UPDATED INFORMATIVE DIGEST FOR THE PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS
(GOV. CODE, § 11347.3(b)(2))

Sections Affected: Proposed amendments to California Code of Regulations, title 17, sections 95480, 95481, 95482, 95483, 95483.1, 95483.2, 95484, 95485, 95486, 95487, 95488, 95489, 95490, 95491, 95492, 95493, 95494, 95495, 95496, and 95497; and proposed amendments to section 2293.6 and Appendix 1 in title 13, chapter 5, article 3, subarticle 2, California Code of Regulations. Proposed adoption of sections 95483.3, 95486.1, 95486.2, 95488.1, 95488.2, 95488.3, 95488.4, 95488.5, 95488.6, 95488.7, 95488.8, 95488.9, 95488.10, 95490, 95491.1, 95498, 95499, 95500, 95501, 95502, and 95503, California Code of Regulations, title 17.

Background and Effect of the Proposed Regulatory Action:

In 2006, the Legislature passed and then-Governor Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32; Stats. 2006, ch. 488). In Assembly Bill (AB) 32, the Legislature declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The Legislature further declared that global warming will have detrimental effects on some of California's largest industries, including agriculture and tourism, and will increase the strain on electricity supplies. The Legislature recognized that action taken by California to reduce emissions of greenhouse gases (GHG) will have far-reaching effects by encouraging other states, the federal government, and other countries to act. AB 32 created a comprehensive, multi-year program to reduce GHG emissions in California, with a goal of restoring emissions to 1990 levels by the year 2020. AB 32 required CARB to take actions that included:

- Establishing a statewide GHG emissions cap for 2020, based on 1990 emissions;
- Adopting a scoping plan by January 1, 2009, indicating how emission reductions will be achieved from significant GHG sources via regulations, market mechanisms, and other actions;
- Adopting a list of discrete, early action GHG emission reduction measures by June 30, 2007, which can be implemented and enforced no later than January 1, 2010; and
- Adopting regulations by January 1, 2010, to implement the measures identified on the list of discrete early action measures.

In 2007, then-Governor Schwarzenegger signed Executive Order S-01-07. This executive order directed CARB to determine whether a Low Carbon Fuel Standard (LCFS) for transportation fuels used in California could be adopted as a discrete early action measure pursuant to AB 32, and if so, to design the LCFS so that it reduces the carbon intensity of transportation fuels used in California by at least 10 percent by the year 2020. In addition to substantially reducing GHG emissions from transportation fuels, the LCFS is expected to help diversify the transportation fuels market in California,

thereby cutting petroleum dependency and creating a sustainable and growing market for cleaner fuels.[1]

In 2007, the Board approved a list of nine discrete early action measures, including a measure entitled, "Low Carbon Fuel Standard." The proposed regulation was designed to implement this measure pursuant to the requirements of AB 32 and Executive Order S-01-07.

The Board approved an LCFS regulation in 2009. The goal of the LCFS regulation was to reduce the carbon intensity of transportation fuels used in California by at least 10 percent by 2020 from a 2010 baseline. CARB approved revisions to the LCFS effective November 26, 2012.

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

To comply with the court ruling, and to update and revise the LCFS regulation, on September 25, 2015, the Board set aside the previous version of the LCFS, and simultaneously adopted a new version of the LCFS. On that same day, the Board also adopted a Regulation on the Commercialization of Alternative Diesel Fuels (ADF regulation), designed preserve or enhance public health, environmental and emission benefits associated with the use of innovative alternative diesel fuels in California.

In the current rulemaking to amend the LCFS regulation in 2018, CARB strengthened the LCFS targets through 2030. In 2016, the California Legislature adopted Senate Bill (SB) 32 (Stats. 2016, ch. 249 (Pavley)), which builds on the progress of AB 32 by codifying a statewide target to reduce GHG emissions by at least 40 percent below 1990 levels by 2030. To encourage additional GHG reductions in strategic areas where decarbonization will be important to meet long-term targets, staff added provisions to recognize eligibility of new fuels and vehicle applications for generating credits under the LCFS program. To enhance the integrity of the emission reduction claims in the program, the amendments include establishing an independent third-party verification and accreditation program for ensuring the accuracy of data reported under LCFS. Finally, the proposed LCFS amendments include a number of changes to integrate the verification system, update program data, quantification methods and analysis tools, and other changes to improve, streamline, and further clarify application and reporting processes. The targeted amendments to the ADF regulation remove expired provisions, correct transcription errors, and adjust an emissions control sunset provision.

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[1] Governor's White Paper, *The Role of a Low Carbon Fuel Standard in Reducing Greenhouse Gas Emissions and Protecting Our Economy*, <http://gov.ca.gov/index.php?/fact-sheet/5155/>.

Description of the Regulatory Action:

Overview

The initial proposal was described in the Notice of Public Hearing[2] and the Staff Report: Initial Statement of Reasons for Proposed Rulemaking,[3] both released on March 6, 2018. After the April 27, 2018 Board Hearing, the California Air Resources Board released two sets of 15-day changes for further public comment; these changes are summarized below. The changes to the initial proposal identified below were necessary to respond to Board direction in Resolution 18-17, to improve the clarity in the LCFS regulation as adopted, and to ensure the regulation would accomplish its goals to reduce transportation fuel carbon intensity, while incentivizing the development and adoption of zero-emission vehicles, fuel, and infrastructure.

Summary of First 15-Day Modifications:

1. In section 95481(a), a number of definitions and acronyms were added, deleted, or modified, 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), the ASTM Specifications that were previously incorporated by reference in the definitions of fuels were removed. The ASTM Specifications were not needed to clearly identify the fuel type, and their inclusion may have resulted 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. This change was proposed to address those comments. The following ASTM Specifications were 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")

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[2] https://www.arb.ca.gov/regact/2018/lcfs18/notice.pdf
[3] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf

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, the name was changed 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. The terms “smart charging” and “smart electrolysis” were used to refer to these provisions for EV charging and electrolytic hydrogen production, respectively.

4. In section 95482(c)(4), an exemption was added 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; staff added this exemption to address this concern, which allows owners of small stations dispensing fossil CNG and fossil propane to voluntarily opt-in for credit generation.

   The year in which use of these fuels would first begin to generate deficits was determined 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 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. The small station exemptions will expire on January 1, 2021 for fossil propane and January 1, 2024 for fossil CNG.

5. In section 95483(a)(3), the two-quarter limit to transfer the credit or deficit generator status to another entity was extended 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.

6. Section 95483(c)(1)(B) established a hierarchy for claims to incremental credits for residential EV charging. 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 were 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.

Automakers received second priority as they can provide detailed telematics information where separate meters are not available to measure the electricity used for EV, 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.

7. Section 95483(c)(1)(B) established a hierarchy for claims to incremental credits for non-residential EV charging. Similar to how gaseous fuel is treated, the owner of the FSE is eligible to generate the credits but has the option to assign that right to other parties contractually if they choose to do so.

8. In section 95483(c)(5), new reporting entities were added for two new vehicle applications using electricity: Electric Cargo Handling Equipment (eCHE) and Electric power delivered to Ocean-going Vessels at-berth (eOGV). These additions are necessary to identify the entities eligible to report quantities of fuel used in the new vehicle applications.

9. In section 95483(c)(7), the eligible reporting entity for electric transportation applications not specifically addressed in 95483(c)(1) through (6) were identified.

10. In section 95483.2(b)(8), Fueling Supply Equipment (FSE) registration requirements were added to clarify registration for various types of FSE and to cover two new vehicle applications using electricity: Electric Cargo Handling Equipment (eCHE) and Electric power delivered to Ocean-going Vessels at-berth (eOGV). These additions are necessary to enable the new vehicle applications to register FSE for reporting electricity for credit generation, and prevent any potential double counting of the credits for the same quantity of electricity.

11. In section 95484(d), the benchmarks for alternative jet fuels were altered. The benchmarks originally proposed in staff's Initial Statement of Reasons[4] (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). Staff revised the jet fuel benchmarks to 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. 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 was 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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[4] 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

12. In section 95486(b)(1), in Table 4, which lists the energy densities and conversion factors for fuels and blendstocks, the propane energy density was modified. Table 4 previously listed 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, the energy density was updated to that of LPG.

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

14. In section 95486.1(a), new Energy Economy Ratio (EER) values were added to Table 5 to allow crediting of Electric Cargo Handling Equipment (eCHE) and Electric power delivered to Ocean-going Vessels At-berth (eOGV). The data, studies, and calculations that were 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).

15. New section 95486.2 was added to credit zero-emission vehicle (ZEV) fueling infrastructure on the basis of the fueling capacity for both Hydrogen Refueling Infrastructure (HRI) and DC Fast Charging Infrastructure (FCI). The change 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 by providing credits for the determined fueling capacity that would decrease as a station reaches full utilization. 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 HRI provision and 2.5 percent for the FCI provisions, for a maximum of 5 percent of total deficits across both).

    a) Credits for Hydrogen Refueling Infrastructure (HRI)

        i. <u>HRI Pathway Eligibility</u>. The 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 provision, 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 must include contact information for the station owner and the location (current or proposed) of the station. The application must also include the nameplate capacity for the station and the HRI refueling capacity (the nameplate capacity or 1,200 kg/day, whichever is less). 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 will be submitted in the LRT-CBTS, with all items designated as Confidential Business Information (CBI) clearly identified.

iii. Application Approval Process. To provide sufficient stimulus for hydrogen infrastructure development without significantly shifting overall program credit supply, CARB will 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 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. HRI are limited to 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, 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.

Stations must be connected to the Station Operational Status System (SOSS), a database established and managed by the California 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, 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 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, the station must be operational within 24 months of application approval, otherwise the application will be cancelled. If cancelled, the applicant can reapply for the same station but will 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 provides the 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. 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, 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. 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 amendment includes 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 provision, promotes infrastructure development and orders all State entities to work to increase the accessibility of electric vehicle (EV) charging infrastructure for all drivers. Second, 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. Third, 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. Fourth, 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, 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 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 will 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, CARB will 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 approving 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 site location, the number and type of charging units, the power rating for each unit and the effective date range for FCI crediting. FCI are limited to 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, a charger must 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, quantities of electricity dispensed for that quarter must be reported in 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 provides the 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. For FCI crediting purposes, an estimated 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 estimated charging 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. 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. 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.

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

17. In section 95487(b)(1)(B) through (D), text was added to clearly identify the three types of credit transfer that can be reported in the LRT-CBTS, along with specific reporting requirements for each type of credit transfer.

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

19. In section 95488.1(b), additional sources of zero-CI electricity were 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,[5] 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.

20. In section 95488.3, the Tier 1 Simplified CI Calculators (released March 6, 2018) were modified. These changes are documented in the CA-GREET3.0 Supplemental Document and Tables of Changes (June 20, 2018).

21. In section 95488.3, 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 were added. Tier 1 Simplified CI Calculators were developed 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

[5] 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

for these three pathways are incorporated by reference by the amended regulation.

22. 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 were 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).

23. In section 95488.6(b), the review process for Tier 1 pathways was revised 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.

24. New section 95488.7(a)(3) added 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.

25. In section 95488.8(h) and (i), and elsewhere as applicable, staff added 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.[6] This addition clarifies that such recognition is permissible under the LCFS.

26. In section 95488.8(h)(3), upon stakeholder request, a provision was added 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.

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

27. In section 95488.8(i), the two-quarter period for transferring renewable attributes of grid-supplied low-CI electricity and pipeline-injected biomethane using book-and-claim accounting was extended to three quarters. This modification is 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 consistency across fuel types, the obligation transfer period for liquid fuels is also extended to three quarters.

28. In section 95488.9(b), the temporary CI values in Table 9 for biomethane CNG, LNG, and L-CNG from dairy manure and wastewater sludge were revised. 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 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, with LNG and L-CNG corrected accordingly.

29. A new subsection 95488.9(f) was added 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 will not be available for new projects. However, projects in place before such future requirements take effect will 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. 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.

30. In section 95489(b), several new crudes and their CI values were 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.

31. In section 95489(c)(1)(A), use of biomethane and biogas were recognized as eligible to generate credits under the innovative crude provision. Modifications clarified that energy must be physically supplied to the crude oil production facilities. Staff believes that 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 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 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.

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

33. In section 95489(c)(4)(C), reporting requirements for California innovative crude producers were revised, as specifying the innovative crude volume sent to individual refineries may be problematic and is unnecessary for in-state producers. In-state producers must 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.

34. In section 95489(e)(1)(C) and (D), in addition to several clarifying changes to the refinery investment credit pilot program, the eligibility threshold was modified such that it only applies to process improvement projects as described in 95489(e)(1)(D)5. The threshold for process improvement projects was 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 amendments retained 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.

35. In section 95489(e)(1)(G), the limit on the amount of credits generated from process improvement projects that can be used to meet an entity's annual compliance obligation was increased 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 modification to the eligibility thresholds in (G) paragraph 2. is described above under modifications to 95489(e)(1)(C). In paragraph 3., the period of time for which a refinery process improvement project can receive credit was changed 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.

36. In section 95489(e)(3)(A), quarterly credit generation was allowed if an entity chooses to obtain quarterly verification statements. This allows stakeholders flexibility in accessing credits generated from the refinery investment credit pilot program.

37. In section 95489(e)(3)(A), an application requirement was 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, the applicant is required to demonstrate that second or higher order indirect impacts are not significant beyond the identified project system boundary.

38. In section 95489(e)(3)(H), an expiration date was added 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.

39. In section 95490, the requirements for how to address invalid credits due to CO_2 leakage from CCS projects were modified. In the initial 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, the method described above was retained for the first 50 years of a project post-injection. After 50 years post injection, the project operator will no longer have any responsibility to make up invalid credits. Instead, the Buffer Account will be used to address such leakage. To account for the greater potential for the Buffer Account to need to cover such situations all CCS projects are required to contribute additional credits to the Buffer Account (see the change to the calculation in Appendix G of the CCS Protocol). This modification brought the minimum Buffer Account contribution to 8 percent, 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 the Buffer Account will 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 changes, while conservative, are reasonable in order to cover the reversal risk.

40. In section 95491(d)(3)(A)(1), the reporting of Daily Average EV Electricity Use data is required 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.

Requirements were also added 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 requirements will prevent duplicate claims of incremental credits for non-metered

EV charging at a residence.

41. In section 95491(d)(3)(G) and (H), reporting requirements were added 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.

42. In section 95491(d)(3)(I), reporting requirements were added 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).

43. In section 95491(e)(1), the list of parameters included in the annual summary was 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.

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

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

46. In section 95500(e)(2), provisions were added 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.

47. In section 95501, requirements were added to allow entities to conduct quarterly review prior to completing annual verification services. These changes were 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.

48. In section 95503(b), the period for phasing in specified high-risk conflict of interest activities was extended 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. The language was also clarified for certain high-risk services.

First 15-Day 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) was modified to be applicable only to on-road applications of biodiesel use.

2. Section 2293.6(a)(4)(B) was 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. New section 2293.6 (a)(4)(C) was added to describe a sunset provision specifically applicable to off-road diesel engines.

4. Section 2293.6(a)(4)(D) was added to provide procedural detail when conditions in 2293.6(a)(4)(C) are met.

First 15-Day Modifications to Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CCS Protocol).

1. Modifications throughout the CCS Protocol
   a. "Pressure front" was changed to "elevated pressure" and the definition was modified to better reflect conditions that define the boundaries of the CO_2 plume's area of influence.
   b. "AOR" was changed to "storage complex" whenever it referred 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.
   c. "Confining layer" was changed 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. Typographical, stylistic, or grammatical errors were corrected, changes in numbering and formatting, and other non-substantive revisions were made to improve clarity. Unnecessary explanatory text was removed.

2. Modifications to Definitions (subsection A.3(a))
   a. "CO_2 leakage" was modified to clarify that leakage means any CO_2 migration out of the storage complex.
   b. "CO_2 recycling" was replaced with "CO_2 separation" as "recycled CO_2" was already defined while "CO_2 separation" was used but not defined.
   c. "Perforation interval" was replaced with "completion interval" to include the multiple methods in which a well can be completed, including but not limited to perforation.

d. “Corrective action” was modified for clarity and to reflect the changes made to “AOR” and “storage complex.”
e. “Plume stabilization” was added for clarity.
f. “Storage complex” was modified to reflect real-world geologic settings, allow for multiple confining layers, and add flexibility in demonstrating containment.
g. A number of other definitions were added, deleted, or modified, 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. References to atmospheric leakage were replaced 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 modified 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), the language was deleted: “CO_{2vent} and $CO_{2fugitive}$ in Equation 4 are zero if the CO_2 is of biogenic origin,” as Equation 4 was modified such that CO_{2vent} and $CO_{2fugitive}$ are no longer variables.
   d. In subsection B.2.2(e), language was added to clarify 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), the text was modified 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, provisions were added 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), language was added to clarify that the results of the geologic evaluation, plume extent modeling, and storage complex revaluation all must be reported to CARB. The changes ensure operators provide CARB with all the data necessary to evaluate the project.
   c. In subsection C.1.1.3, a requirement was added for the 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)

a. In subsection C.2.1(a)(4), the requirement for a secondary confining layer and dissipation interval(s), was removed and the aforementioned requirements were replaced with those that are performance based, consistent with modifications to the definition of storage complex.
b. In subsection C.2.2(a), the language was modified 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 required that the risk assessment quantify CO_2 leakage risk for 100 years post-injection.
c. In subsection C.2.2(b), a provision was added 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), a provision was added 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. These changes are designed to further ensure any approved sites result in permanent sequestration.
e. In subsection C.2.3(a)(6), “all” was changed 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), the requirement was changed 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), “potential release” of production fluid was amended to “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), the testing requirements were modified, because one test of sufficient quality should provide the relevant information on hydrogeologic conditions.
i. In subsection C.2.4(a), staff required that the storage complex delineation and corrective action apply to both the surface area and subsurface volume of 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 modified 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 modified the language to clarify that corrective action applies to all wells that either intersect the storage complex or are within the surface footprint of the storage complex, and which may be potential vectors for CO_2 leakage. The 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 surface footprint of the storage complex that may

allow CO_2 leakage from the shallow subsurface to reach the atmosphere.

l. In subsection C.2.4(b)(1)(D), staff added 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 change further reduces the risk of CO_2 leakage.

m. In subsection C.2.4.1(a), staff added 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.[7]

n. In subsection C.2.4.1(a)(1)(A), staff removed requirements consistent with the change from “pressure front” to “elevated pressure.”

o. In subsection C.2.4.1(a)(1)(C), staff made several changes for consistency, clarity, and specificity. Staff added a requirement for operators to provide justification and sensitivity analysis for choices for model variables. Staff also requires that operators include the site-specific data used to determine the chosen boundary conditions. Staff removed the term “pre-injection,” which is not appropriate for sites that are currently injecting CO_2, and added requirements for the inclusion of operating and monitoring data, as suggested by stakeholders. Staff also modified to the list of suggested model parameters to enable operators to choose appropriate model designs and incorporate technological advances. Finally, staff added 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 added 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 clarified 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 modified to both (1) strengthen requirements for model peer review, and (2) replace prescriptive requirements with performance-based requirements for the code(s) used. Staff also clarified the expected capability of the code(s) used, and identified techniques that demonstrate when an appropriate model or variable is used.

s. In Subsection C.2.4.2, staff clarified that the model must incorporate new data

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[7] 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.

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.

t. Staff rewrote 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 deleted redundant requirements. Staff added 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 clarified provisions for updating and reevaluating the CO_2 plume extent modeling, set forth detailed steps for reevaluation, added 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 clarified 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.

v. Staff reorganized, clarified, and added details throughout subsection C.2.5. Staff also replaced 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 edited the requirements on the baseline testing strategy to increase specificity and clarity.

x. In subsection C.2.5(b), staff added 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 added 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 replaced 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 removed several redundant requirements and revised text to provide clarity and guidance. The new text more explicitly links the baseline site characteristics and the monitoring plan.

6. Modifications to Well Construction and Injection Requirements (subsection C.3)
   a. In subsection C.3.2(d), staff deleted 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 added 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 clarified 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)
   a. In subsection C.4.1(a)(9)-(13), staff added 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 deleted “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 required CARB approval of metering locations to provide sufficiently accurate data and account for complicating factors.
   d. In subsection C.4.2(f), staff exempted 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 changed “well stabilization” to “well pressure re-equilibration” for increased clarity.
   f. Staff made 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 required 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 added 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 relaxed 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 added 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 required 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), a demonstration is required 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 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 added 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 added 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 changed the reporting of surface and near-surface monitoring data to be annual, instead of quarterly. The revised 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 expanded 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), an analysis is required to determine 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), Project Operators are allowed 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 added 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 included 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, the verification team is required to include a professional geologist to provide expertise and assist the team in verifying the information related to the site. Staff added 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 added 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 required 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, the verification team is required to 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. The verification team must also 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 added 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. This section also provides 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. Modifications to well plugging and abandonment and post-injection site care and site closure (subsection C.5)
   a. In subsection C.5.2(a)(2)(A), staff changed 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 changed “Monitoring and observation wells must remain open” to “Monitoring and observation wells may remain open,” and added 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. Newly added subsection C.5.2(b)(3)(C) allowed 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 revised 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 revised 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 revised 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 revised to 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 revised to require that each CCS Project Operator record a notation on the deed within 180 days instead of 30 days after completion of injection. These changes were made 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 revised 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 changed one number in Equation (G.1). This change corresponds to the changes in subsection B.3(d) and increased the CCS project's contribution to the Buffer Account by 5 percent.

<u>Summary of Second 15-Day Modifications:</u>

1. In section 95481(a) and (b), staff added, deleted, or modified a number of definitions and acronyms, including but not limited to: "Animal Fat," "Avoided Cost Calculator," "Biomethane," "Cargo Handling Equipment," "Distiller's (or Technical) Sorghum Oil," "Electric Cargo Handling Equipment," "Electric Power for Ocean-Going Vessels" "Green Tariff," "Hydrogen Station Capacity Evaluator," "Large, Medium, and Small Publicly-owned Utility," "Load Serving Entity," "Low-Carbon Intensity (CI) Electricity," "Renewable Hydrogen," "Shore Power," "Yard Truck," and "Yellow Grease."

2. In section 95481(a)(7) and (154), staff revised the definitions of "Animal Fat" and "Yellow Grease" to clarify that a portion of yellow grease may be characterized as used cooking oil, if evidence is provided to confirm the quantity that it is animal fat and the quantity that is used cooking oil. If no evidence is provided to confirm the portion of yellow grease that is used cooking oil, staff would make the conservative assumption that yellow grease is comprised solely of animal fat.

3. In section 95481(a)(124), staff replaced the list of qualifying energy resources identified in the definition of "Renewable Hydrogen," with "eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36." This clarifies that any resource meeting the criteria established under California's Renewable Portfolio Standard program may also be recognized under the LCFS. These changes are in response to recommendations by the California Public Utilities Commission (CPUC) and other stakeholder comments. A similar change was made to replace the list of energy resources eligible for

reporting under Lookup Table pathway ELCR 95488.1(b)(2)(A).

4. In section 95482(c)(4), staff increased the threshold for exempting stations that dispense fossil compressed natural gas (CNG) or fossil propane (LPG) from participation in the LCFS. The annual throughput per station threshold was 50,000 gasoline-gallons equivalent (GGE), and was revised to 150,000 GGE in response to stakeholder comments. The exemption for stations beneath the threshold expires in 2021 for LPG and in 2024 for CNG, when the use of each fuel becomes deficit-generating in heavy-duty applications.

5. In section 95482(d), staff omitted "shore power provided to ocean-going vessels at-berth" from the exemption for specific applications, meaning that the LCFS regulation does apply to this application.

6. In section 95483(b)(1), staff clarified that bio-CNG, bio-LNG, and bio-L-CNG provided directly to vehicles (as in on-site fueling) are included in the provision that designates the first fuel reporting entity. As previously proposed, the designation could have been interpreted to mean that only biomethane injected to the pipeline is subject to the provisions of subsection (b)(1).

7. In section 95483(c)(1)(A), staff revised to require an opt-in electrical distribution utility (EDU), or its designee, generating base credits for residential EV charging to participate in a statewide point of purchase rebate program funded exclusively by LCFS credit proceeds, if such a program is established. The Board directed the Executive Officer, in resolution 18-17, to explore opportunities to increase the magnitude of ZEV rebates funded by sale of LCFS credits through a statewide point of sale rebate program. Following that direction, staff made several changes:

    a. An opt-in EDU, or its designee, generating base credits for residential EV charging must start contributing to the statewide point-of-purchase rebate program upon California Public Utilities Commission (CPUC) approval of Pacific Gas and Electric's, Southern California Edison's, and San Diego Gas and Electric's filings to initiate a statewide point-of-purchase rebate program. CPUC, in decision D.14-12-083, established the criteria and provided the utilities several options for returning the value of LCFS proceeds to the current and future EV drivers. The investor-owned utilities (IOU) will have to file a request with CPUC to modify the relevant decisions to allow participation in a statewide point-of-purchase rebate program. Opt-in EDUs including Publicly-owned Utilities (POU), which are not regulated by CPUC, must also start contributing to the statewide point-of-purchase rebate program at the same time as IOUs.
    b. Each opt-in EDU must contribute a minimum percentage of base credits or the net proceeds resulting from the sale of base credits to the statewide point-of-purchase rebate program. This percentage must be determined based on the share of base credits received by utilities and the categories specified in

section 95483(c)(1)(A) paragraph 1., which include IOUs, large POUs, medium POUs, and small POUs.
At the outset of the program, in years 2019 through 2022, IOUs must contribute at least 67 percent of their base credits or resulting proceeds, large POUs must contribute at least 35 percent and medium POUs must contribute 20 percent. Given that small POUs receive only a tiny fraction of total base credits they are not required to contribute any credits at the beginning of the statewide rebate program. In 2023 and subsequent years, large POUs must contribute 45 percent, medium POUs 25 percent and small POUs 2 percent. This change would provide transparency as to how many LCFS credits will flow toward the statewide program on an annual basis. Further, staff would like to provide utilities with the flexibility to participate in the statewide rebate program and still be able to retain some value to support other initiatives to promote the use of electricity as a low carbon fuel including but not limited to rebates for purchase of used EVs, programs focused on charging infrastructure, customer education, customer experience, etc.

c. Staff added a requirement that the rebate amounts offered to new EVs in the statewide point-of-purchase rebate program must be calculated based on the rated battery capacity of the EV. The tiered approach for calculating rebate amounts is based on the same tiered approach used for calculating the Plug-in Electric Drive Motor Vehicle Credit (federal EV tax credit). The tiered structure is simple for auto dealers to understand and implement. This would ensure EVs with higher battery capacity get higher rebates as compared to EVs with lower battery capacity, and would promote battery cost decline through deployment of higher capacity batteries.

8. In sections 95483(c)(1)(B), 95483(c)(2)(C), and 95483(c)(6)(C), staff clarified credit generation requirements for entities reporting electricity used as a transportation fuel. These requirements include use of LCFS credit proceeds to benefit EV drivers and the reporting entity's customers, educating EV drivers and reporting entity's customers regarding the benefits of EV transportation, and providing an annual itemized summary of efforts and costs associated with meeting these requirements.

9. In section 95483(c)(1)(B)1., staff revised to state that incremental credits for residential electric vehicle (EV) charging per Fueling Supply Equipment (FSE) may be generated for either providing low-CI electricity, or for smart charging, but not for both. This would simplify the reporting requirements and prevent any double counting of credits. As previously proposed, generating incremental credit for supplying both low-CI electricity and smart charging at each FSE would have required burdensome reporting requirements to prevent any double counting of credits. For smart charging incremental credits, a residence is required to be enrolled in an EV specific Time-of-Use (TOU) rate plan if the (Load Serving Entity) LSE offers one, and enrollment records must be provided to the Executive Officer upon request. This change would ensure the smart charging benefits are aligned with the LSE offered TOU rates and act as a reinforcing

signal to provide maximum grid benefits.

10. In section 95483(c)(2), staff revised to keep opt-in EDUs as the eligible credit generator for electric vehicle charging at multi-family residences. As previously proposed, the entity owning FSE in multi-family residences would have been eligible to generate credits, but stakeholder comments suggest that EDUs are better suited to receive these credits to help support the point of purchase rebate programs and other utility-specific programs promoting use of electricity as a low carbon fuel, which could include infrastructure development in multi-family residences.

11. In section 95483(c)(6), staff designated the owner of the FSE to be the eligible entity for generating credits for supplying electricity to electric transport refrigeration units (eTRU), electric power to ocean-going vessels (eOGV), and Electric Cargo Handling Equipment (eCHE). This is consistent with other electricity categories where the first fuel reporting entity and credit generator is the FSE owner. The FSE owner has an option to designate any other entity to be a credit generator on its behalf.

12. In section 95483.2, staff added parallel requirements that entities must update their LCFS Data Management System account information. This requirement is designed to facilitate effective program administration.

13. In section 95483.2(a), and elsewhere as applicable, staff removed “scanned” from requirements for submitting electronic copy of documents including attestations. Staff intends to update the LCFS data management system to recognize digital signatures, eliminating the need to upload scanned copies of documents with wet signatures.

14. In section 95483.2(b)(8), staff clarified the FSE registration requirements for residential EV charging and for electric forklifts, electric cargo handling equipment, and for electric power supplied to ocean-going vessels.

15. In section 95483.3(a), staff revised to allow up to 30 days for the previous and new owner of a registered entity or facility notification to CARB after a change of ownership of an entity or facility, in order to accommodate practical compliance concerns raised by stakeholder comments.

16. In section 95484(b) through (d), all carbon intensity (CI) benchmarks in Tables 1, 2, and 3, were modified to align with the revised baseline CI values for California Reformulated Gasoline (CaRFG), California Ultra Low Sulfur Diesel (ULSD), and conventional jet fuel. The baseline CI values were recalculated using the updated CA-GREET3.0 (August 13, 2018) model.

    Changes to CA-GREET3.0 that affect the baseline CI values are: (1) updates to the energy intensity for barge and rail transportation modes; and (2) corrections

to the cell references for a few electricity parameters. These changes resulted in a 0.02 gCO2e/MJ decrease in the baseline CI value of CaRFG, a 0.01 gCO2e/MJ decrease in the CI value of ULSD, and a 0.01 gCO2e/MJ decrease in the baseline CI value for conventional jet, compared to the values provided in the first notice of modifications to the original proposal (June 20, 2018). These changes are documented in the updated CA-GREET3.0 Supplemental Document and Tables of Changes (August 13, 2018), and described briefly below:

Regarding transportation modes, in response to public comments, staff consulted technical experts from several reputable research institutes (including Argonne National Laboratory) and updated the energy intensity of the barge and the rail transportation modes to 223 Btu/ton-mile and 274 Btu/ton-mile, respectively. These values account for both outbound and backhaul trips.

Regarding electricity parameters—because CA-GREET3.0 uses 30 regions to develop region-specific greenhouse gas emissions for electricity generation, whereas Argonne's version of GREET1_2016 uses 13 regions—staff adjusted several cell references to accurately match the energy conversion efficiencies, the emission factors, and the technology shares with the region selection and the "Feedstock/Fuel" options.

17. In section 95486(a)(1), in response to stakeholder comments, staff clarified that credits and deficits can be issued only upon reconciliation of fuel quantity reported per Fuel Pathway Code (FPC) using transaction types Sold with Obligation and Purchased with Obligation.

18. In section 95486(a)(5)(A), staff clarified that all carryback credit transfers must be completed in the LRT-CBTS by April 30th. This change would ensure all carryback credit transfer are completed by the annual reporting deadline so that carryback credits acquired can be used for demonstrating compliance.

19. In section 95486.1(c)(1)(A)2., staff revised to allow the quantity of non-metered electricity used in residential EV charging within service territories for which the EDU has not opted in to the LCFS program to be estimated and assigned to opt-in EDUs for generation of base credits based on the pro-rata share of EVs in the opt-in EDU service territories. This change would ensure that the credits for residential EV charging that are not currently claimed are not left stranded and instead could be used to provide a statewide point-of-purchase rebate.

20. In section 95486.1(c)(2), and elsewhere as applicable, staff added "or smart electrolysis" in order to clarify that the provisions apply to both smart charging pathways (for hourly-reported charging of EVs using grid electricity) and smart electrolysis pathways (for hourly-reported use of grid electricity in hydrogen electrolyzers).

21. In section 95486.1(c)(2)(B), staff clarified the instances when the incremental

credit calculation is used to determine the improvements in electricity compared to the average grid carbon intensity. These instances are limited to:

- Low-CI electricity supplied to residential EV charging; or
- Smart charging: electricity supplied to residential EV charging and reported by hourly windows; and
- Smart electrolysis: electricity supplied to a hydrogen electrolyzer and reported by hourly windows.

Incremental smart charging credits cannot be claimed in addition to incremental low-CI credits.

22. In section 95486.1(d)(1), staff clarified the pathway options and the calculation used to determine credits for non-residential EV charging. These options include a smart charging pathway; however, staff deleted subsection (d)(2) because credits for smart charging for non-residential EV charging are not calculated using the incremental credit calculation in section 95486.1(c)(2)(B), and cannot be in addition to credits for a low-CI pathway.

23. In section 95486.1(e), in response to stakeholder comments staff clarified that all non-EV charging applications using electricity as a transportation fuel can generate credits using the Lookup Table pathways for California Average Grid Electricity or Zero-CI electricity, or a carbon intensity value certified using the Tier 2 pathway application process, including through book-and-claim accounting. These applications are not eligible to generate credits using smart charging pathways.

24. In section 95486.1(f), staff clarified the options for obtaining a certified CI value for hydrogen. Hydrogen produced via electrolysis using average grid electricity is eligible to generate incremental credits using smart electrolysis pathway CI values and the incremental credit calculation in section 95486.1(c)(2)(B). These changes also clarify that smart electrolysis credits are incremental and cannot be in addition to credits for a low-CI electricity pathway.

25. In section 95486.2(a)(1)(C), in response to stakeholder comments staff added a provision restricting HRI crediting for stations built as a required mitigation measure pursuant to California Environmental Quality Act (CEQA). This restriction is designed to ensure that the infrastructure credits drive new investment and the installation of new stations rather than stations that would have been built without this credit.

26. In section 95486.2(a)(2)(D), staff added the requirement that applicants report the expected daily permitted hours of operation for the station, which would be used to determine the station capacity and the station availability for HRI credit calculation pursuant to section 95486.2(a)(6)(A). If the permitted hours of operation for the station are less than 24 hours, the applicant must provide

documentation from a permitting authority demonstrating that the permitted hours of operation are limited.

27. In section 95486.2(a)(2)(E), and elsewhere as applicable, staff added the requirement to calculate station nameplate refueling capacity for the permitted hours of operation using the HySCapE 1.0 model or an equivalent model or capacity estimation methodology approved by the Executive Officer. The HySCapE model has been developed by the National Renewable Energy Laboratory (NREL) under contract from the California Energy Commission (CEC) and uses simple, transparent methods for capacity estimation that can be consistently applied for different station configurations. The applicant must provide a completed model with the application. This change was in response to stakeholder comments that the initially-proposed 12-hour capacity is not representative of actual hydrogen station refueling profiles.

28. In section 95486.2(a)(2)(J) and 95486.2(a)(3)(C), staff revised to require justification for the proposed station location in the initial application. The Executive Officer may reject the application if satisfactory justification is not provided for the proposed station location based on the criterion provided in section 95486.2(a)(2)(J). This change would ensure the stations approved under HRI pathway contribute to developing a robust hydrogen refueling station network to support ZEV adoption.

29. In section 95486.2(a)(3)(A), staff added an equation to calculate estimated potential HRI credits to implement the 2.5 percent limit on HRI credits. As proposed by staff in the June 20 notice, new HRI applications wouldn't be approved if the total HRI credits generated in the prior quarter exceeds 2.5 percent of that quarter's total deficits. This requirement was added to encourage early development of stations while capping the maximum supply of HRI credits. The equation would determine the estimated potential HRI credits for all approved stations, including both operational and non-operational stations. This value would be based on the HRI credits issued in the prior quarter multiplied by the ratio of total approved station capacity (including both operational and under construction stations) to the total capacity of operational stations. Once the estimated potential HRI credits, calculated using this equation, exceeds 2.5 percent; new HRI applications would not be approved and would be queued up until the potential HRI credits fall below the 2.5 percent limit.

30. In section 95486.2(a)(3)(B)(3), staff clarified that the Executive Officer may request additional information or clarification necessary to evaluate application adequacy.

31. In section 95486.2(a)(4), staff made several changes to requirements to generate HRI credits:

    a. Stations must be listed as "open for retail" on the Station Operation Status

System (SOSS). SOSS is a database established and managed by the California Hydrogen Fuel Cell Partnership that provides real-time information about station operations. The station availability reported via SOSS would be used for determining the proposed uptime factor for calculating HRI credits pursuant to section 95486.2(a)(6)(A).

b. Staff removed the previously proposed requirement that the station dispenser performance must be verified by the County Department of Weights and Measures. Instead, all dispensers must undergo type evaluation according to the California Type Evaluation Program (CTEP) and have either a temporary use permit or a type approval certificate of approval issued by the California Department of Food and Agriculture/Division of Measurement Standards. This change would allow HRI requirements to align with the current industry practices.
c. Staff added a requirement to complete the Fueling Supply Equipment (FSE) registration process pursuant to section 95483.2(b)(8), consistent with reporting requirements.
d. In response to stakeholder comments, staff increased the maximum company-wide weighted average CI to 150 gCO_2e/MJ. After incorporating the Energy Economy Ratio (EER) adjustment of 2.5 for light-duty hydrogen fuel cell vehicles, the maximum CI still meets the CI requirement of SB 1505 (30 percent reduction relative to gasoline). This change would provide more flexibility for hydrogen production and transport methods (such as liquid hydrogen delivery).

32. In section 95486.2(a)(6), staff updated the reporting and recordkeeping requirements:

    a. Staff modified how station availability is determined to better align with the approach of using the refueling capacity based on permitted hours of operation. Under the initial proposal, station availability was limited to a 6 am to 9 pm window.
    b. Staff changed the quarterly cost and revenue data reporting requirements in section 95486.2(a)(6)(C), to clarify that the total itemized costs and revenues must be reported for all specified items. Staff clarified that other external funding received towards capital expenditures should be included along with total grant revenue for capital expenditures. Staff also added a requirement to provide total funding towards operational and maintenance expenditures.

33. In section 95486.2(b)(1)(A) and 95486.2(b)(2)(I), staff added a requirement that the FSE must be located in California and open to the public for charging, and must report the total permitted hours of operation in the FCI application. If the permitted hours of operation for the site are less than 24 hours, the applicant must provide documentation from a permitting authority demonstrating that daily permitted hours of operations are limited. This change would ensure the FSE availability is accounted based on the total permitted hours of operation which

would be used for FCI credit calculation pursuant to section 95486.2(b)(5). This would allow charging equipment installed in locations with limited access hours to be eligible for infrastructure credits, such as in State and National Parks.

34. In section 95486.2(b)(1)(B), staff initially proposed that each site applying for FCI crediting must have charging equipment capable of supporting at least two different fast charging connector protocols and must have at least one FSE (Fueling Supply Equipment) with SAE Combined Charging System (CCS) and one FSE with CHAdeMO connector protocol type available on the site. In addition, the previously proposed text would have required that no more than two-thirds of all the FSEs at a site could support only one connector protocol.

    This was proposed to ensure the program can promote a diverse charging network capable of supporting variety of electric vehicles. However, stakeholder comments pointed out that given the lack of standardization among charging connector protocols this requirement might be too prohibitive for some technology providers. In response to this feedback, staff increased the limit on one connector type at a site from two-thirds to three-fourths. Further, staff revised these connector type requirements to be applicable only for the applications that are submitted after an applicant's estimated potential FCI credits exceed 0.5 percent of total program deficits in the prior quarter.

    Based on staff's analysis of Department of Motor Vehicle (DMV) data, the maximum share of registered EVs in California by any brand is about 20 percent. Staff applied the same percentage to the total FCI credit limit, which is 2.5 percent of prior quarter's deficits, to arrive at the 0.5 percent value. The estimated potential FCI credits for an applicant would be calculated using the same methodology as will be used for calculating total estimated FCI credits in section 95486.2(b)(3). This change would allow greater flexibility for the market to drive optimal connector protocol ratios, yet maintain equity in the program by requiring a diverse set of connector types to be installed.

35. In section 95486.2(b)(2)(D), in response to stakeholder comments, a provision was added restricting FCI crediting for FSE built as a required mitigation measure pursuant to the California Environmental Quality Act (CEQA). This restriction is designed to ensure that the infrastructure credits drive new investment and the installation of new charging infrastructure rather than infrastructure that would have been built without this credit.

36. In section 95486.2(b)(2)(E), a requirement was added to report connector type and model of each FSE. Staff also limited the total amount of nameplate power rating to 2,500 kW per site. The initial proposal had a limit of 1,500 kW based on total effective simultaneous power rating for FSE at a site. Notwithstanding this limit, an applicant may request the Executive Officer to approve an application with total nameplate power rating for all FSE at a single site up to 6,000 kW. However, the total number of FSE at sites with total nameplate power rating

greater than 2,500 kW cannot exceed 10 percent of total FSE approved under the FCI pathway. In addition, the applicant must provide justification for requesting a total power rating greater than 2,500 kW at the given site. This change was made in response to stakeholder comments that 1,500 kW may be too limiting to meet future demand at some high traffic locations. However, staff would like to emphasize that in no way does this requirement restrict a site to be limited to 2,500 kW (or 6,000 kW) total power rating but only limits the total power rating at a site eligible to receive FCI credits. This section was also revised to use the nameplate power rating, which is a more easily verifiable value, instead of using effective simultaneous power rating for evaluating compliance with the power rating limit per site.

37. In section 95486.2(b)(2)(F), a requirement was added that the effective simultaneous power rating for each FSE must be at least 50 percent of the nameplate power rating. This would ensure that the useful FSE capacity is not significantly lower than the capacity calculated using the nameplate power rating, which is also used in the credit calculation.

38. In section 95486.2(b), and elsewhere as applicable, staff clarified that both nameplate power rating and effective simultaneous power rating must be reported.

39. In section 95486.2(b)(2)(G), the following changes were made:

    a. The FCI Charging Capacity used in the credit calculation was altered to be proportional to the power rating raised to the 0.45 power, rather than directly proportional to power rating as in the original proposal. This change was in response to stakeholder comments that the cost of installing a fast charger is not proportional to the power rating. The FCI charging capacity method for credit calculation was based on best cost estimates available to staff and designed to ensure the estimated value of awarded credits scales proportionally with the installation costs of equipment with higher power ratings.
    b. The maximum power rating for FCI credit calculation was revised to 350 kW instead of 150 kW. Several automakers have already announced or have plans to launch next generation of EVs which could support charging at higher power ratings. This change would allow higher power rating chargers to be eligible for FCI crediting and would provide incentive to create a charging network capable of supporting fast charging for the next generation of EVs.

40. In section 95486.2(b)(3)(A), an equation was added to calculate estimated potential FCI credits to implement the 2.5 percent limit on FCI credits. As proposed by staff in the June 20 notice, new FCI applications wouldn’t be approved if the total FCI credits generated in the prior quarter exceeds 2.5 percent of that quarter's total deficits. This requirement was added to encourage

early development of stations while capping the maximum supply of FCI credits. The added equation would determine the estimated potential FCI credits for all approved FSE, including both operational and non-operational FSE. This value will be based on the FCI credits issued in the prior quarter multiplied by the ratio of total approved FSE capacity (including both operational and under construction FSE) to the total capacity of operational FSE. Once the estimated potential FCI credits, calculated using this equation, exceeds 2.5 percent; new FCI applications will not be approved and will be queued up until the potential FCI credits fall below the 2.5 percent limit.

41. In section 95486.2(b)(3)(B), a method was added for calculating estimated potential FCI credits for an individual applicant which would be used to determine compliance with the connector protocol type requirements in section 95486.2(b)(1)(B).

42. In section 95486.2(b)(3)(C)(3), it was clarified that the Executive Officer may request additional information or clarification necessary to evaluate application adequacy.

43. In section 95486.2(b)(4), the following requirements to generate FCI credits were updated:

    a. In section 95486.2(b)(4)(C), staff clarified that FSEs charging a fee for service must be capable of accepting all major credit and debit cards without putting any limitations on point-of-sale payment methods. In response to stakeholder comments, the initially proposed requirements for payment methods are simplified given that there is a separate rulemaking process occurring in response to Senate Bill 454 (Corbett, 2013), which addresses the details of access and payment methods for electric vehicle charging stations. This rulemaking is expected to be completed in 2019.
    b. In section 95486.2(b)(4)(E), staff removed the initially proposed requirement to include the FSE owner's declaration that the FSE meets an appropriate SAE fueling protocol, as required in California. This requirement had been proposed to align the FCI provision with the HRI provision; however, there is no requirement for fast charging equipment in California to meet any SAE fueling protocol.
    c. In response to stakeholder comments and to avoid including requirements that could be duplicative or in conflict with any future regulations, staff removed the requirement that the charging unit's performance must be verified by the County Department of Weights and Measures. This issue is being addressed by the Division of Measurements and Standards in a separate rulemaking.
    d. In section 95486.2(b)(4)(F), staff added a requirement to complete the Fueling Supply Equipment (FSE) registration process pursuant to section 95483.2(b)(8), consistent with reporting requirements.
    e. In section 95486.2(b)(4)(G), staff added a requirement that an FSE must be

operational within 12 months from the date of approval otherwise the application would be canceled. The applicant could re-apply for the same FSE but it would be eligible for only two years of crediting instead of five years. This requirement would ensure that applicants are committed and prepared to install FSE upon approval of the application and are not holding any FCI credits from other applicants.

f. In section 95486.2(b)(4)(H), staff added a limit to the total value of FCI credits available to any given FSE equal to the difference between the total capital expenditure for the FSE borne by the FSE owner, and the total grant and other funding received by the FSE owner towards the capital expenditure for that FSE installation. The FCI credit value will be estimated based on the quarterly average credit prices published by CARB, and will be discounted by 10 percent to determine the dollar value in the application year. This change was in response to stakeholder comments about potential of over-crediting of FSEs under FCI pathways, and will prevent over-compensating stations when LCFS credit values are very high and/or FSE installation costs become low. This limit does not affect non-FCI LCFS credit generation and derived value for dispensed electricity.

44. In section 95486.2(b)(5), staff revised the equation used for calculating FCI credits to use FCI charging capacity as determined pursuant to section 95486.2(b)(2)(G), instead of using the effective simultaneous power rating. As mentioned above, the changes were made in response to stakeholder comments that the original method of capacity determination, and in turn credit calculation, could have resulted in over-crediting of higher power rating chargers, relative to their installation costs.

45. In section 95486.2(b)(6), staff made minor modifications to the reporting requirements:

    a. Similar to the changes for HRI provision, staff modified how the FSE availability is determined. This change would allow comparison of permitted hours of operation with the reported FSE availability to determine the uptime factor which is used for calculating credits.
    b. Staff made minor changes to the quarterly cost and revenue data reporting requirements in section 95486.2(b)(6)(B). Staff added “total” for all specified cost items to provide additional clarity. Staff clarified that other external funding received towards capital expenditures should be included along with total grant revenue for capital expenditures. Staff also added a requirement to provide total funding towards operational and maintenance expenditures.

46. In section 95487(b)(1)(D), staff clarified the reporting of Type 2 credit transfers, in response to stakeholder comments.

47. In section 95488.1(b)(2)(A), staff replaced the list of energy resources that may

be reported using the Lookup Table pathway for zero-CI electricity with "eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36, excluding biomass, biomethane, geothermal, and municipal solid waste." This clarifies that any resource meeting the criteria established under California's Renewable Portfolio Standard program and which has been determined to achieve a CI of 0 gCO_2e/MJ using the CA-GREET3.0 model may be reported using this pathway. These changes were in response to stakeholder comments.

Stakeholders also requested that staff consider RPS-eligible hydroelectric facilities[8] as a qualifying zero-CI source. The following types of hydroelectric facilities may be RPS-eligible and as such would be included as a zero-CI pathway under the modified regulation: 1) Small hydroelectric facilities 30 MW or less; 2) Conduit hydroelectric facilities 30 MW or less; 3) Hydroelectric generation units 40 MW or less and operated as part of a water supply or conveyance system; and 4) Incremental hydroelectric facilities.

48. In section 95488.1(c), distiller's sorghum oil (or technical sorghum oil) was added as a feedstock for biodiesel and renewable diesel under the Tier 1 classification. In accordance with this change, the Tier 1 Simplified CI Calculator for Biodiesel and Renewable Diesel was modified to accommodate this feedstock. This change mirrors the recent decision by the federal U.S. Environmental Protection Agency to recognize sorghum oil as a feedstock under the Renewable Fuel Standard.[9] Consistent with distiller's corn oil, this feedstock is also added to the list of specified source feedstocks in 95488.8(g).

49. In section 95488.3(b), the emission factors used in each Tier 1 Simplified CI Calculator were recalculated to align with changes to CA-GREET3.0, and other modifications were made to Tier 1 Simplified Cl Calculators (released June 20, 2018). These changes are documented in the CA-GREET3.0 Supplemental Document and Tables of Changes (August 13, 2018).

50. In section 95488.3(b)(1), the title of the "Tier 1 Simplified CI Calculator for Starch and Corn-Fiber Ethanol," which determines CI values for corn ethanol, grain sorghum ethanol, and corn- and grain sorghum-fiber ethanol, was modified to the "Tier 1 Simplified CI Calculator for Starch and Fiber Ethanol." Grain sorghum is often mixed with corn at the ethanol plants and quantities of each feedstock are reported; both ingredients contain similar amounts of fiber, which can be converted to fiber ethanol. The calculator already has the capability of evaluating ethanol production of fiber derived from corn and grain sorghum, and staff believes the new name is more inclusive and representative of common practice.

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[8] The specific criteria for RPS-eligible hydroelectric facilities can be found in California Public Utilities Code sections 399.12 and 399.12.5.

[9] Final Rule. Renewable Fuel Standard Program: Grain Sorghum Oil Pathway. EPA-HQ-OAR-2017-0655. U.S. Environmental Protection Agency. 40 CFR Part 80. www.regulations.gov

51. In section 95488.3(b)(8), staff modified the title of the "Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Food, Green and Other Organic Waste" to "Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Organic Waste." This change was made to reflect the wide variety of organic wastes that can be assessed using this Simplified CI Calculator.

In the Tier 1 Manual, staff also clarified the types of waste that can be included under each of the three categories that are represented: food scraps are waste that is either separated from municipal solid waste or separately collected from residences, restaurants, schools, hospitals, grocery stores and other points of origin identified in the Tier 1 Manual. According to a 2014 statewide waste characterization study,[10] in California, the 97.5 percent (by mass) of these wastes is landfill disposal; therefore, the system boundary for this feedstock includes the fugitive methane emissions from landfills that are avoided by diversion of the material to its use as a biofuel feedstock. The avoided fate (also termed the baseline, or business-as-usual fate) of the remaining 2.5 percent is recycling into compost.

Staff has also clarified what is meant by green waste, by changing this category to "urban landscaping waste (ULW)," which is the portion of MSW that includes materials resulting from landscaping activities, e.g., leaves, grass clippings, branches, and other yard waste typically collected by municipalities. In California, the avoided fate of 35.9 percent (by mass) of these wastes is landfill disposal; therefore, the system boundary for this feedstock includes the fugitive methane emissions from landfills that are avoided by waste diversion. The avoided fate of the remaining 64.1 percent is recycling into compost.

The "other organic waste" category can be used for materials that do not fit the food scraps or ULW descriptions, compositions, and avoided fate assumptions. Applicants for this category must submit the moisture content of the material, the degradable organic carbon (DOC) content and the fraction of DOC that decomposes (DOC_f). Both user-defined DOC and DOC_f must be determined either from representative sampling and laboratory analysis, or using the equations provided in the calculator and the Tier 1 Manual. Additionally, applicants must demonstrate the business-as-usual fate (e.g. landfill, compost, animal feed, and land application) and diversion rate of the material from typical commercial practices.

52. In sections 95488.5(d), (e), and Table 7-1, and elsewhere as applicable, staff modified the description of Lookup Table pathways for electricity to clarify that these pathways can be used for reporting the electricity "used as a transportation fuel" in several applications such as fixed guideways (listed in section

[10] 2014 Disposal-Facility-Based Characterization of Solid Waste in California. October 6, 2015. Publication # DRRR-2015-1546. California Department of Resources Recycling and Recovery (CalRecycle). Available at: http://www.calrecycle.ca.gov/Publications/Documents/1546/20151546.pdf

95483(c)(4) through (7)), not limited to electric vehicle charging. This modification excludes smart charging pathways, which can only be used for charging battery and plug-in hybrid electric vehicles.

53. In section 95488.5(e), Table 7-1, several of the Lookup Table CI values changed minimally as a result of updates to Transportation and Distribution parameters and Electricity parameters in CA-GREET3.0. The CI value of California Average Grid Electricity decreased because staff resolved an error in the California resource mix; the percentage of biomass and nuclear power from CEC (2016) were inadvertently transposed in the previous version of the model. These changes are documented in the CA-GREET3.0 Supplemental Document and Tables of Changes (August 13, 2018) and CA-GREET3.0 Lookup Table Pathways Technical Support Documentation (August 13, 2018).

54. In section 95488.5(f), staff clarified the process for an out-of-state producer of hydrogen by electrolysis to apply for smart electrolysis pathway using the Tier 2 application process, for hydrogen imported to California. The CI values calculated in Table 7-2 are only applicable to California electricity, but staff recognizes the potential benefit of aligning use of electricity for electrolysis with grid demand in other regions.

55. In section 95488.5(f), Table 7-2, under the previous proposal, the CI values for smart charging and smart electrolysis were based on the historical curtailment probability. The intent of the provision is to promote time shifting of EV charging or electrolytic hydrogen production load to provide greater emission reductions. Stakeholder comments expressed that calculating these credits using grid's marginal Greenhouse Gas (GHG) emissions would be a better approach. In response to stakeholder comments, staff updated the methodology and used marginal GHG emissions signal from the California Public Utilities Commission's (CPUC) Avoided Cost Calculator, instead of using curtailment probability, to determine the hourly CI values for smart charging and smart electrolysis pathways.

56. In section 95488.8(i)(1) and (2), staff clarified that book-and-claim accounting may be used for electricity and biomethane supplied to produce hydrogen that is used as a transportation fuel, as well as hydrogen used in the production of a transportation fuel—including both hydrogen used in petroleum refineries, which can be claimed under the Renewable Hydrogen Refinery Credit provision, and hydrogen used e.g., in hydrotreatment for renewable diesel production.

57. In section 95488.8(i)(1)(A), staff added an option to recognize low-CI electricity under the book-and-claim accounting rules that is delivered to a California Balancing Authority (CBA) in a manner that satisfies the criteria of California Public Utilities Code section 399.16, subdivision (b)(1) under California's Renewables Portfolio Standard Program. This category requires that the energy and its environmental attributes are delivered to a CBA without substituting

electricity from another source, and may include out-of-state generation facilities that deliver according to an hourly or sub-hourly schedule. This allows fair treatment of out-of-state renewables in line with existing California law.

58. In section 95488.8(i)(1)(B), staff made several minor clarifying modifications in response to stakeholder comment, including that retirement of Renewable Energy Credits (REC) for the purpose of demonstrating Green Tariff Shared Renewables procurement to the California Public Utilities Commission does not constitute a double claim.

59. In section 95488.9(b)(4), staff revised to allow applicants to request a new Temporary CI only for a fuel or feedstock-fuel combination that is not listed in Table 8. This provision would incentivize novel pathways by allowing applicants to generate credits while the application for fuel pathway certification is being prepared or evaluated by CARB.

60. In section 95488.9(b), staff revised the rounding methodology used in determining the Temporary CI values. Staff identified the highest certified CI for each pathway (where more than one such pathway has been certified), added 5 percent to that value, and rounded to the nearest five CI points—rather than rounding up to the nearest five as originally proposed. Upon detailed examination, staff noticed that using the "rounding up" method would result in disproportionately-conservative values for some pathways. This change results in a decrease to the Temporary CI values for ethanol from any sugar feedstock and biomethane (CNG, LNG and L-CNG) from wastewater or organic waste.

    Staff increased the Temporary CI value for ethanol from cellulosic biomass based on a recently-updated certified pathway using the same methodology described above.

61. In section 95488.9(c), staff clarified that provisional pathways, which are certified on the basis of three months of operational data, may be considered for either a new facility or an existing facility that has implemented a process change. This allows an improved pathway to be more accurately modeled by re-applying with a new operational data set, rather than averaging the new process parameters with the prior 24 months of data.

62. In section 95489(c), staff made multiple clarifications to innovative crude to specify where a provision applies to innovative transport and production.

63. In section 95489(c)(1)(A)5., staff removed the list of additional energy resources that were proposed by staff in the June 20 notice to be eligible for use in innovative crude production or transport, because the benefits of including these sources in crude applications may require a more extensive analysis than can be accomplished given the current rulemaking timeline.

64. In section 95489(e), staff removed the term “pilot” from the Refinery Investment Credit Pilot Program. The “pilot” designation may imply a temporary nature of the program dissuading potential investments in innovative refinery projects with potential for significant greenhouse gas emission reductions. Staff believes that the removal of the pilot designation provides long-term policy certainty that refinery operators are looking for to make investment decisions reading innovative projects.

65. In section 95489(f), staff revised the definitions of carbon intensities for natural gas and renewable natural gas used in calculating credits for the Renewable Hydrogen Refinery Credit Program. The revisions intended to clarify the system boundary and prevent inaccurate credit calculations.

66. In section 95491(d)(1)(C), staff clarified the rules for allocating feedstock to fuel quantities in the case of a fuel production facility that processes multiple feedstocks. These changes clearly prohibit double counting. The system for LCFS verification would include reviewing all feedstock inputs and fuel production regardless of final market to assure no double counting of feedstock attributes. The change to clarify this intent specifies that feedstock attributes must be counted as processed (subtracted from the inventory accounting system) for all fuel produced in each quarter, not just fuel delivered to California and reported in the LRT. Fuel reported in the LRT would use the yield calculation specified in the regulation, or an allocation method approved by the Executive Officer.

    Staff also added a provision to address feedstocks that are differentiated by chemical analysis of a converted fraction of measured feedstock. Because such feedstocks, e.g., the fiber fraction of corn or grain sorghum, are not measured by inventory accounting, a methodology is needed to clarify the requirements for labeling and reporting produced fuel associated with each converted fraction.

67. In section 95491(d)(2), staff cross-referenced the FSE registration requirements as set forth in section 95483.2(b), wherever applicable.

68. In section 95491(d)(3)(A) paragraphs 2. through 7., staff added a separate requirement for LSE and non-LSE electricity credit generators to use LCFS credit proceeds to benefit EV drivers, educate them about the benefits of EV transportation, and annually provide an itemized summary of efforts and costs associated with meeting this requirement. In the current regulation, non-LSEs are required to meet the same requirements as LSEs. This change would ensure requirements for using LCFS proceeds and reporting on those efforts are clear for LSE and non-LSE entities.

69. In section 95491(d)(3)(A)2., staff clarified that an LSE generating credits must use all credit proceeds to benefit the current or future EV drivers across California, not limited to within its service territory. This would allow opt-in utilities

to use base credit proceeds for a statewide point-of-purchase rebate.

70. In section 95491(d)(3)(A)5., Investor-owned Utilities (IOUs) are required to provide, in addition to the supplemental information reported annually, an unredacted copy of the annual implementation report required under Order 4 of Public Utilities Commission of California (PUC) Decision 14-12-083, or any successor PUC Decisions. In the current regulation, the two are available as options but the text is amended to require both. This change will allow CARB to receive most updated and detailed information about IOUs efforts to provide benefits to EV drivers and to promote electricity as a low carbon transportation fuel.

71. In section 95491(d)(3)(B), the reporting requirements for generating credits for metered residential EV charging using different fuel pathways were clarified. If Renewable Energy Certificates (REC) are generated for low-CI electricity that is claimed for EV charging, then that evidence must be provided to demonstrate REC retirement in Western Renewable Energy Generation Information System (WREGIS) for the purpose of LCFS credit generation. For smart charging incremental credits, a residence must be enrolled in an EV specific Time-of-Use (TOU) rate plan if the LSE offers one, and enrollment records must be provided to the Executive Officer upon request.

72. In section 95491(d)(3)(C), the reporting requirements for generating credits for non-residential EV charging using different fuel pathways were clarified. The changes clarify the reporting requirements specific to generating incremental credits using low-CI electricity or smart charging pathways, consistent with the previous section.

73. In section 95491(d)(3)(E)2., staff clarified that in the absence of metered data, the quantity of electricity supplied to electric forklifts can be estimated using a methodology approved by the Executive Officer. This is allowed under the existing LCFS regulation as the majority of electric forklift charging in California is non-metered.

74. In section 95491(d)(4)(D), the requirements for reporting electricity to generate incremental credits for smart electrolysis were clarified, consistent with the requirements for EV smart charging.

75. In section 95491.1(b), staff cited the specific subsection, 95483(a), which applies only to liquid fuels, in order to clarify that requirements related to product transfer document apply only to fuel reporting entities for liquid fuels.

76. In sections 95500(b)(2)(B) and (c)(2)(B), staff included non-liquid alternative fuels and deficit-generating alternative fuels in the eligibility threshold for deferred verification, excluding fuel pathways with biomethane using book-and-claim accounting. Expanding eligibility for verification deferral is necessary for

consistency and would help small fossil CNG and fossil LPG facilities (previously opt-in fuels) to participate in LCFS. Biomethane is a fuel that can be high risk for accounting errors and double counting, therefore biomethane must be verified annually to meet the regulatory requirements. Staff does not believe that many biomethane fuel pathway holders using book-and-claim accounting would be affected by this requirement because they typically generate more than 6,000 credits per year. In addition, biomethane suppliers also voluntarily participate in U.S. EPA's Quality Assurance Plan (QAP) program which requires quarterly audits and semi-annual site visits due to the risk of RIN invalidation. Staff anticipates that LCFS biomethane verification will be stacked with QAP audits for efficiency as QAP auditors seek and maintain accreditation to conduct LCFS verification services.

77. In section 95500(c)(2)(C), staff added a heading to clarify that the verification exemption applies to designated transactions and to state the threshold consistent with the eligibility threshold for deferred verification. This is a non-substantive change, as the actual verification requirements remain the same as in the initial proposal.

78. In section 95501(b)(4)(E), staff clarified that specified source feedstocks in fuel pathways that do not require monitoring and verification of operational CI must be verified during review of Quarterly Fuel Transactions Reports, to ensure the correct characterization of specified source feedstocks. For example, certain Lookup Table pathways may include specified source feedstocks but are not required to monitor operational CI, so they are not required to contract for third-party validation of their application and are not required to submit annual Fuel Pathway Reports which would otherwise include review of specified source feedstocks.

79. In section 95503(b), staff extended the period for phasing in specified high-risk conflict of interest activitities from January 1, 2023 to August 31, 2023 to allow for completion of verification of 2022 data before requiring rotation of verification bodies. One additional category of services considered high risk for potential conflict of interest would be treated as medium risk until August 31, 2023. This change will facilitate smooth implementation of the verification program by providing 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.

80. In section 95503(b)(2)(A), staff provided additional clarifications for for services with high risk of potential conflict of interest by specifically excluding third-party engineering reports provided pursuant to U.S.EPA RFS, which would not require assessment under a risk category.

81. In section 95503(c), staff made clear that audit services provided under U.S. EPA

RFS (QAP audits, attest engagement services, third-party engineering reports) would be disclosed but would not require assessment under a risk category. In addition staff clarified that verifications conducted pursuant to MRR or the Cap-and-Trade Regulation would not require assessment under a risk category as these services are conducted under independence requirements that are similarly rigorous to those under the LCFS verification program.

<u>Second 15-Day Modifications to Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CCS Protocol).</u>

1. Modifications throughout the CCS Protocol
   a. Staff revised the use of the term “confining layer” to agree with the new storage complex definition and to reflect the possibility that the storage complex may include more than one confining layer.
   b. Staff made modifications to correct typographical, stylistic, or grammatical errors, changes in numbering and formatting, and other non-substantive revisions to improve clarity.

2. Modifications to Definitions (subsection A.3(a))
   a. Staff revised the definitions of “pore space” and “porosity” for clarity.
   b. Staff deleted the definition of “area of review” and removed the remaining references to the term throughout the rest of the document, to avoid confusion and improve clarity. “Area of review” was replaced with “the surface projection of the storage complex.”

   c. Staff added definitions for “validation” and “verification,” to improve clarity.

3. Modifications to subsection Permanence Certification of Geologic Carbon Sequestration Projects (subsection C.1)
   a. In subsection C.1.1.1, staff clarified that the professional geologists and engineers who perform third-party reviews may be licensed by jurisdictions other than California.
   b. In subsection C.1.1.3.2(a), staff modified the text for clarity and concision.

4. Modification to Site Characterization (subsection C.2)
   a. In subsection C.2.3.1, staff added a provision that allows existing CCS projects to substitute historical data in lieu of the testing and well logging requirements for new projects, provided that the data submitted is equivalent.
   b. In subsection C.2.4.1(a)(2), staff added an option for the code(s) used to delineate the storage complex and model the plume extent. The additional option includes a set of requirements that allow operators to use proprietary, commercially available software. New requirements for model code(s) include peer-review, CARB access, and third-party validation.
   c. In subsection C.2.4.3(b)(1), staff clarified that operators must use “best available methods and technologies” to identify artificial penetrations through the storage complex in an effort to increase clarity and promote the use of

best practices.

d. In subsection C.2.4.3(b), staff combined subsections (b)(1) and (b)(2) to reduce redundancy.
e. Staff changed the heading of subsection C.2.4.4 from “Plume Reevaluation” to “Plume Extent Reevaluation” for clarity and to match the heading of subsection C.2.4.4.1.
f. Staff added a provision to subsection C.2.4.4(b) that requires operators to submit the reevaluated model for third-party review consistent with the new requirements in subsection C.2.4.1(a)(2).
g. Staff modified subsections C.2.4.4.1(c)(1) and (c)(2) to improve technical accuracy and clarity.

5. Modifications to Well Construction and Operating Requirements (subsection C.3)
   a. In subsections C.3.1(c)(1) and (c)(5), staff added an illustrative example of the type of materials that qualify as “compatible with fluids they will come into contact with” during injection, e.g., corrosion resistant materials.
   b. In subsection C.3.2(a)(1), staff modified the language to clarify that consistent with common practice, data may be collected during both the drilling and construction of wells, not one or the other.
   c. In order to clarify subsection C.3.2(c)(1), staff added language such that deviation checks are required only if pilot holes are drilled as part of the CCS project.
   d. In subsection C.3.3(b), staff added language to allow alternative injection pressures, provided the operator justifies the need for alternative pressure, and pending Executive Officer approval.
   e. Staff modified subsection C.3.3(f) to make clear that operators must act immediately upon discovery that automatic alarm(s) or automatic shut-off system(s) were triggered that were not immediately remedied.
   f. In subsection C.3.4(a)(3), staff clarified that operators must cease injection upon discovery that automatic alarm(s) or shut-off system(s) were triggered that were not immediately remedied.

6. Modifications to Testing and Monitoring (subsection C.4)
   a. In subsection C.4.1(a)(7), staff modified to allow operators to propose an alternative schedule for external mechanical integrity tests (not to exceed once every five years).
   b. In subsection C.4.1(a)(8), staff removed redundant language to improve clarity.
   c. Staff combined subsections C.4.1(a)(9) and (a)(12) to reduce redundancy.
   d. Staff added language to subsection C.4.3.1.3(c) for consistency with modifications to subsection C.3.3(b).
   e. In subsection C.4.3.1.5(a), staff revised to allow alternative test methods and schedules, provided the operator submits a demonstration of the necessity of the method and schedule proposed, and pending Executive Officer approval.
   f. In subsection C.4.3.2.3(a), staff clarified that the seismic monitoring equipment need not be deployed downhole for each well associated with the

CCS project, but that the system must be capable of detecting microseismic activity associated with each well.

g. In subsection C.4.3.2.3(b)(1), staff revised to allow operators to monitor seismic activity via state seismic networks that are equivalent to California's Integrated Seismic Network.
h. In subsection C.4.3.2.3(b)(2), staff clarified that the professional geologists and engineers who perform third-party reviews may be licensed by jurisdictions other than California.

7. Modifications to Well Plugging and Abandonment and Post-Injection Site Care and Site Closure (subsection C.5)
   a. In subsection C.5.2(b)(3)(A), staff clarified that wells must be plugged within 24 months after the CCS project enters the post-injection site care period, to accommodate projects that continue operations after injection for CO_2 sequestration ceases.
   b. In subsection C.5.2(b)(3)(B), staff changed "determines" to "approves," to allow operators to propose a demonstration of stabilization as part of site closure and site care proceedings.
   c. In subsection C.5.2(b)(3)(G), staff removed overly prescriptive requirements, and linked the post-injection monitoring strategy to the risk assessment required in subsection C.2.2. The modifications also include a list of information and data requirements that the post-injection strategy must meet, at a minimum, to receive Permanence Certification pursuant to subsection C.1.1.3.

These modifications primarily consist of refinements and clarifications to the initial proposal, and do not change the conclusions of the environmental analysis included in the Staff Report. As supported by substantial evidence in the administrative record, CARB has determined that any changes in compliance responses resulting from the modifications do not result in any of the circumstances requiring recirculation of the analysis as set forth in section 15088.5 of the CEQA Guidelines.

In the interest of completeness, staff added to the rulemaking record and invited comments on additional documents. The documents, described in more detail in the first and second 15-day notices, included (1) updated models and the Protocol for Carbon Capture and Sequestration that are incorporated into the regulation by reference, and (2) additional references that came to CARB's attention after the initial notice of proposed rulemaking.