.8 and consistent with the California Environmental Protection Agency (Cal/EPA) Guidance Document[59], prior to ARB adoption of a new fuel specification for motor vehicle fuels subject to the LCFS rule. The first of these will be a rulemaking in 2015 to adopt motor vehicle fuel specifications for biodiesel as part of the proposed ADF regulation. To the extent future rulemakings involving CNG, E85, or other fuels may involve the establishment of motor vehicle fuel specifications, a multimedia evaluation may be required for those rulemakings as well.

P. Reporting and Recordkeeping

(1) Reporting Requirements

Under the proposed LCFS regulation reporting is required by all entities in the chain-of-custody that held obligation for a transportation fuel. This includes initial regulated parties as well as those that acquired the LCFS obligation from upstream entities. Such entities are collectively referred to as reporting parties in the proposed regulation. Each reporting party must report to ARB a specified set of information, including fuel pathway code (which includes its carbon intensity), fuel quantity, and other information for each fuel or blendstock supplied in California on a quarterly basis. This includes the transaction date (when title transfers), fuel pathway codes, fuel amounts, transaction types, business partners, fuel production facilities, and other information for each fuel or

[59] California Environmental Protection Agency. *Cal/EPA Fuels Guidance Document.* November 15, 2011.

blendstock supplied in California. Any party that voluntarily opts into the LCFS to generate credits must also submit quarterly and annual reports. These reports are due according to the schedules specified in the proposed LCFS regulation.

While quarterly reports are intended to provide progress reports, as well as for the generation of credits, a reporting party must submit an annual report by April 30th of the following year for compliance. The annual report is for determining compliance with the LCFS for the previous reporting year. The annual report must be submitted to the Executive Officer in the LRT-CBTS, demonstrating with documentation the yearly fuel amounts and the fuel pathway codes associated with each of these fuels or blendstocks supplied for transportation use in California. In addition, all credit transfers with other reporting parties and any prior year deficit obligations are required to be reported and all pending transfers must be completed prior to annual report submission. The Executive Officer will determine whether the regulated party complies with the LCFS based on the outcome of the annual report.

The annual compliance report is a compilation of the information submitted in the quarterly reports for the compliance period. The current LCFS regulation requires that each quarterly report be submitted two months after the end of the quarter. Under the proposed change this would become a three month period after the end of the quarter. The first 45 days would be for completing an initial data upload for the quarter. The second 45 days would be for reconciling discrepancies with business partners prior to officially submitting a quarterly report. The annual compliance report is on a schedule where they are due four months after the end of the compliance period and this would not change.

Any “opt-in” reporting party in the LCFS must also submit quarterly and annual compliance reports. It does not matter whether a company is registered in the program as an “opt-in” or not, all reporting parties are required to comply with the reporting schedule on an ongoing basis even if there are no fuel transactions or fuel amounts to report for the given period.

ARB has developed an online, interactive LRT used to support quarterly and annual reporting. The Credit Bank & Transfer System has been integrated online with the LRT to handle the LCFS credit banking and credit transfers. Together these two integrated applications are referred to as the LRT-CBTS, which will serve as the central online application to facilitate the upload, validation, and submission of fuel transaction data. The first year of the LCFS program in 2010 was a reporting year only. It allowed reporting parties to become familiar with the reporting system and related requirements. It enabled ARB staff to take program requirements and related policy and develop and implement business logic and data validation routines. Additional programmatic changes needed to the program have been implemented since the beginnings of the LCFS program in 2010.

Table III-12 below provides descriptions for each of the various transaction types expected under the LCFS along with each of the actual “Transaction Types” to be used for reporting.

Table III-13 below of the proposal includes a replacement for the term “Biofuel Production Facility” to “Production Company ID and Facility ID,” which may include alternative fuels and other fuel production facilities in the future. The proposed LCFS includes the replacement of the term "Physical Pathway Code" with "Fuel Transport Mode," which is also defined below.

Table III-12. Descriptions of LCFS Transaction Types

Description of Fuel Transaction	***Transaction Type* for Reporting**
Fuel was designated for use only in California at production, where it acquired a compliance obligation under LCFS regardless of production inside or outside of California	*Production for use in California*
Fuel purchased with the compliance obligation from a regulated party	*Purchased with Obligation*
Fuel purchased without the compliance obligation from a regulated party	*Purchased without Obligation*
Fuel sold with the compliance obligation by a regulated party	*Sold with Obligation*
Fuel was sold without the compliance obligation by a regulated party	*Sold without Obligation*
Fuel with compliance obligation exported outside of California	*Export*
Fuel entered California fuel pool and had LCFS obligation but was not used in a motor vehicle due to spillage or shrinkage	*Loss of Inventory*
Fuel entered California fuel pool and had an LCFS obligation due to a gain in volume	*Gain of Inventory*
Transportation fuel was reported with compliance obligation under the LCFS but was later not used for transportation purposes in California or otherwise determined to be exempt under section 95482(d)	*Not Used for Transportation*
Providing electricity to recharge plug-in electric vehicles, included are battery and plug-in hybrid electric vehicles	*EV Charging*
Fueling light rail or heavy rail, exclusive right-of-way bus operations, or trolley coaches with electricity	*Fixed-Guideway Charging*
Providing electricity to recharge electric forklifts	*Forklift Charging*
Dispensing natural gas at a fueling station designed for fueling NG vehicles	*NGV Fueling*

Table III-13. Quarterly Reporting Parameters

Parameters to Report from Table 13 of the Proposed Regulation	**Parameter Description**
Company or Organization Name	Reporting Party identification
Reporting Period	Quarterly and Annual; applies to all fuels
Fuel Pathway Code	Comprises the carbon intensity value; reported for all fuel transactions.
Transaction Type	Specifies the type of transaction and is integral in assigning initial obligation incurred and tracking transfer of obligation; applies to all fuels
Transaction Date	Required entry with each fuel transaction; enter date of title transfer except for aggregated fuel transactions (where last day of quarter is to be entered).
Business Partner	Required entry with each fuel transaction; "Not Applicable" entered for Production for use in California Transaction Types.
Production Company ID and Facility ID	Submit with each reported fuel transaction; Required for designated fuels reported, excluding gasoline, diesel, and electricity.
Fuel Transport Mode (FTM)	Identifies how fuel was transported to California for each fuel transaction reported (without an approved FTM demonstration, credits are designated as "pending")
Aggregated Transaction (T/F)	Entered for each fuel transaction; indicates whether fuel transaction is a sum of transactions (T), or not (F); if True, report Transaction Date as last day of quarter.
Amount of each gasoline and diesel and blendstock	Entered amount for each gasoline or diesel fuel transaction.
Amount of each fuel used as gasoline replacement	Entered for each fuel transaction for all fuels that are gasoline fuel replacements.
Amount of each fuel used as diesel fuel replacement	Entered for each fuel transactions for all fuels that are diesel fuel replacements.
Credits/deficits generated per quarter (MT)	Derived from <u>quarterly reporting</u>; reporting is in LRT-CBTS where credits/deficits are tracked
MCON or other crude oil name designation, volume (in gal), and country (or state) of origin for each crude supplied to the refinery	Derived from <u>quarterly and annual reporting</u>; Reporting is in LRT-CBTS; Deficits tracked
Credits and Deficits generated per year (MT)	Derived from <u>quarterly reporting</u> Calculated and stored in LRT-CBTS
Credits/deficits carried over from the previous year (MT), if any	Based on <u>annual reporting</u>; Tracked in LRT-CBTS
Credits acquired from another party (MT), if any	Derived from <u>credit transfers</u>; Tracked in LRT-CBTS
Credits sold to another party (MT), if any	Derived from <u>credit transfers</u>; Tracked in LRT-CBTS
Credits exported to another program (MT), if any	Based on results from <u>annual reporting</u>; Tracked in LRT-CBTS

The proposal includes a listing of the general quarterly reporting parameters for fuels, as well as the quarterly reporting parameters specific to given types of transportation fuels, including natural gas (CNG, LNG, and biomethane), electricity, and hydrogen. It also identifies the general and specific reporting requirements for annual compliance reporting. These requirements pertain to all transportation fuels under LCFS and to credit and deficit reporting and related accounting, which will be calculated in the LRT-CBTS for review and approval by regulated parties prior to submission. LCFS provisions will require that all pending credit transfers be completed prior to the submittal of the compliance report for the same period. This avoids the overlap of pending credit transfers between compliance periods and enables the LRT-CBTS to readily determine the credit balance for the compliance period and complete the calculations to determine the compliance status for all regulated parties.

There are requirements for reporting of Marketable Crude Oil Name (MCON) volumes and sources (oil field) reporting crude oil in order to calculate and apply the appropriate deficit associated with different crude oils refined into gasoline and diesel fuels.

Corrections of previously submitted reports can be requested and will be approved on a case-by-case basis. These requests will require an explanation and justification for those transactions to be corrected. This must be accompanied by a letter on company letterhead explaining why the current reporting is not accurate.

(2) Recordkeeping and Auditing

Records associated with LCFS reporting are proposed to be retained by each regulated party for a period of five years instead of the current three years. These records may be requested by ARB within the five-year period and are to be made available within 20 days upon request by the Executive Officer. The documents are to include product transfer documents (PTD), which is a single document and bills of lading, contracts, invoices, meter tickets, rail inventory sheets, RFS2 product transfer documents, etc., related to and substantiating each reported fuel transaction.

(3) Documenting Fuel Transfers

The PTD is the document to be used to substantiate the transfer of fuel and LCFS fuel obligation between business partners. The proposed regulatory language will specify the information which comprises a PTD. Each regulated party that has held a fuel obligation under LCFS will need to report the associated fuel transactions, as well as maintain records to document these transactions for the retention period of five years. In all cases, there needs to be a recorded Transaction Date. This is the date when the title transferred.

(4) Access to Records

In this section the proposed regulatory language provides the right of entry to any premises used, leased, or controlled by a regulated party, a reporting party, a verifier, or an applicant, by the Executive Officer. This access to records by the Executive Officer is needed in order to inspect and copy records relevant to the determination of compliance. Although access shall be arranged in advance where feasible to minimize operational disruptions it is expected the access to records will be provided in a timely manner and not delayed unreasonably

Q. Authority to Suspend, Revoke or Modify; Enforcement Protocols

Staff proposes to clarify and amplify the Executive Officer's authority to suspend, revoke, or place restrictions (put credits on hold) on the regulated LRT-CBTS account when violations have occurred or are being investigated. Such procedures will decrease the number of LCFS account holders affected by subsequent revocation.

The proposal allows the Executive Officer to enter into written agreement with a reporting party on the topics of recordkeeping, reporting, or demonstration of fuel transport mode requirements detailed in section 95486 so that they can lawfully meet the requirements in the regulation. If the reporting party does not adhere to the conditions in the agreement, then they are in violation of this regulation and subject to all available penalties under the law.

When a company's specific circumstances do not align with a regulatory requirement such that compliance with the regulation's exact terms would cause undue hardship, the company may request that the Executive Officer approve an alternative means of meeting the requirement, provided that the alternative means is set forth in a written agreement that can be enforced as if it were part of the regulation. Such protocol agreements have functioned well in other ARB programs, reducing regulatory impacts or costs for individual businesses.

R. Jurisdiction

This section specifies the actions which establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California.

This section is necessary to clarify the program with respect to out-of-state producers and intermediate entities who voluntarily elect to become regulated parties and, therefore, become subject to California jurisdiction. It notifies out-of-state fuel producers and credit brokers who choose to conduct business in California that they are subject to the jurisdiction of California courts when they establish an LRT-CBTS account.

This section specifies the actions which establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California for regulated parties, reporting parties, entities submitting fuel pathway certifications, and credit brokers.

S. Violations

Although violations against the LCFS program could take many forms, this section discusses some of the more obvious ones to LCFS; namely, reporting violations and failing to meet the annual compliance obligation. Most violations, including late or inaccurate reporting, would be subject to per-day penalties for each violation, staff proposes that failing to retire sufficient credits for a compliance period be subject to a per-deficit penalty where each deficit would constitute a separate violation. That approach, authorized by H&S section 38580, subdivision (b)(3), allows the "punishment to fit the crime." Such an approach allows courts to more fairly differentiate between the small- and large-volume fuel suppliers regulated under the LCFS.

IV. EMISSIONS AND HEALTH IMPACTS

Over and above the effects of other state and federal GHG-reduction programs, the LCFS proposal is anticipated to deliver environmental benefits that include an estimated reduction in greenhouse gas (GHG) emissions of about 35 million metric tons of carbon dioxide equivalent (MMTCO_2e) from transportation fuels used in California from 2016 through 2020. Implementation of the LCFS proposal will also diversify the transportation fuel portfolio, and is expected to improve California's air quality. In fact, the LCFS proposal may reduce criteria pollutant emissions from the 2020 projected vehicle fleet, predominately attributable to reductions in diesel use. These emissions reductions include the reduced tailpipe emissions of $PM_{2.5}$ associated with the replacement of conventional diesel with substitute fuels despite possible increased emissions of $PM_{2.5}$ associated with feedstock and fuel truck trips from additional California biofuel production facilities and transport from out-of-state biofuel production facilities.

One of the fuels that the LCFS is expected to incentivize is biodiesel. Biodiesel is generally beneficial, providing reductions in direct PM emissions and GHG emissions. However, depending on engine, feedstock, and blend level biodiesel can increase NO_X relative to conventional CARB diesel. Any additional NO_X emissions that result from the increased use of biodiesel blends are required to be mitigated by the Alternative Diesel Fuel regulation.

A. Emissions Impacts

GHG Benefits Achieved from the Current Regulation

Since 2011, the LCFS regulation has required reductions in the carbon intensity (CI) of transportation fuels used in California. As a result of these requirements, GHG emissions have been reduced from the production and use of transportation fuel in California.

The number of credits accumulated in the LCFS Reporting Tool is representative of the GHG emissions reductions of the LCFS program to date. The number of credits acquired annually is shown in the following table for 2011 through 2013, and for the first two quarters of 2014. Although earned credits may be used in future years to offset deficits, the GHG emissions reductions shown can be used as an approximate representation of program benefits to date.

Table IV-1. LCFS Credits Generated

	2011	2012	2013	Q1, Q2 2014	total
Required CI reduction from 2010 baseline	0.25%	0.5%	1.0%	1.0%	
Credits (MMT CO2e)	1.31	1.67	3.74	2.01	8.72

Projected GHG benefits 2014-2020

The proposal includes annual CI compliance requirements that have been revised from the current regulation. The required reduction in the CI of the transportation fuel pool is expected to result in annual GHG emissions reductions as shown in Table IV-2. These estimates do not include a reduction to eliminate the double counting of the Zero Emission Vehicle mandate, the federal Renewable Fuel Standard program, the Pavley standards, or the federal Corporate Average Fuel Economy program.

Table IV-2. Projected LCFS GHG Emissions Reductions

	2016	**2017**	**2018**	**2019**	**2020**
$MMTCO_2e$	6.0	8.8	11.6	16.2	20.7

Emissions Associated with Transportation Fuel Production

(1) Petroleum Refineries

According to ARB's CEIDARS database,[60] there are currently 25 facilities that fall under the category of petroleum refining in California. However, of those 25 facilities, only 15 of them produce transportation fuel according to the California Energy Commission (CEC). Five of those facilities reside in the Bay Area Air Quality Management District, seven reside in the South Coast Air Quality Management District, and three reside in the San Joaquin Valley Unified Air Pollution Control District. A list of the 15 refineries is presented in Table IV-3. The list has been updated from the CEC list to reflect the current refinery owners.

Table IV-3. Currently Operating Petroleum Refineries in California

Facility Name	Location
ALON USA, Bakersfield Refinery	Bakersfield
Chevron U.S.A. Inc.	El Segundo
Chevron U.S.A. Inc.	Richmond
ExxonMobil Refining & Supply Company	Torrance
Kern Oil & Refining Company	Bakersfield
Paramount Petroleum Corporation	Paramount
Phillips66 Company	Wilmington
Phillips66 Company	Rodeo
San Joaquin Refining Company Inc.	Bakersfield
Shell Oil Products US	Martinez
Tesoro Refining & Marketing Company	Carson
Tesoro Refining & Marketing Company	Martinez
Tesoro Refining & Marketing Company	Wilmington
Valero (Ultramar)	Wilmington
Valero Benicia Refinery	Benicia

[60] ARB's emissions inventory: CEIDARS Database Structure

ARB's Air Quality Planning and Science Division compiles each of the local districts' estimates of emissions from stationary sources within its jurisdiction.[61] There are six subcategories that have been used to estimate emissions associated with petroleum refining in each district. These subcategories are: oil and gas production (combustion), petroleum refining (combustion), oil and gas production, petroleum refining, petroleum marketing, and "other" (petroleum production and marketing). The following tables show the estimated emissions from petroleum refining for 2010 (Table IV-4) and the projected emissions from petroleum refining for 2015 (Table IV-5) and for 2020 (Table IV-6). The projected emissions are based on the 2012 base year inventory and the growth and control data maintained by the ARB and Districts. The applied control data reflects only adopted rules.

Table IV-4. 2010 California Petroleum Refining Emissions (tons/day)

Air District	TOG	ROG	CO	NO_X	SO_X	PM	PM_{10}	$PM_{2.5}$
Bay Area AQMD	72.7	17.8	9.0	12.5	15.9	2.9	2.7	2.6
Santa Barbara County APCD	13.4	3.8	1.9	1.9	0.3	0.1	0.1	0.1
San Joaquin Valley Unified APCD	141.2	36.7	6.1	3.8	3.2	2.2	2.1	2.1
San Luis Obispo County APCD	1.5	1.0	0.2	0.4	0.4	0.0	0.0	0.0
South Coast AQMD	151.8	57.7	39.6	22.6	7.2	5.0	3.9	3.6
Total	**380.6**	**117.1**	**56.8**	**41.1**	**27.0**	**10.2**	**8.9**	**8.5**

Table IV-5. 2015 California Petroleum Refining Emissions (tons/day)

Air District	TOG	ROG	CO	NO_X	SO_X	PM	PM_{10}	$PM_{2.5}$
Bay Area AQMD	75.8	18.0	10.2	11.2	7.0	3.3	3.0	2.9
Santa Barbara County APCD	13.3	3.7	1.7	1.7	0.3	0.1	0.1	0.1
San Joaquin Valley Unified APCD	140.8	34.2	5.8	3.3	1.4	2.1	2.1	2.0
San Luis Obispo County APCD	1.3	0.8	0.1	0.3	0.4	0.0	0.0	0.0
South Coast AQMD	128.6	39.8	10.3	12.9	5.8	4.3	3.4	3.1
Total	**359.7**	**96.5**	**28.1**	**29.5**	**14.8**	**9.9**	**8.5**	**8.2**

Table IV-6. 2020 California Petroleum Refining Emissions (tons/day)

Air District	TOG	ROG	CO	NO_X	SO_X	PM	PM_{10}	$PM_{2.5}$
Bay Area AQMD	78.9	18.8	10.8	11.8	7.3	3.5	3.2	3.0
Santa Barbara County APCD	13.0	3.4	1.6	1.6	0.2	0.1	0.1	0.1
San Joaquin Valley Unified APCD	142.8	32.2	5.2	2.9	1.3	1.9	1.9	1.9
San Luis Obispo County APCD	1.2	0.8	0.1	0.3	0.4	0.4	0.4	0.4
South Coast AQMD	125.6	39.0	10.4	13.1	4.5	4.4	3.4	3.1
Total	**361.6**	**94.1**	**28.0**	**29.6**	**13.8**	**9.8**	**8.5**	**8.1**

Staff does not anticipate that refineries will operate at a lower capacity in 2020 as compared to 2014; California refineries will likely export transportation fuel that is not sold in-state.

[61] ARB's Almanac Emission Projection Data

For comparison, the statewide stationary source emissions are provided in Table IV-7.

Table IV-7. California Statewide Stationary Source Emissions (tons/day)

Year	TOG	ROG	CO	NO_X	SO_X	PM	PM_{10}	$PM_{2.5}$
2010	3,005	426	324	320	65	340	186	83
2015	3,085	401	267	288	55	240	134	65
2020	3,265	424	281	290	56	260	145	70

(2) Ethanol Facilities

There are currently four permitted ethanol facilities in California (Table IV-8).

Table IV-8. Ethanol Facilities in California

Facility Name	Location	Feedstock	Capacity (MMgpy)
Aemetis Advanced Fuels	Keyes	sorghum, corn	60
Pacific Ethanol	Stockton	corn	60
Pixley Ethanol LLC (Calgren)	Pixley	sorghum, corn	58
Parallel Products	Rancho Cucamonga	Beverage waste	4

The following emissions from ethanol facilities in California were obtained from ARB's Emissions Inventory.[62]

Table IV-9. 2012 Emissions from Ethanol Facilities in California

Facility Name	Air Basin	TOG (tpy)	ROG (tpy)	CO (tpy)	NO_X (tpy)	SO_X (tpy)	PM_{10} (tpy)
Aemetis Advanced Fuels	SJVAB	11.3	6.8	7.5	5.4	1.9	5.1
Pacific Ethanol	SJVAB	7.7	5.5	9.5	3.9	1.5	5.8
Pixley Ethanol LLC (Calgren)	SJVAB	3.5	2.5	2.1	0.7	0	3.6
Parallel Products	SCAB	2.2	0.8	2.8	5.0	0	9.9

(3) Biodiesel Facilities

California biodiesel facilities currently in operation use the fatty-acid methyl ester (FAME) transesterification process. The capacity of FAME biodiesel facilities is generally less than ten MMgpy. There are currently 12 operating biodiesel facilities in California, although the following table includes only those facilities that could be verified.

[62] Ibid

Table IV-10. Biodiesel Facilities in California

Facility Name	Location	Feedstock	Estimated Capacity (MMgpy)
Simple Fuels Biodiesel	Chilcoot	Yellow Grease	2.0
Southern California Biofuel	Anaheim	Used Cooking Oil, Yellow Grease	1.0
North Star Biofuels, LLC	Redwood City	Multi-feedstock	15.0
New Leaf Biofuel, LLC	San Diego	Yellow Grease	6.0
Imperial Western Products, Inc.	Coachella	Multi-feedstock	10.5
Extreme Biodiesel, Inc.	Corona	Multi-feedstock	2.0
Community Fuels	Encinitas	Multi-feedstock	15.0
Blue Sky Biofuels	Oakland	Multi-feedstock	4.0
Biodico Sustainable Biorefineries – Five Points	Five Points	Multi-feedstock	10.0
Bay Biodiesel, LLC	San Jose	Virgin Oils/Yellow Grease	5.0
Crimson Renewable Energy, LP	Bakersfield	Multi-feedstock	36.0

Table IV-11. Estimated Emissions from Biodiesel Facilities in California

Facility Name	Air Basin	ROG (tpy)	CO (tpy)	NO_X (tpy)	SO_X (tpy)	PM_{10} (tpy)
Simple Fuels Biodiesel	MCAB	1.1	5.9	1.1	0.1	0.5
Southern California Biofuel	SCAB	0.6	3.0	0.5	0.03	0.3
North Star Biofuels, LLC	SFBAAB	8.5	44.6	8.1	0.4	4.1
New Leaf Biofuel, LLC	SDAB	3.4	17.8	3.2	0.2	1.6
Imperial Western Products, Inc.	SSAB	6.0	31.2	5.7	0.3	2.8
Extreme Biodiesel, Inc.	SCAB	1.1	5.9	1.1	0.1	0.5
Community Fuels	SDAB	8.5	44.6	8.1	0.4	4.1
Blue Sky Biofuels	SFBAAB	2.3	11.9	2.2	0.1	1.1
Biodico Sustainable Biorefineries – Five Points	SJVAB	5.7	29.7	5.4	0.3	2.7
Bay Biodiesel, LLC	SFBAAB	2.8	14.9	2.7	0.1	1.4
Crimson Renewable Energy, LP	SJVAB	20.4	106.9	19.4	1.0	9.7

(4) Renewable Diesel Facilities

Table IV-12. Renewable Diesel Facilities in California

Facility Name	Location	Estimated Capacity (MMgpy)
Kern Oil and Refining Co.	Bakersfield	3.45

Table IV-13. Estimated Emissions from Renewable Diesel Facilities in California

Facility Name	Air Basin	TOG (tpy)	ROG (tpy)	CO (tpy)	NO_X (tpy)	SO_X (tpy)	PM_{10} (tpy)
Kern Oil and Refining Co.	SJVAB	2.7	1.4	0.7	0.2	0.1	0.1

(5) Potential California Cellulosic Ethanol Facilities

Staff has estimated criteria pollutants emissions for a cellulosic ethanol facility that could be built in California by 2020. Based on the fuel type and volume of fuels projected in staff's illustrative scenario for compliance with the LCFS re-adoption, new cellulosic ethanol production facilities could be established in California. Staff estimated criteria pollutant emissions for one of these facilities using permit evaluations for a currently operating out-of-state facility.

Emissions are based on data gathered from permits and engineering evaluations for Abengoa Bioenergy Biomass of Kansas, a cellulosic ethanol production plant with an annual capacity of 23.3 million gallons (MMgpy).[63] The feedstock used for ethanol production at Abengoa is agricultural waste, non-food energy crops, and wood waste.

Table IV-14. Emissions per Million Gallons of Fuel Produced Abengoa Bioenergy Biomass of Kansas

Fuel Type	VOC (lb/MMgal)	NO_X (lb/MMgal)	PM_{10} (lb/MMgal)
Cellulosic Ethanol	2,753	63,235	11,219

Staff used the emissions profile of Abengoa Bioenergy Biomass of Kansas (capacity 23.3 MMgpy) as an estimate of future emissions associated with potential cellulosic ethanol facilities in California (estimated capacity 50 MMgpy).

[63] Kansas Department of Health and Environment. Abengoa Bioenergy Biomass

Table IV-15. Cellulosic Ethanol Facility Emissions

Facility Name	Facility Location	Production Process	Capacity (MMgal/yr)	VOC (tpy)	NO_X (tpy)	PM_{10} (tpy)
Abengoa Bioenergy Biomass	Hugoton, Kansas	Enzymatic hydrolysis	23.3	29	669	119
Potential California Cellulosic Ethanol Facility	*Northern California*	*Enzymatic hydrolysis*	*50*	*62*	*1,435*	*255*

Kansas Department of Health and Environment. Air Emission Source Construction Permit, Abengoa Bioenergy Biomass of Kansas, LLC, September, 2011

Emissions from Fuel and Feedstock Transportation and Distribution

Staff estimated NO_X and $PM_{2.5}$ emissions for the transportation and distribution of finished fuels in 2014 and in 2020. These emissions result from the movement of fuel and feedstock in heavy-duty diesel trucks and railcars.[64,65,66] Staff also estimated fuel and feedstock transport emissions that would likely occur if the LCFS and ADF regulations were not in place in 2014 and 2020. Emissions under this scenario can be attributed to the fuels delivered to California under the federal RFS program. Therefore, for this analysis, emissions were estimated for fuel and feedstock transport under the federal RFS program only and under the LCFS and ADF regulations as proposed.

Production capacity of biofuel facilities in California in 2020 is not expected to supply the total volume of biofuels necessary for California transportation use. To acquire the necessary volume of biofuels, they will be imported domestically and internationally. Ethanol is expected to continue to be delivered to California by unit train through Needles, Yuma, or Reno, and then delivered to Selby or Carson. Ethanol is then delivered to CARBOB blending facilities or to storage facilities by heavy-duty diesel trucks.

Ethanol is also expected to continue to be delivered to California by tanker vessel via the Port of Long Beach and the Port of Oakland. Diesel trucks then deliver the fuel to blending facilities.

Staff estimated that one 50 MMgpy cellulosic ethanol production facility might be operational in California by 2020. Transportation and distribution emissions include emissions of heavy-duty trucks delivering feedstock to the facility and fuel from the facility to CARBOB blending facilities.

[64] CARB 2011 EMFAC
[65] US EPA Emission Factors for Locomotives
[66] U.S.EPA 2008 Federal Register Part II, 40 CFR Parts 9,…

Biodiesel produced in California will likely continue to be transported by diesel truck to blending facilities. In the future, biodiesel and renewable diesel may be imported into California in significant quantities and delivered to blending facilities by unit train and diesel truck.

Table IV-16. Emissions from Fuel and Feedstock Transportation and Distribution

Scenario	2014 NO_X (tpy)	2020 NO_X (tpy)	2014 $PM_{2.5}$ (tpy)	2020 $PM_{2.5}$ (tpy)
With LCFS/ADF	1,037	1,277	18	23
Without LCFS/ADF	1,105	987	20	17

Motor Vehicle Emissions

The ADF regulation is being proposed for adoption at the same time as the LCFS re-adoption. The ADF regulation is expected to keep NO_X emissions impacts of biodiesel below current levels and decrease their use over time. For a more detailed discussion, please refer to the ADF staff report.

B. Health Impacts

California experiences some of the highest ambient levels of $PM_{2.5}$ in the nation [1][67]. In fact, the majority of California's population lives in areas that exceed national and state PM2.5 ambient air quality standards[68,69] [2, 3]. These standards are based upon an assessment of research that has linked $PM_{2.5}$ exposure to adverse health effects, including hospitalization due to cardiopulmonary and respiratory illness, and premature death [4][70]. Furthermore, U.S. EPA has determined that exposure to $PM_{2.5}$ plays a "causal" role in premature death, meaning that a substantial body of scientific evidence shows a relationship between $PM_{2.5}$ exposure and increased mortality, a relationship that persists when other risk factors such as smoking rates and socioeconomic factors are taken into account [4][71].

Staff estimated the number of premature deaths avoided related to the decrease in $PM_{2.5}$ exposure expected from implementation of the LCFS and ADF regulations. This estimate is based on a peer-reviewed methodology developed by the U.S. Environmental Protection Agency, which uses an incidence-per-ton (IPT) factor to

[67] U.S. EPA (2013), Fine Particle Concentrations Based on Monitored Air Quality from 2009 – 2011 http://www.epa.gov/pm/2012/20092011table.pdf
[68] ARB (2013), area designations for state air quality standards: http://www.arb.ca.gov/desig/adm/2013/state_pm25.pdf
[69] ARB (2013), area designations for national air quality standards: http://www.arb.ca.gov/desig/adm/2013/fed_pm25.pdf
[70] U.S. EPA (2009), Integrated Science Assessment for Particulate Matter http://www.epa.gov/ncea/pdfs/partmatt/Dec2009/PM_ISA_full.pdf
[71] same as footnote 66.

quantify the health benefits of regulatory controls designed to reduce ambient $PM_{2.5}$ [5][72]. Staff developed California-specific IPT factors [6][73] and used California-specific exposure, demographic, and baseline mortality rate data to calculate health impacts. The reduction of both directly emitted PM and secondary PM (produced in the atmosphere from the precursor NO_X) are included in the estimate. The estimate is also based on the emission changes that are projected to occur between 2014 and 2020 from fuel and feedstock transportation and distribution and from motor vehicle emissions from the increased use of biodiesel and renewable diesel.

Using this methodology, staff found that statewide, 91 (67 – 110, 95 percent confidence interval) deaths would be avoided for the year 2020 from implementation of the LCFS and ADF regulations.

Health Risk Assessment for a Potential California Biofuel Facility

(1) Introduction

Staff conducted a health risk assessment (HRA) study to evaluate the health impacts associated with toxic air contaminants that could be emitted from a typical biofuel facility within California. The HRA focused on the potential cancer risk associated with diesel particulate matter (diesel PM) emissions caused by truck travel to and from the facility. Emissions that result from production activities at the facility are expected to be mitigated pursuant to local permit and air district rules.

An HRA uses mathematical models to evaluate the health impacts from exposure to certain chemical or toxic air contaminants released from a facility or found in the air. HRAs provide information to estimate potential life-time (i.e., 70 years) cancer and non-cancer health risks. HRAs do not gather information or health data on specific individuals, but are estimates for the potential health impacts on a population at large.

An HRA consists of three major components: the air pollution emission inventory, the air dispersion modeling, and an assessment of associated health risks. The air pollution emission inventory provides an understanding of how the air toxics are generated and emitted. The air dispersion modeling takes the emission inventory and meteorology data such as temperature and wind speed/direction as its inputs, then uses a computer model to predict the distributions of air toxics in the air. Based on this information, an assessment of the potential health risks of the air toxics to an exposed population is performed.

[72] Neal Fann, Charles M. Fulcher, Bryan J. Hubbell (2009). The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution. Air Qual Atmos Health (2009) 2:169–176

[73] ARB (2010). Initial Statement of Reasons, Appendix J, Regulation to Reduce Emissions of Diesel Particulate Matter, Oxides of Nitrogen and Other Criteria Pollutants from In-Use Heavy-Duty Diesel-Fueled Vehicles.
http://www.arb.ca.gov/regact/2010/truckbus10/correctedappj.pdf

The most frequently used expression of estimated adverse health impacts is potential cancer health effects, which is usually presented as the number of chances in a population of a million people exposed. The number may be stated as “ten in a million” or “ten chances per million.” The methodology used to estimate the potential cancer risks is consistent with the Tier-1 analysis of *Air Toxics Hot Spots Program Risk Assessment Guidelines*[74] . A Tier-1 analysis assumes that an individual is exposed to an annual average concentration of a given pollutant continuously for 70 years. The length of time that an individual is exposed to a given air concentration is proportional to the risk.

The potential cancer risk from a given carcinogen estimated from the health risk assessment is expressed as the incremental number of potential cancer cases that could be developed per million people, assuming population is exposed to the carcinogen at a constant annual average concentration over a presumed 70-year lifetime. For example, if the cancer risk were estimated to be 100 chances per million, the probability of an individual developing cancer would be expected to not exceed 100 chances in a million. If a population (e.g., one million people) were exposed to the same potential cancer risk (e.g., 100 chances per million), then statistics would predict that no more than 100 of those million people exposed are likely to develop cancer from a lifetime of exposure (i.e., 70 years) due to diesel PM emissions from a facility.

Why did the HRA focus on Diesel PM?

In 1998, ARB identified particulate matter from diesel exhaust (diesel PM) as a toxic air contaminant based on its potential to cause cancer and other adverse health problems, including respiratory illnesses, and increased risk of heart disease (ARB, 1998)[75]. Subsequent research has shown that diesel PM contributes to premature death[76],[77] (ARB, 2002). Exposure to diesel PM is a health hazard, particularly to children whose lungs are still developing and the elderly who may have other serious health problems. In addition, the diesel PM particles are very small. By mass, approximately 94 percent of these particles are less than 2.5 microns in diameter ($PM_{2.5}$). Because of their tiny size, diesel PM is readily respirable and can penetrate deep into the lung and enter the bloodstream, carrying with them an array of toxins. Population-based studies in hundreds of cities in the U.S. and around the world demonstrate a strong link between elevated PM levels and premature deaths (ARB, 2007)[78], increased hospitalizations for respiratory and cardiovascular causes, asthma and other lower respiratory symptoms, acute bronchitis, work loss days, and minor restricted activity days (ARB, 2006a)[79].

[74] Air Toxics Hot Spots Program Risk Assessment Guidelines
[75] Proposed Identification of Diesel Exhaust as a Toxic Air Contaminant, Staff Report, June, 1998
[76] Premature Death: as defined by U.S. Centers for Disease Control and Prevention's Years of Potential Life Lost, any life ended before age 75 is considered premature death.
[77] ARB, 2002. Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates, Staff Report, May. 2002.
[78]ARB, 2007. Health Risk Assessment for the Union Pacific Railroad Commerce Railyard
[79] ARB, 2006a. Emission Reduction Plan for Ports and Goods Movement in California.

Diesel PM emissions are the dominant toxic air contaminant (TAC) in and around a bio-refinery facility. Diesel PM typically accounts for about 70 percent of the state's estimated potential ambient air toxic cancer risks. This estimate is based on data from ARB's ambient monitoring network in 2000[80]. These findings are consistent with that of the study conducted by South Coast Air Quality Management District: *Multiple Air Toxics Exposure Study in the South Coast Air Basin*[81]. Based on these scientific research findings, the health impacts in this study primarily focus on the risks from the diesel PM emissions.

Prototype Biofuel Facilities

According to AB32 Scoping Plan, there is a potential, based on feedstock availability, that a number of biofuel facilities with an average production capacity of 50 million gallon per year be established in the whole state of California by 2020. In order to estimate the potential cancer risk associated with a newly established biofuel facility, ARB staff developed a prototype biofuel facility for a case study of Health Risk Assessment. In the study, staff intended to emphasize the health impact of the facility related activities by eliminating other possible impact factors of health risks, such as local topographic and emission source geometric conditions.

Based on the size of some in-state biofuel facilities, staff assumes the prototype facility located in a 400 meters-by-400 meters square fence line (depicted in the Figure 1). The selection of square shape facility is to avoid the influence of complexity of sources geometry on the estimated potential health effects. The emission sources from the facility include natural gas or biomass boilers and turbines. Diesel PM emissions are generally generated by the heavy-duty trucks that are used to transport feedstocks and finished biofuel. As indicated in the Figure IV-1, staff assumes an "L" shape truck routes within the facility, with a longer edge starting from the north side of the fenceline to the center of the facility (200 meter in length), and a shorter edge extending toward the east side of the fenceline (150 meters in length).

There are three major types of biofuel facilities: corn ethanol, cellulosic ethanol, and biodiesel. Among them, cellulosic ethanol facilities require the greatest amount of feedstock. Using farm trees as an example, staff estimates that over 500,000 tons of feedstock are required to support a 50 million gallon per year capacity facility. Assuming one heavy duty truck can load up to 25 tons of farm tree or up to 7,500 gallons of ethanol, staff estimates an average of about 128 daily truck trips would be made to transport feedstock in and finished fuel out for a 50 million gallon per year facility. Based on above truck routes assumption, each truck round trip within the facility boundary is 700 meters. Staff also assumes each truck to be idling at the loading and unloading area located in the center of the facility for five minutes.

[80] ARB, Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel Fueled Engines and Vehicles, Staff Report, October, 2000
[81] Multiple Air Toxics Exposure Study in the South Coast Air Basin

Staff assumes that one main truck route connects a major freeway and the biofuel facility, as indicated in Figure IV-1. The truck route from the freeway to the Facility 1 is about 2 mile (3200 meters).

Figure IV-1. The Layout of the Prototype Biofuel Facility

Based on the EMFAC emission factors for model year 2010 and newer, the total diesel PM emissions from the prototype biofuel facility, including truck movements and idling, are about 0.0033 tons per year. Staff defines this portion of emissions as “onsite.” The diesel PM emissions from the truck routes are also directly caused by the biofuel facility, although these routes are outside of the facility boundaries. The total diesel PM emissions from these routes are about 0.04 tons per year. Staff defines this portion of emissions as “offsite.” Staff considered the diurnal variation of the emission by assuming the truck activities occur between 8 a.m. and 6 p.m.

Air Dispersion Modeling

Air dispersion models are often used to simulate atmospheric processes for applications where the spatial scale is in the tens of meters to tens of kilometers. Selection of air dispersion models depends on many factors, such as characteristics of emission sources (point, area, volume, or line), the type of terrain (flat or complex) at the emission source locations, and source-receptor relationships. For the prototype bio-refinery facility, ARB staff selected the U.S. EPA air dispersion model AERMOD to estimate the impacts associated with diesel PM emissions. AERMOD represents for American Meteorological Society / Environmental Protection Agency Regulatory Model

Improvement Committee (**AER**MIC) **MOD**EL. It is a state-of-science air dispersion model and is a replacement for its predecessor, the U.S. EPA Industrial Sources Complex (ISC) air dispersion model.

Emission Source Characterization and Parameters

When a mobile source, such as a large heavy-duty truck, is moving, the emissions are simulated as a series of volume sources to represent the initial lateral dispersion of emissions by the exhaust stack's movement through the air. Key model parameters for volume sources include emission rate (strength), source release height, and initial lateral and vertical dimensions of volumes. Diesel exhaust emissions from truck activity in a biofuel facility are considered as a major diesel PM source in the facility. For modeling simulations, staff assumes the initial lateral and vertical dimensions of the volume to be 10 meters and 4.15 meters, respectively.

Meteorological Data

In order to run AERMOD, the following hourly surface meteorological data are required: wind speed, wind direction, ambient temperature, and opaque cloud cover. In addition, the daily upper air sounding data need to be provided (U.S. EPA, 2004b)[82]. These meteorological variables are important to describe the air dispersion in the atmosphere. The wind speed determines how rapidly the pollutant emissions are diluted and influences the rise of emission plume in the air, thus affecting downwind concentrations of pollutants. Wind direction determines where pollutants will be transported. The difference of ambient temperature and the emission releasing temperature from sources determines the initial buoyancy of emissions. In general, the greater the temperature difference, the higher the plume rise. The opaque cloud cover and upper air sounding data are used in calculations to determine other important dispersion parameters. These include atmospheric stability (a measure of turbulence and the rate at which pollutants disperse laterally and vertically) and mixing height (the vertical depth of the atmosphere within which dispersion occurs). The greater the mixing height is, the larger the volume of atmosphere is available to dilute the pollutant concentration.

The meteorological data used in the model are selected on the basis of representativeness. Representativeness is determined primarily on whether the wind speed/direction distributions and atmospheric stability estimates generated through the use of a particular meteorological station (or set of stations) are expected to mimic those actually occurring at the facility where such data are not available. Typically, the key factors for determining representativeness are proximity of the meteorological station and the presence or absence of nearby terrain features that might alter airflow patterns.

In this study, staff conducted an HRA analysis of prototype a biofuel facility that is independent of geographic location. Based on the estimates of potential biofuel facility locations, staff selected the meteorological data from San Joaquin Valley Air Basin

[82] User's Guide for the AERMOD Meteorological Preprocessor. Report No. EPA-454/B-03-002

(Stockton station). The hourly surface meteorological data were selected from the Stockton station. The upper air sounding data were chosen from the Metropolitan Oakland International Airport station[83].

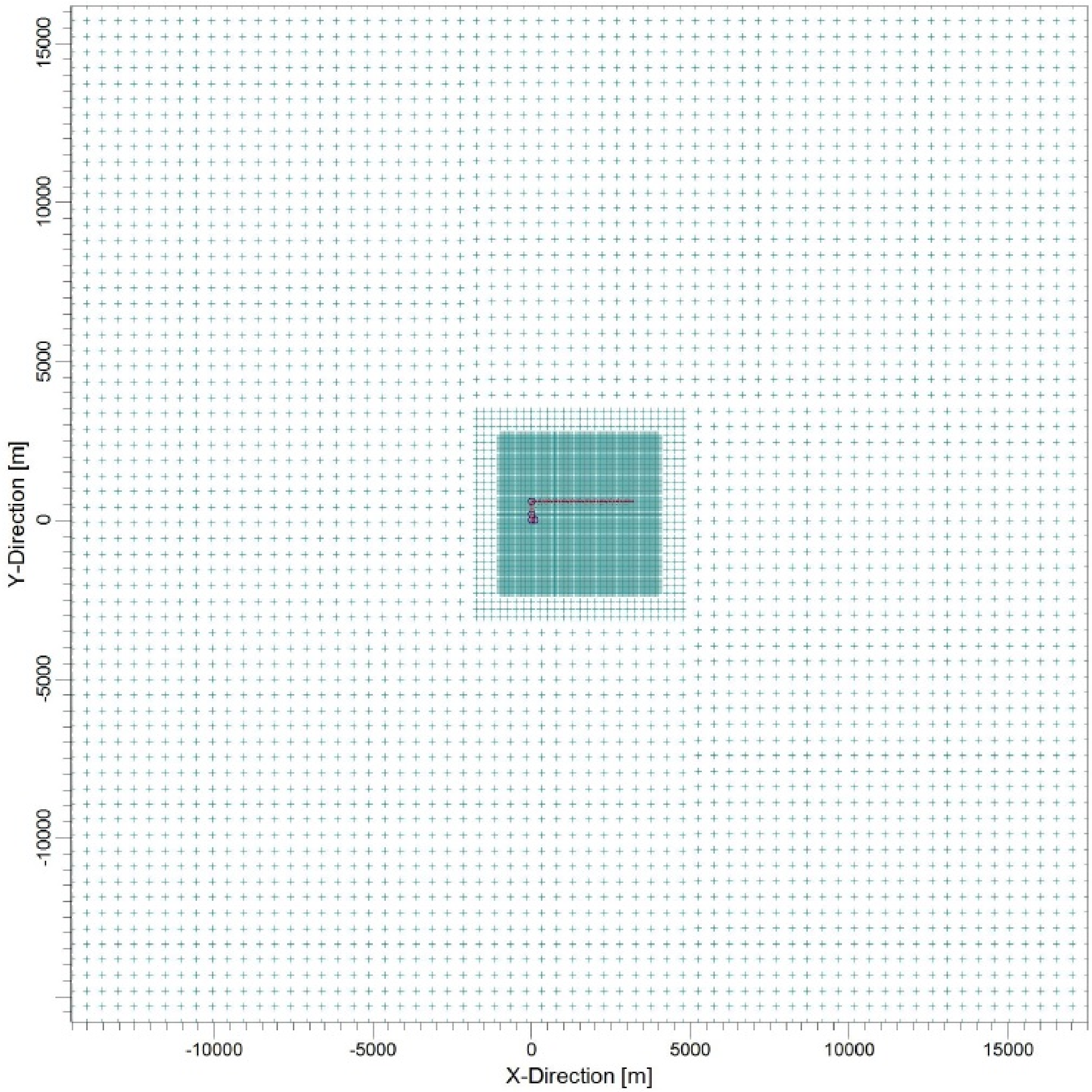
Model Receptors

Model receptors are the locations where the model provides concentrations. A Cartesian grid receptor network is used in this study where an array of points are identified by their x (east-west) and y (north-south) coordinates. The modeling domain is defined as an 18 x 18 km (km: kilometers) region, which covers the biofuel facility in the center of the domain. To better capture the different concentration gradients surrounding the facility, 3 receptor grid networks were used. A fine grid of 50 m x 50 m (m: meter) surrounding the biofuel facility and the truck routes was used for modeling within 0.5 mile of the fence line and truck routes, a medium grid of 250 m x 250 m was used for modeling the domain from 0.5 mile to 1 mile of the facility fence lines and truck routes, and a coarse receptor grid of 500 m x 500 m was used throughout the rest of the modeling domain.

Figure IV-2 illustrates the grid receptor networks and model domain used in air dispersion modeling for the biofuel facility.

[83] ARB, 2007. Health Risk Assessment for the Union Pacific Railroad Commerce Railyard

Figure IV-2. Air Dispersion Modeling Grid Receptor Network and Domain Used for the Biofuel Facility



Health Risk Assessment

The Health Risk Assessment (HRA) follows *The Air Toxics Hot Spots Program Risk Assessment Guidelines*[84] (OEHHA, 2003) published by the California Office of Environmental Health Hazard Assessment (OEHHA). The HRA is based on the facility specific emission inventory and air dispersion modeling predictions.

Exposure assessment is a comprehensive process that integrates and evaluates many variables. Three process components have been identified to have significant impacts on the results of a health risk assessment: emissions, meteorological conditions, and

[84] http://oehha.ca.gov/air/hot_spots/pdf/HRAguidefinal.pdf

exposure duration of nearby residents. The emissions have a linear effect on the risk levels, given meteorological conditions and defined exposure duration. Meteorological conditions can also have a critical impact on the resultant ambient concentration of a toxic pollutant, with higher concentrations found along the predominant wind direction and under calm wind conditions. An individual's proximity to the emission plume, how long he or she breathes the emissions (exposure duration), and the individual's breathing rate play key roles in determining potential risk. In general, the longer the exposure time for an individual, the greater the estimated potential risk for the individual. The risk assessment adopted in this study generally assumes that the receptors will be exposed to the same toxic levels for 24 hours per day for 70 years. If a receptor is exposed for a shorter period of time to a given pollutant concentration of diesel PM, the cancer risk will proportionately decrease. Children have a greater risk than adults because they have greater exposure on a per unit body weight basis and also because of other factors.

Risk characterization is defined as the process of obtaining a quantitative estimate of risk. The risk characterization process integrates the results of air dispersion modeling and relevant toxicity data (e.g., diesel PM cancer potential factor) to estimate potential cancer or non-cancer health effects associated with air contaminant exposure.

Exposures to pollutants that were originally emitted into the air can also occur in different pathways as a result of breathing, dermal contact, ingestion of contaminated produce, and ingestion of fish that have taken up contaminants from water bodies. These exposures can all contribute to an individual's health risk. However, diesel PM risk is evaluated by the inhalation pathway only in this study because the risk contributions by other pathways of exposure are insignificant relative to the inhalation pathway. It should be noted that the background or ambient diesel PM concentrations are not incorporated into the risk quantification in this study. Therefore, the estimated potential health risk in the study should be viewed as risk level above those due to the background impacts.

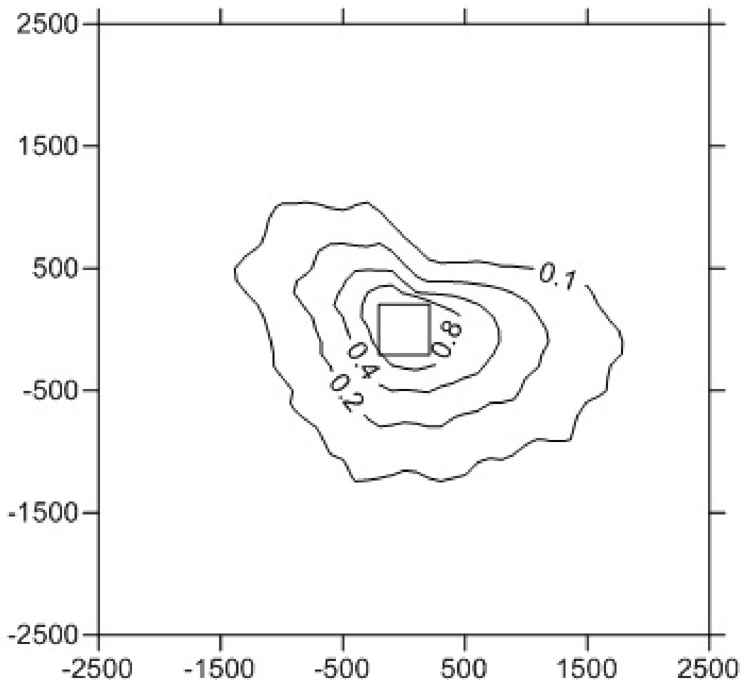
Risk Characterization Associated with Onsite Emissions of the Prototype Biofuel Facility

The potential cancer risks levels associated with the onsite diesel PM emissions from the prototype biofuel facility are displayed by using isopleths, based on the 80^{th} percentile breathing rate and 70-year exposure duration for residents. An isopleth is a line drawn on a map through all points of equal value of some measurable quantity; in this case, cancer risk. Figure IV-3 presents the isopleths of estimated potential cancer risks caused by the onsite diesel PM emissions from the prototype biofuel facility.

As indicated by Figure IV-3, the area with the greatest impact has an estimated potential cancer risk of approximately 0.8 chances in a million, surrounding the facility fence lines. At about 200 yards from the facility boundaries, the estimated cancer risks decrease to about 0.4 chances per million. The estimated potential cancer risks further decrease to about 0.2 chances per million at about 400 yards from the facility boundaries.

It is important to understand that these risk levels represent the predicted risks (due to the biofuel facility diesel PM emissions) above the existing background risk levels. For the broader San Joaquin Valley Air Basin, for instance, the estimated regional background risk level is estimated to be about 390 in a million caused by diesel PM and about 590 in a million caused by all toxic air pollutants in 2000 (ARB, 2006b).

Figure IV-3. Estimated Lifetime Cancer Risks (chances per million people) Associated with the Onsite Diesel PM Emissions from the Prototype Biofuel Facility

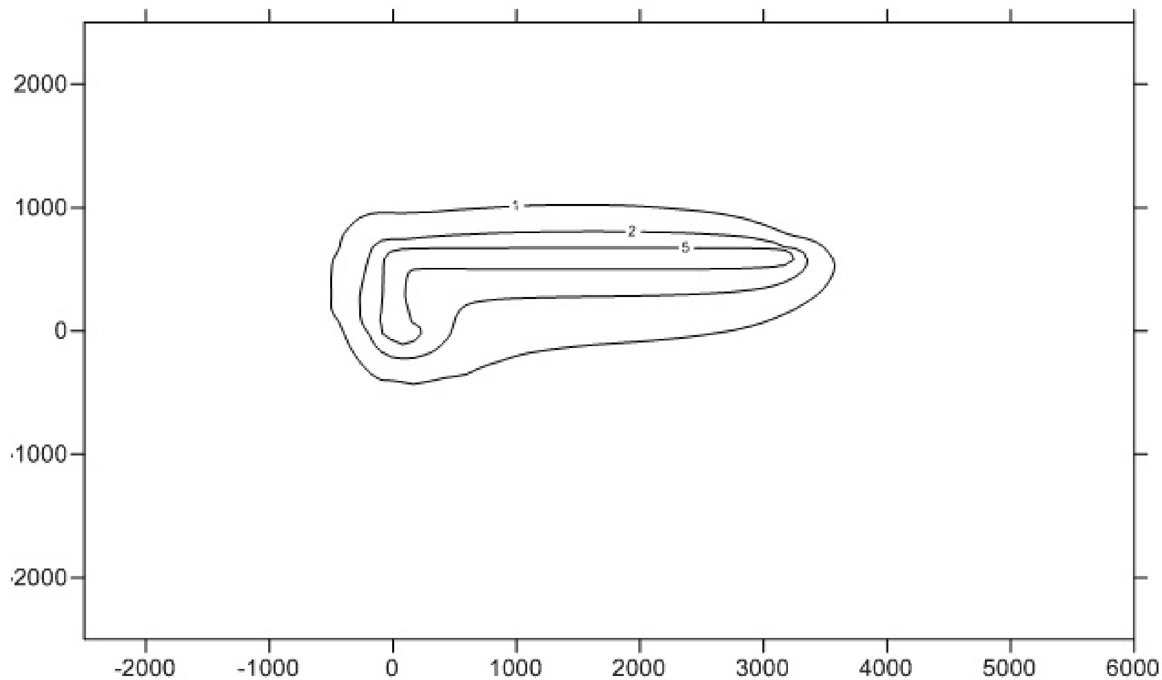


Risk Characterization Associated with Combined Onsite and Offsite Emissions of the Prototype Biofuel Facility

Staff also estimated the health impact associated with the combined onsite and offsite emissions of the prototype biofuel facility. Figure 4 presents the isopleths of estimated potential cancer risks caused by the combined onsite and offsite emissions.

As indicated by Figure IV-4, the area with the greatest impact has an estimated potential cancer risk of approximately 5 chances in a million, mostly occurring along the main truck route that connects the prototype biofuel facility and the major freeway. At about 200 yards from truck route, the estimated cancer risk drops to about 2 chances per million. At about 500 yards from the truck routes, the estimated cancer risk further decreases to about 1 chance per million.

Figure IV-4: Estimated Lifetime Cancer Risks (chances per million people) Associated with the Combined Onsite and Offsite Diesel PM Emissions from the Prototype Biofuel Facility



Uncertainties in Health Risk Assessment

The HRA is a complex process that is based on current knowledge and a number of assumptions. However, there is a certain extent of uncertainty associated with the process of risk assessment. The uncertainty arises from lack of data in many areas necessitating the use of assumptions. The assumptions used in the assessments are often designed to be conservative on the side of health protection in order to avoid underestimation of risk to the public. As indicated by the OEHHA Guidelines, the Tier-1 evaluation is useful in comparing risks among a number of facilities and similar sources. Thus, the risk estimates should not be interpreted as a literal prediction of disease incidence in the affected communities but more as a tool for comparison of the relative risk between one facility and another. In addition, the HRA results are best used to compare potential risks to target levels to determine the level of mitigation needed. They are also an effective tool for determining the impact a particular control strategy will have on reducing risks.

V. ENVIRONMENTAL ANALYSIS

The Air Resources Board (ARB), as the lead agency for the proposed regulation, has prepared an environmental analysis under its certified regulatory program (Cal. Code Regs., tit. 17, §§ 60000 through 60008) to comply with the requirements of the California Environmental Quality Act (CEQA). ARB's regulatory program, which involves the adoption, approval, amendment, or repeal of standards, rules, regulations, or plans for the protection and enhancement of the State's ambient air quality has been certified by the California Secretary for Natural Resources under Public Resources Code section 21080.5 of CEQA (Cal. Code Regs., tit. 14, § 15251(d)). ARB, as a lead agency, prepares a substitute environmental document (referred to as an "Environmental Analysis" or "EA") as part of the Staff Report to comply with CEQA (Cal. Code Regs., tit. 17, § 60005).

The Draft Environmental Analysis (Draft EA) for the proposed regulation is included in Appendix D to this Staff Report. The Draft EA provides a single coordinated programmatic environmental analysis of an illustrative, reasonably foreseeable compliance scenario that could result from implementation of the proposed re-adoption of the Low Carbon Fuel Standard (LCFS) regulation and the proposed Alternative Diesel Fuel (ADF) regulation. The proposed LCFS and ADF regulations have two separate regulatory notices and staff reports and will be considered by the Board in separate proceedings. This approach is consistent with CEQA's requirement that an agency consider the whole of an action when it assesses a project's environmental effects, even if the project consists of separate approvals (Cal. Code Regs., tit. 14, § 15378(a)).

The Draft EA states that implementation of the proposed regulations could result in beneficial impacts to GHGs through substantial reductions in emissions from transportation fuels in California from 2016 through 2020 and beyond, long-term beneficial impacts to air quality through reductions in criteria pollutants, and beneficial impacts to energy demand.

For the purpose of determining whether the proposed regulations have a potential adverse effect on the environment, ARB evaluated the potential physical changes to the environment resulting from a reasonable foreseeable compliance scenario for the proposed LCFS regulation. Approval and implementation of the proposed LCFS regulation would result in re-adoption of an LCFS with the revisions described above. The environmental effects of the proposed LCFS regulation would, therefore, build upon the compliance responses of the existing LCFS regulation. In many instances, compliance responses associated with the proposed LCFS regulation would be a variation of actions that are already occurring.

Implementation of the proposed LCFS is anticipated to provide incentives for various projects, including: processing plants for agriculture-based ethanol, cellulosic ethanol, and biomethane. The proposed regulations could also incent minor expansions to existing operations, such as collection of natural gas from landfills, dairies, and wastewater treatment plants; modifications to crude production facilities (onsite solar, wind, heat, and/or steam generation electricity); and installation of energy management systems at refineries. In addition, LCFS credits could be generated through development of CCS facilities and operation of expanded fixed guideway systems.

While many impacts associated with the proposed regulation could be reduced to a less-than-significant level through conditions of approval applied to project-specific development, the authority to apply that mitigation lies with land use agencies or other agencies approving the development projects, not with ARB. Consequently, the EA takes the conservative approach in its significance conclusions and discloses, for CEQA compliance purposes, that impacts from the development of new facilities or modification of existing facilities associated with reasonably foreseeable compliance responses to the proposed LCFS regulations could be potentially significant and unavoidable. Table V-1 below summarizes potential impacts of re-adopting the LCFS with proposed revisions to the existing LCFS regulation.

Table V-1. Summary of Potential Environmental Impacts

Resource Area Impact	Significance
Short-Term Construction-Related and Long-Term Operational Impacts on Aesthetics	Potentially Significant and Unavoidable
Conversion of Agricultural and Forest Resources Related to New Facilities	Potentially Significant and Unavoidable
Agricultural and Forest Resource Impacts Related to Feedstock Cultivation	Potentially Significant and Unavoidable
Short-Term Construction-Related Air Quality Impacts	Potentially Significant and Unavoidable
Long-Term Operation Air Quality Emission	Beneficial
Short-Term Construction-Related and Long-Term Operational Impacts from Odors	Less Than Significant
Short-Term Construction-Related and Long-Term Impacts on Biological Resources Related to New Facilities	Potentially Significant and Unavoidable
Effects of Biological Resources Associated with Land Use Changes	Potentially Significant and Unavoidable
Short-Term Construction-Related Impacts on Cultural Resources	Potentially Significant and Unavoidable
Short Term Construction-Related Impacts on Energy Demand	Less Than Significant
Long-Term Operational Impacts on Energy Demand	Beneficial
Short-Term Construction-Related and Long-Term Operational Effects on Geology and Soil Related to New Facilities	Potentially Significant and Unavoidable
Long-Term Operational Impacts Associated with Carbon Capture and Sequestration Projects	Potentially Significant and Unavoidable

Resource Area Impact	Significance
Long-Term Operational Impacts to Geology and Soil Associated with Land Use Changes	Potentially Significant and Unavoidable
Short-Term Construction- and Long-Term Operational Related Greenhouse Gas Impacts	Beneficial
Short-Term Construction-Related Hazard Impacts	Potentially Significant and Unavoidable
Long-Term Increased Transport, Use, and Disposal of Hazardous Materials	Less Than Significant
Long-Term Operational Hazards Related to Carbon Capture and Sequestration	Potentially Significant and Unavoidable
Short-Term Construction-Related and Long-Term Operational Hydrologic Resource Impacts	Potentially Significant and Unavoidable
Long-Term Effects on Hydrology and Water Quality Related to Changes in Land Use	Potentially Significant and Unavoidable
Long-Term Impacts on Hydrology and Water Quality Related to Carbon Capture and Sequestration Projects	Potentially Significant and Unavoidable
Short-Term Construction-Related Impacts Related to New or Modified Facilities	Potentially Significant and Unavoidable
Long-Term Operational Impacts Related to Feedstock Production	Potentially Significant and Unavoidable
Short-Term Construction-Related Impacts and Long-Term Operational Impacts on Mineral Resources	Less Than Significant
Short-Term Construction-Related Noise Impacts	Potentially Significant and Unavoidable
Long-Term Operational Noise Impacts	Less Than Significant
Short-Term Construction-Related Impacts and Long-Term Operational Impacts on Population, Employment, and Housing	Less Than Significant
Short-Term Construction-Related Impacts and Long-Term Operational Impacts on Public Services	Less Than Significant
Short-Term Construction-Related Impacts and Long-Term Operational Impacts on Recreation	Less Than Significant
Short-Term Construction-Related Impacts on Traffic and Transportation	Potentially Significant and Unavoidable
Long-Term Operational Impacts on Traffic and Transportation	Potentially Significant and Unavoidable
Increased Demand for Water, Wastewater, Electricity, and Gas Services	Potentially Significant and Unavoidable

Written comments on the Draft EA will be accepted starting January 2, 2015 through 5 p.m. on February 17, 2015. The Board will consider the final EA and responses to comments received on the Draft EA before taking action to adopt an LCFS regulation.

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VI. ENVIRONMENTAL JUSTICE

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to making environmental justice an integral part of its activities. The Board approved its Environmental Justice Policies and Actions (Policies) on December 13, 2001, to establish a framework for incorporating environmental justice into ARB's programs consistent with the directives of State law[85]. These policies apply to all communities in California, but recognize that environmental justice issues have been raised more in the context of low-income communities and communities of color.

Many of these low-income communities and communities of color are located near industrial sources, such as petroleum refineries. One of the proposed revisions to the Low Carbon Fuel Standard (LCFS) regulation that may lead to reduced emissions from petroleum refineries is the Refinery Investment Credit provision. This credit provision would recognize, on a project-by-project basis, reductions in greenhouse gas (GHG) emissions from petroleum refineries. Awarding such credits is consistent with conducting a full life cycle analysis of fuel production facilities. Emissions of toxic and criteria pollutants from the petroleum refineries are also expected to be reduced by these projects, however, if these emissions increase, despite a decrease in GHG emissions, the projects are ineligible for credits under the LCFS program.

Another potential air quality impact on low-income communities and communities of color is the construction and operation of new biofuel production facilities. In 2009, the Board directed the Executive Officer, in Resolution 09-31, to work with local air districts, regulated parties, environmental and public health groups, and other stakeholders to develop a best practices guidance document for use by stakeholders when they are assessing and mitigating the air emissions associated with biofuel production facilities in California. The Guidance[86] identifies the lowest permitted emission limits for stationary source process equipment used at biofuel production facilities and identifies strategies for mitigating mobile source emissions associated with these facilities.

The Guidance is a resource document developed to assist air quality agencies, local land use planners, environmental and public health groups, project developers, and other stakeholders that would conduct air quality evaluations for new or expanding biofuel production facilities. The Guidance is not intended to substitute for project-specific evaluations conducted at the local level by California air districts, California Environmental Quality Act lead agencies, and other regulatory entities.

ARB staff will continue working with local air districts and other permitting agencies on updating the Guidance document as newer technology evolves.

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[85] Policies and Actions for Environmental Justice
[86] http://www.arb.ca.gov/fuels/lcfs/bioguidance/bioguidance.htm

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VII. ECONOMIC IMPACTS ANALYSIS/ASSESSMENT

A. Overview

The Low Carbon Fuel Standard (LCFS) regulation and the Commercialization of Alternative Diesel Fuels (ADF) regulation will be proposed to the Air Resources Board for consideration in 2015. The primary goal of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in California by at least ten percent by 2020 from a 2010 baseline. Over and above the effects of other state and federal GHG-reducing programs, this lower CI is expected to reduce the annual greenhouse gas emissions from the state's transportation sector by about 35 million metric tons (MMT) by 2020 and support the development of a diversity of cleaner fuels with other attendant co benefits. It is also expected to achieve other important benefits as well, including greater diversification of the state's fuel portfolio, provide consumers with more clean fuel choices, thereby increasing competition, greater innovation and development of cleaner fuels, and support for California's ongoing efforts to improve ambient air quality. The reductions in CI by 2020 are expected to account for almost 17 percent of the total GHG emission reductions needed to meet the Assembly Bill (AB) 32 mandate of reducing California's GHG emissions to 1990 levels by 2020 and are also expected to set the stage for greater changes in the state's transportation fuel portfolio in subsequent years.

The primary goals of the ADF proposal are twofold: 1) establish a comprehensive, multi-stage process governing the commercialization of ADF formulations in California, and 2) to establish special provisions for biodiesel as the first recognized ADF to permit its use within California. Both these regulations affect the types and volumes of transportation fuels demanded in California. Due to the complementary nature of these policies, the economic effects of the two programs are modeled together for the purposes of this economic analysis (referred to as the combined LCFS/ADF proposal).

The estimated direct cost to regulated parties is highly sensitive to the price of LCFS credits, which cannot be forecast with certainty because prices will depend on the supply and demand for credits as well as the mitigation pathways chosen by biodiesel producers. From 2012 through 2013, while the LCFS standards for gasoline and diesel were tightening, the average credit price reported in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS) was $57.[87] The current LCFS credit price is about $25.[88] Based on historic credit prices and the fuel volumes that will be required to meet the increasing stringency of the LCFS proposal, ARB assumes a credit price of $100 for the period 2016 through 2020. This method likely over-estimates costs because many (or even most) lower-CI fuels with embedded credits can be generated and secured at costs lower than the market price for stand-alone credits. Although most of the economic impact analysis is based on an assumed LCFS credit price of $100, to gauge a range of potential costs, staff analyzed three cases, based on current credit

[87] Weighted average of quarterly LCFS credit prices reported through the LRT available at: http://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.
[88] http://www.arb.ca.gov/fuels/lcfs/credit/20141209_novcreditreport.pdf

prices of $25, historical 2012-2013 average prices of $57, and a higher assumed price of $100.

Regulated parties can either generate credits themselves by purchasing low-CI fuels and reporting them in the LRT-CBTS, or they can go out into the market and buy LCFS credits generated by others. In 2013, California's seven major refineries self-generated a vast majority of their compliance obligation through the purchase of low-CI fuels.[89] In addition, the credit price represents the marginal cost of abatement (the cost of the last ton of emission reductions needed to comply); most other reductions will be achieved at a lower price

B. Direct Costs

1. Costs to Regulated Parties and Other Businesses

The direct costs of the proposed LCFS can be calculated as the difference in the cost of producing the volumes of low-CI fuels required for compliance with the regulation and the cost of producing the volumes of low-CI fuels that would have been consumed without the proposed regulation. The proposed LCFS offers regulated parties flexibility in choosing a least-cost compliance strategy, including banking credits, purchasing credits from the open market, and self-generating credits by blending low-CI fuels with hydrocarbon blendstocks. As a simplifying assumption, and to take a conservative approach in estimating the costs of compliance, the price of LCFS credits is used as a proxy to estimate this difference in the cost of producing low-CI fuels relative to the conventional fuels displaced. This is consistent with economic theory, which holds that LCFS credit prices are equal to the cost of producing the last credit demanded by regulated parties. This method likely over-estimates costs because many (or even most) lower-CI fuels with embedded credits can be generated and secured at costs lower than the market price for stand-alone credits.

The price of credits in the out years of analysis (2016 through 2020) will depend on the supply and demand for credits in the LCFS market. The demand for credits is predominately determined by the quantity of deficits, which are generated from the use of conventional fuels. A regulated party generates deficits by selling a transportation fuel with a CI above the annual standard, and regulated parties demonstrate compliance by retiring one credit for each deficit generated.

In the scenario, regulated parties are, in aggregate, anticipated to generate between 6 and 20 million deficits annually, and are therefore anticipated to demand an equal number of credits in order to demonstrate compliance.

[89] Information obtained through business confidential transactions reported through the LRT.

Table VII-1. Deficits Generated by Fuel Type

	2016	2017	2018	2019	2020
Gasoline (millions of gallons)	12,658	12,513	12,361	12,184	11,986
Deficits Generated from Gasoline (millions of deficits)	5.10	7.27	9.38	12.87	16.22
Diesel (millions of gallons)	3,299	3,259	3,240	3,221	3,202
Deficits Generated from Diesel (millions of deficits)	0.91	1.58	2.24	3.35	4.44
Total deficits	**6.01**	**8.85**	**11.63**	**16.22**	**20.66**

The cost of compliance can be estimated by multiplying the number deficits generated by sales of conventional fuels by the credit price. Based on the scenario, Table VII-2 shows the calculated compliance costs at the assumed LCFS credit price of $100/credit in all years analyzed (2016 through 2020). The cost of compliance that regulated parties incur will vary based on regulated parties' compliance approach and the price of credits. All else equal, higher credit prices will translate to higher costs of compliance.

Table VII-2. Potential Range of Direct Costs of Compliance (million $)

LCFS credit price	2016	2017	2018	2019	2020
$25 (current price)	$150	$221	$291	$406	$517
$57 ('12-'13 average)	$343	$504	$663	$925	$1,178
$100	$601	$885	$1,163	$1,622	$2,066

*All credits are assumed to be sold at the same price.

2. Fuel Availability and Credit Price

The supply of credits is determined by the quantity and carbon intensity of low-CI fuels sold in the California market.

The financial incentives provided by the LCFS credit value is anticipated to stimulate investments in, and production of, very low-CI fuels. The LCFS credit value represents a source of additional revenues for low-CI fuel producers and distributors, who can sell credits generated by their fuel. The LCFS credit value can offset the higher initial costs of producing low-CI fuels, and is anticipated to be used to reduce the higher initial price of those fuels to enable them to compete with conventional fuels. The value added from the sale of LCFS credits depends on the fuel's carbon intensity, the stringency of the annual standards, the LCFS credit price, and the volume of conventional fuel displaced.

Table VII-3. Value Added from the Sale of LCFS Credits at $100/credit

Fuel Type	Assumed CI in 2020	Value Added in 2020 ($/gal)
Corn Ethanol	67.24	$ 0.18
Cellulosic Ethanol	20.00	$ 0.56
Waste Grease Biodiesel	14.97	$ 1.09
Renewable Diesel	35.00	$ 0.78
Renewable CNG	25.00	$ 0.91

Because the supply of credits depends on the availability of low-CI fuels, market participants may face uncertainty regarding whether low-CI fuels will be available in sufficient volumes to achieve compliance, particularly in later years when the stringency of the regulation increases. Staff has analyzed the projected availability of low-CI fuel technologies, which is summarized in Chapter II. This analysis indicates that sufficient volumes of low-CI fuels will be available for compliance in all years analyzed. Historical data indicates a strong market response to the regulation stimulating demand for low-CI fuels. A Low Carbon Fuel Standard has been continuously implemented in California since 2010, and regulated parties have generated more credits than needed every year. The accumulation of banked credits has been augmented by a standard that will have been frozen at 1.0 percent through 2015. The scenario projects approximately 3.6 million banked credits available at the start of 2016.

Table VII-4. Deficits and Credits by Year (MMTs of Credits or Deficits)

Fuels	2016	2017	2018	2019	2020
Gasoline	-5.1	-7.3	-9.4	-12.9	-16.2
Ethanol	4.0	4.1	4.4	4.4	4.4
Electricity (LDV and HDV)	0.7	0.8	1.0	1.2	1.4
Renewable Gasoline	0.0	0.0	0.0	0.1	0.2
Hydrogen	0.0	0.0	0.1	0.1	0.1
Diesel	-0.9	-1.6	-2.2	-3.3	-4.4
Biodiesel	1.5	1.8	2.1	1.9	1.9
Renewable Diesel	2.1	2.5	2.6	2.8	3.0
Natural Gas	1.2	1.3	1.7	2.0	2.4
These values are based on $100 LCFS credit price. The above values are rounded to the nearest tenth.					

Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation. Many innovative, low-CI fuel technologies have moved past the demonstration stage, and have overcome techno-economic challenges that have in recent years limited the supplies of innovative, very-low CI fuels such as cellulosic ethanol, renewable diesel, and renewable natural gas. Staff analysis indicates that the supplies of low-CI fuels in future years (2016 through 2020) will continue to exhibit the existing trend of increasing production. As the scenario shows, existing low-CI fuel technologies are anticipated to continue to play a large role in achieving LCFS compliance. The stringency of the standard in later years demands increasing quantities of very-low CI fuels, and is anticipated to stimulate the increased production of innovative emerging and nascent technologies like renewable diesel, cellulosic ethanol, biomethane, and hydrogen fuel cell vehicles.

3. Costs to Businesses and Individuals

Costs to Individuals

The proposed LCFS regulates fuel suppliers that produce and sell transportation fuels into the California market. Because the point of regulation is upstream of the end-users—California motorists—the proportion of the direct costs that are passed along to consumers is uncertain. Economic theory indicates that a portion of the cost of compliance will be passed-through to California fuel consumers and a portion will be absorbed by regulated parties as an increased cost of production; the amount that is passed-through to California motorists is anticipated to vary by regulated party, as it is a business decision that depends on regulated parties' individual compliance strategies. The ability of regulated parties to pass through the direct cost of compliance to consumers in the form of increased prices for conventional fuels is uncertain, and will depend on the elasticity of demand for their fuel, and the availability and price of near substitute fuels. The magnitude of the price increase varies based on the assumed LCFS credit price and the stringency of that year's standard.

Using assumptions that are conservative in the direction of overstating the fuel price impacts of the proposed LCFS, the scenario may result in price increases for petroleum-based fuels on the order of a few cents per gallon. Table VII-5 shows a range of fuel price impacts at the various credit prices. The potential fuel price impacts in Table VII-5 represent the upper bound of the fuel price impacts, as the calculation relies on the assumption that regulated parties pass through 100 percent of their costs of compliance to California motorists, and that all credits are purchased at per-credit prices of $25 - $100.

Table VII-5. Range of Estimated Fuel Price Impacts

Credit price	Fuel	2016	2017	2018	2019	2020
$25	Gasoline	$0.009	$0.013	$0.017	$0.024	$0.030
	Diesel	$0.007	$0.012	$0.017	$0.026	$0.035
$57	Gasoline	$0.021	$0.030	$0.039	$0.054	$0.068
	Diesel	$0.016	$0.027	$0.039	$0.059	$0.079
$100	Gasoline	$ 0.036	$ 0.052	$ 0.068	$ 0.094	$ 0.120
	Diesel	$ 0.028	$ 0.048	$ 0.069	$ 0.104	$ 0.139

While staff has completed this analysis to quantify the upper bounds of any potential fuel price impacts, this simplified dollars-per-gallon translation should not be relied upon to determine the impact of credit prices on the final retail price of transportation fuels. Retail prices are strongly influenced by many factors beyond LCFS credit prices (e.g., global events, holiday weekends, seasonal fluctuations, refinery disruptions, seasonal fuel blends, etc. Between 2008 and 2012, the retail price of gasoline fell as low as $1.74 and rose as high as $4.66. The proposed LCFS introduces competition into the fuels market and ultimately will help to provide California drivers with clean fuel choices that insulate them from potentially large fluctuations in global oil prices.

While the proposed regulation may result in small increases in the cost of conventional fuels, it also results in cost-savings for low-CI fuels. The LCFS credit price provides a premium to the producers of low-CI fuels, which can be used to lower the price of those fuels. The price impact of the proposed regulation is anticipated to result in increased costs per household on the order of $65 per year in 2020, assuming $100/credit. Households that use low-CI fuels will be less affected by increases in the prices of conventional fuels resulting from the pass-through of compliance costs than will households that predominately refuel with gasoline and diesel. Similarly, households that have lower vehicle miles travelled will be less affected by any potential fuel price impacts.

Costs to Other Businesses

The potential impact of the LCFS on businesses depends on how much transportation fuel those businesses use. Businesses such as delivery services and taxis would be more impacted than businesses that use much less fuel, although the cost of their delivered inventory may be affected. Therefore, the cost impacts to a “typical” business are unquantifiable. Nevertheless, some illustrative examples may be useful. (Note: For clarity and brevity, the following examples use $100/credit; the costs at the $25 and $57 credit prices would be lower in a linear fashion. Furthermore, instead of calculating separate impacts for diesel and gasoline, the examples use an average between the two.)

If a small business has a vehicle fleet that travels 100,000 miles annually and achieves an average fuel mileage of 25 miles per gallon, that business would consume 4,000 gallons of fuel in a year. In 2020, when the maximum cost impact on fuel would be roughly 13 cents/gallon in our conservative analysis, the cost impact would be about $500. Using the same approach, for a “typical” business that may have a fleet traveling a million miles per year collectively, their costs would be about $5,000 in 2020. An individual driving 12,000 miles in 2020 would potentially experience increased fuel costs of $65.

4. Fiscal Impacts on State and Local Governments

Fiscal Impacts

Based on the theoretical compliance scenario, ARB estimates the impacts on State and local revenue from transportation fuels. Fuel taxes[90] are collected in two ways: as an

[90] More information is available at: http://www.api.org/oil-and-natural-gas-overview/industry-economics/~/media/Files/Statistics/StateMotorFuel-OnePagers-Oct-2014.pdf

excise tax on the volumes of transportation fuels consumed in California, and as state and local sales taxes from expenditures on fuels. The change in excise tax is calculated as:

$$\Delta Tax_{excise} = Tax_{excise}(Volumes_{reference} - Volumes_{baseline}$$

The change in sales tax is calculated as:

$$\Delta Tax_{sales} = \left(Price_{reference} \times Tax_{sales} \times Volumes_{reference}\right) \\ -(Price_{baseline} \times Tax_{sales} \times Volumes_{baseline})$$

<u>Local Government</u>

Due to the increase in price of petroleum diesel, gasoline, and their alternatives due to the full-pass through of the theoretical $100 credit price[91], there will be increases in the local revenue collected from sales tax. While the magnitude of the increase depends on the credit price and varies depending upon the tax rate in the locality, ARB estimates a total change of $4 million in 2016 to $15 million in 2020. These results vary greatly depending on the local tax rate, the consumption patterns of consumers in these areas, the realized credit price, and the amount of the credit price that is passed on to consumers.

As with the impacts on businesses and individuals, the potential impact of the LCFS would be on transportation fuel prices. The LCFS standards for 2014 and 2015 are frozen at 1.0 percent by a court order, and—since the regulated parties are over-complying with the standards, and LCFS credit prices are about $25—the impact of the LCFS on fuel prices are imperceptible at the pump. As shown in Table 6 and the related discussion, the fuel price impact will be on the order of 2 to 7 cents per gallon in 2018 and 3 to 14 cents per gallon in 2020.

These maximum impacts are well within the normal volatility of fuel prices and would essentially be unseen at the pump. Nevertheless, as an illustrative example, for a local government whose combined fleet of vehicles consumes 100,000 gallons of fuel annually, the fiscal impact would be (at $100/credit):

FY 14/15: None
FY 15/16: $1,750 (1.75 cpg: 6 months negligible and 6 months at 3.5 cpg)
FY 16/17: $4,250 (4.25 cpg: 6 months at 3.5 cpg and 6 months at 5 cpg)

<u>State Government</u>

Because of the increase in price of petroleum diesel, gasoline, and their alternatives due to the conservatively assumed full-pass through of the theoretical $100 credit

[91] See Appendix F, Table 1 for the assumed pass-through for the theoretical compliance scenario.

price[92], there will be increases in the State revenue collected from sales tax. ARB estimates a total increase in state revenues of $11 million in 2016 and up to about $42 million in 2020. These results vary greatly depending on the realized credit price and the amount of the credit price that is passed on to consumers. Additionally, excise taxes are reduced due to reductions in diesel consumed amounting to a reduction in excise taxes of $7 million in 2016 and $2 million in 2020. Overall, the impact to the State budget, based on the theoretical compliance scenario is an increase of $4 million in 2016 and $40 million in 2020. Similar impacts from the increased price at the pump, a state agency that consumes 100,000 gallons of fuel annually, they will see a slight increase in their spending on transportation fuels.

<u>ARB</u>

The LCFS program will likely need additional personnel to enhance compliance assistance and enforcement. Over the next five years, potentially twelve personnel will be required, two of which were requested for the fiscal year 2013-2014. The cost of these positions yearly will cost the state about $2 million in total compensation.

<u>Other State Agencies</u>

State agencies are required to estimate the potential fiscal impacts of a proposed regulation on State and local governments for the current fiscal year and the following two fiscal years. As with the impacts on businesses and individuals, the potential impact of the LCFS would be on transportation fuel prices. The LCFS standards for 2014 and 2015 are frozen at 1.0 percent by a court order, and since the regulated parties are over-complying with the standards, and LCFS credit prices are about $25, the impact of the LCFS on fuel prices are imperceptible at the pump. With a CI-reduction target of two percent in 2016, the estimated maximum cost impact on fuel prices would be 3 to 4 cents per gallon (cpg). Similarly, for 2017's target of 3.5 percent reduction, the estimated maximum impact would be 5 cpg.

The primary impact of the proposal would be the changing prices on fuels. The fiscal impact will vary depending upon the types of fuels chosen and are no greater than the impacts calculated in Table VII-6.

Table VII-6. Impacts on State and Local Tax Revenue (Millions 2014$)

	2016	2017	2018	2019	2020
State					
Total Change for State (Excise)	-7	-5	-4	-3	-2
Total Change for State (Sales)	11	17	23	33	42
Local					
Total Change for Local (Sales)	4	6	8	12	15

92 See Appendix F, Table 1 for the assumed pass-through for the theoretical compliance scenario.

e. Benefits

In combination with other state and federal GHG-reduction programs (the state Advanced Clean Cars and Pavley Vehicle Standards programs; the U.S. Environmental Protection Agency's Renewable Fuel Standard 2 and Corporate Average Fuel Economy programs), the LCFS proposal is anticipated to deliver environmental benefits that include an estimated reduction in GHG emissions of more than 60 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) from transportation fuels used in California from 2016 through 2020. By itself, the LCFS is expected to deliver about 35 MMT CO_2e in GHG emissions reductions. Implementation of the LCFS proposal will also diversify the transportation fuel portfolio, thereby reducing the economic impact of volatile global oil price changes on gasoline and diesel prices in California.

The LCFS proposal is expected to improve California's air quality by reducing criteria pollutant emissions from the projected 2020 vehicle fleet. These reductions are predominately attributable to reductions in petroleum diesel use. Among the improvements this reduced reliance on petroleum diesel will produce will be a cumulative estimated reduction in the $PM_{2.5}$ emissions of more than 1200 tons from 2016 through 2020. These emissions reductions consist of the reduced tailpipe emissions of $PM_{2.5}$ associated with the replacement of conventional diesel with substitute fuels net of any increased emissions of $PM_{2.5}$ associated with feedstock and fuel truck trips from additional California biofuel production facilities and transport from out-of-state biorefineries. Any additional NO_X emissions that result from the increased use of biodiesel blends are required to be mitigated by the Alternative Diesel Fuel regulation.

If the proposed LCFS stimulates increased biodiesel production, the associated increases in particulate matter, total hydrocarbons, and carbon monoxide would be attributable to the LCFS rather than the ADF.

<u>Benefits to Individuals</u>

In California, petroleum-based transportation fuels are responsible for almost forty percent of statewide greenhouse gas emissions, and an even higher percentage of the harmful ozone and toxic air contaminants that disproportionally impact our State's most disadvantaged communities. Based on the modeled compliance scenario, the LCFS proposal results in reduced criteria and toxic emissions, and the ADF proposal maintains the NO_X emissions level of CARB diesel with increased biodiesel use. Additionally, residents of California will enjoy improved air quality in the form of decreased ground-level ozone relative to the baseline scenario.

These air quality improvements translate into health benefits for all Californians: the proposed regulations will result in reduced risk of premature deaths, hospital visits, emergency room visits for asthma, and a variety of other health effects. These benefits accrue disproportionately to sensitive receptors including children, elderly, and people with chronic heart or lung disease.

As the proposed regulations incent the displacement of petroleum-based transportation fuels and increase the supplies of cost-effective low-CI fuels, individuals in California will also benefit from a wider selection of in cleaner transportation fuels. Increasing the availability of non-petroleum fuel options will reduce California motorists' exposure to fuel price volatility driven by international crude prices. The LCFS will also result in reduced U.S. oil consumption, resulting in energy security benefits, such as the avoided national economic losses associated with the risk of macroeconomic disruption caused by oil supply shocks.

Benefits to California Businesses

The LCFS proposal provides opportunities for businesses, within and outside of California, to generate credits for low-CI transportation fuels. The proposed LCFS stimulates demand for low-CI fuels, which creates incentives to invest in and produce innovative low-CI fuels. Credits have a monetary value when sold in the LCFS credit market and can be generated by producers of low-CI biofuels, biomethane and natural gas providers selling CNG and LNG, fleet operators utilizing opt-in fuels such as electricity, utilities providing electricity for the residential fueling of electric vehicles, and service providers installing and maintaining public electric vehicle charging equipment. Because the LCFS is a fuel-neutral, performance-based standard, it provides equal incentives to businesses, without regard to location, to increase the production of low-CI fuels. The proposed regulation provides the incentive structure to foster the low-CI fuels market; individual business decisions and the economics of producing the low-CI fuels will determine where the resultant increases in supplies comes from.

Firms that are early investors in innovative, low-CI fuel technologies may be at a competitive advantage if more carbon-intensity standards are adopted by other state, federal, or international jurisdictions.

As the proposed regulations increase the penetration of low-CI transportation fuels and displace petroleum-based fuels, California businesses may also benefit from a larger portfolio of cleaner transportation fuels for fleet and service vehicles, which offers them an opportunity to reduce their exposure to volatile prices for petroleum-based fuels.

The LCFS also benefits California fuel providers with compliance obligations under Cap-and-Trade. As the LCFS reduces the carbon intensity of fuels, it changes the composition of the state's transportation fuel mix and dependence on traditional petroleum-based fuels. The LCFS and Cap-and-Trade programs are designed to complement one another. Investments made to comply with one of the programs will result in reduced compliance requirements for the other program. Reductions in the carbon intensity of fuel due to the LCFS reduce compliance obligations under the Cap-and-Trade Program. Similarly, selling cleaner fuels to comply with Cap-and-Trade helps meet the requirements of the LCFS.

Benefits to Small Businesses

The benefits to California businesses enumerated in Section 4, above, may also apply to some small businesses. Operators of natural gas and electric fleets may participate in the regulation to generate credits. The LCFS proposal may increase the fuel options for small businesses, which could impact total fuel consumption and expenditures.

Most California biodiesel producers are small businesses. The proposed regulations increase the demand for low-CI fuels, which is anticipated to result in growth in the low-CI fuels sector. The ADF may expand the market for some or all alternative diesel fuels, many of which are produced by small businesses, including small businesses in and outside of California; however, in the early years much of the benefits may be offset by the reduction in volumes of biodiesel that will likely result from the combined LCFS/ADF proposal. In addition, small businesses that produce low-CI fuels can opt into the regulation and generate credits for LCFS. The ADF proposal results in an overall expansion in the market for renewable diesel and other ADFs in California, resulting in a benefit to California businesses in the form of a wider array of available transportation fuels.

C. Macroeconomic Analysis

1. Major Regulations

As required by Title I, CCR 2000-2004, staff estimated the expected cost of the LCFS. The resulting estimates exceeded $50 million in all years analyzed (2016 through 2020). This result placed the LCFS into the major regulation category, and triggered the preparation of a standardized regulatory impact analysis (SRIA). For a major regulation proposed on or after January 1, 2014, a SRIA is required. ARB submitted a SRIA to the Department of Finance in October 2014.

2. Analytic Approach

The intent of this analysis is to investigate how the proposed LCFS/ADF regulations impact California's economy. The goals of the LCFS proposal are to achieve a 10 percent reduction in the carbon intensity of California transportation fuels by 2020, to diversify California's transportation fuel portfolio, and to create a durable regulatory framework that can be adopted by other jurisdictions. The primary goals of the ADF proposal are twofold: 1) establish a comprehensive, multi-stage process governing the commercialization of ADF formulations in California, and 2) to establish special provisions for biodiesel as the first recognized ADF to permit its use within California without significant adverse impacts on public health or the environment. Both these regulations affect the types and volumes of transportation fuels demanded in California. Due to the strongly complementary nature of these policies, the economic effects of the two programs are modeled together for the purposes of this economic analysis (referred to as the combined LCFS/ADF proposal). As a result, the economic impacts of the two regulations cannot be disaggregated.

This analysis begins with forecasted demand for transportation fuels in California, based on the 2013 IEPR estimated adopted by the California Energy Commission and historical fuel consumption data from the LRT-CBTS.[93] This forecast takes into account the existing trend of reduced demand for transportation fuels due to increased fuel efficiency of the projected vehicle fleet, and projects decreasing demand for transportation fuels in future years of the analysis. The majority of California's transportation energy demand is met by conventional fuels, which generate deficits due to high carbon intensity values. Because regulated parties demonstrate compliance with the LCFS by retiring a credit for each deficit generated, the demand for credits is determined by the volumes of conventional fuels sold, their carbon intensity, and the stringency of the annual standard.

Staff projected the volumes and types of fuels demanded for compliance with the proposed regulations in the illustrative compliance scenario (scenario). This scenario represents one of many potential paths to compliance with the LCFS, and reflects staff's analysis of alternative fuel availability and feasible assumptions regarding increased production of low-CI fuels. Staff estimated the change in types and volumes of fuels consumed as a result of the proposed regulations by comparing the scenario to a baseline scenario that represented the projected types and volumes of fuels consumed under a counterfactual scenario in which both the ADF and LCFS do not exist.

Because the proposed regulations affect California's transportation fuels market, the direct costs of the regulation can be estimated using the demand for credits and the cost of generating a credit.

As the proposed regulations may induce changes in markets beyond California's fuel market, the indirect costs and economic impacts are modeled using a computational general equilibrium model of the California economy known as Regional Economic Models, Inc. (REMI). The REMI model generates year-by-year estimates of the total regional effects of a policy or set of policies. ARB used the REMI PI+ model for this analysis—a one-region, 160-sector model that has been modified by the Department of Finance to include California-specific data for population, demographics, and employment.[94]

Because the proposed regulations result in changes in the types of fuels consumed in California, the impact of the regulations was modeled in REMI as a change in consumer transportation fuel expenditures. The price of transportation fuels is based on forecasted prices from the U.S. Energy Information Agency's (EIA's) 2014 Annual

[93] California Energy Commission (2013) Integrated Energy Policy Report (IEPR) http://www.energy.ca.gov/2013_energypolicy/ accessed 12.15.2014

[94] Information regarding the Department of Finance's affiliation with REMI and baseline scenario modifications is available at: http://www.dof.ca.gov/research/economic_research_unit/SB617_regulation/view.php.

Energy Outlook (AEO2014) reference scenario.[95] The price of LCFS credits may be passed through to consumers in the form of a small increase in the price of conventional fuels. The value of producing and selling those credits may be passed on to consumers in the form of decreased prices for low-CI fuels, including biofuels, natural gas, electricity, and hydrogen.

Assumptions and Limitations of the REMI Model

This analysis relies on the use of models. It is important to remember that modeling of any kind is inherently uncertain, but even with uncertainties modeling is useful in policy evaluation. The analysis presented here relied on the REMI model, and as illustrated in the above tables, expenditure categories in the REMI model are highly aggregated. The aggregated expenditure categories may limit the degree to which Computable General Equilibrium (CGE) models like REMI are able to fully represent nuanced changes within a sector. The REMI model processes a dollar spent on any fuel, regardless of CI, equally. As the REMI model is limited in its ability to accurately reflect the incentive to invest in and produce alternative fuels based on their favorable carbon intensity, REMI may not present a complete picture of how expenditures on low-CI fuels move through the economy.

Nonetheless, CGE models such as REMI are standard tools of empirical analysis, and they are widely used to analyze the aggregate impacts of policies whose effects may ripple through multiple markets. The policies affect behavior in agricultural and fuel markets, as well as fiscal impacts from fuel tax revenues. The use of REMI provides a more complete look at the economic effects of the proposed LCFS than is possible with an analysis of the direct costs of the regulation alone.

The intent of this analysis is to investigate how the proposed LCFS/ADF regulations impact California's economy. When making the many assumptions necessary, staff selected assumptions that would drive the economic impacts toward the high end of the foreseeable range. Specifically:

- LCFS credit price is $100 from 2016 through 2020 (despite much lower current prices);
- The full LCFS credit price is reflected in the final price of conventional fuels;
- The full value of the LCFS credit associated with electricity as a transportation fuel is reflected in a reduced electricity rate for electricity consumers;

[95] For petroleum and other liquids more information is available at: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=12-AEO2014&region=0-0&cases=ref2014-d102413a.
For NG and electricity, more information can be found at: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=3-AEO2014&region=1-0&cases=ref2014-d102413a.

- LCFS credit values are simulated as a decrease in production cost for natural gas and electricity and an increase in production cost for conventional fuels. To remain conservative, LCFS credit values are assumed to have no effect on biofuel prices, even though producers of low-CI biofuels will receive revenues from the sale of the LCFS credits their fuels generate. In addition, biofuel producers are anticipated to increase production in response to these financial incentives.

- Alternative fuels are priced at parity with their fungible conventional fuel;

- Production of conventional fuels in California remains static due to increasing exports offsetting anticipated reduction in conventional fuel demand in California;

- The volumes and types of fuels in the compliance scenario come on-line as anticipated; and

- Hydrogen is included in the volumes for the compliance scenario but excluded from the expenditure changes due to lack of reliable price data; therefore, any credit value associated with hydrogen is not included in the analysis.

Baseline Information

As of December 2014, the LCFS adopted by the Board in 2009 is currently in effect, although its implementation schedule is frozen at 2013 levels, or a one percent reduction in CI from the 2010 baseline. The regulatory baseline, however, does not assume the existence of the 2009 LCFS. The regulatory baseline for the LCFS/ADF rulemaking will not include any provisions from the existing LCFS regulation per the July 15, 2013 court order, which found that the existing LCFS regulation would no longer be in effect if the Board does not re-adopt the LCFS and remedy the shortcomings it identified, including possible negative air quality impacts associated with the increased emissions of oxides of nitrogen (NOx emissions) from biodiesel.

The baseline represents a counterfactual scenario in which neither the proposed LCFS nor proposed ADF affect California's transportation fuel market. Staff created a baseline scenario to estimate the volumes and types of fuels that would have been consumed without the proposed regulations, including the carbon intensities of those fuels. The volumes of non-conventional fuels in the baseline scenario is based on California's proportional share of the forecasted alternative fuels produced for compliance with the federal RFS2, as estimated in the 2014 Annual Energy Outlook reference scenario.[96]

To isolate the effects of the LCFS from outcomes that would have occurred without the regulation, the baseline includes existing regulations and trends that influence the types

[96] U.S. Energy Information Agency (2014) Annual Energy Outlook. http://www.eia.gov/forecasts/aeo/ Accessed 12.15.2014

and carbon intensities of transportation fuels consumed in California. The major regulations and trends include:

- *Advanced Clean Cars (ACC)*: ACC incentivizes the adoption of alternative technology vehicles that consume fuels such as electricity, natural gas, and /or hydrogen. The adoption rate of these vehicles is assumed to be driven by the ACC, although somewhat enhanced because use of low-CI fuels in these vehicles may qualify for credit generation under the LCFS.

- *U.S. Environmental Protection Agency's (U.S. EPA) Renewable Fuel Standard 2 (RFS2)*: The U.S. EPA's RFS2 mandates minimum volumes of renewable fuels, which are required to be blended into transportation fuels. In a baseline scenario, which represents the composition of the fuel portfolio without the LCFS' influence, ARB staff assumes that California will receive its proportional share of alternative fuels produced for compliance with the RFS2. In other words, because California consumes approximately 10 percent of national transportation fuels, staff assumed that California would consume approximately 10 percent of the renewable fuels produced for compliance with the Federal RFS2. Staff used the fuel types and volumes forecasted by the U.S. Energy Information Agency in the 2014 Annual Energy Outlook.

- *ARB's Pavley Vehicle Standards and the U.S. EPA's Corporate Average Fuel Economy (CAFE)*: The U.S. EPA's CAFE requires vehicle manufacturers to comply with new fuel economy standards. Taken together, CAFE and Pavley reduce transportation energy demanded. Increased fuel economy will reduce demand for all transportation fuels, which is accounted for in the gasoline and diesel demand forecasts.

- *Existing fuel trends*: Aggregate demand for transportation fuels in California has exhibited a decreasing trend, which is modeled in the forecasted gasoline and diesel demand forecasts. Additionally, the favorable economics on the cost of natural gas versus conventional fuels is modeled in the baseline. Fuel cost savings due to low natural gas prices is incentivizing heavy-duty fleets to switch from conventional vehicles to NG vehicles. ARB staff anticipates a continuation of this trend. ARB staff also modeled conventional and alternative fuel prices in future years using the US Energy Information Agency's fuel prices forecasted in the 2014 Annual Energy Outlook.

<u>Inputs to the Assessment</u>

The LCFS/ADF proposal allows for many compliance strategies. The LCFS proposal does not dictate the types and quantities of fuel used for compliance, but instead relies on a market-based approach to allow the lowest possible cost of compliance. To estimate the economic impacts of the combined LCFS/ADF proposal, ARB has chosen one potential compliance scenario among the many potential compliance paths. This compliance scenario includes the volumes and types of fuels consumed in California each year for compliance with the combined LCFS/ADF proposal. The compliance scenario has been constructed with input from stakeholders and external researchers. It utilizes fuels that are technically feasible and that are expected to be available at the needed volumes during the time frame of the analysis. The fuels included in the compliance scenario are:

- California Reformulated Gasoline (E10 and E85)
- Corn Ethanol
- Sorghum Ethanol
- Cane Ethanol
- Cellulosic Ethanol
- Sorghum/Corn/Wheat Slurry Ethanol
- Renewable Gasoline
- Hydrogen
- Electricity for Light- and Heavy-Duty Vehicles
- CARB Diesel
- Soy Biodiesel
- Waste Grease Biodiesel
- Tallow Biodiesel
- Corn Oil Biodiesel
- Renewable Tallow Diesel
- Liquefied Natural Gas (LNG)
- Compressed Natural Gas (CNG)
- Renewable LNG
- Renewable CNG

The combined LCFS/ADF proposal was modeled in REMI as a change in consumer transportation fuel expenditures because the regulations will change the type, the volume, and the price of fuel consumed in California. Calculating the change in transportation fuel expenditures requires analyzing two effects of the LCFS/ADF proposal: a fuel substitution effect, which is the change in the types of fuels consumed, and a price effect, which is the change in the prices paid for those fuels.

The fuel substitution effect of the LCFS/ADF proposal is quantified as the difference in the volumes and types of fuels consumed for compliance and the volumes and types of fuels consumed in the baseline scenario, in the absence of the proposed regulations. In the compliance scenario, conventional fuel volumes decrease, while the quantity of lower-CI fuels, including biodiesel, cellulosic ethanol, and renewable NG, increases. The illustrative compliance scenarios are based on forecasted transportation energy demand, fuel availability, carbon intensity, and price.

Table VII-7. Fuels Consumed under Reference Compliance Scenario versus Baseline

		2016		2020	
Fuel		**Baseline**	**Illustrative Compliance Scenario**	**Baseline**	**Illustrative Compliance Scenario**
Ethanol	million gallons	1,495	1,495	1,485	1,485
California reformulated gasoline	million gallons	12,658	12,658	12,011	11,986
Electricity for LDVs	1000 MWH	596	596	1,629	1,629
Biodiesel	million gallons	106	129	108	180
Renewable Diesel	million gallons	7	250	7	400
Natural Gas	million DGE	160	160	300	300
Electricity for HDVs/Rail	1000 MWH	0	900	0	900
CARB Diesel	million gallons	3,579	3,299	3,673	3,202

To model changes in consumer spending on transportation fuels, ARB estimated the price effect of the LCFS/ADF proposal, or the change in fuel prices once the LCFS credit price is reflected in the price of fuels. For the baseline scenario, ARB constructed a forecast of California fuel prices over the period 2016 through 2020, based on the EIA's forecast in the AEO 2014 reference scenario. As EIA forecasts national fuel prices, ARB made adjustments to account for the difference between California and national fuel prices. This was done by adjusting the gasoline and diesel prices upward by the average price differential between the weekly reported California and national fuel prices from 2007 through 2014, and natural gas (NG) was similarly adjusted using monthly data for the same time period.

The California-adjusted baseline fuel prices were further adjusted to reflect the value of the LCFS credit price that is either generated with the production of low-CI fuel or must be purchased to cover the deficits incurred by high-CI fuels. The price of gasoline and conventional diesel are increased to reflect the purchase of credits required to cover the deficits incurred by these fuels. The credit value is reflected in the final price of electricity on a per-kilowatt basis as the difference in CI between electricity and gasoline or diesel, respectively. The LCFS credit value is not reflected in the retail price of alternative fuels. Rather, ARB assumes that fungible alternatives to gasoline and diesel (i.e., ethanol, biodiesel, and renewable diesel) will be priced at parity on a volumetric basis to the fuels they replace.

The total fuel expenditure was calculated for the compliance scenario on a fuel-by-fuel basis and compared to the expenditures incurred in the baseline scenario, as seen in the equation below.

$$\begin{aligned} &Changes\ in\ Expenditures \\ &\qquad = (FuelDemand_{with\ LCFS+ADF} \times FuelPrices_{with\ LCFS+ADF}) \\ &\qquad - (FuelDemand_{without\ LCFS+ADF} \times FuelPrices_{without\ LCFS+ADF}) \end{aligned}$$

These expenditures are translated into a shift in consumer prices and input into the REMI model. REMI models consumer spending using highly aggregated expenditure categories similar to the North American Industrial Classification System (NAICS) codes. These categories combine similar products into groups such that all products in a group will have the same characteristics in the model. The calculated expenditures are input into REMI through a variable called “consumer prices,” which changes prices by consumption category. Changing “consumer prices” for transportation fuel means that all businesses and consumers that purchase final products from an affected category (here transportation fuels) will face the same price change.

In the REMI model, transportation fuel expenditures and prices are separated into three highly aggregated categories: motor vehicle fuels (including lubricants and fluids), NG, and electricity. The motor vehicle fuels category, for instance, not only models changes in consumption of gasoline and diesel but their alternatives (not including NG and electricity). Biodiesel, renewable diesel, and diesel are all treated the same in the model as they are all classified as motor vehicle fuels. As presented in Table VII-2, the expenditures on motor vehicle fuels increase as a result of the LCFS/ADF proposal.

As modeled, expenditures on electricity are anticipated to decrease slightly with the LCFS/ADF proposal. As the penetration of electric vehicles is driven primarily by compliance with other ARB regulations—notably the Advanced Clean Cars regulation—the combined LCFS/ADF proposal does not increase the total quantity of electricity consumed as a transportation fuel. However, the value of the LCFS credit decreases the price of electricity relative to the baseline scenario. For this reason, overall expenditures on electricity decrease due to the combined LCFS/ADF proposal.

Table VII-8. Changes in Consumer Expenditures (Millions 2009$) on Transportation Fuels

REMI Category	Fuels	2016	2017	2018	2019	2020	2021	2022	2023
Motor vehicle fuels, lubricants, and fluids	Gasoline and Diesel	-498	-548	-518	-347	-214	-757	-1,183	-1,609
	Renewable Diesel, Renewable Gasoline, Ethanol and Biodiesel	961	1,266	1,482	1,706	1,954	2,460	2,853	3,250
Natural Gas	Natural Gas (LNG and CNG)	0	0	0	0	0	0	0	0
Electricity	Electricity	-66	-77	-92	-109	-134	-165	-201	-241

These values are based on $100 LCFS credit price.

While prices of transportation fuels will change due to the impact of the LCFS credit on consumer spending, an additional step is required to input the change in the costs to fuel providers of the LCFS/ADF proposal. For a conventional fuel provider, an increase in the retail price of gasoline or diesel increases revenue. For an electricity provider, a lower final price for electricity (due to the value of the LCFS credit generated with the low-CI fuel) leads to a reduction in revenue in the REMI model. An additional step is required to account for the transfer of credits from the electricity providers to the conventional fuel providers to cover the deficits incurred by the high-CI fuels. Ideally, the transfer would be input as an increase in revenue for the alternative fuel firms, and a decrease in revenue for conventional fuels. However, due to the construction of REMI, ARB simulates the transfer of credits between high-CI and electricity providers as an increase in the production cost for conventional fuels and a decrease in production cost for electricity. For alternative fuel producers (excluding natural gas and electricity), the increase in revenue is assumed to equal the difference between their actual production cost and the average production cost of all fuel producers (which is aggregated in REMI).

The compliance scenario illustrates one pathway of fuel volumes that can achieve the goals of the LCFS/ADF proposal. From the volumes of fuel in the compliance scenario, ARB calculates the credits and deficits each year, multiplies the number of deficits generated by the $100 assumed credit price, and passes those costs to the regulated fuel providers as an increase in production cost for conventional fuels. Similarly, the credits generated are multiplied by the $100 assumed credit price, and that revenue is passed through as a decrease in production cost for electricity as shown in Table VII-2. However, the industrial categories, as related to transportation fuel, are highly aggregated in the REMI model and include: petroleum and coal products manufacturing (conventional fuels), basic chemical manufacturing (ethanol), natural gas distribution, and electric power generation, transmission, and distribution. The high level of aggregation in the modeling may not fully capture the incentives for innovation that could occur as a result of the LCFS/ADF proposal.

Table VII-9. Distribution of LCFS Credit Value, Represented as Changes in Production Cost (Expenditures in Million 2009$)

NAICS Industry	Fuels	2016	2017	2018	2019	2020	2021	2022	2023
Petroleum and coal products manufacturing	Gasoline and Diesel	557	820	1080	1504	1915	1867	1826	1786
Natural gas distribution	Natural Gas (LNG and CNG)	-107	-122	-155	-183	-220	-265	-298	-332
Electric power generation, transmission, and distribution	Electricity	-65	-75	-90	-107	-126	-155	-188	-225

These values are based on $100 LCFS credit price.

ARB also modeled the administrative costs of the LCFS/ADF proposal by changing labor productivity to account for record-keeping and administrative costs to regulated entities. ARB also adjusted exports such that a reduction in California's domestic demand for transportation fuels results in proportional increases in exports of transportation fuels to other jurisdictions using the unadjusted AEO base price. This inverse trade relationship is based on historical demand trends in California, as identified by the AEO historic data and exports as identified by the U.S. Census. Additionally, world oil demand is forecasted to increase[97] by 38 percent by 2040 providing sufficient global demand for California's increased exports.[98]

Results of the REMI Assessment

California Employment Impacts

As modeled, the LCFS/ADF proposal will have very small impacts on employment growth from 2016 through 2023. Table VII-10 shows that, with an LCFS credit price of $100, the growth in employment is reduced annually from 0.01 percent in 2016 to 0.08 percent in 2020. Table 5 outlines the change in employment growth each year. ARB interprets these results as negligible given the size of California's $2 trillion economy, and the uncertainty regarding inputs, particularly future prices for LCFS credits.

[97] http://www.nytimes.com/2012/03/09/us/oil-exports-have-become-huge-business-in-the-san-francisco-bay-area.html?_r=0
[98] http://www.eia.gov/pressroom/releases/press412.cfm

Table VII-10. Changes in Employment Growth

	2016	2017	2018	2019	2020
Change (millions 2009$)	-2,400	-5,100	-8,000	-12,700	-17,300
Change (%)	-0.01%	-0.02%	-0.04%	-0.06%	-0.08%

The change in employment value for each year is interpreted as the difference between the reference value and the baseline value for that year. Therefore these values should not be represented as cumulative values, but instead year-by-year changes.

California Business Impacts

The modeling results show that the LCFS/ADF proposal may generally produce a slight increase in the output across all sectors affected from 2016 through 2023. The results reflect the increased demand for alternative fuels, modeled as increased production in the petroleum and coal manufacturing sector. The growth in the petroleum manufacturing sector is likely explained by the assumed increase in exports in response to decreases in California demand for conventional fuels. There is no change in revenue for the electricity sector as the credit value received in the form of a production cost decrease is directly passed to the consumer and the consumer faces a lower electricity price. Similarly, the basic chemical manufacturing sector, which includes ethanol, obtains revenue from the LCFS credits, but does not see a reduction in the price for their product. Therefore, ethanol producers, in California and elsewhere, should see increases in output due to increased prices, and reduced production costs. Table VII-11 presents the growth in the output of California's transportation fuels industry and includes both conventional and alternative fuels.

Table VII-11: Changes in Output Growth

	2016	2017	2018	2019	2020
Electric Power Generation, Transmission, and Distribution	50 (0.19%)	60 (0.23%)	70 (0.27%)	80 (0.31%)	100 (0.36%)
Natural Gas Distribution	30 (0.11%)	40 (0.16%)	60 (0.21%)	80 (0.25%)	90 (0.30%)
Basic Chemical Manufacturing	0 (0.00%)	0 (-0.01%)	-1 (-0.02%)	-1 (-0.03%)	-1 (-0.04%)
Petroleum and Coal Products Manufacturing	340 (0.34%)	170 (0.16%)	-120 (-0.12%)	-570 (-0.54%)	-1080 (-1.01%)

The value in each year is interpreted as the reference year value less the baseline value in that same year. Therefore these values should not be represented as cumulative values, but instead changes year-by-year.

Impacts on Investments in California

As modeled, the LCFS/ADF proposal would produce very small investment impacts from 2016 through 2023. Table VII-12 shows that, at a credit price of $100, the annual change in the growth of investments in California ranges from a decrease of 0.01 to 0.11 percent, representing a slight slowing of growth but not a discernable change from the baseline scenario. ARB interprets these results as insignificant given the size of California's $2 trillion economy and the uncertainty regarding inputs, particularly future prices for LCFS credits. Additionally, limitations prevent the proper modeling of the incentives for investment that the combined LCFS/ADF proposal is likely to provide by diversifying the fuel mix.

Table VII-12. Change in Gross Domestic Private Investment Growth

	2016	2017	2018	2019	2020
Private Investment (millions 2009$)	-20	-90	-190	-340	-520
	(-0.01%)	(-0.03%)	(-0.05%)	(-0.09%)	(-0.13%)

The value in each year is interpreted as the reference year value less the baseline value in that same year. Therefore these values should not be represented as cumulative values, but instead changes year-by-year.

Impacts on Individuals in California

The proposed regulation is mostly likely to affect California fuel consumers through changes in the price of transportation fuels. Staff assumes that the cost of compliance, represented in the analysis as the price of LCFS credits, will be passed along through consumers via that fuel's market price. The pass-through of LCFS credit price will increase the price of conventional fuels like gasoline, diesel, and other fuels with carbon intensities above that year's standard. The pass-through of LCFS credit prices will decrease the price of fuels with carbon intensities below that year's standard. On average, the pass-through of the LCFS credit price creates a small price increase in the price per gallon of gasoline or diesel, but creates a significant decrease in the price per gallon of low-carbon fuels.

LCFS credits are anticipated to reduce the price paid for low-carbon fuels and slightly increase the price of conventional fuels. The combined LCFS/ADF proposal would produce a very small change in personal income for all years analyzed, 2016 through 2023. Table VII-13 shows that with a credit price of $100, the change in the growth of personal income ranges from a decrease of 0.01 to 0.05 percent annually. The changes in the growth of personal income correlate with the modeled reduction in employment in California, which are in the same range and negligible size relative to the size of the California economy.

Table VII-13. Changes in Personal Income Growth

	2016	**2017**	**2018**	**2019**	**2020**
Personal Income (millions 2009$)	-120	-320	-580	-1,000	-1,470
	-0.01%	-0.01%	-0.02%	-0.04%	-0.06%

The value in each year is interpreted as the reference year value less the baseline value in that same year. Therefore these values should not be represented as cumulative values, but instead changes year-by-year.

<u>Impacts on Gross State Product (GSP)</u>

Table VII-14 shows that the annual change in the growth of GSP ranges from a decrease of less than 0.01 to 0.07 percent, depending upon the year. ARB interprets these results as small relative to the size of California's $2 trillion economy and the uncertainty regarding inputs, particularly future prices for LCFS credits.

Table VII-14: Changes in Gross State Product Growth

	2016	**2017**	**2018**	**2019**	**2020**
GSP (millions 2009$)	-30	-300	-630	-1,160	-1,730
	0.00%	-0.01%	-0.03%	-0.05%	-0.07%

The value in each year is interpreted as the reference year value less the baseline value in that same year. Therefore these values should not be represented as cumulative values, but instead changes year-by-year.

Summary and Interpretation of the Results of the Economic Impact Assessment

The LCFS/ADF proposal encourages the production and consumption of innovative, low-CI transportation fuels. The LCFS/ADF proposal provides a market for innovative alternative fuels through 2023, and as modeled, can shift California's consumption of transportation fuels from polluting, high-carbon-intensity energy sources to clean, low-carbon-intensity fuels and efficient technologies with little or no economic penalty. These results are consistent with other economic analyses of California's 2010 LCFS and other AB 32 regulations.

As modeled, the LCFS/ADF proposal is unlikely to significantly impact California's economy. The impact of the LCFS/ADF proposal on the growth of employment, investment, personal income, transportation sector output, and gross state product does not represent a significant change from the baseline scenario.

D. Reasonable Alternatives to the Regulation and the Agency's Reason for Rejecting those Alternatives

1. Alternatives Analyzed

Staff analyzed two alternatives to the proposed regulation: one less stringent than the LCFS proposal (Alternative 1: Gasoline Only); and one more stringent than the LCFS proposal (Alternative 2: Retain Full Benefits of the Original CI Reduction Curve). The alternatives analyzed and their compliance schedules are outlined in Table VII-15.

Table VII-15. Comparison of LCFS Compliance Schedules (Percent Reduction in Carbon Intensity)

Year	2010 LCFS	LCFS Proposal	Alternative 1: Gasoline Only	Alternative 2: Retain Full Benefits
2016	3.5%	2.0%	2.0%*	4.0%
2017	5.0%	3.5%	3.5%*	5.5%
2018	6.5%	5.0%	5.0%*	7.0%
2019	8.0%	7.5%	7.5%*	8.5%
2020	10.0%	10.0%	10.0%*	10.0%

*Standards for the Gasoline Only Case apply only to gasoline and gasoline substitute fuels only; diesel and diesel substitute fuels are exempted from any CI reductions under the alternative.

The primary goal of the LCFS proposal is to reduce the carbon intensity of transportation fuels in California by 10 percent by 2020, from a 2010 baseline. In addition, the LCFS is designed to diversify California's transportation fuel portfolio and to create a durable regulatory framework that can be exported to other jurisdictions. This is anticipated to result in multiple benefits, including reduced fuel price volatility and energy security benefits. Given the multiple goals of the LCFS proposal, staff evaluated alternatives on the basis of their ability to achieve the carbon intensity goals of the LCFS proposal, not solely by their impact on GHG emissions.

No alternative considered by the agency would be more effective in carrying out the purpose for which the regulation is proposed or would be as effective as or less burdensome to affected private persons than the proposed regulation. Additionally, staff has not identified any alternatives that would lessen any adverse impact on small businesses.

2. LCFS First Alternative: Gasoline Only Case

The California Trucking Association submitted this alternative to ARB as part of the Standardized Regulatory Impact Analysis (SRIA) process. This alternative proposes removing the diesel standard from the LCFS proposal so that the regulation would achieve a 10 percent reduction in carbon intensity by 2020 from a 2010 baseline for gasoline and gasoline substitute fuels only (rather than from the transportation sector as a whole). This alternative proposes no reduction in carbon intensity for diesel and diesel substitute fuels. Based on the assumed $100 credit price, this alternative is less stringent than the proposed regulation, as it would exempt nearly four billion gallons of transportation fuel from any CI-reduction requirements. As discussed below, however, implementation of this alternative would exert greater upward pressure on credit prices than would the proposed alternative.

Benefits

This alternative is less stringent than the proposed regulation because it only reduces carbon intensity of gasoline and gasoline substitute fuels, but does not reduce the carbon intensity of diesel and diesel substitute fuels. The emissions reduction benefits of this alternative are lower than those associated with the proposed regulation.

Costs

At the assumed LCFS credit price of $100, this alternative would reduce the direct cost of compliance compared with the LCFS proposal because regulated parties would not be required to purchase credits for diesel. Excluding diesel and diesel substitute fuels from carbon intensity reduction standards is anticipated to decrease the cumulative number of credits that regulated parties must generate or purchase for compliance in 2016 through 2020 by 12.7 million credits. This translates into an estimated cumulative direct cost of $5.1 billion for the years analyzed (2016 through 2020).

Table VII-16. Direct Cost of Compliance ($ mil)

LCFS credit price	2016	2017	2018	2019	2020	CUMULATIVE
$50	$254.82	$363.43	$468.42	$641.62	$805.96	$2,534.24
$100	$509.65	$726.85	$936.84	$1,283.23	$1,611.92	**$5,068.49**

While excluding diesel from carbon intensity requirements decreases the demand for credits, it removes an important cost-containment feature of the proposed LCFS. Credit fungibility between the gasoline and diesel standards is a large potential source of cost-savings in the program.[99] Removing diesel from the standard also excludes low-CI diesel substitute fuels such as renewable diesel, biodiesel, electricity, biomethane and natural gas from generating credits. These low-CI diesel alternatives are anticipated to contribute significantly to credit supply; removing these sources of credits is likely to result in upward pressure on credit prices. Staff analysis indicates that the demand for credits will outpace the supply of low-CI fuels available exclusively in the gasoline pool.

Economic Impacts

The REMI model is used to look at the economic impact of the alternative. For employment, REMI shows slightly larger negative growth for the alternative compared with the combined LCFS/ADF proposal. Growth in GSP is higher for the reference case as well, which is predominantly driven by increased output projected in the model, likely due to an increasing alternatives market.

Cost-Effectiveness

The cost of complying with the gasoline only alternative is lower than the cost of complying with the LCFS proposal. The costs are lower for the alternative because it exempts diesel and diesel substitute fuels—approximately 20 percent of the transportation fuel market—from any carbon intensity reduction requirements. Excluding diesel and diesel substitutes, however, precludes the alternative from meeting the carbon intensity reduction goals of the proposed regulation.

Reason for Rejection

The gas only alternative, which was proposed to ARB by the California Trucking Association through the SRIA process, proposes analyzing an alternative regulation wherein the 10 percent reduction in the carbon intensity of the transportation fuels sold in California by 2020, from a 2010 baseline, is achieved exclusively via the gasoline standard (i.e. diesel and diesel substitutes are excluded from any carbon intensity requirements).

This alternative would only achieve reductions in the carbon intensity of a portion of transportation fuels. Staff analysis of this proposed alternative indicates that the gas only alternative cannot achieve the same level of CI reduction as the proposed regulation due to constraints in the available supply of low-CI gasoline alternatives, and physical constraints such as the ethanol blendwall and limited penetration of electric and hydrogen vehicles and vehicles that can re-fuel with higher ethanol blends such as

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[99] The National Low Carbon Fuel Standard: Technical Analysis Report (2012)
http://nationallcfsproject.ucdavis.edu/files/pdf/2012-07-nlcfs-technical-analysis-report.pdf
Accessed 12.15.2014

E85. With highly optimistic assumptions regarding the availability of very-low CI ethanol and highly optimistic assumptions regarding the reduction in carbon intensity values, staff analysis indicates that the gas only alternative could deliver a 7.7 percent reduction in the carbon intensity of the transportation fuels sold in California by 2020, from a 2010 baseline. This alternative does not achieve the carbon intensity reduction goals of the proposed regulation.

By removing diesel and diesel substitute fuels from the CI reduction requirements of the LCFS, the gasoline only alternative decreases regulated parties' flexibility in meeting the standard. Due to the availability and favorable economics of diesel substitute fuels, staff analysis indicates that regulated parties are likely to employ a cost-minimizing compliance strategy of over-compliance with the diesel standard in order to generate credits at a lower cost than via gasoline substitutes. By reducing the availability of LCFS credits, this alternative is likely to create upward pressure on the price of LCFS credits, compared with the proposed regulation. If the demand for credits outpaces the supply of low-CI fuels, then regulated parties may drive up the price of credits in an attempt to out-bid their competitors. With insufficient supply, prices for credits may spike drastically, as has been observed in other environmental markets when credit supply is insufficient to meet demand. During the California electricity crisis in 2000, the South Coast RECLAIM market for Nitrous Oxides (NO_X) allowances experienced a supply shortage which resulted in allowance prices 66 times higher than the prior year's average – representing a 6,687-percent price increase. The price of RECLAIM allowances increased from an average price in 1999 of $1,827/ton to a high price of $124,000/ton in 2000.[100] The gas only alternative stresses the fuel market's ability to deliver the quantity of low-CI fuels demanded due to insufficient volumes of low-CI gasoline substitute fuels available and physical constraints that limit the amount of low-CI gasoline substitute fuels that can be consumed by California motorists.

As it is anticipated to achieve only 77 percent of the proposed regulation's goal of a 10 percent reduction in CI, the gas only alternative not only falls short of providing a feasible pathway to achieve the proposed regulation's carbon intensity goals, it is likely to deliver reduced benefits at an higher cost, compared with the proposed the regulation. The gas only alternative will provide upward pressure on the price of credits due to a tight supply of credits, increasing the price of credits—and therefore the cost of compliance—with little reduced environmental benefits as compared with the proposed regulation. An increased credit price associated with the gasoline only alternative would increase the cost of compliance for regulated parties, and increase any adverse impacts on small business and California individuals.

The gas only alternative results in carbon intensity reductions in the light duty fleet only, resulting in less incentive for innovation and investments in low-carbon fuel technologies than the proposed LCFS. This alternative also results in increased emissions of greenhouse gas emissions from the transportation sector, and increased emissions of

[100] US EPA 2006 "An overview of the Regional Clean Air Incentives Market (RECLAIM)" http://www.epa.gov/AIRMARKET/resource/docs/reclaimoverview.pdf

oxides of nitrogen and $PM_{2.5}$ when compared with the proposed regulation in all years analyzed.

3. LCFS Second Alternative: Maintain Benefits of Original CI Reduction Curve

This alternative proposes to maintain the cumulative GHG emission reduction benefits estimated for the 2010 LCFS such that in addition to achieving a 10 percent reduction in the carbon intensity of transportation fuels by 2020 from a 2010 baseline, GHG reductions in the program's early years are enhanced. Compared with the 2010 LCFS, the LCFS proposal is anticipated to result in slightly lower cumulative GHG emissions reductions benefits between 2010 and 2020 due to the Court decision to freeze the implementation of the 2010 LCFS at the 2013 carbon intensity standard during the re-adoption process, and because the LCFS proposal is less stringent than the 2010 standards from 2016 through 2018. To recover the lost GHG emissions reductions benefits, this alternative proposes setting the standards from 2016 through 2018 at more stringent levels than both the 2010 LCFS and the LCFS proposal. This alternative is more stringent than the LCFS proposal because it is requires more aggressive carbon intensity reductions from 2016 through 2018.

Table VII-17. Compliance Schedule: Maintain Benefits of Original CI Reduction Curve Case

Year	Gasoline and Substitutes (Percent Reduction)	Diesel and Substitutes (Percent Reduction)
2016	4.0%	4.0%
2017	5.5%	5.5%
2018	7.0%	7.0%
2019	8.5%	8.5%
2020	10.0%	10.0%

<u>Benefits</u>

This alternative is more stringent than the LCFS proposal because the annual carbon intensity standards are more stringent from 2016 through 2019. This increased stringency is associated with increased benefits. This alternative also reduces the emissions of $PM_{2.5}$ and NO_X compared with the LCFS proposal.

<u>Cost</u>

At the assumed LCFS credit price of $100, this alternative would increase the direct cost of compliance because conventional fuels will generate more deficits each year due to the increased stringency of the annual CI reductions required. This alternative is anticipated to increase the cumulative number of credits that regulated parties must generate or purchase for compliance. In addition this alternative will further strain the ability of regulated parties to secure sufficient volumes of lower CI fuels to meet their obligations. This approach increases the likelihood that a substantial number of parties may not be able to comply with their annual obligations, and could result in a lack of liquidity in the credit market. As a result credit prices would likely increase substantially above the level anticipated under the staff's proposal. This will further increase the cost of this option.. This translates into an estimated cumulative direct cost of $7.6 billion for the years analyzed (2016 through 2020).

Table VII-18. Direct Cost of Compliance ($ mil)

LCFS credit price	2016	2017	2018	2019	2020	CUMULATIVE
$50	$492.36	$628.25	$763.40	$894.84	$1,020.35	$3,799.20
$100	$984.73	$1,256.49	$1,526.80	$1,789.68	$2,040.70	**$7,598.41**

Economic Impacts

For comparison, the REMI model is used to look at the economic impact of the alternative. For employment, REMI shows varying differences in employment growth for the alternative compared with the combined LCFS/ADF proposal. The alternative leads to large reductions in growth in early years, likely due to the increased stringency of the regulation in early years. Similarly for GSP, the combined LCFS/ADF proposal yields higher GSP growth changes in early years, and the alternative backloads the GSP growth. While REMI shows differences in the results for the alternative, this is likely not a discernable change from the business-as-usual.

Cost-Effectiveness

The cost of complying with the original benefits alternative are higher than the cost of complying with the LCFS proposal because the alternative sets more stringent annual carbon intensity reduction requirements than the proposed regulation in the early years (2016 through 2018). The original CI case alternative satisfies the carbon intensity reduction goal of the LCFS proposal—10 percent reductions by 2020 from a 2010 baseline—but achieves these goals at an increased cost; as such, it is less cost-effective than the ARB proposal.

Reason for Rejection

Although this alternative satisfies the 10 percent CI reduction by 2020 goal of the LCFS proposal, staff rejects the maintain original benefits alternative because it is likely to achieve the CI reduction goal at a higher cost than the proposed regulation, increases the likelihood of non-compliance, and because it reduces regulatory flexibility. Because this alternative is anticipated to increase regulated parties' cumulative compliance obligation, it will increase the demand for LCFS credits. An increased demand for credits will create upward pressure on the price of LCFS credits, compared with the proposed regulation. An increased credit price associated with the original CI curve alternative would increase the cost of compliance for regulated parties, and increase any adverse impacts on small business and California individuals.

E. Justification for Adoption Regulations Different from Federal Regulations Contained in the Code of Federal Regulations

There are no current federal regulations comparable to the proposed regulation. The U.S. Environmental Protection Agency (U.S. EPA) has adopted its Renewable Fuel Standard (RFS2) regulation—title 40, Code of Federal Regulations (CFR), part 80, section 1100 et seq.—that mandates the blending of specific volumes of renewable fuels into gasoline and diesel sold in the U.S. to achieve a specified ratio for each year (i.e., the renewable fuel standard). As defined, “renewable fuels” under the RFS superficially resembles the list of transportation fuels subject to the LCFS. However, there are a number of reasons why the RFS is not comparable to the LCFS.

Congress adopted a renewable fuels standard in 2005 and strengthened it in December 2007 as part of the Energy Independence and Security Act. The RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be “advanced” biofuels and the other 15 billion gallons can be corn ethanol. The advanced biofuels are those that achieve at least 50 percent reduction from baseline lifecycle GHG emissions, with a subcategory required to meet a 60 percent reduction target. These reduction targets are based on lifecycle emissions, including emissions from land use changes.

The RFS2 volumetric mandate alone will not achieve the objectives of the LCFS. The RFS2 targets only biofuels and not other alternatives; therefore, the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels. In addition, the targets of 50 percent and 60 percent GHG reductions only establish minimum requirements for biofuels, without incentivizing continuous improvements. It forces biofuels into a small number of fixed categories, without incentivizing other innovations. Finally, it does not apply to existing and planned corn ethanol production plants from the GHG requirements, thus providing no incentive for reducing the carbon intensity from these fuels.

By contrast, the LCFS regulates all transportation fuels, including biofuels and non-biofuels, with a few narrow and specific exceptions. Thus, non-biofuels such as compressed natural gas, electricity, and hydrogen may play important roles in the LCFS program. In addition, the LCFS encourages much greater innovation than the federal program by providing important incentives to continuously improve the carbon intensity of biofuels and to deploy other fuels with very low carbon intensities.

If California were to rely solely on the RFS2 (i.e., the “No LCFS” alternative), the State would neither achieve the fuel carbon intensity goals called for in Executive Order S-01-07, nor stimulate the innovation needed to support future dramatic GHG reductions from the transportation sector. As noted in the Staff Report, RFS2, by itself, achieves only approximately 30 percent to 40 percent of the GHG reductions projected under the LCFS program. Because of these differences, the federal RFS regulation is complementary but not comparable to the staff's proposal.

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VIII. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION

In this chapter, we provide a summary and rationale for each of the sections in this regulation.

Section 95480. Purpose.

<u>Summary of Section 95480:</u>

Section 95480 briefly describes the purpose of the regulation.

<u>Rationale for Section 95480:</u>

This section is necessary to give a brief overview of the regulation.

Section 95481. Definitions and Acronyms.

<u>Summary of Section 95481:</u>

This section provides the most widely-used crucial definitions and terminology for understanding of the LCFS regulation. Revised and new definitions and acronyms are included.

<u>Rationale for Section 95481:</u>

This section is necessary to provide the definitions and acronyms used in the regulation. It will help minimize confusion associated with interpreting of the provisions of the LCFS regulation.

Section 95482. Fuels Subject to the Regulation

<u>Summary of Section 95482:</u>

This section outlines the fuels that are incorporated into the LCFS program. It provides a distinction between fuels that are to be regulated, those that may opt into the program, and fuels that are exempt from regulation.

<u>Rationale for Section 95482:</u>

This section delineates the fuels that have a CI potentially greater than the compliance standard for the program versus those that exclusively have a lower carbon intensity value through the 2020 compliance set forth in the LCFS program. Also, it outlines fuels that are not included in the LCFS program either because of their interstate use or non-transport application.

Section 95483. Regulated Parties

Summary of Subsection 95483(a):

This section focuses on gasoline, diesel and diesel fuel blends, where the initial designation of the regulated party status falls, and how it may travel downstream to other entities.

Rationale for Subsection 95483(a):

As a regulated fuel and one that has the potential to generate deficits because the fuels have a greater carbon intensity value than the compliance standard, the emphasis is for the producers and importers of the fuels to retain the compliance obligation unless otherwise stated in a product transfer document passing the obligation to a downstream entity.

Summary of Subsection 95483(b-c):

This section focuses on Oxygenates and Biomass-based diesel fuel blends and where the initial designation of the regulated party status falls and how it may be transferred downstream to other entities.

Rationale for Subsection 95483(b-c):

As these biofuels are likely to generate credits because they have a lesser carbon intensity than the compliance standard, the emphasis is for the obligation to remain with the fuel to benefit those that are producing/importing the product unless otherwise stated in a product transfer document passing the obligation to a downstream entity.

Summary of Subsection 95483(d):

This section focuses on Natural Gas (including compressed natural gas [CNG], liquefied natural gas [LNG], and LNG regassified to CNG [L-CNG]), where the initial designation of the regulated party status falls, and how it may travel downstream to other entities.

Rationale for Subsection 95483(d):

The regulation must include regulated party designation to make clear who is eligible to generate credits for a specific amount of CNG, LNG and L-CNG delivered to a natural gas vehicle.

As an opt-in fuel and one that is only capable of generating credits because the fuels have a lesser carbon intensity than the compliance standard, the emphasis is for the obligation to remain with the fuel to benefit those that are distributing the product unless otherwise stated in a product transfer document passing the obligation to a downstream entity. In the case of CNG, the dispenser of the fuel shall be granted the initial obligation as they are delivering the gas directly. For LNG and L-CNG, the producers of the LNG shall be granted the initial obligation as they have invested significantly in their facility to clean and generate the fuel. In scenarios involving biomethane, the initial obligation of that fuel shall be with the producer of the biomethane based fuel as they have the greatest investment in processing the fuel to vehicle or pipeline standards.

Summary of Subsection 95483(e):

Section 95483(e) designates parties who are eligible to opt into the regulation and generate credits for delivery of electricity for electric vehicle charging. This section further includes the requirements that regulated parties of electricity must satisfy to generate credits.

Rationale for Subsection 954839(e):

The regulation must include regulated party designation to make clear who is eligible to generate credits for a specific amount of electricity delivered to an electric vehicle.

Summary of Subsection 95483(f):

Section 95483(f) designates parties who are eligible to opt into the regulation and generate credits for hydrogen used as a transportation fuel. The section also defines the requirements that must be met in order for regulated party status to be transferred.

Rationale for Subsection 95483(f):

The regulation must include regulated party designation to make clear who is eligible to generate credits for a specific amount of hydrogen that will be used as a transportation fuel. When hydrogen fuel ownership is transferred, regulated party status may also be transferred. Requirements of transfer of regulated party status are necessary for the transfer to be valid under the regulation.

Section 95483.1 Opt-In Parties

Summary of Section 95483.1:

This section allows for entities that handle opt-in fuels, as well as entities that are in the fuel custody chain but located outside the jurisdiction of the state to opt in as well as opt out of the LCFS program. Depending on the fuel they are handling, they may be generating credits or deficits but would be under the same requirements as regulated parties to record and report for the LCFS program.

Rationale for Section 95483.1:

This section allows for entities that provide opt-in fuels to enter into the LCFS program and generate LCFS credits. It provides procedures for producers of fuels that are regulated but located outside the state of California to enter and generate the LCFS credits for their products that are being imported into the state. Opt-in parties will be regarded in the same fashion as regulated parties and will be required to follow the same standards. Lastly, the provisions allow regulated and opt-in parties to opt out of the LCFS program if they are no longer conducting fuel related business covered by the LCFS program.

Section 95483.2 Establishing a LCFS Reporting Tool Account

Summary of Section 95483.2:

This provision included requirements to create an LCFS Reporting Tool (LRT) organizational account. Registering organizations are to include a statement of basis of how they are subject to this regulation pursuant to section 95483 or 95483.1, along with various disclosure attestations. Additionally, this section details user roles and their subsequent responsibilities in terms of reporting and credit transfers capabilities.

Rationale for Section 95483.2:

The LRT has incorporated the credit banking and trading system (CBTS). This addition to house LCFS credits requires more security and information regarding account holders. The proposed language will clarify account user roles and conform the regulation to minor upgrades and required attestations staff would like to incorporate into the LRT-CBTS.

Many of the entities that are currently reporting into the LRT-CBTS will be able to continue using their user accounts. However, they will need to provide the specified user profile information within 90 days of regulation being adopted.

Section 95484. Average Carbon Intensity Requirements

Summary of Section 95484:

This section sets forth the annual carbon intensity requirements for gasoline, diesel, and the fuels that replace them. ARB staff is proposing to amend the these average carbon intensity requirements.

Rationale for Section 95484:

ARB is under a court order to maintain the average carbon intensity requirements for transportation gasoline and diesel fuel at the 2013 levels, which is 97.96 gCO_2e/MJ for gasoline and 97.05 gCO_2e/MJ for diesel, until the LCFS regulation is readopted. During the proposed re-adoption process, ARB staff has updated the methodology that calculates the carbon intensity values for all of the low-CI fuels, as well as the carbon intensities for both transportation gasoline and diesel fuel. These updates to the carbon intensity methodology result in values that are different from the values that currently exist in the regulation for transportation gasoline and diesel fuel. In addition to the methodology changes, the resumption of the existing carbon intensity reduction schedule if and when the LCFS is readopted would likely cause a disruption in the fuel market. The current carbon intensity reduction for gasoline and diesel is about one percent below the 2010 baseline levels, and resumption of the existing LCFS annual requirements would likely occur in 2016 at a 3.5 percent reduction. Staff believes this jump from 1.0 to 3.5 percent CI reduction would likely cause a disruption in the fuel market. To avoid a disruption in the fuel market, staff believes it would be more appropriate to change the carbon intensity requirements to ease the fuel market back into the low carbon fuel standards. In summary, as a result of the court-ordered carbon intensity freeze and the changes to the carbon intensity methodology calculation, staff is proposing to amend the average carbon intensity requirements for transportation gasoline and diesel fuel to account for the change in carbon intensity methodology calculation and to ease the fuel market back into the low carbon fuel standard.

Section 95485. Demonstrating Compliance

Summary of Section 95485(a):

This section specifies how a regulated party is expected to demonstrate compliance with the LCFS regulation by being able to retire sufficient credits to equal a compliance obligation at the time their annual report is submitted.

Rationale for Section 95485(a):

This section provides reporting parties with the information they need to remain in compliance. Reporting parties are informed of the basic criteria used to determine compliance.

Summary of Section 95485(b):

This section defines the parameters used in the Credit Balance and Compliance Obligation equations, along with providing the definitions of terms used in these two critical equations.

Rationale for Section 95485(b):

This section sets forth the basic equations important in the determination of compliance under LCFS. It provides necessary transparency of all the parameters included in these equations. Reporting parties have knowledge of all terms used in the LRT-CBTS to implement the compliance-related equations under LCFS.

Summary of Section 95485(c):

This section describes how a year-end credit clearance market will operate. The year-end credit clearance market will provide regulated parties with an additional compliance option, increase market certainty regarding maximum compliance costs, strengthen incentives to invest in and produce low-CI fuels, reduce the probability of price spikes, and contain potential negative impacts resulting from credit price spikes.

Rationale for Section 95485(c):

This section specifies how a year-end credit clearance market will provide regulated parties an additional path to compliance in the event that a shortage of credits renders them unable to otherwise meet their annual compliance obligation.

Section 95486. Generating and Calculating Credits and Deficits

Summary of Section 95486(a):

This section specifies when credits are generated and that they can be banked indefinitely. There is no retroactivity associated with credit generation unless expressly provided elsewhere in the regulation. Credit generation is subject to audit and review by ARB. Carryback credits can be purchased and applied to the preceding compliance period.

Rationale for Section 95486(a):

This section clarifies for the reporting parties the important limitations and restrictions within the LCFS related to credit generation. It identifies when and how credits are generated within LCFS, and it notifies reporting parties that the generation of credits is subject to audit and review. This section also provides important information regarding the acquisition of carryback credits for meeting a compliance obligation. It indicates that retroactive credit generation is limited, and in no event will include any periods prior to the quarter when a pathway applicant has submitted all information and taken all steps necessary for approval of a pathway or Fuel Transport Mode demonstration.

Summary of Section 95486(b):

This section identifies the parameters and equations used for calculating credits as part of the quarterly reporting process. It also contains the energy densities of LCFS fuels and blendstocks.

Rationale for Section 95486(b):

This section sets forth the basic equations important in the generation of credits and deficits under LCFS. It provides necessary transparency of all the parameters included in these equations. Reporting parties have knowledge of all terms used in the LCFS

Reporting Tool-Credit Banking and Trading System (LRT-CBTS) to implement the calculations for credit and deficit generation.

Summary of Section 95486(c):

This section specifies how frequently and when credits may be generated under LCFS.

Rationale for Section 95486(c):

Regulated parties will know when they can generate LCFS credits and that they are expected to reconcile their reporting with that of their business partners. This section clearly states the expectation that reporting parties are to reconcile their reporting prior to submitting quarterly reports and generating credits. This should have the added benefit of minimizing or eliminating many correction requests that would otherwise be submitted after the reporting deadlines have passed.

Section 95487. Credit Transactions

Summary of Section 95487:

This section specifies information regarding: 1) credit generation frequency; 2) credit acquisition, banking, borrowing, expiration, sale and transfer; and 3) the nature of credits.

Rationale for Section 95487:

Section 95487 is necessary to provide regulated parties with the information needed to understand when a regulated party may generate credits, and what a regulated party may or may not do to retain, acquire, transfer, import, and export credits for compliance.

Summary of Section 95487(a):

Section 95487(a) provides the following information on credits: 1) retaining credits without expiration, 2) credit acquisition or transfer, and 3) exporting credits outside LCFS.

Rationale for Section 95487(a):

Section 95487(a) is needed to define the basic characteristics and restrictions associated with LCFS credit retirement.

Summary of Section 95487(b):

Section 95487(b) provides the following: 1) requirements for the mandatory retirement of credits, 2) calculation of credits retired to deficits ratio, and 3) credit retirement hierarchy.

Rationale for Section 95487(b):

Section 95487(b) is needed to define how credits are retired at the end of the annual compliance period and the order in which accumulated credits will be retired to meet an annual compliance obligation.

Summary of Section 95487(c):

Section 95487(c) provides the list of requirements for: 1) the determination of total transferable credits, 2) the associated documentation to confirm a transfer has occurred, and 3) the purchase of a credit.

Rationale for Section 95487(c):

This section is needed to clarify when credits can be transferred and the process and confirmation of each transfer between regulated parties.

Summary of Section 95487(d):

Section 95487(d) provides for public disclosure of credit transfer activity and a description on the program summary information to be made available monthly to the public. The information will include credit and deficit generation by the LCFS program, as well as credit market activity.

Rationale for Section 95487(d):

The section 95487(d) is needed as this information will be disclosed to the public relaying market activity and overall health of the LCFS program, and this is needed as the regulation requires a certain level of transparency. The public and market participants will, therefore, receive routine, periodic releases of information on credit and deficit generation, as well as trading activity to allow the public an overview of LCFS progress.

Summary of Section 95487(e):

Section 95487(e) specifies practices related to credit transactions that would be prohibited under LCFS.

Rationale for Section 95487(e):

The section 95487(d) is needed to ensure a healthy LCFS market. It deters manipulative practices that can destabilize or compromise the LCFS credit market.

Section 95488. Obtaining and Using Fuel Pathways.

Summary of Section 95488:

The LCFS requires that regulated parties comply with annual limits on the aggregate carbon intensity (CI) of the fuels they sell. In order to determine compliance, transactions involving regulated fuels must be reported in the LRT-CBTS system. Each report must identify the CI of the fuel volume being reported, as well as the physical transport mode used for bringing that fuel volume to California for transportation use. Section 95488 identifies the entities that are required to obtain a CI under the regulation, and the procedures those entities must follow in order to obtain CIs for the fuels they sell. Before regulated parties can earn credits on the regulated fuels they sell, they must demonstrate the mode by which those fuels were transported to California, and obtain Executive Officer approval for that fuel transport mode demonstration. Section 95488 describes the procedures for obtaining a fuel transport mode approval.

Rationale for Section 95488:

Because the CI is a fundamental element of the LCFS, it is essential to clearly identify the entities that are required to obtain CIs, and how those entities go about obtaining CIs for the fuels they sell. Because the generation and sale of LCFS credits is also critical to the smooth functioning of the program, it is also necessary to describe how fuel providers obtain fuel transport mode approval.

Summary of Section 95488(a):

Section 95488(a) identifies the entities that must comply with the provisions in subsections (b), (c), (d), and (e). The separate requirements that apply to entities with CIs certified under the provisions of the previous LCFS regulation, and to entities seeking pathway certifications under the provisions of the proposed regulation, are described. Although all fuels must have a current, certified CI before transactions involving those fuels can be reported under the LCFS, CIs that were approved under the provisions of the prior LCFS regulation would remain in effect for specified periods of time under the provisions of the proposed regulation.

Rationale for Section 95488(a):

It is essential for the LCFS regulation to provide clear guidance to all categories of fuel providers on when they must obtain a fuel pathway CI under the provisions set forth in section 95488.

Summary of Section 95488(b):

For purposes of fuel pathway CI determination, transportation fuels are divided into two primary categories: Tier 1 and Tier 2. Section 95488(b) defines these two categories, and provides examples of the types of fuels that fall into each category.

Rationale for Section 95488(b):

Section 95488 provides providers of many conventionally produced first-generation fuels with an expedited CI application and approval process. Staff was able to draw on its relatively long history of experience with these fuels in designing this process. Newer fuels, with which staff has had less experience, are subject to an application and approval process that is similar to the one that has been in use since the LCFS first went into effect. Section 95488(b) provides fuel providers with the information they need to determine which application and approval process they must follow for the fuels they wish to sell in California.

Summary of Section 95488(c):

Section 95488(c) sets forth the procedures that providers of regulated fuels must follow in order to obtain a fuel pathway CI. Sections (c)(1) and (2) describe the uniform New Pathway Request Form (NPRF) that all fuel providers must complete. The NPRF consists of a secure, interactive, electronic form, available on the LRT-CBTS web site. It culminates with the creation of an inactive record for the proposed fuel pathway in the LRT-CBTS system, and a final determination concerning the Tier into which the proposed fuel falls. For Tier 2 fuels, this determination includes a finding on whether a Tier 2 Lookup Table, a Method 1, or a Method 2 pathway may be pursued. Sections (c)(3) and (4) describe in detail the application requirements that apply to each of these application types. Section (5) describes how completed applications are evaluated and either certified or denied. Following pathway certification, the inactive LRT-CBTS record created when the NPRF is submitted is activated. Section (6) describes what information a certified CI conveys about the fuel with which it is associated, and when certified CIs can and cannot be associated with volumes of fuel sold in California. Section (7) describes the records that holders of certified fuel pathway CIs must retain and be prepared to produce upon request from the Executive Officer.

Rationale for Section 95488(c):

Because all regulated fuels must obtain a CI, it is essential to provide fuel pathway applicants with a clear, comprehensive description of the requirements to which they are subject, both during the application process, and after a proposed fuel pathway is certified.

Summary of Section 95488(d):

Section 95488(d) covers the procedures that must be followed when the following two special circumstances arises:

1. A fuel provider is seeking to sell a volume of fuel which has no CI associated with it. Section (d) provides a table of temporary default CIs that can be used to report transactions involving such fuel.
2. A fuel provider wishes to apply for a fuel pathway CI, but does not have the required two-year record of energy consumption by the fuel production plant. This Section provides for a conditional approval while the producer continues to submit energy consumption data until staff is in possession of the required two-year record.

Rationale for Section 95488(d):

Section 95488(d) allows the LCFS regulation to accommodate two specific sets of circumstances that have occurred, and are expected to continue to occur. These are fuel sales involving fuel volumes that have no pathway CIs, and applications covering fuel production operations that have not accumulated energy consumption records covering a full two years.

Summary of Section 95488(e):

After a CI is certified for a fuel pathway, sellers of that fuel in California cannot generate credits under the LCFS until the regulated party reporting that fuel has submitted evidence of a fueltransport mode for that fuel, and that submittal has been approved by the Executive Officer. Evidence of Fuel Transport Mode consists of records showing the combination of actual fuel delivery methods, such as truck routes, rail lines, and gas/liquid pipelines through which the regulated party expects the fuel to be transported under contract from the entity that generated or produced the fuel to the fuel blender, producer, importer, or provider in California. Section 95488(e) describes the Evidence of Fuel Transport Mode submittal procedures and approval process.

Rationale for Section 95488(e):

Only fuels consumed in California must comply with the Low Carbon Fuel Standard. It is essential, therefore, that fuel pathway certifications are only issued for fuels that are actually transported to and sold in California. It is particularly important that transactions involving low-CI fuels that are not transported to California do not get reported in the LRT-CBTS system. If this were to occur, fuels not sold in California could earn and sell LCFS credits.

Section 95489. Provisions for Petroleum-Based Fuels.

Summary of Section 95489:

This section provides the following information: 1) calculation of base and incremental deficits for CARBOB and diesel fuels, 2) requirements for adding incremental deficits to a regulated party's compliance obligation, 3) process for generating credit for producing crude oil using innovative methods that reduce greenhouse gas emissions, 4) special requirements for Low-Complexity/Low-Energy-Use refineries, and 5) process for generating credit for refinery investment projects that reduce greenhouse gas emissions.

Rationale for Section 95489:

This section is necessary to provide requirements for the calculation of deficits for CARBOB and diesel fuels. The section is also necessary to specify requirements for crude oil producers and refineries to generate credits for projects that reduce greenhouse gas emissions associated with producing and refining crude oil.

Summary of Section 95489(b):

This section provides the base and incremental deficit calculations for CARBOB and diesel fuel.

Rationale for Section 95489(b):

This section is necessary to specify and clearly describe the equations to be used to calculate both base and incremental deficits for CARBOB and diesel fuels.

Summary of Section 95489(c):

This section provides requirements for determining the annual crude average carbon intensity and adding incremental deficits to a regulated party's compliance obligation. Staff proposes to add requirements for new crudes that are not listed in the Crude Lookup Table. These requirements include a process for adding the new crude to the lookup table and the use of a default carbon intensity until the crude is added to the lookup table.

Rationale for Section 95489(c):

The section is necessary to clearly describe the process used to calculate the annual crude average carbon intensity and to specify when incremental deficits become effective and are to be added to the regulated party's compliance obligation. The current regulation does not include a process for adding crudes to the Crude Lookup Table, so staff is proposing additional language to clearly describe this process.

Summary of Section 95489(d):

This section defines innovative crude oil production methods and describes the process by which credits may be generated for producing crude using these innovative methods. Staff is proposing to add the following to the list of allowable innovative methods, which currently includes solar steam generation and CCS: 1) solar-based heat generation and 2) solar and wind electricity generation. Staff also proposes to allow crude oil producers to opt-in as a LCFS regulated party and generate credit for producing crude using innovative methods. Finally, staff is proposing to simplify the credit calculation and application process for solar steam generation and solar or wind electricity generation.

Rationale for Section 95489(d):

The carbon intensity values for CARBOB and diesel include a single “California average” carbon intensity for crude oil production. This section is necessary to allow for LCFS credit to be generated for crude oil supplied to California that is produced using innovative methods that reduce greenhouse gas emissions. Staff’s proposed revisions are necessary to acknowledge additional innovative methods currently being considered by oil producers, provide a standardized and more streamlined application for three innovative methods, and provide a more direct link between the financial risk and reward for implementing an innovative method.

Summary of Section 95489(e)(1):

Section 95489(e)(1) specifies the calculation methodologies for classification as a low-complexity/low-energy-use refinery.

Rationale for Section 95489(e)(1):

This section is necessary to clearly outline the calculation methodologies for a refinery to be classified as a low-complexity/low-energy-use refinery.

Summary of Section 95489(e)(2):

Section 95489(e)(2) specifies reporting requirements for low-complexity/low-energy-use refinery.

Rationale for Section 95489(e)(2):

This section is necessary to outline additional reporting requirements for low-complexity/low-energy-use refineries. These reporting requirements will be used to determine the total volume of CARBOB and CARB diesel that is eligible for the 5 gCO_2/MJ credit.

Summary of Section 95489(e)(3):

Section 95489(e)(4) specifies the calculation methodology for calculating credits and deficits in the compliance tool for low-complexity/low-energy-use refineries.

Rationale for Section 95489(e)(3):

This section is necessary to clearly outline the calculation methodology for handling the low-complexity/low-energy-use credit in the compliance tool.

Summary of Section 95489(e)(4):

This proposed revision allows for a low-complexity/low-energy-use refinery to opt for refinery-specific accounting for incremental deficits in lieu of the California average accounting and fully describes the calculation of incremental deficits under the refiner-specific option.

Rationale for Section 95489(e)(4):

Low-complexity/low-energy-use refineries process small volumes of crude relative to the larger refineries. They are not able to affect the annual crude average carbon intensity, and, therefore, under the California average provision, are at the mercy of crude purchasing decisions made by the larger refineries. Staff's proposed revision is necessary to allow the low-complexity/low-energy-use refinery to option of controlling the incremental deficit incurred by CARBOB and diesel derived from crudes they purchase.

Summary of Section 95489(f)(1):

Section 95489(f)(1) specifies the general requirements for a refinery to receive a credit for a GHG emissions reduction project.

Rationale for Section 95489(f)(1):

This section is necessary to clearly outline the implementation date and carbon intensity change threshold. This section is necessary to outline the calculation methodology for generating credits.

Summary of Section 95489(f)(2):

Section 95489(f)(2) specifies the calculation methodology of a refinery investment credit.

Rationale for Section 95489(f)(2):

This section is necessary to outline the calculation methodology for generating credits.

Summary of Section 95489(f)(3):

Section 95489(f)(3) specifies the requirements for a refinery to submit an application to the Executive Officer for approval of a refinery investment credit.

Rationale for Section 95489(f)(3):

This section is necessary to clearly outline all the documentation that must be included in a refinery's application for a refinery investment credit.

Summary of Section 95489(f)(4):

Section 95489(f)(4) specifies the requirements for the approval of the application for the refinery investment credit.

Rationale for Section 95489(f)(4):

This section is necessary to clearly outline the approval process for a refinery investment credit.

Summary of Section 95489(f)(5):

Section 95489(f)(5) specifies the requirements for the annual review of the refinery investment credit.

Rationale for Section 95489(f)(5):

This section is necessary to clearly outline that the refinery investment will be reviewed annually. This section is necessary to clearly outline when the refinery investment credit will be adjusted if the CI of a refinery's fuels change.

Summary of Section 95489(f)(6):

Section 95489(f)(6) specifies the recordkeeping requirements for the refinery investment credit.

Rationale for Section 95489(f)(6):

This section is necessary to clearly outline the recordkeeping requirements for refineries that have approved refinery investment credits.

Section 95490. Requirements for Multimedia Evaluation.

Summary of Section 95490(a):

Subsection (a) states that regulated parties must not sell, supply, distribute, import, offer for sale, or offer for use in California a regulated fuel unless a multimedia evaluation has been conducted and approved by the Executive Officer.

Rationale for Section 95490(a):

Subsection (a) is needed to specify pre-sale approval requirements for regulated fuels that are subject to a multimedia assessment.

Summary of Section 95490(b):

Subsection (b)(1) states that the Executive Officer shall not approve a multimedia evaluation unless the evaluation has undergone the review and approval process specified in H&S section 43830.8.

Subsection (b)(2) states that all multimedia evaluations shall be evaluated in accordance with the California Environmental Protection Agency (Cal/EPA) guidance document entitled, *Guidance Document and Recommendations on the Types of Scientific Information Submitted by Recommendations on the Types of Scientific Information Submitted by Applicants for California Fuels Environmental Multimedia Evaluations* (Multimedia Evaluation Guidance Document).

Rationale for Section 95490(b):

Subsection (b)(1) is needed to specify the requirements in H&S section 43830.8 that must be met before Executive Officer approval of a multimedia evaluation.

Subsection (b)(2) is needed to specify that all multimedia evaluations will also be evaluated in accordance to the Multimedia Evaluation Guidance Document.

Summary of Section 95490(c):

Section 95490(c) specifies the exemptions in which the requirements of this section 95490 do not apply.

Subsection 95490(c)(1) specifies that the requirements of this section 95490 do not apply to a regulated fuel if the fuel is subject to a proposed ARB regulation that establishes new or amends existing fuel specifications, and for which the CEPC has conclusively determined that the regulation will not have any significant adverse impact on public health or the environment.

Subsection 95490(c)(2) specifies that the requirements of this section 95490 do not apply to a fuel that is subject to an ARB-adopted fuel specification, including California reformulated gasoline (CaRFG), diesel, E85, E10, and CNG.

Subsection 95490(c)(3) specifies that the requirements of this section 95490 do not apply to a fuel that is subject to the Division of Measurement Standards' Engine Fuels Standards, but is not subject to ARB-adopted fuel specifications. These fuels include biomass diesel and electricity.

Rationale for Section 95490(c):

Subsection (c) is needed to specify the exemptions in which the requirements do not apply.

Subsection (c)(1) is needed to specify that the requirements of this section 95490 do not apply to fuels subject to a proposed ARB regulation, and for which the regulation is determined to not have any significant adverse impact on public health or the environment by the CEPC.

Subsection (c)(2) is needed to specify that the requirements of this section 95490 do not apply to fuels subject to an existing ARB-adopted fuel specification.

Subsection (c)(3) is needed to specify that the requirements of this section 95490 do not apply to fuels subject to the Division of Measurement Standards' Engine Fuels Standards, but not subject to ARB-adopted fuel specifications.

Section 95491. Reporting and Recordkeeping.

Summary of Section 95491.

This section specifies information regarding: 1) reporting frequency, online reporting, reporting requirements, specific fuel based reporting, requirements for annual compliance reporting, 2) recordkeeping, auditing, and documenting fuel transfers.

Rationale for Section 95491:

Section 95491 is necessary to provide regulated parties with the information needed for reporting and recordkeeping and the related requirements.

Summary of Section 95491(a):

Section 95491(a) provides the following information on reporting: 1) reporting frequency, 2) online reporting, 3) quarterly and annual compliance reporting, 4) general and specific reporting requirements (quarterly and annual), 5) market crude oil names (MCONs), natural gas, hydrogen and electricity reporting requirements, and 6) correcting previously submitted reports.

Rationale for Section 95491(a):

Section 95491(a) is needed to provide regulated parties with the reporting requirements that must be met under LCFS. This section is necessary to ensure there is a promulgated schedule for reporting with specified deadlines and to provide requirements and instruction on what, where, and how to report, including reporting MCON, natural gas, hydrogen and electricity reporting. The process for making corrections to previously submitted reports also needs to be defined.

Summary of Section 95491(b):

Section 95491(b) provides the duration of the record retention period for maintaining report-related documentation expected to be provided during an audit.

Rationale for Section 95491(b):

Section 95491(b) is needed to ensure that regulated parties know the period of time for which they need to retain records associated with LCFS reporting. It defines the specific documentation that needs be retained.

Summary of Section 95491(c):

Section 95491(c) provides the information that must accompany an LCFS obligated fuel if the obligation is transferred to a transferee/buyer or if it is retained by the transferor/seller.

Rationale for Section 95491(c):

Section 95491(c) is needed in order to clarify what information is required to be documented as part of a product transfer document. Product transfer documents will be audited by ARB to ensure that reporting of fuel transactions can be substantiated. This may occur at any time during the five-year retention period.

Summary of Section 95491(d):

Section 95491(d) provides the clarification for regulated parties that all data and calculations submitted are subject to verification by ARB.

Rationale for Section 95491(d):

Section 95491(d) is needed by regulated parties as they must be able to attest to the accuracy of the data submitted and that data is subject to verification for ensuring validity of credits they generate.

Summary of Section 95491(e):

Section 95491(e) makes it clear that ARB Executive Officer has authority to access records for audit purposes.

Rationale for Section 95491(e):

Section 95491(e) is needed so that reporting parties are informed of the extent of ARB authority to access facilities necessary to complete auditing activities and the expectations regarding timeliness of access.

Section 95492. Enforcement Protocols

Summary of Section 95492:

This section allows the Executive Officer to enter into written agreement with a reporting party on the topics of recordkeeping, reporting, or demonstration of fuel transport mode requirements detailed in section 95486 so that they can lawfully meet the requirements in the regulation. If the reporting party does not adhere to the conditions in the agreement, then it is in violation of this regulation and subject to all available penalties under the law.

Rationale for Section 95492:

When a company's specific circumstances do not align with a regulatory requirement such that compliance with the regulation's exact terms would cause undue hardship, the company may request that the Executive Officer approve an alternative means of meeting the requirement, provided that the alternative means is set forth in a written agreement that can be enforced as if it were part of the regulation. Such protocol agreements have functioned well in other ARB programs, reducing regulatory impacts or costs for individual businesses.

Section 95493. Jurisdiction

Summary of Section 95493:

This section specifies the actions which establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California for regulated parties, reporting parties, entities submitting fuel pathway certifications, and credit brokers.

Rationale of Section 95493:

This section is necessary to ensure that the regulated parties and those that are voluntarily participating in this regulation are subject to the jurisdiction of the State of California courts for enforcement purposes.

Section 95494. Violations.

Summary of Section 95494:

This section sets out a non-inclusive list of violations and associated penalties, with references to applicable H&S statutes. Additionally, it defines a violation for not meeting the annual compliance obligation in terms of the number of deficits, each one of which constitutes a violation subject to a penalty.

Rationale for Section 95494:

The proposal contains enforcement provisions defining violations to provide clear notice of potential penalties, and to allow for penalties that are fair, consistent, and effective at deterring noncompliance.

Section 95495. Authority to Suspend, Revoke, or Modify

Summary of Section 95495:

This regulatory language explicitly states that the Executive Officer has the authority to suspend, revoke, or place restrictions (put credits on hold) on an LRT-CBTS account when violations have occurred or are being investigated. Additionally, this section includes a notification procedure to alert all regulated parties likely to be affected by actions to suspend, revoke or modify credits, pathways or accounts.

Rationale for Section 95495:

This provision is important to ensure that transactions cannot occur without a resolution to an issue being investigated. Additionally, this procedure will decrease the number of LCFS credit balances affected by the sale of credits that might later be invalidated.

Section 95496. Regulation Review.

Summary of Section 95496:

Section 95496 allows the Executive Officer to review the implementation of the LCFS program. It describes the timing andminimum scope of the review.

Rationale for Section 95496:

This section allows stakeholders to provide input to ARB regarding the implementation of the LCFS program.

Section 95497. Severability.

Summary of Section 95497:

Section 95497 provides that if any one provision is deemed invalid by a court, the remaining provisions remain in effect.

Rationale for Section 95497:

This section is necessary because it ensures that if a provision in the subarticle is ruled to be illegal or unconstitutional, the remaining regulatory provisions remain intact.

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IX. PUBLIC PROCESS FOR DEVELOPMENT OF PROPOSED ACTION

In this chapter, ARB staff provides a brief overview of the regulatory process and actions taken to develop the staff's proposed LCFS regulation, which includes revisions and updates to the 2010 LCFS regulation.

During the rulemaking process, ARB staff conducted 20 public workshops and numerous meetings with individual stakeholders to discuss the proposed LCFS regulation, including revisions and updates to the 2010 LCFS regulation, and address various concerns that were raised. ARB staff provided ample opportunities for stakeholders to provide feedback on and present information about the proposed re-adoption. Meeting attendees included transportation fuel producers, providers and importers, environmental groups, academia, and other interested persons. These individuals participated both by reviewing draft regulations and supporting documentation, providing data, and participating in workgroup meetings.

Table IX-1 lists dates for the meetings that were held to apprise the public about the proposed re-adoption and other related developments.

Table IX-1. LCFS Workshops

Meeting	Date	Location	Time
LCFS Public Workshops			
First 2013 Public Workshop	March 5, 2013	Cal/EPA Building, Sierra Hearing Room	9:00 a.m.
Second 2013 Public Workshop	May 24, 2013	Cal/EPA Building, Sierra Hearing Room	9:30 a.m.
First 2014 Public Workshop	March 11, 2014	Cal/EPA Building, Sierra Hearing Room	9:00 a.m.
Second 2014 Public Workshop and Related Environmental Analysis	May 30, 2014	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Third 2014 Public Workshop	November 13, 2014	Cal/EPA Building, Byron Sher Auditorium	9:00 a.m.
Topic-Specific Public Workshops			
OPGEE Revisions	March 5, 2013	Cal/EPA Building, Sierra Hearing Room	1:30 p.m.
Electricity Provisions and Regulatory Clean-Up	April 3, 2013	Cal/EPA Building, Coastal Hearing Room	9:30 a.m.
Refinery-Specific Incremental Deficit Option	June 20, 2013	Cal/EPA Building, Sierra Hearing Room	9:30 a.m.
Low-Complexity/Low-Energy-Use Refinery Provisions	June 20, 2014	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
Indirect Land Use Change	March 11, 2014	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.

Meeting	Date	Location	Time
Fuel Pathways/Producer Facility Registration	April 4, 2014	Cal/EPA Building, Sierra Hearing Room	9:00 a.m.
Cost Containment Provisions	April 4, 2014	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
Refinery and Crude Oil Provisions	April 18, 2014	Cal/EPA Building, Sierra Hearing Room	9:00 a.m.
Reporting and Enforcement Provisions	April 18, 2014	Cal/EPA Building, Sierra Hearing Room	1:00 p.m.
Refinery and Crude Oil Provisions and Regulated Party Provisions	July 10, 2014	Cal/EPA Building, Sierra Hearing Room	9:00 a.m.
Updates to the GREET2.0 Model	August 22, 2014	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Fuel Availability	September 25, 2014	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Indirect Land Use Change/Refinery Investment Provisions	September 29, 2014	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.
Compliance Scenarios/Cost Containment Provisions	October 27, 2014	Cal/EPA Building, Byron Sher Auditorium	9:00 a.m.
Indirect Land Use Change	November 20, 2014	Cal/EPA Building, Coastal Hearing Room	9:00 a.m.

Over 9,000 individuals or companies were notified for each workshop/hearing. Notices for the public meetings were posted to ARB's LCFS public meetings/workshop web pages and e-mailed to subscribers of the "LCFS" and "FUELS" list serves. The public workshops were webcast live whenever possible. In addition, ARB staff participated in numerous stakeholder meetings, presenting information on the implementation of the proposed re-adoption of the LCFS.

During the original 2009 rulemaking process, staff created the LCFS informational portal web site[101] to increase public participation and enhance the information flow between ARB staff and interested parties. Since that time, staff has consistently made available online materials related to this rulemaking, including meeting presentations and draft regulatory language. The web site has also provided background information on the LCFS, workshop and meeting notices and materials; other GHG related information; and links to other web sites with related information. The web site also includes letters from stakeholders in response to ARB workshop regarding the LCFS re-adoption.[102]

Beyond the public and workgroup meetings noted above, staff's outreach efforts also included numerous personal contacts via telephone, electronic mail, regular mail, and

[101] LCFS informational portal web site: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm
[102] All letters are posted at the following LCFS web site: http://www.arb.ca.gov/fuels/lcfs/regamend14/2014lcfsletters.htm

individual meetings with interested parties. These contacts included regulated parties, transportation fuel producers, providers, marketers, importers, environmental, community, public health organizations, and other entities.

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