State of California
AIR RESOURCES BOARD

Notice of Public Availability of Modified Text and Availability of Additional Documents and Information

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

Public Hearing Date: April 27, 2018
Public Availability Date: June 20, 2018
Deadline for Public Comment: July 5, 2018

At its April 27, 2018, public hearing, the California Air Resources Board (CARB or Board) considered staff's proposed amendments to title 17, California Code of Regulations (CCR), proposed sections 95480 to 95503 and to section 2293.6 and Appendix 1 in CCR title 13, chapter 5, article 3, subarticle 2. These sections respectively comprise the Low Carbon Fuel Standard (LCFS) Regulation and part of the Regulation on Commercialization of Alternative Diesel Fuels (ADF Regulation). The Board did not take action on the proposal at the April 2018 Board hearing.

The Board directed the Executive Officer to determine if additional conforming modifications to the regulation were appropriate and to make any proposed modified regulatory language available for public comment, with any additional supporting documents and information, for a period of at least 15 days in accordance with Government Code section 11346.8. The Board further directed the Executive Officer to consider written comments submitted during the public review period and make any further modifications that are appropriate available for public comment for at least 15 days. The Executive Officer was directed to evaluate all comments received during the public comment periods, including comments raising significant environmental issues, and prepare written responses to such comments as required by CARB's certified regulations at California Code of Regulations, title 17, sections 60000-60007 and Government Code section 11346.9(a). The Executive Officer was further directed to present to the Board, at a subsequently scheduled public hearing, staff's written responses to environmental comments and the final environmental analysis for consideration for approval, along with the finalized amendments for consideration for adoption.

The resolution and all regulatory documents for this rulemaking are available online at the following CARB website:

https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

The text of the modified regulatory language is shown in Attachment A. The originally proposed regulatory language is shown in ~~strikethrough~~ to indicate deletions and underline to indicate additions. New deletions and additions to the proposed language that are made public with this notice are shown in ~~double strikethrough~~ and double underline format, respectively.

In the Final Statement of Reasons, staff will respond to all comments received on the record during the comment periods. The Administrative Procedure Act requires that staff respond to comments received regarding all noticed changes. Therefore, staff will only address comments received during this 15-day comment period that are responsive to this notice, documents added to the record, or the changes detailed in attachments to this notice.

Summary of Proposed Modifications

Staff's proposed new section 95486.2, title 17, and modifications to the originally proposed amendments to sections 95481, 95482, 95483, 95483.2, 95484, 95486, 95486.1, 95487, 95488.1, 95488.3, 95488.5, 95488.6, 95488.7, 95488.8, 95488.9, 95488.10, 95489, 95490, 95491, 95491.1, 95500, 95501, 95502, and 95503, title 17, and section 2293.6, title 13, CCR are summarized below and attached to this notice as Attachment A.

Staff's proposed modifications to the originally proposed Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, which is incorporated by reference by the proposed amendments, are summarized below and attached to this notice as Attachment B.

Staff's updates to the original CA-GREET3.0 Technical Support Documentation are summarized below and attached to this notice as Attachment C. Parts C-2 and C-3 of Attachment C are proposed to be incorporated by reference by the proposed amendments.

Supplemental information to support proposed Energy Economy Ratio (EER) values for two newly proposed electric vehicle applications is attached to this notice as Attachment D.

The updated Crude Lookup Table values are documented in Attachment E to this notice.

All materials that were posted in conjunction with a June 11, 2018, public workshop are available at the LCFS meetings web page and are attached to this notice as Attachment F.

The following summary does not include all modifications to correct typographical or grammatical errors, changes in numbering or formatting, or non-substantive revisions made to improve clarity. For a complete account of all modifications in the originally proposed regulatory amendments, refer to the double underline and double strikeout sections of the regulation(s) in Attachment A.

A. Modifications to Section 95481. Definitions and Acronyms.

1. In section 95481(a), staff proposes to add, delete, or modify a number of definitions and acronyms, including but not limited to: "Biomass," "Biomass-based Diesel," "Biomethane," "Electric Cargo Handling Equipment (eCHE)," "Electric Auxiliary Engine for Ocean-going Vessel (eOGV)," "Electric Transport Refrigeration Units (eTRUs)," "Diesel Fuel Blend," "Green Tariff," "Renewable Hydrogen," "Multi-family Residence," "Direct Current Fast Charging," and "Station Operational Status System (SOSS)."

2. In section 95481(a), staff proposes to remove the ASTM Specifications that were previously incorporated by reference in the definitions of fuels. Staff does not believe the ASTM Specifications are needed to clearly identify the fuel type, and their inclusion may result in unnecessary duplication of requirements. The removal of ASTM specifications also avoids potential confusion from referencing outdated specifications, which was an issue raised by stakeholders. Staff proposes this change to address those comments. The following ASTM Specifications are proposed to be removed from the list of materials incorporated by reference (the fuels definition they pertained to is provided in parentheticals):

    a. ASTM Specification D910-17 (2017), Standard Specification for Aviation Gasolines (definition for "Aviation Gasoline")
    b. ASTM D975-14a, (2014), Specification for Diesel Fuel Oils (definition for "Biomass-based Diesel")
    c. ASTM D1655-17 (2017), Standard Specification for Aviation Turbine Fuels (definition for "Conventional Jet Fuel")
    d. ASTM D975-14a, (2014), Standard Specification for Diesel Fuel Oils (definition for "Diesel Fuel Blend")
    e. ASTM D4806-14 (2014), Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel (definition for "E100," also knows as "Denatured Fuel Ethanol")
    f. ASTM D1835-16, (2016), Standard Specification for Liquefied Petroleum (LP) Gases (definition for "Renewable Propane")

3. In section 95481(b) and throughout the modified regulation order, staff proposes to change the name of the provisions that incentivize electric vehicle charging behaviors and electrolytic hydrogen production to coincide with periods of likely curtailment of renewable electricity. These provisions were originally referred to as "time-of-use," which may create confusion with utility time-of-use rate structures. Staff proposes to use the term "smart charging" and "smart electrolysis" to refer to these provisions for electricity and hydrogen, respectively.

B. Modifications to Section 95482. Fuels Subject to Regulation.

1. In section 95482(c)(4), staff is proposing an exemption for small fossil CNG and fossil propane fueling stations from LCFS requirements until the respective fuel becomes a deficit generating fuel. Stakeholders raised concerns that small station operators would find it challenging to participate in the LCFS; to address this concern, staff proposes this exemption which allows small CNG and propane station owners to voluntarily opt-in for credit generation.

   Staff has determined the year in which use of these fuels would first begin to generate deficits, using each fuel's CI value from Table 7-1, the EER of 0.9 from Table 5, and the proposed benchmarks for diesel substitutes in Table 2. The results are shown in the table below. The benchmarks and EER values, corresponding to the use of the fuel as a diesel substitute in heavy-duty/off-road applications, were selected to determine the earliest year that each fuel could generate deficits; staff proposes that the small station exemption expire in those years, even though the total quantity of each fuel reported may result in net credits for the station (if the credits generated by the quantity dispensed to light/medium-duty applications at a given station exceed the quantity of deficits generated by fuel dispensed to heavy-duty/off-road applications).

Fuel:	**Fossil CNG**	**Fossil Propane**
Lookup Table Carbon Intensity (CI, gCO_2e/MJ)	79.21	83.65
Energy Economy Ratio (EER)	0.9	0.9
EER-adjusted CI (Heavy-duty/ Off-road Use)	88.01	92.94
Credits for 50,000 GGE in 2019 (MT)	32	6
First Year of Deficit Generation	2024	2021
Deficits for 50,000 GGE in First Year of Deficit Generation (MT)	1	7

   Upon analyzing the data reported to the program and consulting with stakeholders, CARB staff is proposing an exemption threshold of 50,000 GGE per year. Staff believes that the potential benefit of reporting and generating credits for 50,000 GGE or more of CNG or propane in the LCFS would most likely outweigh the cost of participating in the program. Currently, many CNG stations dispensing more than 50,000 GGE per year are participating in the program, as are a few below this threshold.

C. Modifications to Section 95483. Fuel Reporting Entities.

1. In section 95483(a)(3), staff proposes to extend the two quarter transfer period for the credit or deficit generator status to another entity to three quarters. This means, for example, that if the ownership of the fuel with obligation is received, produced or purchased in Q1, then it can be transferred with obligation (the ability to generate credits or deficits) no later than the end of Q3. After that, ownership of the fuel can still be transferred without obligation (meaning, without the ability to generate the associated credits by the buyer), and the resulting credits or deficits would be retained by the upstream entity, which can transfer any credits separately in the LRT-CBTS.

2. In section 95483(c)(1) and (2), staff proposes to differentiate between entities claiming credits for charging at single-family and multi-family residences. Because charging equipment at multi-family residences are more similar to non-residential charging than to charging at single-family residences, the proposed changes would allow the owner of the Fueling Supply Equipment (FSE) to receive first priority to claim credits.

3. In section 95483(c)(1)(B) staff proposes to establish a hierarchy for claims to incremental credits for charging at single-family residences. This hierarchy would be used to resolve situations of multiple claims of incremental credit for the same FSE.

   Load Serving Entities (e.g., utilities and community choice aggregators) with metered charging data are assigned first priority because they have the clearest ability to quantify the supply of low carbon electricity to the customer under existing California energy policy, including through green tariff programs. These entities also have the knowledge and ability to ensure electric charging supports the needs of the electric grid, including through avoiding curtailment of renewables through smart charging.

   Automakers receive second priority as they can provide detailed telematics information where separate meters on charging equipment are unavailable, they also have the ability to procure green electricity for owners of their vehicles through the book-and-claim accounting provisions, and they have demonstrated an interest in dispatching electric vehicle load to serve grid needs.

4. In section 95483(c)(1)(B), staff proposes to establish a hierarchy for claims to incremental credits for non-residential charging. Similar to how gaseous fuel is treated, staff proposes that the owner of the FSE be eligible to generate the credits but have the option to assign that right to other parties contractually if they choose to do so.

5. In section 95483(c)(5), new reporting entities are added for two new vehicle applications using electricity: cargo handling equipment and auxiliary power engines of ocean going vessels at berth. These additions are necessary to identify the entities eligible to report quantities of fuel used in the new vehicle applications.

6. In section 95483(c)(7), staff proposes to identify the eligible reporting entity for electricity applications not specifically addressed in 95483(c)(1) through (6).

D. Modifications to Section 95483.2. LCFS Data Management System.

1. In section 95483.2(b)(8), Fueling Supply Equipment (FSE) registration requirements are added to clarify registration for various types of FSE and to cover two new vehicle applications using electricity: cargo handling equipment and auxiliary power engines of ocean going vessels at-berth. These additions are necessary to enable the new vehicle applications to register FSE for reporting quantities of fuel for credit generation, and prevent any potential double claiming of the credits from the same equipment.

E. Modifications to Section 95484. Annual Carbon Intensity Benchmarks.

1. In section 95484(b) through (d), all carbon intensity (CI) benchmarks in Tables 1, 2, and 3, have been modified to align with the baseline CI values for California Reformulated Gasoline (CaRFG), California Ultra Low Sulfur Diesel (ULSD), and conventional jet fuel. The baseline CI values have been recalculated using the updated CA-GREET3.0 (June 20, 2018) and OPGEE2.0 (June 20, 2018) models.

   Changes to OPGEE2.0 are described under modifications to section 95489(b); these changes result in a 0.42 gCO_2e/MJ decrease in the CI of crude oil.

   The updates to CA-GREET3.0 that affect the baseline CI values are: (1) the use of U.S. EPA's 11th edition of the Emissions & Generation Resource Integrated Database with year 2014 data (eGRID2014v2, released February 27, 2017); and (2) the adjustments of transportation parameters. In the prior release of CA-GREET3.0 (March 6, 2018), CARB staff used eGRID2014 data that was released in January 2017 and was later found by EPA to contain errors. Also, in response to public comments, CARB staff adjusted the fuel economy of heavy duty and medium trucks (HDT and MDT) used for transporting feedstocks and fuel, and adjusted the trucking payloads for corn, soybean, and canola. The back-haul trip for all transportation modes (except for pipeline transport) was also added or modified. These changes are documented in CA-GREET3.0 Supplemental Document and Tables of Changes (June 20, 2018) which is included with this notice as Attachment C.

The changes resulted in a 0.18 gCO_2e/MJ decrease in the CI value of CaRFG, a 0.11 gCO_2e/MJ decrease in the CI value of ULSD, and a 0.07 gCO_2e/MJ decrease in the baseline CI value for conventional jet, compared to staff's original proposal.

2. In section 95484(d), the proposed benchmarks for alternative jet fuels are altered. The benchmarks originally proposed in staff's Initial Statement of Reasons[1] (ISOR) included the same CI reduction percentages as the gasoline and diesel benchmarks (i.e., beginning in 2019 with a 6.25 percent reduction from the baseline CI for conventional jet fuel). This is shown in Figure 1 as the "Jet (ISOR)" line. Staff is now proposing that the jet fuel benchmarks would remain fixed at the 2010 baseline CI for conventional jet fuel, with a zero percent reduction in each year, until the benchmark for diesel substitutes declines below the CI baseline for jet fuel in 2023. This is shown by the "Jet (new)" curve in the figure below. Beginning in 2023 and each year thereafter, the annual CI benchmark for conventional jet substitutes is equivalent to the annual CI benchmark for diesel substitutes. This change is proposed in response to stakeholder comments related to the disparity in incentives between alternative jet fuels and renewable diesel, which are often co-produced in the same hydrotreating process. By modifying the jet fuel benchmarks in this way, the use of alternative jet fuels in place of conventional jet fuel is more strongly incentivized.

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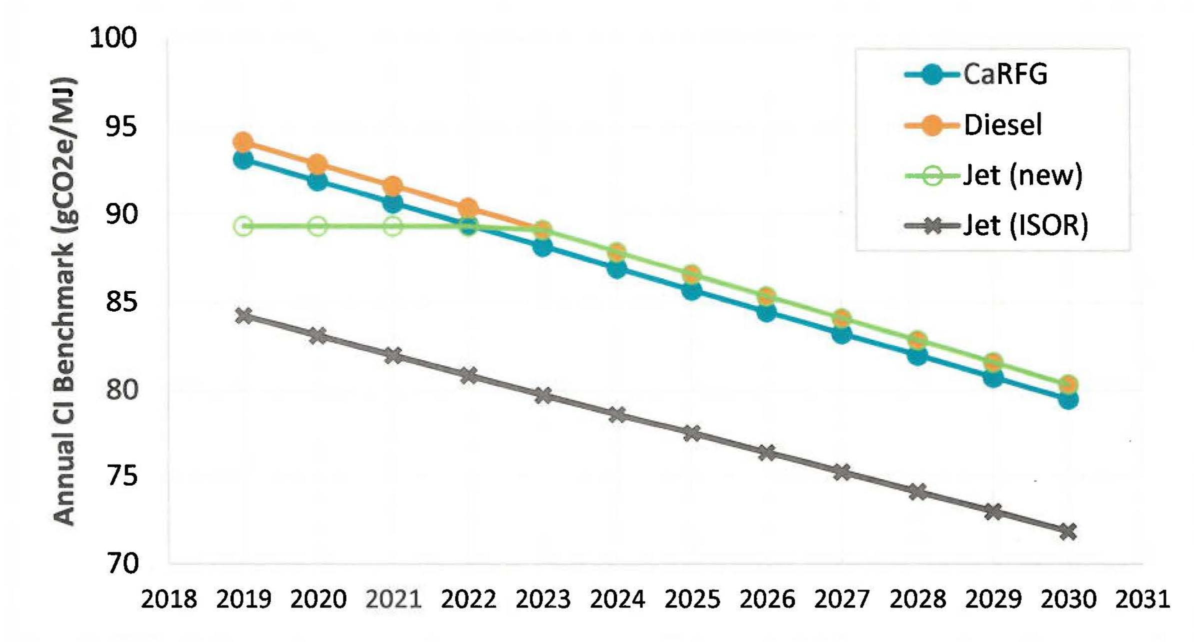
[1] CARB. 2018. Staff Report: Initial Statement of Reasons for the Proposed Amendments to the Low Carbon Fuel Standard Regulation. March 6, 2018. Available at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

Figure 1. Proposed Annual CI Benchmarks



F. Modifications to Section 95486. Generating and Calculating Credits and Deficits.

1. In section 95486(b)(1), in Table 4, which lists the energy densities and conversion factors for fuels and blendstocks, the propane energy density has been modified. Table 4 currently lists the energy density for pure propane. However, the LCFS recognizes LPG, which is a flammable mixture of hydrocarbon gases predominantly propane and butane, as propane. Since the energy density for pure propane is currently not being used, staff is proposing to update the energy density to that of LPG.

G. Modifications to Section 95486.1. Generating and Calculating Credits and Deficits Using Fuel Pathways.

1. In section 95486.1(a)(2), staff proposes to allow applicants to use an EER-adjusted CI value that is obtained through the Tier 2 application process proposed in section 95488.7(a)(3) for credit calculation purposes, for a vehicle-fuel combination that does not appear in Table 5.

2. In section 95486.1(a), new Energy Economy Ratio (EER) values are added to Table 5 to allow crediting of electric cargo handling equipment and auxiliary power engines of ocean going vessels at-berth. The data, studies and calculations that staff relied upon in determining the proposed EER values are documented in detail in the report, "Analyses Supporting the Addition or revision of Energy Economy Ratio Values for the Proposed Low Carbon Fuel

Standard Amendments" (June 20, 2018), which is provided as Attachment D to this Notice.

H. Addition of Section 95486.2. Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways.

1. Newly proposed section 95486.2 would credit zero-emission vehicle (ZEV) fueling infrastructure on the basis of the fueling station capacity for both hydrogen refueling infrastructure (HRI) and DC fast charging infrastructure (FCI). The proposal is responsive to the Governor's Executive Order B-48-18, direction in Board Resolution 18-17, and stakeholder comments. This amendment is intended to support development of ZEV infrastructure and is designed to sunset after an initial period of enhanced support for ZEV infrastructure build-out. The maximum quantity of infrastructure credits issued will be capped at 2.5 percent of overall program deficits for each category (2.5 percent for the hydrogen station provision and 2.5 percent for the fast charging provisions, for a maximum of 5 percent of total deficits across both).

a) Credits for Hydrogen Refueling Infrastructure (HRI)

i. HRI Pathway Eligibility. The proposed amendment includes three HRI pathway eligibility conditions. First, hydrogen stations must be located in California and open to the public to be eligible for HRI credit generation. Executive Order B-48-18, which provided the initial direction for this proposal, promotes infrastructure development and orders all State entities to work to increase the accessibility of hydrogen fueling infrastructure for all drivers. Second, applicants must submit HRI applications before December 31, 2025, consistent with the Executive Order B-48-18 goal of spurring the construction and installation of 200 hydrogen stations by 2025. Prior to 2026, staff plan to conduct an evaluation to determine whether HRI application eligibility should be extended beyond 2025, and propose an amendment to the LCFS, if warranted. Third, stations receiving funds as a result of an enforcement settlement are not eligible to apply for a HRI pathway. This restriction ensures that infrastructure credits drive new investment and the installation of new stations and are not used for projects mandated by such settlements.

ii. HRI Application Requirements. Consistent with other LCFS fuel pathway application requirements, HRI applications are proposed to include contact information for the station owner and the location (current or proposed) of the station. The application must also include the design nameplate capacity (12-hour) for the station and the HRI refueling capacity (the design nameplate capacity or 1,200 kg/day, whichever is less). Staff designated the 12-hour capacity because it aligns with the hours most likely to see customer traffic at stations and therefore represents a more realistic operational upper bound for station throughput than a 24-hour capacity. The upper limit of 1,200 kg/day provides protection against providing capacity credits for unrealistically large stations and promotes the installation of more, lower capacity stations instead of fewer large capacity stations. The application must also include basic information about each station such as the number of dispensing units, information on the expected source(s) of hydrogen including methods of delivery and expected CI, and the expected operational date of the station. Consistent with the fuel pathway application process, an attestation letter guaranteeing the veracity of information submitted in the application must also be provided. The application would be submitted in the LRT-CBTS, with all items designated as CBI clearly identified.

iii. Application Approval Process. To provide sufficient stimulus for hydrogen infrastructure development without significantly shifting overall program credit supply, staff proposes that CARB would not approve HRI applications if the total HRI credits generated in the prior quarter exceeds 2.5 percent of that quarter's total deficits. This requirement encourages early development of stations while capping the maximum supply of HRI credits.

The proposed application approval process is similar to the process suggested for Tier 1 pathways. The Executive Officer will first conduct a completeness check of the application, and take actions necessary to secure a complete application or to reject the pathway if the applicant is non-responsive. If the application is complete, the Executive Officer will examine the materials provided in the application package and determine whether all eligibility and application requirements have been met. If the application is approved, an application summary will be posted on the LCFS website including the location and station identifier, the number of dispensing units, the HRI refueling capacity and the effective date range for HRI crediting. Staff is proposing a 15 year crediting period starting from application approval. Applicants will not be able to generate HRI credits until a station is built and commissioned, incentivizing entities to bring their stations online as soon as possible to maximize credit generation within the crediting period.

iv. Requirements to Generate Credits. Although the 15-year period to generate HRI credits begins after application approval, staff proposes that a station must meet a number of conditions before HRI crediting may actually begin. Any deviation from the HRI refueling capacity provided in the original application must be communicated to CARB staff for credit generation purposes, and the new capacity attested to. The station must be open to the public, precluding all barriers to entering the premises and using the equipment to dispense fuel. Pursuant to the public access requirements, the station must accept major credit and debit cards.

Staff proposes to require stations to be connected to the Station Operational Status System (SOSS), a network established by the CA Hydrogen Fuel Cell Partnership that provides real-time information about station operations. CARB staff will use the same data as reported to SOSS regarding station "up-time", informally defined as the proportion of time during the quarter that the station was operational, as one of the variables in the HRI credit calculation. In addition, the station must be fully commissioned and permitted to operate and fuel retail fuel cell vehicles, including verification of dispenser performance. To further establish that the station is ready to begin dispensing fuel, at least three OEMs (original equipment manufacturers) must have confirmed that all protocol expectations are met and that the station meets requirements to provide fuel to their vehicles.

In order to receive HRI credits for a given quarter, staff proposes the station must report quantities of fuel dispensed for that quarter into the LRT-CBTS. HRI credits will not be provided to stations that provide no hydrogen throughput, as this could indicate substandard station availability or poor site selection. In addition, reporting entities must meet a company-wide weighted average CI of 75 gCO_2e/MJ (non-EER adjusted) for dispensed fuel, as well as a renewable content requirement of 40 percent or greater. These requirements promote the production of low-CI hydrogen, and were suggested by the hydrogen community to go beyond the CI and renewable content requirements of SB 1505 (Lowenthal, 2006).

Finally, staff proposes to require the station to be operational within 24 months of application approval, otherwise the application would be cancelled. If cancelled, the applicant could reapply for the same station but would be eligible for only ten years of crediting. This requirement is designed to ensure that applicants are committed and prepared to install stations upon approval of the application.

v. Calculation of HRI Credits. This subsection proposes a methodology for calculating infrastructure credits. The amount of infrastructure credits generated in a given quarter is proportional to the difference between the station capacity and actual hydrogen throughput. As the number of Fuel Cell Electric Vehicles (FCVs) sold in California increases the amount of hydrogen dispensed at each station is also expected to increase, resulting in a progressive reduction in infrastructure credit generation as the throughput increases relative to the station capacity. The infrastructure credit calculation also provides an incentive to produce or purchase hydrogen with a CI lower than the threshold CI of 75 g/MJ. This added incentive is intended to promote the development of very low-CI hydrogen production. Finally, the calculation also provides protection against providing infrastructure credit for stations that are not operational by reducing the infrastructure credit generation for periods of downtime.

vi. Reporting and Recordkeeping Requirements. During each reporting period, staff proposes that the station operator must report station availability and the company-wide weighted average renewable content of dispensed hydrogen. Station availability data must be consistent with records logged in SOSS. As discussed above, station availability will be factored into the overall crediting calculation. The 40 percent renewable content requirement will not directly affect the credit calculation, but the requirement must be met in order to generate credits. The station owner must also provide a quarterly account of station costs and revenues. This data will be used by staff to evaluate the economics of approved projects, which will allow staff to make informed adjustments to the provision and ensure that the provision is achieving the intended goals of reducing station costs and the retail price of dispensed hydrogen over time.

vii. Applications for Expanded HRI Refueling Capacity. Staff proposes that station operators that expand the capacity of their hydrogen stations may submit an application to revise their approved HRI refueling capacity in the LRT-CBTS. Approved applications for increased capacity at a station already receiving HRI credits do not reset the 15 year crediting period established at initial application approval, and must still be submitted by December 31, 2025. The application must demonstrate that station throughput has reached or exceeded 50 percent capacity to be eligible for HRI crediting of capacity expansion, to confirm that the expansion of capacity is justified. The updated nameplate capacity and HRI refueling capacity must also be included. Any changes to the originally approved sources and delivery methods of hydrogen must be updated as well, to ensure CARB staff has the most up to date information. All permitting requirements for the original equipment also apply to the equipment added in the capacity expansion.

b) Credits for DC Fast Charging Infrastructure (FCI)

i. FCI Pathway Eligibility. The proposed amendment includes six FCI pathway eligibility conditions. First, DC fast chargers must be located in California and open to the public to be eligible for FCI credit generation. Executive Order B-48-18, which provided the initial direction for this proposal, promotes infrastructure development and orders all State entities to work to increase the accessibility of electric vehicle (EV) charging infrastructure for all drivers. Second, each site must support at least two of the three commercial fast charging connectors: CHAdeMO, SAE CCS and/or Tesla. Each site must have at least one charger with CHAdeMo connector and one charger with SAE CCS connector, and no more than two-thirds of all charging equipment at a site can support one fast charging connector only. This requirement ensures that each site supports charging of a variety of vehicle models. Third, applicants must submit FCI applications before December 31, 2025, consistent with the Executive Order B-48-18 goal of spurring the construction and installation of 10,000 DC fast chargers by 2025. Prior to 2026, staff plan to conduct an evaluation to determine whether FCI application eligibility should be extended beyond 2025, and propose an amendment to the LCFS if warranted. Fourth, chargers which have been permitted to operate prior to 2019 or are receiving funds as a result of an enforcement settlement are not eligible to apply for a FCI pathway. These restrictions ensure that infrastructure credits drive new investment and the installation of new chargers and are not used for projects already in operation or mandated by such settlements. Fifth, a minimum nameplate power rating of

50 kW is required for each charger. This lower limit was chosen because it provides sufficient power to achieve a reasonable level of charge (e.g. 75 miles) within a 30 minute charging period. Finally, each charger must be networked and capable of tracking and reporting its availability for charging. This requirement ensures the uptime of a charger can be reported for FCI credit generation.

ii. FCI Application Requirements. Consistent with other LCFS fuel pathway application requirements, staff is proposing FCI applications must first include contact information for the charging equipment owner and the location (current or proposed) of the site. The application must also include the design nameplate power rating and the effective simultaneous power rating for each charging unit, which is the power that each unit at a location could deliver if all units were charging vehicles simultaneously. The total simultaneous power for all units at a location must not exceed 1,500 kW. This limitation protects against providing capacity credits for charging sites with unrealistically large capacity and promotes the installation of more, lower capacity sites instead of fewer large capacity sites. The application must also include basic information about each site such as the number of charging units and the expected operational date of the site. Consistent with the fuel pathway application process, an attestation letter guaranteeing the veracity of information submitted in the application must also be provided. The application would be submitted in the LRT-CBTS, with all items designated as CBI clearly identified.

iii. Application Approval Process. To provide sufficient stimulus for fast charging infrastructure development without significantly shifting overall program credit supply, staff proposes that CARB would not approve FCI applications if the total FCI credits generated in the prior quarter exceeds 2.5 percent of that quarter's total deficits. This requirement encourages early development of charging sites while capping the maximum supply of FCI credits. Moreover, when the 2.5 percent threshold is reached, staff would stop receiving new applications until FCI credits drop below the threshold.

The application approval process is similar to the process suggested for Tier 1 pathways. The Executive Officer would first conduct a completeness check of the application, and take actions necessary to secure a complete application or to reject the pathway if the applicant is non-responsive. If the application is complete, the Executive Officer will examine the materials provided in the application package and determine whether all eligibility and application requirements have been met. If the application is approved, an application summary will be posted on the LCFS website including the location and charger identifier, the number and type of charging units, the power rating for each unit and the effective date range for FCI crediting. Staff is proposing a five-year crediting period starting from application approval. Applicants will not be able to generate FCI credits until a charger is built and commissioned, incentivizing entities to bring their chargers online as soon as possible to maximize credit generation within the crediting period.

iv. Requirements to Generate Credits. Although the five-year period to generate FCI credits would begin after application approval, staff proposes to require a charger to meet a number of conditions before crediting may actually begin. Any deviation from the nameplate and effective simultaneous power ratings provided in the original application must be communicated to CARB staff for credit generation purposes, and the new power ratings attested to. As mentioned previously, the charging site must be open to the public, precluding all barriers to entering the premises and using the equipment to dispense fuel. Pursuant to the public access requirements, the charger must support a point-of-sale method that accepts major credit and debit cards. In addition, the charger must be fully commissioned and permitted to operate and charge electric vehicles, including verification of charging unit performance.

In order to receive FCI credits for a given quarter, staff proposes to require the charger to report quantities of electricity dispensed for that quarter into the LRT-CBTS. FCI credits will not be provided to chargers that provide no electricity throughput, as this could be an indicator of substandard charger availability or poor site selection.

v. Calculation of FCI Credits. This subsection proposes a methodology for calculating infrastructure credits. The amount of infrastructure credits generated in a given quarter is proportional to the difference between the charger capacity and actual electricity throughput. The power rating for each charging unit is limited to the effective simultaneous power rating or 150 kW, whichever is less. The 150 kW limit does not restrict installation of chargers with higher power rating, it only provides an upper bound for crediting under the provision. As the number of new vehicle models capable at charging above this level increases, staff will reevaluate this limit and update it in a future rulemaking if warranted. For FCI crediting purposes, an effective 6-hour charging capacity will be used, which provides a reasonable upper bound for utilization for a charging unit in any given day. As the number of EVs sold in California increases the amount of electricity dispensed at each charger is also expected to increase, resulting in a progressive reduction in infrastructure credit generation as the throughput increases relative to the 6-hour capacity. The calculation also provides protection against providing infrastructure credit for chargers that are not operational by reducing the infrastructure credit generation for periods of downtime.

vi. Reporting and Recordkeeping Requirements. Staff is proposing during each reporting period, the charging equipment owner must report availability for each charging unit. As discussed above, charger availability will be factored into the overall crediting calculation. The owner must also provide a quarterly account of costs and revenues for each fast charging site. This data will be used by staff to evaluate the economics of approved projects, which will allow staff to make informed adjustments to the provision and ensure that the provision is achieving the intended goals of reducing charger costs and the retail price of dispensed electricity through fast charging infrastructure over time.

vii. Applications for Expanded FCI Capacity. Staff proposes that charging equipment owners that increase the power rating of a charging unit or add charging units to a site that is already generating FCI credit may submit a revised application. Approved applications for increased capacity of a charger already receiving FCI credits do not reset the five-year crediting period established at initial application approval, and must still be submitted by December 31, 2025. The updated nameplate and effective simultaneous power ratings for each charging unit must also be included. All permitting requirements for the original equipment also apply to the equipment added or upgraded in the capacity expansion.

I. Modifications to Section 95487. Credit Transactions.

1. In section 95487(a)(2)(B), text is added to clarify that the provision does not preclude contracting for future delivery of LCFS credits as described in section 95487(b)(1)(B).

2. In section 95487(b)(1)(B) through (D), text is added to clearly identify the three types of credit transfer that can be requested in the LRT-CBTS. Staff also proposes specific reporting requirements for each type of credit transfer.

3. In section 95487(d)(7), text is added to provide clarification on the process by which the Executive Officer may cancel or reverse a prohibited credit transactions.

J. Modifications to Section 95488.1. Fuel Pathway Classifications.

1. In section 95488.1(b), additional sources of zero-CI electricity are proposed to be added to the Lookup Table pathways, for electricity supplied to electric vehicles or to electrolysis for hydrogen production, that were formerly limited to wind and solar. In response to stakeholder comments, staff examined electricity generation pathways in GREET, and generation sources that meet eligibility for California's Renewable Portfolio Standard,[2] to determine all sources that are expected to achieve a zero CI. Stakeholders also requested the addition of geothermal and biomass power as zero-CI sources; however, these sources are low-CI, yet typically result in some non-zero emissions. The additions provide flexibility for all zero-CI generation sources to utilize the Lookup Table pathway.

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[2] Renewables Portfolio Standard Eligibility Guidebook. Eighth Edition. California Energy Commission, June 2015. Available at: http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf

K. Modifications to Section 95488.3. Calculation of Fuel Pathway Carbon Intensities.

1. In section 95488.3, staff proposes modifications to Tier 1 Simplified CI Calculators (released March 6, 2018). These changes are documented in the CA-GREET3.0 Supplemental Document and Tables of Changes (June 20, 2018), which is included in Attachment C to this Notice. The updated Tier 1 Simplified CI Calculators (June 20, 2018) are listed under the References section of this Notice, to be incorporated by reference by the proposed amendments.

2. In section 95488.3, staff proposes to add new Tier 1 pathways for biomethane produced by anaerobic digestion of 1) dairy or swine manure, 2) wastewater sludge, and 3) food and green and other organic wastes. Staff developed Tier 1 Simplified CI Calculators for these pathways in response to stakeholder comments requesting the inclusion of all sources of biomethane in the Tier 1 classification. This addition also supports the objectives of California's Short Lived Climate Pollutant Reduction Strategy, by facilitating the participation of projects that reduce methane emissions from organic residues. The Simplified CI Calculators for these three pathways are added to be incorporated by reference by the proposed amendments, and are listed under the References section of this Notice.

3.

L. Modifications to Section 95488.5. Lookup Table Fuel Pathway Application Requirements and Certification Process.

1. In section 95488.5(e) and (f), the Lookup Table CI values (Table 7-1) changed as a result of updates to the Transportation and Distribution parameters in CA-GREET3.0. The CI values for smart charging in Table 7-2 are also updated to align the Lookup Table pathway for California average grid electricity. These changes are documented in the CA-GREET3.0 Supplemental Document and Tables of Changes (June 20, 2018) and CA-GREET3.0 Lookup Table Pathways Technical Support Documentation (June 20, 2018), which is included in Attachment C to this Notice.

M. Modifications to Section 95488.6. Tier 1 Fuel Pathway Application Requirements and Certification Process.

1. In section 95488.6(b), staff proposes to revise the review process for Tier 1 pathways in order to streamline the Tier 1 certification process. The applicant must submit the application and obtain third party validation. Once a positive or qualified positive validation statement has been received, staff will proceed with a completeness review.

N. Modifications to Section 95488.7. Tier 2 Fuel Pathway Application Requirements and Certification Process.

1. Newly proposed section 95488.7(a)(3), would add a Tier 2 application process for requesting EER-adjusted carbon intensities for alternative fuels used in transportation applications for which an EER value is not available in Table 5. In order to recognize and incentivize new and innovative technologies using low carbon fuels for transportation in California, this update will allow an entity supplying low carbon fuel for innovative transportation applications to apply for and obtain an EER-adjusted CI for reporting and credit generation purposes. This section requires the methodology used for calculating EER-adjusted CI to compare useful output from the alternative fuel technology to that of comparable conventional fuel technology.

O. Modifications to Section 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.

1. In section 95488.8(h) and (i), and elsewhere as applicable, staff proposes language specifically recognizing that greenhouse gas reduction claims for LCFS credits may "stack" (i.e., be recognized under both programs) with claims for the same actions recognized by California's Cap-and-Trade Program.[3] This addition clarifies that such recognition is permissible under the LCFS.

2. In section 95488.8(h)(3), upon stakeholder request, staff proposes adding a provision to specifically state that solar steam or heat that is physically supplied directly to a fuel production facility may be used to reduce CI. Generally, any form of renewable or low-CI process energy that is physically supplied and directly consumed onsite may be recognized in the determination of CI. The provisions for (1) renewable electricity and (2) biogas or biomethane were added by staff to clarify the meaning of "directly consumed" (i.e., behind-the-meter electrical connection) or to state specific conditions that must be met (i.e., attestation) to demonstrate compliance.

3. In section 95488.8(i), staff proposes to extend the two quarter period for transferring renewable attributes of grid-supplied low-CI electricity and pipeline-injected biomethane using book-and-claim accounting, to three quarters. This modification is proposed in response to stakeholder comments expressing concern that the two quarter limit may prohibit fuel providers from generating LCFS credits for actual, verifiable emission reductions. For

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[3] Title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

consistency across fuel types, the obligation transfer period for liquid fuels is also proposed to be extended to three quarters.

P. Modifications to Section 95488.9. Special Circumstances for Fuel Pathway Applications.

1. In section 95488.9(b), staff proposes to revise the temporary CI values provided in Table 9 for biomethane CNG, LNG, and L-CNG from dairy manure and wastewater sludge. In response to stakeholder comments raising concerns that a CI of zero for dairy biomethane was overly conservative, staff considered the likely range of CI values that could be achieved and concluded that a value of -150 gCO2e/MJ is likely to be sufficiently conservative for any dairy project avoiding methane emissions. Staff also addressed an error in the calculation of the temporary CI for biomethane from wastewater sludge. Staff corrected this value by applying the methodology provided in staff's March 6 proposal (using the most conservative pathway certified with that feedstock-fuel combination, increased by an additional five percent and rounded up to the nearest five CI points when applicable, to ensure the pathway CIs are conservative with respect to claimed greenhouse gas reductions). This resulted in an increase of the Bio-CNG from wastewater sludge CI to 50 gCO2e/MJ, with LNG and L-CNG corrected accordingly.

2. Staff proposes to add a new subsection 95488.9(f) to clarify that, pursuant to Senate Bill 1383 (Lara, 2016), pathways utilizing biomethane from dairy and swine manure or organic material diverted from landfill disposal may be certified with a CI that reflects avoided methane emissions, until the State of California enacts a future regulatory requirement to reduce manure methane emissions from livestock and dairy projects, or a requirement to divert organic material from landfill disposal. After future regulatory requirements take effect, credits for avoided methane emissions under the LCFS would not be available for new projects. However, projects in place before such future requirements take effect would still be able to generate credits for avoided methane emissions for their current crediting period, which is ten years of operation.

   The crediting period begins with the first reporting to either the LCFS or Cap-and-Trade Program. Staff proposes that, if the initial crediting period expires before the regulatory requirements are in effect, projects may apply for up to two additional 10-year crediting periods. Projects that have already initiated a crediting period under the Cap-and-Trade Regulation's Livestock Projects Compliance Offset Protocol may begin credit generation under the LCFS, however, this does not initiate a new crediting period.

Q. Modifications to Section 95489. Provisions for Petroleum-Based Fuels.

1. In section 95489(b), several new crudes and their CI values are added in Table 9. The CI values for all crudes in Table 9 have been modified to align with the updated OPGEE2.0 model (June 20, 2018). Revisions to the model include:
   - Update to default steam quality values for oilfields using thermal enhanced oil recovery (steam flooding, cyclic steam stimulation, and steam assisted gravity drainage) based on literature data and data provided by stakeholders.
   - Update to default wellhead pressure for oilfields in California using thermal enhanced oil recovery based on data provided by stakeholders.
   - Correction of an error in unit conversion, resulting in a CI change for all crudes using thermal enhanced oil recovery.
   - Incorporation of an option for blowdown with heat recovery to produce dry steam for thermal enhanced oil recovery.

2. In section 95489(c)(1)(A), additional technologies are proposed to be recognized as eligible to generate credits under the innovative crude provision. Geothermal, ocean wave, ocean thermal, and tidal current energy are proposed to be recognized as innovative methods. Uses of biomethane and biogas are also proposed to be recognized. For each method, proposed modifications clarify that energy must be physically supplied to the crude oil production facilities. Staff believes that each of these additional technologies are in keeping with the intent of the provision to promote the use of innovative technologies to reduce emissions during crude oil production. Staff has also clarified that the provision applies not only for innovative projects implemented at oil fields, but also for projects that reduce emissions during transport of the crude to the refinery. Finally, staff has clarified that storage may be used for solar and wind electricity projects, thereby increasing the potential amount of electricity from these intermittent sources that may be credited under this provision.

3. In section 95489(c)(1)(F), a lower steam quality bin (45-55 percent) is added as eligible to generate credits, as some fields in San Joaquin Valley operate at lower steam quality due to reservoir characteristics. Staff has also clarified the methodology used to calculate the avoided emissions values for solar steam projects.

4. In section 95489(c)(4)(C), reporting requirements for California innovative crude producers are revised, as specifying the innovative crude volume sent to individual refineries may be problematic and is unnecessary for in-state producers. Staff is proposing that in-state producers submit documentation showing the innovative crude was supplied to one or more California refinery, the total volume (barrels) of innovative crude supplied to one or more

California refineries, and the total volume (barrels) of innovative crude exported from California.

5. In section 95489(e)(1)(C) and (D), in addition to several clarifying changes to the refinery investment credit pilot program, staff has proposed to modify the eligibility threshold such that it only applies to process improvement projects as described in 95489(e)(1)(D)5. The threshold for process improvement projects is modified from a carbon intensity based threshold of 0.1 gCO_{2e}/MJ to a quantity based threshold 10,000 MT/year or one percent of pre-project emissions, as described in 95489(e)(1)(G)2. A threshold based on emission reduction per year is simpler to evaluate for these projects than a carbon intensity reduction threshold. The threshold value of 10,000 MT/year greenhouse gas reduction was chosen based on survey information submitted by stakeholders. The proposed amendments retain a one percent threshold as a secondary approach, which could allow smaller refiners to apply for projects that do not meet the 10,000 MT/year threshold.

6. In section 95489(e)(1)(G), staff proposes to increase the limit on the amount of credits generated from process improvement projects that can be used to meet an entity's annual compliance obligation from 5 percent in the original proposal to 10 percent. The 10 percent limit was chosen based on survey information submitted by stakeholders. Credits from refinery investment projects are limited to 20 percent of annual compliance obligation under the current regulation. The proposed modification to the eligibility thresholds in (G) paragraph 2. is described above under modifications to 95489(e)(1)(C). In paragraph 3., staff proposes to change the period of time for which a refinery process improvement project can receive credit to 15 years starting from the quarter in which CARB approves the application. The amendments as initially proposed would have limited credit generation for these projects by instating a sunset date of January 1, 2025. Due to the long time horizons necessary to recover capital expenditures for many of these projects, a longer credit generation window could allow for more projects.

7. In section 95489(e)(3)(A), staff proposes a revision to allow quarterly credit generation if an entity chooses to obtain quarterly verification statements. This allows stakeholders flexibility in accessing credits generated from the refinery investment credit pilot program.

8. In section 95489(e)(3)(A), an application requirement is added to demonstrate that indirect impacts, beyond the identified project system boundary, are not significant. Refineries are extremely complex and CARB staff may not possess the expertise necessary to evaluate the adequacy of the system boundary proposed by the applicant in all cases. Accordingly, staff proposes to require the applicant to demonstrate that second or higher order indirect impacts are not significant beyond the identified project system boundary.

9. In section 95489(e)(3)(H), staff proposes adding an expiration date for receiving applications for refinery process improvement projects. Adding an expiration date for project applications could encourage refiners to complete these projects quickly, thereby maximizing the emission reduction benefits.

R. Modifications to Section 95490. Provisions for Fuels Produced Using Carbon Capture and Sequestration.

1. Staff proposes to modify the requirements for how to address invalid credits due to CO_2 leakage from CCS projects. In the prior proposal a hierarchy of dealing with invalid credits due to leakage was established with the project's contribution to the Buffer Account being used first to address the invalid credits. If the amount the project had contributed to the Buffer Account was exhausted, the project operator would be responsible for making up any additional invalid credits. If the project operator was unable to do so, the Executive Officer would have the flexibility to retire additional credits from the Buffer Account (using credits contributed from other sources).

   In response to stakeholder concerns about financial liability for 100 years, staff now proposes to retain the method described above for the first 50 years of a project post-injection. After 50 years post injection, the project operator would no longer have any responsibility to make up invalid credits. Instead, the Buffer Account would be used to address such leakage. To account for the greater potential for the Buffer Account to need to cover such situations staff is also proposing that all CCS projects contribute additional credits to the Buffer Account (see the change to the calculation in Appendix G of the CCS Protocol, attached to this Notice as Attachment B). Staff's proposal brings the minimum Buffer Account contribution to 8 percent, which is in line with other CCS accounting requirements (generally 5-10 percent).

   Staff believes that this additional 5 percent contribution is reasonable for several reasons. First, there are a limited number of CCS projects in which sequestration is the primary goal, and none of these projects have reached 50 years post-injection. CO_2-EOR projects in which sequestration is not the focus are more common, however, these projects have not reached 50 years post-injection either. Additionally, CO_2-EOR projects do not typically have the level of monitoring or publically available data necessary to perform accurate estimates of CO_2 leakage, should it occur. Because CARB has proposed that the Buffer Account cover any credit reversals after 50 years post-injection, Buffer Account contributions must be conservative enough to cover a potential future leak. For these reasons, staff believes that a 5 percent contribution is appropriate, as it allows for a margin of error over the modeled 1 percent leakage rate. Some projects may perform exactly as expected, but the Buffer Account pools risk, and thus needs to account for cumulative potential future invalidation risk. Assuming a project operates for 20 years and sequesters approximately 1 million metric tons of CO_2 per year, it would need 20 projects of similar size with no leakage to have contributed at 5 percent to cover a full reversal. Staff believes that the proposed changes, while conservative, are reasonable in order to cover the reversal risk.

S. Modifications to Section 95491. Fuel Transactions and Compliance Reporting.

1. In section 95491(d)(3)(A)(1), staff proposes to require the reporting of Daily Average EV Electricity Use data for the calculation of credits for non-metered charging for a quarter within the first 45 days after the end of each quarter. To synchronize the crediting cycle of non-metered EV charging with quarterly crediting cycle for all other fuel types, the necessary data for calculating credits must be promptly made available to CARB. Quarterly generation of credits for non-metered EV charging, rather than annual, will allow credit generators to monetize credits sooner.

   Staff also proposes requirements for the incremental credit generator for non-metered residential EV charging to provide Vehicle identification Number (VIN) for EVs claimed and the evidence of EV ownership and low carbon electricity supply (e.g., green tariff enrollment) upon request of the Executive Officer. The proposed requirements will prevent duplicate claims of incremental credits for non-metered EV charging at a residence.

2. In section 95491(d)(3)(G) and (H), staff proposes adding reporting requirements for two new vehicle applications: electric cargo handling equipment and electric auxiliary power engines of ocean going vessels at-berth. These additions are necessary to enable the new vehicle applications to report quantities of fuel for credit generation.

3. In section 95491(d)(3)(I), staff proposes adding reporting requirements for new transportation applications which are not included in Table 5 but can be reported upon obtaining an EER-adjusted CI through the Tier 2 application process pursuant to proposed section 95488.7(a)(3).

4. In section 95491(e)(1), the list of parameters included in the annual summary is updated to include credits purchased as carryback credits and credits on administrative hold. These parameters are already being reported in the annual summary by reporting entities but were not included in the list.

T. Modifications to Section 95491.1. Recordkeeping and Auditing.

1. In section 95491.1(c)(1)(G), staff propose to clarify that monitoring plan requirements do not apply to data reported in LRT-CBTS for generating EV charging credits.

U. Modifications to Section 95500. Requirements for Validation of Fuel Pathway Applications; and Verification of Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Project Reports, and Low-Complexity/Low-Energy-Use Refinery Reports.

1. In sections 95500(b)(2)(B) and (c)(2)(B), staff has clarified the option to defer verification for fuel pathway holders below the threshold.

2. In section 95500(e)(2), staff is proposing to add provisions for reporting entities to conduct either quarterly or annual verification of project reports. These requirements allow flexibility for project operators to determine the frequency at which they could be issued credits based on verified data.

V. Modifications to Section 95501. Requirements for Validation and Verification Services.

1. In section 95501, staff is proposing to add requirements to allow entities to conduct quarterly review prior to completing annual verification services. These changes are made to address stakeholder comments by providing flexibility for verifiers to review reported data and identify any issues prior to annual reporting and verification. These quarterly review provisions provide requirements for verification planning and documentation that must be generated and maintained by verification bodies.

W. Modifications to Section 95503. Conflict of Interest Requirements for Verification Bodies and Verifiers.

1. In section 95503(b), staff is proposing to extend the period for phasing in specified high-risk conflict of interest activities from January 1, 2022, to January 1, 2023. Extending the phase-in period will give reporting entities and verifiers more time to plan for a rotation of verification bodies. It also gives CARB staff adequate time to monitor verification program implementation and onboarding of verifiers to determine whether any changes are needed to address concerns of verifier availability. Staff also clarified the language for certain high-risk services.

X. Modifications to In-Use requirements for Specific ADFs Subject to Stage 3A (Section 2293.6 of the ADF regulation).

1. Section 2293.6(a)(4)(A) is proposed to be modified to be applicable only to on-road applications of biodiesel use.

2. Section 2293.6(a)(4)(B) is modified to include the process for issuing an executive order for the on-road application sunset and to clarify that off-road in-use requirements will still be in effect until the conditions of 2293.6 (a)(4)(C) are met and an executive order is issued per 2293.6 (a)(4)(D).

3. Section 2293.6 (a)(4)(C) is new proposed text added to describe a sunset provision specifically applicable to off-road diesel engines.

4. Section 2293.6(a)(4)(D) is new proposed text added to provide procedural detail when conditions in 2293.6(a)(4)(C) are met.

Y. Modifications to Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CCS Protocol, included in Attachment B to this Notice).

1. Modifications throughout the CCS Protocol

a. Staff proposes to change "pressure front" to "elevated pressure" and modify the definition to better reflect conditions that define the boundaries of the CO_2 plume's area of influence.

b. Staff proposes to change "AOR" to "storage complex" whenever referring to the three-dimensional (3D) storage volume and all geologic layers and structures that impede the lateral or vertical migration of the CO_2 plume. The storage complex comprises a sequestration zone, confining system, and any other layers/structures that may serve as dissipation intervals or help to retard CO_2 plume migration. The protocol still uses "AOR" when referring to the two-dimensional surface footprint of the plume.

c. Staff proposes to change "confining layer" to "confining system" because there may be multiple confining layers that impede the vertical migration of CO_2 within the storage complex. This change is necessary to accommodate different geologic settings that provide secure CO_2 containment.

d. Staff proposes modifications to correct typographical, stylistic, or grammatical errors, changes in numbering and formatting, and other non-substantive revisions made to improve clarity. Staff also proposes to remove unnecessary explanatory text.

2. Modifications to Definitions (subsection A.3(a))

a. Staff proposes to modify "area of review" to reflect the proposed change from "pressure front" to "elevated pressure."

b. Staff proposes to modify "CO_2 leakage" to clarify that leakage means any CO_2 migration out of the storage complex.

c. Staff proposes to replace "CO_2 recycling" with "CO_2 separation" as "recycled CO_2" is already defined while "CO_2 separation" was used but not defined.

d. Staff proposes to replace "perforation interval" with "completion interval" to include the multiple methods in which a well can be completed, including but not limited to perforation.

e. Staff proposes to modify "corrective action" for clarity and to reflect the changes made to "AOR" and "storage complex."

f. Staff proposes to add "plume stabilization" for clarity.

g. Staff proposes to modify "storage complex" to reflect real-world geologic settings, allow for multiple confining layers, and add flexibility in demonstrating containment.

h. Staff proposes to add, delete, or modify a number of other definitions, including but not limited to: dissipation interval, geographic location, geomechanical analysis, leak-off test, pore space, and porosity.

3. Modifications to the Accounting Requirements (section B)

   a. Staff proposes to replace references to atmospheric leakage throughout section B with references to CO_2 leakage, which is defined as any CO_2 that may, or has, migrated out of the storage complex.

   b. In subsection B.2.2(a), staff proposes edits to modify where measurements are collected for accounting and monitoring purposes from "at" the point of injection to "before" injection, but after transport. In some operations, measuring directly at the point of injection results in double counting the recycled CO_2.

   c. In subsection B.2.2(d), staff proposes to delete language that "CO_{2vent} and $CO_{2fugitive}$ in Equation 4 are zero if the CO_2 is of biogenic origin," as Equation 4 has been modified such that CO_{2vent} and $CO_{2fugitive}$ are no longer variables.

   d. In subsection B.2.2(e), staff proposes to add language that clarifies that the minimum value for the $CO_{2leakage}$ term in Equation (6) must reflect the detection limit for the method used to detect leaks, which includes both the equipment and the analysis.

   e. In subsection B.3(a), staff proposes to modify the text for clarity and to better define CO_2 leakage as any migration of the CO_2 plume out of the storage complex, not just to the atmosphere.

4. Modification to Permanence Certification of Geologic Carbon Sequestration Projects (subsection C.1)

   a. In subsection C.1.1.1, staff proposes to add provisions that require the third-party reviewers of the Sequestration Site Certification and CCS Project

Certification must be licensed professional geologists or engineers, respectively. These additions are designed to ensure that the reviewers have appropriate knowledge and experience to be able to perform robust reviews.

b. In subsection C.1.1.2(b)(2)(A) and (B), and C.1.1.3.3(a)(1)(H), staff proposes to add language to clarify that the results of the geologic evaluation, plume extent modeling, and storage complex revaluation all must be reported to CARB. The proposed changes ensure operators provide CARB with all the data necessary to evaluate the project.

c. In subsection C.1.1.3, staff proposes to require CCS Project Operator to attest that the information reported to CARB is true, accurate, and complete. This requirement is necessary to ensure the operator exercises due diligence in reporting all required data.

5. Modifications to Site Characterization (subsection C.2)

Subsection 2.1: Minimum Site Selection Criteria

a. In subsection C.2.1(a)(4), staff propose to remove the requirement for a secondary confining layer and dissipation interval(s), and to replace the aforementioned requirements with those that are performance based, consistent with modifications to the definition of storage complex.

Subsection 2.2: Risk Assessment

b. In subsection C.2.2(a), staff proposes to modify the language to require that the results of the risk assessment inform and guide the design of the Testing and Monitoring Plan, ensuring that the Plan will be more effective at reducing leakage risk. Staff also proposes to require that the risk assessment quantify CO_2 leakage risk for 100 years post-injection.

c. In subsection C.2.2(b), staff proposes to add a provision to the risk assessment such that it will be used to evaluate the risk of CO_2 leakage outside of the storage complex and inform scenarios in the Emergency and Remedial Response Plan. This change will increase the effectiveness of the risk management plan.

d. In subsection C.2.2(f), staff proposes to add a provision that CARB will only certify sites in which the fraction of CO_2 retained in the sequestration zone is very likely to exceed 99% over 100 years. This subsection also requires operators to evaluate and model specific uncertainties, which ensures that the modeling is robust and considers a full suite of subsurface characteristics. Staff's proposed changes are designed to further ensure any approved sites result in permanent sequestration.

Subsection 2.3: Geologic and Hydrologic Evaluation Requirements

e. In subsection C.2.3(a)(6), staff proposes to change "all" to "significant" geologic structures. The potential list of geologic structures could be extensive and the change to "significant" is more appropriate for ensuring permanence.

f. In subsection C.2.3(a)(10), staff proposes to change the requirement from "any" to "known" mineral deposits to reflect that there may be mineral deposits that are unknown.

g. In subsection C.2.3(b)(2)(A), staff proposes to amend "potential release" of production fluid to be "potential unintentional release," as intentional release such as planned venting is already considered in the accounting methods.

h. In subsection C.2.3.1(h)(1), staff proposes to modify the testing requirements, because one test of sufficient quality should provide the relevant information on hydrogeologic conditions.

Subsection 2.4: Storage Complex Delineation and Corrective Action

i. In subsection C.2.4(a), staff proposes edits to require that the storage complex delineation and corrective action apply to both the surface area (the AOR) and subsurface volume (the storage complex), and more explicitly link the risk assessment to monitoring, to further ensure that monitoring will detect leakage or potential leakage.

j. Staff proposes to modify Figure 5 to add several steps and requirements that were inadvertently missing from the original flow chart.

k. In subsection C.2.4(b)(1)(C), staff proposes to modify the language to clarify that corrective action applies to all wells that either intersect the storage complex or are within the AOR and which may be potential vectors for CO_2 leakage. The proposed changes increase clarity and further reduce the risk of CO_2 leakage by requiring the assessment of both deep wells that may allow CO_2 leakage to reach the shallow subsurface, and shallow wells within the AOR that may allow CO_2 leakage from the shallow subsurface to reach the atmosphere.

l. In subsection C.2.4(b)(1)(D), staff proposes to add a stipulation that the computational model must include the retention and containment of the CO_2 plume within the storage complex until at least the end of the post-injection site care and monitoring period. The proposed change further reduces the risk of CO_2 leakage.

Subsection 2.4.1 - Computational Modeling Requirements

m. In subsection C.2.4.1(a), staff proposes to add requirements to the storage complex delineation and risk assessment such that the model(s) will demonstrate that the storage complex will contain the CO_2 plume for a minimum of 100 years post injection. The risk assessment must be based on results of the computational modeling, and the model must account for the physical properties and characteristics of the sequestration zone and injected CO_2 stream over the proposed life of the CCS project. These requirements provide additional certainty that the CCS projects under the LCFS program are permanent, safe, and in line with IPCC guidance.[4]

n. In subsection C.2.4.1(a)(1)(A), staff proposes to remove requirements consistent with the change from "pressure front" to "elevated pressure."

o. In subsection C.2.4.1(a)(1)(C), staff proposes several changes for consistency, clarity, and specificity. Staff proposes to add a requirement for operators to provide justification and sensitivity analysis for choices for model variables. Staff also proposes that operators include the site-specific data used to determine the chosen boundary conditions. Staff proposes to remove the term "pre-injection," which is not appropriate for sites that are currently injecting CO_2, and to add requirements for the inclusion of operating and monitoring data, as suggested by stakeholders. Staff also proposes modifications to the list of suggested model parameters to enable operators to choose appropriate model designs and incorporate technological advances. Finally, staff proposes adding model parameters to accommodate the full range of potential reservoir types. The changes are necessary to ensure robust modeling.

p. In subsection C.2.4.1(a)(1)(D), (E), (F), and (H), staff proposes to add provisions to perform and document statistical analyses, and to justify and document simplifications, equations, constitutive relationships, history matching methods, and any assumptions in the computational modeling. These changes are designed to ensure that CARB has all data necessary to evaluate the project and modeling.

q. In subsection C.2.4.1(a)(1)(J) and (K), staff proposes to clarify that operators should incorporate the model-derived leakage risk into the risk assessment and that modeling must include material uncertainties. These changes are designed to increase the effectiveness of risk management.

r. In subsection C.2.4.1(a)(2), staff proposes to both (1) strengthen requirements for model peer review, and (2) replace prescriptive requirements with performance-based requirements for the code(s) used.

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[4] IPCC, 2005, Special Report on Carbon Dioxide Capture and Storage [B. Metz, O. Davidson, H. de Coninck, M. Loos, and L. Mayer (eds.)]. IPCC, Cambridge University Press, New York, 442 pp.

Staff also proposes edits to clarify the expected capability of the code(s) used, and to identify techniques that demonstrate when an appropriate model or variable is used.

Subsection 2.4.2 - Storage Complex Delineation using Computational Modeling Results.

s. In Subsection C.2.4.2, staff proposes to clarify that the model must incorporate new data as the project progresses, include all wells associated with the CCS project, and include post-closure CO_2 migration in model predictions. This ensures that the plume shape and projected evolution are up-to-date and that the site continues to meet the permanence requirements.

Subsection 2.4.4: Plume Reevaluation.

t. Staff proposes to rewrite subsection C.2.4.4 in an effort to reorganize, clarify, and simplify details throughout subsection C.2.4.4. Staff kept key provisions on plume reevaluation, but propose deleting redundant requirements. Staff proposes to add required actions to be undertaken in the case of CO_2 leakage or if the model predicts future CO_2 leakage. The changes further ensure that the plume reevaluation is robust, and that any CO_2 leakage or predicted CO_2 migration out of the storage complex will be accounted for and handled appropriately.

u. In subsection C.2.4.4(a) – (f), staff proposes edits to clarify provisions for updating and reevaluating the CO_2 plume extent modeling, set forth detailed steps for reevaluation, add reporting requirements for corrective actions, and set forth measures and reporting requirements to be implemented upon CO_2 leakage or anticipated future (modelled) CO_2 leakage. These edits provide clarity and ensure that the project information and modeling is up to date, well documented, and continues to meet the permanence requirements. Staff also proposes to clarify that the most recently delineated storage complex must be used in all required plans and the demonstration of financial responsibility. This helps to ensure that each CCS project remains in compliance with the CCS Protocol.

Subsection 2.5: Baseline Testing and Monitoring.

v. Staff proposes to reorganize, clarify, and add details throughout subsection C.2.5. Staff also proposes to replace prescriptive requirements with more flexible requirements in the overall testing and monitoring strategy for baseline data collection. The baseline monitoring and testing must support and inform the detection of CO_2 leakage, including leakage that results in credit reversals. The changes in requirements allow for the inclusion of new and more site-specific monitoring technologies, which may provide additional or improved data.

w. In subsection C.2.5(a), staff proposes to add edits to the requirements on the baseline testing strategy to increase specificity and clarity.

x. In subsection C.2.5(b), staff proposes to add requirements that the baseline testing and monitoring plan must be able to detect, validate, quantify, and enable mitigation. The addition is necessary to provide overall plan criteria, guidance, and support monitoring goals, as well as to balance against the removal of more prescriptive requirements.

y. In subsection C.2.5(c), staff proposes to add details on baseline testing and monitoring data collection and analysis, including specifying the types of data that must be collected, the adequacy of the data collection and analysis, and the potential tools that the operators may use for baseline testing. The new requirements include criteria for a monitoring strategy such that monitoring is sufficient to track the plume and appropriate for history matching. This section now explicitly links the risk assessment to the testing and monitoring plan, and emphasizes the evaluation of potentially impacted properties. These changes increase clarity and provide further guidance on baseline testing and monitoring data collection and analysis.

z. In subsection C.2.5(d), staff proposes to replace certain required data (e.g., soil type, soil carbon content, surface water hydrology, etc.) with new data requirements (downhole pressure, fluid chemistry, etc.). The new data provide more appropriate information for detecting CO_2 leakage than the deleted data. This change makes the monitoring and testing plan more robust.

aa. In subsection C.2.5(e), staff proposes to remove several redundant requirements and to revise text to provide clarity and guidance. The new text more explicitly links the baseline site characteristics and the monitoring plan.

6. <u>Modifications to Well Construction and Injection Requirements (subsection C.3)</u>

a. In subsection C.3.2(d), staff proposes to delete the requirement for static fluid level, as staff agrees with stakeholder comments that the other requirements are sufficient.

b. In subsection C.3.3(b), staff proposes to add a prohibition on increases in the risk of significant induced seismicity, which further ensures public safety in concert with other seismicity-related requirements.

c. In subsection C.3.3(f), staff proposes to clarify that only affected wells need to cease injection, as shutting down all wells could potentially result in unintended risks.

7. Modifications to Injection Monitoring Requirements (subsection C.4)

Subsection 4.1: Testing and Monitoring

a. In subsection C.4.1(a)(9)-(13), staff proposes to add new requirements on testing and monitoring that are related to model validation, assurance that the CO_2 plume will remain in the storage complex, determination of CO_2 plume location, and detection and quantification of any CO_2 leaks, if they should occur. The changes further ensure that the risk of CO_2 leakage is minimized, and if a CO_2 leak does occur, it will be detected and appropriately remediated or mitigated.

b. In subsection C.4.1(a)(11), staff proposes to delete "air and soil-gas" to allow the project operators flexibility to choose the best available surface monitoring technologies for CO_2 leak detection for the site and account for technology advancement over time.

c. In subsection C.4.1(a)(14), staff proposes to require CARB approval of metering locations to provide sufficiently accurate data and account for complicating factors.

Subsection 4.2: Mechanical Integrity Testing

d. In subsection C.4.2(f), staff proposes an exemption for the gauge and meter calibration of permanent downhole gauges, because they are placed in the well at depth and cannot be calibrated from surface.

e. In subsection C.4.2.1(a)(9), staff proposes to change "well stabilization" to "well pressure re-equilibration" for increased clarity.

Subsection 4.3: CCS Project Monitoring

f. Staff proposes minor clarifying edits and corrections throughout this subsection, such as using the term "fluid "instead of "gas," and explicitly referring to calibration.

g. In subsection C.4.3.1.1(e), staff proposes to require that the CCS Project Operators demonstrate that the composition of the sampled stream is representative of the total injectate composition. The changes ensure that the fluid composition is reflective of the injectate, especially in cases where the recycled CO_2 may be injected into the stream after being metered.

h. In subsection C.4.3.1.2(d)(1)-(2), staff proposes to add requirements on the accuracy of flow meter measurement and location. The changes ensure accurate accounting for injected CO_2. Similar changes are made to injectate composition to ensure accuracy of information.

i. In subsection C.4.3.1.3(d), staff proposes to relax the requirement for maintaining a higher annular pressure than injection pressure, by removing the numerical values at which that higher pressure must be set. This edit will ensure the mechanical integrity of the well is maintained, yet allow for differences in geology and operating conditions.

j. In subsection C.4.3.2(b)-(e), staff proposes minimum requirements for the Monitoring, Measurement, and Verification Plan. The changes are necessary to ensure operators document and submit the required information for CARB and verification team review, and to ensure that consistent information is submitted across all CCS projects.

k. In subsection C.4.3.2(e), staff proposes to require an estimate of the accuracy and precision of methods in the Monitoring, Measurement, and Verification Plan. This change is necessary to ensure that CARB has accurate enough information to evaluate the methods for CO_2 leakage quantification. Accurate CO_2 leakage data are critical to ensure the market is appropriately compensated through invalidation of credits if CO_2 leaks occur.

l. In subsection C.4.3.2.1(b)-(e), staff proposes to require a demonstration that the monitoring approach, sensitivity, schedule, and methods for CO_2 plume and elevated pressure tracking will be effective in producing accurate data, especially leakage data if a CO_2 leak occurs. The proposed changes include the link between monitoring observations and plume evolution, and requires updates to the modelling and periodic reevaluation. The edits explicitly link the monitoring to the risk assessment and risk management strategies. The changes further ensure that monitoring is appropriate and provides accurate data for the accounting of injected CO_2, as well as for leak detection and prevention.

m. In subsection C.4.3.2.2(c), staff proposes to add requirements such that the monitoring methods used by the operator must be able to distinguish between CO_2 leakage signals and other signal variations not related to leakage. The changes reduce the likelihood of collecting incorrect and inaccurate data.

n. In subsection C.4.3.2.2(g) – (h), staff proposes to add conditions on when the required near surface monitoring should be conducted. The changes provide further guidance on when near surface monitoring will be needed.

o. In subsection C.4.3.2.2(i), staff proposes to change the reporting of surface and near-surface monitoring data to be annual, instead of quarterly. The proposed reporting frequency is more appropriate, as it would allow operators sufficient time to analyze and interpret the data and prepare reports.

p. In subsection C.4.3.2.3(a), staff proposes to expand the requirement for the downhole seismic monitoring system from only the injection wells such that operators monitor all wells and any important discontinuities, faults, or fractures in the subsurface, as wells and discontinuities areas are critical areas for potential leakage.

q. In subsection C.4.3.2.3(a)(1), staff proposes to require the analysis of whether injection will significantly increase the risk of triggering an earthquake of Richter magnitude 2.7. If increased risk is identified, mitigation of the risk is required. The changes are necessary to minimize the risk of CCS-related injection triggering earthquakes.

r. In subsection C.4.3.2.3(e), staff proposes to allow the Project Operators more time to work on the final report of the seismic evaluation, as it takes time to analyze seismic data. Preliminary results are still required within the original time period of 30 days.

s. Staff proposes to add subsection 4.3.2.4, which includes specific requirements that CCS projects must meet for verification.

t. In subsection C.4.3.2.4(b), staff proposes to include an oil and gas systems specialist on the verification team to ensure the team has specific knowledge related to verifying GHG reductions in this sector. In addition, staff proposes to require the verification team include a professional geologist to provide expertise and assist the team in verifying the information related to the site. Staff proposes that the experience and expertise requirements for the oil and gas systems specialist and the professional geologist can be fulfilled by a single individual or a combination of individuals. This will allow more flexibility for the verification body to form the verification team.

u. In subsection C.4.3.2.4(c), staff proposes to add specific requirements for information that must be reviewed during verification services for CCS projects. The changes are needed to ensure that information monitored, measured, collected, and submitted under the protocol meet the requirements of the LCFS Regulation and the CCS Protocol. In addition to verifying the information related to GHG emission reductions, staff proposes that the verification team review the operator's CCS project's risk rating for determining its contribution to the LCFS Buffer Account, as calculated under Appendix G. The changes are needed to ensure that the determination made by the operator is reasonable and meets the regulatory requirements. In addition, staff proposes that the verification team review the project boundaries and the locations of monitoring and measurement equipment to ensure that all relevant GHG sources and sinks are included within the project boundary. Staff also proposes that the verification team review all assessments, plans, and reports that are required to be submitted for conformance with the requirements in the CCS Protocol. The changes are needed to ensure that the documents meet the requirements of the protocol, and that the operator has complied with the actions required under the plans and assessments, including but not limited to the Emergency and Remedial Response Plan and the Corrective Action Plan.

v. In subsection C.4.3.2.4(d), staff proposes to add verification requirements for verifying the mass of CO_2 leakage that the operator reports after an event has occurred. The changes are needed to ensure that CARB is retiring the proper amount of credits from the Buffer Account based on the most accurate data. Staff also proposes the timing (six months) for when verification of CO_2 leakage must occur. Staff believes that six months will allow operators enough time to verify any reversals and allow CARB to retire credits in a timely fashion based on verified data.

8. <u>Modifications to well plugging and abandonment and post-injection site care and site closure (subsection C.5)</u>

   a. In subsection C.5.2(a)(2)(A), staff proposes to change the post-injection site care and closure requirements to consider a timeframe based on pressure stabilization, instead of pressure returning to pre-injection levels. This change is necessary to accommodate sites with different geologic settings that provide secure CO_2 containment.

   b. In subsection C.5.2(b)(3)(B), staff proposes to change "Monitoring and observation wells must remain open" to "Monitoring and observation wells may remain open," and add edits for clarity. Pressure in all settings will begin to decrease as soon as injection stops, and CO_2 plume movement will begin to abruptly decrease as well. These results can be matched to the model predictions and used to establish a reliable trend toward stabilization. The changes are necessary to strike a balance between the leakage risk of open wells against the decreasing risk of plume migration after injection stops.

   c. In subsection C.5.2(b)(3)(C) (newly added subsection), staff proposes to allow CCS Project Operators to submit evidence showing that plume stabilization has occurred 15 years after injection completion. Subsection C.5.2(b)(3)(C) also sets forth requirements on such evidence. The changes set up a minimum period of time for intensive post-injection monitoring to ensure public safety.

   d. In subsection C.5.2(b)(3)(D) (previously subsection C.5.2(b)(3)(C)), staff proposes to require the drilling of a new monitoring well, if an existing monitoring well leaks and is plugged and abandoned, provided there is a need to continue with the monitoring activities performed by the previously existing well. The changes are necessary to continue performing the mandatory monitoring activities.

e. In subsection C.5.2(b)(3)(E) (previously subsection C.5.2(b)(3)(D)), staff proposes to allow frequency of quarterly bottom-hole pressure measurement to be adjusted based on the previously measured rate of change, provided the CCS Project Operator provides a justification for an alternative monitoring strategy. The changes are necessary to handle complexities due to different geologic settings and operational conditions.

f. In subsection C.5.2(b)(3)(G).3, staff proposes to require that CCS Project Operators inspect the areas that are shown in the risk assessment to be preferential pathways for CO_2 or brine migration, and to test these areas if needed. The changes are necessary because although leakage is rare, in known cases fluid migration has both vertical and lateral components and can move to land surface far away from wellheads. Areas not in the vicinity of the wells may need to be inspected and tested, depending on the findings of the risk assessment.

g. In subsection C.5.2(d), staff proposes changes that allow CCS Project Operators to restore the site to a condition that is as close to pre-injection conditions as practicable, instead of the exact pre-injection condition, as some changes may be outside of the operator's control.

h. In subsection C.5.2(f), staff proposes to require that each CCS Project Operator record a notation on the deed within 180 days instead of 30 days after completion of injection. Staff proposes the changes to allow more time to meet this requirement in response to stakeholder comments.

9. Modifications to Emergency and Remedial Response (subsection C.6)

a. In subsection C.6(b)(1), staff proposes to require immediate cessation of injection only in well(s) that are affected by potentially harmful events and any other wells that may exacerbate risk of leakage in the affected well(s). The changes are necessary because depending on nature of risk, other wells in a multi-well project may be able to safely continue to accept CO_2.

10. Modifications to Determination of a CCS Project's Risk Rating for Determining its Contribution to the LCFS Buffer Account (Appendix G)

a. In Appendix G, staff proposes to change one number in Equation (G.1). This change corresponds to the changes proposed in subsection B.3(d) and increases the CCS project's contribution to the Buffer Account by 5 percent.

Environmental Analysis

These proposed modifications do not change implementation of the regulation in any way that is anticipated to affect the conclusions of the environmental analysis included in the Staff Report because the modifications consist primarily of refinements and clarifications to the initial proposal. At this stage in this rulemaking process, CARB does not expect that any changes in compliance responses resulting from the modifications would result in any of the circumstances requiring recirculation of the analysis as set forth in section 15088.5 of the CEQA Guidelines.

Additional Documents or Incorporated Document(s) Added to the Record

Staff has added to the rulemaking record and invites comments on the following additional documents:

Documents Incorporated by Reference

1. California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation version 3.0 (CA-GREET3.0) model, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
2. Oil Production Greenhouse gas Emissions Estimator Version 2.0, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/crude-oil/crude-oil.htm)
3. CA-GREET3.0 Lookup Table Pathways Technical Support Documentation, June 20, 2018 (included in Attachment C to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)
4. Tier 1 Simplified CI Calculator Instruction Manual, June 20, 2018 (included in Attachment C to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)
5. Tier 1 Simplified CI Calculator for Starch and Corn-Fiber Ethanol, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
6. Tier 1 Simplified CI Calculator for Sugarcane-derived Ethanol, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
7. Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
8. Tier 1 Simplified CI Calculator for LNG and L-CNG from North American Natural Gas, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
9. Tier 1 Simplified CI Calculator for Biomethane from North American Landfills, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)

10. Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Wastewater Sludge, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
11. Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
12. Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Food, Green, and Other Organic Waste, June 20, 2018 (available at: https://www.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm)
13. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, June 20, 2018 (included as Attachment B to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)

Additional References and Supplemental Documents

1. CA-GREET3.0 Supplemental Document and Tables of Changes, June 20, 2018 (included in Attachment C to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)
2. Analyses Supporting the Addition or Revision of Energy Economy Ratio Values for the Proposed Low Carbon Fuel Standard Amendments, June 20, 2018 (included as Attachment D to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)
3. Final Renewable Fuel Standards for 2018, and the Biomass-Based Diesel Volume for 2019. U.S. EPA Webpage, accessed May 18, 2018. Available at: https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2018-and-biomass-based-diesel-volume.
4. Renewables Portfolio Standard Eligibility. Eighth Edition. California Energy Commission, June 2015. Available at: http://www.energy.ca.gov/2015publications/CEC-300-2015-001/CEC-300-2015-001-ED8-CMF.pdf
5. One Petro – Document Preview, Society of Petroleum Engineers, "Fluid Distribution Model for Structurally Complex Reservoirs in El Carito-Mulata and Santa Bárbara Fields, Venezuela", 2007, accessed May 17, 2018. Available at: https://www.onepetro.org/conference-paper/SPE-107948-MS.
6. One Petro – Document Preview, Society of Petroleum Engineers, "8500 PSI Gas Injection Project", 1996, accessed May 17, 2018. Available at: https://www.onepetro.org/conference-paper/SPE-35603-MS.

7. One Petro – Document Preview, Society of Petroleum Engineers, "Design of High Angle Wells in the Santa Barbara Field, Eastern Venezuela", 2001, accessed May 17, 2018. Available at: https://www.onepetro.org/conference-paper/SPE-69450-MS.
8. Staff Report: Multimedia Evaluation of Biodiesel. Multimedia Working Group, California Environmental Protection Agency. May 2015.
9. A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions, Draft Technical Report. U.S. Environmental Protection Agency. October 2002.
10. CARB B5 Biodiesel Preliminary and Certification Testing. Durbin, et al. April 2013.
11. CARB Comprehensive B5/B10 Biodiesel Blends Heavy-Duty Engine Dynamometer Testing. Karavalakis, Georgios et al., June 2014.
12. The R Project for Statistical Computing. The R Foundation Webpage, accessed December 10, 2014. Available at: http://www.R-project.org/
13. lme4: Linear Mixed-Effects Models using Eigen and S4. R package version 1.1-7, Bates, Douglas et al., July 14, 2014. Available at: http://CRAN.R-project.org/package=lme4
14. Stock and Optimized Performance and Emissions with 5 and 20% Soy Biodiesel Blends in a Modern Common Rail Turbo-Diesel Engine. Energy Fuels, 24 (2), pp 928–939. Bunce, Michael et al, 2010.
15. Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity, SAE Int. J Fuels Lubr., 5(3). Lammert, Michael et al., November 2012.
16. Emissions and Redox Activity of Biodiesel Blends Obtained from Different Feedstocks from a Heavy-Duty Vehicle Equipped with DPF/SCR Aftertreatment and a Heavy-Duty Vehicle without Control Aftertreatment, SAE 2014-01-1400. Gysel, Nicholas et al., April 1, 2014.
17. Emission and Performance Implications of Biodiesel Use in an SCR-equipped Caterpillar C6.6, SAE 2010-01-2157. McWilliam, Lyn and Anton Zimmermann, October 25, 2010.
18. Effect of Biodiesel on NOx Reduction Performance of Urea-SCR system, SAE 2010-01-2278. Mizushima, Norifumi et al.,, October 25, 2010.
19. On-Road and In-Laboratory Testing to Demonstrate Effects of ULSD, B20, and B99 on a Retrofit Urea-SCR Aftertreatment System, SAE 2009-01-2733. Walkowicz, Kevin et al., November 2-4, 2009.
20. Performance and Emissions of Diesel and Alternative Diesel Fuels in Modern Light-Duty Vehicles, SAE 2011-24-0198. Nikanjam, Manuch, et al., September 11, 2011.

21. Regulated Emissions from Biodiesel Fuels from On/Off road Applications, Atmospheric Environment, Volume 41, p. 5647-5658. Durbin, Thomas et al., 2007.
22. Transient Emissions Comparisons of Alternative Compression Ignition Fuels. SAE 1999-01-1117. Clark, Nigel et al., 1999.
23. CARB B20 Biodiesel Preliminary and Certification Testing. Durbin, Thomas et al., July 2013.
24. Effects of Methyl Ester Biodiesel Blends on NOx Emissions. SAE 2008-01-0078. Eckerle, Wayne et al., 2008.
25. Fuel Additive and Blending Approaches to Reducing NOx Emissions from Biodiesel. SAE 2002-01-1658. McCormick, Robert et al., 2002.
26. Regulated Emissions from Biodiesel Tested in Heavy-Duty Engines Meeting 2004 Emission Standards. SAE 2005-01-2200. McCormick, Robert et al., 2005.
27. Performance and Emissions of Diesel and Alternative Diesel Fuels in a Heavy-duty Industry-Standard Older Engine. SAE 2010-01-2281. Nikanjam, Manuch et al., October 25, 2010.
28. Evaluation of the NOx Emissions from Heavy Duty Diesel Engines with the Addition of Cetane Improvers. Proc. IMechE Vol. 223 Part D: J. Automobile Engineering: 1049-1060. Nuszkowski, J et al., 2009.
29. Neat Fuel Influence on Biodiesel Blend Emissions. Int. J. Engine Res. Vol. 11: 61-77. Thompson, G.J., and J. Nuszkowski, 2010.
30. Starcrest Consulting Group, LLC. July 2017. Port of Long Beach Air Emissions Inventory - 2016. July 2017. Available at: http://www.polb.com/civica/filebank/blobdload.asp?BlobID=14109
31. Deriving fuel-based emission factor thresholds to interpret heavy-duty vehicle roadside plume measurements. Quiros, David C et al. California Air Resources Board. April 13, 2018. Available at: https://www.tandfonline.com/doi/abs/10.1080/10962247.2018.1460637
32. Cargo Handling Equipment Inventory, Appendix B: Emissions Inventory Methodology. California Air Resources Board, August 3, 2011. Available at: https://www.arb.ca.gov/regact/2011/cargo11/cargoappb.pdf
33. Thermal Efficiency for Diesel Cycle. Nuclear Power for Everybody, accessed June 18, 2018. Available at: https://www.nuclear-power.net/nuclear-engineering/thermodynamics/thermodynamic-cycles/diesel-cycle-diesel-engine/thermal-efficiency-for-diesel-cycle/
34. Carl Moyer Program Status Reports. California Air Resources Board, 2018. CARB Webpage, accessed May 29, 2018. Available at: https://www.arb.ca.gov/msprog/moyer/status/status.htm

35. Federal Register, Volume 80, No 111. June 10, 2015. 40 CFR Part 80. Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017; Proposed Rule.
36. Estimating Carbon Intensity Values for the Crude Lookup Table, June 20, 2018 (included as Attachment E to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)
37. Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model Version 2.0, User Guide and Technical Documentation. El-Houjeiri, H.M., Masnadi, M.S., Vafi, K., Duffy, J., and A.R. Brandt, June 20, 2018.
38. MCON Inputs Spreadsheet for Crude Lookup Table, Spreadsheet titled "Lookup_Table_MCON_Inputs_OPGEE_v2.0_(June_20_2018).xlsx."
39. MCON Inputs Spreadsheet for 2010 Baseline Crudes, Spreadsheet titled "2010_Baseline_MCON_Inputs_OPGEE_v2.0_(June_20_2018).xlsx."
40. Public Workshop Materials, June 20, 2018 (included as Attachment F to this Notice at: https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm)

These documents are available for inspection by contacting Bradley Bechtold, Regulations Coordinator, at (916) 322-6533.

Agency Contacts

Inquiries concerning the substance of the proposed regulation may be directed to the agency representative Sam Wade, Branch Chief, Transportation Fuels Branch, Industrial Strategies Division, at (916) 322-8263, or Anthy Alexiades, Air Resources Engineer, Alternative Fuels Section, at (916) 324-0368.

Public Comments

Written comments will only be accepted on the modifications identified in this Notice. Comments may be submitted by postal mail or by electronic submittal no later than 5:00 p.m. on the due date to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Please note that under the California Public Records Act (Gov. Code § 6250 et seq.), your written and verbal comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

In order to be considered by the Executive Officer, comments must be directed to CARB in one of the two forms described above and received by CARB by 5:00 p.m., on the deadline date for public comment listed at the beginning of this notice. Only comments relating to the modifications to the text of the regulations in attachments to this notice shall be considered by the Executive Officer.

If you need this document in an alternate format or another language, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 no later than five (5) business days from the release date of this notice. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Si necesita este documento en un formato alterno u otro idioma, por favor llame a la oficina del Secretario del Consejo de Recursos Atmosféricos al (916) 322-5594 o envíe un fax al (916) 322-3928 no menos de cinco (5) días laborales a partir de la fecha del lanzamiento de este aviso. Para el Servicio Telefónico de California para Personas con Problemas Auditivos, ó de teléfonos TDD pueden marcar al 711.

CALIFORNIA AIR RESOURCES BOARD

Richard W. Corey
Executive Officer

Date: April 20, 2018

Attachments

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see CARB's website at www.CARB.ca.gov.