Attachment A-1.1

Final Regulation Order, Alternate/Accessible Format

Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

[Note: This alternate version of the Final Regulation Order is provided in a tracked changes format to improve the accessibility of the regulatory text. This version is not the authoritative version for this rulemaking, nor is it additional regulatory text, but is an alternate/duplicate version provided for the purposes of improved accessibility. The amendments are incorporated into the current regulatory text for ease of readability only. For the authoritative version that complies with California Code of Regulations, title 1, section 8, subdivision (b), please see the pdf version titled, “Attachment A-1, Final Regulation Order.” To review this document in a clean format (no underline or strikeout to show changes), please select “Simple Markup” or “No Markup” in Microsoft Word’s Review menu. You can also change the view to the original (current regulatory text prior to proposed amendments) by selecting “Original. Additionally, “Advanced Track Changes Options” will allow for further options regarding color and other markings. Instructions on using/viewing Track Changes can be found here]

Final Regulation Order

Title 17, California Code of Regulations

(Note: The amendments to existing regulatory language are shown in strikethrough to indicate deletions and underline to indicate additions. Various portions of the regulation that are not modified by the amendments are omitted from the text shown and indicated by "* * * * *".)

Subarticle 1. General Requirements for Greenhouse Gas Reporting

§ 95100. Purpose and Scope.

(a) The purpose of this article is to establish mandatory greenhouse gas (GHG) reporting, verification, and other requirements for operators of certain facilities that directly emit GHGs, suppliers of certain fuels and carbon dioxide, electric power entities, verifiers of GHG emissions data reports and offset project data reports submitted pursuant to the ~~c~~Cap-and~~-trade regulation~~Invest Regulation, and verification bodies. This article is designed to meet the requirements of section 38530 of the Health and Safety Code, and to support GHG emissions inventory and regulatory programs of the California Air Resources Board.

(b) *Organization of this Article*. Subarticle 1 specifies general requirements for the reporting of GHG emissions that apply to all reporting entities listed in section 95101. Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities and entities. Subarticle 3 specifies additional requirements for reported data, including procedures for the substitution for missing data. Subarticle 4 specifies verification requirements for GHG emissions data reports, requirements for those who provide verification services for GHG reporting entities, and accreditation requirements for verifiers of emissions data reports and offset project data reports. Subarticle 5 specifies reporting requirements and calculation methods for petroleum and natural gas production, processing, and storage facilities.

(c) *U.S. EPA GHG Reporting Rule*. This article incorporates various provisions of title 40, Code of Federal Regulations (CFR), Part 98. These provisions are a portion of the U.S. Environmental Protection Agency (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases. Unless otherwise specified, references in this article to 40 CFR Part 98 are to those requirements promulgated by U.S. EPA and published in the Federal Register on October 30, 2009, July 12, 2010, September 22, 2010, October 28, 2010, November 30, 2010, December 17, 2010, and April 25, 2011.

(d) Except as otherwise specifically provided:

(1) Wherever the term “Administrator” is used in the federal rules referred to in this article, the term “Executive Officer of the California Air Resources Board” or “Executive Officer” shall be substituted.

(2) Wherever the term “EPA” is used in the federal rules referred to in this article, the term “California Air Resources Board” or “CARB” shall be substituted.

(3) In cases where the owner and operator of a facility or a supplier are not the same party, the operator is responsible for compliance with this article.

(4) For purposes of reporting GHG emissions in California, reporting entities must follow the requirements of this article where any incorporated provisions of 40 CFR Part 98 or Part 75 appear in conflict with it.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95101. Applicability

(a) *General Applicability*.

(1) This article applies to the following entities:

(A) Operators of facilities located in California with source categories listed below are subject to this article regardless of emissions level:

1. Electricity generation units that report CO_2 mass emissions year round through 40 CFR Part 75;

2. Cement production;

3. Lime manufacturing;

4. Nitric acid production;

5. Petroleum refineries and biorefineries;

6. Geologic sequestration of carbon dioxide;

7. Injection of carbon dioxide.

(B) Operators of facilities located in California with source categories listed below, are subject to this article when stationary combustion and process emissions of CO_2, CH_4, and N_2O equal or exceed 10,000 metric tons CO_2e for a calendar year:

1. Stationary fuel combustion, which includes electricity generating units not subject to 40 CFR Part 75~~;~~ and electricity generating units that utilize thermochemical and/or electrochemical fuel conversion;

2. Glass production;

3. Hydrogen production;

4. Iron and steel production;

5. Pulp and paper manufacturing;

6. Petroleum and natural gas systems;

7. Geothermal electricity generation;

8. Lead production;

(C) Suppliers of fuels provided for consumption within California that are specified below in paragraph (c);

(D) Carbon dioxide suppliers as specified below in paragraph (c), including CO_2 producers regardless of quantity produced, and CO_2 importers and exporters when annual bulk imports or exports equal or exceed 10,000 metric tons;

(E) Electric power entities as specified below in paragraph (d); and,

(F) Operators of petroleum and natural gas systems as specified below in paragraph (e).

(G) Any California reporting entity subject to subparts E, F, G, I, K, L, O, R, T, U, X, Z, BB, CC, EE, FF, GG, II, LL, OO, QQ, SS, or TT of 40 CFR Part 98 that emits over 10,000 metric tons of CO_2e resulting from CO_2, N_2O, or CH_4 emissions. If a reporting entity utilizes the above industrial processes and emits over 10,000 metric tons of CO_2e resulting from CO_2, N_2O, or CH_4 emissions, they must notify the Executive Officer within 90 days of the effective date of this regulation or within 90 days of commencing the industrial process. This notification requirement also applies to facility operators subject to section 95103(a), for abbreviated reporting.

(H) Importers of cement, as defined in section 95102(a), whose total annual emissions from imported cement or clinker equal or exceed 10,000 MT CO_2e, as calculated pursuant to section 95126(b)(3).

(I) Importers of hydrogen that import at least 500 metric tons of hydrogen to California in a calendar year, and operators of in-state hydrogen plants that produce at least 500 metric tons of hydrogen utilizing electricity in a calendar year that are not subject to reporting under section 95101(a)(1)(B)3.

(2) Any reporting entity in one or more of the categories in subsection (a)(1) above must submit an annual emissions data report, except as provided in the cessation provisions of subsections (h) and (i) of this section. The emissions data report must cover all source categories and GHGs for which calculation methods are provided or referenced in this article, for the reporting entity. Except as otherwise specified in this article, the report must be compiled using the methods specified by source category in 40 CFR Part 98.

(3) If a facility operator determines their reporting applicability and responsibility on the basis of common ownership, the basis of reporting applicability and responsibility can only be changed to common control at the beginning of a compliance period. If a facility operator determines their reporting applicability and responsibility on the basis of common control, the basis of reporting applicability and responsibility can only be changed to common ownership at the beginning of a compliance period. These provisions do not apply if there is a legal change in facility ownership. If there is a change in facility ownership, the provisions of section 95103(n) apply.

(4) Verifiers and Verification Bodies. In addition to the reporting entities specified in subsection (a)(1) above, this article contains requirements for entities acting as verification bodies and individuals acting as third party verifiers of emissions data reports and offset project data reports. These requirements are specified in sections 95130 through 95133 of this article.

(b) *Calculating Facility GHG Emissions Relative to Thresholds*. For facilities for which an emissions-based applicability threshold is specified in section 95101(a)(1), the operator must calculate emissions for comparison to applicable thresholds as specified below:

(1) For the purpose of computing emissions relative to the 25,000 metric ton CO_2e threshold specified in section 95812 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, operators must include all covered emissions of CO_2, CH_4, and N_2O.

(2) For the purpose of computing emissions relative to the 10,000 metric ton CO_2e threshold for reporting applicability specified in section 95101(a), operators must include emissions of CO_2, CH_4 and N_2O from stationary combustion sources and process emissions, but may exclude any vented and fugitive emissions from the estimate. Petroleum and natural gas system facilities identified under section 95101(e) must include all flaring emissions in the 10,000 metric ton CO_2e threshold determination. If all the CO_2, CH_4, and N_2O emissions emitted within the reporting entity's facility boundary, including vented and fugitive emissions, exceed the 25,000 metric ton CO_2e threshold specified in sections 95103(a) and 95103(f), the reporting entity is not eligible for the abbreviated reporting option provided in section 95103(a) and must submit an emissions data report pursuant to the full requirements of this Article, including obtaining verification services pursuant to section 95103(f).

(3) When determining applicability relative to the thresholds for emissions reporting in sections 95101(b)(1) and (2) above, facility operators must include any supplier emissions from source categories in sections 95101(c)(5), (7), (8) and (10). If the threshold for reporting is exceeded, the facility and supplier emissions must be reported. If emissions are reported under multiple ARB facility IDs, the operator must report the other ARB facility ID's associated with the facility.

(4) Operators of facilities and suppliers must include emissions of CO_2 from the combustion of biomass and other biofuels when determining applicability relative to thresholds for emissions reporting and cessation of reporting.

(5) Operators of geothermal generating units must report when total facility emissions of CO_2 and CH_4 equal or exceed 10,000 metric tons of CO_2e.

(6) Operators of a ~~hydrogen~~ fuel cell or linear generator unit must include emissions from the ~~hydrogen fuel cell~~ unit in calculating emissions for comparison to applicability thresholds.

(c) *Fuel and Carbon Dioxide Suppliers*. The suppliers listed below, as defined in section 95102(a), are required to report under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO_2e in California, unless otherwise specified in this article:

(1) Position holders at terminals and refiners delivering ~~petroleum fuels and/or biomass-derived~~transportation fuels, as described in section 95121;

(2) Enterers that import transportation fuels outside the bulk transfer/terminal system, as described in section 95121, and ~~biofuel~~biomass-derived fuel production facilities that produce and deliver transportation fuels outside the bulk/terminal system, as described in section 95121;

(3) All refiners that produce fossil or biomass-derived liquefied petroleum gas, without regard to quantities, as described in section 95121;

(4) Operators of interstate pipelines delivering natural gas, as described in section 95122;

(5) Importers of fossil or biomass-derived liquefied petroleum gas, compressed natural gas, or liquefied natural gas ~~into California,~~that are the “importer of fuel,” as de~~scr~~fi~~b~~ned in section ~~95122;~~95102(a);

(6) Local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities delivering natural gas, as described in section 95122;

(7) Operators of intrastate pipelines delivering natural gas as described in section 95122;

(8) All natural gas liquid fractionators, without regard to quantities produced, as described in section 95122;

(9) All producers of carbon dioxide without regard to quantity produced, and importers and exporters of carbon dioxide with annual bulk imports into or exports from California of 10,000 metric tons or more, as described in section 95123.

(10) Facilities that make liquefied natural gas products or compressed natural gas products by liquefying or compressing natural gas received from interstate pipelines, as described in section 95122;

(d) *Electric Power Entities*. The entities listed below are required to report under this article:

(1) Electricity importers and exporters, as defined in section 95102(a);

(2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);

(3) California Department of Water Resources (DWR);

(4) Western Area Power Administration (WAPA);

(5) Bonneville Power Administration (BPA).

(e) *Petroleum and Natural Gas Systems*. The facility types listed below, as further specified in section 95150, are required to report under this article when their stationary combustion emissions (including flaring) and process emissions equal or exceed 10,000 metric tons of CO_2e, or their stationary combustion, process, fugitive, and vented emissions equal or exceed 25,000 metric tons of CO_2e.

(1) Offshore petroleum and natural gas production facilities;

(2) Onshore petroleum and natural gas production facilities;

(3) Onshore natural gas processing plants;

(4) Onshore natural gas transmission compression facilities;

(5) Underground natural gas storage facilities;

(6) Liquefied natural gas storage facilities;

(7) Liquefied natural gas import and export facilities;

(8) Natural gas distribution facilities.

(f) *Exclusions*. This article does not apply to, and greenhouse gas emissions reporting is not required for:

(1) Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy, unless on-site stationary combustion emissions equal or exceed 10,000 metric tons of CO_2e;

(2) Generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;

(3) Fire suppression systems and equipment;

(4) Portable equipment, except where specifically required to report under 40 CFR Part 98 or this article;

(5) Primary and secondary schools with a NAICS code of 611110;

(6) Fugitive methane emissions from municipal solid waste landfills described in 40 CFR Part 98, Subpart HH;

(7) Fugitive methane and fugitive nitrous oxide emissions from livestock manure management systems described in 40 CFR Part 98, Subpart JJ, regardless of the magnitude of emissions produced;

(8) Agricultural irrigation pumps.

(g) *Demonstration of Nonapplicability*. The Executive Officer may request a demonstration from any operator, supplier, or entity that the operator, supplier, or entity does not meet one or more of the applicability criteria specified in this article. Such demonstration must be provided to the Executive Officer within 20 days of receipt of a written request.

(h) *Cessation of Reporting and Verification for Reduced Emissions*. The requirements for facility operators, suppliers, and electric power entities whose emissions are reduced below applicable reporting and verification thresholds are as follows for ceasing reporting and verification. Cessation requirements for facility operators that permanently "shut down" are in section 95101(i).

(1) Reporting Entities Subject to a Compliance Obligation.

(A) Facility operators and suppliers. Facility operators and suppliers that are subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation must report and verify until covered emissions are less than 25,000 MT CO_2e for an entire ~~subsequent~~ compliance period, or until the reporting entity is no longer a covered entity, except as specified in section 95101(h)(1)(A). If annual covered emissions for a facility operator or supplier exceed 25,000 MT CO_2e in any year after cessation requirements have been met, the operator or supplier must resume verification as required under this article, and the operator or supplier would again have a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, and must meet all applicable requirements.

1. If a facility operator or supplier's emissions drop below 25,000 MT CO_2e, in meeting the requirements for cessation in section 95101(h)(1)(A), but a facility operator or supplier's ~~total~~ reported ~~emissions remain~~data remains above ~~10,000 MT CO_2e~~the applicable reporting threshold, the facility operator or supplier must continue to report under MRR until emissions drop below ~~10,000 MT CO_2e~~the applicable

threshold for a consecutive three-year period and in this case the facility operator or supplier must meet the requirements in section 95101(h)(2) before exiting MRR.

2. Notwithstanding section 95101(h)(1)(A), facilities with source categories in section 95101(a)(1)(A) that are subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, are subject to reporting and verification regardless of emission level, and so must follow the cessation of reporting and verification provisions in section 95101(i).

3. Once an opt-in covered entity begins reporting, it must continue to report and verify for each data year in which it incurs a compliance obligation under the Cap-and-~~Trade~~Invest Regulation.

4. Fuel suppliers that cease to supply fuel in California and whose emissions drop to zero during a Cap-and-~~Trade~~Invest compliance period must continue to report until emissions are zero for an entire ~~subsequent~~ compliance period as defined in the Cap-and-~~Trade~~Invest Regulation. Pursuant to section 95103(n)(2)(D), entities that cease to have a compliance and/or reporting obligation as a fuel supplier due to a change in ownership or sale or relinquishment of an inventory position at a terminal must continue to report and verify emissions from the reportable fuel transactions that occurred prior to the change. Fuel suppliers that cease to supply fuel in California and no longer have any reportable emissions must verify their emissions data report in the first year in which they report zero emissions. Any reporting year thereafter with zero reportable emissions is not subject to verification.

(B) Electric power entities. Electric power entities that import electricity to California~~,~~ and ~~therefore~~ are subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, must report until the entity ~~has no reportable imported electricity to California~~reports zero imports and zero exports, and until the entity is no longer subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation for an entire ~~subsequent~~ compliance period. Electric power entities that no longer import or export electricity must verify their emissions data report in the first year in which they report zero imports ~~or~~and zero exports. Any reporting year thereafter with zero imports ~~or~~and zero exports is not subject to verification.

(C) An entity that meets the cessation requirements pursuant to sections 95101(h)(1)(A) and (B) must notify the Executive Officer, in writing, that it is ceasing to report and verify pursuant to this article and provide the reason(s) for the reduction of emissions. The notification must be submitted no later than the applicable reporting deadline for the year following the last data year that the entity is required to submit an emissions data report. Entities must provide the cessation notification to the address indicated in section 95103(o) of this article.

(D) Operators, suppliers, and electric power entities that are subject to a compliance obligation and fully exit reporting pursuant to section 95101(h)(1) must maintain the corresponding records required under section 95105 and retain such records for 10 years following the submission of the final emissions data report to CARB.

(2) Reporting Entities Not Subject to a Compliance Obligation

(A) Facility operators and suppliers. Facility operators and suppliers whose total reported emissions are below 25,000 MT CO_2e in each reporting year, or have total reported emissions but not covered emissions that exceed 25,000 MT CO_2e a year, and therefore are not subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, must report under this article until ~~total~~ reported ~~emissions are~~data is less than ~~10,000 MT CO_2e~~the applicable reporting threshold for a consecutive three-year period. ~~If total reported emissions for~~If a facility operator or supplier exceeds ~~10,000 MT CO_2e~~the applicable reporting threshold in any year after cessation requirements have been met, the operator or supplier must resume reporting as required under this article.

1. Facility operators and suppliers that have total reported emissions, but not covered emissions, including CO_2 from biomass-derived fuels and geothermal sources, that exceed 25,000 MT CO_2e a year, and therefore are not subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, and total reported emissions fall below 25,000 MT CO_2e in a reporting year, must have their emissions data report verified for the first year that total reported emissions are reduced below the 25,000 MT CO_2e threshold. Any

reporting year thereafter with total reported emissions that are below 25,000 MT CO_2e is not subject to verification.

a. If in any subsequent year after meeting the verification cessation requirements in section 95101(h)(2)(A)1., total reported emissions exceed 25,000 MT CO_2e, the operator or supplier must have its emissions data report verified, and verification must continue until cessation is met again.

b. Facility operators and suppliers that meet the verification cessation requirements in section 95101(h)(2)(A)1. must notify CARB pursuant to the requirements in section 95101(h)(2)(E), if they choose to cease verification.

2. If in meeting the cessation requirements in section 95101(h)(2)(A) a fuel supplier ceases to supply fuel in California and emissions drop to zero, the entity must continue to report until emissions are zero for a consecutive three-year period. Pursuant to section 95103(n)(2)(D), entities that cease to have a reporting obligation as a fuel supplier due to a change in ownership or sale or relinquishment of an inventory position at a terminal must continue to report and verify emissions from the reportable fuel transactions that occurred prior to the change.

(B) For facilities and suppliers with source categories in section 95101(a)(1)(A) whose total reported emissions are below 25,000 MT CO_2e, and therefore are not subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, cessation of reporting and verification provisions in section 95101(i) apply.

(C) Electric power entities that ~~only report exports of electricity from California, and therefore~~ are not subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, must report until there are zero imports and zero exports to report for a consecutive three-year period. Verification is not required for the report of the first full year where there are zero imports and zero exports reported.

(D) Electric power entities who meet the definition of “retail provider” must always report retail sales for each calendar year, even if they have zero retail sales to report. Entities that are registered as ESPs but have never provided retail electricity to California customers are not required to report under MRR until they meet the definition of "retail provider." WAPA and DWR must always report pump loads for each calendar year.

(E) An entity that meets the cessation requirements for reporting, and verification if applicable, pursuant to sections 95101(h)(2)(A) through (D) must notify the Executive Officer, in writing, that it is ceasing to report, or verify if applicable, pursuant to this article and provide the reason(s) for cessation of reporting, or verification if applicable. The notification must be submitted no later than the applicable reporting deadline for the year following the last data year that the entity is required to submit an emissions data report. Entities must provide the cessation notification to the address indicated in section 95103(o) of this article.

(F) Operators, suppliers, and electric power entities that fully exit reporting pursuant to section 95101(h)(2) must maintain the corresponding records required under section 95105 and retain such records for five years following the submission of the final emissions data report to CARB.

(i) *Cessation of Reporting and Verification for Shutdown* ~~*Facilities*~~*Entities*. The requirements for ~~facility operators~~entities that cease to operate or permanently shut down as defined in this section are as follows for ceasing reporting and verification.

(1) If the operations of ~~a facility~~an entity are changed such that all applicable GHG-emitting processes and operations cease to operate or are permanently shut down, the owner or operator must submit an emissions data report for the year in which the ~~facility's~~entity's GHG-emitting processes and operations ceased ~~to operate~~or shut down, and for the first full year of non-operation that follows. The owner or operator must submit a notification to CARB that announces the cessation of reporting and certifies to the cessation of all GHG-emitting processes and operations no later than the reporting deadline of the year following the cessation of operations or permanent shutdown.

(2) For the purposes of this provision, "cease to operate" means the facility did not operate any GHG-emitting processes for an entire calendar year. Continued operation of space heaters and water heaters as necessary until operations are restarted in a subsequent year does not preclude a facility from meeting the definition of "cease to operate." The owner or operator must resume reporting for any future calendar year during which

any of the GHG-emitting processes or operations resume operation and are subject to reporting.

(3) For the purposes of this provision, for facilities, permanently “shut down” means the ~~reporting entity~~facility has objective evidence that the industrial operations are permanently shut down, including but not limited to, decommissioning and cancelling air permits. ~~For this provision, permanent~~Permanent shutdown ~~may include~~status of a facility is not affected by the continued operation of space heaters and water heaters as necessary to support decommissioning activities. For the purposes of this provision, for electric power entities and suppliers, permanently “shut down” means the entity has objective evidence that operations are permanently shut down, including but not limited to, deregistration with the California Energy Commission (CEC) or ceasing to exist or to be recognized as a business entity in California.

(4) Section 95101(i)(1) does not apply to seasonal or other temporary cessation of operations.

(5) The owner, operator, or supplier must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting.

(6) If ~~a facility owner or operator~~an entity meets the requirements for cessation of reporting pursuant to section 95101(i), the owner or operator must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the year in which the ~~facility's~~entity's GHG-emitting processes and operations ceased to operate or shut down. Verification is not required for the emissions data report of the first full year of non-operation that follows. If the reporting entity was not subject to verification before meeting the cessation of reporting requirements pursuant to 95101(i), verification is not required under this section for the year in which the ~~facility's~~entity's GHG-emitting processes and operations ceased to operate or shut down.

(7) Facilities and suppliers with source categories in section 95101(a)(1)(A) that met the cessation requirements under a previous version of MRR must reenter the reporting program and are subject to this subarticle only if their emissions exceed 10,000 MT CO_2e in a calendar year.

(j) If an entity has met the cessation requirements pursuant to MRR section 95101(h) or (i) and remains in the Cap-and-~~Trade~~Invest Program solely to meet the requirements of section 95835(f), then the entity need not report and verify data pursuant to MRR for any time period after which the MRR cessation requirements have been met.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95102. Definitions

(a) General Definitions. For the purposes of this article, the definitions in subsections (a), (b), and (c) shall apply. Subsection (b) is specific to product data definitions. Subsection (c) is specific to definitions regarding refining and related processes.

"Absorbent circulation pump" means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

"Accuracy" means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

"Acid gas" means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

"Acid gas removal unit (AGR)" means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

"Acid gas removal vent stack emissions" mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

"Adverse emissions data verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the emissions data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirement to fix such errors pursuant to section 95131(b)(9), or both.

"Adverse product data verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the covered product data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirements to fix such errors pursuant to section 95131(b)(9), or both.

“Adverse verification statement” means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the emissions or covered product data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirements to fix such errors pursuant to section 95131(b)(9), or both. This definition applies to the adverse emissions data verification statement and the adverse product data verification statement.

“Agricultural waste” means waste produced on land used for horticulture, fruit growing, seed growing, dairy farming, livestock breeding and keeping, or grazing land, meadow land, osier land (growing willow), market gardens and nursery grounds as a result of agricultural activity.

“Air injected flare” means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

“Annual” means with a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

“API” means the American Petroleum Institute.

"API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.

“AQMD/APCD” or “air district” or “air quality management district” or “air pollution control district” means any district created or continued in existence pursuant to the provisions of Part 3 (commencing with Section 40000) of Division 26 of the Health and Safety Code.

~~“ARB” means the California Air Resources Board.~~

“ARB ID” means, for the purposes of this article, the unique identification number assigned to each facility, supplier, and electric power entity that reports GHG emissions to ~~the ARB~~<u>CARB</u>.

~~“ARB offset credit” is as defined in the cap-and-trade regulation.~~

"Artificial island" is a plot of land or other structure constructed on a body of water to support onshore petroleum or natural gas production.

"Asphalt" means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

"Asset-controlling supplier" or "ACS" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them, and is assigned a supplier-specific identification number and system emission factor by CARB for the wholesale electricity procured from its system and imported into California. Asset controlling suppliers are considered specified sources.

"Assigned emissions level" means an amount of emissions, in CO_2e, assigned to the reporting entity by the Executive Officer under the requirements of section 95103(g).

"Associated gas" or "produced gas" means a natural gas that is produced in association with the production of crude oil.

"ASTM" means the American Society of Testing and Materials.

"Atomic hydrogen content" means the mass fraction of all hydrogen atoms in a gas, mixture of gases, or a mixture of other materials.

"Authorized project designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

"Aviation gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910–07a, "Standard Specification for Aviation Gasolines" (2007).

"Baghouse dust" means dust collected from an air pollution control device designed to remove particulate matters using fabric filters in the shape of a tube or an envelope, or other air filters that are built into a frame or cartridge.

"Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

“Balancing authority area” means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

“Barrel” means a volume equal to 42 U.S. gallons.

“Basin” means geological provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991), which is hereby incorporated by reference.

"Best available data and methods" means CARB methods for emissions calculations set forth in this article where reasonably feasible, or facility fuel use and other facility process data used in conjunction with CARB-provided emission factors and other data, or other industry standard methods for calculating greenhouse gas emissions.

“Bias” means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

“Bigeneration unit” means a unit that simultaneously generates electricity and useful thermal energy from the same fuel source but without waste heat recovery. An example of bigeneration includes a boiler generating steam that is split into two streams, and one stream powers a steam turbine to generate electricity, while the other stream is used for other industrial, commercial, heating and cooling purposes that are not in support of or a part of the electricity generation system.

“Biodiesel” means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

A mono-alkyl ester;

Meets American Society for Testing and Material designation ASTM D 6751-08 “Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels” (2008), which is hereby incorporated by reference;

Intended for use in engines that are designated to run on conventional diesel fuel; and

Derived from nonpetroleum renewable resources.

~~“Biofuel production facility” means a production facility that produces one or more of the following biomass-derived transportation fuels: ethanol, biodiesel, renewable diesel, rendered animal fat, or vegetable oil.~~

“Biogas” means gas that is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including anaerobic digestion, anaerobic decomposition, and thermochemical decomposition. These processes are applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, green waste, and waste from energy crops, to produce landfill gas, digester gas, and other forms of biogas.

“Biogenic portions of CO_2 emissions” means carbon dioxide emissions generated ~~as~~from the ~~result of biomass~~ combustion ~~from combustion units~~or consumption of biomass-derived fuels or feedstocks.

“Biomass” means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

“Biomass-derived California reformulated gasoline blendstock for oxygenate blending” or “biomass-derived CARBOB” or “biomass-derived RBOB” means any CARBOB equivalent product that is produced from solely biomass-derived feedstock, or the portion of a CARBOB equivalent product that is derived from biomass.

“Biomass-derived fuel production facility” means a production facility, other than a biorefinery, that produces transportation fuels solely from biomass-derived feedstocks.

“Biomass-derived fuels” or “biomass fuels” or “biofuels” or “biomass-based fuels” means fuels derived from biomass.

“Biomass-derived liquefied petroleum gas" or “biomass-derived LPG” means an LPG equivalent product that is produced from solely biomass-derived feedstock, or the portion of an LPG equivalent product that is derived from biomass.

“Biomass-derived natural gas liquids” or “biomass-derived NGLs” means an NGL equivalent product that is produced from solely biomass-derived feedstock, or the portion of an NGL equivalent product that is derived from biomass.

"Biomethane" means biogas that meets pipeline quality natural gas standards.

<u>"Biorefinery" means an industrial facility that converts biomass feedstocks into commercially saleable hydrocarbon transportation biofuels using hydrocracking or hydrotreating processes.</u>

"Blowdown" means the act of emptying or depressurizing a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

"Blowdown vent stack emissions" mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

"Boiler" means a closed vessel or arrangement of vessels and tubes, together with a furnace or other heat source, in which water is heated to produce hot water or steam.

"Bone dry short ton" means an amount of material that weighs 2,000 pounds at zero percent moisture content.

"Bottom ash" means ash that collects at the bottom of a combustion chamber.

"Bottoming cycle" means a type of cogeneration system in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"British thermal unit" or "Btu" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

"BTEX" means gaseous compounds of benzene, toluene, ethyl benzene, and xylenes.

"Bulk transfer/terminal system" means a fuel distribution system consisting of refineries, pipelines, vessels, and terminals. Fuel storage and blending facilities that are not fed by pipeline or vessel are considered outside the bulk transfer system.

"Busbar" means a power conduit of a facility with electricity generating units that serves as the starting point for the electricity transmission system.

"Business-as-usual scenario" means the set of conditions reasonably expected to occur within the offset project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

("Butane" or "n-Butane" is a paraffinic straight-chain hydrocarbon with molecular formula C4H10.

"Butylene" or "n-Butylene" means an olefinic straight-chain hydrocarbon with molecular formula C4H8.

"Bypass dust" means discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

<u>"CAISO markets" means competitive, wholesale electricity markets operated by the California Independent System Operator (CAISO). CAISO markets include energy (day-ahead and real-time), ancillary services, congestion revenue rights, the Western Energy Imbalance Market (WEIM), and the Extended Day-Ahead Market (EDAM).</u>

<u>"CAISO Markets Purchaser" or "CAISO Purchaser" means, for a given data year, an electrical distribution utility that directly or indirectly purchases any electricity through the WEIM, or through the EDAM and WEIM, to serve California load in the data year, and receives allowance allocation in the subsequent year pursuant to section 95892 of the Cap-and-Invest Regulation. An electrical distribution utility is considered to have purchased electricity through the CAISO markets in a given data year if, during any 5-minute interval in the data year, the electrical distribution utility serves California load through imbalance energy purchased directly from CAISO markets, or the electrical distribution utility participates in CAISO markets indirectly through a CAISO scheduling coordinator that meets any part of the electrical distribution utility's California load with imbalance energy.</u>

<u>"CAISO Scheduling Coordinator" means the CAISO market(s) participant scheduling coordinator, resource owner or operator, or a third-party designated by the resource owner or operator that is certified by the CAISO and enters into a pro forma CAISO Scheduling Coordinator agreement, under which it is responsible for meeting the requirements specified in the CAISO Tariff on behalf of the resource owner or operator.</u>

"Calcination" means the thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

"Calcine" means to heat a substance so that it oxidizes or reduces.

“Calendar year” means the time period from January 1 through December 31.

“Calibrated bag” means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

“California balancing authority” means a balancing authority with control over a balancing authority area primarily located in the State of California. A California balancing authority is responsible for the operation of the transmission grid within its metered boundaries which may extend beyond the geographical boundaries of the State of California.

“California Climate Action Registry” or “CCAR” means the entity established pursuant to former Health and Safety Code Section 42800 et seq.

“California consignee” means the person or entity in California to whom the shipment is to be delivered.

“California Energy Commission” or “CEC” means the California Energy Resources Conservation and Development Commission.

“California Independent System Operator” or “CAISO” means the Independent System Operator that serves California EDUs, which operates competitive wholesale electricity markets, manages the reliability of the CAISO-controlled transmission grid, provides open access to transmission, and performs long-term planning. CAISO markets include energy (day-ahead and real-time), ancillary services, congestion revenue rights, ~~and~~ the Western Energy Imbalance Market (~~EIM~~WEIM), and the Extended Day-Ahead Market (EDAM).

“California Reformulated Gasoline Blendstock for Oxygenate Blending” or “CARBOB” has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

“Cap-and-~~trade regulation~~Invest Regulation” or “~~c~~Cap-and-~~trade program~~Invest Program” means CARB’s regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

“CARB” means the California Air Resources Board.

“CARB offset credit” has the same meaning as “ARB Offset Credit” as defined in the Cap-and-Invest Regulation.

“Carbon dioxide” or “CO_2” means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

“Carbon dioxide equivalent” or “CO_2 equivalent” or “CO_2e” means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas when calculated using the individual global warming potentials as specified in the “global warming potential” definition of this article.

“Carbon dioxide supplier” means: (a) facilities with production process units located in the State of California that capture a CO_2 stream for purposes of supplying CO_2 to another entity or facility or that capture the CO_2 stream in order to utilize it for geologic sequestration where capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process, (b) facilities with CO_2 production wells located in the State of California that extract or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that extract a CO_2 stream in order to utilize it for geologic sequestration, (c) exporters (out of the State of California) of bulk CO_2 that export CO_2 for the purpose of geologic sequestration, (d) exporters (out of the State of California) of bulk CO_2 that export for purposes other than geologic sequestration, and (e) importers (into the State of California) of bulk CO_2. This source category is focused on upstream supply and is not intended to place duplicative compliance obligations on CO_2 already covered upstream. The source category does not include transportation or distribution of CO_2, purification, compression or processing of CO_2, or on-site use of CO_2 captured on-site.

“Carbonate” means compounds containing the radical CO_3^{-2}. Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO_2). Common carbonates consumed in the mineral industry include calcium carbonate ($CaCO_3$) or calcite; magnesium carbonate ($MgCO_3$) or magnesite; and calcium-magnesium carbonate ($CaMg(CO_3)_2$) or dolomite.

“Carbonate-based raw material” means any of the following materials used in the manufacture of glass: Limestone, dolomite, soda ash, barium carbonate, potassium carbonate, lithium carbonate, and strontium carbonate.

“Catalyst” means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

~~“CBOB-summer” or “conventional blendstock for oxygenate blending-summer” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-summer.~~

~~“CBOB-winter” or “conventional blendstock for oxygenate blending-winter” means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-winter.~~

~~“Cement” means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.~~

“Cement” means a manufactured material that meets the specification standards for portland cement (such as ASTM C150 (2022), which is incorporated by reference herein) or hydraulic blended cements (such as ASTM C595 (2023), which is incorporated by reference herein), or that meets performance-based standards for functional equivalents of portland or hydraulic blended cements (such as ASTM C1157 (2023), which is incorporated by reference herein). Cement is used to make concrete, masonry cement, plastic (stucco) cement, and mortar cement.

“Cement kiln dust” or “CKD” means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices. CKD consists of partly calcined kiln feed material and includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

“Centrifugal compressor” means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

“Centrifugal compressor dry seals” mean a series of rings around the compressor shaft where it exits the compressor case that operate mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

“Centrifugal compressor wet seal degassing vent emissions” means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressors seals.

“Certification” or “certify” refers to the procedure in 40 CFR §98.4(e), as required for reports submitted to CARB under this article.

“Chain of title” means the sequence of historical transfers of title to a fuel from the producer to the reporting entity.

“City gate” means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this article, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

“Coal” means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 “Standard Classification of Coals by Rank” (2005), which is hereby incorporated by reference.

(“Coal coke” means a solid residue high in carbon content produced by the destructive distillation of coal at high temperatures in either a by-product coke oven battery or a non-recovery coke oven battery.

“Cogeneration” means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (b) Steam turbines generating electricity as a byproduct of steam generation through a fired boiler; (c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this article, a combined-cycle power generation unit, where none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

“Cogeneration system” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

“Cogeneration unit” means a unit that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy and waste heat recovery.

"Coke (petroleum)" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

"Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

"Combustion source" means a source of emissions resulting from combustion.

"Commercial propane" means liquefied petroleum gas that has a wide mixture of gases that can sustain combustion as defined by ASTM D1835 05 "Standard Specification for Liquefied Petroleum (LP) Gases" (2005), which is hereby incorporated by reference.

"Committed capacity" means electricity generation from an electricity generation source located outside the state of California that is committed via a contract to serve California load and is registered with the CAISO pursuant to section 33.32.2.3 of the CAISO Fifth Replacement Electronic Tariff dated May 1, 2026, which is hereby incorporated by reference.

"Common control" means having common "operational control" as defined herein.

"Compliance instrument" is as defined in the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

"Compliance obligation" means the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to CARB.

"Compliance offset protocol" means an offset protocol adopted by the Board.

"Compliance period" means the period for which the compliance obligation is calculated for covered entities pursuant to the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

"Component" for the purposes of sections 95150 to 95157 of this article means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

“Compressed natural gas” or “CNG” means natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction), typically to pressures ranging from 2900 to 3600 psi.

“Compressor” means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas and discharging significantly higher pressure natural gas or CO_2.

“Condensate” means hydrocarbon and other liquid, including both water and hydrocarbon liquids, separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions.

“Conflict of interest” means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification statement of a potential client’s greenhouse gas emissions data report, or the person or body’s objectivity in performing verification services is or might be otherwise compromised.

“Consignee” means the same as “California consignee.”

“Continuous bleed” means a continuous flow of pneumatic supply natural gas to the process control device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

“Continuous emissions monitoring system” or “CEMS” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Continuous physical transmission path” means the full transmission path shown in the physical path table of a single NERC e-tag from the first point of receipt closest to the generation source to the final point of delivery closest to the final sink. This is one criterion to establish direct delivery.

~~“Conventional-summer” means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40, but which meet summer RVP standards required under 40 CFR §80.27 (July 2011), which is hereby incorporated by reference or as specified by the state. Note: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.~~

“Conventional wells” mean crude oil or gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of crude oil or natural gas.

~~“Conventional-winter” means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 or the summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.~~

“Correctable errors” means errors identified by the verification team that affect covered emissions data or covered product data in the submitted emissions data report that result from a nonconformance with this article. Differences that, in the professional judgment of the verification team, are the result of differing but reasonable methods of truncation or rounding or averaging, where a specific procedure is not prescribed by this article, are not considered errors and therefore do not require correction.

“Covered emissions” mean all emissions included in a compliance obligation under sections 95852 through 95852.2 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, regardless of whether the ~~c~~Cap-and-~~trade regulation~~Invest Regulation imposes a compliance obligation for the data year.

“Covered entity” has the same definition as in section 95802 of the Cap-and-Invest Regulation (Cal. Code Regs, tit. 17 §§ 95801-96022).

“Covered product data” means all product data included in the allocation of allowances under sections 95870, 95890, and 95891 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, regardless of whether the ~~c~~Cap-and-~~trade regulation~~Invest Regulation imposes a compliance obligation for the data year.

“Cracking” means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

"Crude oil" means a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending upon the characteristics of the crude stream, it may also include any of the following:

Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included.

Small amounts of non-hydrocarbons, such as sulfur and various metals.

Drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale.

Petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator.

Liquids produced at natural gas processing plants and natural gas fractionating facilities are excluded, unless the produced natural gas liquids are extracted from produced gas, associated gas, and waste gas at a facility and re-injected into barrels of crude oil produced by the same facility. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubricants; asphalt; ethane, propane, and butane; and many other products used for their energy or chemical content.

“Customer” means a purchaser of electricity not for the purposes of retransmission or resale.

“Customer meter” means natural gas meter, riser, and fittings at residential, commercial, or industrial premise(s).

“Data year” means the calendar year in which emissions occurred.

“De minimis” means those emissions reported for a source or sources that are calculated using alternative methods selected by the operator, subject to the limits specified in section 95103(i).

“Dehydrator” means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

“Dehydrator vent emissions” means natural gas and CO_2 release from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

“Delayed coking” means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

"Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

"Demethanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in the feed natural gas stream.

"Desiccant" means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption or absorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent or absorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface or absorbed and dissolves the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto or absorbed into the desiccant material, leaving the dry gas to exit the contactor.

"Designated representative" means the person responsible for certifying, signing, and submitting the GHG emissions data report.

"Diesel fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and nontaxed fuels.

"Direct delivery of electricity" or "directly delivered" means electricity that meets any of the following criteria:

The facility has a first point of interconnection with a California balancing authority;

The facility has a first point of interconnection with distribution facilities used to serve end users within California balancing authority area;

The electricity is scheduled for delivery from the specified source into California balancing authority via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in the State of California; or

There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.

"Distillate fuel oil" means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene (EIA product code 311), kerosene-type jet fuel (EIA product codes 213, 217, and 218), diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4; EIA product codes 465, 466, and 467), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4; EIA product codes 508, 509, and 510).

"Distillate Fuel No. 1" has a maximum distillation temperature of 550°F at the 90 percent recovery point and a minimum flash point of 100°F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

"Distillate Fuel No. 2" has a minimum and maximum distillation temperature of 540°F and 640°F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

"Distillate Fuel No. 4" means a distillate fuel oil with a minimum flash point of 131 °F made by blending distillate fuel oil and residual fuel oil.

"Distribution pipeline" means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) in 49 CFR §192.3.

"District Heating Facility" means a facility that, at a central plant, produces hot water, steam and/or chilled water that is distributed through underground pipes to buildings and facilities connected to the system that are not part of the same facility. District Heating Facility does not include a facility that produces electricity.

"Double-Valve Cylinder," for purposes of Appendix B, means a cylinder used for gathering crude oil or condensate samples. The cylinder is provided by a laboratory filled with laboratory grade water which prevents flashing within the cylinder.

"Dry gas" means a natural gas that is produced from gas wells not associated with the production of crude oil.

"Dynamically tagged power" means specified transmission of electric power from a generation source updated in real time by telemetered reading or value in an interval on a NERC e-Tag.

"E&P Tank" means E&P Tank Version 2.0 for Windows software, copyright 1996-1999 by the American Petroleum Institute and the Gas Research Institute (published 2000).

“EIA” means the Energy Information Administration. The Energy Information Administration (EIA) is a statistical agency of the United States Department of Energy.

“Electric arc furnace” or "EAF" means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

“Electrical Distribution Utility(ies)” or “EDU” means an entity that owns and/or operates an electrical distribution system, including: 1) a public utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU); or 2) a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3; or 3) an Electrical Cooperative (COOP) as defined in Public Utilities Code section 2776, that provides electricity to retail end users in California.

“Electric Power Entity” or “EPE” means those entities specified in section 95101(d) of this article, including electricity importers and exporters; retail providers, including multi-jurisdictional retail providers; the California Department of Water Resources (DWR); the Western Area Power Administration (WAPA); and the Bonneville Power Administration (BPA).

“Electricity exporter” means electric power entities that deliver exported electricity. The entity that exports electricity is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag’s physical path, with the point of receipt located inside the State of California and the point of delivery located outside the State of California. Electricity exporters include ~~Energy Imbalance Market (EIM) Entity~~CAISO Scheduling Coordinators serving ~~the EIM market that can~~CAISO markets whose transactions result in exports from California.

“Electricity generating facility” means a facility that generates electricity and includes one or more generating units at the same location.

“Electricity generation provider” means a provider of the energy or generation component of electricity services, as distinguished from the provider of transmission and/or distribution service that provides the wires for the transport of electricity. Electricity generation providers may include electricity service providers, community choice aggregators, cogeneration facilities, and other entities in addition to electrical distribution utilities that may provide both generation and transmission/distribution service.

“Electricity generating unit” or “EGU” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power. An EGU may include a unit that generate electricity from fuel combustion or from other renewable energy sources, such as solar and wind.

“Electricity importers” deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the State of California, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag’s physical path with the point of receipt located outside the State of California and the point of delivery located inside the State of California. For facilities physically located outside the State of California with the first point of interconnection to a California balancing authority’s transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of CARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR). For electricity that is imported into California through the CAISO ~~Energy Imbalance Market~~markets, the electricity importer is identified as the ~~EIM Participating Resource~~CAISO Scheduling Coordinators~~ and EIM Purchasers serving the EIM market~~ whose transactions result in electricity imports into California.

“Electricity sold into the CAISO markets” means electricity sold into California Independent System Operator (CAISO) markets~~, including but not limited to the day-ahead market, real time market, integrated forward market, and energy imbalance market.~~. Transactions excluded as CAISO sales pursuant to section 11.29(a)(iii) of the CAISO Fifth Replacement Tariff dated May 1, 2014 do not fall under this definition.

“Electricity transaction” means the purchase, sale, import, export or exchange of electric power.

“Electricity wheeled through California” or “wheeled electricity” means electricity that is generated outside the State of California and delivered into California with the final point of delivery outside California. Electricity wheeled through California is documented on a single NERC e-Tag showing the first point of receipt located outside the State of California, an intermediate point of delivery located inside the State of California, and the final point of delivery located outside the State of California.

“Eligible renewable energy resource” is as defined in section 95802(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

"Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned.)

"Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids.

"Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to CARB that provides the information required by this article. The emissions data report is for the submission of required data for the calendar year prior to the year in which the report is due. For example, a 2013 emissions data report would cover emissions and product data for the 2013 calendar year and would be reported in 2014.

"Emissions data verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's covered emissions data in their emissions data report is free of material misstatement, and whether the emissions data conforms to the requirements of this article.

"Emulsion" means a mixture of water, crude oil, associated gas, and other components from the oil extraction process that is transferred from an existing platform that is permanently affixed to the ocean floor and that is located outside the distance specified in the "offshore" definition of this article, to an onshore petroleum and natural gas production facility. For purposes of Appendix B, emulsion means a mixture of crude oil, condensate, or produced water in any proportion.

"End user" means a final purchaser of an energy product, such as electricity, thermal energy, or natural gas not for the purposes of retransmission or resale. In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

~~"Energy Imbalance Market" or "EIM" means the operation of the CAISO's real-time market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined CAISO and EIM footprint.~~

~~"Energy Imbalance Market Purchaser" or "EIM Purchaser" means, for a given data year an electrical distribution utility that directly or indirectly purchases any electricity through the EIM to serve California load in the data year, and receives allowance allocation in the subsequent year pursuant to section 95892 of the~~

~~Cap-and-Trade Regulation. An electrical distribution utility is considered to have purchased electricity through the EIM in a given data year if, during any 5-minute interval in the data year, the electrical distribution utility serves California load through imbalance energy purchased directly from the CAISO market. An electrical distribution utility is considered to have purchased electricity through the EIM in a given data year if, during any 5-minute interval in the data year, the electrical distribution utility participates in CAISO markets indirectly through a CAISO scheduling coordinator that meets any part of the electrical distribution utility's California load with imbalance energy.~~

~~"Energy Imbalance Market, Participating Resource Scheduling Coordinator" or "EIM" Participating Resource Scheduling Coordinator means the participating resource owner or operator, or a third-party designated by the resource owner or operator that is certified by the CAISO and enters into the pro forma EIM Participating Resource Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in the CAISO Tariff on behalf of the resource owner or operator.~~

"Energy storage system" or "ESS" or "secondary generation source" means a device, structure, or operation designed and used to store electric potential from electric power that discharges electric power as imports or CAISO sales into California. Energy storage systems can be either integrated as part of a primary generation source (integrated energy storage system, ISS) or a stand-alone energy storage system (SASS). All ESS, unless registered with a reported and verified emissions factor under section 95111(i), are not specified sources.

"Enforceable" means the authority for CARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

"Engineering estimation," for the purposes of sections 95150 to 95157 of this article, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

"Enhanced oil recovery" or "EOR" means the use of certain methods such as steam (thermal EOR), water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

"Enterer" means an entity that imports into California ~~motor vehicle~~a transportation fuel~~, diesel fuel, fuel ethanol, biodiesel, non-exempt~~ regulated under section 95121 of this article other than fossil or biomass-derived ~~fuel or renewable fuel~~LPG and who is the importer of record under federal customs law or the owner of fuel upon import into California if the fuel is not subject to federal customs law. Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.

"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

"Equipment" means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district.

"Equipment leak" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

"Equipment leak detection" means the process of identifying emissions from equipment, components, and other point sources.

"Ethane" is a paraffinic hydrocarbon with molecular formula C_2H_6.

"Ethanol" is an anhydrous alcohol with molecular formula C_2H_5OH.

"Ethylene" is an olefinic hydrocarbon with molecular formula C_2H_4.

"Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

"Exclusive marketer" means a marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

"Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

"Exported electricity" means electricity generated inside the State of California and delivered to serve load located outside the State of California. This includes electricity delivered from a first point of receipt inside California, to the first point of delivery outside California, with a final point of delivery outside the State of California. Exported electricity delivered across balancing authority areas ~~is~~can be documented on NERC e-Tags with the first point of receipt located inside the

State of California and the final point of delivery located outside the State of California. Exported electricity does not include electricity generated inside the State of California then transmitted outside of California, but with a final point of delivery inside the State of California. Exported electricity does not include electricity generated inside the State of California that is allocated to serve the California retail customers of a multi-jurisdictional retail provider, consistent with a cost allocation methodology approved by the California Public Utilities Commission and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

“Extended Day-Ahead Market” or “EDAM” means the CAISO’s day-ahead market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined CAISO and EDAM footprint. EDAM entities participate in both the CAISO EDAM and WEIM. EDAM transactions are settled in the real-time WEIM.

“External combustion” means fired combustion in which the flame and products are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

“Facility,” unless otherwise specified in relation to natural gas distribution facilities, gas processing facilities, and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

“Facility,” with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, means the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

“Facility,” with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single basin as defined in section 95102(a). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility. Onshore natural gas processing equipment as defined in section 95150(a)(3) that is owned and/or operated by the facility owner/operator and located within the same basin, is considered “associated with a well pad” and is included with the onshore petroleum and natural gas production facility, unless such equipment is required to be reported as part of a separate onshore petroleum and natural gas processing facility.

“Facility,” with respect to onshore natural gas processing for the purposes of sections 95150 to 95158 of this article, means equipment associated with the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, including separation of sulfur and carbon dioxide, that processes an annual average throughput of 25 MMscf per day or greater, or whose owner/operator does not also own/operate a production facility in the same basin.

“Farm taps” are pressure regulation stations that deliver gas directly from transmission pipelines to rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

“Feedstock” means the raw material supplied to a process.

“Field,” in the context of oil and gas systems, means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08), January 2009, which is hereby incorporated by reference.

“Field accuracy assessment” means a test, check, or engineering analysis intended to confirm that a flow meter or other mass or volume measurement device is operating within an acceptable accuracy range. A field accuracy assessment should be conducted in a manner that does not interrupt operations or require removal of the meter or require primary element inspection. The selected method for field accuracy assessment will vary based on meter type and piping system design, and may be performed by the facility operator, a third party meter servicing firm, or the original equipment manufacturer.

“Final point of delivery” means the sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

“First deliverer of electricity” or “first deliverer” means the owner or operator of an electricity generating facility in California, <u>or</u> an electricity importer~~, or an EIM Purchaser~~.

“First point of delivery in California” means the first defined point on the transmission system located inside California at which imported electricity and electricity wheeled through California may be measured, consistent with defined points that have been established through the NERC Registry.

“First point of receipt” means the generation source specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

“Flare” means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

“Flare combustion” means unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares.

“Flare combustion efficiency” means the fraction of liquid and gases sent to the flare, on a volume or mole basis, that is combusted at the flare burner tip.

“Flare stack emissions” means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in the flare.

“Flash Analysis,” for purposes of Appendix B, means laboratory methodologies for measuring the volume and composition of gases released from liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a Gas-Oil Ratio or Gas-Water Ratio required to calculate the specified emission rates as described in Section 10 of Appendix B.

"Flash point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

"Flashing," for purposes of Appendix B, means the release of hydrocarbons and carbon dioxide from liquid to surrounding air when the liquid changes temperature and pressure, also known as phase change.

"Fleet emission factor" means an electricity generation emission factor calculated by the Executive Officer pursuant to section 95111(b)(2)(D) of this article.

"Floating-Piston Cylinder," for purposes of Appendix B, means a cylinder used for gathering produced water. The cylinder contains an internal piston controlled by gas pressure. The piston prevents sample liquid from flashing within the sampling cylinder and provides a means of extracting the sample liquid.

"Flow meter" means a measurement device consisting of one or more individual components that is designed to measure the bulk fluid movement of liquid or gas through a piped system at a designated point. Bulk fluid movement can be measured with a variety of devices in units of mass flow or volume.

"Flow monitor" means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

"Flowback Fluid," for purposes of Appendix B, means chemicals, fluids, or propellants injected underground under pressure to stimulate or hydraulically fracture a crude oil or natural gas well or reservoir and that flows back to the surface as a fluid after injection is completed.

"Fluid catalytic cracking unit" or "FCCU" means a process unit in a refinery in which petroleum derivative feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

"Fluid coking" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

"Fluorinated greenhouse gas" means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A, (May 1995), which is hereby incorporated by reference, and substances with vapor pressures of less than 1 mm of Hg absolute at 25°C. With these exceptions, “fluorinated GHG” includes any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

“Forced extraction of natural gas liquids” means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself, natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

“Forest-derived wood and wood waste” means wood harvested pursuant to the California Forest Practice Rule, Title 14, California Code of Regulations, Chapters 4, 4.5, and 10 or pursuant to the National Environmental Policy Act, or wood harvested from areas of the State designated by CalFire as Tier 1 High Hazard Zones (HHZ) for Tree Mortality pursuant to the Proclamation of a State of Emergency by Governor Brown on October 30, 2015.

“Fossil fuel” means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

“Fractionates” means the process of separating natural gas liquids into their constituent liquid products.

“Fractionator” means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

“Fuel” means solid, liquid or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel, and such destruction does not result in a commercially useful end product.

"Fuel analytical data" means data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

"Fuel cell" means a device that converts the chemical energy of a fuel and an oxidant directly into electrical energy without using combustion. Fuel cells require a continuous source of fuel and oxidant to operate.

"Fuel characteristic data" means, for the purpose of this article, properties of a fuel used for calculating GHG emissions including carbon content, high heat value, and molecular weight.

"Fuel combusting electricity generating or cogeneration unit" means an electricity generating unit, which may include a cogeneration or bigeneration unit, that produces electricity from fuel combustion.

"Fuel ethanol" means ethanol that meets ASTM D-4806-~~08~~21 "Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel" (20~~08~~21), specifications, which is hereby incorporated by reference~~, for blending with gasolines for use as automotive spark-ignition engine fuel~~.

"Fuel flowmeter system" means a monitoring system which provides a continuous record of the flow rate of fuel oil or gaseous fuel. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g., transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

"Fuel production facility" means a facility, other than a refinery, in which motor vehicle fuel, diesel fuel or biomass-based fuel is produced.

"Fuel supplier" means a supplier of ~~petroleum products, a supplier of biomass-derived~~ transportation fuels, a supplier of natural gas ~~including operators of interstate and intrastate pipelines, a supplier of liquefied~~or natural gas liquids or their biomass-derived equivalents, or a supplier of ~~liquid petroleum gas~~hydrogen, as specified in this article.

"Fuel transaction" means the record of the exchange of fuel possession, ownership, or title from one entity to another.

"Fugitive emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

“Fugitive emissions detection” means the process of identifying emissions from equipment, components, and other point sources.

“Fugitive equipment leak” means the unintended or incidental emissions of greenhouse gases from the production, transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other equipment.

"Fugitive source" means a source of fugitive emissions.

“Full verification” means all verification services as provided in section 95131.

“Gas” means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

“Gas conditions” means the actual temperature, volume, and pressure of a gas sample.

“Gas gathering/booster stations” means centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

“Gas-to-oil ratio” or “GOR” means the ratio of gas produced from a barrel of crude oil or condensate when cooling and depressurizing these liquids to standard conditions, expressed in terms of standard cubic feet of gas per barrel of oil. Where used in this article, the terms “Total gas-to-oil ratio” and “Total GOR” refer to the ratio of the total volume of produced associated gas to the total volume of produced crude oil from one or more wells, including any associated gas that is separated and either recovered or emitted to the atmosphere prior to the collection of samples for a Flash Analysis.

“Gas-to-water ratio” or “GWR” means the ratio of gas produced from a barrel of produced water when cooling and depressurizing produced water to standard conditions, expressed in terms of standard cubic feet of gas per barrel of water.

“Gas well” means a well completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.

“Generated electricity” means electricity generated by an electricity generating unit at the reporting facility. Generated electricity does not include any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility.

“Generated energy” means electricity or thermal energy generated by the electricity generating, cogeneration, or bigeneration units included in the reporting facility.

“Generating unit” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

“Generation providing entity” or “GPE” means a facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation from the facility or generating unit, party to a tolling agreement with the owner, or exclusive marketer recognized by CARB that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

“Geologic sequestration” means the process of injecting CO_2 captured from an emissions source into deep subsurface rock formations for permanent storage.

“Geothermal” means heat or other associated energy derived from the natural heat of the earth.

"Global warming potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2. For 2011 through 2020 data years, the GWP values used for emissions estimation and reporting are as specified in Table A-1 to Subpart A of Title 40, Code of Federal Regulations (CFR) Part 98 as published to the Federal Register on 10/30/2009. For data years 2021 and onward, the GWP values are as specified in the Table A-1 to Subpart A of Title 40 Code of Federal Regulations Part 98 as published to the CFR on 12/11/2014, which is hereby incorporated by reference.

“Graduated Cylinder,” for purposes of Appendix B, means a measuring instrument for measuring fluid volume, such as a glass container (cup or cylinder or flask) which has sides marked with or divided into amounts.

“Greenhouse gas” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

“Greenhouse gas emission reduction” or “GHG emission reduction” or “greenhouse gas reduction” or “GHG reduction” means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

“Greenhouse gas removal enhancement” or “GHG removal” means the calculated total mass of a GHG removed, relative to a project baseline, from the atmosphere over a specified period of time.

“Greenhouse gas reservoir” or “GHG reservoir” means a physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store, accumulate, or release of a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

“Greenhouse gas sink” or “GHG sink” means a physical unit or process that removes a GHG from the atmosphere.

“Grid” or “electric power grid” means a system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers.

“Grid-dedicated facility” means an electricity generating facility in which all net power generated is destined for distribution on the grid through retail providers or electricity marketers, ultimately serving wholesale or retail customers of the grid.

“Grind aid” means chemical agents added in the cement grinding process to improve grinding efficiency.

“Gross generation” or “gross power generated” means the total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

“HD-5” or “special duty propane” means a consumer grade of liquefied petroleum gas containing a minimum of 90% propane, a maximum of 5% propylene, and a maximum of 2.5% butane as specified in ASTM D1835-05.

“HD-10” means the fuel that meets the specifications for propane used in transportation fuel found in Title 13, California Code of Regulations, section 2292.6.

“Heat input rate” means the product (expressed in MMBtu/hr) of the gross calorific value of the fuel (expressed in MMBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

"Heavy crude oil" or "heavy crude" means a category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density having an API gravity of less than 20.

"High-bleed pneumatic devices" means automatic, continuous or intermittent bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

"High heat value" or "HHV" means the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

"Horizontal well" means a well bore that has a planned deviation from primarily vertical to primarily horizontal inclination or declination tracking in parallel with and through the target formation.

"Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

"Hydrofluorocarbons" or "HFCs" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

"Hydrogen" means diatomic molecular hydrogen, the lightest of all gases.

"Hydrogen plant" means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

"Imported electricity" means electricity generated outside the State of California and delivered to serve load located inside the State of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the State of California, to the first point of delivery located inside the State of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the State of California from a facility or unit physically located outside the State of California with the first point of interconnection to a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the State of California. Imported electricity does not include electricity wheeled through California, defined pursuant to this section. Imported electricity does not include electricity imported into the California Independent System Operator

(CAISO) balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the State of California. Imported Electricity does not include electricity imported into California by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall include Western Energy Imbalance Market (~~EIM~~WEIM) and Extended Day-Ahead Market (EDAM) dispatches designated by the CAISO's optimization model and reported by the CAISO to ~~EIM Participating Resource~~CAISO Scheduling Coordinators as electricity imported to serve retail customers load that are located within the State of California.

"Importer of ~~fuel"~~cement" or "cement importer" means the owner or operator who is the importer of record under federal customs law of a cement terminal receiving imported cement or clinker if the terminal owner/operator owns the imported cement or clinker being received. Any entity which owns a majority interest in, or exercises operational control over, two or more importers must aggregate the cement imported by those importers, and such entity shall be considered, or shall designate one of the importers as, the "importer of cement" of, and the single reporting entity for, such aggregated quantity of cement for purposes of section 95101(a)(1)(H). If the terminal owner or operator does not own the imported cement or clinker being received, then the importer of cement is the first entity that owns and receives the imported cement or clinker in California who is the importer of record under federal customs law, such as the owner of a concrete batch plant purchasing the imported cement or clinker for consumption.

"Importer of fuel" with respect to any quantity of fuel means an entity that imports fuel into California and who is the importer of record under federal customs law~~.~~ ~~For imported~~, or if such fuel is not subject to federal customs law, means the ~~"importer of fuel"~~entity that is the ~~owner of~~upstream supplier which owned the fuel ~~upon its entering into~~before the fuel entered California ~~if the eventual transfer of~~and that transferred ownership of the ~~product~~fuel to an end user or ~~marketer~~local retail supplier located in California ~~occurs at a location inside California. However, where the transfer of ownership of the fuel to a California end user or marketer occurs at a location~~, regardless of whether title to or possession of the quantity of fuel was transferred within or outside of California~~, the "importer of fuel" is the producer, marketer, or distributor that is the seller of the fuel to the end user or marketer located inside California~~. Pursuant to section 95122, only importers of liquefied petroleum gas, compressed natural gas, and liquefied natural gas are subject to reporting as an importer of fuel. Additionally, any entity which owns a majority interest in, or exercises operational control over, two or more importers of fuel shall aggregate the fuel imported by those importers, and such entity shall be considered, or shall designate one of the importers as, the "importer of fuel" of, and the single reporting entity for, such aggregated quantity of fuel for purposes of section 95101(c).

"Importer of hydrogen" means an entity that imports hydrogen into California. For hydrogen imported by transport (e.g., truck, rail), the importer is the title holder of the hydrogen as it enters California. For hydrogen imported by pipeline, the importer is the entity in California who contracts for delivery of hydrogen produced outside of California that is injected into a pipeline in North America.

"Importer of record" means the owner or purchaser of the goods that are imported into California.

"Independently operated and sited cogeneration/bigeneration facility" means a cogeneration or bigeneration facility that is not located on the same facility footprint as its thermal host and has different operational control and different ownership than the thermal host.

"Independently operated cogeneration/bigeneration facility co-located with the thermal host" means a cogeneration or bigeneration facility that is located on the same property footprint as its thermal host but has different operational control and different ownership than the thermal host.

"Independent reviewer" has the same meaning as "lead verifier independent reviewer."

"Industrial/institutional/commercial facility with electricity generation capacity" means a facility whose primary business is not electricity generation and includes one or more electricity generating, cogeneration, or bigeneration units.

"Intermittent bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Intermittent bleed devices which bleed at a cumulative rate of 6 standard cubic feet per hour or greater are considered high bleed devices for the purposes of this regulation.

"Internal combustion" means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and high-pressure gases produced by combustion, applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

“Interstate pipeline” means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

“Intrastate pipeline” means any pipeline or piping system wholly within the State of California that is delivering natural gas to end-users and is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), is not a publicly-owned natural gas utility, and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission. For purposes of this article, only intrastate pipeline operators that physically deliver gas to end users in California are subject to reporting under this article. This definition includes onshore petroleum and natural gas production facilities and natural gas processing facilities, as defined by sections 95150(a)(2)-(3) of this article, that deliver pipeline and/or non-pipeline quality natural gas to one or more end users. Facility operators that are required to report facility GHG emissions under MRR and also own or operate an interconnection pipeline that connects their facility to an interstate pipeline, or that ~~share~~jointly own or operate an interconnection pipeline to an interstate pipeline with other nearby facilities, are not considered intrastate pipeline operators. Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.

“Inventory position” means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

"ISO" means the International Organization for Standardization.

“Isobutane” is a paraffinic branch chain hydrocarbon with molecular formula C_4H_{10}.

“Isobutylene” is an olefinic branch chain hydrocarbon with molecular formula C_4H_8.

“Isopentane” is the methylbutane or 2-methylbutane, branched chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

“Joint powers authority” means a public agency that is formed and created pursuant to the provisions of Government Code sections 6500. et seq.

“Jurisdiction” means U.S. state or Canadian province. For purposes of this article, “U.S. state” means U.S. State, the District of Columbia, the

Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this article, "province" means any Canadian province or territory.

"Kerosene" is a light petroleum distillate with a maximum distillation temperature of 400°F at the 10-percent recovery point, a final maximum boiling point of 572°F, a minimum flash point of 100°F, and a maximum freezing point of -22°F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. "Kerosene" does not include kerosene-type jet fuel.

"Kerosene-type jet fuel" means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A–1, JP–5, and JP–8.

"Kiln" means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

"Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.)

"Last point of delivery in California" means the last defined point on the transmission system located inside California at which exported electricity may be measured, consistent with defined points that have been established through the NERC Registry.

"Lead verifier" means a person that has met all of the requirements in section 95132(b)(2) and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

"Lead verifier independent reviewer" or "independent reviewer" means a lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, offset project developer, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 95131. The independent reviewer is not required to meet the requirements for a sector specific verifier.

"Legacy contract" shall have the meaning defined in section 95802(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

“Legacy contract transition assistance” means allowances provided under section 95894 of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation to an entity which has applied for allowances on the basis of its legacy contract(s).

“Less intensive verification” means the verification services provided in interim years between full verifications; less intensive verification of a reporting entity’s emissions data report only requires data checks and document reviews of a reporting entity’s emissions data report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

"Light Crude Oil" means a category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density having an API gravity of greater than or equal to 20.

“Linear Generator” means any power generation technology that uses a thermochemical reaction to create linear motion that is directly converted into electricity and has electricity-only generation efficiency greater than 30%.

“Linkage” is as defined in section 95802(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

“Linked jurisdiction” means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

“Liquefied natural gas” or “LNG” means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

“Liquefied petroleum gas” or “LP-Gas” or “LPG” means a flammable mixture of hydrocarbon gases used as a fuel. LPG is a natural gas liquid (NGL) that is primarily a mixture of propane and butane, with small amounts of propene (propylene) and ethane. The most common specification categories are propane grades HD-5, HD-10, and commercial grade propane, and propane/butane mix. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as propane.

“LNG boiloff gas” means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

“Local distribution company” or “LDC,” for purposes of this article, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations~~,~~ and publicly-owned natural gas utilities ~~and intrastate pipelines~~ that ~~are delivering~~deliver natural gas to end users.

"Local retail supplier" as it is used in the definition of "importer of fuel" means a business entity that purchases fuel in large volume quantities, typically tens of thousands to millions of gallons, from an upstream supplier and sells or distributes the fuel in smaller quantities directly to end users and retail establishments. "Local retail suppliers" may include, but are not limited to, entities referred to as marketers, retailers, or dispensers.

"Lookback period" means the specified time period of historical data that the operators must use for missing data substitution as required by the regulation.

"Low-bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

"Low Btu gas" means gases recovered from casing vents, vapor recovery systems, crude oil and petroleum product storage tanks and other parts of the crude oil refining and natural gas production process.

"Marketer" means a purchasing-selling entity that delivers electricity and is not a retail provider.

"Market-shifting leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services.

"Material misstatement" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that the total reported covered emissions (metric tons of CO_2e) or reported covered product data contains errors greater than 5%, as applicable, in an emissions data report. Material misstatement is calculated separately for covered emissions and covered product data, as specified in section 95131(b)(12)(A).

"Maximum potential fuel flow rate" or "maximum fuel consumption rate" means the maximum fuel use rate the source is capable of combusting, measured in physical unit of the fuel (e.g. million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids). When the source consists of multiple units, the maximum potential fuel use rate is the sum of the maximum potential fuel use rates of all the units aggregated as a source.

"Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

"Meter/regulator run" means a series of components used in regulating pressure or metering natural gas flow or both.

"Metering/regulating station" means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

"Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

"Metric ton" or "MT" means a common international measurement for mass, equivalent to 2204.6 pounds or 1.1 short tons.

"Midgrade gasoline" means gasoline that has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For midgrade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

"Missing data period" means a period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements. In the context of periodic fuel sampling, missing data period is the entire sampling period (e.g. week, month, or quarter) for which corresponding fuel characteristic data are not obtained. In the context of periodic fuel consumption monitoring and recording, a missing data period consists of the consecutive time intervals (e.g. hours, days, weeks, or months) for which fuel consumption during the time period is not monitored and recorded.

"MMBtu" means million British thermal units.

"Motor vehicle fuel" means gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, or racing fuel.

"Mscf" means thousand standard cubic feet.

"Multi-jurisdictional retail provider" or "MJRP" means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

"Municipal solid waste" or "MSW" means solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. §6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

"NAICS" means North American Industry Classification System.

"Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in Kilowatts (kW) on a nameplate physically attached to the generator.

"Naphthas" (< 401°F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122°F and 400°F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

"Natural gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

“Natural gas distribution facility” means the collection of all distribution pipelines, metering stations, and regulating stations that are operated by a local distribution company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

“Natural gas driven pneumatic pump” means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

“Natural gas liquids” or “NGLs” means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

“Natural gas liquid fractionator” means an installation that fractionates natural gas liquids (NGLs) <u>or their biomass-derived equivalents </u>into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

“Natural gas supplier” means, for the purposes of this article, the local distribution company<u>, intrastate pipeline,</u> or interstate pipeline that owns or operates the distribution pipelines that physically deliver natural gas to end users.<u> “Natural gas supplier” also means the entity that sells or delivers fossil or biomass-derived liquefied petroleum gas, compressed natural gas, and liquefied natural gas to end users.</u>

“Natural gasoline” means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane. Natural gasoline is a natural gas liquid of intermediate vapor pressure.

“NERC e-Tag” means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

“Net generation” or “net power generated” means the gross generation minus station service or unit service power requirements, expressed in megawatt hours

(MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

“Nitrous oxide” or “N_2O” means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

“Nonconformance” means the failure to use the methods or emission factors specified in this article to calculate emissions, or the failure to meet any other requirements of the regulation.

“Non-exempt biomass-derived CO_2” means CO_2 emissions resulting from the combustion of fuel not listed under section 95852.2(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation, or that does not meet the requirements of section 95131(i) of this article.

“Non-exempt biomass-derived fuel” means fuel not listed under section 95852.2(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation, or that does not meet the requirements of section 95131(i) of this article.

“Non-fuel based renewable electricity generating unit” means a unit that generates electricity not from fuel sources, but from renewable energy sources, such as solar, wind, or hydropower. For the purpose of this article, a non-fuel based renewable electricity generating unit does not include other types of generation explicitly listed in section 95112(a)-(f).

"Non-submitted/non-verified emissions data report" means an emissions data report that is not submitted to CARB by the applicable reporting deadline, or for which a verification statement has not been issued by the applicable verification deadline.

“North American Industry Classification System (NAICS) code(s)” means the six-digit code(s) that represent the product(s)/activity(s)/service(s) at a facility or supplier as defined in North American Industrial Classification System Manual 2007, available from the U.S. Department of Commerce, National Technical Information Service.

“Offset project” means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions or GHG removal enhancements within the offset project boundary.

“Offset project boundary” is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset

Project Operator or Authorized Project Designee are not included in the offset project boundary.

"Offset project data report" means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a compliance offset protocol.

"Offset project operator" means the entity(ies) with legal authority to implement the offset project.

"Offset project specific verifier" means an individual who has been accredited by CARB to verify offset projects of a specific offset project type.

"Offset protocol" means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

"Offshore," for purposes of this article, means all waters within three nautical miles of the California baseline, starting at the California-Oregon border and ending at the California-Mexico border at the Pacific Ocean, inclusive. For purposes of this definition, "California baseline" means the mean lower low water line along the California Coast.

"Oil well" means a well completed for the production of crude oil from at least one oil zone or reservoir.

"Oil and gas systems specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators of petroleum refineries, biorefineries, hydrogen production units or facilities, and petroleum and natural gas systems listed in section 95101(e).

"Onshore petroleum and natural gas production facility" means all petroleum or natural gas equipment on a well pad, or associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator that are located in a single basin as defined in 40 CFR §98.238. When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or operating entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

"Onshore petroleum and natural gas production owner or operator" means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in section 95102(a)). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

"On-site" or "onsite" in the context of GHG reporting means within the facility boundary.

"Operating pressure" means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

"Operational control" ~~for a facility subject to this article~~ means the authority to introduce and implement operating, environmental, health, and safety policies. ~~In~~For purposes of this article, in any circumstance where this authority is shared among multiple ~~entities~~facility operators, the ~~entity holding~~holder of the permit to operate from the local air pollution control district or air quality management district is considered to have operational control ~~for purposes of this article~~.

"Operator" means the entity, including an owner, having operational control of a facility. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

"Operating Pressure," for purposes of Appendix B means the working pressure that characterizes the conditions of crude oil, condensate, or produced water inside a particular process, pipeline, vessel or tank. In general, low pressure liquid is under less than approximately 200 psig of pressure.

"Outside of the facility boundary" means not within the physical boundary of the facility (regardless of ownership or operational control), or not in the same operational control of the reporting entity if within the same physical boundary of the facility. For example, an entity outside of the facility boundary may include another facility not in the reporting entity's operational control, another facility under the same operational control but considered a separate facility according to the definition of "facility" in this section, or an on-site industrial operation (e.g. a cogeneration system) within the facility fence line but that is operated by another operator and for which the on-site industrial operation has not been included in the reporting entity's GHG report.

"Parasitic load" means the amount of electricity consumed by auxiliary equipment that supports the electricity generation or cogeneration process. The equipment may include fans, pumps, drive motors, pollution control equipment, lighting, computer, CEMS, and other equipment.

"Particular end-user" means a final purchaser of an energy product (e.g. electricity or thermal energy) for whom the energy product is delivered for final consumption and not for the purposes of retransmission or resale.

"Pentane" is the n-pentane, straight chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

"Pentanes plus" or "C5+" means a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

"Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

"Percent Water Cut," for purposes of Appendix B, means the percentage of water by volume, of the total emulsion throughput as measured using ASTM D-4007-08. The percent water cut is expressed as a percentage.

"Performance review" means an assessment conducted by CARB of an applicant seeking to become accredited as a verification body, verifier, lead verifier, offset project specific verifier, or sector specific verifier pursuant to section 95132 of this article. Such an assessment may include a review of applicable past sampling plans, verification reports, verification statements, conflict of interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

"Petroleum" means oil removed from the earth and the oil derived from tar sands and shale.

"Petroleum coke" means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke.

"Petroleum ~~refinery" or "~~refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

"Physical address," with respect to a United States parent company as defined in this section, means the street address, city, State and zip code of that company's physical location.

"Pipeline dig-in" means unintentional puncture or rupture to a buried natural gas transmission and distribution pipeline during excavation activities.

"Pipeline quality natural gas" means, for the purpose of calculating emissions under this article, natural gas having ~~a~~all of the following characteristics on an annual weighted average basis: high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, ~~and which is~~ at least ninety percent methane by volume, and ~~which is~~ less than five percent carbon dioxide by volume.

"Point of delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

"Point of receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

"Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

"Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

The equipment is attached to a foundation.

The equipment or a replacement resides at the same location for more than 12 consecutive months.

The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

“Portland cement” means hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter-ground addition.

“Position holder” means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal. “Position holder” does not include inventory held outside of a terminal, fuel jobbers (unless directly holding inventory at the terminal), retail establishments, or other fuel suppliers not holding inventory at a fuel terminal.

“Positive emissions data verification statement” means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of this article.

“Positive product data verification statement” means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and that the covered product data conforms to the requirements of this article.

“Positive verification statement” means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and that the emissions data report conforms to the requirements of this article. This definition applies to the emissions data verification statement and the product data verification statement.

“Power” means electricity, except where the context makes clear that another meaning is intended.

“Power contract” or “written power contract,” as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document, including associated verbal or electronic records if included as part of the written power contract, arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, and tariff provisions, without regard to duration, or written agreements to import or export on behalf of another entity, as long as that other entity also reports to CARB the same imported or exported electricity. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier’s system that is designated at the time the transaction is executed.

“Premium grade gasoline” is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For premium grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

“Primary fuel” means the fuel that provides the greatest percentage of the annual heat input to a stationary fuel combustion unit.

“Primary generation source” means a resource that generates electric power imported into California or has CAISO sales that is not an energy storage system (ESS).

“Primary Vessel,” for purposes of Appendix B means a separator or tank that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more crude oil, condensate, or natural gas wells or field gathering systems.

“Prime mover” means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

“Process” means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

“Process emissions” means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

~~“Process emissions specialist” means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators of facilities engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, nitric acid production, and lead production.~~

“Process gas” means any gas generated by an industrial process such as petroleum refining.

“Process Heater” means equipment for the heating of process streams (gases, liquids, or solids) other than water through heat provided by fuel combustion.

“Process unit” means the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final or an intermediate product used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.

“Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

“Produced water” means the resulting water that is produced as a byproduct of crude oil or natural gas production.

“Producer” means a person who owns, leases, operates, controls or supervises a California production facility.

“Product data” means the sector-specific data specified in subarticles 2 and 5 of this article, including requirements in 40 CFR Part 98.

“Product data verification statement” means the final statement rendered by a verification body attesting whether a reporting entity’s covered product data in their emissions data report is free of material misstatement, and whether the product data conforms to the requirements of this article.

“Professional judgment” means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

“Project baseline” means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or GHG removal enhancements for the offset project’s GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

“Propane” is a paraffinic hydrocarbon with molecular formula C_3H_8.

“Propylene” is an olefinic hydrocarbon with molecular formula C_3H_6.

“Pseudo-tie” means the treatment of an electricity generating facility located outside the State of California, in a non-California balancing authority area, as being within a California balancing authority area for the purposes of transmission. Electric power from pseudo-tied resources are considered imports for the purposes of this article.

“Public utility gas corporation” is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

“Publicly-owned natural gas utility” means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

“Pump” means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

“Pump seal emissions” means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

“Pump seals” means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

“Purchasing-selling entity” or “PSE” means the entity that is identified on a NERC e-Tag for each physical path segment.

“Pure” means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

“PURPA Qualifying Facility” means a facility that has acquired a “qualifying facility (QF)” certification pursuant to 18 CFR §292.207 under the Public Utility Regulatory Policies Act of 1978 (PURPA).

“QA/QC” means quality assurance and quality control.

“Qualified positive emissions data verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data may include one or more other nonconformances with the requirements of this article which do not result in a material misstatement.

“Qualified positive product data verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the product data may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement.

“Qualified positive verification statement” means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data report may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement. This definition applies to the qualified positive emissions data verification statement and the qualified positive product data verification statement.

“Qualified Thermal Output” means the thermal energy generated by a cogeneration unit or district heating facility that is sold to particular end-users and reported pursuant to MRR section 95112(a)(5)(A) and the thermal energy used on-site by industrial processes or operations and heating and cooling operations that is not in support of or a part of the electricity generation or cogeneration system and is reported pursuant to MRR sections 95112(a)(5)(C). Qualified thermal output does not include thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations, or, for a facility with a cogeneration unit, any thermal energy generated by equipment that is not an integral part of the cogeneration unit.

“Quality-assured data” or “quality-assured value” means the data are obtained from a monitoring system that is operating within the performance specifications and the quality assurance/quality control procedures set forth in the applicable rules, for example 40 CFR Part 60 (July 1, 2009) or Part 75, (July 1, 2009), which is hereby incorporated by reference, without unscheduled maintenance, repair, or adjustment.

"Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

"RBOB-summer" or "reformulated blendstock for oxygenate blending-summer" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-summer.

"RBOB-winter" or "reformulated blendstock for oxygenate blending-winter" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-winter.

"Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

"Reciprocating compressor" means a piece of equipment that increases the pressure of a process natural gas or CO_2 by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

"Reciprocating compressor rod packing" means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO_2 that escapes to the atmosphere.

"Reciprocating internal combustion engine" or "RICE" or "piston engine" means an engine that uses heat from the internal combustion of fuel to create pressure that drives one or more reciprocating pistons, creating mechanical energy.

"Re-condenser" means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

"Refiner" means, for purposes of this article, an individual entity or a corporate-wide entity that delivers transportation fuels to end users in California that were produced by petroleum refineries <u>or biorefineries</u> owned by that entity or a subsidiary of that entity.

"Refinery fuel gas" or "still gas" means gas generated at a ~~petroleum~~ refinery or ~~any gas generated~~ by a refinery process unit~~, and~~ that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

“Reformulated Gasoline Blendstock for Oxygenate Blending” or “RBOB” has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

“Reformulated-summer” means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, and summer RVP standards required under 40 CFR §80.27 or as specified by the state. Reformulated gasoline excludes RBOB as well as other blendstock.

“Reformulated-winter” means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, but which do not meet summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes RBOB as well as other blendstock.

“Regular grade gasoline” is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For regular grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

"Relative Accuracy Test Audit" means a method of determining the correlation of continuous emissions monitoring system data to simultaneously collected reference method test data, for example as required in 40 CFR Part 60 (July 1, 2009) and 40 CFR Part 75 (July 1, 2009).

“Rendered animal fat” or “tallow” means fats extracted from animals which are generally used as a feedstock in making biodiesel.

“Renewable diesel” means a motor vehicle fuel or fuel additive that is all of the following:

Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

Not a mono-alkyl ester;

Intended for use in engines that are designed to run on conventional diesel fuel; and

Derived from nonpetroleum renewable resources.

“Renewable energy” means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

“Renewable Energy Credit” or “REC” has the same meaning defined in the California Energy Commission’s “Renewable Portfolio Standard Eligibility,” ~~7~~9th edition, Commission Guidebook, pp. 85-86, ~~April, 2013~~January, 2017; CEC-300-~~2013-005-ED7-~~-2016-006-ED9-CMF-REV.

~~“Renewable liquid fuels” means fuel ethanol, biomass-based diesel fuel, other renewable diesel fuel and other renewable fuels.~~

“Reporting entity” means a facility operator, supplier, or electric power entity subject to the requirements of this article.

“Reporting period” means the calendar year which coincides with the data year for the GHG report.

“Reporting year” or “report year” means data year.

“Reservoir” means a porous and permeable underground natural formation containing crude oil or gas. A reservoir is characterized by a single natural pressure.

“Residual fuel oil” means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

“Residue gas and residue gas compression” means, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

“Retail end-use customer” or “retail end user” means a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product and not for resale.

“Retail provider” means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section

218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electric cooperatives, as defined by Public Utilities Code section 2776, are excluded.

~~"Retail sales" means electricity sold to retail end users.~~

"Retail sales" means sales of electricity by a retail supplier to end-use customers over the course of a calendar year, measured in megawatt hours. Residential retail sales are the subset of retail sales sold to residential customers. Total retail sales are the total amount of retail sales to all end-use customers. Retail sales do not include self-consumption by a retail supplier or electricity produced for onsite consumption that was not sold to an end-use customer by the retail supplier. Reported retail sales are used in the Outstanding Emissions Calculation described in section 95111(h)(1).

"Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

"Secondary Vessel," for purposes of Appendix B means a separator or tank that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more primary vessel separators or tanks.

"Sector" means a broad industrial categorization such as specified in section 95101.

"Sector specific verifier" means a verifier accredited pursuant to section 95132(b)(5)(A) as one or more of the following types of specialists defined pursuant to this section: a transactions specialist~~,~~ or an oil and gas systems ~~specialist, or a process emissions~~ specialist.

"Separator" means a sump or vessel used to separate crude oil, condensate, natural gas, produced water, emulsion or solids.

"Short ton" means a common international measurement for mass, equivalent to 2,000 pounds.

"Shutdown" means the cessation of operation of an emission source for any purpose.

"Simplified block diagram" means a diagram consisting of boxes, shapes, lines, arrows, and labels that meets the requirements of section 95112(a)(6) or section 95105(c). A simplified block diagram is not an architectural drawing or an engineering drawing that shows the likeness of the physical objects being depicted and their actual locations and sizes in scale; it is a simplified graphical representation of the objects being depicted, their relative locations, and how they are connected through flows of energy or energy carrier (e.g. steam, water, electricity, or fuel).

“Sink” or “sink to load” or “load sink” means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

“Sorbent” means a material used to absorb or adsorb liquids or gases.

“Sour natural gas” means natural gas that contains significant concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

“Source” means greenhouse gas source; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

“Source category” means categories of emission sources as defined by Tables A-3, A-4, and A-5 of 40 CFR Part 98.

“Source of generation” or “generation source” means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

“Specified source of electricity” or “specified source” means primary generation sources such as a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by ~~the ARB~~CARB. Unless registered per section 95111(i), energy storage systems (ESS) are not specified sources for the purposes of this article but can be used to store and claim specified source power from primary generation sources if all specified source requirements are met, including seller warranties.

“SSM” means periods of startup, shutdown and malfunction.

“Stand-alone electricity generating facility” means an electricity generating facility whose primary business and sole industrial operation is electricity generation, and is not a cogeneration or bigeneration facility.

“Standard conditions” or “standard temperature and pressure (STP)” means either 60 or 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

“Standard cubic foot” or “scf” is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and either 14.696 pounds per square inch (1 atm) or 14.73 PSI (30 inches Hg) of pressure.

“Steam generator” means equipment that produces steam using an external heat source.

“Stationary” means neither portable nor self-propelled, and operated at a single facility.

“Storage tank” means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

“Sub-facility” for purposes of reporting data disaggregated pursuant to section 95156(a), means the geographic area, or areas, within a single township or within a group of contiguous or adjacent townships identified in the Public Land Survey System of the United States, where operations and equipment are located. The operator may disaggregate sub-facilities based on contiguous township areas to smaller sub-facilities according to similar operational, geological, or geographical characteristics. Sub-facility disaggregation may be retained from year to year, or may be updated when some of the operations cease or equipment is reconfigured within the previously designated sub-facilities. Sub-facility disaggregation must be updated from previous reporting years if there are new operations or equipment that lies outside previous township boundaries. The Principal Meridian name, Township and Range designations, and the section numbers that apply to each sub-facility, must be identified in the operator’s GHG Monitoring Plan required pursuant to section 95105(c). The operator must also describe in the GHG Monitoring Plan any operational, geological or geographical characteristics used to determine sub-facility boundaries.

“Substitute power” or “substitute electricity” means electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit when that facility or unit is not generating electricity.

“Sulfur hexafluoride” or “SF_6” means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

"Sump," for purposes of Appendix B means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used for separating crude oil, condensate, produced water, emulsion, or solids.

"Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle cogeneration facility.

"Supplier" means an entity, or multiple entities held under common ownership or common control, that is a producer, importer, exporter, position holder, interstate pipeline operator, intrastate pipeline operator, or local distribution company of ~~a fossil~~ fuel, or an ~~industrial greenhouse gas.~~importer of cement or hydrogen.

"Sweet gas" means natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

"Tactical support equipment" is as defined in title 17, California Code of Regulations, section 93116.2(a)(36).

"Tank," for the purposes of Appendix B, means a container, constructed primarily of non-earthen materials, used for holding or storing crude oil, condensate, produced water, or emulsion.

"Tentatively Identified Compound List," for purposes of Appendix B means a list of target compounds that laboratories can use to evaluate uncommon gaseous compounds when performing a Gas Chromatograph/ Mass Spectrometry analysis.

"Terminal" means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which fuel may be removed at a rack. "Terminal" includes a fuel production facility where motor vehicle or diesel fuel is produced and stored and from which fuel may be removed at a rack.

"Terminal operator" means any entity that owns, operates or otherwise controls a terminal that is supplied by pipeline or vessel and from which accountable fuel products may be removed at a rack.

"Thermal energy" means the thermal output produced by a combustion source used directly as part of a manufacturing process, industrial/commercial process, or heating/cooling application, but not used to produce electricity.

“Thermal host” means the user of the steam or heat output of a cogeneration or bigeneration facility.

“Three-Phase Separator,” for purposes of Appendix B, means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil, produced water and gases.

“Throughput” for the purposes of Appendix B, means the average volume of liquid processed by a vessel over a period of time, such as barrels per day. The throughput of crude oil or condensate may need to be calculated using the Percent Water Cut. The throughput of crude oil or condensate is calculated as the difference in volume between these liquids and the produced water.

“Tier” means the level of calculation method from 40 CFR §98.33 that is required for a stationary combustion source in section 95115 of this article.

“Tier 1” means a stationary combustion calculation method that applies default values for emission factors and high heat value to generate an emissions estimate, as specified in 40 CFR §98.33.

“Tier 2” means a stationary combustion calculation method that applies a default value for an emission factor and a fuel’s measured high heat value (or a boiler efficiency for steam-generating solid fuels) to generate an emissions estimate, as specified in 40 CFR §98.33.

“Tier 3” means a stationary combustion calculation method that utilizes a fuel’s measured carbon content to generate an emissions estimate, as specified in 40 CFR §98.33.

“Tier 4” means a stationary combustion calculation method that utilizes quality-assured data from a continuous emission monitoring system to generate an emissions estimate, as specified in 40 CFR §98.33. This method may also capture process emissions from a common stack.

“Tolling agreement” means an agreement whereby a party rents a power plant from the owner. The rent is generally in the form of a fixed monthly payment plus a charge for every MW generated, generally referred to as a variable payment.

“Topping cycle” means a type of cogeneration system in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

“Total thermal output” means the total amount of usable thermal energy generated by a cogeneration or bigeneration unit that can potentially be made available for use in any industrial or commercial processes, heating or cooling applications, or delivered to other end users. This quantity excludes the heat content of returned condensate and makeup water, but includes the thermal energy used for supporting (but not directly used for) power generation, thermal energy used in other on-site processes or applications that are not in support of or a part of the electricity generation system, thermal energy provided or sold to particular end-user, and thermal energy that is otherwise not utilized. Thermal energy directly used for power generation (e.g., steam used to drive a steam turbine generator for electricity generation) is not included in total thermal output.

“Transactions specialist” means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to electric power entities; suppliers of petroleum products and biofuels; suppliers of natural gas, natural gas liquids, and liquefied petroleum gas; and suppliers of carbon dioxide.

“Transmission-distribution (T-D) transfer station” means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

“Transmission pipeline” means a high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas from processing to natural gas distribution pressure let-down, metering, regulating stations, where the natural gas is typically odorized before delivery to customers.

“Traceable” means that a standard used to calibrate a device has an unbroken chain of comparisons to a stated reference (such as a standard set by the National Institute of Standards and Technology), with each comparison having a stated uncertainty.

“Turbine” means any of various types of machines in which the kinetic energy of a moving fluid is converted into mechanical energy by causing a bladed rotor to rotate.

“Turbine meter” means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

“Two-Phase Separator,” for purposes of Appendix B, means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil and produced water that still contain entrained gases.

“Type of thermal energy product” means the form in which energy is transferred from a facility producing thermal energy to another facility, or if not transferred, the form in which the energy is used. Types of thermal energy products include steam, hot water, chilled water, and distilled water.

“Uncertainty” means the degree to which data or a data system is deemed to be indefinite or unreliable.

“Uncontrolled blowdown system” means the use of a blowdown procedure that does not result in the recovery of emissions for flaring or re-injection.

“Unconventional wells” means crude oil or gas wells in producing fields that employ hydraulic fracturing to enhance crude oil or gas production volumes.

“United States parent company(s)” mean the highest-level United States company(s) with an ownership interest in the reporting entity as of December 31 of the reporting year.

“Unspecified source of electricity” or “unspecified source” means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity.

“Upstream entity” means the last entity in the chain of title prior to the fuel being received by the reporting entity.

“Upstream supplier” as it is used in the definition of “importer of fuel” means a “supplier” as defined herein, that sells fuel in large volume quantities, typically tens of thousands to millions of gallons, to end users or local retail suppliers. Upstream suppliers may include but are not limited to producers, wholesale suppliers, midstream suppliers, brokers, multistate distributors, or other bulk suppliers. For the purposes of this regulation, LPG suppliers that integrate upstream, distribution, and retail services across the supply chain are considered to be upstream suppliers.

“Urban waste” means waste pallets, crates, dunnage, manufacturing and construction wood waste, tree trimmings, mill residues and range land maintenance residues.

“U.S. EPA” means the United States Environmental Protection Agency.

“Used oil” means a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of handling or use, such that the oil cannot be used for its original purpose. Used oil consists primarily of automotive oils (e.g., used motor oil, transmission oil, hydraulic fluids, brake fluid, etc.) and industrial oils (e.g., industrial engine oils, metalworking oils, process oils, industrial grease, etc.).

“Vapor recovery system” means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

"Vegetable oil" means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

"Vented emissions" means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

"Verification" means a systematic, independent and documented process for evaluation of a reporting entity's emissions data report against CARB's reporting procedures and methods for calculation and reporting GHG emissions and product data.

"Verification body" means a firm accredited by CARB that is able to render a verification statement and provide verification services for reporting entities subject to reporting under this article.

"Verification services" means services provided during verification as specified in section 95131 beginning with the development of the verification plan or first site visit, including but not limited to reviewing a reporting entity's emissions data report, ensuring its accuracy according to the standards specified in this article, assessing the reporting entity's compliance with this article, and submitting a verification statement(s) to ~~the ARB~~CARB.

"Verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's emissions data report is free of material misstatement, and whether it conforms to the requirements of this article. This definition applies to the emissions data verification statement and the product data verification statement.

"Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for a reporting entity.

"Verified emissions data report" means an emissions data report that has been reviewed by a third-party verifier and has a verification statement, or statements, if applicable, submitted to ~~the ARB~~CARB.

"Verifier" means an individual accredited by CARB to carry out verification services as specified in section 95131.

“Verifier review” means a verifier conducts all reviews and services in section 95131, except the material misstatement assessment under section 95131(b)(12). If some of the sources are selected for data checks based on the sampling plan, the verifier will check for conformance with the requirements of this article.

“Vertical well” means a well bore that is primarily vertical but has some unintentional deviation to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

“Vessel,” for the purposes of Appendix B, means any container, constructed primarily of non-earthen materials, used to separate or store crude oil, condensate, natural gas, produced water, or emulsion.

“Volatile organic compound” or “VOC” means any volatile compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions.

“VOC_{C3-C9},” for purposes of Appendix B, means Volatile Organic Compounds with three to nine carbon atoms.

“VOC_{C10+},” for purposes of Appendix B, means Volatile Organic Compounds with 10 or more carbon atoms. This value is needed for laboratory and quality control purposes.

“Weighted monthly average” means the sum of the products of two values measured during the same time period divided by the sum of the values not being averaged. For weighted average HHV it would be the sum of the products of volume and HHV measured during the same time period divided by the sum of the volumes.

“Well completions” means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

"Well testing venting and flaring" means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after a well completion or workover, then it is considered part of well completion or workover.

"Well workover" means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

"Wellhead" means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (i.e. well pad) surrounding one or multiple wellheads.

"Western Energy Imbalance Market" or "WEIM" means the operation of the CAISO's real-time market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined CAISO and WEIM footprint.

"Wet natural gas" means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

"Wholesale sales" means sales to other LDCs.

(b) Product Data Definitions. For the purposes of this article, the following definitions associated with reported product data shall apply:

"Adjusted hulled and dried pistachios" means the raw pistachios that have been received and subjected to a hulling and drying process. Hulling is the process of removing pistachio hulls that cover pistachio shells and kernels. Drying is the process of reducing the moisture content of hulled pistachios. Adjusted hulled and dried pistachios shall conform to the sampling methodology specified in the "Representative Sampling" section of "Pistachios In the Shell, Shipping Point and Market Inspection Instructions" (U.S. Department of Agriculture 2005), which is hereby incorporated by reference, and the weight shall be corrected to 5 percent moisture.

"Air dried ton of paper" means paper with 6 percent moisture content.

“Almond” means the edible seed of the almond (Prunus amygdalus).

“Aluminum alloy” is an alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.

“Aluminum and aluminum alloy billet” means a solid bar of nonferrous metal, produced by casting molten aluminum alloys that is suitable for subsequent rolling, casting, or extrusion.

“Anhydrous milkfat” means fatty products derived exclusively from milk and/or products obtained from milk by means of processes which result in almost total removal of water and non-fat solids.

“Aseptic preparation” is a system in which a product is sterilized before filling into pre-sterilized packs under sterile conditions.

“Aseptic tomato paste” means tomato paste and tomato puree packaged using aseptic preparation. Aseptic paste is normalized to 31 percent tomato soluble solids. Aseptic paste normalized to 31% TSS = (%TSS - raw TSS)/(31 - raw TSS)

“Aseptic whole and diced tomato” means the sum of whole and diced tomatoes packaged using aseptic preparation. Sum of aseptic whole and diced tomatoes = whole tomatoes + (diced tomatoes x 1.05))

“Asphalt production” means, for the purposes of non-CWB product data reporting, the processing required to produce asphalt and road oils through distillation of petroleum or through re-distillation, cracking, or reforming of unfinished petroleum derivatives. The modification of asphalt produced from offsite petroleum refining, such as by blending or asphalt blowing, is not considered asphalt production.

“Baked potato chip” means a potato chip made from potato dough that is rolled to a specified thickness, cut into a chip shape and then toasted in an oven.

"Barrel of oil equivalent," with respect to reporting of oil and gas production, means barrels of crude oil produced, plus associated gas and dry gas produced, converted to barrels at 5.8 MMBtu per barrel.

“Blanched almonds” means raw almond meats that are introduced to the blanching process. Blanching is the process through which skins are detached from almond meats.

“Boric Oxide Equivalent” means the theoretical equivalent mass of boric oxide (B_2O_3) in all produced borate products, which is not necessarily equal to the mass of the physical substance boric oxide. This theoretical chemically equivalent mass of B_2O_3 in produced borate product is measured either (1) by using the methods described in "Method to Determine the Boric Oxide Equivalent in Borate Products" (~~ARB~~March 2017), which is hereby incorporated by reference, or (2) by multiplying the mass of borates by the default boric oxide equivalency factors and summing the products. The default boric oxide equivalency factors are as follows: 38 percent for borax decahydrate ($Na_2B_4O_7*10H_2O$), 49 percent for borax pentahydrate ($Na_2B_4O_7*5H_2O$), 69 percent for anhydrous borax ($Na_2B_4O_7$), 56 percent for boric acid (H_3BO_3), and 99 percent for anhydrous boric acid (B_2O_3).

"Butter" means the product made by gathering the fat of fresh or ripened milk or cream into a mass that also contains a small portion of other milk constituents including nonfat solids. Moisture and nonfat solids are essential constituents of butter.

"Buttermilk" means the low-fat portion of milk or cream remaining after the milk or cream has been churned to make butter.

“Buttermilk powder” means milk powder obtained by drying liquid buttermilk that was derived from the churning of butter and pasteurized prior to condensing. Buttermilk powder has a protein content of no less than 30%. It may not contain, or be derived from, nonfat dry milk, dry whey, or products other than buttermilk, and contains no added preservatives, neutralizing agents, or other chemicals.

“By-product hydrogen gas” means pure hydrogen gas produced as a result of a process or processes dedicated to producing other products (e.g. catalytic reforming).

“Calcined coke” means petroleum coke purified to a dry, pure form of carbon suitable for use as anode and other non-fuel applications.

~~"Calcium ammonium nitrate solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.~~

“Calyx” means the leaflike structure composing the outermost part of a flower. This structure often encloses and protects a bud and may remain after a fruit forms.

“Casein” means a group of proteins found in milk which is coagulated by enzymes and acid to form cheese.

"Cheese" means a food product derived from milk that is produced in a wide range of flavors, textures, and forms by coagulation of the milk protein casein.

“Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

"Cold rolled and annealed steel sheet" means steel that is cold rolled and then annealed. Cold rolling means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature. Annealing is a heat or thermal treatment process by which a previously cold-rolled steel coil is made more suitable for forming and bending. The steel sheet is heated to a designated temperature for a sufficient amount of time and then cooled.

"Cold rolling of steel" means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature.

"Condensed milk" means the food obtained by partial removal of water only from a milk product. The finished food contains not less than 28 percent by weight of total milk solids. The composition of the milk solid components and nutritional content in condensed milk remains the same relative ratios as the parent fluid milk product except for minor composition changes due to processing.

“Container Glass pulled" means the quantity of glass removed from the melting furnace in the container glass manufacturing process where "container glass" is defined as glass products intended for packaging.

“Corn” means the kernels of the dent corn plant (Zea mays var. indentata.) that have been shelled and contain no more than 10.0 percent of other grains.

“Corn chip” is a food product made from masa (ground corn dough) that is rolled to a specific thickness, cut into a chop shape, lightly toasted in an oven, and then deep fried.

“Corn curl” is a food product made from a deep-fried extrusion of masa (ground corn dough).

“Corn entering wet milling process” means corn entering the process in which feed corn is steeped in liquid in order to help separate the kernel’s various components into starch, germ, fiber and protein (gluten) and then process the components into useful products such as starch, syrup, high fructose corn syrup, animal feed, and by-products such as gluten meal and germ.

“Cream” means that portion of milk, rich in milk fat, which rises to the surface of milk that is left standing or which is separated from milk by centrifugal force.

“Dehydrated chili pepper” means chili pepper that has been dehydrated to no more than 12 percent water by ~~volume~~mass in order to extend the shelf life and to concentrate the flavor. Chili peppers are the fruit of plants from the genus Capsicum, and are members of the nightshade family Solanaceae.

“Dehydrated garlic” means garlic that has been dehydrated to no more than 6.8 percent water by ~~volume~~mass in order to extend the shelf life and to concentrate the flavor. Garlic is an onion-like plant (Allium sativum) having a bulb that breaks up into separable cloves with a strong distinctive odor and flavor.

“Dehydrated onion” mean onion that has been dehydrated to no more than 5.5 percent water by ~~volume~~mass in order to extend the shelf life and to concentrate the flavor. Onion (Allium cepa) is a plant that has a fan of hollow, bluish-green leaves and the bulb at the base of the plant begins to swell when a certain day-length is reached.

“Dehydrated parsley” means parsley that has been dehydrated to no more than 5 percent water by ~~volume~~mass in order to extend the shelf life and to concentrate the flavor. Parsley (Petroselinum crispum) is a species of Petroselinum in the family Apiaceae widely cultivated as an herb, a spice, and a vegetable.

“Dehydrated spinach” means spinach that has been dehydrated to no more than 7 percent water by ~~volume~~mass in order to extend the shelf life and to concentrate the flavor. Spinach (Spinacia oleracea) is an edible flowering plant in the family of Amaranthaceae.

"Deproteinized whey" means products manufactured through the cold ultrafiltration of sweet dairy whey, removing a portion of the protein from sweet whey to result in a non-hygroscopic, free-flowing and clean flavored powder containing greater than 80% carbohydrate (lactose) levels.

“Diced Tomatoes” means the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are diced or crushed, and shall have had the stems and calyces removed.

“Distilled spirit” means a spirit made from the separation of alcohol and a fermented product.

“Dolime" is calcined dolomite.

“Dry color concentrate” means precipitated solids extracted from fruits and vegetables whose uses are for altering the color of materials and/or food.

“Ductile iron pipe” means pipe made of cast ferrous material in which a major part of the carbon content occurs as free graphite in a substantially nodular or spheroidal form. Pipes are used mainly to convey substances which can flow.

“EIA product code” means the code used to report a specific product to the U.S. Energy Information Administration (EIA) through EIA reporting forms.

"Fiberglass pulled" means the quantity of glass removed from the melting furnace in the fiberglass manufacturing process where "fiberglass" is defined as insulation products for thermal, acoustic, and fire applications manufactured using glass.

"Flat glass pulled" means the quantity of glass removed from the melting furnace in the flat glass manufacturing process where "flat glass" is defined as glass initially manufactured in a sheet form.

“Flavored Almonds” means pasteurized almond meats that are introduced to the flavoring process. Flavoring occurs when almonds are passed through a seasoning mixture to add various snack food flavors and then dehydrated to a desired moisture level for packaging.

“Flavored Pistachios” means hulled and dried pistachios that are introduced to the flavoring process. Flavoring occurs when pistachios are passed through a seasoning mixture to add various snack food flavors and then dehydrated to a desired moisture level for packaging. Flavored pistachios may include pistachios hulled and dried internally, or pistachios hulled and dried by other facilities.

“Fluid milk product” means a product that meets the definition of milk, skim milk, buttermilk, ultrafiltered milk, or cream.

“Freshwater diatomite filter aids” means inorganic mineral powders derived by processing freshwater diatomite which is fossilized single-celled algae found in lake beds. Filter aids are used in combination with filtration hardware to enhance filtration performance to separate unwanted solids from fluids.

“Fried potato chip” means a thin slice of potato that is deep fried until crunchy.

"Galvanized steel sheet" means steel coated with a thin layer of zinc to provide corrosion resistance for such products as garbage cans, storage tanks, or framing for buildings. Sheet steel normally must be cold-rolled prior to the galvanizing stage.

“Granulated refined sugar” means white refined sugar (99.9% sucrose), made by dissolving and purifying raw sugar then drying it to prevent clumping.

“Grape juice concentrate” means the liquid from crushed grapes, from the botanical genus Vitas, processed to remove water.

“Grape seed extract” means the extract from grape seeds containing concentrations of proanthocyanidin.

“Gypsum” means a mineral with the chemical formula $CaSO4·2H2O$.

“Horsepower tested” means the total horsepower of all turbine and generator set units tested prior to sale.

"Hot rolled steel sheet" means steel produced from the rolling mill that reduces a hot slab into a coil of specified thickness at a relatively high temperature.

“Imported protein” means protein found in pre-concentrated whey that is imported from other dairy facilities for further processing.

“Intermediate dairy ingredients” means intermediate (non-final) dairy product imported from other dairy facilities that enter the rehydrating process, which uses water and heat to manufacture powdered products.

“Lactose” means a white to creamy white crystalline product, possessing a mildly sweet taste. It may be anhydrous, contain one molecule of water of hydration, or be a mixture of both forms.

“Lager beer” means beer produced with bottom fermenting yeast strains, Saccharomyces uvarum (or carlsbergensis) at colder fermentation temperatures than ales.

“Lead and lead alloys” means lead or the metal alloy that combines lead and other elements such as antimony, selenium, arsenic, copper, tin, or calcium.

“Light-duty vehicle” means a passenger vehicle with a gross vehicle weight rating under 8,500 pounds.

“Limestone” means a sedimentary rock composed largely of the minerals calcite and aragonite, which are different crystal forms of calcium carbonate ($CaCO_3$).

“Liquid Color Concentrate” means a fluid extract from fruits and/or vegetables reduced by driving off water and that has the purpose of altering the color of materials and/or food.

“Liquid hydrocarbon fuel” means produced motor gasoline blendstocks, diesel, lubricants, jet fuel, hydrocarbon gas liquids sold as finished fuels, and any functionally equivalent non-fossil hydrocarbon fuels or non-fossil hydrocarbon fuel blendstocks, such as renewable diesel, renewable naphtha, and sustainable aviation fuel. Liquid hydrocarbon fuels exclude unfinished oils, residual oils, refinery fuel gas, petroleum coke, ethanol, biodiesel, asphalt, and road oils.

“Liquid Hydrogen" means hydrogen in a liquid state.

“Milk” means the lacteal secretion, practically free from colostrum, obtained by the complete milking of one or more healthy cows. Milk that is in final package form for beverage use shall have been pasteurized or ultra-pasteurized, and shall contain not less than 8 ¼ percent milk solids not fat and not less than 3 ¼ percent milk fat. Milk may have been adjusted by separating part of the milk fat from, or by adding cream to, concentrated milk, dry whole milk, skim milk, concentrated skim milk, or nonfat dry milk. Milk may be homogenized.

“Milk powder (high heat)” means milk powder obtained by removing water from pasteurized milk. It contains no more than 5% moisture (by weight) and includes undenatured whey protein nitrogen content less than 1.5 mg/g powder.

“Milk powder (low heat)” means milk powder obtained by removing water from pasteurized milk. It contains no more than 5% moisture (by weight) and includes undenatured whey protein nitrogen content greater than or equal to 6 mg/g powder.

“Milk powder (medium heat)” means milk powder obtained by removing water from pasteurized milk. It contains no more than 5% moisture (by weight) and includes undenatured whey protein nitrogen content greater than or equal to 1.51 mg/g powder and less than 6 mg/g powder.

“Milk Protein Concentrate” means milk powder obtained by concentrating skim milk through filtration processes so that the finished dry product contains 40 percent or more protein by weight. The filtration methods used capture essentially all of the casein and whey proteins contained in the raw material, resulting in a casein-to-whey protein ratio equivalent to that of the original milk."

“Nitric acid” means HNO_3 of 100 percent purity.

“Non-Aseptic tomato juice” means tomato juice packaged using methods other than aseptic preparation.

“Non-aseptic tomato paste and tomato puree” means the sum of tomato paste and tomato puree packaged using methods other than aseptic preparation. Non-aseptic paste and puree is normalized to 24 percent tomato soluble solids. Non-aseptic paste and puree normalized to 24% TSS = (%TSS - raw TSS)/(24 - raw TSS).

“Non-aseptic whole and diced tomato” means the sum of whole and diced tomatoes packaged using methods other than aseptic preparation. Sum of non-aseptic whole and diced tomatoes = whole tomatoes + (diced tomatoes x 1.05).

“Non-thermal enhanced oil recovery” or “non-thermal EOR” means the process of using methods other than thermal EOR, which may include water flooding or CO_2 injection, to increase the recovery of crude oil from a reservoir.

“On-purpose hydrogen gas” means pure molecular hydrogen gas produced by a process or processes dedicated to producing hydrogen (e.g., steam methane reforming).

“Passenger Vehicle” has the same meaning as defined in section 39046 of the Health and Safety Code.

“Pasteurized almonds” means raw almond meats that are introduced to the pasteurizing process. Pasteurizing partially sterilizes the almonds to destroy objectionable organisms without major chemical alteration of the almond meats.

“Pickled steel sheet” means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides, and includes both finished pickled steel, and steel produced by the facility as an intermediate product for further processing.

“Pistachio” means the nut of the pistachio tree (Pistacia vera).

"Plaster" is calcined gypsum that is produced and sold as a finished product and is not used in the production of plasterboard at the same facility.

"Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper. For the purpose of this article, plasterboard includes only saleable plasterboard, which does not include trimmings.

“Poultry deli product” means the products, including corn dogs, sausages, and franks, that contain a significant portion of pre-processed poultry, that are cooked and sold wholesale or retail, or transferred to other facilities.

“Pretzel” is a crisp biscuit made from dough formed into a knot or stick, flavored with salt, passed through a caustic hot water bath and baked in an oven.

“Proof Gallons” means one liquid gallon of distilled spirits that is 50% alcohol at 60 degrees F.

“Protein meal and fat” means meal, feather meal, and fat rendered product from poultry tissues including meat, viscera, bone, blood, and feathers.

“Raw TSS” means the average annual percent tomato soluble solids of raw tomatoes to be processed in a tomato processing facility.

“Rare earth elements” means a set of seventeen chemical elements in the periodic table, specifically the fifteen lanthanides (Lanthanum, Cerium, Praseodymium, Neodymium, Promethium, Samarium, Europium, Gadolinium, Terbium, Dysprosium, Holmium, Erbium, Thulium, and Lutetium) plus Scandium and Yttrium.

“Rare earth oxide equivalent” means the mass of oxide if all of the rare earth elements in the product are isolated and converted to their oxide form.

“Recycled” refers to a material that is reused or reclaimed.

"Recycled boxboard" means containers of solid fiber made from recycled fibers, including cereal boxes, shoe boxes, and protective paper packaging for dry foods. It also includes folding paper cartons, set-up boxes, and similar boxboard products. Recycled boxboard is made from recycled fibers.

"Recycled linerboard" means types of paperboard made from recycled fibers that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made.

"Recycled medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.

“Salt” means sodium chloride, determined as chloride and calculated as percent sodium chloride, by the method prescribed in “Official Methods of Analysis of the Association of Official Analytical Chemists,” 13th Ed., 1980, sections 32.025 to 32.030, under the heading “Method III (Potentiometric Method).”

“Seamless rolled ring” means a metal product manufactured by punching a hole in a thick, round piece of metal, and then rolling and squeezing (or in some cases, pounding) it into a thin ring. Ring diameters can be anywhere from a few inches to 30 feet.

"Skim milk" means the product that results from the complete or partial removal of milk fat from milk.

"Soda ash equivalent" means the total mass of all soda ash, biocarb, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

"Steel produced using an electric arc furnace" means steel produced by an electric arc furnace or "EAF." EAF means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition of EAF.

“Stucco” means hemihydrate plaster ($CaSO_4 \bullet \frac{1}{2} H_2O$) produced by heating (“calcining”) raw gypsum, thereby removing three-quarters of its chemically combined water.

“Sulfuric acid regeneration” means the same definition found in 95102(c).

<u>“Supplementary cementitious materials” or “SCMs” are materials that are added to and contribute to the properties of a cementitious mixture through hydraulic or pozzolanic activity, or both, such as fly ash, ground granulated blast furnace slag, silica fume, natural pozzolan, calcined clay, and glass pozzolan.</u>

<u>“Sweet whey powder” is a powder that is obtained by drying fresh whey (derived from the manufacture of cheeses such as cheddar, mozzarella, and Swiss) that has been pasteurized and to which no preservatives have been added. Sweet whey powder contains all the constituents of whey, except water, in the same relative proportions.</u>

“Thermal enhanced oil recovery” or “thermal EOR” means the process of using injected steam to increase the recovery of crude oil from a reservoir.

"Tin Plate" means thin sheet steel with a very thin coating of metallic tin. Tin plate also includes Tin Free Steel or TFS which has an extremely thin coating of metallic chromium and chromium oxide. Tin plate is used primarily in can making.

“Tomato juice” is the liquid obtained from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato juice may contain salt, lemon juice, sodium bicarbonate, water, spices and/or flavoring. This food shall contain not less than 4.0 percent by weight tomato soluble solids.

“Tomato paste” is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato paste is prepared by concentrating tomato ingredients until the food contains not less than 24.0 percent tomato soluble solids.

“Tomato puree” is the semisolid food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato puree is prepared by concentrating tomato ingredients until the food contains not less than 8.0 percent but less than 24.0 percent tomato soluble solids.

“Tomato soluble solids” (TSS or NTSS) means the sucrose value of raw tomatoes or tomato product. For raw tomatoes, this value shall be determined by the methods prescribed in “Inspection Procedures” (2014) for Soluble Solids Testing – Digital Refractometer, as published by the Processing Tomato Advisory Board (PTAB), which is hereby incorporated by reference. For the tomato products tomato juice, tomato paste, tomato puree, and whole and diced tomatoes, this value shall be determined by the method prescribed in “Inspection Procedures” (2014) for Soluble Solids Testing – Digital Refractometer, as published by PTAB, or the “Official Methods of Analysis of the Association of Official Analytical Chemists,” 13th Ed., 1980, sections 32.014 to 32.016 and 52.012 (AOAC, 1980), depending on availability. For instances in which no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or through the application of the acidified break, determine the percent of such added sodium chloride as specified in the regulation’s definition of salt. Subtract the percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of “tomato soluble solids.” The centrifuges, centrifuge spin rate, centrifuge spin time, and other lab measurement equipment specified in AOAC (1980) may be exchanged with more modern equipment and measurement procedures where the operator deems necessary. Tomato soluble solids must be rounded to the nearest tenth of a percent of solids.

“Ultrafiltered milk” means raw or pasteurized milk or nonfat milk that is passed over one or more semipermeable membranes to partially remove water, lactose, minerals, and water soluble vitamins without altering the casein-to-whey protein ratio of the milk or nonfat milk and resulting in a liquid product.

“Waste gas” means a natural gas that contains a greater percentage of gaseous chemical impurities than the percentage of methane. For purposes of this definition, gaseous chemical impurities may include carbon dioxide, nitrogen, helium, or hydrogen sulfide.

"Whey protein concentrate" means the substance obtained by the removal of sufficient nonprotein constituents from pasteurized whey so that the finished dry product contains greater than 25% protein. Whey protein concentrate is produced by physical separation techniques such as precipitation, filtration, or dialysis. The acidity of whey protein concentrate may be adjusted by the addition of safe and suitable pH adjusting ingredients.

“Whole chicken and chicken parts” means the whole chicken or edible chicken parts (including breasts, thighs, wings, and drums) that are packaged for wholesale or retail sale; transferred to other facilities; or binned, sent to an on-site rendering plant, and rendered into protein meal and fat.

“Whole Tomatoes” is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are kept whole, and shall have had the stems and calyces removed.

(c) Refining and Related Process Definitions. For the purposes of this article, the following definitions associated with refining and related processes shall apply:

“Air separation unit” means a refinery unit which separates air into its components including oxygen utilizing a cryogenic or other method.

“Alkylation/poly/dimersol” means a range of processes transforming C3/C4/C5 molecules into C7/C8/C9 molecules over an acidic catalyst. This can be accomplished by alkylation with sulfuric acid or hydrofluoric acid, polymerization with a C3 or C3/C4 olefin feed, or dimersol.

“Ammonia recovery unit” means a refinery unit in which ammonia-rich sour water stripper overhead is treated to separate ammonia suitable for reuse in the refinery, for fertilizer, for other sales, for the reduction of NOx emissions, or other commercial activities. This unit is the second stage of a two stage sour water stripping unit. The ammonia recovery unit may include the adsorber, stripper and fractionator.

“Aromatic saturation of distillates” means the saturation of aromatic rings over a fixed catalyst bed at low or medium pressure in the presence of hydrogen.

“AROMAX®” means a special application of catalytic reforming for the specific purpose of producing light aromatics.

“Aromatics production” means extraction of light aromatics from reformate and/or hydrotreated pyrolysis gasoline by a solvent.

“Asphalt production” means, for the purposes of CWB data reporting, the processing required to produce asphalts and bitumen, including bitumen oxidation (mostly for road paving). This includes polymer-modified asphalt.

“Atmospheric Crude Distillation” means primary atmospheric distillation of crude oil and other feedstocks. The atmospheric crude distillation unit includes any ancillary equipment such as a crude desalter, naphtha splitting, gas plant and wet treatment of light streams for mercaptan removal and may have more than one distillation column.

“Benzene saturation” means a selective hydrogenation of benzene in gasoline streams over a fixed catalyst bed at moderate pressure.

“C4 isomer production” means conversion of n-butane into isobutane over a fixed catalyst bed in the presence of hydrogen at low to moderate pressure.

“C5/C6 isomer production - including ISOSIV” means conversion of normal paraffins into isoparaffins over a fixed catalyst bed in the presence of hydrogen at low to moderate pressure.

“Complexity weighted barrel” or “CWB” means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The CWB value for an individual refinery is calculated using actual refinery throughput to specified process units and emission factors for these process units. The emission factor is denoted as the CWB factor and is representative of the greenhouse gas emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for production, and for average process emissions of the process units across a sample of refineries. Each CWB factor is expressed as a value weighted relative to atmospheric crude distillation.

“Conradson carbon level” means a measurement describing the mass of carbon residue which an oil deposits when evaporated, as defined by ASTM D189 - 06(2010)e1 “Standard Test Method for Conradson Carbon Residue of Petroleum Products” (2010), which is hereby incorporated by reference.

“Conventional naphtha hydrotreating” means desulfurization of virgin and cracked naphthas over a fixed catalyst bed at moderate pressure in the presence of hydrogen. For cracked naphthas this also involves saturation of olefins.

<u>“Coprocessing” means the simultaneous transformation of biomass-derived feedstocks and intermediate petroleum distillates in petroleum refinery process units to produce blending components for finished fuels. That transformation involves cracking, hydrogenation, or other reformation of biomass-derived oils in combination with petroleum intermediates.</u>

“Cryogenic LPG recovery” means a refinery unit in which liquefied petroleum gas (LPG) is extracted from refinery gas streams through cooling and removing the condensate heavy fractions. The processes and equipment for this unit may include refrigeration, drier, compressor, absorber, stripper and fractionation.

“Cumene production” means the alkylation of benzene with propylene.

“Cyclohexane production” means hydrogenation of benzene to cyclohexane over a catalyst at high pressure.

“Delayed Coker” means a refinery unit which conducts a semi-continuous process where the heat of reaction is supplied by a fired heater. Coke is produced in alternate drums that are swapped at regular intervals. Coke is cut out of full coke drums as a product. For the purposes of analysis, facilities include coke handling and storage.

“Desalination” means a refinery’s desalination of seawater or contaminated water.

“Desulfurization of C4–C6 Feeds” means desulfurization of light naphthas over a fixed catalyst bed, at moderate pressure in the presence of hydrogen.

“Desulfurization of pyrolysis gasoline/naphtha” means selective or non-selective desulfurization of pyrolysis gasoline (by-product of light olefins production) and other streams over a fixed catalyst bed, at moderate pressure in the presence of hydrogen.

“Diolefin to olefin saturation of gasoline” means selective saturation of diolefins over a fixed catalyst bed, at moderate pressure in the presence of hydrogen to improve stability of thermally cracked and coker gasolines.

“Distillate hydrotreating” means desulfurization of distillate blends of components such as diesel and heating oil over a fixed catalyst bed at low or medium pressure in the presence of hydrogen.

“Ethylbenzene production” means the process of combining benzene and ethylene to form ethylbenzene.

“FCC gasoline hydrotreating with minimum octane loss” means selective desulfurization of FCC gasoline cuts with minimum olefins saturation, over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.

“Flare gas recovery” means a refinery unit in which flare gas is captured and compressed for other uses. Usually recovered flare gas is treated and routed to the refinery fuel gas system. The equipment for this process may include the compressor and separator.

“Flexicoker” means a refinery unit which conducts a proprietary process incorporating a fluid coker and where coke is gasified to produce a low BTU gas which is used to supply the refinery heaters and surplus coke is drawn off as a product.

“Flue gas desulfurizing” means a process in which sulfur dioxide is removed from flue gases with contaminants. This often involves an alkaline sorbent which captures sulfur dioxide and transforms it into a solid product. Flue gas desulfurizing systems can be of the regenerative type or the non-regenerative type. The processes and equipment for this process may include the contactor, catalyst/reagent regeneration, scrubbing circulation and solids handling.

“Fluid Catalytic Cracking” means cracking of a hydrocarbon stream typically consisting of gasoils and residual feedstocks over a catalyst. The finely divided catalyst is circulated in a fluidized state from the reactor where it becomes coated with coke to the regenerator where coke is burned off. The hot regenerated catalyst returning to the reactor may supply the heat for the endothermic cracking reaction and for most of the downstream fractionation of cracked products.

“Fluid Coker” means a continuous process where the fluidized powder-like coke is transferred between the cracking reactor and the coke burning vessel and burned for process heat production. Surplus coke is drawn off as a product.

“Fuel gas sales treating & compression” means treatment and compression of refinery fuel gas for sale to a third party.

“Houdry catalytic cracking” means a method of catalytic cracking which uses a fixed or moving bed of pellets of an aluminum silicate type catalyst. The catalyst is not fluidized.

“Hydrodealkylation” means dealkylation of toluene and xylenes into benzene over a fixed catalyst bed in the presence of hydrogen at low to moderate pressure.

“Kerosene hydrotreater” means a refinery process unit which treats and upgrades kerosene and gasoil streams using aromatic saturation of distillates, distillate hydrotreating, middle distillate dewaxing, the S-Zorb™ process for kerosene and gasoil or selective hydrotreating of C3-C5 streams for alkylation.

“Lube catalytic dewaxing” means the catalytic breakdown of long paraffinic chains in intermediate streams for the manufacture of lube oils.

“Lube solvent dewaxing” means the solvent removal of long paraffinic chains (wax) from intermediate streams in the manufacture of lube oils. This may include solvent regeneration. Different processes use different solvents, such as chlorocarbon, MEK/toluene, MEK/MIBK, or propane.

“Lube solvent extraction” means the solvent extraction of aromatic compounds from intermediate streams for the manufacture of base lube oils. This includes solvent regeneration. Different processes use different solvents, such as Furfural, NMP, phenol, or sulfur dioxide.

“Lube/Wax hydrofining” means the hydrotreating of lube oil fractions and wax for improving the quality of the lube and wax.

“Lubricant hydrocracking” means hydrocracking of heavy feedstocks for the manufacture of lube oils.

“Methanol synthesis” means the recombination of CO_2 and hydrogen to produce methanol. Methanol synthesis is only applicable when a refinery produces hydrogen via partial oxidation.

“Middle distillate dewaxing” means the cracking of long paraffinic chains in gasoils to improve cold flow properties over a fixed catalyst bed at low or medium pressure in the presence of hydrogen. This process includes the desulfurization step.

“Mild Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of 2.25% to 3.5% by weight.

“Naphtha/Distillate Hydrocracker” means a refinery process unit which conducts cracking of a hydrocarbon stream typically consisting of gasoils and distillates over a fixed catalyst bed, at high pressure and in the presence of hydrogen. The process combines cracking and hydrogenation reactions.

“Naphtha hydrotreater” means a refinery process unit that treats and upgrades naphtha/gasoline and lighter streams using any combination of one or more of the following processes: benzene saturation, desulfurization of C4–C6 feeds, conventional naphtha hydrotreating, diolefin to olefin saturation of gasoline, FCC gasoline hydrotreating with minimum octane loss, olefinic alkylation of thio sulfur, desulfurization of pyrolysis gasoline/naphtha. For naphtha/distillates, selective hydrotreating or the S-Zorb™ process may be used.

“Non-Crude Input” means the total volume of non-crude raw materials processed in process units at the refinery, excluding returns from a lube refiner or a chemical plant within a refining/petrochemical complex and excluding non-processed blendstock. Non-crude input excludes crude petroleum, hydrogen, natural gas, and any input to a hydrogen production unit.

“Olefinic alkylation of thio sulfur” means a gasoline desulfurization process in which thiophenes and mercaptans are catalytically reacted with olefins to produce higher-boiling sulphur compounds removable by distillation. This process does not utilize hydrogen.

“Other FCC” means early catalytic cracking processes on fixed catalyst beds, including Houdry catalytic cracking and Thermofor catalytic cracking.

“Oxygenates” means ethers that are produced by reacting an alcohol with olefins.

“Paraxylene production” means the physical separation of paraxylene from mixed xylenes.

“Process CWB” means the contribution to the total CWB of a refinery that results from summing, for each on-site CWB unit, the product of the CWB factor and annual throughput. Process CWB excludes CWB contributions from off-sites and non-energy utilities and non-crude sensible heat that are calculated using total refinery input and non-crude input.

“Propane/Propylene splitter (propylene production)” means a refinery unit that conducts separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC or coker. This unit produces chemical or polymer grade propylene.

“POX syngas for fuel” means the production of synthesis gas by gasification (partial oxidation) of heavy residues. This includes syngas clean-up.

“Reactor for selective hydrotreating” means a special configuration where a distillation/fractionation column contains a solid catalyst that converts diolefins in FCC gasoline to olefins or where the catalyst bed is in a preheat train reactor vessel in front of the column.

“Reformer - including AROMAX” means a refinery unit which increases the octane rating of naphtha by dehydrogenation of naphthenic rings and paraffin isomerisation over a noble metal catalyst at low pressure and high temperature. The process also produces hydrogen.

“Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of greater than or equal to 3.5% by weight.

“Residual hydrotreater” means a refinery unit which conducts desulfurization of residues over a fixed catalyst bed at high pressure and in the presence of hydrogen. It results in a limited degree of conversion of the residue feed into lighter products.

“Residual Hydrocracker” means a refinery unit which conducts hydrocracking of residual feedstocks. Different processes involve continuous or semi-continuous catalyst replenishment. The residual hydrocracker unit must process residuum with a Conradson carbon level of at least 3.5% by weight.

“S-Zorb™ process for kerosene and gasoil” means desulfurization of gasoil using an absorption process. This process does not utilize hydrogen.

“S-Zorb™ process for naphtha/distillates” means desulfurization of naphtha/gasoline streams using a proprietary fluid-bed hydrogenation adsorption process in the presence of hydrogen.

“Selective hydrotreating of C3-C5 streams for alkylation” means selective saturation of diolefins for alkylation over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen, or hydrotreatment of distillates for conversion of diolefins to olefins.

“Solvent deasphalter” means a refinery unit which uses a solvent such as propane, butane or a heavier solvent to remove asphaltines from a residual oil stream and produce asphalt and a deasphalted gasoil.

“Special Fractionation” means fractionation processes excluding solvents, propylene and aromatics fractionation, which are accomplished by a deethanizer, depropanizer, deisobutanizer, debutanizer, deisopentanizer, depentanizer, deisohexanizer, dehexanizer, deisoheptanizer, deheptanizer, naphtha splitter, alkylate splitter or reformate splitter.

“Standard FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of less than 2.25% by weight.

“Sulfur Recovery” means a process where hydrogen sulfide is converted to elemental sulfur.”

“Sulfuric acid regeneration” means a catalytic process in which spent acid is regenerated to concentrated sulfuric acid. The equipment for this process may include the combustor, waste heat boiler, converter, absorber, SO3 recycle, gas cleaning including electrostatic precipitator and amine regenerator.

“Thermal Cracking” means thermal cracking of distillate feedstocks. A thermal cracking unit may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

“Thermofor catalytic cracking” means a method of catalytic cracking in which gravity is used to pass the catalyst through the feedstock or to pass the feedstock through the catalytic reactor bed. The catalyst is not fluidized.

“Toluene disproportionation/transalkylation means a fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen.

“Total Refinery Input” means the total volume of the following brought in to the refinery: crude oil and condensate, excluding basic sediment and water; finished product additives such as dyes, diesel pour point depressants and cetane improvers; antiknock compounds; and other raw materials, including crude diluents, feedstock from outside the refinery which is processed in other process units or blend stock blended into refinery products. Total refinery input excludes hydrogen, natural gas, and any input to a hydrogen production unit.

"Vacuum Distillation" means distillation of atmospheric residues under vacuum. Some units may have more than one main distillation column.

"Visbreaker" means a refinery unit which conducts mild thermal cracking of residual feedstocks to produce some distillates and reduce the viscosity of the cracked residue. It may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

"VGO Hydrotreater" means a refinery unit which conducts desulfurization of a hydrocarbon stream typically made up of vacuum gasoils and cracked gasoils, principally destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure in the presence of hydrogen.

"Wax deoiling" means solvent removal of lighter hydrocarbons from wax obtained from lube dewaxing. Different proprietary processes use different solvents, such as MEK/toluene, MEK/MIBK, or propane.

"Xylene isomerization" means isomerization of mixed xylenes to paraxylene.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95103. Greenhouse Gas Reporting Requirements

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this part.

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e*. A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the ~~c~~Cap-and~~-trade regulation~~Invest Regulation during any year of the current compliance period; the operator is not subject to the reporting requirements of 40 CFR Part 98 specified in this article; and the facility total stationary combustion, process, fugitives and venting emissions are below 25,000 metric tons of CO_2e in the data year. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the information in paragraphs (1)-(7) below, and comply with the requirements specified in paragraphs (8)-(11) below:

(1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, geographic location, natural gas supplier name, natural gas supplier customer identification number, natural gas supplier service account identification number or other primary account identifier, and annual billed MMBtu (10 therms = 1 MMBtu).

(2) Facility GHG stationary combustion emissions for all stationary fuel combustion units and calculated according to any method in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O. Using any applicable method in 40 CFR §98.33 or 95153(l), reporting entities identified under section 95101(e) for petroleum and natural gas systems must also quantify and report emissions of CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O resulting from flaring activities. If a facility includes multiple stationary fuel combustion units that belong to more than one unit type category listed in section 95115(h), the operator may report the multiple units in aggregate but must indicate the percentage of the aggregated fuel consumption attributed to each unit type category. In addition, if a facility includes an electricity generating unit, the facility operator must report the electricity generating unit separate from other stationary fuel combustion sources by following the unit aggregation provisions in sections 95112(b) and 95103(a)(6). The operator has the option of using engineering estimation or any combination of existing meters to meet the requirements of this paragraph.

(3) Total facility GHG process emissions aggregated for all process emissions sources and calculated according to the requirements in the following parts, expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O, as applicable:

(A) 40 CFR §98.143 for glass production;

(B) 40 CFR §98.163 for hydrogen production;

(C) 40 CFR §98.173 for iron and steel production;

(D) 40 CFR §98.273 for pulp and paper manufacturing;

(E) Subarticle 5 of this article for petroleum and natural gas systems.

(4) Identification of the methods chosen for determining emissions.

(5) Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions. Missing fuel use or fuel characteristics data must be substituted according to the requirements of 40 CFR §98.35.

(6) For facilities with on-site electricity generation or cogeneration, the applicable information specified in sections 95112(a)-(b) of this article. Geothermal facilities must also report the information specified in section 95112(e). Operators of ~~hydrogen~~ fuel cells and linear generators must report the information specified in section 95112(f).

(7) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(8) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year.

(9) Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted if an error is discovered after the submission of the emissions data report. If the error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, a report that meets the full requirements of this article must be submitted within ninety days of discovery.

(10) For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR §98.3(g), except that a written GHG Monitoring Plan is not required.

(11) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

(b)–(d) *Reserved*

(e) *Reporting Deadlines*. Except as provided in section 95103(a)(7)-(8), each facility operator or supplier must submit an emissions data report no later than April 10 of each calendar year. Each electric power entity must submit an emissions data report no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines*. The requirements of this paragraph apply to each reporting entity submitting an emissions data report that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, electric power entities that are electricity importers or exporters, facilities with sources as identified in section 95101(b)(3), or each reporting entity that has or has had a compliance obligation under the ~~c~~Cap-and~~-trade regulation~~Invest Regulation in any year of the current compliance period. The requirements of this paragraph apply to reporting entities that have not met the requirements for cessation of verification in section 95101(i). The requirements of this paragraph do not apply to data reported under section 95126 by importers of cement and data reported under section 95127 by importers of hydrogen and producers of hydrogen utilizing electricity. The reporting entity subject to verification must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and separate verification statements for emissions data and for product data, as applicable, must be submitted by the verification body to the Executive Officer by August 10 each year. Each reporting entity must ensure that these verification statements are submitted by this deadline. Contracting with a verification body without providing sufficient time to complete the verification statements by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

(g) *Non-submitted/Non-verified Emissions Data Reports*. When a reporting entity ~~that holds a compliance obligation under the cap-and-trade regulation~~subject to verification fails to submit an emissions data report or fails to obtain a positive emissions data verification statement or qualified positive emissions data verification statement by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the reporting entity as set forth in section 95131(c)(5)(A)-(C).

(h) ~~Reporting in 2018.~~ All provisions of the regulation are in full effect for 20~~19~~27 data report~~ing~~ed in 202~~0~~8 and beyond, except when noted otherwise in this article and in the following cases:

(1) The ~~requirements~~provisions of section 95101(h) and (i) of this article are ~~effective~~applicable for ~~2018 data reported in 2019.~~

~~(2) The method in section 95153(a) for continuous bleed pneumatic devices applies to 2019~~2026 data reported in 202~~0~~7.

~~(3) The provisions of Subarticle 6 of this article become effective for 2021 data submitted in 2022, if U.S. EPA has approved, as memorialized by publication in the Federal Register and Code of Federal Regulations, that provision as part of California's plan for compliance with the Clean Power Plan.~~

(2) The following definitions related to Electric Power Entities in section 95102(a) of this article are applicable for 2026 data reported in 2027: “Asset-controlling supplier” or “ACS”; “CAISO markets”; “CAISO Markets Purchaser” or “CAISO Purchaser”; “CAISO Scheduling Coordinator”; “California Independent System Operator” or “CAISO”; “Committed capacity”; “dynamically tagged power”; “Electricity exporter”; “Electricity importers”; “Electricity sold into the CAISO markets”; “Energy storage system” or “ESS” or “secondary generation source”; “Exported electricity”; “Extended Day-Ahead Market” or “EDAM”; “First deliverer of electricity” or “first deliverer”; “Fleet emission factor”; “Imported electricity”; “Multi-jurisdictional retail provider” or “MJRP”; “Primary generation source”; “Pseudo-tie”; “Renewable Energy Credit” or “REC”; “Retail sales”; “Specified source of electricity” or “specified source”; and “Western Energy Imbalance Market” or “WEIM”

(3) The definitions in section 95102(b) of this article are applicable for 2026 product data reported in 2027.

(4) The provisions of section 95111 of this article are applicable for 2026 data reported in 2027

(5) The provisions of sections 95130 through 95133 of this article are applicable for 2026 data reported in 2027

(i) *Calculation and Reporting of De Minimis Emissions*. A facility operator may designate as de minimis a portion of GHG emissions representing no more than 3 percent of a facility’s total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstocks), not to exceed 20,000 metric tons of CO_2e. The operator or supplier may estimate de minimis emissions using alternative methods of the operator’s choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the de minimis limits. The operator must separately identify and include in the emissions data report the emissions from designated de minimis sources. The operator must determine CO_2 equivalence according to the global warming potentials as specified in the “global warming potential” definition of this article.

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels*. The operator or supplier must separately identify and report all biomass-derived fuels as described in section 95852.2(a) of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation. Except for operators that use the methods of 40 CFR §98.33(a)(2)(iii) or §98.33(a)(4), the operator or supplier must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion or consumption of biomass-derived fuels as specified in sections 95112 and 95115 for facilities, and sections 95121 and 95122 for suppliers. A biomass-derived fuel not listed in section 95852.2(a) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements ~~of~~for exempt biomass-derived fuel in section 95852.1~~.1~~ of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, or the fuel must be identified as non-exempt biomass-derived fuel. Carbon dioxide combustion emissions from non-exempt biomass-derived fuel will be identified as non-exempt biomass-derived CO_2. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.~~2~~1 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation.

(1) When reporting solid waste, the reporting entity must separately report the mass, in short tons, of urban waste, agricultural waste, and municipal solid waste.

(2) When reporting the use of forest~~-~~-derived wood and wood waste as identified in section 95852.2(a)(4) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation and harvested pursuant to any of the California Forest Practice Rules, Title 14, California Code of Regulations, or Chapters 4, 4.5 and 10 of the Federal National Environmental Policy Act, or harvested from areas of the State identified by CalFire as Tier 1 High Hazard Zones (HHZs) for Tree Mortality pursuant to the Proclamation of a State of Emergency by Governor Brown on October 30, 2015, the reporting entity must report: the bone-dry mass received; information about the supplier, including the name, physical address, mailing address, contact person with phone number and e-mail address; and the corresponding identification number under which the wood was removed.

(3) When reporting biomethane, the operator or supplier who is reporting biomass emissions from biomethane fuel must also report the following information for each contracted delivery:

(A) Name and address of the biomethane vendor from which biomethane is purchased;

(B) Annual MMBtu delivered by each biomethane vendor.

(C) Whether or not the purchased biomethane is an exempt biomass-derived fuel pursuant to section 95852.1 of the Cap-and-Invest Regulation.

(4) The operator must also report the name, address, and facility type of the facility from which the biomethane is produced. In addition, relevant documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or CARB review to demonstrate the receipt of eligible biomethane.

(5) Reporting of fuel consumption from non-exempt biomass-derived fuel is subject to the requirements of section 95103(k) and reporting of emissions from non-exempt biomass-derived fuels is subject to the requirements of sections 95110 to 95158.

(k) *Measurement Accuracy Requirement*. The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements for data used for calculating non-covered emissions and non-covered product data, except as otherwise specified in this paragraph. In addition, the following accuracy requirements apply to data used for calculating covered emissions and covered product data. The operator or supplier with covered product data or covered emissions equal to or exceeding 25,000 metric tons of CO_2e or a compliance obligation under the ~~c~~Cap-and~~-trade regulation~~Invest Regulation in any year of the current compliance period must meet the requirements of paragraphs (k)(1)-(10) below for calibration and measurement device accuracy. Inventory measurement, stock measurement, or tank drop measurement methods are subject to paragraph (11) below. The requirements of paragraphs (k)(1)-(11) apply to fuel consumption monitoring devices, feedstock consumption monitoring devices, process stream flow monitoring devices, steam flow devices, product data measuring devices, mass and fluid flow meters, weigh scales, conveyer scales, gas chromatographs, mass spectrometers, calorimeters, and devices for determining density, specific gravity, and molecular weight. The provisions of paragraph (k)(1)-(11) do not apply to: stationary fuel combustion units that use the methods in 40 CFR §98.33(a)(4) to calculate CO_2 mass emissions; emissions reported as de minimis under section 95103(i); and devices that are solely used to measure parameters used to calculate emissions that are not covered emissions or that are not covered product data. The provisions of paragraphs (k)(1)-(9) and (k)(11) do not apply to stationary fuel combustion units that use the methods in 40 CFR Part 75 Appendix G §2.3 to calculate CO_2 mass emissions, but the provisions in paragraph (k)(10) are applicable to such units.

(1) Except as otherwise provided in sections 95103(k)(7) through (9), all flow meter and other measurement devices used to provide data for the GHG emissions calculations or covered product data must be calibrated prior to the year data collection is required to begin using the procedures specified in this section, and subsequently recalibrated according to the frequency specified in paragraph (4). Flow meters and other measurement devices

that were calibrated prior to January 1, 2012 using procedures specified in previous versions of the Mandatory Reporting Regulation or methods specified in 40 CFR Part 98 must be subsequently recalibrated according to the frequency specified in paragraph (4). A flow meter device consists of a number of individual components which might include a flow constriction component, mechanical component, and temperature and pressure measurement components. Each meter or measurement device must meet the applicable accuracy specification in section 95103(k)(6), however each individual component of a flow meter device is not required to meet the accuracy specifications. The procedures and methods used to quality-assure the data from each measurement device must be documented in the written monitoring plan required by section 95105(c).

(2) All flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be calibrated according to either the manufacturer's recommended procedures or a method specified in an applicable subpart of 40 CFR 98. The calibration method(s) used must be documented in the monitoring plan required under section 95105(c), and are subject to verification under this article and review by CARB to ensure that measurements used to calculate GHG emissions or product data have met the accuracy requirements of this section.

(3) For facilities and suppliers that become subject to this article after January 1, 2012, all flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be installed and calibrated no later than the date on which data collection is required to begin under this article.

(4) Except as otherwise provided in sections 95103(k)(7) through (9), subsequent recalibrations of the flow meter and other measurement devices subject to the requirements of this section must be performed no less frequently than at one of the following time intervals, whichever is shortest:

(A) The frequency specified in a subpart of 40 CFR Part 98 that is applicable under this article.

(B) The frequency recommended by the manufacturer.

(C) Once every 36 months.

(D) Immediately upon replacement of a previously calibrated meter.

(E) Immediately upon replacement or repair of a device that is deemed out of calibration as determined in paragraph (6).

(F) If the device manufacturer explicitly states in the product documentation that calibration is required at a period exceeding three years, the operator may follow the procedures in paragraph (9) to obtain Executive Officer approval to relieve the operator from having to comply with provisions (A) and (C) of this subparagraph.

(5) All standards used for calibration must be traceable to the National Institute of Standards and Technology or other similar national government body responsible for measurement standards.

(6) In addition to the specific calibration requirements specified below, and, if applicable, the field accuracy assessment requirements specified below, all flow meter and other measurement devices covered by this section, regardless of type, must be selected, installed, operated, and maintained in a manner to ensure accuracy within ±5 percent.

(A) Perform all mass and volume measurement device calibration as specified in the original equipment manufacturers (OEM) documentation. If OEM documentation is unavailable, calibrate as specified in 40 CFR §98.3(i)(2) (3), except that a minimum of three calibration points must be used spanning the normal operating conditions. When using the three calibration points, one point must be at or near the zero point, one point must be at or near the upscale point, and one point at or near the mid-point of the devices operating range. If OEM documentation does not specify a method or is unavailable, and calibration methods specified in 40 CFR §98.3(i)(2)-(3) are not possible for a particular device, the procedures in section 95109(b) must be followed to obtain approval for an alternative calibration procedure. Additionally:

1. Pressure differential devices must be inspected at a frequency specified in paragraph (k)(4) of this section, unless the device is located at a refinery or hydrogen plant that operates continuously with infrequent outages. In such cases, the owner or operator of the refinery or hydrogen plant must inspect each device at a frequency of at least once every six years. The inspection must be conducted as described in the appropriate part of ISO 5167-2 (2003), or AGA Report No 3 (2003) Part 2, both of which are incorporated by reference, or a method published by an organization listed in 40 CFR §98.7 applicable to the analysis being conducted. If the device fails any one of the tests then the meter shall be deemed out of calibration. If OEM guidance for a particular pressure differential device

recommends against disassembly and inspection of the device, disassembly and inspection requirements in this paragraph do not apply. Documentation of OEM guidance must be made available to verifiers and CARB upon request.

a. Records of all tests, including an as-found condition, must be preserved pursuant to section 95105 and made available to verifiers and CARB upon request.

b. Where inspection requirements apply, the primary element must also be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe.

2. Devices used to measure total pressure and temperature must be calibrated using methods specified in section 95103(k)(2) and at a frequency specified in section 95103(k)(4).

3. If temperature and/or total pressure measurements are not available or are taken at a remote location, the uncertainty caused by this must be factored into the evaluation of the overall measurement accuracy required under section 95103(k)(6).

(B) Operators and suppliers may conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±5 percent. When performing a field accuracy assessment, the as-found condition must be recorded to ensure the device is measuring with accuracy within ±5 percent. Should a device be found to be operating outside the ±5 percent accuracy bounds, the device shall be deemed out of calibration. Records of all field accuracy assessments must clearly indicate the assessment procedure and the as-found condition, be preserved pursuant to section 95105, and be made available to verifiers and CARB upon request. Device accuracy may be assessed using one of the following options:

1. Engineering analysis;

2. OEM calibration guidance or other OEM recommended methods;

3. Standard industry practices; or

4. Portable instruments.

(C) Pursuant to paragraph (k)(10) of this section, in the event of a failed calibration or recalibration, operators or suppliers who choose not to perform the annual field accuracy assessment specified in paragraph (6)(B) of this section for one or more mass or volume measurement devices must demonstrate data accuracy going back multiple years to the most recent successful calibration. Multiple years of data may be deemed invalid if accuracy cannot be demonstrated by other means, including strap-on meters or engineering methods. For operators and suppliers who conduct the annual field accuracy assessment, and a device is found to be out of calibration, accuracy must be demonstrated back to the most recent successful calibration or the most recent successful field accuracy assessment, whichever is most recent.

(7) The requirements of section 95103(k) do not apply under the following circumstances:

(A) Financial transaction meters are exempted from the calibration requirements of section 95103(k) if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Financial transaction meters where the supplier and the purchaser do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the calibration requirements of section 95103(k) if one of the following is true:

1. The financial transaction meter is also used by other companies that do not share common ownership with the ~~fuel~~ supplier; or

2. The financial transaction meter is sealed with a valid seal from the county sealer of weights and measures or from a county certified designee; or

3. The financial transaction meter is operated by a third party.

(B) Upstream ethanol and additive meters used to ensure proper blendstock percentage for finished gasoline are exempted from the calibration requirements of section 95103(k).

(C) Non-financial transaction meters used by Public Utility Gas Corporations for purposes of reporting natural gas supplier emissions are exempt from the calibration requirements in sections 95103(k)(1)-(6) if the supplier can demonstrate that the meters are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of the California Public Utilities Commission General Order 58A (1992).

(8) For units and processes that operate continuously with infrequent outages, it may not be possible to meet deadlines for the initial or subsequent calibrations of a flow meter or other fuel measurement or sampling device, or inspection of orifice plates without disrupting normal process operation. In such cases, the owner or operator may submit a written request to the Executive Officer to postpone calibration or inspection until the next scheduled maintenance outage. Such postponements are subject to the procedures of section 95103(k)(9) and must be documented in the monitoring plan that is required under section 95105(c).

(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date. The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to CARB within ten (10) working days of a request by CARB.

(B) The request must include:

1. The date of the required calibration, recalibration, or inspection;

2. The date of the last calibration or inspection;

3. The date of the most recent field accuracy assessment, if applicable;

4. The results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;

5. The proposed date for the next field accuracy assessment, if applicable;

6. The proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.

7. A description of the meter or other device, including at a minimum:

   a. make,

   b. model,

   c. install date,

   d. location,

   e. annual emissions calculated or annual product data reported using data from the device,

   f. sources for which the device is used to calculate emissions or product data,

   g. calibration or inspection procedure,

   h. reason for delaying calibration or inspection,

   i. proposed method to assure the accuracy requirements of section 95103(k)(6) are met,

   j. name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.

(10) If the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the required accuracy specification, and the emissions or product data estimated using the data provided by the device represent more than 5 percent of total facility emissions or product data on an annual basis, the operator must demonstrate by other means to the

satisfaction of the verifier or CARB that measurements used to calculate GHG emissions and product data still meet the ± 5 percent accuracy requirements going back to the last instance of successful field accuracy assessment or calibration of the device. Where the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the accuracy specifications, the verifier shall note at a minimum a nonconformance as part of the emissions data verification statement.

(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses the method must be accurate to ±5 percent for the time periods required by this article, including annually for covered product data. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this section. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 95131(b)(12) of this article. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1)-(10) above, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using the following equations:

Fuel consumed (volume or mass) = (inputs during time period – outputs during time period) + (amount stored at beginning of time period) – (amount stored at end of time period)

Product produced (volume or mass) = (outputs during time period - inputs during time period) + (amount stored at end of time period - amount stored at beginning of time period)

(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95124 and 95156 of this article. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data. Covered product data is evaluated for material misstatement and conformance, while the remaining reported product data is evaluated for conformance only. Reporting entities must exclude inaccurate covered product data, and may elect to exclude accurate covered product data. Reporting entities that exclude covered product data must report a description of the excluded data and an estimated magnitude using best available methods. The excluded covered product data will not be used for the material misstatement assessment or for the total covered product data variable described in section 95131(b)(12)(A). Operators of cement plants may not exclude covered product data.

(1) Beginning in calendar year 2027, a reporting entity may voluntarily submit covered product data for up to five data years immediately preceding the current data year for the purpose of one-time new product allocation pursuant to section 95891(b)(1) of the Cap-and-Invest Regulation.

(A) Covered product data for prior data years must be submitted along with the emissions data report for the current data year by the April 10th reporting deadline. All prior product data will be evaluated by CARB based on the requirements in the regulation in effect on the date the data is submitted to CARB, and the Executive Officer shall act to accept, deny, or request additional information for the prior covered product data by April 30th.

(B) Covered product data for prior data years that is reported and accepted must complete verification by the verification deadline set forth in section 95103(f) and be verified in accordance with the requirements in the regulation in effect on the date the data is submitted to CARB.

(m) *Changes in Methodology*. Except as specified below, where this article permits a choice between different methods for the monitoring and calculation of GHGs and product data, the operator must use the method chosen for all future emissions data reports, except as provided pursuant to sections 95103(m)(1) and (2).

(1) Changes in Prescribed Methods.

(A) Permanent Improvement in Monitoring or Calculation Methodology for Emissions Data. The operator or supplier is permitted to permanently improve the emissions or product data monitoring or calculation method to a higher-tier monitoring or calculation method specified in this article, such as the addition of a continuous emissions monitoring system. Permanent improvements to emissions monitoring or calculation methods do not require approval in advance by the Executive Officer; however, the operator or supplier must notify CARB by the reporting deadline for the applicable reporting year.

(B) Permanent Change to a Lower-Tier Methodology for Emissions Data. The operator or supplier is permitted to submit a request for approval of a permanent change to a lower-tier monitoring or calculation method specified in this article for emissions data. The request must be provided to CARB prior to January 1 of the year for which the data will be reported, and must be approved by the

Executive Officer and implemented per the timing requirements in sections 95103(m)(2)-(3). The request must include a description of why the change in method is being proposed, a detailed description of the data that are affected by the method change, and a demonstration of differences in estimated data under the current and proposed methods.

(C) Permanent changes to all covered product data monitoring or calculation methods must be submitted to CARB pursuant to section 95103(m)(2), except in the circumstances described in section 95103(m)(4).

(2) Alternative Methods. If an operator or supplier identifies a situation where conventional metering, monitoring, or reporting methods are not feasible or not applicable, the operator ~~may~~must submit a request to the Executive Officer for approval of an alternative measurement/monitoring method that achieves accuracy at an equivalent level to the ±5 percent required by section 95103(k)(6). ~~The request must include a description of why the change in method is being proposed, include a detailed description of the data that are affected by the alternative measurement/monitoring method, and include a demonstration of differences in estimated data under the current and proposed methods. ARB~~The request must include the items specified below, where applicable. CARB will make an approval determination based on the necessity of the alternative method and whether the operator or supplier can sufficiently demonstrate accuracy of the method during verification.

The alternative method request must be provided to CARB prior to January 1 of the year for which the new method would be implemented for data collection, and must be approved by the Executive Officer. If CARB approves the alternative method, and upon request by the reporting entity, CARB may also determine whether the methodology can be applied to the current data year based on the information submitted pursuant to this section. In order to apply the method to the current data year, the reporting entity must show that they have collected the necessary data to apply the method for the entire current reporting year.

(A) The alternative method request must include:

1. The submittal date of the proposed alternative method request;

2. The proposed start date and time period to be covered by the alternative method;

3. The reason for using an alternative method;

4. A description of the alternative method;

5. A description of data necessary to apply the alternative method, and, if available, at least 3 months of this data to demonstrate accuracy of the alternative method;

6. If applicable, a description of affected equipment that includes engineering diagrams and other figures showing equipment locations and relevant data collection and sampling points;

7. A description of how accuracy requirements of section 95103(k) will be met under the alternative method;

8. When possible, a data comparison of annual greenhouse gas emissions that would be reported using the alternative method versus the existing method;

9. The name, title, phone number, and e-mail of a contact who can answer questions regarding the alternative method.

(B) The Executive Officer may request additional documentation to validate the operator's claim that the alternative method meets the requirements of this section. The operator shall provide any additional documentation to CARB within ten days of a request by CARB.

(3) When permitted under sections 95103(m)(1) and (2), a change in the calculation or monitoring method must be made for an entire data year and apply to the start of a data year, except in the circumstances described in section 95103(m)(4).

(4) Use of a Temporary Methodology. The operator or supplier is permitted to temporarily modify the emissions or product data monitoring or calculation method when necessary for the avoidance of missing data or to comply with the missing data provisions of this article. For emissions data, in the event of an unforeseen breakdown in fuel analytical data monitoring equipment or CEMS equipment, operators and suppliers must use the procedures in section 95129(h) and section 95129(i), respectively, for seeking approval of interim data collection procedures. For all other instances that temporary methods are used, CARB must be notified by the reporting deadline of the following information: a description of the temporary method, the affected data, and the duration that the temporary

method was used. A temporary method ~~may~~can only be used for a period not to exceed 365 consecutive days, commencing from the initial date of implementation, unless the method is concurrently or subsequently submitted and approved by the Executive Officer as a permanent method per the requirements in section 95103(m)(1)(B) or (2). Operators and suppliers must be able to demonstrate during verification that the temporary method provides data accuracy within ± 5 percent as specified in section 95103(k)(6). Covered product data that does not meet the required accuracy specification must be excluded using the procedure in section 95103(l) to avoid an adverse verification statement.

(5) When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

(n) *Changes in Ownership or Operational Control*. If a reporting entity undergoes a change of ownership or operational control, the following requirements apply regarding notifications to CARB and reporting responsibilities.

(1) *CARB Notifications*. Prior to the change of ownership or operational control, the previous owner or operator of the reporting entity and the new owner or operator of the reporting entity must provide the following information to CARB. Required information must be submitted to the ~~ARB~~CARB email account: ghgreport@arb.ca.gov

(A) The previous owner or operator must notify CARB via email of the ownership or operational control change including the name of the new owner or operator and the date of the ownership or operational control change.

(B) The new owner or operator must notify CARB via email of the ownership or operational control change, including the following information:

1. Previous owner or operator;

2. New owner or operator;

3. Date of ownership or operator change.

4. Name of a new Designated Representative pursuant to section 95104(b) for the affected entity's account in the

California Reporting Greenhouse Gas Reporting Tool (Cal e-GGRT) specified in section 95104(e);

(2) *Reporting Responsibilities*. Except as specified in section 95103(n)(2)(D), the owner or operator of record at the time of a reporting or verification deadline specified in this article has the responsibility for complying with the requirements of this article, including certifying that the emissions data report is accurate and complete, obtaining verification services, and completing verification.

(A) Except as specified in section 95103(n)(2)(D), the owner or operator of record at the time of a reporting deadline is responsible for submitting the emissions data report covering the complete calendar year data.

(B) Except as specified in section 95103(n)(2)(D), if an ownership change takes place during the calendar year, reported data must not be split or subdivided for the year, based on ownership. A single annual data report must be submitted for the entity by the current owner or operator. This report must represent required data for the entire, calendar year.

(C) Previous owners or operators are required to provide data and records to new owners or operators that is necessary and required for preparing annual emissions data reports required by this article.

(D) ~~Fuel suppliers~~Suppliers that cease to have reportable emissions as a result of an ownership change that affects supplier operations retain the responsibility for complying with the requirements of this article, including certifying that the emissions data report is accurate and complete, obtaining verification services, and completing verification, for the emissions from all fuel transactions that occurred prior to the date of the change of ownership.

(o) *Addresses*. The following address shall be substituted for the addresses provided in 40 CFR §98.9, and used for any necessary notifications or materials that are not submitted by other means:

Manager, Climate Change Reporting Section
Program Planning and Management Branch
Industrial Strategies Division
CALIFORNIA AIR RESOURCES BOARD
P.O. BOX 2815
SACRAMENTO, CA 95812

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95104. Emissions Data Report Contents and Mechanism

The reporting entities specified in section 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) *General Contents*. In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, geographic location, and indicate whether the reporting entity qualifies for small business status pursuant to California Government Code 11342.610. Electricity generating units must also provide Energy Information Administration and California Energy Commission identification numbers, as applicable. Reporters subject to the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95200 to 95207), must report the official responsible for fees payment and the billing address for fees.

(b) *Designated Representative*. Each reporting entity must designate a reporting representative and an alternate designated representative and adhere to the requirements of 40 CFR §98.4 for ~~this representative and for any~~these named ~~alternate designated~~ representatives.

(c) *Corporate Parent and NAICS Codes*. Each reporting entity must submit information to meet the requirements specified in amendments to 40 CFR Part 98 on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration, as promulgated by U.S. EPA on September 22, 2010.

(d) *Facility Level Energy Input and Output*. The operator must include in the emissions data report information about the facility's energy acquisitions and energy provided or sold as specified below. For the purpose of reporting under this paragraph, the operator may exclude any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility. The operator may also exclude electricity consumed by operations or activities that do not generate any emissions, energy outputs, or products that are covered by this article, and that are neither a part of nor in support of electricity generation or any industrial activities covered by this article. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

(1) Electricity purchases or acquisition from sources outside of the facility boundary (MWh) and the name and ARB identification number of each electricity provider, as applicable.

(A) Facilities with a NAICS code listed in Table 8-1 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation must report the MWh from each electrical distribution utility that provides transmission and/or distribution service and the MWh from each electricity generation provider.

(2) Thermal energy purchases or acquisitions from sources outside of the facility boundary (MMBtu) and the name and ARB identification number of each energy provider, as applicable. If the operator acquires thermal energy from a PURPA Qualifying Facility and vents, radiates, wastes, or discharges more than 10 percent of the acquired thermal energy before utilizing the energy in any industrial process, operation, or heating/cooling application, the operator must report the amount of thermal energy actually needed and utilized, in addition to the amount of thermal energy received from the provider.

(3) Electricity provided or sold, as specified in section 95112(a)(4), if applicable.

(4) Thermal energy provided or sold to entities outside of the facility boundary: the operator must report the amount of thermal energy provided or sold (MMBtu), the names and ARB identification number of each end-user as applicable, and the type of unit that generates the thermal energy. If section 95112 applies to the operator, the operator must follow the requirements of section 95112(a)(5) in reporting the thermal energy generated by cogeneration or bigeneration units, and if applicable, also separately report the information required in paragraph 95104(d)(4) for the thermal energy provided or sold that is not generated by cogeneration or bigeneration units.

(5) If the facility boundary includes more than one cogeneration system, boiler, or steam generator, and each unit/system or each group of units produces thermal energy for different particular end-users or on-site industrial processes and operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions, and by the type of thermal energy product provided.

(e) *Reporting Mechanism*. Reporting entities shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's

(CARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by CARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation. Reporting entities are not responsible for reporting data required under this article that is not specified for reporting in the reporting tool.

(f) *Increases and Decreases in Facility Emissions*. The operator of a facility identified in section 95101(a)(1)(A)-(B) that is subject to the ~~c~~Cap-and-~~trade regulation~~Invest Regulation must include the following information in the emissions data report:

(1) Whether a change in the facility's operations or status resulted in an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous data year.

(2) If there is an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous year, the operator must provide a brief narrative description of what caused the increase or decrease in emissions. Include in this description any changes in your air permit status.

(3) Verifiers must ensure the information reported pursuant to section 95104(f)(1) is reported in conformance with this article. Section 95104(f)(2), the narrative description, is not subject to the third-party verification requirements of this article.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95105. Recordkeeping Requirements.

Each reporting entity that is required to report greenhouse gases under this article, except as provided in section 95103(a)(9), must keep records as required by 40 CFR §98.3(g)-(h) with the following qualifications.

(a) *Duration.* Reporting entities with a compliance obligation under the Cap-and-~~Trade~~Invest Regulation in any year of the current compliance period must maintain all records specified in 40 CFR §98.3(g), and records associated with revisions to emissions data reports as provided under 40 CFR §98.3(h), for a period of ten years from the date of emissions data report certification. The retained documents, including GHG emissions data and input data, covered product data and associated inputs; data associated with thermal energy provided, sold, purchased, or acquired; and, data associated with electricity provided, sold, purchased, or acquired, must be sufficient to allow for verification of each emissions data report. Reporting entities that do not have a compliance obligation under the Cap-and-~~Trade~~Invest Regulation during any year of the current compliance period must maintain required records for a period of five years from the date of certification.

(b) *CARB Requests for Records.* Copies of any records or other materials maintained under the requirements of 40 CFR Part 98 or this article must be made available to the Executive Officer upon request, within 14 days of receipt of such request by the designated representative of the reporting entity, unless a different schedule is agreed to by CARB. This includes, but is not limited to, information used to quantify or report emissions and product data in the emissions data report, underlying monitoring and metering data, invoices of receipts or deliveries, sales transaction data, calculation methods, protocols used, analysis results, calibration records, electricity transaction data, and other relevant information.

(c) *GHG Monitoring Plan for Facilities and Suppliers.* Each facility operator or supplier that reports under 40 CFR Part 98, each facility operator or supplier with emissions equal to or exceeding 25,000 MT CO_2e (including biomass-derived CO_2 emissions and geothermal emissions), and each facility operator or supplier with a compliance obligation under the Cap-and-~~Trade~~Invest Regulation in any year of the current compliance period, must complete and retain for review by a verifier or CARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5). For facilities, the Plan must also include the following elements, as applicable:

(1) All fuel use measurement devices used for emissions calculations or product data must be clearly identified, and the plan must indicate how data from these devices are incorporated into the emissions data report.

(2) Original equipment manufacturer (OEM) documentation, or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used in the calculation of GHG emissions.

(3) Reference to one or more simplified block diagrams that provide a clear visual representation of the relative locations and positions of measurement devices and sampling locations, as applicable, required for calculating covered emissions and covered product data (e.g. temperature, total pressure, HHV, fuel consumption). The diagram(s) must include fuel sources, combustion units, and production processes, as applicable.

(4) The dates of measurement device calibration or inspection, and the dates of the next required calibration or inspection.

(5) Identification of low flow cutoffs, as applicable.

(6) A listing of the equation(s) used to calculate mass or volume flows, and from which any non-measured parameters are obtained.

(7) Records of the most recent orifice plate inspection performed according to the requirements of ISO 5167-2 (2003), section 5, or AGA Report No 3 (2003) Part 2, which are hereby incorporated by reference.

(8) Training practices for personnel involved in GHG monitoring, including documented training procedures, and training materials.

(9) Copies of methodologies used for all fuel-based emissions analyses, including the standardized methods chosen as specified in section 95109.

(10) At the operator's choosing, a fuel monitoring plan to verify on a regular basis the proper functioning of fuel measurement equipment that is used to determine facility GHG emissions. The operator wishing to preserve the option of using the missing data substitution procedures in section 95129(d)(2) in the event that such procedures become necessary to use, must monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption data at least weekly. The operator exercising this option may fulfill periodic fuel monitoring either through manual monitoring or by using an automatic data acquisition system that electronically records, stores, and identifies measurement device malfunctioning periods. The records of fuel consumption must be sufficient for the application of the missing data substitution procedure in section 95129(d)(2) if that option is later chosen by the operator.

(d) *GHG Inventory Program for Electric Power Entities that Import or Export Electricity.* In lieu of a GHG Monitoring Plan, electric power entities that import or export electricity must prepare GHG Inventory Program documentation that is maintained and available for verifier review and CARB audit pursuant to the recordkeeping requirements of this section. The following information is required:

(1) Information to allow the verification team to develop a general understanding of entity boundaries, operations, and electricity transactions;

(2) Reference to management policies or practices applicable to reporting pursuant to section 95111;

(3) List of key personnel involved in compiling data and preparing the emissions data report;

(4) Training practices for personnel involved in reporting delivered electricity pursuant to section 95111 and responsible for data report certification, including documented training procedures;

(5) Query of NERC e-Tag source data to determine the quantity of electricity (MWh) imported, exported, and wheeled for transactions in which they are the purchasing-selling entity on the last physical path segment that crosses the border of the state of California, access to review the raw e-Tag data, a tabulated summary, and query description;

(6) Reference to other independent or internal data management systems and records, including written power contracts and associated verbal or electronic records, full or partial ownership, invoices, and settlements data used to document whether reported transactions are specified or unspecified and whether the requirements for adjustments to covered emissions pursuant to sections 95852(b)(1)(B), ~~95852(b)(4)~~ and 95852(b)(~~5~~4) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation are met, specifically how the entity determined that the electricity associated with the RECs claimed for the RPS adjustment was not directly delivered to California, if reporting an RPS adjustment;

(7) Description of steps taken and calculations made to aggregate data into reporting categories required pursuant to section 95111;

(8) Records of preventive and corrective actions taken to address verifier and CARB findings of past nonconformances and material misstatements;

(9) Log of emissions data report modifications made after initial certification; and

(10) A written description of an internal audit program that includes emissions data report review and documents ongoing efforts to improve the GHG Inventory Program.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95106. Confidentiality.

(a) Emissions data submitted to CARB under this article is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR

Part 98 which has been released to the public by U.S. EPA shall be considered public information by CARB.

(b) Any entity submitting information to the Executive Officer pursuant to this article may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 7920.000, et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95107. Enforcement.

(a) Penalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580. In seeking any penalty amount, CARB shall consider all relevant circumstances, including any pattern of violation, the size and complexity of the reporting entity's operations, and the other criteria in Health and Safety Code section 42403(b).

(b) Each day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate is a single, separate violation. For purposes of this section, "report" means any emissions data report, verification statement, or other document required to be submitted to the Executive Officer by this article.

(c) Each metric ton of CO_2e emitted but not reported as required by this article is a separate violation. CARB will not initiate enforcement action under this subparagraph until after any applicable verification deadline for the pertinent report.

(d) Each failure to measure, collect, record or preserve information in the manner required by this article constitutes a separate violation, except where the reporting entity can demonstrate that the failure results solely from maintenance or calibration required by this article.

(e) The Executive Officer may revoke or modify any Executive Order issued pursuant to this article as a sanction for a violation of this article.

(f) The violation of any condition of an Executive Order that is issued pursuant to this article is a separate violation.

(g) Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38530, 38580, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 38580, 39600 and 41511, Health and Safety Code.

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Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

§ 95110. Cement Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart H of 40 CFR Part 98 (§§98.80 to 98.88) in reporting annual stationary combustion and process emissions and other data from cement production to CARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95110(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95110(c)-(d), 95115, and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR §98.83(d) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the monthly raw material consumption or monthly clinker production used to calculate emissions, the operator must apply a substitute value according to paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.85(c) or 40 CFR §98.85(d), as applicable.

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum short tons of clinker per day capacity of the system or the maximum short tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data*. In addition to the information required by 40 CFR §98.86, the operator must report the parameters provided in paragraphs (1)-(4) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity clinker produced (short tons).

(2) Annual quantity clinker consumed (short tons).

(3) Annual quantity of limestone and gypsum (including both natural and synthetic gypsum) consumed for blending (short tons).

(4) Annual quantity of cement ~~substitute~~kiln dust and annual quantity of grind aids consumed, by type, for blending (short tons~~). This parameter is~~) that were not ~~subject to review for material misstatement~~reported under ~~the requirements of~~ section ~~95131(b)(12~~95110(d)(1) and (2).

(5) Annual quantity of SCMs consumed for blending (short tons) that is received from SCM manufacturers that are opt-in or covered entities in the Cap-and-Invest Program, by SCM type (e.g., fly ash, ground granulated blast furnace slag, silica fume) and SCM manufacturer.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities

The electric power entity who is required to report under section 95101 of this article must comply with the following requirements.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters*.

(1) *Greenhouse Gas Emissions*. The electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (MT of CO_2e), according to the calculation methods in section 95111(b).

(2) *Delivered Electricity*. The electric power entity must report imported, exported, and wheeled electricity in MWh disaggregated by first point of receipt (POR) or final point of delivery, as applicable, and must also separately report imported and exported electricity from unspecified sources and from each specified source. Substitute electricity defined pursuant to section 95102(a) must be separately reported for each specified source, as applicable. First points of receipt and final points of delivery (POD) must be reported using the standardized code used in NERC e-Tags, as well as the full name of the POR/POD.

(3) *Imported Electricity from Unspecified Sources*. When reporting imported electricity from unspecified sources, the electric power entity must report for each first point of receipt the following information:

(A) Whether the first point of receipt is located in a linked jurisdiction published on the CARB website;

(B) The amount of electricity from unspecified sources as measured at the first point of delivery in California; and

(C) GHG emissions, including those associated with transmission losses, as required in section 95111(b).

(4) *Imported Electricity from Specified Facilities or Units*. The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity. A GPE must report imported electricity as from a specified source when the importer is a GPE

of that facility. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The reporting entity must also report total GHG emissions and MWh from specified sources and the sum of emissions from specified sources explicitly listed as not covered pursuant to section 95852.2 of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation. Seller Warranty: The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path.

(A) Claims of specified sources of imported electricity, defined pursuant to section 95102(a), are calculated pursuant to section 95111(b), must meet the requirements in section 95111(g), and must include the following information:

1. *Measured at Busbar*. The amount of imported electricity from specified facilities or units as measured at the busbar; and

2. *Not Measured at Busbar*. If the amount of imported electricity ~~deliveries~~ from specified facilities or units as measured at the busbar is not provided, report the amount of imported electricity as measured at the first point of delivery in California, including estimated transmission losses as required in section 95111(b~~), and the reason why measurement at the busbar is not known.~~).

(5) *Imported Electricity Supplied by Asset-Controlling Suppliers*. The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by CARB. The reporting entity must:

(A) Report the asset-controlling supplier standardized purchasing-selling entity (PSE) acronym or code, full name, and the ARB identification number~~;~~ (ARB ID);

(B) Report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

(C) Report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in the state of California; and,

(D) Report GHG emissions calculated pursuant to section 95111(b), including transmission losses.

(E) Tagging ACS Power. To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner.

(6) *Exported Electricity*. The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e for unspecified sources disaggregated by each final point of delivery outside the State of California, and for each specified source disaggregated by each final point of delivery outside the State of California, as well as the following information:

(A) Exported electricity as measured at the last point of delivery located in the State of California, if known. If unknown, report as measured at the final point of delivery outside California.

(B) Do not report estimated transmission losses.

(C) Report whether the final point of delivery is located in a linked jurisdiction published on the CARB website.

(D) Report GHG emissions calculated pursuant to section 95111(b).

(7) *Exchange Agreements*. The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into the state of California under exchange agreements must be reported as imported electricity and electricity delivered out of California under exchange agreements must be reported as exported electricity.

(8) *Electricity Wheeled Through California*. The electric power entity who is the PSE on the last physical path segment that crosses the border of the State of California on the NERC e-tag must separately report electricity wheeled through California, aggregated by first point of receipt, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the electric power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the State of California. Only an electric power entity, as defined in section 95102(a), must report wheeled electricity through California.

(9) *Verification Documentation*. The electric power entity must retain for purposes of verification NERC e-Tags, written power contracts,

settlements data, and all other information required to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 95105.

(10) *Electricity Generating Units and Cogeneration Units in California*. Electric power entities that also operate electricity generating units or cogeneration units located inside the state of California that meet the applicability requirements of this article must report GHG emissions to CARB under section 95112.

(11) *Electricity Generating Units and Cogeneration Units Outside California*. Operators and owners of electricity generating units and cogeneration units located outside the state of California who elect to report to CARB under section 95112 must fully comply with the reporting and verification requirements of this article.

(12) *Electrical Distribution Utility Sales into CAISO*. ~~All~~In the final data year of each Cap-and-Invest Regulation compliance period, or in the final report for entities subject to the shutdown provisions of section 95101(i), all electrical distribution utilities (EDU) except IOUs must report for each year of the compliance period the annual MWh of all electricity sold into ~~the~~ CAISO markets for which an EDU or generator receiving EDU-allocated allowances has a compliance obligation under the Cap-and-~~Trade~~Invest Regulation. This reporting requirement also applies to CAISO sales from a generator to whose compliance account the reporting EDU directed CARB to deposit allocated allowances pursuant to section 95892(b)(2~~)(A~~) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation; in this case, the reporting requirement is on the EDU that directed CARB to deposit allocated allowances.

(A) EDUs must report MWh by source of generation (if known), of the electricity sold into the CAISO markets and for which the EDU or generator receiving EDU-allocated allowances has a compliance obligation, and the emission factor (if known) for each source of generation, as follows:

1. For emissions associated with CAISO sales from a specified source ~~located outside of California~~or in-state resource, the reporting EDU must use the emissions factors calculated by CARB pursuant to section 95111(b)(2).

~~2. For known in-State resources that are the source of CAISO sales:~~

~~i.~~ ~~If the EDU is the GPE, or has verifiable information related to the annual emissions and electricity production associated of the in-State resource, the EDU must calculate an emission factor for the resource. This calculation is subject to verifier review.~~

~~ii.~~ If the EDU does not know the emissions and electricity production associated with ~~the~~an in-~~S~~state resource, the EDU must use the default emission factor for unspecified electricity set forth in section 95111(b)(1).

~~3~~2. For sales into CAISO for which the source of generation is unknown or unspecified, the reporting EDU must use the default emission factor for unspecified electricity set forth in section 95111(b)(1).

(B) This requirement does not apply to EDUs that have had all of their directly allocated allowances allocated for the ~~data year~~compliance period placed in their limited use holding account pursuant to section 95892(b)(2) of the Cap-and-~~Trade~~Invest Regulation. Verifiers must contact the Air Resources Board directly to confirm that a specific EDU is not subject to this requirement.

(C) Excess electricity for non-native load. An EDU must report whether any electricity from any resource in its portfolio, for which an EDU has a compliance obligation, was sold into CAISO markets to ultimately serve any non-native load, in accordance with CAISO Fifth Replacement Tariff section 11.29(a)(iii) dated May 1, 2014. Excess electricity that does not serve an EDU's native load, and meets the other requirements in this section, is reportable as CAISO sales, even if the generation resource causing the excess electricity is funded by municipal tax-exempt debt.

(D) Netting of electricity across intervals is prohibited in the calculation of reportable CAISO sales. Excess electricity sold into the CAISO markets in any interval cannot be netted against the electricity purchased from the CAISO markets in a different interval.

(E) The data sources and procedures used to report CAISO sales and emission factors must be specified in the GHG inventory plan documentation required by section 95105(d).

(13) Aggregated zero-emissions generation sources. Aggregated hydroelectric or other zero-emissions generation sources can be collectively claimed as a single specified source if all the following requirements are met:

(A) All aggregated generation sources are hydroelectric or other zero-emission sources, and all aggregated sources share a need to be aggregated due to interdependent water flows or other physical limitations.

(B) The aggregated generation sources' e-Tag is unique to the aggregated sources and no individual source or subset of sources within or external to the aggregate sources can be tagged from it.

(C) The output of any source, or combination of sources included in the aggregated generation sources, cannot be individually supplied to serve load independent of the aggregated sources configuration.

(D) The seller warranty is maintained pursuant to section 95111(a)(4) to claim each source in the aggregate as a specified source.

(E) The GPE of the aggregate generation source maintains meter data and provides to reporters subject to this article, no later than February following each emission year, documentation, data, and records, which can include but are not limited to:

1. Written contracts with hourly data;

2. Allocated meter reports for each source, including all information required to conduct the lesser of analysis;

3. Supplemental data to allow EPEs reporting imports into California to separately report the imports from each source in the aggregate. Each source in the aggregate may contribute a different share of the importer's total aggregate imports, including within the same hour.

(b) *Calculating GHG Emissions*

(1) *Calculating GHG Emissions from Unspecified Sources*. For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{unsp} \times ELF$$

Where:

CO_2e =	Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (MT of CO_2e).
MWh =	Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.
EF_{unsp} =	Default emission factor for unspecified electricity imports.
EF_{unsp} =	0.428 MT of CO_2e/MWh
TL =	Transmission loss correction factor.
TL =	1.02 to account for transmission losses between the busbar and measurement at the first point of receipt in California.
ELF =	Energy storage system (ESS) loss factor
ELF =	1.00 for unspecified power not delivered through an ESS
ELF =	1.18 for unspecified power delivered through ESS sources to account for losses within the storage system
ELF =	3.00 for unspecified power delivered through ESS sources that store power as hydrogen produced by electrolysis to account for losses within the storage system

(2) *Calculating GHG Emissions from Specified Facilities or Units*. For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{sp} \times ELF$$

Where:

CO_2e =	Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).
MWh =	Megawatt-hours of specified electricity deliveries from each facility or unit claimed.
EF_{sp} =	Facility-specific or unit-specific emission factor published on the CARB website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.
~~EF_{sp} =~~	~~0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.~~

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses associated with generation outside of a California balancing authority.

TL = 1.0 if the reporting entity provides documentation that demonstrates to the satisfaction of a verifier and CARB that transmission losses (1) have been accounted for, (2) are supported by a California balancing authority, or (3) are compensated by using electricity sourced from within California.

ELF = Energy storage system (ESS) loss factor

ELF = ESS loss factor calculated by an ESS Registrant pursuant to section 95111(i)

ELF = 1.00 for power delivered, if using an ESS emission factor calculated by an ESS Registrant pursuant to section 95111(i)

ELF = 1.18 for power delivered through an ESS, to account for losses within the storage system

ELF = 3.00 for power delivered through an ESS that stores power as hydrogen produced by electrolysis to account for losses within the storage system

The Executive Officer shall calculate facility-specific or unit-specific emission factors and publish them on the CARB website using the following equation:

$$EF_{sp} = E_{sp} / EG$$

Where:

E_{sp} = CO_2e emissions for a specified facility or unit for the report year (MT of CO_2e).

EG = Net generation from a specified facility or unit for the report year ~~shall be~~ based on data reported to the Energy Information Administration (EIA).

To register a specified unit(s) source of power pursuant to section 95111(g)(1), the reporting entity must provide to ~~ARB unit level GHG emissions consistent with the data source requirements of this section and net generation data as reported to the EIA, along with~~ CARB contracts for delivery of power from the specified unit(s) to the reporting entity, and proof of direct delivery of the power by the reporting entity as an import to California.

(A) For specified facilities or units whose operators are subject to this article or whose owners or operators voluntarily report under this article, E_{sp} shall be equal to the sum of CO_2e emissions reported pursuant to section ~~-~~ 95112.

(B) For specified facilities or units whose operators are not subject to reporting under this article or whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} shall be based on GHG emissions reported to U.S. EPA pursuant to 40 CFR Part 98. For GHG emissions reported to U.S. EPA pursuant to 40 CFR Part 98, if it is not possible to isolate the emissions that are directly related to electricity production, ~~ARB may~~ or if U.S. EPA data is otherwise unavailable, CARB will calculate E_{sp} based on EIA data. ~~Emissions from combustion~~In absence of ~~biomass-derived fuels will be~~both U.S. EPA and EIA data, CARB will calculate E_{sp} based on ~~EIA data until such time~~ the ~~emissions are reported to~~most recent historical U.S. EPA~~.~~ and EIA data that is available.

(C) For specified generation facilities or units ~~whose operators are~~ not ~~subject to reporting under this article or whose owners or operators do not voluntarily report under this article, nor are~~ subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} is calculated using heat of combustion data reported to the Energy Information Administration (EIA) as shown below.

$$E_{sp} = 0.001 \times \Sigma(Q \times EF)$$

Where:

0.001 = conversion factor kg to ~~-~~ MT

Q = Heat of combustion for each specified fuel type from the specified facility or unit for the report year (MMBtu). For cogeneration, Q is the quantity of fuel allocated to electricity generation consistent with EIA reporting. For geothermal electricity, Q is the steam data reported to EIA (MMBtu).

EF = CO_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu). For geothermal electricity, EF is the estimated CO_2 emission factor published by EIA.

(D) Facilities or units will be assigned an emission factor by the Executive Officer based on the type of fuel combusted or the technology used when a U.S. EPA GHG Report or EIA fuel consumption report is not available, including new facilities and facilities located outside the U.S.

(E) Meter Data Requirement. For verification purposes, electric power entities shall retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered.

1. A lesser of analysis is ~~applicable to~~ required for imports from specified sources~~, including imported electricity under EIM,~~ for which CARB has calculated an emission factor of zero~~,~~ ~~and for imports~~ or which are from California Renewable Portfolio Standard (RPS) eligible resources, including imported electricity under WEIM or EDAM, and for power from a primary generation source reported for charging an ESS that is not metered pursuant to section 95111(i), excluding the following: (1) contract or ownership agreements, known as grandfathered contracts that meet California RPS program requirements in Public Utilities Code Section 399.16(d) or California Code of Regulations, Title 20 Section 3202(a)(2)(A); (2) dynamically tagged power deliveries; (3) nuclear power; (4) asset controlling supplier power; ~~and~~ (5) ~~imports~~power from hydroelectric facilities for which an entity's share of metered output on an hourly basis is not established by power contract~~.~~; and (6) imports from ESSs. A lesser of analysis is required pursuant to the following equation:

$$\text{Sum of Lesser of MWh} = \Sigma HM_{sp} \min(MG_{sp} * S_{sp}, TG_{sp})$$

Where:

ΣHM_{sp} = Sum of the Hourly Minimum of MGsp and TG_{sp} (MWh).

MG_{sp} = metered facility or unit net generation (MWh).

S_{sp} = entity's share of metered output, if applicable.

TG_{sp} = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

2. An EPE may conduct the lesser of analysis voluntarily for those resources excluded in section 95111(b)(2)(E)(1.).

(3) *Calculating GHG Emissions of Imported Electricity Supplied by Asset-Controlling Suppliers*. Based on annual reports submitted to CARB pursuant to section 95111(f), CARB will calculate and publish on the CARB website the system emission factor for all asset-controlling suppliers recognized by ~~the ARB~~CARB. The reporting entity must calculate emissions for electricity supplied using the following equation:

$$\cancel{CO_2e = MWh \times TL \times EF_{ACS}}$$

$$CO_2e = MWh \times TL \times EF_{ACS}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from CARB-recognized asset-controlling suppliers (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Asset-Controlling Supplier system emission factor published on the CARB website (MT CO_2e/MWh). CARB will assign the system emission factors for all asset-controlling suppliers based on a previously verified GHG report submitted to CARB pursuant to section 95111(f). The supplier-specific system emission factor is calculated annually by CARB. The calculation is derived from data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification statement. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

EF_{ACS} = Sum of System Emissions- MT of CO_2e / Sum of System MWh

Sum of System Emissions, MT of CO_2e =
$\Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$

Sum of System MWh = $\Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$

Where:

ΣE_{asp} = *Emissions from Owned Facilities*. Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = Net Generation from Owned Facilities. Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to CARB under this article (MWh).

PE_{sp} = Electricity Purchased from Specified Sources. Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to CARB under this article (MWh).

PE_{unsp} = Electricity Purchased from Unspecified Sources. Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to CARB under this article (MWh).

SE_{sp} = Electricity Sold from Specified Sources. Amount of wholesale electricity sold from specified sources by the asset-controlling supplier for the data year as reported to CARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) (MT CO_2e/MWh).

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

(4) *Calculating GHG Emissions of Imported Electricity for Multi-jurisdictional Retail Providers*. Multi-jurisdictional retail providers must include emissions and megawatt-hours in the terms below from facilities or units that contribute to a common system power pool. Multi-jurisdictional retail providers do not include emissions or megawatt-hours in the terms below from facilities or units allocated to serve retail loads in designated states

pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service. Multi-jurisdictional retail providers must calculate emissions that have a compliance obligation using the following equation:

$$CO_2e = (MWh_R \times TL_R - MWh_{WSP\text{-}CA} - EG_{CA}) \times EF_{MJRP} + MW_{WSP\text{-}notCA} \times TL_{WSP} \times EF_{unsp} - CO_2e_{linked}$$

Where:

CO_2e =	Annual CO_2e mass emissions of imported electricity (MT of CO_2e).
MWh_R =	Total electricity procured by multi-jurisdictional retail provider to serve its retail customers in California, reported as retail sales for California service territory, MWh.
$MWh_{WSP\text{-}CA}$ =	Wholesale electricity procured in California by multi-jurisdictional retail provider to serve its retail customers in California, as determined by the first point of receipt on a NERC e-Tag and pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.
$MWh_{WSP\text{-}not\ CA}$ =	Wholesale electricity imported into California by multi-jurisdictional retail provider with a final point of delivery in California and not used to serve its California retail customers, MWh.
EF_{MJRP} =	Multi-jurisdictional retail provider system emission factor calculated by CARB pursuant to subsection 95111(b)(3) and consistent with a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

EF_{unsp} =	Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).
EG_{CA} =	Net generation measured at the busbar of facilities and units located in California that are allocated to serve its retail customers in California pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.
TL =	Transmission loss correction factor.
TL_{WSP} =	1.02 for transmission losses applied to wholesale power.
TL_R =	Estimate of transmission losses from busbar to end user reported by multi-jurisdictional retail provider.
CO_2e_{linked} =	Annual CO_2e mass emissions recognized by <u>C</u>ARB pursuant to linkage under subarticle 12 of the ~~c~~<u>C</u>ap-and~~-trade regulation~~<u>Invest Regulation</u> (MT of CO_2e).

(5) *Calculation of Covered Emissions*. For imported electricity with covered emissions as defined pursuant to section 95102(a), the electric power entity must calculate covered emissions pursuant to the equation in 95852(b)(1)(B) of the ~~c~~<u>C</u>ap-and~~-trade regulation~~<u>Invest Regulation</u>. $CO_2e_{RPS\_adjustment}$ is calculated based on the following equation:

<u>$CO_2e_{RPS\_adjustment}$ = MWh_{RPS} x EF_{unsp} (MT CO_2e/MWh)</u>

<u>Where:</u>

~~RPS~~ <u>$CO_2e_{RPS\_adjustment}$</u> =	Sum of CO_2 equivalent mass emissions adjustment <u>(MT CO_2e)</u> is calculated using the ~~following~~<u>preceding</u> equation~~.~~ for electricity generated by each eligible renewable energy resource located outside the State of California and registered with <u>C</u>ARB by the reporting entity pursuant to section 95111(g)(1), but not directly delivered as defined pursuant to section 95102(a~~).~~<u>), less electricity associated with withdrawn RECs reported under section 95111(g)(1)(F)2.</u> Electricity <u>and associated RECs</u> included in the RPS adjustment must meet the requirements ~~pursuant to~~<u>of</u> section 95852(b)(4) of the

~~c~~Cap-and~~-trade regulation (MT of CO_2e).~~Invest Regulation.

~~$CO_2e_{RPS\_adjustment}$ = MWh$_{RPS}$ x EF$_{unsp}$ (MT CO_2e/MWh)~~

~~Where:~~

MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the State of California, registered with CARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the ~~cap-and-trade regulation~~Cap-and-Invest Regulation minus the sum of MWh associated with RECs withdrawn as reported under section 95111(g)(1)(F)2.

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

(c) *Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers*. Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b) and (g).

(1) Retail providers must report total and residential California retail sales. A retail provider who is required only to report retail sales may choose not to apply the verification requirements specified in section 95103, if the retail provider deems the emissions data report non-confidential.

(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.

(3) For facilities or units located outside California in a jurisdiction where a GHG emissions trading system has not been approved for linkage pursuant to subarticle 12 of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation, that are fully or partially owned by a retail provider that have GHG emissions greater than the default emission factor for unspecified imported electricity based on the most recent GHG emissions data report submitted to CARB or U.S. EPA, the retail provider must include:

(A) Information required in section 95111(g)(1) in data years with no reported imported electricity from the facility or unit;

(B) The quantity of electricity from the facility or unit sold by the retail provider or on behalf of the retail provider having a final point of delivery outside California, as measured at the busbar.

(C) *High GHG-Emitting Facilities or Units*. For facilities or units that are ~~op~~repor~~a~~ted by ~~a retail provider or fully or partially owned by a retail provider~~the GPE, excluding multi-jurisdictional retail providers,~~ and~~ that have emissions greater than the default emission factor for unspecified electricity based on the most recent GHG emissions data report submitted to CARB or to U.S.EPA, the ~~retail provider~~GPE must report the following information:

1. When the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions associated with electricity not imported into California must be reported as

CO_2e not imported = $(EG_{sp} * OS – I_{sp}) * EF_{sp}$.

Where:

EG_{sp} = facility or unit net generation, MWh.

OS = fraction ownership share.

I_{sp} = imported electricity, MWh.

EF_{sp} = facility or unit-specific emission factor, MT of CO_2e/MWh.

2. List the replacement generation sources, locations, and whether they are new units when $I_{sp} < 90$ percent of EG_{sp}*OS and when a facility specified in the previous report year has no imported electricity in the current report year.

(4) Retail providers that report as electricity importers or exporters also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer. In addition, all imported electricity transactions documented by NERC e-Tags where the retail provider is the PSE at the sink must be reported.

(d) *Additional Requirements for Multi-Jurisdictional Retail Providers*. Multi-jurisdictional retail providers that provide electricity into California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b).

(1) A report of the electricity transactions and GHG emissions associated with the common power system or contiguous service territory that includes consumers in California. This includes the requirements in this section as applicable for each generating facility or unit in the multi-jurisdictional retail provider's fleet;

(2) The multi-jurisdictional retail provider must include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for CARB to calculate a supplier-specific emission factor;

(3) Total retail sales (MWh) by the multi-jurisdictional retail provider in the contiguous service territory or power system that includes consumers in California;

(4) Retail sales (MWh) to California customers served in California's portion of the service territory;

(5) GHG emissions associated with the imported electricity, including both California retail sales and wholesale power imported into California from the retail provider's system, according to the specifications in this section;

(6) Multi-jurisdictional retail providers that serve California load must claim as specified power all power purchased or taken from facilities or units in which they have operational control or an ownership share or written power contract;

~~(7) Multi-jurisdictional retail providers that serve California load may elect to exclude information listed in 95111(g)(1)(E)-(J) when registering claims to specified power from facilities located outside California and participating in the Federal Energy Regulatory Commission's PURPA Qualifying Facility program.~~

(e) *Additional Requirements for WAPA and DWR*.

(1) In reporting its GHG emissions to CARB, the California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the State Water Project.

(2) In reporting its GHG emissions to CARB, the Western Area Power Agency shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the Central Valley Project.

(f) *Additional Requirements for Asset-Controlling Suppliers*. Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from CARB. Approved asset-controlling suppliers may request that CARB calculate a supplier-specific emission factor pursuant to section 95111(b)(3).

To apply for asset-controlling supplier designation, the applicant must:

(1) Meet the requirements in this article, including reporting pursuant to section 95111 as applicable for each generating facility or unit in the supplier's fleet;

(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for CARB to calculate a supplier-specific emission factor;

(3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;

(4) Provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(5) To apply for and maintain asset-controlling supplier status, the entity shall submit as part of its first emissions data report the following information~~, annually~~:

(A) General business information, including entity name and contact information;

(B) List of officer names and titles;

(C) Data requirements per section 95111(b)(3);

(D) Data requirements per section 95111(g)(1);

(E) A list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to 95102(a); and,

(F) An attestation, in writing and signed by an authorized officer of the applicant, as follows:

"I certify under penalty of perjury under the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], that [name of entity] meets the definition of an asset-controlling supplier as specified in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, title 17, California Code of Regulations, section 95100 et seq., and that the information submitted herein is true, accurate, and complete."

Asset-controlling suppliers must annually adhere to all reporting and verification requirements of this article, or be removed from asset-controlling supplier designation. Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation.

(g) *Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment*.

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with CARB pursuant to subsection 95111(g)(1) by February 1 following each data year to obtain associated emission factors calculated by CARB for use in the emissions data report required to be submitted by ~~June 1 of the same year. If an operator fails to register a specified source by the June 1~~the reporting deadline specified in section 95103(e~~), the operator~~) of the same year. Specified source operators must use the emission factor provided by CARB for a specified facility or unit in the emissions data report~~ required to be submitted by June 1 of the same year~~. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation must include registration information for the eligible renewable energy resources pursuant to subsection 95111(g)(1) in the emissions data report. Prior registration and subsection 95111(g)(2)-(5) do not apply to RPS adjustments. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled ~~and corrections must be certified~~ within ~~45~~30 days following the emissions data report due date.

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment*. The following information is required:

(A) The facility names and, for specification to the unit level, the facility and unit names.

(B) For sources with a previously assigned ARB identification number~~,~~ (ARB ID), the ARB ~~facility or unit identification number or supplier number~~ID published on CARB's mandatory reporting program website. For newly specified sources, CARB will assign a unique ~~identification number~~ARB ID.

(C) If applicable, the facility and unit identification numbers as used for reporting to the U.S. EPA ~~Acid Rain Program, U.S. EPA~~ pursuant to 40 CFR Part 98, U.S. Energy Information Administration, ~~Federal Energy Regulatory Commission's PURPA Qualifying Facility program,~~and California Energy Commission~~, and California Independent System Operator~~, as applicable.

(D) The physical address of each facility, including jurisdiction.

(E) ~~Provide names of facility owner and operator.~~

~~(F) The percent ownership share and whether the~~ Whether the facility has one or ~~unit is under the electricity importer's operational control.~~

~~(G) Total facility~~more ESS units or energy storage capabilities, and if so, for each ESS unit indicate whether the unit ~~gross and net nameplate capacity when the electricity importer is a GPE.~~

~~(H) Total facility or unit gross and net generation when the electricity importer is a GPE.~~

~~(I) Start date of commercial operation and, when applicable, date of repowering.~~

~~(J) GPEs claiming additional capacity at an existing facility~~ must ~~include the implementation date, the expected increase in net generation (MWh), and a description of the actions taken to increase capacity.~~

~~(K) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the~~

~~previous report year that will not~~ be ~~specified in the current report year.~~

~~(L) Provide the primary technology or fuel type as listed below:~~

~~1. Variable renewable resources by type, defined for purposes of this article as pure solar, pure wind, and run-of-river hydroelectricity;~~

~~2. Hybrid facilities such as solar thermal;~~

~~3. Hydroelectric facilities ≤ 30 MW, not run-of-river;~~

~~4. Hydroelectric facilities > 30 MW;~~

~~5. Geothermal binary cycle plant or closed loop system;~~

~~6. Geothermal steam plant or open loop system;~~

~~7. Units combusting biomass-derived fuel, by primary fuel type;~~

~~8. Nuclear facilities;~~

~~9. Cogeneration by primary fuel type;~~

~~10. Fossil~~charged solely from the facility, or if it can be charged from other sources ~~by primary fuel type;~~ as well, including grid power.

~~11. Co-fired fuels;~~

~~12. Municipal solid waste combustion;~~

~~13. Other.~~

~~(M~~(F) Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired within 30 days following the emissions data report due date for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.

3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount. Failure to report REC serial numbers associated with specified source imported electricity from an eligible renewable energy resource ~~represents a nonconformance with this article and in itself~~ will not result in an adverse verification statement. In such cases, the specified source emission factors assigned by CARB must still be used to calculate emissions associated with the imported electricity.

(2) *Emission Factors*. The emission factor published on the CARB website, calculated by CARB according to the methods in section 95111(b), must be used when reporting GHG emissions for a specified source of electricity.

(3) *Delivery Tracking Conditions Required for Specified Electricity Imports*. Electricity importers must claim a specified source when the electricity delivery meets any of the criteria for direct delivery of electricity defined in section 95102(a), and one of the following sets of conditions:

(A) The electricity importer is a GPE; or

(B) The electricity importer has a written power contract for electricity generated by the facility or unit, subject to meeting all other specified source requirements.

(4) ~~Additional Information~~*Delivery Tracking Conditions Required* *for* ~~Specified Sources. For each claim to a specified source of electricity, the electricity importer must indicate whether one or more of the following descriptions applies:~~

~~(A) Deliveries from specified sources previously reported as consumed in California. Specified source of electricity has been reported in a 2009 verified data report and is claimed for the current data year by~~

~~the same electricity importer, based on a written power contract or status as a GPE in effect prior to January 1, 2010 that remains in effect, or that has been renegotiated for the same facility or generating unit for up to the same share or quantity of net generation within 12 months following prior expiration; or a specified facility for which imported electricity was reported as greater than 80 percent of net generation in the 2009 or 2010 data years;~~

~~(B) Deliveries from existing federally owned hydroelectricity facilities by exclusive marketers.~~*Energy Storage Systems*. Electricity ~~from specified federally owned hydroelectricity facility delivered by exclusive marketers;~~

~~(C) Deliveries from existing federally owned hydroelectricity facilities allocated by contract. Specified federally owned hydroelectricity source delivered by electricity~~ importers ~~with a written power contract in effect within 12 months after changes in rights due to federal power allocation or redistribution policies, including acts of Congress, and~~must report if any electric power deliveries originated from, were stored in, or passed through an ESS along the transmission path, if not ~~related to price bidding, that remains in effect or has been renegotiated for the same facility for up to the same share or quantity of net generation within 12 months following prior contract expiration;~~

~~(D) Deliveries from new facilities. Specified source of electricity is first registered~~ already required to be reported pursuant to ~~section 95111(g)(1) and delivered by an electricity importer within 12 months of the start date of commercial operation and the electricity importer making a claim in the current data year is either a GPE or purchaser of electricity under a written power contract;~~

~~(E) Deliveries from existing facilities with additional capacity. Specified source of electricity is first registered pursuant to section 95111(g)(1) and delivered by a GPE within 12 months of the start date of an increase in the facility's generating capacity due to increased efficiencies or~~ other ~~capacity increasing actions.~~sections of this article.

(5) Substitute electricity. Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section.

(h) *Imported Electricity in the* ~~Energy Imbalance Market (EIM).~~*CAISO Markets*.

(1) *Calculation of ~~EIM~~CAISO Markets Outstanding Emissions*. Each year after the verification deadline in section 95103(f), CARB will calculate "~~EIM~~CAISO Markets Outstanding Emissions" for the previous calendar year using information reported annually by ~~EIM Participating Resource~~CAISO Scheduling Coordinators ~~with~~for imported electricity in ~~EIM~~WEIM and EDAM pursuant to section 95111(h)(1)(C), and information received from CAISO under an annual subpoena. Annual information reported by ~~EIM Participating Resource~~CAISO Scheduling Coordinators must be based on the results of each 5-minute interval~~. In 2019, ARB will calculate EIM Outstanding Emissions separately for~~ in the ~~time periods of January 1, 2019 to March 31, 2019,~~WEIM, which is where CAISO markets transactions and ~~April 1, 2019 to December 31, 2019.~~deemed delivered emissions are settled.

(A) ~~EIM Outstanding~~*Total California WEIM Emissions as calculated by* ~~ARB. "EIM Outstanding Emissions" equals "Total California EIM Emissions" less the sum of "Deemed Delivered EIM Emissions" as reported by EIM Participating Resource Scheduling Coordinators in section 95111(h)(1)(C) for a data year.~~

~~(B) Total California EIM Emissions as calculated by ARB.~~CARB. Annually, based on each 5-minute interval, CARB will calculate the CO_2 equivalent mass emissions associated with imported electricity in ~~EIM~~WEIM by importers in WEIM only using the following equation:

$$CO_2\cancel{e = MWh}e_{WEIM} = MWh_{below\ base} \times EF_{unsp} \times TL$$

Where:

$CO_2\cancel{e}e_{WEIM}$ = CO_2 equivalent mass emissions from Total California WEIM electricity (MT of CO_2e).

~~MWh~~$MWh_{below\ base}$ = Megawatt-hours of WEIM imports used to serve California load that were below participating resources' base schedules, adjusted for net export constraints and imported electricity from committed capacity.

EF_{unsp} = Default emission factor for unspecified electricity imports in 95111(b)(1)

EF_{unsp} = 0.428 MT of CO_2e/MWh

TL = 1.02 (transmission loss correction factor) in 95111(b)(1).

(B) *Total California EDAM Emissions as calculated by CARB.* Annually, based on each day-ahead interval, CARB will calculate the CO_2 equivalent mass emissions associated with imported electricity in EDAM using the following equation:

$$CO_2e_{EDAM} = MWh_{below\ GHG\ counterfactual} \times EF_{unsp} \times TL$$

Where:

CO_2e_{EDAM} = CO_2 equivalent mass emissions from Total California EDAM electricity (MT of CO_2e).

$MWh_{below\ GHG\ counterfactual}$ = Real-time megawatt-hours of WEIM imports settled from EDAM day-ahead schedules used to serve California load that were below participating resources' EDAM GHG counterfactuals adjusted for net export constraints and electricity imports from committed capacity.

EF_{unsp} = Default emission factor for unspecified electricity imports in 95111(b)(1).

EF_{unsp} = 0.428 MT of CO_2e/MWh.

TL = 1.02 (transmission loss correction factor) in 95111(b)(1).

(C) *Total California CAISO Markets Outstanding Emissions as calculated by CARB*. Annually, CARB will calculate the CO_2 equivalent mass emissions associated with imported electricity in WEIM and EDAM using the following equation:

$$CO_2e = CO_2e_{WEIM} + CO_2e_{EDAM}$$

Where:

CO_2e = CO_2 equivalent mass emissions from Total California CAISO Markets electricity (MT of CO_2e).

CO_2e_{WEIM} = CO_2 equivalent mass emissions from Total California WEIM-Only electricity (MT of CO_2e).

CO_2e_{EDAM} = CO_2 equivalent mass emissions from Total California EDAM electricity (MT of CO_2e).

(D) *Deemed Delivered ~~EIM~~WEIM and EDAM Emissions Reported by ~~EIM Participating Resource~~CAISO Scheduling Coordinators*. Annually, based on the results of each 5-minute interval, each ~~EIM Participating Resource~~CAISO Scheduling Coordinator must calculate, report, and cause to be verified, emissions associated with electricity imported as deemed delivered to California by the ~~EIM optimization model. For data year 2019 only, EIM Participating Resource Scheduling Coordinators shall calculate, report, and cause to be verified Deemed Delivered EIM Emissions for two time periods. EIM Participating Resource Scheduling Coordinators shall separately calculate, report, and cause to be verified Deemed Delivered EIM Emissions from January 1, 2019 through March 31, 2019. EIM Participating Resource Scheduling Coordinators shall separately calculate, report, and cause to be verified Deemed Delivered EIM Emissions from April 1, 2019 through December 31, 2019~~WEIM and EDAM optimization models.

(2) ~~EIM~~*CAISO Markets Purchaser Emissions as Calculated by CARB*. Each year after the verification deadline in section 95103(f), CARB will calculate each ~~EIM Purchaser's "EIM~~"CAISO Markets Purchaser Emissions" for the previous calendar year using information reported annually by ~~EIM Participating Resource~~CAISO Scheduling Coordinators with imported electricity in WEIM, retail sales in MWh reported annually by ~~EIM~~CAISO Markets Purchasers pursuant to 95111(h)(2)(B), and information received from CAISO under an annual subpoena. ~~For data year 2019, this section is applicable from April 1, 2019 through December 31, 2019 using EIM Outstanding Emissions calculated pursuant to 95111(h)(1) for the time period April 1, 2019 to December 31, 2019.~~

(A) ~~EIM~~*CAISO Markets Purchaser Emissions as calculated by CARB*. For each ~~EIM~~CAISO Markets Purchaser, as defined in section 95102, CARB will calculate the CO_2 equivalent mass ~~EIM~~CAISO Markets Purchaser Emissions, using the following equation:

$$\cancel{EIM}\,\underline{CAISO\ Markets}\ Purchaser\ Emissions =$$

$$\cancel{EIM}\,\underline{CAISO\ Markets}\ Outstanding\ Emissions * \cancel{\frac{EIM\ Purchaser's\ Retail\ Sales}{Total\ EIM\ Purchasers'\ Retail\ Sales}}\underline{\left(\frac{CAISO\ Markets\ Purchaser's\ Retail\ Sales}{Total\ CAISO\ Markets\ Purchasers'\ Retail\ Sales}\right)}$$

~~Where:~~

~~EIM~~Where:

CAISO Markets Outstanding Emissions equals the total emissions calculated pursuant to section 95111(h)(1).

~~EIM~~CAISO Markets Purchaser's Retail Sales equals the ~~EIM~~CAISO Markets Purchaser's total retail sales reported pursuant to section 95111(h)(2)(B).

Total ~~EIM~~CAISO Markets Purchasers' Retail Sales is the sum of all EIM Purchaser's Retail Sales as reported pursuant to 95111(h)(2)(B).

(B) ~~EIM~~CAISO Markets Purchaser's Retail Sales. Each ~~EIM~~CAISO Markets Purchaser's retail sales will equal its annual total California retail sales reported and verified pursuant to this section.

1. Each ~~EIM~~CAISO Markets Purchaser that also reports as an EPE subject to the verification requirements in 95103(f) shall calculate, report, and verify its annual California retail sales pursuant to this section and sections 95101(h)(2)(D), 95111(c)(1) and 95111(d)(4), as applicable.

~~2. EIM~~2. Each CAISO Markets Purchaser that is not subject to the verification requirements in 95103(f) shall calculate and report its annual California retail sales pursuant to this section and sections 95101(h)(2)(D), 95111(c)(1) and 95111(d)(4), as applicable, and annually provide to CARB for review and verification documentation that evidences the total volume of retails sales reported in MWh.

3. CAISO Markets Purchasers who are investor owned utilities, shall calculate, report and cause to be verified, the name(s) and total California retail sales of each load-serving entity in its electrical distribution service territory.

(i) Additional Requirements for Energy Storage System Registrants. Annually, prior to the year an ESS emissions factor is used, and as part of their emissions data reporting, the ESS GPE or ESS reporting entity may choose to voluntarily report and have verified as ESS registrants the specified and unspecified sources of electric power stored and delivered and associated emissions for calculating an ESS emission factor, ESS loss factor, or both, for their registered ESS pursuant to the requirements of this article. For ESS with an operational start date in the current calendar year, or newly registering as a specified source in the following calendar year, the ESS registrant may optionally calculate an ESS specified source emission factor or ESS loss factor based on all available data of the current calendar year pursuant to this section. This section applies to both stand-alone energy storage systems (SASS) and integrated energy storage (ISS) units.

(1) For each ESS with data reported by an ESS registrant, the ESS specified source emission factor must be calculated using the following equation:

$$EF_{sp\text{-}ESS} = \Sigma(MWh_i \times EF_i) / EG$$

Where:

MWh_i = Megawatt-hours of unspecified electricity deliveries or specified electricity deliveries from each facility or unit claimed for charging the ESS unit, calculated pursuant to section 95111(b)(2)(E) where applicable.

EF_i = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh), or facility-specific or unit-specific emission factor published on the CARB website.

EG = Net discharge, in MWh, metered at the ESS, for the year.

(2) For each ESS with data reported by an ESS registrant, the specified ESS loss factor (ELF) must be calculated using the following equation:

$$ELF_{sp\text{-}ESS} = \Sigma(MWh_i) / EG$$

Where:

MWh_i = Megawatt-hours of unspecified electricity deliveries or specified electricity deliveries from each facility or unit claimed for charging the ESS unit, calculated pursuant to section 95111(b)(2)(E) where applicable.

EG = Net discharge, in MWh, metered at the ESS, for the year.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95112. Electricity Generation and Cogeneration Units

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must report as specified below and comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions and other data from electricity generating and cogeneration units to CARB, except as otherwise provided in this section. Notwithstanding the above, the operator of a facility with total facility nameplate generating capacity of less than 1 MW may elect to follow section 95115 in reporting electricity generating units as general combustion sources, in lieu of the requirements of section 95112. If engineering estimation is used to report disposition of generated energy or energy flow data that are not used directly to determine emissions, facility operators must demonstrate accuracy of the chosen engineering estimation method.

(a) *Information About the Electricity Generating Facility*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. However, facility operators that are applying for or receiving the legacy contract transition assistance under the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, or that are applying for or receiving the limited exemption for emissions from the production of qualified thermal output under the ~~c~~Cap-and-~~trade regulation~~Invest Regulation, must report the information in sections 95112(a)(4)-(6), even if they do not provide or sell any generated energy outside of the facility boundary.

(1) If applicable, facility identification numbers assigned by the California Energy Commission, U.S. Energy Information Administration, Federal Energy Regulatory Commission's PURPA Qualifying Facility program, and California Independent System Operator;

(2) Total facility nameplate generating capacity in megawatts (MW);

(3) Indicate whether the facility is a stand-alone electricity generating facility, an independently operated cogeneration/bigeneration facility co-located with the thermal host, an independently operated and sited cogeneration/bigeneration facility, or an industrial/institutional/commercial facility with electricity generation capacity, as applicable. Also indicate whether the facility is a grid-dedicated facility, a facility that does not provide any generated energy outside of the facility boundary, as applicable.

(4) The disposition of generated electricity in MWh, reported at the facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Electricity For Grid*. Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer.

(B) *Generated Electricity For Other Users*. Generated electricity provided or sold directly to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, and ARB ID if applicable.

1. In addition to reporting the overall amount of electricity provided or sold directly to end users, separately quantify and report the subset of generated electricity used to produce cooling energy (e.g., chilled water) to end-users outside of the facility boundary.

(C) *Generated Electricity For On-Site Industrial Applications Not Related to Electricity Generation*. If the facility includes industrial processes or operations that are neither in support of or a part of the power generation system, report the total amount of generated electricity used by those on-site industrial processes or operations.

1. In addition to reporting the overall amount of electricity used for on-site industrial applications not related to electricity generation, also separately quantify and report the subset of generated electricity that is used to produce cooling energy used on-site that is neither in support of nor a part of the power generation system.

If the facility includes equipment that utilizes generated electricity to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, account for such electricity as a part of the difference between gross generation and net generation (parasitic load) pursuant to section 95112(b)(2).

If a facility includes more than one electricity generating unit or cogeneration system, and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated electricity from the group of units is provided to the same destination.

(5) The operator of a cogeneration or bigeneration unit must report the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit ("generated thermal energy"), reported at the

facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Thermal Energy For Other Users*. Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user.

1. In addition to reporting the overall amount of generated thermal energy for other users, separately quantify and report the subset of generated thermal energy that is used to produce cooling energy (e.g., chilled water) or distilled water for a particular end-user outside of the facility boundary.

(B) *Parasitic Steam Use*. Thermal energy used for supporting power production that has been included in the quantity reported under paragraph 95112(b)(3) but that is not accounted for in the quantities reported under paragraphs 95112(a)(5)(A) and (C). This thermal energy quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include steam used for power augmentation, NOx control, sent to a de-aerator, or sent to a cooling tower.

(C) *Generated Thermal Energy For On-Site Industrial Applications Not Related to Electricity Generation*. If the facility includes other industrial processes or operations that are neither in support of or a part of the electricity generation or cogeneration system, report the total amount of generated thermal energy that is used by those on-site industrial processes or operations and heating or cooling applications. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations. This quantity does not include the amount of thermal energy generated by equipment that is not an integral part of the cogeneration unit.

1. In addition to reporting the overall amount of thermal energy for on-site industrial applications not related to electricity generation, also separately quantify and report the subset of

generated thermal energy that is used on-site to produce cooling energy or distilled water that is neither in support of or a part of the power generation system.

If the facility includes equipment that utilizes generated thermal energy to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, follow section 95112(a)(5)(B) in reporting such use of generated thermal energy.

If a facility includes more than one cogeneration or bigeneration unit/system, and each unit/system or each group of units generate thermal energy for different particular end-users or on-site industrial processes or operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated thermal energy from the group of units is provided to the same destination.

(6) For the first year of reporting, operators of cogeneration or bigeneration units must submit a simplified block diagram depicting the following, as applicable: individual equipment included in the generation system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (a)(4)-(5), (b)(2)-(4) and (b)(7)-(8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements. If the cogeneration or bigeneration system is modified after the initial submission of the diagram, the operator must resubmit an updated diagram to CARB.

(b) *Information About Electricity Generating Units*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must meet the applicable criteria in 40 CFR §98.36(c)(1)-(4), unless otherwise specified in sections 95115(h) and 95112(b). For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to CARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40

CFR §98.36(d)(1)(i). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h). Operators of geothermal facilities, ~~hydrogen~~ fuel cells and linear generators, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).

(1) Basic information about the generating unit, including:

(A) Nameplate generating capacity in megawatts (MW);

(B) Prime mover technology;

(C) For aggregation of units, provide a description of the individual equipment included in the aggregation;

(D) If the unit generates both electricity and thermal energy, indicate whether the unit is a cogeneration or a bigeneration unit. If the unit is a cogeneration unit, indicate whether it is topping or bottoming cycle.

(2) Net and gross power generated, in megawatt hours (MWh). The difference between net generation and gross generation is the parasitic load of electricity generation or cogeneration. The net generation quantity represents the amount of generated electricity that can be provided to the disposition categories in section 95112(a)(4).

(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined in section 95102, that was generated by the unit and can be potentially utilized in other industrial operations that are not electricity generation, including thermal energy that is vented, radiated, wasted, or discharged. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation. The total thermal output quantity represents the amount of generated thermal energy that can be provided to the thermal energy disposition categories in section 95112(a)(5).

(4) Fuel consumption by fuel type, reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids.

(5) If not already required to be reported under 40 CFR §98.36(b) for Subarticle C units and §98.46 for Subarticle D units, annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas.

(6) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(e)(2)(ii)(C) and (iv)(C), report weighted or arithmetic average carbon content and high heat value by fuel type, whichever is used in calculating emissions as specified in 40 CFR §98.33.

(7) For cogeneration systems, where supplemental firing has been applied to support electricity generation or thermal output, report the information in paragraphs (b)(4)-(6). Indicate by fuel type the portion of the total fuel consumption (MMBtu) that is used for supplemental firing, and indicate the purpose of the supplemental firing.

(8) *Other Heat Input for Electricity Generation*. If the electricity generation unit uses additional heat input that is not already accounted for in paragraphs 95112(b)(4)-(6) (for example, if steam or heat is acquired from outside of the electricity generation system boundary or acquired from another facility for the generation of electricity), report the amount of acquired steam or heat (MMBtu). For bottoming cycle cogeneration units only, also report the input steam to the steam turbine (MMBtu) and the output of the heat recovery steam generator (MMBtu).

(c) *Emissions from Fuel Combustion and Sorbent*. When calculating CO_2, CH_4, and N_2O emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 must use a method in 40 CFR §98.33(a)(1)-(4) as specified by fuel type in section 95115 of this article, except that for CO_2 emissions the operator who is subject to Subpart D of 40 CFR Part 98 may elect instead to follow the provisions in 40 CFR §98.43, within the limitations of section 95103(m) of this article.

(1) The operator of a Subpart D unit must report emissions from fuels combusted within the data year but not reported pursuant to 40 CFR Part 75 requirements, such as prior to initial provisional or monitoring certification of CEMS. The operator must use a method in 40 CFR §98.33(a)(1)-(4) as specified by fuel type in section 95115, or if applicable, according to the de minimis provisions in section 95103(i) of this article.

(2) The operator of a Subpart D unit with contractual deliveries of biomethane or biogas is subject to the requirements in section 95131(i) of this article and must follow the procedure in sections 95115(e)(4)-(5) in calculating emissions from biomethane, biogas, and natural gas.

(3) The operator of a Subpart D unit who reports CO_2 emissions using emission calculation methods specified in 40 CFR Part 75, and who operates a unit with a wet flue gas desulfurization system, must indicate the portion of the total reported CO_2 emissions that is generated from sorbent injection for acid gas removal.

(d) *Monitoring, Data and Records*. For each emissions calculation method chosen under section 95112(c), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95112, 95115, and 95129 of this article.

(e) CO_2 *and* CH_4 *Emissions from Geothermal Facilities*. Operators of geothermal generating facilities must report CO_2 and CH_4 emissions from geothermal energy sources, the amount of geothermal steam utilized (MMBtu) if steam quantity is used in calculating emissions, and applicable requirements in section 95112(a)(1)-(4), (b)(1)(A)-(C), and (b)(2). Operators of geothermal generating facilities must also report whether the source is, (i) a geothermal binary cycle plant or closed loop system, or (ii) a geothermal steam plant or open loop system.

The operator must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by ~~the ARB~~CARB. The operator must submit to the Executive Officer a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the Executive Officer, the test procedures in that plan must be performed as specified in the plan.

(f) ~~Hydrogen~~ *Fuel Cells and Linear Generators*. Operators of stationary ~~hydrogen~~ fuel cell and linear generator units must include the following information in the annual GHG emissions data report:

(1) Basic information about the generating unit specified in section 95112(b)(1) (2);

(2) Fuel or feedstock consumption by fuel/feedstock type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;

(3) The provider of each fuel or feedstock, and the user's customer account number;

(4) Cogeneration information in section 95112(b)(3), if applicable.

(5) CO_2 emissions from the ~~hydrogen~~ fuel cell or linear generator, calculated using one of the following methods:

(A) The fuel and feedstock mass balance approach in 40 CFR 98.163(b). If the fuel's carbon content is not known, the facility operator may use the default carbon content percentage value listed in Table 3-1 of section 95129(c).

(B) For natural gas and biogas, if the fuel heat input is measured by the facility operator or by the fuel supplier, the operator may use the following equation to estimate emissions.

$$CO_2 \text{ (MT/year)} = H \text{ (MMBtu/year)} \times EF \text{ (kg } CO_2\text{/MMBtu)} \times 0.001 \text{ (MT/kg)}$$

Where

CO_2 = Annual CO_2 emissions from fuel and feedstock consumption (metric tons/year)

H = Total fuel heat input for the year (MMBtu/year)

EF = Default CO_2 emission factor. Use 53.02 kg CO_2/ MMBtu for natural gas. Use 52.07 kg CO_2/MMBtu for biogas.

0.001 = Conversion factor from kg to metric tons.

(C) For biogas fuels, the facility operator may elect to use the best available estimation and engineering estimation approach to calculate emissions.

(g) *On-site Renewable Electricity Generation*. The requirements in this paragraph apply to facilities that meet the applicability for reporting under section 95101 and are not otherwise exempted from reporting under section 95101(f). If such facility includes non-fuel-based renewable electricity generating units with nameplate generating capacity of greater than 0.5 MW, the operator must report the nameplate generating capacity (MW), gross power generated (MWh) by the non-fuel-based renewable electricity generating units, and the applicable information in 95112(a). For facility operators that do not operate other electricity generating units that are subject to the requirements in paragraphs (a)-(f) of section 95112, reporting of information specified in section 95112(a)(4)(C) and (a)(5)-(6) is optional.

(h) *Missing Data Substitution Procedures*. To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

(i) *Additional Reporting Requirements for Legacy Contract Applicants*. The additional requirements in section 95112(i) apply to every facility operator that is applying for legacy contract transition assistance under the ~~c~~Cap-and-~~trade regulation~~Invest Regulation. A legacy contract generator with an industrial counterparty must submit a simplified block diagram in every year that the facility operator applies for legacy contract transition assistance. Legends or attachments may be used when labeling the diagram. If any of the amounts requested are sums of measurements made by different devices, the amounts for each device must be shown in the diagram and the summation described in an attachment.

(1) The diagram must depict the following elements:

(A) For the data year, all of the information described in sections 95112(a)(4) (5), as applicable, regardless of whether the facility operator, or the equipment, is itself otherwise subject to sections 95112(a)(4)-(5). This information reflects electricity and thermal energy flows, including information identifying the recipient(s) of the electricity and/or thermal energy. Also report the quantities of any other products provided or sold under the legacy contract, using the units in which they are reported elsewhere in this regulation, if applicable. The diagram must indicate where each of these energy flows or products is measured. In addition, the following information must be included:

1. Each of the amounts reported under section 95112(i)(1)(A) must be labeled indicating whether or not it was provided under the legacy contract; and

2. All thermal energy products must be labeled with the type of thermal energy product (e.g., steam, hot water, chilled water, distilled water).

(B) The individual equipment included in the system for which the facility operator is applying for legacy contract transition assistance, and other equipment that is not an integral part of that system but produces or consumes energy that is sent to or received from that system and is owned or operated by the facility operator. Boilers, individual generators such as heat recovery steam generators, turbines if separate from generators, ice plants, chillers, purifiers and other equipment that meet these criteria must each be shown separately in the diagram. In addition, label each piece of equipment with the amount of fuel consumed (in MMBtu) by that piece of equipment during the data year, if any, and the resulting greenhouse gas emissions in CO_2e as reported elsewhere under this regulation. The diagram must also indicate the fuel meter where this fuel use was measured, and the amount measured.

(C) An outline showing the boundary of the activities covered by the legacy contract.

(j) Additional Reporting Requirements for Emissions from a Declared Emergency. An electricity generating facility that seeks to exclude covered emissions from their Cap-and-Invest applicability threshold calculation pursuant to section 95812(c)(2)(A)1. of the Cap-and-Invest Regulation must report the total annual covered emissions (MT CO_2e) that occurred during eligible states of emergency.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95113. ~~Petroleum~~ Refineries

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Y of 40 CFR Part 98 (40 CFR §§98.250 to 98.258) in reporting emissions and other data from biorefineries and petroleum refineries to CARB, except as otherwise provided in this section. ~~Petroleum refinery~~Biorefineries are subject to all requirements in section 95113. Refinery operators and refiners are considered separate reporting entities for the purposes of this article.

(a) *CO_2 from ~~Fossil~~ Fuel Combustion*. When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.252(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article. CO_2 emissions from refinery fuel gas combustion must be calculated using a Tier 3 or Tier 4 methodology of subpart C, as specified in 40 CFR §98.252(a).

(b) *Monitoring, Data and Records*. For each emissions calculation method chosen under section 95113(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95113(k), 95115, and 95129 of this article.

(c) *Refinery Fuel Gas Sampling*. ~~As required by 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform~~Operators must conduct daily sampling and analysis ~~of~~to determine carbon content and molecular weight for refinery fuel gas ~~is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013~~.

(d) *Calculating CO_2 from Flares*. For periods of normal flare operation, the operator must use Equation Y-1a, Y-1b, or Y-2 as specified in 40 CFR §98.253(b)(1)(ii)(A) or 98.253(b)(1)(ii)(B). For periods of startup, shutdown, and malfunction (SSM) during which the operator was unable to measure the parameters required by Equations Y-1a, Y-1b, or Y-2, the operator must determine the quantity of gas discharged to the flare separately for each SSM~~,~~ and calculate the CO_2 emissions as specified in the equation shown below. All SSM events must be reported, irrespective of any emission limits or thresholds. For SSM periods the operator must use engineering calculations and process knowledge to estimate the carbon content of flared gas as required by §98.253(b)(1)(iii)(A). The terms of the equation below are defined as they are for Equation Y-3 in 40 CFR §98.253(b)(1)(iii)(C).

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[44/12 \times (\text{Flare}_{\text{SSM}})_p \right] \times MW_p / MVC \times CC_p \right)$$

(e) *Calculating* CO_2 *from FCCUs and Fluid Coking*. The requirements of 40 CFR §98.253(c)(2) apply under this article regardless of the rated capacity of a fluid catalytic cracking unit or a fluid coking unit. The operator may not use Equation Y-8 or the option provided under 40 CFR §98.253(c)(3) for units with rated capacities of 10,000 barrels per stream day or less.

(f) *Uncontrolled Blowdown Systems*. When calculating CH_4 emissions for uncontrolled blowdown systems as required by 40 CFR §98.253(k), the operator must use the methods for process vents in 40 CFR §98.253(j).

(g) *Data Reporting Requirements for Flares*. When the operator has calculated flare emissions for SSM periods using the modified equation specified in section 95113(d), the operator reporting data under the requirements of 40 CFR §98.256(e)(8) must report only the total number of SSM events, the volume of gas flared, and the average molecular weight and carbon content of the flare gas for each SSM event, using the units specified.

(h) Data Reporting Requirements for FCCUs and Coking Units. When the operator has calculated CO_2 from fluid catalytic cracking units or fluid coking units consistent with section 95113(e), the operator shall not report the data required by 40 CFR §98.256(f)(9).

(i) *Data Reporting Requirements for Uncontrolled Blowdown Systems*. When the operator has calculated CH_4 from uncontrolled blowdown systems consistent with section 95113(g), the operator must report the information required for process vents in 40 CFR §98.256(l), as applicable, in lieu of the information required by 40 CFR §98.256(m)(2).

(j) *Records that Must Be Retained*. In addition to the requirements of 40 CFR §98.257, for each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in 40 CFR §98.253(j), the operator must maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentrations, and all supporting documentation necessary to demonstrate that the thresholds in 40 CFR §98.253(j) are not exceeded during the data year pursuant to the record keeping requirements of section 95105.

(k) *Missing Data Substitution Procedures*. The operator must comply with 40 CFR §98.255 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(l) *Additional Product and Process Data*.

(1) *Refinery Products*. For each material in Table 2 1, as defined in the U.S. Energy Information Administration Glossary (May 27, 2016), which is hereby incorporated by reference, the operator must report the annual on-site production amount and the annual amount of product produced elsewhere and brought on-site. Amounts must be reported in standard cubic feet for gaseous products, barrels for liquid products, and short tons for solid products. The methods for reporting production and receipts on Part 5 of the federal Energy Information Agency's Form EIA-810 that are described by the Monthly Refinery Report Instructions for Form EIA-810 (Revised 2013), which is hereby incorporated by reference, must be used to report on-site production amounts and amounts produced elsewhere and brought on-site. These reported on-site production quantities and quantities of material produced elsewhere and brought on-site are not covered product data and will not be subject to review for material misstatement under the requirements of section 95131(b)(12).

(2) *Calcined Coke*. The operator must report the annual mass (metric tons) of calcined coke produced on-site during the data year. The operator must specify whether the calciner is integrated with the petroleum refinery operation.

(3) *Complexity Weighted Barrel (CWB) Calculation*. The CWB calculation provisions in this subsection remain in effect through 2030 data reported in 2031. Beginning in the 2026 data year reported in 2027, a facility operator may voluntarily elect to permanently switch to reporting product data pursuant to subsection 95113(l)(4) instead of this subsection. Operators of facilities that have reportable throughput for an Asphalt Production CWB unit only and no other CWB unit are no longer permitted to report product data under this section and must report product data pursuant to section 95113(l)(5).

(A) *Reporting CWB Throughputs*. The operator must report the annual throughput for each CWB unit in Table 2-2 of this section using the units specified in Table 2-2 of this section. Liquid throughput volumes must be reported at standard conditions of 60 °F and atmospheric pressure. The volume correction from nonstandard conditions must be calculated by the methods described in the American Petroleum Institute (API) Manual of Petroleum Measurement Standards Chapter 11 – Physical Properties Data (May 2004), the American Society of Testing and Materials Standard Guide for Use of the Petroleum Measurement Tables, ASTM D1250-08 (Reapproved 2013)) or the American Petroleum Institute Technical Data Book (-- Petroleum Refining (Sixth Edition, April 1997), all three of which are hereby incorporated by reference, or by comparable means that can be demonstrated to a verifier to be consistent with these standard methods. Reported throughputs based on feed must include only fresh feed and exclude recycled streams, except for reported throughputs for the CWB units "C4 Isomer Production" and "C5/C6 Isomer Production – including ISOSIV," which may include recycled material. The coke-on-catalyst volume percent also must be reported for each catalytic cracking unit. Beginning with data year 2013, CWB throughputs are considered covered product data and subject to the accuracy requirements of section 95103(k).

(B) *Total facility CWB*. The total facility CWB production must be calculated according to the following formula.

$$CWB_{Total} = CWB_{Process} + CWB_{Off-Sites} + CWB_{Non-Crude\ Sensible\ Heat}$$

Where CWB_{Total} is the total complexity weighted barrels for a petroleum refinery, and $CWB_{Process}$, $CWB_{Off\text{-}Sites}$, and $CWB_{Non\text{-}Crude\ Sensible\ Heat}$ must be calculated as follows:

$CWB_{Process} = \sum(CWB_{Factor} \times Throughput)$

$CWB_{Off\text{-}Sites}$ = (0.327) x (*Total Refinery Input* in thousands of barrels per year) + (0.0085) x ($CWB_{Process}$)

$CWB_{Non\text{-}Crude\ Sensible\ Heat}$ = (0.44) x (*Non-Crude Input* in thousands of barrels per year)

In these equations, CWB_{Factor} is the CWB Factor for a CWB unit from Table 2-2 of this section. Throughput is the process throughput for each CWB unit identified in Table 2-2 of this section reported pursuant to section 95113(l)(3)(A). Total Refinery Input and Non-Crude Input are the annual volumes of raw materials as defined in section 95102(c) and must be reported in units of thousands of barrels per year. Total facility CWB is covered product data and subject to material misstatement evaluation during verification.

(C) Correction to CWB_{Factor} for Fluid Catalytic Cracking. The following equation must be used to adjust CWB_{Factor} for Fluid Catalytic Cracking (FCC) units and mild residual FCC units that result in coke on the catalyst:

$$CWB_{Factor,FCC} = CWB_{Factor} + (A \times COC)$$

Where:

$CWB_{Factor,FCC}$ = The corrected CWB factor used to calculate the contribution to $CWB_{Process}$ for a fluid catalytic cracking unit.

CWB_{Factor} = The uncorrected CWB factor for a catalytic cracking unit from Table 2-2 of this section.

A = The coke-on-catalyst factor for a fluid catalytic cracking unit listed in the fourth column of Table 2-2 of this section.

COC = The coke-on-catalyst volume percent reported to three significant figures and calculated by:

COC = 100 × (Volume of coke consumed in the FCC)/(Volume of fresh feed to the FCC)

(D) Density. In cases where a density measurement is needed for purposes of converting a throughput from barrel to mass units, the following applies:

1. For a throughput with a known density, utilize the applicable default value from Section 3-1, Physical Constants of Organic Compounds, of the CRC Handbook of Chemistry and Physics, CRC Press Inc., Boca Raton 83rd Edition, 2002 – 2003, incorporated herein by reference;

2. If the throughput density is not known, it must be determined following the requirements of section 95103(k).

(E) Measurement Accuracy. All throughputs must follow the accuracy requirements outlined in sections 95103(k)(1)-(10). No single refinery activity may be reported under more than one CWB function.

(4) Production of Liquid Hydrocarbon Fuel (LHF). Beginning with 2031 data, in lieu of reporting complexity weighted barrel data pursuant to section 95113(l)(3), operators are required to report the on-site production quantity for each fuel that meets the definition of LHF in section 95102(b) of this article. LHF quantities must be reported in barrels at standard conditions of 60 °F and atmospheric pressure, except that compressed liquids are reported at whatever pressure the fuel is sold, as corrected to 60° F. Prior to 2031 data, operators may voluntarily elect to permanently

transition to reporting LHF production data beginning with 2026 data. LHF production data is considered covered product data and is subject to verification and the accuracy requirements of section 95103(k).

(A) LHF production data must include only fuel volumes produced onsite. To qualify as produced onsite, a fuel's onsite production must involve the processing of fossil crude oil, biomass-derived feedstocks, or the chemical transformation of minimally processed feedstocks derived from fossil crude oil or biomass-derived feedstocks. Fuel blending is not considered onsite production. In cases where LHF is produced from intermediate feedstocks produced elsewhere and brought onsite, the LHF volumes are only included in LHF covered product data if the intermediate feedstocks were produced by another covered entity; in all other cases, LHF produced onsite from intermediate feedstocks must be excluded from LHF covered product data. In all cases, LHFs produced elsewhere and brought on-site must be excluded from LHF covered product data.

(5) Asphalt Production. The operator of an asphalt production unit that does not report complexity weighted barrel product data must report the total barrels of asphalt and road oils produced in the data year.

(6) Additional Data Reporting. Operators must report the annual quantity (in barrels) of total refinery inputs, total fossil crude inputs, and biomass-derived feedstock inputs.

(m) *Reporting to Support the Cost of Implementation Fee Regulation*. The operator must report the volume of:

(1) CARBOB, as defined by "California reformulated gasoline blendstock for oxygenate blending" in section 95202 of the AB 32 Cost of Implementation Fee Regulation, produced and imported for use in California and the designated volume of oxygenate associated with the reported CARBOB;

(2) Finished California gasoline, as defined by "California gasoline" in section 95202 of the AB 32 Cost of Implementation Fee Regulation, produced and imported for use in California; and

(3) California Diesel, as defined by "California diesel fuel" in section 95202 of the AB 32 Cost of Implementation Fee Regulation, produced and imported for use in California and the volume of biodiesel and/or renewable diesel associated with the reported fuels.

(n) Additional Requirements for Reporting Biogenic Emissions from Processing or Coprocessing of Biomass-Derived Feedstocks. Operators of refineries and biorefineries must report emissions from all applicable sources as specified in section 95113. Biogenic emissions from processing or coprocessing of biomass-derived feedstocks or combustion of biomass-derived or partially biomass-derived fuels may optionally be reported separately from non-biogenic emissions only if measurement and quantification accuracy standards meet the accuracy requirements specified in section 95103(k). To quantify and report exempt biogenic emissions from processing or coprocessing of biomass-derived feedstocks, the operator must obtain approval of an alternative method pursuant to section 95103(m)(2).

(1) Biogenic emissions quantified using methods outside of an approved alternative method or that are deemed by CARB or a verifier not to meet the ±5 percent accuracy standard must be reported as non-exempt biogenic emissions.

Table 2-1. Refinery Products

Product	EIA Product Code	Eligible to Report as Liquid Hydrocarbon Fuel (LHF)**
Petroleum Coke, Marketable	021	N
Still Gas	045	N
NGPL and LRG* – Ethane/Ethylene, TOTAL (includes EIA Product Codes 631 and 641)	108	Y
Finished Aviation Gasoline	111	Y
Aviation Gasoline Blending Components	112	Y
Motor Gasoline Blending Components – Gasoline Treated as Blendstock	117	Y
Motor Gasoline Blending Components – Reformulated Blendstock for Oxygenate Blending (RBOB)	118	Y
Finished Motor Gasoline – Reformulated, Blended with Fuel Ethanol	125	Y***
Finished Motor Gasoline – Reformulated, Other	127	Y***
Finished Motor Gasoline – Conventional, Other	130	Y***
Motor Gasoline Blending Components – All Other Motor Gasoline Blending Components	138	Y
Motor Gasoline Blending Components – Conventional Blendstock for Oxygenate Blending (CBOB)	139	Y
Renewable Fuels – Fuel Ethanol	141	N
Finished Motor Gasoline – Conventional, Blended with Fuel Ethanol (Greater than Ed55)	149	Y***
Finished Motor Gasoline – Conventional, Blended with Fuel Ethanol (Ed55 and Lower)	166	Y***
Renewable Fuels – Biomass-Based Diesel Fuel	203	Y
Renewable Fuels – Other Renewable Diesel Fuel	205	Y
Renewable Fuels – Other Renewable Fuels	207	Y
Kerosene-Type Jet Fuel, TOTAL (includes EIA Product Codes 217 and 218)	213	Y
NGPL and LRG* – Pentanes Plus	220	Y
NGPL and LRG* – Butane/Butylene, TOTAL (includes EIA Product Codes 249, 633, and 643)	244	Y
NGPL and LRG* – Isobutane/Isobutylene, TOTAL (includes EIA Product Codes 247, 634 and 644)	245	Y
NGPL and LRG* – Propane/Propylene, TOTAL (includes EIA Product Codes 632 and 642)	246	Y

Product	EIA Product Code	Eligible to Report as Liquid Hydrocarbon Fuel (LHF)**
Kerosene	311	Y
Distillate Fuel Oil – Ultra Low Sulfur (sulfur content < 15 ppm)	465	Y
Distillate Fuel Oil – Low Sulfur (15 ppm ≤ sulfur content ≤ 500 ppm)	466	Y
Distillate Fuel Oil – High Sulfur (sulfur content > 500 ppm)	467	Y
Residual Fuel Oil, TOTAL (includes EIA Product Codes 508, 509, and 510)	511	N
Unfinished Oils – Naphthas and Lighter	820	N
Petrochemical Feedstocks – Naphtha, end-point < 401 °F	822	N
Petrochemical Feedstocks – Other Oils, end-point ≥ 401 °F	824	N
Unfinished Oils – Kerosene and Light Gas Oils	830	N
Unfinished Oils – Heavy Gas Oils	840	N
Unfinished Oils – Residuum	850	N
Lubricants, TOTAL (includes EIA Product Codes 852 and 853)	854	Y
Asphalt and Road Oil	931	N

* _NGPL and LRG = Natural Gas Plant Liquids and Liquefied Refinery Gases

** To be eligible for inclusion in the reported LHF product data, fuel must meet criteria stipulated in the LHF definition and section 95113(l)(4).

*** Ethanol does not meet the definition of LHF and must be subtracted from the fuel quantity reported as LHF. Unless they meet the LHF definition and are produced at the facility, other blendstocks must also be subtracted from the fuel quantity reported as LHF.

Table 2-2. CWB Units and Factors

CWB Unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
Atmospheric Crude Distillation	Feed	thousands of barrels/year	1	401	Mild Crude Unit, Standard Crude Unit
Vacuum Distillation	Feed	thousands of barrels/year	0.91	402	Mild Vacuum Fractionation, Standard Vacuum Column, Vacuum Fractionating Column, Vacuum Flasher Column,
					Heavy Feed Vacuum Unit
Visbreaker	Feed	thousands of barrels/year	1.6	403	Processing Atmospheric Residual (w/o a Soaker Drum), Processing Atmospheric Residual (with a Soaker Drum), Processing Vacuum Bottoms Feed (w/o a Soaker Drum), Vacuum Bottoms Feed (with a Soaker Drum)
Delayed Coker	Feed	thousands of barrels/year	2.55	405	Delayed Coking

CWB Unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
Fluid Coker	Feed	thousands of barrels/year	10.3	404	Fluid Coking
Flexicoker	Feed	thousands of barrels/year	23.6		Flexicoking
Fluid Catalytic Cracking	Feed	thousands of barrels/year	1.150, Coke-on-Catalyst Factor = 1.041	407	Fluid Catalytic Cracking (Feed ConCarbon <2.25 wt%)
Mild Residual FCC	Feed	thousands of barrels/year	0.6593, Coke-on-Catalyst Factor = 1.1075		Mild Residualuum Catalytic Cracking (Feed ConCarbon 2.25-3.5 wt %)
Other FCC	Feed	thousands of barrels/year	4.65		Houdry Catalytic Cracking
Other FCC	Feed				Thermofor Catalytic Cracking
Thermal Cracking	Feed	thousands of barrels/year	2.95	406	Thermal Cracking
Naphtha/Distillate Hydrocracker	Feed	thousands of barrels/year	3.15	439 / 440	Mild Hydrocracking (Normally less than 1,500 psig and consumes between 100 and 1,000 SCF H2)
					Severe Hydrocracking
					Naphtha Hydrocracking
Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	Feed	thousands of barrels/year	4.4	441	H-Oil
					LC-Fining™ and Hycon
Naphtha Hydrotreater	Feed	thousands of barrels/year	0.91	420/425/426	Benzene Saturation
					Desulfurization of C4–C6 Feeds
					Conventional Naphtha Hydrotreating
					Diolefin to Olefin Saturation of Gasoline
					FCC Gasoline Hydrotreating with Minimum Octane Loss
					Olefinic Alkylation of Thio Sulfur
					Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization
					Pyrolysis Gasoline/Naphtha Desulfurization
					Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization
					Reactor for Selective Hydrotreating
					S-Zorb™ Process
Kerosene Hydrotreater	Feed	thousands of barrels/year	0.75	421	Aromatic Saturation of Kerosene

CWB Unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
					Conventional Hydrotreating of Kerosene/Jet Fuel
					High Severity Hydrotreating Kerosene/Jet Fuel
Diesel/Selective Hydrotreater	Feed	thousands of barrels/year	0.9	422 / 423	Aromatic Saturation of Distillates
					Conventional Distillate Hydrotreating
					High Severity Distillate Hydrotreating
					Ultra-High Severity Hydrotreating
					Middle Distillate Dewaxing
					S-Zorb™ Process
					Diolefin to Olefin Saturation of Alkylation Feed
					Selective Hydrotreating of C3-C5 Streams for Alkylation
Residual Hydrotreater	Feed	thousands of barrels/year	1.8	424	Desulfurization of Atmospheric Residual
					Desulfurization of Vacuum Residual
VGO Hydrotreater	Feed	thousands of barrels/year	1	413	Hydrodesulfurization/denitrification
					Hydrodesulfurization
Reformer - including AROMAX	Feed	thousands of barrels/year	3.5	430 / 431	Continuous Regeneration, Cyclic, Semi-Regenerative, and AROMAX
Solvent Deasphalter	Feed	thousands of barrels/year	2.8	432	Conventional Solvent, Supercritical Solvent
Alkylation/Poly/Dimersol	C5+ Alkylate	thousands of barrels/year	5	415	Alkylation with Hydrofluoric Acid
					Alkylation with Sulfuric Acid
	C5+ Product				Polymerization C3 Olefin Feed
					Polymerization C3/C4 Feed
					Dimersol
C4 Isomer Production	Feed	thousands of barrels/year	1.25	615/644	C4 Isomerization
C5/C6 Isomer Production - including ISOSIV	Feed	thousands of barrels/year	1.8	438	C5/C6 Isomerization
					ISOSIV
POX Syngas for Fuel	Product	millions of standard cubic feet/year[1]	2.75		POX Syngas for Fuel
POX Syngas for Fuel					Air Separation Unit
Sulfur Recovery	Product Sulfur	thousands of long tons/year	140	435	Sulfur Recovery Unit
					Tail Gas Recovery Unit
	Sulfur Sprung				H2S Springer Unit
Aromatics Production (All)	Feed	thousands of barrels/year	3.3	437	Aromatics Solvent Extraction: Extraction Distillation

CWB Unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
					Aromatics Solvent Extraction: Liquid/Liquid Extraction
					Aromatics Solvent Extraction: Liq/Liq w/ Extr. Distillation
					Benzene Column
					Toluene Column
					Xylene Rerun Column
					Heavy Aromatics Column
Hydrodealkylation	Feed	thousands of barrels/year	2.5		Hydrodealkylation
Toluene Disproportionation/ Transalkylation	Feed	thousands of barrels/year	1.9		Toluene Disproportionation / Transalkylation
Cyclohexane production	Cyclohexane Product	thousands of barrels/year	2.8		Cyclohexane
Xylene Isomerization	Feed	thousands of barrels/year	1.9		Xylene Isomerization
Paraxylene Production	Paraxylene Product	thousands of barrels/year	6.5		Paraxylene Adsorption
		thousands of barrels/year			Paraxylene Crystallization
	Feed	thousands of barrels/year			Xylene Splitter
		thousands of barrels/year			Orthoxylene Rerun Column
Ethylbenzene Production	Ethylbenzene Product	thousands of barrels/year	1.6		Ethylbenzene Manufacture
	Feed	thousands of barrels/year			Ethylbenzene Distillation
Cumene Production	Cumene Product	thousands of barrels/year	5		Cumene
Lubricant Solvent Extraction	Feed	thousands of barrels/year	2.2	815/854	Extraction: Solvent is Duo-Sol, Furfural, NMP, Phenol, or SO2
Lubricant Solvent Dewaxing	Feed	thousands of barrels/year	4.55		Dewaxing: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane
Lubricant Catalytic Dewaxing	Feed	thousands of barrels/year	1.6		Catalytic Wax Isomerization and Dewaxing, Selective Wax Cracking
Lubricant Hydrocracking	Feed	thousands of barrels/year	2.5		Lube Hydrocracker with Multi-fraction Distillation, Lube Hydrocracker with Vacuum Stripper
Lubricant Wax Deoiling	Product	thousands of barrels/year	11.8		Deoiling: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane
Lubricant and Wax Hydrofining	Feed	thousands of barrels/year	1.15		Lube Hydrofinishing with Vacuum Stripper
					Lube Hydrotreating with Multi-Fraction Distillation, Lube Hydrotreating Vacuum Stripper

CWB Unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
					Wax Hydrofinishing with Vacuum Stripper, Wax Hydrotreating with Multi-Fraction Distillation, Wax Hydrotreating with Vacuum Stripper
Asphalt Production	Total Asphalt Production	thousands of barrels/year	2.7	931	Asphalt Production
Oxygenates	Product	thousands of barrels/year	4.9		Distillation Units
					Extraction Units
					ETBE
					TAME
Methanol Synthesis	Product	thousands of barrels/year	-36		Methanol Synthesis
Desalination	Product (Water)	millions of gallons/year	32.7		Desalination
Special Fractionation	Feed	thousands of barrels/year	0.8		All Special Fractionation ex Solvents, Propylene, and Aromatics
Propane/Propylene Splitter (Propylene Production)	Feed	thousands of barrels/year	2.1		Chemical Grade
					Polymer Grade
Fuel Gas Sales Treating & Compression (hp)	Horsepower	hp	0.92		Fuel Gas Sales Treating & Compression
Ammonia Recovery Unit	Product	thousands of short tons/year	453		Ammonia Recovery Unit: PHOSAM
Cryogenic LPG Recovery	Feed	millions of standard cubic feet/year	0.25		Cryogenic LPG Recovery
Flare Gas Recovery	Feed	millions of standard cubic feet/year	0.13		Flare Gas Recovery
Flue Gas Desulfurizing	Feed	millions of standard cubic feet/year	0.02		Flue Gas Desulfurizing
CO_2 Liquefaction	CO_2 product	thousands of short tons/year	-160	.	CO_2 Liquefaction
[1] Standard cubic feet are dry @ 60° F and 14.696 psia or 15 °C and 1 atmosphere.					

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95114. Hydrogen Production

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart P of 40 CFR Part 98 (40 CFR §§98.160 to 98.168) in reporting emissions and other data from molecular hydrogen production to CARB, except as otherwise provided in this section. GHG emissions and output associated with hydrogen production must be reported separately from other emissions and output associated with a petroleum refinery or biorefinery.

(a) *Definition of Source Category*. This source category is defined consistent with 40 CFR §98.160(b) and (c). This category is further defined as a hydrogen production source that produces molecular hydrogen whether sold to other entities or consumed on-site.

(b) CO_2 *from ~~Fossil~~ Fuel Combustion*. When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.162(b)-(c), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(c) *Monitoring, Data and Records*. For each emissions calculation method chosen under section 95114(b), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95114(h), 95115, and 95129 of this article.

(d) CO_2 *Emissions from Hydrogen Production Units*. When calculating CO_2 emissions from hydrogen production units under the fuel and feedstock material balance approach specified at 40 CFR §98.163(b), the operator must apply the weighted average carbon content values (the term CC_n in Equations P-1 through P-3) and, for gaseous fuels and feedstocks, the weighted average molecular weight values obtained according to the frequencies specified in section 95114(e)(2).

(e) *Fuel and Feedstock Contents*. For each hydrogen production unit, operators must report the following information:

(1) When monitoring GHG emissions with a CEMS as specified in 40 CFR §98.163(a), the operator must report the monthly carbon content, atomic hydrogen content (excluding hydrogen atoms contained in steam), and molecular hydrogen content for each feedstock. The reported values must be weighted averages from the results of one or more analyses per month.

(2) When monitoring GHG emissions without a CEMS as specified in 40 CFR §98.163(b), the operator must report the monthly weighted average atomic hydrogen content (excluding hydrogen atoms contained in steam) and weighted average molecular hydrogen content for each feedstock from the results of one or more analyses per month. The operator must also report

the monthly carbon content for each fuel and feedstock, and the molecular weight for each gaseous fuel and feedstock as follows:

(A) The reported values must be weighted averages from the results of one or more analyses per month for natural gas or standardized materials specified in Table 2-3 of section 95115.

(B) The reported values must be weighted averages from the results of daily sampling for each month for nonstandard materials not specified in Table 2-3 of section 95115, such as refinery fuel gas. For liquid and solid fuels and feedstocks, daily samples may be combined to generate a monthly composite sample for carbon content analysis.

(f) *Weighted Average Sampling*. Where this section requires sampling of a parameter on a more frequent basis than 40 CFR Part 98, the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n} (V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by this article.

n = The number of periods j in period E.

V_j = The value of the sample for period j.

M_j = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in the equation above and of the calculation of each weighted average included

in the emissions data report, pursuant to the record keeping requirements of section 95105.

(g) *Data Reporting Requirements*. When reporting data as specified in 40 CFR §98.166, the operator must also report the mass of carbon and methane for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation (e.g., carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods specified in this regulation). To avoid double-counting, these emissions must be subtracted from the total facility emissions.

(h) *Missing Data Substitution Procedures*. The operator must comply with 40 CFR §98.165 when substituting for missing data, except for 2013 and later emissions data reports as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems); the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(i) *Transferred* CO_2. The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Refineries and hydrogen production facilities must subtract this reported mass of CO_2 that is captured and sold or transferred off-site from their facility emissions report to avoid double counting.

(j) *Additional Product Data*. Operators must report the total annual mass of on-purpose and by-product gaseous hydrogen produced (metric tons) and total annual mass of liquid hydrogen sold (metric tons). Operators must separately report all gaseous and all liquid hydrogen sold or otherwise transferred (metric tons) to petroleum refineries, biorefineries, and hydrogen vehicle fueling stations and include the name of the purchaser (or receiver) and the quantity sold or transferred to each facility or entity. Operators must also specify if the hydrogen plant is an integrated refinery operation. Hydrogen plants integrated in refinery operations must also report any sales or transfers of hydrogen as specified in this subsection.

(k) *Methane and Nitrous Oxide Emissions from Stationary Combustion*. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively), and CH_4 and N_2O from fuel stationary combustion sources as set-forth in 40 CFR §98.33(c).

(l) Hydrogen producers shall use the methodology found in section 95113(d) to calculate and report CO_2, CH_4, and N_2O emissions from all flaring at their facility.

(m) Hydrogen producers must report for process vents the information required in 40 C.F.R. § 98.256(l) for any process vent that meets the applicability criteria and concentration thresholds specified in 40 C.F.R. § 98.253(j).

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95115. Stationary Fuel Combustion Sources

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart C of 40 CFR Part 98 (§§98.30 to 98.38) in reporting stationary fuel combustion emissions and related data to CARB, except as otherwise provided in this section.

(a) *CO_2 from Steam Producing Units.* The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR §98.33(a)(2)(B)(iii), unless required to use Tier 3 or 4 by 40 CFR Part 98 or Part 75. Operators of steam producing units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 methods.

(b) *CEMS CO_2 Monitoring.* Notwithstanding the allowed use of oxygen concentration monitors in 40 CFR §98.33(a)(4)(iv), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2012, and who reports CO_2 emissions using this system, must install and use a CO_2 monitor. An operator without a CO_2 monitor who uses a CEMS and O2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a Relative Accuracy Test Audit (RATA) for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 95105 and make them available to CARB upon request. The requirements of this paragraph do not apply to facilities for which pipeline natural gas is the only fuel consumed.

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 2-3 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels listed in Table C-1 of 40 CFR Part 98 when these emissions are not subject to a compliance obligation under Cap-and-~~Trade~~Invest Regulation, except as limited by section 95115(e).

(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section 95102 of this article, and for distillate fuels listed in Table 2-3 of this section. Tier 1 may be selected when the fuel supplier is providing pipeline quality natural gas measured in units of therms or million Btu. Equation C-2c of 40 CFR §98.33(a) may be selected for the units specified in paragraph (a) of this section.

(3) The operator may select any calculation method specified in 40 CFR §98.33(a) when calculating emissions that are shown to be de minimis under section 95103(i) of this article, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, unless not permitted under 40 CFR §98.33(b).

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel

use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume is measured by lot, the term “n” in Equation C-2b is substituted as the number of lots received in the year.

(d) *Source Test Option for N_2O and CH_4.* In lieu of other methods specified in this article, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in title 17, California Code of Regulations, section 95471. For source testing:

(1) The facility operator must submit to the Executive Officer a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved CARB or U.S. EPA test methods. Process rates during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the Executive Officer, the test procedures in that plan must be repeated as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least ten days in advance of subsequent tests.

* * * *

(n) *Additional Product Data*. Operators of the following types of facilities must also report the production quantities indicated below.

(1) The operator of a facility engaged in hot rolling and/or cold rolling of steel must report the quantity of hot rolled steel sheet, pickled steel sheet, cold rolled and annealed steel sheet, galvanized steel sheet, and tin plate produced in the data year (short tons). For cold rolled and annealed steel sheet, the operator must also report a description of the process used to produce the products, such as continuous annealing process or batch annealing.

(2) The operator of a soda ash manufacturing facility must report the quantity of soda ash equivalent produced in the data year (short tons).

(3) The operator of a gypsum manufacturing facility must report the quantity of plaster that is sold as a separate finished product and the amount of stucco used to produce saleable plasterboard produced in the data year (short tons~~)~~).

(4) The operator of a turbine and turbine generator set testing facility must report the nameplate power of the units tested (horsepower tested).

(5) The operator of a poultry processing facility must report the quantity of whole chicken and chicken parts, poultry deli products, and protein meal and fat produced in the data year (short tons).

(6) The operator of a facility that manufactures dehydrated flavors must report the production of dehydrated onion, dehydrated garlic, dehydrated chili peppers, dehydrated parsley, and dehydrated spinach in the data year (short tons).

(7) The operator of a beer brewery must report the production of lager beer in the data year (gallons).

(8) The operator of a snack food manufacturing facility must report the production of fried potato chips, baked potato chips, corn chips, corn curls, and pretzels in the data year (short tons).

(9) The operator of a sugar manufacturing facility must report the production of granulated refined sugar in the data year (short tons)

(10) The operator of a tomato processing facility must report the quantity of aseptic tomato paste (short ton of 31 percent TSS), aseptic whole and diced tomato (short ton), non-aseptic tomato paste and tomato puree (short ton of 24 percent TSS), non-aseptic whole and diced tomato (short ton), and non-aseptic tomato juice (short ton) produced in the data year.

(11) The operator of a pipe foundry must report the production of ductile iron pipes produced in the data year (short tons).

(12) The operator of a facility producing aluminum billets must report the production of aluminum and aluminum alloy billets in the data year (short tons).

(13) The operator of a facility mining or processing of rare earth minerals must report the production of rare earth oxide equivalents in the data year (short tons).

(14) The operator of a facility mining or processing freshwater diatomite filter aids must report the production of freshwater diatomite filter aids in the data year (short tons).

(15) The operator of a forging facility must report the production of seamless rolled ring during the data year (short tons).

(16) The operator of a dairy product facility must report the production of fluid milk product, butter, condensed milk, buttermilk powder, intermediate dairy ingredients, lactose, whey protein concentrate (WPC), deproteinized whey, sweet whey powder, cheese by cheese type, milk powder by the type of heat treatment (low heat, medium heat, or high heat), anhydrous milkfat, and milk protein concentrate by product type during the data year (short tons). Butter re-melted and re-introduced to the manufacturing process may be reported again as butter production. Buttermilk powder and nonfat dry milk and skimmed milk powder that is re-constituted and re-introduced to the manufacturing process may be reported as production. The operator must report the production of total WPC and WPC with high protein concentration using diafiltration process during the data year (short tons). The operator must also report the amount of imported protein.

(17) The operator of an almond or pistachio processing facility must report the production of adjusted hulled and dried pistachios, flavored pistachios, blanched almonds, flavored almonds, and pasteurized almonds (short tons).

(18) The operator of a wet corn milling facility must report the production of corn entering wet milling process during the data year (short tons).

(19) The operator of a winery must report the production of distilled spirits (proof gallons), dry color concentrate (short tons), grape juice concentrate (gallons), grape seed extract (short tons), and liquid color concentrate (gallons) during the data year.

(20) The operator of a sulfuric acid regeneration facility must report the production of sulfuric acid produced (short tons).

(21) The operator of a borate manufacturing facility must report the quantity of borate produced in the data year in boric oxide equivalent (short tons).

(22) The operator of a facility that produces supplementary cementitious materials (SCM) must report the annual total quantity of SCMs produced (short tons) and the annual quantity of SCMs delivered to cement or

concrete plants to make cement (short tons) disaggregated by SCM type and customer.

(23) The operator of a facility that manufactures light-duty vehicles must report the annual number of light-duty vehicles produced in the data year.

Table 2-3: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	**Default High Heat Value**	**Default CO_2 Emission Factor**
	MMBtu/gallon	*kg CO_2 /MMBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.0~~9~~69	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline (finished)	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

[1] Commercially sold as "propane" including grades such as HD5.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95116. Glass Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart N of 40 CFR Part 98 (§§98.140 to 98.148) in reporting stationary combustion and process emissions and related data from glass production to CARB, except as otherwise provided in this section.

* * * *

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95117. Lime Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart S of 40 CFR Part 98 (§§98.190 to 98.198) in reporting stationary combustion and process emissions and related data from lime manufacturing to CARB, except as otherwise provided in this section.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95118. Nitric Acid Production

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart V of 40 CFR Part 98 (§§98.220 to 98.228) in reporting stationary combustion and process emissions and related data from nitric acid production to CARB, except as otherwise provided in this section.

* * * *

(d) *Additional Product Data*. The operator of a nitric acid manufacturing facility must report the annual production of nitric acid (HNO_3) ~~and calcium ammonium nitrate solution (short tons). Reporting the annual production of calcium ammonium nitrate solution is no longer required beginning in 2019 for reporting of 2018 data.~~solution (short tons).

(e) Site-Specific Emission Factor and Production Data. The operator of a nitric acid manufacturing facility that determines N_2O process emissions per the requirements 40 CFR §98.223(a)(1) that is subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, must conduct performance tests for each nitric acid train as specified in 40 CFR §98.223(b)(1) at least twice per calendar year, with at least four months between testing events. The results of each testing event for each nitric acid train shall be arithmetically averaged (non-weighted) to compute an annual average site-specific N_2O emission factor for each nitric acid train, and applied to equation V-1 of 40 CFR §98.223(c) to compute annual N_2O process emissions. The operator of a nitric acid manufacturing facility that determines N_2O process emissions per the requirements 40 CFR §98.223(a)(1), but is not subject to a compliance obligation under the Cap-and-~~Trade~~Invest Regulation, must conduct performance tests for each nitric acid train as specified in 40 CFR §98.223(b)(1) at least once per calendar year.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95119. Pulp and Paper Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA of 40 CFR Part 98 (40 CFR §§98.270 to 98.278) in reporting stationary combustion and process emissions and related data from pulp and paper manufacturing to CARB, except as otherwise provided in this section.

* * * *

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95120. Iron and Steel Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Q of 40 CFR Part 98 (40 CFR §§98.170 to 98.188) in reporting stationary combustion and process emissions and related data from iron and steel production to CARB, except as otherwise provided in this section.

* * * *

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95121. Suppliers of Transportation Fuels

Any position holder, refiner, ~~or~~ enterer, or ~~biofuel~~biomass-derived fuel production facility who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting emissions and related data to CARB, except as otherwise provided in this section.

(a) *GHGs to Report*.

(1) In addition to the CO_2 emissions specified under 40 CFR §98.392, all refiners that produce fossil or biomass-derived liquefied petroleum gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual ~~quantity of~~quantities of fossil and biomass-derived liquefied petroleum gas sold or delivered, except for fuel for which a final destination outside California can be demonstrated.

(2) Refiners, position holders of fossil ~~fuels~~ and biomass-derived fuels that supply fuel at California terminal racks, ~~and~~ enterers that import ~~fossil~~ transportation fuels for distribution outside the bulk transfer/terminal system, and biomass-derived fuel production facilities that produce and deliver biomass-derived fuels outside the bulk transfer/terminal system in California must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2-5~~Table 2-4~~ of this section. However, emissions reporting is not required for fuel ~~in~~for which a final destination outside California~~, where~~ or a use in exclusively aviation or marine applications can be demonstrated, or for ~~fossil~~ transportation fuels that can be demonstrated to have been previously delivered by a position holder or refiner out of an upstream California terminal or refinery rack prior to delivery out of a second terminal rack. The volume of all Blendstocks, Distillate Fuel Oils, and biomass-derived fuels that are excluded from emissions reporting based on the criteria in this paragraph must be reported pursuant to the requirements in section 95121(d)(9). No fuel shall be reported as finished fuel. Fuels must be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2-~~4~~5 of this section. For purposes of this article, CARBOB blendstocks are reported as RBOB blendstocks.

(b) *Calculating GHG emissions*.

(1) Refiners, position holders at California terminals, ~~and~~ enterers that import ~~fossil~~ transportation fuels for distribution outside the bulk transfer system,

and biomass-derived fuel production facilities that produce and deliver biomass-derived fuels outside the bulk transfer/terminal system in California must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel. Emissions must be based on the quantity of fuel removed from the rack (for refiners and position holders), fuel imported ~~for distribution outside~~or produced that was not delivered to the bulk transfer/terminal system (by enterers and biomass-derived fuel production facilities), and fuel sold to unlicensed entities as specified in section 95121(d)(3) (by refiners). For fuels that are blended, emissions must be reported for each individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2-5 of this section separately, and not as motor gasoline (finished), biofuel blends, or other similar finished fuel. ~~Emissions from denatured fuel ethanol must be calculated as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.~~Fuel ethanol is assumed to be a blend of pure ethanol and denaturant volumes. The denaturant must be reported as fossil pentanes plus, or, if the denaturant can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived pentanes plus. The quantity of denaturant reported must be based on a measured value, if it is known and can be demonstrated, or calculated as 2 percent of the total fuel ethanol volume. The remaining fuel ethanol volume that is not reported as denaturant must be reported as pure ethanol. Transportation fuel supplied as E85 is assumed to be a blend of RBOB and pure ethanol. The hydrocarbon content in E85 must be reported as fossil RBOB of an appropriate seasonal blend and grade, or, if the hydrocarbon content can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived RBOB of an appropriate seasonal blend and grade, and the remaining E85 volume must be reported as pure ethanol. Emission factors must be taken from column C of 40 CFR 98 Table MM-1 or MM-2 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1), except that the emission factor for renewable diesel is equ~~ivalent~~ to the emission factor for Distillate No. ~~2.~~2, the emission factors for biomass-derived Blendstocks are equal to those of their fossil equivalents, and the emission factors for biomass-derived LPG components are equal to those of their fossil equivalents. If a position holder ~~in diesel or biodiesel~~of any fuel regulated under section 95121 does not have sealed or financial transaction meters at the rack, and the position holder is the sole position holder at the terminal, the position holder must calculate emissions based on the delivering entity's invoiced volume of fuel or a meter that meets the requirements of section 95103(k) either at the rack or at a point prior to the fuel going into the terminal storage tanks.

(2) Refiners that produce fossil or biomass-derived liquefied petroleum gas must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel supplied. For calculating the emissions from fossil or biomass-derived liquefied petroleum gas, the emissions from the individual components must be summed. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(3) Refiners, position holders at California terminals, ~~and~~ enterers, and biomass-derived fuel production facilities identified in this section must estimate and report CH_4 and N_2O emissions using Equation C–8 and Table C-2 as described in 40 CFR §98.33(c)(1), except that the emission factors in Table 2-4 of this section will be used for each fuel required to be reported in section 95121(a)(2) above.

Table 2-4. Transportation Fuel CH_4 and N_2O emission factors

Fuel	**CH_4 (g/bbl)**	**N_2O (g/bbl)**
Blendstock (Fossil and Biomass-Derived)	20	20
Distillate	2	1
Ethanol	37	27
Biodiesel and Renewable Diesel	2	1

(4) All fuel suppliers in this section must estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas as specified in the "global warming potential" definition of this article.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements*. For the emissions calculation method chosen under section 95121(b), the operator must meet all the monitoring and

QA/QC requirements as specified in 40 CFR §98.394, and the requirements of 40 CFR §98.3(i) as further specified in section 95103 of this article and below.

(1) Position holders are exempt from 40 CFR §98.3(i) calibration requirements except when the position holder and entity receiving the fuel have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR §98.3(i) calibration requirements apply, unless:

(A) The fuel supplier does not operate the fuel billing meter;

(B) The fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or

(C) The fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR §98.394(a)(1)(iii), for fuels that are liquid at 60 degrees Fahrenheit and one standard atmosphere, the volume reported must be temperature- and pressure-adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60 degrees Fahrenheit.

(d) *Data Reporting Requirements*. In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table~~-~~ 2-5 of this section, that is delivered across the rack in California, except for fuel for which a final destination outside California~~, where~~ or use in exclusively aviation or marine applications can be demonstrated, or for ~~fossil~~ transportation fuels that can be demonstrated to have been previously delivered by a position holder or refiner out of an upstream California terminal or refinery rack prior to delivery out of a second terminal rack. ~~Denatured fuel ethanol will be reported with the entire volume as 100 percent ethanol only. The volume of denaturant~~ Fuel ethanol is assumed to be ~~zero~~ a blend of pure ethanol and ~~is not required~~denaturant volumes. The denaturant must be reported as fossil pentanes plus or, if the denaturant can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived pentanes plus. The quantity of denaturant reported~~.~~ must be based on a measured value, if it is known and can be demonstrated, or

calculated as 2 percent of the total fuel ethanol volume. The remaining fuel ethanol volume that is not reported as denaturant must be reported as pure ethanol. Transportation fuel supplied as E85 is assumed to be a blend of RBOB and pure ethanol. The hydrocarbon content in E85 must be reported as fossil RBOB of an appropriate seasonal blend and grade, or, if the hydrocarbon content can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived RBOB of an appropriate seasonal blend and grade, and the remaining E85 volume must be reported as pure ethanol.

(2) California position holders that are also terminal operators and refiners must report the annual quantity in barrels delivered across the rack of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table~~-~~ 2-~~4~~5 of this section, except for fuel for which a final destination outside California~~, where a~~ or use in exclusively aviation or marine applications can be demonstrated, or for~~ fossil~~ transportation fuels that can be demonstrated to have been previously delivered by a position holder or refiner out of an upstream California terminal or refinery rack prior to delivery out of a second terminal rack. ~~Denatured fuel ethanol will be reported with the entire volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If there is only a single position holder at the terminal, and only diesel or biodiesel is being dispensed at the rack then the position holder must report the annual quantity of fuel using a meter meeting the requirements of section 95103(k) or billing invoices from the entity delivering fuel to the terminal.~~Fuel ethanol is assumed to be a blend of pure ethanol and denaturant volumes. The denaturant must be reported as fossil pentanes plus or, if the denaturant can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived pentanes plus. The quantity of denaturant reported must be based on a measured value, if it is known and can be demonstrated, or it must be calculated as 2 percent of the total fuel ethanol volume. The remaining fuel ethanol volume that is not reported as denaturant must be reported as pure ethanol. Transportation fuel supplied as E85 is assumed to be a blend of RBOB and pure ethanol. The hydrocarbon content in E85 must be reported as fossil RBOB of an appropriate seasonal blend and grade, or, if the hydrocarbon content can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived RBOB of an appropriate seasonal blend and grade, and the remaining E85 volume must be reported as pure ethanol.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California ~~Board of Equalization~~Department of Tax and

Fee Administration as a fuel supplier must report the annual quantity in barrels delivered of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2-5 of this section, except for fuel for which a final destination outside California or where a use in exclusively aviation or marine applications can be demonstrated. ~~Denatured fuel ethanol will be reported with the entire volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported~~Fuel ethanol is assumed to be a blend of pure ethanol and denaturant volumes. The denaturant must be reported as fossil pentanes plus or, if the denaturant can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived pentanes plus. The quantity of denaturant reported must be based on a measured value, if it is known and can be demonstrated, or it must be calculated as 2 percent of the total fuel ethanol volume. The remaining fuel ethanol volume that is not reported as denaturant must be reported as pure ethanol. Transportation fuel supplied as E85 is assumed to be a blend of RBOB and pure ethanol. The hydrocarbon content in E85 must be reported as fossil RBOB of an appropriate seasonal blend and grade, or, if the hydrocarbon content can be demonstrated to be biomass-derived, it may be reported as biomass-derived RBOB of an appropriate seasonal blend and grade, and the remaining E85 volume must be reported as pure ethanol.

(4) Enterers and biomass-derived fuel production facilities delivering ~~fossil~~ transportation fuels for distribution outside the bulk transfer/terminal system must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2-5 of this section ~~that is imported as a blended component of a finished transportation fuel~~, except for fuel for which a final destination outside California or where a use in exclusively aviation or marine applications can be demonstrated. ~~The denatured fuel ethanol component of a finished transportation fuel must be reported with the entire denatured ethanol volume as 100 percent ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.~~Fuel ethanol is assumed to be a blend of pure ethanol and denaturant volumes. The denaturant must be reported as fossil pentanes plus or, if the denaturant can be demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived pentanes plus. The quantity of denaturant reported must be based on a measured value, if it is known and can be demonstrated, or it must be calculated as 2 percent of the total fuel ethanol volume. Transportation fuel supplied as E85 is assumed to be a blend of RBOB and pure ethanol. The hydrocarbon content in E85 must be reported as fossil RBOB of an appropriate seasonal blend and grade, or, if the hydrocarbon content can be

demonstrated to be biomass-derived, the supplier may elect to report it as biomass-derived RBOB of an appropriate seasonal blend and grade, and the remaining E85 volume must be reported as pure ethanol. Biodiesel or renewable diesel blends containing no more than one percent petroleum diesel by volume are considered to be 100 percent biodiesel or renewable diesel. ~~Biomass-derived fuels are not reported by enterers unless they are a blended component of an imported finished transportation fuel.~~

(5) In addition to the information required in 40 CFR §98.396, refiners must also report the volumes of fossil and biomass-derived liquefied petroleum gas in barrels supplied in California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for fuel for which a final destination outside California can be demonstrated.

(6) All fuel suppliers identified in this section must also report CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O and CO_2e emissions in metric tons that would result from the complete combustion or oxidation of each ~~petroleum~~ fuel identified in ~~95121(a)(~~Table 2~~), liquefied petroleum gas, or biomass-derived fuel reported in this section~~-5, calculated according to section 95121(b).

(7) All fuel suppliers identified in this section, except for refiners that report pursuant to section 95113(m), must report the total quantity of CARBOB, California Gasoline, California diesel fuel, and biodiesel and/or renewable diesel that was imported from outside of California for use in California. In addition, for CARBOB imports, the designated percentage of oxygenate must be reported.

(8) Fuel suppliers identified in this section, except for refiners that report pursuant to section 95113(m), must report the total quantity of biodiesel and/or renewable diesel blended into California diesel for use in California. However, if the resulting blended product is not marketed as "California diesel fuel" as defined in section 95202(a)(22) of the AB 32 Cost of Implementation Fee Regulation, the fuel supplier is not required to report this quantity.

(9) Fuel suppliers identified in this section must report the total quantity in barrels of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2-~~4~~5 of this section that is excluded from emissions reporting ~~due to demonstration of~~by reason for its exclusion: a final destination outside California ~~or~~, exclusive use in ~~exclusively~~ aviation ~~or~~applications, exclusive use in marine applications, or ~~demonstration that the fuel was previously delivered~~previous delivery by a position holder or

refiner out of an upstream California terminal or refinery rack prior to delivery out of a second terminal rack.

(e) *Procedures for Missing Data*. For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR §98.395. The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

Table 2-5
Blendstocks, Distillate Fuel Oils, and Biomass-Derived Fuels
Subject to Reporting under section 95121

~~CBOB—Summer~~Fossil and Biomass-Derived RBOB (CARBOB)—Summer
Regular
Midgrade
Premium
~~CBOB—Winter~~
~~Regular~~
~~Midgrade~~
~~Premium~~
~~RBOB (CARBOB)—Summer~~
~~Regular~~
~~Midgrade~~
~~Premium~~

Fossil and Biomass-Derived RBOB (CARBOB)—Winter
Regular
Midgrade
Premium
Distillate Fuel Oils
Distillate No. 1
Distillate No. 2
Fossil and Biomass-Derived Liquefied Petroleum Gas (LPG)
Ethane
Ethylene
Propane
Propylene
Butane
Butylene
Isobutane
Isobutylene
Pentanes Plus
Other Biomass-Derived Fuel
Ethanol (100%)
Biodiesel (≥99%, methyl ester)
Renewable Diesel (≥99%)
Rendered Animal Fat
Vegetable Oil

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, Liquefied Petroleum Gas, Compressed Natural Gas, and Liquefied Natural Gas

Any supplier of natural gas or natural gas liquids, or their biomass-derived equivalents, who is required to report under section 95101 must comply with Subpart NN of 40 CFR Part 98 (§§98.400 to 98.408) in reporting emissions and related data to CARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.402(a), natural gas liquid fractionators must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of fossil and biomass-derived liquefied petroleum gas sold or delivered to others that was produced on-site, except for products for which a final destination outside California can be demonstrated.

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies and intrastate pipelines delivering gas to California end-users must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of the annual volume of natural gas delivered to all entities on their distribution systems in California.

(3) The importer of fossil or biomass-derived liquefied petroleum gas, compressed natural gas, or liquefied natural gas into California must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantit~~y~~ies of ~~liquefied petroleum gas,~~fossil and biomass-derived compressed natural gas~~,~~ and liquefied natural gas imported into the state, except for products for which a final destination outside California or exclusive use in ocean-going vessels can be demonstrated.

(4) Operators of facilities that make liquefied natural gas products or compressed natural gas products by liquefying or compressing natural gas received from interstate pipelines must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of all liquefied natural gas sold or delivered to others, except for product for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions*.

(1) Natural gas liquid fractionators must use calculation methodology 2 as specified in 40 CFR §98.403(a)(2) to estimate the CO_2 emissions that would result from the complete combustion of all fossil and biomass-derived natural gas liquid products supplied except that Table MM-1 must be used in place of Table NN-2. For calculating the emissions from fossil or biomass-derived liquefied petroleum gas, the fractionators must sum the emissions from the individual constituents of liquefied petroleum gas sold or delivered to others that was produced on-site, except for products for which a final destination outside of California can be demonstrated. CO_2 emissions from biomass-derived products must be calculated using the same methods and emission factors as their fossil equivalents.

(2) For the calculation of CO_{2i} in section 95122(b)(6), local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(3) For the calculation of CO_{2j} in section~~-~~ 95122(b)(6), public utility gas corporations and publicly owned natural gas utilities must estimate annual CO_2 emissions from instate receipts of pipeline quality natural gas from other public utility gas corporations, interstate pipelines and intrastate transmission pipelines, and annual CO_2 emissions from all natural gas redelivered to ~~other public utility gas corporations or~~ interstate pipelines. Annual CO_2 emissions from redelivered natural gas to intrastate pipelines, public utility gas corporations, or publicly owned natural gas utilities must be estimated only if emissions from the redelivered natural gas equals or exceeds 25,000 MT CO_2e calculated according to subparagraph (2) above. Emissions are calculated according to Equation NN-3 of 40 CFR §98.403(b)(1) except that CO_{2j} will be the product of $MMBtu_{Total}$ and the default emission factor from Table NN-1 or the product of $MMBtu_{Total}$ and the reporter specific emission factor. $MMBtu_{Total}$ must be calculated as follows:

$$\mathrm{MMBtu_{Total}} = \mathrm{MMBtu_{redelivery}} - \mathrm{MMBtu_{receipts}}$$

Where

$MMBtu_{Total}$ =	Total annual MMBtu used in equation NN-3
$MMBtu_{redelivery}$ =	Total annual MMBtu of natural gas delivered to other companies as specified above
$MMBtu_{receipts}$ =	Total annual MMBtu of natural gas received from other companies as specified above

(4) For the calculation of CO_{2l} in section 95122(b)(6), emissions from receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to Equation NN-5 of 40 CFR §98.403(b)(3) except that CO_{2l} will be calculated as the product of the net annual MMBtu and a default emission factor from Table NN-1 or the product of the net annual MMBtu and a reporter specific emission factor.

(5) Determination of pipeline quality natural gas is based on the annual weighted average HHV, determined according to Equation C-2b of 40 CFR §98.33(a)(2)(ii)(A), for natural gas from a single city gate, storage

facility, or connection with an in-state producer, interstate pipeline, intrastate pipeline or local distribution company. If the HHV is outside the range of pipeline quality natural gas, emissions will be calculated using the appropriate subparagraph of section 95122(a) replacing the default emission factor with either a reporter specific emission factor as calculated in 40 CFR §98.404(b)(2) or one determined as follows:

(A) For natural gas or biomethane with an annual weighted HHV below 970 Btu/scf and not exceeding 3 percent of total emissions estimated under this section, the local distribution company may use the reporter specific weighted yearly average higher heating value and the default emission factor or an emission factor as determined in 40 CFR §98.404(c)(3). If emissions exceed 3 percent of the total, then the Tier 3 method specified in 40 CFR §98.33(a)(3)(iii) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is below 970 Btu/scf.

(B) For natural gas or biomethane with an annual HHV above 1100 Btu/scf and not exceeding 3 percent of total emissions estimated under this section, the local distribution company must use the reporter specific weighted yearly average higher heating value and a default emission factor of 54.67 kg CO_2/MMBtu or an emission factor as determined in 40 CFR §98.404(c)(3). If emissions exceed 3 percent of the total, then the Tier 3 method specified in 40 CFR §98.33(a)(3)(iii) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is above 1100 Btu/scf.

(6) When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2l}$$

Where:

CO_2 = Total emissions.

CO_{2l} = Emissions from natural gas received at the state border or city gate, calculated pursuant to section 95122~~95122(~~(b)(2).

CO_{2j} = Emissions from natural gas received for redistribution to or received from other natural gas transmission companies, calculated pursuant to section 95122~~95122(~~(b)(3).

CO_{2l} = Emissions from storage and direct deliveries from producers calculated pursuant to section 95122(b)(4).

(7) Natural gas liquid fractionators and local distribution companies must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C 2 as described in 40 CFR §98.33(c)(1) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR §98.406 and this section. Local distribution companies must use the annual MMBtu determined in paragraphs (2)-(4) above in place of the product of the Fuel and HHV in equation C-8 when calculating emissions. CH_4 and N_2O emissions from biomass-derived products must be calculated using the same methods and emission factors as their fossil equivalents.

(8) Local distribution companies must separately and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in the equation in section 95122(b)(6) with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e. CO_2 emissions from biomass-derived fuel are based on the fuel the LDC has contractually purchased on behalf of and delivered to end users. LDCs can elect to report biomethane directly purchased by an end user and delivered by the LDC if the LDC can provide the information required by section 95103(j)(3), and can provide access during verification to the documentation necessary to identify the biomethane as exempt or non-exempt pursuant to section 95103(j). Emissions from contractually purchased biomethane are calculated using the methods for natural gas required by this section, including the use of the emission factor for natural gas found in 40 CFR§98.408, table NN-1. Biomass-derived fuels directly purchased by end users and delivered by the LDC must be reported as natural gas by the LDC, unless the LDC has elected to report the delivery as biomethane and can provide the necessary documentation during verification to determine exemption status as stated above.

(9) The importer of liquefied petroleum gas into California must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions except that ~~for liquefied petroleum gas~~ table-_MM-1 of 40 CFR Part 98 must be used in place of Table-_NN-2. For liquefied petroleum gas, the importer must either sum the emissions from the individual components of the gas to calculate the total emissions~~. If the composition is not supplied by the producer, the importer must~~ or use the default value for liquefied petroleum gas presented in Table-_C-1 of 40

CFR Part 98. The importer of fossil or biomass-derived compressed natural gas or liquefied natural gas into California must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of the imported compressed natural gas and liquefied natural gas. CO_2 emissions from biomass-derived products must be calculated using the same methods and emission factors as their fossil equivalents.

(10) The importer of fossil or biomass-derived liquefied petroleum gas, compressed natural gas, or liquefied natural gas into California must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1). CH_4 and N_2O emissions from biomass-derived products must be calculated using the same methods and emission factors as their fossil equivalents.

(11) Operators of facilities that make liquefied natural gas products or compressed natural gas products as described in section 95122(a)(4) must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of the liquefied natural gas sold or delivered in California.

(12) Operators of facilities that make liquefied natural gas products or compressed natural gas products as described in section 95122(a)(4) must estimate and report CH_4 and N_2O emissions based on the MMBtu of liquefied natural gas sold or delivered using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(13) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from as specified in the “global warming potential” definition of this article.

n= Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements*. For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC requirements specified in 40 CFR §98.404, except as modified in sections 95103, 95115, and below.

(1) All ~~natural gas suppliers~~LDCs and intrastate pipelines must measure required values at least monthly.

(2) All ~~natural gas suppliers~~LDCs and intrastate pipelines must determine reporter specific HHV at least monthly, or if the local distribution company or intrastate pipeline does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.

(3) All natural gas liquid fractionators must sample for composition at least monthly.

(4) All ~~importers~~suppliers of imported liquefied petroleum gas ~~into California~~who choose to calculate total fossil and biomass-derived LPG emissions by summing emissions from individual components must record composition~~, if provided by the supplier,~~ and quantity in barrels, corrected to 60 degrees Fahrenheit, for each shipment ~~received.~~of imported fossil or biomass-derived LPG for which emissions are calculated by component under section 95122(b)(9).

(d) *Data Reporting Requirements*.

(1) For the emissions calculation method selected under section 95122(b), natural gas liquid fractionators must report, in addition to the data required by 40 CFR §98.406(a), the annual ~~volume of~~volumes of fossil and biomass-derived liquefied petroleum gas, corrected to 60 degrees Fahrenheit, that ~~was~~were produced on-site and sold or delivered to others, except for products for which a final destination outside California can be demonstrated. Natural gas liquid fractionators must report the annual ~~quantity of~~quantities of fossil and biomass-derived liquefied petroleum gas produced and sold or delivered to others as the total volume in barrels as well as the volume of the individual components for all components listed in 40 CFR 98 Table MM-1. Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the ~~volume of~~volumes of fossil and biomass-derived liquefied petroleum gas reported in 40 CFR §98.406(a)(5) as modified by this regulation, calculated in accordance with section 95122(b).

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

(A) Publicly-owned natural gas utilities that report in-state receipts at the city gate under 40 CFR §98.406(b)(1) must also identify each delivering entity by name and report the annual energy of natural gas received in MMBtu.

(B) Local distribution companies that report under 40 CFR §98.406(b)(1) through (b)(7) must also report the annual energy of natural gas in MMBtu associated with the volumes.

(C) In addition to the requirements in 40 CFR §98.406(b)(8), local distribution companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR §98.403(a) and (b)(1) through (b)(3) as modified by section 95122(b).

(D) In lieu of reporting the information specified in 40 CFR §98.406(b)(6), local distribution companies and intrastate pipelines that deliver natural gas to downstream gas pipelines and other local distribution companies, must report the annual energy in MMBtu, and the information required in 40 CFR §98.406(b)(12). These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies ~~and intrastate pipelines~~ must report the annual energy in MMBtu, customer information required in 40 CFR §98.406(b)(12), and ARB ID number if available for all end-users registering supply equal to or greater than 188,500 ~~MMBtu during the calendar year.~~ MMBtu during the calendar year. Intrastate pipelines must report the annual energy in MMBtu, customer information required in 40 CFR §98.406(b)(12), and ARB ID number if available, for all deliveries to other entities, regardless of the supplied amount. In addition to reporting the information specified in 40 CFR §98.406(b)(13), local distribution companies and intrastate pipelines that deliver to end users must report the annual energy in MMBtu delivered to the following end-use categories: residential consumers; commercial consumers; industrial consumers; electricity generating facilities; and other end-users not identified as residential, commercial, industrial, or electricity generating facilities. Local distribution companies must also report the total energy in MMBtu delivered to all California end-users.

(F) Local distribution companies that report under 40 CFR §98.406(b)(9) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with section 95122(b).

(3) In addition to the information required in 40 CFR §98.3(c), the operator of an interstate pipeline, which is not a local distribution company, must report the customer name, address, and ARB ID along with the annual energy of natural gas in MMBtu for natural gas delivered to each customer, including themselves.

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline that delivers natural gas directly to end users must follow the reporting requirements described under Subpart NN of 40 CFR Part 98 and this section for local distribution companies. In lieu of the city gate information specified by section 95122(b)(2), the intrastate pipeline operator must report the summed energy (MMBtu) of natural gas delivered to each entity receiving gas from the intrastate pipeline for purposes of estimating the CO_{2i} parameter as specified in section 95122(b)(6). Additionally, intrastate pipeline operators are required to estimate a value for CO_{2j} as specified in section 95122(b)(3) for natural gas delivered to local distribution companies, interstate pipelines, and other intrastate pipelines. The CO_{2l} parameter as specified in section 95122(b)(4) must have a value of 0 for calculating emissions as required by section 95122(b)(6).

(5) In addition to the information required in 40 CFR §98.3(c), the importer of liquefied petroleum gas ~~into California~~ must report the annual quantit~~y~~ies of fossil and biomass-derived imported liquefied petroleum gas ~~imported~~ as the total volume in barrels ~~as well as~~or the volume of its individual components in barrels, for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b). All importers of fossil or biomass-derived compressed or liquefied natural gas into California and liquefied natural gas production facilities as described in section 95122(a)(4) must report the annual quantities imported, and delivered or sold, respectively, in MMBtu, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons

separately for fossil and biomass-derived compressed natural gas and liquefied natural gas using the calculation methods in section 95122(b).

(6) In addition to the information required in 40 CFR §98.3(c), all local distribution companies that report biomass emissions from biomethane fuel that was contractually purchased by the LDC on behalf of and delivered to end users, and all liquefied natural gas production facilities reporting biomass emission from biomethane, must report, for each contracted delivery, the information specified in section 95103(j)(3).

(7) All operators of facilities that make liquefied natural gas products as described in section 95122(a)(4) must report end-user information for deliveries of liquefied natural gas to industrial facilities and natural gas utility customers, including customer name, address, and the annual quantity of liquefied natural gas delivered to each customer in MMBtu.

(8) All natural gas liquid fractionators~~ and importers~~, suppliers of imported liquefied petroleum gas (fossil or biomass-derived), and importers of fossil or biomass-derived compressed natural gas or liquefied natural gas identified in this section must report the total quantity in barrels of ~~liquefied petroleum gas~~ each fuel that is excluded from emissions reporting ~~due to demonstration of~~by reason for its exclusion (i.e., a final destination outside California~~.~~ or exclusive use in ocean-going vessels).

(e) *Procedures for estimating missing data*. Suppliers must follow the missing data procedures specified in 40 CFR §98.405. The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95123. Suppliers of Carbon Dioxide.

Any supplier of carbon dioxide who is required to report under section 95101 of this article must comply with Subpart PP of 40 CFR Part 98 (§§98.420 to 98.428) in reporting to CARB, except as otherwise provided in this section.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95124. Lead Production.

The operator of a facility who is required to report under section 95101(a)(1)(B)(8.) of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart R of 40 CFR Part 98 (§§98.180 to 98.188) in reporting stationary combustion and process emissions and related data from lead production to CARB, except as otherwise provided in this section.

* * * *

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95125. Geologic Sequestration

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must report emissions data from geologic sequestration to CARB in accordance with Subpart RR of 40 CFR § 98.440 to 98.449 (7-1-23 Edition), which is incorporated by reference herein.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95126. Importers of Cement

Any importer of cement who is required to report under section 95101(a)(1)(H) of this article must comply with this section's requirements beginning in data year 2027. Cement importers must report the information required by this section associated with any cement or clinker that is imported into California. Cement importers must also report the information required by this section associated with any cement or clinker that is imported into California and then exported for use outside of California.

(a) *Greenhouse Gas Emissions Reporting.* Cement importers must report the annual GHG emissions (MT CO_2e) associated with imported cement and clinker from each individual manufacturing facility, as well as the total annual GHG emissions associated with imported cement and clinker from all manufacturing facilities.

(b) *Greenhouse Gas Emissions Calculations*.

(1) GHG Emissions by Manufacturing Facility. Cement importers must calculate the annual GHG emissions (MT CO_2e) associated with imported cement and clinker for each manufacturing facility as:

$$CO_2e_{i,a} = P_{i,a} * CEI_a$$

Where:

$CO_2e_{i,a}$ = CO_2 equivalent mass emissions associated with imported cement and clinker *i* from manufacturing facility *a* (MT CO_2e)

$P_{i,a}$ = Annual amount of imported cement and clinker *i* produced at cement manufacturing facility *a* (short tons)

CEI_a = Annual Cement GHG Emissions Intensity for cement manufacturing facility *a*, calculated pursuant to section 95126(b)(2)(A) (MT CO_2e/short ton)

(2) Annual Cement GHG Emissions Intensity.

(A) If the annual GHG emissions and annual cement production for a cement manufacturing facility is known, cement importers must calculate the annual cement GHG emissions intensity (CEI) for the facility as:

$$CEI_a = \frac{CO_2e_a}{P_a}$$

Where:

CEI_a = Annual cement GHG emissions intensity for manufacturing facility *a* (MT CO_2e/short ton)

CO_2e_a = Total annual GHG emissions from cement production at manufacturing facility *a* (MT CO_2e)

P_a = The sum of clinker produced and limestone, gypsum, other mineral additives, and SCMs consumed to make cement at manufacturing facility *a* (short tons)

(B) If the annual GHG emissions and annual cement production for a cement manufacturing facility are not known, CEI_a = 0.758 MT CO_2e/short ton of cement.

(3) Total GHG Emissions. The cement importer must calculate the total annual emissions from imported cement and clinker as:

$$CO_2e_i = \sum_{a=1}^{n} CO_2e_{i,a}$$

Where:

CO_2e_i = Total annual CO_2 equivalent mass emissions from imported cement and clinker *i* (MT CO_2e)

$CO_2e_{i,a}$ = CO_2 equivalent mass emissions associated with imported cement and clinker *i* from manufacturing facility *a* (MT CO_2e)

n = Total number of cement manufacturing facilities at which imported cement or clinker was produced

(c) *Additional Data Reporting Requirements*.

(1) Cement importers must report the short tons of cement or clinker imported from each manufacturing facility based on the best available data. When known, importers must also report the mass (short tons) of each component in the cement imported from each manufacturing facility. Component materials include clinker, gypsum, limestone, other mineral additives, and specific types of SCMs.

(2) For each CEI_a calculated pursuant to section 95126(b)(2)(A), cement importers must provide the data sources and methods used to obtain the facility's annual GHG emissions from cement production and the masses of clinker produced and limestone, gypsum, other mineral additives, and SCMs consumed.

(3) Cement importers must report the annual amount of electricity used to produce cement in MWh and the associated average annual electric grid emission factor in $MTCO_2e$ per MWh using the best available information.

(4) If known, the cement importer must report the name and address of the facility where the imported cement or clinker was produced.

(d) *Verification exemption*. Data reported under this section is exempt from the third-party verification requirements of this article.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95127. Importers of Hydrogen and Producers of Hydrogen Utilizing Electricity

Any importer of hydrogen or operator of a facility that is required to report under section 95101(a)(1)(I) of this article must comply with requirements in this section for reporting non-covered emissions and other data from hydrogen production and import of hydrogen. The requirements in this section do not apply to the operator of a facility that is required to report data from hydrogen production pursuant to section

95101(a)(1)(B)(3) of this article. GHG emissions data reported under this section are not considered covered emissions.

(a) Operators of in-state facilities that produce hydrogen utilizing electricity must comply with the following requirements.

(1) Greenhouse Gas Emissions. The operator must report GHG emissions from electricity consumed for hydrogen production in metric tons of carbon dioxide equivalent (MT CO_2e):

(A) GHG Emissions from Unknown Generation Sources. For electricity from unknown generation sources, the operator must report the total GHG emissions as calculated in section 95127(a)(3) of this article.

(B) GHG Emissions from Known Generation Sources. For electricity from known generation sources, the operator must report the total associated GHG emissions for each fuel type or prime mover and the total GHG emissions for all fuel types and prime movers, as calculated in section 95127(a)(4) of this article.

(C) Total Annual GHG Emissions. The operator must report total annual GHG emissions as the sum of emissions from unknown and known generation sources, as calculated in section 95127(a)(5).

(2) Consumed Electricity for Hydrogen Production. The operator must report the electricity consumed by the facility to produce hydrogen in megawatt hours (MWh).

(A) Electricity from Unknown Generation Sources. The operator must report in MWh the total amount of electricity from unknown sources consumed at the facility for hydrogen production.

(B) Electricity from Known Generation Sources. The operator must report in MWh the amount of electricity from known generation sources consumed at the facility for hydrogen production for each fuel type or prime mover, as applicable.

(C) Total Annual Electricity Consumed. The operator must report the total annual electricity consumed at the facility for hydrogen production as the sum of electricity from unknown and known generation sources in MWh.

If the facility is not connected to the electricity grid, the operator must report electricity consumed from the source(s) providing electricity for hydrogen production.

(3) Calculating GHG Emissions from Unknown Generation Sources. For electricity from unknown generation sources, the operator must calculate the annual CO_2 equivalent mass emissions from electricity consumed to produce hydrogen using the following equation:

$$CO_2e_{un} = MWh_{un}\ x\ EF_{un}\ x\ TL$$

Where:

CO_2e_{un} = Annual CO_2 equivalent mass emissions from electricity procured from unknown sources (MT of CO_2e) consumed to produce hydrogen.

MWh_{un} = Megawatt-hours of electricity from unknown sources consumed to produce hydrogen.

EF_{un} = Default emission factor for marginal electricity procured from the grid.

EF_{un} = 0.428 MT of CO_2e/MWh

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses between the power source and the hydrogen generation facility.

(4) Calculating GHG Emissions from Known Generation Sources. For electricity from known generation sources contracted and delivered to the hydrogen production facility, the operator must calculate emissions from electricity consumed to produce hydrogen using the following equation:

$$CO_2e_k = \sum_f (MWh_{k,f}\ x\ EF_f\ \ x\ TL\ )$$

Where:

CO_2e_k = Total annual CO_2 equivalent mass emissions from known generation source electricity consumption (MT CO_2e).

$MWh_{k,f}$ = Megawatt-hours of electricity contracted and delivered from each known source for a specific fuel type or prime mover *f*. Electricity contracted and delivered must be generated in the same calendar month that the hydrogen production facility utilizes that electricity to produce hydrogen (monthly matching).

EF_f = Fleet emission factor for a specific fuel type or prime mover *f*, calculated by the Executive Officer as described in section 95111(b)(2) of this article. The emission factor is based on data from the year prior to the current data year.

EF_f = For electricity procured from an Asset Controlling Supplier (ACS), the emission factor equals the ACS system emission factor published on the CARB website (MT CO_2e/MWh). The ACS-specific system emission factor is calculated annually by CARB based on data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification.

TL = Transmission loss correction factor.

TL = 1.00 when the source is co-located with the hydrogen production facility, or the facility is not grid-connected.

TL = 1.02 to account for transmission losses between the power source and the hydrogen production facility when the source is not co-located with the hydrogen production facility.

(5) Calculating Total Annual GHG Emissions. The operator must calculate the annual CO_2 equivalent mass emissions from all electricity consumed to produce hydrogen using the following equation:

$$CO_2e = CO_2e_{un} + CO_2e_k$$

Where:

CO_2e = Total annual CO_2 equivalent mass emissions from electricity procured from all sources (MT of CO_2e) consumed to produce hydrogen.

CO_2e_{un} = Annual CO_2 equivalent mass emissions from electricity procured from unknown sources (MT of CO_2e) consumed to produce hydrogen as calculated in section 95127(a)(3).

CO_2e_k = Annual CO_2 equivalent mass emissions from electricity procured from known sources (MT of CO_2e) consumed to produce hydrogen as calculated in section 95127(a)(4).

(b) Importers of hydrogen for use in California must comply with the following requirements:

(1) Greenhouse Gas Emissions. The importer of liquid or gaseous hydrogen into California via truck, rail, or pipeline must report the total GHG

emissions that resulted from the production of the hydrogen that is imported into the state, except for products for which a final destination outside California can be demonstrated.

(A) For all imported hydrogen, the importer must calculate emissions based on the production emissions associated with the imported hydrogen. The importer must calculate emissions using the following equation:

$$CO_2e_i = \sum_p (M_p \times EF_p)$$

Where:

CO_2e_i = Total Annual CO_2 equivalent mass emissions (MT CO_2e) from imported hydrogen from all hydrogen production sources *p*.

M_p = Annual mass of imported hydrogen from producer *p* (MT).

EF_p = Emissions factor for identified producer of hydrogen as calculated in section 95127(b)(1)(B).

EF_p = 11.2 MT CO_2e/MT hydrogen for unknown or unidentified producers of hydrogen, or where the producer has not provided the documentation necessary to calculate the emissions factor pursuant to section 95127(b)(1)(B).

(B) For hydrogen imports from identified producers, the hydrogen emissions factor for each identified producer must be calculated using the following equation:

$$EF_p = (CO_2e_{un,p} + CO_2e_{k,p}) / M_p$$

Where:

EF_p = Hydrogen production emissions factor for producer *p* (MT CO_2e/MT hydrogen)

$CO_2e_{un,p}$ = Annual CO_2 equivalent mass emissions (MT CO_2e) from production of hydrogen utilizing unknown generation source electricity as calculated pursuant to 95127(a)(3) for producer *p*

$CO_2e_{k,p}$ = Annual CO_2 equivalent mass emissions (MT CO_2e) from production of hydrogen produced utilizing known generation source electricity, as calculated pursuant to 95127(a)(4) for producer *p*

M_p = Total annual hydrogen production (MT) for producer *p*

(c) Use of Alternative Methods. In instances where quantification methods in 95127(a) and (b) of this article are not applicable or not viable, operators of in-state hydrogen production facilities and importers of liquid or gaseous hydrogen from known sources may elect to submit an alternative method for measurement and quantification of GHG emissions to CARB for approval pursuant to section 95103(m)(2) of this article.

(d) Additional Data Reporting Requirements.

(1) In addition to the information required in section 95127(a), operators of facilities producing hydrogen must report, if applicable, the MWh of electricity consumed for hydrogen production for each known generation source, the source name, and the associated fuel type or prime mover of each known source.

(2) Importers of hydrogen into California must report the following for each producer of imported hydrogen:

(A) The annual mass of hydrogen imported (MT) and the point at which the measurement of imported hydrogen was taken (e.g., source, border, or sink).

(B) The producer name, location, hydrogen production technology, and date of commencement of hydrogen plant operations.

(e) Verification Exemption. Data reported under this section is exempt from the third-party verification requirements of this article.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Subarticle 3. Additional Requirements for Reported Data

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Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

§ 95130. Requirements for Verification of Emissions Data Reports

The reporting entity who is subject to verification must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this article, as specified in section 95103(f).

(a) *Annual Verification*.

(1) Reporting entities required to obtain annual verification services as specified in section 95103(f) are subject to full verification requirements in the first year that verification is required ~~in each compliance period.~~and every three years thereafter until cessation of verification requirements have been met. Upon receiving a positive verification statement, or statements, if applicable, under full verification requirements, the reporting entity may choose to obtain less intensive verification services ~~for the remaining years of the compliance period.~~. Reporting entities subject to this section are also required to obtain full verification services if any of the following apply:

(A) There has been a change in the verification body;

(B) An adverse verification statement or qualified positive verification statement was issued for the previous year for either emissions data or product data, or both;

(C) A change of operational control of the reporting entity occurred in the previous year.

(D) Nothing in this paragraph shall be construed as preventing a verification body from performing a full verification in instances where there are changes in sources or emissions or covered products. ~~The verification body must provide information on the causes of the emission changes and justification in the verification report if a full verification was not conducted in instances where the total reported GHG emissions differ by greater than 25 percent relative to the preceding year's emissions data report.~~

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifier(s) for a period of more than six consecutive ~~years, which includes any verifications conducted under this article and for the California Climate Action Registry; The Climate Registry; Climate Action Reserve; or other third-party verifications, validations, or audits conducted under impartiality provisions substantively equivalent to section 95133, which may include third-party certification of environmental management systems to the ISO 14001 standard or third-~~

~~party certification of energy management systems to the ISO 50001 standard.~~verifications or more than six consecutive years, whichever is shorter. This limitation applies only to those third-party verifications, validations, or audits that include the scope of activities or operations under the ARB identification number for the emissions data report.

~~The six-year period begins on the date the reporting entity or its agent first contracts for any third-party verifications, validations, or audits under any protocols, including ARB verification services, for the scope of activities or operations under the ARB identification number for the emissions data report, and ends on the date the final verification statement is submitted. Verification bodies may not provide verification services if the six year period ends prior to sixty days after the emissions data report is certified by the reporting entity, unless a verification plan is agreed to by the reporting entity, the verification body, and the Executive Officer. If the six-year time limit is exceeded, the reporting entity must engage a different verification body and meet the verification deadline. Even if these services are provided before the verification body or verifiers have received ARB accreditation, the six year period still begins when these services are contracted for, if accreditation is later received.~~

~~The six-year limit also applies to verification bodies and verifiers providing ARB or any other third-party verifications, validations, or audits that include the scope of activities or operations under the ARB identification number for the emissions data report and~~ The limit does not reset upon a change in reporting entity ownership or operational control.

(3) If a reporting entity is required or elects to contract with another verification body or verifier(s), the reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifier(s) for at least three years.

(A) If a reporting entity is required to select a new verification body to verify an emissions data report(s) that has been set aside pursuant to section 95131(e), the reporting entity may continue to contract for verification services with its current verification body, subject to the six-year time limit.

Note: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95131. Requirements for Verification Services

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services*. After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to CARB. The verification body may begin verification services for the reporting entity after the notice is received by the Executive Officer, but must allow ~~14~~ten days advance notice of the site visit unless an earlier date is approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). Verification services may not begin until the reporting entity certifies the emissions data report in Cal e-GGRT. The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification.

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited as a sector specific verifier that is not also the independent reviewer, when required below:

(A) For providing verification services to an electric power entity; a supplier of petroleum products or biofuels; a supplier of natural gas, natural gas liquids, or liquefied petroleum gas; or a supplier of carbon dioxide, at least one verification team member must be accredited by CARB as a transactions specialist;

(B) For providing verification services to the operator of a petroleum refinery, biorefinery, hydrogen production unit or facility, or petroleum and natural gas system listed in section 95101(e), at least one verification team member must be accredited by CARB as an oil and gas systems specialist;

~~(C) For providing verification services to the operator of a facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing if process emissions~~

~~are included in the scope of operations, iron and steel production, nitric acid production, or lead production, at least one verification team member must be accredited by ARB as a process emissions specialist.~~

(3) General information on the reporting entity, including:

(A) The name of the reporting entity and the facilities and other locations that will be subject to verification services~~, reporting entity contact, address, telephone number, and e-mail address~~;

(B) The ~~industry sector and the North American Industry Classification System (NAICS) code for the reporting facility;~~

~~(C) The~~ date(s) of the on-site visit, ~~if~~including site visits required ~~in~~under section 95130(a)(1~~), with facility address and contact information;~~);

(C) If a remote site visit will be conducted pursuant to section 95131(b)(3)(A);

(D) A brief description of expected verification services to be performed~~, including expected completion date~~.

(4) If any of the information under section ~~-~~ 95131(a)(1) or 95131(a)(3) changes after the notice is submitted to CARB, the verification body must notify CARB by submitting an updated conflict of interest self-evaluation form and updated notice of verification services as soon as the change is made~~.~~ and no fewer than ten days before the new site visit date if a site visit is included. The conflict of interest must be reevaluated pursuant to section 95133(f) and CARB must approve any changes in writing.

(b) Verification services shall include, but are not limited to, the following:

(1) *Verification Plan*. The verification team shall develop a verification plan based on the following:

(A) Information from the reporting entity. Such information shall include:

1. Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, product data, and electricity or fuel transactions as applicable;

2. Information regarding the training or qualifications of personnel involved in developing the emissions data report;

3. Description of the specific methodologies used to quantify and report greenhouse gas emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

4. Information about the data management system used to track greenhouse gas emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

5. Previous verification reports.

(B) Timing of verification services. Such information shall include:

1. Dates of proposed meetings and interviews with reporting facility personnel;

2. Dates of proposed site visits;

3. Types of proposed document and data reviews~~;~~.

~~4. Expected date for completing verification services.~~

(2) *Planning Meetings with the Reporting Entity*. The verification team shall discuss with the reporting entity the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall create a draft sampling plan and verification plan prior to the site visit during full verification. The verification team shall also review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(3) *Site Visits*. At least one accredited verifier in the verification team, including the sector specific verifier, if applicable, shall at a minimum make one site visit~~,~~ during each year full verification is required~~, t~~for each ~~facility~~entity for which an emissions data report is submitted. The ~~verification team member(s) shall visit~~verifier must conduct the site visit at the facility or, when the reporting entity is an EPE or supplier, at the headquarters or other location of central data management ~~when the reporting entity is~~ , or conduct a ~~retail provider, marketer, or fuel supplier. During the~~remote site visit~~, the verification team member(s) shall conduct the following:~~ if permitted under section 95131(b)(3)(A).

~~(A)~~(A) Remote Site Visits. A verifier may elect to conduct a remote site visit when one or more of the following circumstances apply:

1. Verification is not required due to a set aside of a verification statement pursuant to section 95131(e) or a qualified positive verification statement, and the entity being verified is a fuel supplier with total reported emissions below 10,000 MT CO_2e.

2. Verification is not required due to a set aside of a verification statement pursuant to section 95131(e) or a qualified positive verification statement, and the entity being verified is an EPE that does not report as an ACS, MJRP, or ESS registrant, does not participate in CAISO markets, and meets one or more of the following criteria:

   a. The EPE is not subject to the Cap-and-Invest Regulation, or

   b. The EPE has no reported specified source imports, or

   c. The EPE has no reported metered imports from a non-zero emission specified source and total reported emissions are less than 10,000 MT CO_2e.

3. The entity has no physical headquarters or accessible central data management location.

(B) During the site visit, the verification team member(s) shall conduct the following:

1. The verification team member(s) shall check that all sources specified in sections 95110 to 95123, and 95150 to 95158, as applicable to the reporting entity are identified appropriately.

~~(B)~~2. The verification team member(s) shall review and understand the data management systems used by the reporting entity to track, quantify, and report greenhouse gas emissions and, when applicable, product data, and electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

~~(C)~~3. The verification team shall carry out tasks that, in the professional judgment of the team, are needed in the verification process, including the following:

~~1~~a. Interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;

~~2~~b. Making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;

~~3~~c. Assessing conformance with measurement accuracy, data capture, and missing data substitution requirements, as well as CARB-approved alternate methods, temporary methods, and CARB-approved meter calibration postponements;

4d. Reviewing financial transactions to confirm fuel, feedstock, product data and electricity purchases and sales, and confirming the complete and accurate reporting of required data such as facility fuel suppliers, fuel quantities delivered, and if fuel was received directly from an interstate pipeline.

4. If conducted remotely, the site visit must utilize video conferencing or screen sharing and must meet all the requirements of subsection 95131(b)(3)(B).

(4) *Review of Reporting Entity's Operations, Product Data and Emissions*. The verification team shall review facility operations to identify applicable greenhouse gas emissions sources and product data. This shall include a review of the emissions inventory and each type of emission source to ensure that all sources listed in sections 95110 to 95123 and sections 95150 to 95158 of this article are properly included in the emissions data report. This shall also include a review of the product data to ensure that all product data listed in sections 95110 to 95123 and sections 95150 to 95158 of this article are included in the emissions data report as required by this article. The verification team shall also ensure that the reported current primary and any secondary (if reported) NAICS codes reported pursuant to section 95104(c) accurately represent the NAICS-associated Activities listed in Table 8-1 of the Cap-and-~~Trade~~Invest Regulation.

Review of these NAICS codes and associated activities must be documented in the verification team's sampling plan.

(5) *Other Reporting Entity Information*. Reporting entities shall make available to the verification team all information and documentation used to calculate and report emissions, product data, fuels and electricity transactions, and other information required under this article, as applicable.

(6) *Electricity Importers and Exporters*. The verification team shall review the GHG Inventory Program documentation required pursuant to section 95105(d), electricity transaction records, including deliveries and receipts of power via North American Electric Reliability Corporation (NERC) e-Tags, written power contracts, settlements data, and any other applicable information required to confirm reported electricity procurements and deliveries.

(7) *Sampling Plan*. As part of confirming emissions data, product data, electricity transactions, or fuel transactions, the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for a reporting entity. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of data management systems, and the coordination within the reporting entity's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. The verification team shall also include in the sampling plan a ranking of the product data by units specified in the appropriate section of this article and a ranking of the product data with the largest uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the reporting entity including risk of incomplete reporting.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95123, 95129 , and 95150 to 95158:

1. Data acquisition equipment;

2. Data sampling and frequency;

3. Data processing and tracking;

4. Emissions calculations;

5. Product data;

6. Data reporting;

7. Management policies or practices in developing emissions data reports.

(D) After completing the analyses required by sections 95131(b)(7)(A)-(C), the verification team shall include in the sampling plan a list which includes the following:

1. Emissions sources, product data, and/or transactions that will be targeted for document reviews, and data checks as specified in 95131(b)(8), and an explanation of why they were chosen;

2. Methods used to conduct data checks for each source, product data, or transaction;

3. A summary of the information analyzed in the data checks and document reviews conducted for each emissions source, product data, or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services. The final sampling plan must describe in detail how the identified risks were addressed during the verification.

(E) The verification team shall revise the sampling plan to describe tasks completed by the verification team as information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this article.

(F) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each verification statement. The sampling plan shall be made available to CARB upon request.

(G) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(8) *Data Checks*. To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions, product data and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources, fuel and electricity transactions covered under sections 95110 to 95123, 95129, and 95150 to 95158;

(B) The verification team shall use data checks to ensure the accuracy of product data reported under sections 95110 to 95123, and 95150 to 95158 of this article;

(C) The verification team shall choose data checks for emissions sources, product data, and fuel and electricity transactions data, as applicable, based on their relative contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(D) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reported covered emissions and covered product data are free of material misstatement. At a minimum, data checks must include the following:

1. Tracing data in the emissions data report to its origin;

2. Looking at the process for data compilation and collection;

3. Recalculating emission estimates to check original calculations;

4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and

5. Reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 95103(k).

(E) As applicable, the verification team shall review the following information when conducting data checks for product data:

1. Product inventory and stock records;

2. Product sales records and contracts;

3. Onsite and offsite product delivery records;

4. Purchase and delivery records for inputs to product(s);

5. Product measurement records; and

6. Other information or documentation that provides financial or direct measurement information about total product(s) reported.

(F) The verification team is responsible for ensuring via data checks that there is reasonable assurance that the emissions data report conforms to the requirements of this article. In addition, and as applicable, the verifier's review of conformance must confirm the following information is correctly reported:

1. For facilities that combust natural gas, natural gas supplier customer account number, service account identification number, or other primary account identifier(s) reported pursuant to section-_95115(k);

2. For suppliers of natural gas, end-user names, account identification numbers, and natural gas deliveries in MMBtu, reported pursuant to section 95122(d)(4);

3. Energy generation and disposition information reported pursuant to section 95104(d), 95112(a), 95112(b) and electricity and thermal energy purchases and acquisitions reported pursuant to 95104(d)(1) and 95104(d)(2), if any of the following apply:

a. The facility belongs to an industry sector (e.g., reported a NAICS code) listed in Table 8-1 of section 95870 of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation;

b. The facility is applying for legacy contract transition assistance under the ~~c~~Cap-and-~~trade regulation~~Invest Regulation; or

c. The facility is eligible for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation.

4. Emissions associated with a state of emergency that is declared by the Governor to address high energy demand or electric grid reliability that are optionally reported by electricity generation facilities to CARB under section 95112(j), if the facility was not a covered entity in the previous data year.

(G) The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must also include a narrative to indicate which sources, product data, and transactions were checked, the types and quantity of data that were evaluated for each source, product data, and transaction, the percentage of reported emissions covered by the data checks, the percentage of product data covered by the data checks, and any separate discrepancies that were identified in emission data or product data.

(9) *Emissions Data Report Modifications*. As a result of data checks by the verification team and prior to completion of a verification statement(s), the reporting entity must fix all correctable errors that affect covered emissions or covered product data in the submitted emissions data report, and submit a revised emissions data report to CARB. Failure to do so will result in an adverse verification statement. Failure to fix misreported data that do not affect covered emissions or covered product data represents a nonconformance with this article but does not, absent other errors, result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

The verification team shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation or rounding or averaging.

If the verification team determines that the reported NAICS code(s) reviewed pursuant to section 95131(b)(4) is inaccurate, and the reporting entity does not submit a revised emissions data report to correct the current NAICS code(s), the result will be an adverse verification statement.

The verification team must document the source of any difference identified, including whether the difference results in a correctable error or whether the difference does not require further investigation because it is the result of truncation, rounding, or averaging.

(10) *Findings*. To verify that the emissions data report is free of material misstatements, the verification team shall make its own determination of emissions for checked sources and product data for checked data and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement in GHG emissions reported for the reporting entity, on a CO_2 equivalent basis and/or a material misstatement in product data for the reporting entity, using the units required by the applicable parts of this article. To assess conformance with this article the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this article and ensure that other requirements of this article are met.

(11) *Log of Issues*. The verification team must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, whether identified by the verifier or by the reporter regarding the original or subsequent certified reports, or identified by CARB staff. The issues log must identify the regulatory section related to the nonconformance or potential nonconformance, if applicable, and indicate if the issues were corrected by the reporting entity prior to completing the verification. Any other concerns that the verification team has with the preparation of the emissions data report, including with any de minimis method calculations, must be documented in the issues log and communicated to the reporting entity during the course of verification activities. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both and whether an adverse verification statement may result if not addressed.

(12) *Material Misstatement Assessment*. Assessments of material misstatement are conducted independently on total reported covered emissions and total reported covered product data (units from the applicable sections of this article). <u>A material misstatement assessment is not required for emissions data when an entity reports no covered emissions and is not required for product data when an entity reports no covered product data; however, a conformance review is required for all verifications.</u>

(A) In assessing whether an emissions data report contains a material misstatement, the verification team must separately determine whether the total reported covered emissions and total reported covered product data contain a material misstatement using the following equation(s):

$$Percent\ error\ (emissions) = \cancel{\sum \frac{[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{Total\ reported\ covered\ emissions}}\ \underline{\frac{\sum[Discrepancies, Omissions, Misreporting]\ x\ 100}{Total\ reported\ covered\ emissions}}$$

$$or$$

$$Percent\ error\ (product\ data) = \cancel{\sum \frac{[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{Total\ covered\ product\ data}}\ \underline{\frac{\sum[Discrepancies, Omissions, Misreporting]\ x\ 100}{Total\ reported\ covered\ product\ data}}$$

Where:

“Discrepancies” means any differences between the reported covered emissions or covered product data and the verifier’s review of covered emissions or covered product data for a data source or product data subject to data checks in section 95131(b)(8).

“Omissions” means any covered emissions or covered product data the verifier concludes must be part of the emissions data report, but were not included by the reporting entity in the emissions data report.

“Misreporting” means duplicate, incomplete or other covered emissions the verifier concludes should, or should not, be part of the emissions data report or duplicate or other product data the verifier concludes should not be part of the emissions data report.

“Total reported covered emissions or covered product data” means the total annual reporting entity covered emissions or total reported covered product data for which the verifier is conducting a material misstatement assessment.

For instances in which an entity reports covered product data in different units of measurement or reports covered product data subject to sections 95156(a)(7) and 95156(a)(8), the verifier must conduct a material misstatement evaluation according to the requirements of sections 95131(b)(12)(D) and (E), respectively.

(B) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(C) The omissions variable described in section 95131(b)(12)(A) does not apply to excluded covered product data as described in section 95103(l), such that excluded covered product data is not considered in the material misstatement assessment.

~~(D) Beginning with 2017 data reported in 2018, if~~(D) If multiple types of covered product data are reported with different units of measurement, the verifier shall conduct a separate material misstatement evaluation for each product~~,~~ (for example, wineries (NAICS code 312130) with products reported in proof gallons shall have one material misstatement assessment, products reported in shorts tons shall have another material misstatement assessment, and products reported in gallons shall have another material misstatement assessment), except as provided in section 95131(b)(12)(E).

~~(E) Beginning with 2019 data reported in 2020, the verifier~~(E) Verifiers shall conduct a separate material misstatement evaluation for covered product data reported pursuant to section- 95156(a)(7) and 95156(a)(9) on a barrel of oil equivalent basis, and for covered product data reported pursuant to section- 95156(a)(8~~).~~) and 95156(a)(10) on a barrel of oil equivalent basis. If a facility reports covered product data under sections 95156(a)(7), 95156(a)(8), and another section(s) that requires reporting covered product data, three (or more) separate covered product data material misstatement assessments must be completed and three (or more) separate product data verification statements must be issued.

(13) *Review of Missing Data Substitution*. If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

(A) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.

(B) If 20 percent or less of any single data elements used to calculate emissions are missing, and emissions are correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158 these emissions will be considered accurate and as meeting the reporting requirements for that source.

(C) If greater than 20 percent of any single data element used to calculate emissions are missing or any combination of data elements are missing that would result in more than 5 percent of a facility's emissions being calculated using missing data requirements in sections 95110 to 95123, 95129 , and 95150 to 95158, the verifier must include a finding of nonconformance with the required emissions calculation methodology as part of the verification statement.

(D) The verifier must note the date, time and source of any missing data substitutions discovered during the course of verification in the verification report.

(14) *Review of Product Data*. The verifier's review of product data must include the following, where applicable.

(A) Verifiers must confirm that data substitutions were not used for covered product data.

(B) Verifiers must confirm that all covered product data specified in sections 95110-95124 and 95156 of this article conforms to the reporting requirements of MRR, including, but not limited to, meeting the applicable product data definitions, and meter accuracy and calibrations requirements. Covered product data subject to this confirmation include underlying product data that are measured and reported to support the calculation of other covered product data (e.g., CWB throughputs reported by refineries pursuant to section 95113(l)(3) that are used to calculate the total facility CWB). Verifiers shall describe in their sampling plan how they determined that reported covered product data conforms to the requirements of MRR.

(c) Completion of verification services must include:

(1) *Verification Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete an emissions data verification statement and product data verification statement(s), and provide those statements to the reporting entity and CARB by the applicable verification deadline specified in section 95103(f). Before the emissions data verification statement and product data verification statement(s) are completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

(2) *Independent Review.* The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(A) Errors in planning,

(B) Errors in data sampling, and

(C) Errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents applicable to the verification services provided, and identify any failure to comply with requirements of this article or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement(s) can be issued.

(3) *Completion of Findings and Verification Report.* The verification body is required to provide each reporting entity with the following:

(A) A detailed verification report, which shall at a minimum include:

1. A detailed description of the facility or entity including all emissions and product data sources and boundaries;

2. A detailed description of data acquisition, tracking and emission calculation/product data systems;

3. The verification plan;

4. The detailed comparison of the data checks conducted during verification services for emissions and product data sources;

5. The log of issues identified in the course of verification activities and their resolution;

6. Any qualifying comments on findings during verification services; and

7. The calculation performed in section 95131(b)(12)(A) for emissions and product data.

The verification report shall be submitted to the reporting entity at the same time as or before the final emissions data verification statement and product data verification statement(s) are submitted to CARB. The detailed verification report shall be made available to CARB upon request.

(B) The verification team shall have a final discussion with the reporting entity explaining its findings, and notify the reporting entity of any unresolved issues noted in the issues log before the verification statement(s) are finalized.

(C) The verification body shall provide the verification statement(s) to the reporting entity and CARB, attesting whether the verification body has found the submitted emissions data report to be free of material misstatements, and whether the emissions data report is in conformance with the requirements of this article. For every qualified positive verification statement, the verification body shall explain the nonconformances contained within the emissions data report and shall cite the section(s) in this article that corresponds to the nonconformance and why the nonconformances do not result in a material misstatement. For every adverse verification statement, the verification body must explain all nonconformances and material misstatements leading to the adverse verification statement and shall cite the section(s) in this article that corresponds to the nonconformance(s) and material misstatements.

(D) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier who has conducted the independent review of verification services and findings shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

1. The lead verifier must attest in the verification statement, in writing, to CARB as follows:

"I certify under penalty of perjury under the laws of the State of California that the verification team has carried out all verification services as required by this article."

2. The lead verifier independent reviewer who has conducted the independent review of verification services and findings must attest in the verification statement, in writing, to CARB as follows:

"I certify under penalty of perjury under the laws of the State of California that I have conducted an independent review of the verification services and findings on behalf of the verification body as required by this article and that the findings are true, accurate, and complete."

(4) *Adverse Verification Statement and Petition Process.* Prior to the verification body providing an adverse verification statement for emissions or product data, or both, to CARB, the verification body shall notify the reporting entity and the reporting entity shall be provided at least 14 days to modify the emissions data report to correct any material misstatements or nonconformance found by the verification team. The verification body must provide notice to CARB of the potential for an adverse verification statement(s) at the same time it notifies the reporting entity, and include a preliminary issues log. The modified report and verification statement(s) must be submitted to CARB before the verification deadline, even if the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

(A) If the reporting entity and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement or qualified positive verification statement for the emissions or product data because of a disagreement on the requirements of this article, the reporting entity may petition the CARB Executive Officer before the verification deadline and before the verification statement is submitted to make a final decision as to the verifiability of the submitted emissions data report. The reporting entity may petition either emissions or product data verification statements, or both. At the same time that the reporting entity petitions the Executive Officer, the reporting entity must submit all information it believes is necessary for the CARB Executive Officer to make a final decision.

(B) The Executive Officer shall make a final decision no later than October 10 following the submission of a petition pursuant to section 95131(c)(4)(A). If at any point CARB requests information from the verification body or the reporting entity, the information must be submitted to CARB within ten days. CARB will notify both the reporting entity and the verification body of its determination, which may also include an assigned emissions level calculated pursuant to section 95131(c)(5), if applicable.

(5) *Assigned Emissions Level.* When a reporting entity fails to receive a verification statement for a data year by the applicable deadline or receives an adverse emissions data verification statement, the Executive Officer shall develop an assigned emissions level for the data year for the reporting entity. Within ten days of a written request by the Executive Officer, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within ten days of a request by the Executive Officer, the reporting entity shall provide the data that is required to calculate GHG emissions for the entity according to the requirements of this article, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the Executive Officer, including the operating days and hours of the reporting entity during the data year. The reporting entity shall also make available personnel who can assist the Executive Officer's determination of an assigned emissions level for the data year.

(A) In preparing the assigned emissions level for the reporting entity, the Executive Officer shall consider at a minimum the following information:

1. The number, types and days and hours of operation of the sources operated by the reporting entity for the emissions data year;

2. Any previous emissions data reports submitted by the reporting entity and verification statements rendered for those reports;

3. The potential maximum fuel and process material input and output capacities for the reporting entity's emissions sources during operating hours;

4. For electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the applicable data year and for previous years;

5. Emissions, electricity transactions, fuel use, or product output information reported to CARB or other State, federal, or local agencies.

(B) In preparing the assigned emissions level for the reporting entity, the Executive Officer may use the following methods, as applicable:

1. The sector specific calculation methodologies in this article;

2. In the event of missing data, the Executive Officer will rely on the missing data provisions of this article; and

3. Any information reported under this article for this data year and past years.

(C) The Executive Officer shall assign the emissions level for the reporting entity using the best information available, including the information in section 95131(c)(5)(A) and methods in section 95131(c)(5)(B), as applicable. The Executive Officer shall include an assigned emissions level in the decision made pursuant to section 95131(c)(4)(B), if applicable.

(d) Upon provision of the verification statement, or statements, if applicable, to CARB, the emissions data report shall be considered final. No changes shall be made to the report as submitted to CARB, notwithstanding the requirements of 40 CFR §98.3(h), and all verification requirements of this article shall be considered complete except in the circumstance specified in section 95131(e).

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails ~~an ARB~~a CARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days. This paragraph applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by CARB to not affect the covered emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement.

(f) Upon request by the Executive Officer, the reporting entity shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 14 days.

(g) Upon request of the Executive Officer, the verification body shall provide CARB the full verification report given to the reporting entity, as well as the sampling plan, contracts for verification services, and any other supporting documents and calculations, within 14 days.

(h) Upon written notification by the Executive Officer, the verification body shall make itself and its personnel available for ~~an ARB~~a CARB audit.

(i) *Verifying Biomass-derived Fuels*. In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of subarticle 4 of this article as modified below when verifying biomass-derived fuel:

(1) *General biomass-derived fuel verification requirements*. The following requirements apply to the biomass-derived fuel verification:

(A) *Annual Verification*. Biomass-derived fuel is subject to annual verification as specified in section 95103(f).

(B) *Verification Services for Biomass-derived Fuels*. When a reporting entity reports that biomass-derived fuels are used, the biomass-derived fuels must be considered when providing all verification services required under section 95131(b) of this article. The verification team must:

1. Review the reporting entity's reported biomass-derived fuel emissions to ensure the biomass-derived fuels are properly listed in the emissions data report as required in section 95103(j) of this article and section~~s~~ 95852.1~~.1 and 95852.2~~ of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

2. Conduct separate data checks that are consistent with the requirements in 95131(i)(2)(D) for the fuel type being verified using the following documentation, as appropriate: the invoice, nomination, scheduling, storage, in-kind fuel purchase, allocation, transportation and balancing reports or other documents used as evidence of the fuel delivery.

a. The reporting entity may arrange for the documentation to be supplied directly to the verifier if there are confidentiality issues that would prevent these documents from being made available to the reporting entity.

(C) *Completion of Verification Services for Biomass-derived Fuels*.

1. All information used for the verification of biomass-derived fuels must be included in the independent review as required in section 95131(c)(2) of this article.

2. Conformance for biomass-derived fuels is evaluated against the requirements of this article and section~~s~~ 95852.1~~.1 and 95852.2~~ of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

3. Reported carbon dioxide emissions from biomass-derived fuels are considered an omission in the evaluation for material misstatement when:

a. The fuel does not conform with ~~sections~~requirements for exempt biomass-derived fuel in section 95852.1~~.1 and 95852.2~~ of the ~~c~~Cap-and~~-trade regulation~~Invest Regulation and

b. The emissions are listed as exempt biomass-derived CO_2.

(2) Specific biomass-derived fuel verification requirements.

(A) For urban, agricultural and forest derived wood and wood waste, the verifier must determine the reporting entity met the requirements of section 95103(j).

(B) For biodiesel, renewable diesel, and fuel ethanol, the verifier must determine the reporting entity met the requirements of section 95103(j) and the following requirements:

1. At combustion sources that purchase biomass-derived fuels, verify records to demonstrate that volume purchased equals or exceeds volume reported.

2. At combustion sources that produce their own fuel, verify:

a. that raw material is sufficient to produce the quantity of fuel reported;

b. that the facility has the ability to produce the biomass-derived fuel reported;

c. that the emissions from the fuel are accurately reported and do not lead to the underreporting of fossil fuel emissions.

(C) For municipal solid waste and tires, the verifier must determine the reporting entity met the requirements of section 95103(j).

(D) For biomethane and biogas, the verifier must:

1. Examine all nomination, invoice, scheduling, allocation, transportation, storage, in-kind fuel purchase and balancing reports from the producer to the reporting entity and have reasonable assurance that the reporting entity is receiving the identified fuel;

2. Determine that the biogas or biomethane meets all requirements ~~of sections~~for exempt biomass-derived fuel in section 95852.1~~.1 and 95852.2~~ of the ~~c~~Cap-and-~~trade regulation~~Invest Regulation and that no fossil-derived fuel is used to supplement the biomass-derived fuel deliveries except for documented fuel purchases to avoid loss of metered volumes in connection with the transportation of the biomethane to the reporting entity. Where one or more contracts is used to procure biogas or biomethane, ensure all applicable contracts meet the requirements of section 95852.1.1(a);

3. Ensure any discrepancies in the fuel volumes, heat values and/or energies will be carried over into the evaluation of material misstatement for the reporting entity;

(~~E~~3) *Assessment*. If the reporting entity is unable to demonstrate that the biomass-derived fuel is consistent with the requirements in section~~s~~ 95852.1~~.1 and 95852.2~~ of the ~~cap-~~Cap-and-Invest Regulation for exempt biomass and~~-trade regulation~~ biomass-derived fuels, the emission data report must be revised to list these biomass CO_2 emissions as non-exempt biomass-derived CO_2.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article and under the ~~c~~Cap-and~~-trade regulation~~Invest Regulation.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application*. To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including CARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall employ and retain at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2).

2. A verification body shall employ and retain at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings, enforcement actions, or administrative actions filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services. Neither general nor umbrella liability policies can be used for the professional liability insurance minimum for the purposes of this provision.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;

2. A detailed organizational chart that includes the verification body, its management structure, and any related entities;

3. The verification body's internal conflict of interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees and procedures to monitor, assess, and notify CARB of potential conflicts of interest.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in CARB verifier training on an ongoing basis.

(F) The verification body shall notify CARB within 30 days of when it no longer meets the requirements for accreditation as a verification body in section 95132(b)(1). The verification body may request that the Executive Officer provide additional time to hire additional staff to meet the requirements of this section.

(G) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) *Lead Verifier Accreditation Application*. To apply for accreditation as a lead verifier, the applicant shall submit documentation to the Executive Officer that provides the evidence specified in section 95132(b)(2)(A), and section 95132(b)(2)(B), or (C):

(A) Evidence that the applicant meets the criteria in 95132(b)(3); and,

(B) Evidence that the applicant has been ~~an ARB~~a CARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of ~~an~~

~~ARB~~a CARB accredited lead verifier, with evidence of favorable assessment by CARB for services performed; or,

(C) Evidence that the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories; or,

2. As a lead environmental data or financial auditor.

(3) *Verifier Accreditation Application*. To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) Evidence demonstrating the minimum education background required to act as a verifier for CARB. Minimum education background means that the applicant has either:

1. A bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or

2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of full-time work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant must take ~~an ARB~~a CARB approved general verification training and receive a passing score of greater than an unweighted 70 percent on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the CARB approved general verification training course. Training under the previous version of the regulation does not qualify an applicant

to retake an exam under this version without first taking the training for this revised regulation.

(5) Sector Specific and Offset Project Specific Verifiers.

(A) *Sector Specific Verifier*. The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take CARB sector specific verification training and receive a passing score of greater than an unweighted 70 percent on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the CARB approved sector specific verification training.

(B) *Offset Project Specific Verifier*. ~~The~~In addition to meeting the requirements for accredited lead verifier or verifier qualification, the applicant seeking to be accredited as an offset project specific verifier as specified in the ~~c~~Cap-and-~~trade regulation~~Invest Regulation must~~, in addition to meeting the requirements for accredited lead verifier or verifier qualification, meet one of the following requirements:~~

~~1. Have at least two years of professional experience related to developing emission inventories, conducting technical analyses, or environmental audits of the offset project type, and~~ take general CARB offset verification training and CARB offset project specific verification training for an offset project type~~,~~ and receive a passing score of greater than an unweighted 70 percent on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the applicable CARB-approved offset verification training~~; or,~~.

~~2. Be a verifier in good standing for the Climate Action Reserve prior to October 28, 2011, taken Climate Action Reserve project specific verifier training, have performed at least two project verifications for a project type by October 28, 2011, and have taken general ARB offset verification training, and receive a passing score of greater than an unweighted 70~~

~~percent on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general ARB offset verification training and offset project specific verification training.~~

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier, or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) *CARB Accreditation*.

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, verifier, sector specific verifier, or offset project specific verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verification body, verifier, lead verifier, sector specific verifier, or offset project specific verifier is complete, meets all applicable regulatory requirements, and passes a performance review as defined in section 95102(a), the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to withhold accreditation or issue an Executive Order to grant accreditation for the verification body, lead verifier, sector specific verifier, offset project specific verifier or verifier.

(4) The Executive Order for initial accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, sector specific verifier, offset project specific verifier, or verification body if the applicant has not been subject to CARB enforcement action under this article. All CARB approved general, sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer. In addition, the performance review requirement set forth in section 95132(c)(2) must be met for accreditation to be renewed by the Executive Officer. Renewal of

accreditation can be granted for a period up to six years, at the discretion of the Executive Officer.

(5) All verification body requirements in section 95132(b)(1) must be met for the Executive Officer to renew the verification body accreditation.

(6) Within 20 days of being notified of any nonconformance in another voluntary or mandatory GHG program, ~~an ARB~~a CARB accredited verification body, lead verifier, sector specific verifier, offset project specific verifier, or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

* * * *

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by CARB to perform the verification services for which the subcontractor has been engaged by the verification body.

(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers.

(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.

(4) A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for a reporting entity.

(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the reporting entity for which it will provide verification services.

(6) A verification body may not use a subcontractor as the independent reviewer.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95133. Conflict of Interest Requirements for Verification Bodies

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by CARB to perform verification services for reporting entities. Any individual person or company that is hired by a reporting entity to contract with a verification body on behalf of the reporting entity is subject to the conflict of interest assessment in this article. In such instances, the verification body must assess the potential conflict of interest between itself and the contracting entity as well as between itself and the reporting entity, and must also address the potential conflict of interest between the contracting entity and the reporting entity, including a written assessment provided and signed by the contracting entity.

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and reporting entity share any management staff or board of directors membership, or any of the ~~senior~~ management staff of the reporting entity have been employed by the verification body, or vice versa, within the previous five years; or

(2) Any employee of the verification body, or any employee of a related entity, or a subcontractor who is a member of the verification team has provided to the reporting entity any of the following services within the previous five years:

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services;

(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information;

(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the ~~c~~Cap-and~~-trade regulation~~Invest Regulation;

(E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity;

(F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;

(G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting entity;

(H) Appraisal services of carbon or greenhouse gas liabilities or assets;

(I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(J) Directly managing any health, environment or safety functions for the reporting entity;

(K) Bookkeeping or other services related to accounting records or financial statements;

(L) Any service related to development of information systems, including consulting on the development of environmental management systems, such as those conforming to ISO 14001 or energy management systems such as those conforming to ISO 50001, unless those systems will not be part of the verification process;

(M) Appraisal and valuation services, both tangible and intangible;

(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;

(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;

(Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the reporting entity;

(R) Any legal services;

(S) Expert services to the reporting entity, a trade or membership group to which the reporting entity belongs, or a legal representative for the purpose of advocating the reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation.

(T) Verification services that are not conducted in accordance with, or equivalent to, section 95133 requirements, unless the systems and data reviewed during those services, as well as the result of those services, will not be part of the verification process.

(U) "Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to a reporting entity to secure a verification services contract.

(4) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the reporting entity except within the time periods in which the reporting entity is allowed to use the same verification body as specified in section 95130(a).

<u>(5) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided consulting services to the reporting entity to comply with CARB's Low Carbon Fuel Standard in the previous five years.</u>

(c) The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

(1) No potential for a high conflict of interest is found pursuant to section 95133(b); and

(2) Any services provided by any member of the verification body or verification team to the reporting entity, within the last five years, are valued at less than 20 percent of the fee for the proposed verification services. Any verification conducted in accordance with, or equivalent to, section 95133 provided by the verification body or verification team outside the jurisdiction of CARB is excluded from this financial assessment but must be disclosed to CARB in accordance with section 95133(e).

(3) Non-CARB verification services are deemed to be low risk if those services are conducted in accordance with, or equivalent to, section 95133, including, but not limited to, third-party certification of environmental management system under ISO 14001 or energy management system under 50001 standards.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95133(b) and 95133(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the reporting entity, and when a conflict of interest self-evaluation is submitted pursuant to section 95133(h).

(1) If a verification body identifies a medium potential for conflict of interest and intends to provide verification services for the reporting entity, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) As provided in section 95133(f)(4), the Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies*.

(1) Before the start of any work related to providing verification services to a reporting entity, a verification body must first ~~be authorized~~seek authorization in writing ~~by~~from the Executive Officer to provide verification services. In cases where the verification body determines the potential for a conflict of interest is low pursuant to section 95133(c), the verification body can begin providing verification services prior to receiving authorization from the Executive Officer. To obtain authorization, the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the verification body, related entities, or any subcontractors performing verification services may have with the reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

(B) Identification of whether the verification body, related entities, or any member of the verification team has previously provided verification services for the reporting entity or related entities and, if so, provide a description of such services and the years in which such services were provided;

(C) Identification of whether any member of the verification team, verification body, or related entity has engaged in services of any nature, other than CARB verification services, with the reporting entity or related entities that share operational control with the reporting entity, either within or outside California during the previous five years. If services other than CARB verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the reporting entity or related entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work

with implications for the reporting entity's greenhouse gas emissions pursuant to this article;

2. The nature of past, present or future relationships of any member of the verification team, verification body, or related entities with the reporting entity or related entities including:

   a. Instances when any member of the verification team, verification body, or related entities has performed or intends to perform work for the reporting entity or related entities;

   b. Identification of whether work is currently being performed for the reporting entity or related entities, and if so, the nature of the work;

   c. How much work was performed for the reporting entity or related entities in the last five years, in dollars;

   d. Whether any member of the verification team, verification body, or related entities has contracts or other arrangements to perform work for the reporting entity or a related entity;

   e. How much work related to greenhouse gases the verification team has performed for the reporting entity or related entities in the last five years, in dollars.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(D) A list of names of the staff that would perform verification services for the reporting entity, and a description of any instances of personal or family relationships with management or employees of the reporting entity that potentially represent a conflict of interest; and,

(E) Identification of any other circumstances known to the verification body, or reporting entity that could result in a conflict of interest.

(F) Attest, in writing, to CARB as follows:

(G) "I certify under penalty of perjury under the laws of the State of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) *Conflict of Interest Determinations*. The Executive Officer must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95133(e) is deemed complete. Within 20 days of deeming the information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and must so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to section 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the reporting entity and related entities, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, the Executive Officer will authorize the verification body to provide verification services.

* * * *

(h) Specific Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(1) If an air district has provided or is providing any services listed in section 95133(b)(2) as part of its regulatory duties, those services do not constitute non-verification services or a potential for high conflict of interest for purposes of this subarticle;

(2) Before providing verification services, an air district shall either submit a conflict of interest self-evaluation pursuant to section 95133(e) for each reporting entity for which it intends to provide verification services, or shall submit an annual self-evaluation to CARB no later than April 10 of each calendar year containing the information specified in section 95133(e)(1)(A)-(F) for all reporting entities for which it intends to provide verification services;

(3) As part of its conflict of interest self-evaluation submittal under section 95133(e), the air district shall certify that it will prevent conflicts of interests and resolve potential conflict of interest situations pursuant to its policies and mechanisms submitted under section 95132(b)(1)(G);

(4) If an air district hires a subcontractor who is not an air district employee to provide verification services, the air district shall be subject to all of the requirements of section 95133.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems

§ 95150. Definition of the Source Category

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production*. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production*. Onshore petroleum and natural gas production means all equipment on a well-pad or associated with a well pad (including compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). Onshore natural gas processing equipment as defined in section 95150(a)(3) that is owned and/or operated by the facility owner/operator and located within the same basin is considered "associated with a well pad" and is included with the onshore petroleum and natural gas production facility, unless such equipment is required to be reported as part of a separate onshore petroleum and natural gas processing facility. Gas processing plants that have an annual average throughput of 25 MMscf per day or greater are not included in this segment.

(A) This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations (both thermal and non-thermal), and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Crude oil and associated gas that is piped to an onshore production facility as an emulsion as defined in section

95102(a) must follow the requirements of section 95156(a)(7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the platform.

(3) *Onshore natural gas processing*. Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that have an annual average throughput of 25 MMscf per day or greater. This industry segment also includes fractionation facilities that have no petroleum and gas production activity within the same basin.

(4) *Onshore natural gas transmission compression*. Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment. This industry segment also includes all booster stations owned and/or operated by the facility owner/operator.

(5) *Underground natural gas storage*. Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process or equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage*. LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural

gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for regasification of the liquefied natural gas.

(7) *LNG import and export equipment*. LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system in California. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to California.

(8) *Natural gas distribution*. Natural gas distribution means the transmission and distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within California that is regulated by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

* * * *

§ 95152. Greenhouse Gases to Report

(a) The operator of a facility must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (i) of this section, and stationary and portable combustion emissions as applicable and as specified in paragraph (j) of this section.

* * * *

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines at above grade transmission-distribution transfer stations;

(2) Equipment leaks at below grade transmission-distribution transfer stations;

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations;

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks;

(6) Distribution services equipment leaks;

(7) Report under section 95150 of this article the emissions of CO_2, CH_4, and N_2O from stationary fuel combustion sources following the methods in 95153(y);

(8) Flare stack emissions;

(9) Equipment and pipeline blowdowns~~;~~<u>, including transmission pipeline blowdowns;</u>

(10) CO_2 and CH_4 emissions from customer meters (N_2O emissions excluded); and

(11) CO_2 and CH_4 emissions from pipeline dig-ins (N_2O emissions excluded).

* * * *

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95153. Calculating GHG Emissions.

The operator of a facility must calculate and report annual GHG emissions as prescribed in this section. The facility operator who is a local distribution company reporting under section 95122 of this article must comply with section 95153 for reporting emissions from the applicable source types in section 95152(i) of this article.

* * * *

(j) Well testing venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) gas and oil well testing venting and flaring emissions as follows:

(1) Determine the total gas-to-oil ratio (GOR) of the hydrocarbon production from all oil well(s) tested. Determine the production rate from all gas well(s) tested.

(2) If total GOR cannot be determined from available data, then the facility operator must measure quantities reported in this section according to one of the two procedures in paragraph (j)(2) of this section to determine total GOR.

(A) The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists, including CARB's sampling methodology and flash liberation test procedure in Appendix B of this regulation (if flash liberation testing is representative of all produced associated gas); or

(B) The facility operator may use an industry standard practice as described in section 95154(b).

* * * *

(k) Associated gas venting and flaring. Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing as follows:

(1) Determine the total GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If total GOR from each well is not available, the total GOR from a cluster of wells in the same basin shall be used.

(2) If total GOR cannot be determined from available data, then use one of the two procedures in paragraph (k)(2) of this section to determine total GOR.

(A) Use an appropriate standard method published by a consensus-based standards organization if such a method exists, including CARB's sampling methodology and flash liberation test procedure in Appendix B of this regulation (if flash liberation testing is representative of all produced associated gas); or

(B) The facility operator may use an industry standard practice as described in section 95154(b).

* * * *

(v) Crude Oil, Condensate, and Produced Water Dissolved CO_2 and CH_4. The operator must calculate dissolved CO_2 and CH_4 in crude oil, condensate, and produced water. This reporting requirement includes emissions from hydrocarbon liquids and water produced using EOR operations. Emissions must be reported for crude oil, condensate, and produced water sent to storage tanks, ponds, and holding facilities. The facility operator must also report the volume of produced water in barrels per year.

(1) Calculate CO_2 and CH_4 emissions from crude oil, condensate, and produced water using Equation 33A:

$$E_{CO2/CH4} = (S * V)\big(1 - (VR * CE)\big) \quad \text{(Eq. 33A)}$$

Where:

E_{CO_2/CH_4} = Annual CO_2 or CH_4 emissions in metric tons.

S = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of crude oil, condensate, and produced water (as determined in paragraph (v)(1)(A)1. or mass of CO_2 or CH_4 recovered in a vapor recovery system per barrel of crude oil, condensate, or produced water (as determined in paragraph (v)(1)(A)2.

V = Barrels of crude oil, condensate, or produced water sent to tanks, ponds, or holding facilities annually.

VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).

CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(A) S (the mass of CO_2 or CH_4 per barrel of crude oil, condensate, or produced water) shall be determined using one of the following methods:

1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from crude oil, condensate, or produced water when the crude oil, condensate, or produced water changes temperature and pressure from well stream to standard atmospheric conditions, using CARB's sampling methodology and flash liberation test procedure entitled "Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems," which is included as Appendix B of this article. The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of crude oil, condensate, or produced water. The test results from the flash liberation test must be submitted to CARB as part of

the emissions data report. When required to quantify emissions, flash liberation test samples must be collected at least annually. Flash liberation test samples may be collected from a single location/separator system, or from multiple locations; however, the sample(s) must be reasonably representative of the liquids to which the results are applied. A sufficient number of samples must be collected to reasonably represent the ratio of gas-to-oil, water, and condensate that are separated at multiple locations within a facility.

2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from crude oil, condensate, or produced water as follows:

a. Measure the annual gas stream volume captured by the vapor recovery system.

b. Calculate the annual mass of CO_2 and CH_4 in the gas stream using the gas stream volume and mole percentage of CO_2 and CH_4 as determined by a laboratory analysis of an annual gas stream sample.

c. Calculate S by dividing the total mass of CO_2 and CH_4 in the gas stream by the total volume, in barrels, of the crude oil, condensate, or produced water throughput of the storage tank system.

d. Vapor recovery system measurements and analyses may include gases from crude oil, condensate, and produced water.

e. The vapor recovery system method is included in Appendix B.

(B) Emissions resulting from the destruction of the vapor recovery system gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

(2) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir are exempt from paragraph (v) of this section.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

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§ 95156. Additional Data Reporting Requirements

Operators must conform to the data reporting requirements in section 95157 in addition to the data reporting requirements specified below. Sales records or sales records with an inventory adjustment are allowable methods to quantify the covered product data required by paragraphs (a)(7)-(10), (b), (c) and (d) of this section, for products that are sold or produced during the data year, if the measurement system meets the criteria in section 95103(k). Any changes in the covered product data reporting method must conform to the requirements in section 95103(m). Reporting entities must exclude inaccurate product data pursuant to section 95103(l).

* * * *

(c) The operator of a natural gas liquid fractionating facility, or a natural gas processing facility, or an onshore petroleum and natural gas production facility with a natural gas processing plant that processes less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

(1) Ethane

(2) Ethylene

(3) Propane

(4) Propylene

(5) Butane

(6) Butylene

(7) Isobutane

(8) Isobutylene

(9) Pentanes plus

(10) Natural gasoline

(11) Liquefied petroleum gas

(12) Bulk natural gas liquids not included in 95156(~~d~~c)(1)-(11)

If a facility extracts natural gas liquids from produced gas, associated gas, or waste gas, and re-injects these natural gas liquids into barrels of crude oil produced at the same facility, the operator of such a facility shall report the amount of any re injected natural gas liquids as covered product data pursuant to section 95156(a)(7) or (8). All other natural gas liquids produced at the facility should be reported as covered product data pursuant to section 95156(c).

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95157. Activity Data Reporting Requirements

In addition to the information required by section 95103, each annual report must contain reported emissions and related information as specified in this section.

* * * *

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG type. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring of the gas. Both the vented and flared emissions will be reported under respective source types and not under flare source type.

(1) For natural gas pneumatic devices (refer to Equations 1 and 2 of section 95153), report the following:

(A) Actual count and estimated count separately of natural gas pneumatic high bleed devices, as applicable.

(B) Actual count and estimated count separately of natural gas low bleed devices, as applicable.

(C) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices, as applicable.

(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) For natural gas driven pneumatic pumps (refer to Equation 1 and 2 of section 95153), report the following:

(A) Count of natural gas driven pneumatic pumps.

(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all natural gas driven pneumatic pumps combined.

(3) For each acid gas removal unit (refer to Equation 3 and Equations 4A-B of section 95153), report the following:

(A) Total throughput of the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.

(B) For Calculation Methodology 1 and Calculation Methodology 2 of section 95153(c), annual fraction of CO_2 content in the vent from acid gas removal unit (refer to section 95153(c)(6)).

(C) For Calculation Methodology 3 of section 95153(c), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to section 95153(c)(6)).

(D) Report the annual quantity of CO_2, expressed in metric tons that was recovered from the AGR unit and transferred outside the facility, under section 95153.

(E) Report annual CO_2 emissions for the AGR unit, expressed in metric tons.

(F) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.

(G) An indication of which methodology was used for the AGR unit.

(4) For dehydrators, report the following:

(A) For each Glycol dehydrator (refer to section 95153(d)(1)), report the following:

1. Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.

2. Glycol dehydrator absorbent circulation pump type.

3. Whether stripper gas is used in glycol dehydrator.

4. Whether a flash tank separator is used in glycol dehydrator.

5. Type of absorbent.

6. Total time the glycol dehydrator is operating in hours.

7. Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.

8. Concentration of CH_4 and CO_2 in wet natural gas.

9. What vent gas controls are used (refer to sections 95153(d)(3) and (d)(4)).

10. For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.

11. For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons for each gas.

12. For the onshore natural gas processing industry segment only, report a unique name or ID number for (each) glycol dehydrator.

(B) For absorbent desiccant dehydrators (refer to Equation 5 of section 95153), report the following:

1. Count of desiccant dehydrators.

2. Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(A) For Calculation Methodology 1 (refer to Equation 6 of section 95153(e)), report the following:

1. Count of wells vented to the atmosphere for liquids unloading.

2. Count of plunger lifts. Whether the well had a plunger lift (yes/no).

3. Cumulative number of unloadings vented to the atmosphere.

4. Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet.

5. Casing pressure, in psia, of each well that does not have a plunger lift.

6. Tubing pressure, in psia, of each well that has a plunger lift.

7. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(B) For Calculation Methodologies 2 (refer to Equation 7 of section 95153(e)), report the following for each basin:

1. Count of wells vented to the atmosphere for liquids unloading.

2. Count of plunger lifts.

3. Cumulative number of unloadings vented to the atmosphere.

4. Average internal casing diameter, in inches, of each well, where applicable.

5. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each GHG gas.

(6) For well completions and workovers, report the following for each basin category:

(A) Total field count of gas well completions and total field count of oil well completions by average depth (in thousands of feet) in calendar year.

1. Total number of gas well completions by average depth (in thousands of feet) using hydraulic fracturing;

2. Total number of oil well completions by average depth (in thousands of feet) using hydraulic fracturing;

(B) Total field count of gas well workovers and total field count of oil well workovers by average depth (in thousands of feet) in calendar year.

1. Total number of gas well workovers by average depth (in thousands of feet) using hydraulic fracturing;

2. Total number of oil well workovers by average depth (in thousands of feet) using hydraulic fracturing;

(C) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.

(D) Report number of workovers employing purposely designed equipment that's separates natural gas from the backflow and the amount of natural gas recovered using engineering estimate based on best available data.

(E) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.

(F) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons for each gas.

(G) The following field average activity data for oil wells:

1. Casing diameter;

2. Tubing diameter;

3. Typical pressure inside the well at the wellhead, immediately prior to removing the wellhead for well work activities;

4. Typical producing temperature inside the well;

5. Time, in hours, to complete well work (workover or completion).

(7) For each equipment and pipeline blowdown event (refer to Equation 13 and Equation 14 of section 95153(g)), report the following:

(A) For each unique physical volume that is blowdown more than once during the calendar year, report the following:

1. Total number of blowdowns for each unique physical volume, expressed in metric tons for each gas.

2. Annual CO_2 and CH_4 emissions for each unique physical blowdown volume, expressed in metric tons for each gas.

3. A unique name or ID number for the unique physical volume.

(B) For all unique volumes that are blow down once during the calendar year, report the following:

1. Total number of blowdowns for all unique physical volumes in the calendar year.

2. Annual CO_2 and CH_4 emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(A) If a wellhead separator dump valve is functioning improperly during the calendar year (refer to section 95153 (i)), report the following:

1. Count of wellhead separators that dump valve factor is applied.

2. Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons for each gas, at the basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas imaging instrument pursuant to section 95154(a) (refer to section 95153(i)), or acoustic leak detection of scrubber dump valves, report the following:

(A) For each vent stack, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.

(B) For each transmission storage tank, report annual CO_2, CH_4 and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons for each gas.

(C) A unique name or ID number for the vent stack monitored according to section 95153(i).

(10) For well testing venting and flaring (refer to Equation 15 or 16 of section 95153(j)), report the following:

(A) Number of wells tested per basin in calendar year.

(B) Average gas-to-oil ratio for each basin.

(C) Average number of days the well is tested in a basin.

(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emissions from well testing venting.

(E) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation 17 of section 95153), report the following for each basin:

(A) Number of wells venting or flaring associated natural gas in a calendar year.

(B) Average gas-to-oil ratio for each basin.

(C) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emission s from associated natural gas venting.

(D) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation 18, 19, and 20 of section 95153(l)), report the following for each flare:

(A) Whether flare has a continuous flow monitor.

(B) Volume of gas sent to flare in cubic feet per year.

(C) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(D) Whether flare has a continuous gas analyzer.

(E) Flare combustion efficiency.

(F) Report CH_4 emissions, in metric tons (refer to Equation 18 of section 95153).

(G) Report CO_2 emissions, in metric tons (refer to Equation 19 of section 95153).

(H) Report N_2O emissions, in metric tons.

(I) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(J) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(13) For each centrifugal compressor:

(A) For compressors with wet seals in operational mode (refer to Equation 21 and 22 of section 95153(m)), report the following for each degassing vent:

1. Number of wet seals connected to the degassing vent.

2. Fraction of vent gas recovered for fuel or sales or flared.

3. Annual throughput in million scf, use an engineering calculation based on best available data.

4. Type of meters used for making measurements.

5. Total time the compressor is operating in hours.

6. Report seal oil degassing vent emissions for compressors measured (refer to Equation 21 of section 95153) and for compressors not measured (refer to Equation 22 of section 95153).

(B) For wet and dry seal centrifugal compressors in operating mode, (refer to Equation 21 and 22 of section 95153(m)), report the following:

1. Total time in hours the compressor is in operating mode.

2. Report blowdown vent emissions when in operating mode (refer to Equation 21 and 22 of section 95153).

(C) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations 21 and 22 of section 95153(m)), report the following:

1. Total time in hours the compressor is in shutdown, depressurized mode.

2. Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equations 21 and 22 of section 95153).

(D) Report total annual compressor emissions from all modes of operation.

(14) For reciprocating compressors:

(A) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

1. Annual throughput in million scf, use an engineering calculation based on best available data.

2. Total time in hours the reciprocating compressor is in operating mode.

3. Report rod packing emissions for compressors measured (refer to Equation 23 of section 95153).

(B) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode, report the following:

1. Total time in hours the compressor is in standby, pressurized mode.

2. Report blowdown vent emissions when in operating and standby modes.

(C) For reciprocating compressors in not operating, depressurized mode report the following:

1. Total time the compressor is in not operating depressurized mode.

2. Facility operator emission factor for isolation valve emissions in not operating mode, depressurized mode in cubic feet per hour.

3. Report the isolation valve leakage emissions in not operating, depressurized mode.

(D) Report total annual compressor emissions from all modes of operation.

(E) For reciprocating compressors in onshore petroleum and natural gas production report the following:

1. Count of compressors.

2. Report emissions collectively.

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to sections 95153(o) and (p)).

(A) For equipment leaks found in each leak survey (refer to section 95153(o)), report the following:

1. Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leak emission factor in Tables 2, 3, 4, 5, 6, and 7 of Appendix A.

2. For onshore natural gas processing, range of concentrations of CH_4 and CO_2.

3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(B) For equipment leaks calculated using population counts and factors (refer to section 95153(p)), report the following:

1. For source categories listed in sections 95150(a)(4), (a)(5), (a)(6), and (a)(7), total count for each component type in

Tables 2, 3, 4, 5, and 6 of Appendix A for which there is a population emission factor, listed by major heading and component type.

2. For onshore production (refer to section 95150(a)(2)), total count for each type of major equipment in Table 1B and Table 1C of Appendix A, by facility.

3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(16) For local distribution companies, report the following:

(A) Total number of above grade T-D transfer stations in the facility.

(B) Number of years over which all T-D transfer stations will be monitored at least once.

(C) Number of T-D stations monitored in calendar year.

(D) Total number of below grade T-D transfer stations in the facility.

(E) Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.

(F) Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.

(G) Leak factor for meter/regulator run developed in Equation 28 of section 95153.

(H) Number of miles of unprotected steel distribution mains.

(I) Number of miles of protected steel distribution mains.

(J) Number of miles of plastic distribution mains.

(K) Number of miles of cast iron distribution mains.

(L) Number of unprotected steel distribution services.

(M) Number of protected steel distribution services.

(N) Number of plastic distribution services.

(O) Number of copper distribution services.

(P) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade T-D transfer stations combined.

(Q) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.

(R) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.

(S) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution mains combined.

(T) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution services combined.

(U) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from customer meters serving residential, commercial, and industrial customers, respectively.

(V) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from pipeline dig-ins.

(W) Number of customer meters at residential, commercial, and industrial premises, respectively.

(X) Number of pipeline dig-ins.

<u>(Y) Annual number of transmission pipeline blowdowns.</u>

(17) For each EOR injection pump blowdown (refer to Equation 33 of section 95153), report the following:

(A) Pump capacity, in barrels per day.

(B) Volume of critical phase gas between isolation valves.

(C) Number of blowdowns per year.

(D) Critical phase EOR injection gas density.

(E) For each EOR pump, report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(18) For crude oil, condensate, and produced water dissolved CO_2 and CH_4 (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.

(B) Report annual CO_2 and CH_4 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(A) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 MMBtu/hr, by type of unit.

(B) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(C) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(D) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(E) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 MMBtu/hr or 130 horsepower, by type of unit.

(F) Report annual CO_2, CH_4 and N_2O emissions from internal fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(G) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 MMBtu/hr or 130 horsepower, by fuel type.

(H) Annual volume of associated gas produced in Mscf using thermal enhanced oil recovery and non-thermal enhanced oil recovery.

(I) Onshore petroleum and natural gas production facilities may voluntarily report total thermal input (MMBtu) to EOR wells generated using renewable energy source(s) as defined in section 95102(a).

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

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