NOTE: Changes to the regulation are shown in underline; deletions from the regulation are shown in ~~strikeout~~. "***" indicates sections of regulation not printed are not changed.

POTENTIAL AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

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

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8. Lead production;

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(G) Any California reporting entity subject to subparts E, F, G, I, K, L, O, R, T, X, Z, BB, CC, DD, 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. If a reporting entity utilizes the above industrial processes, 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 also applies to facility operators subject to section 95103(a).

(2) Any reporting entity ~~that fits~~ in~~to~~ one or more of the categories in subsection (a)(1) above ~~for calendar year 2011 or later~~ must submit an annual emissions data report ~~for that year and for subsequent calendar years~~, except as provided in the report cessation provisions of subsection (h) 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.

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(b) *Calculating GHG Emissions Relative to Thresholds.* For ~~industrial~~ 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 ~~using the requirements of 40 CFR §98.2(b)-(c), except~~ 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 cap-and-trade 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 vented and fugitive emissions from the estimate. However, if all the emissions captured 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 a GHG report pursuant to the full requirements of this Article, including obtaining verification services pursuant to section 95103(f).

(3) Facilities with only stationary combustion emissions are subject to reporting according to the requirements of 40 CFR §98.2(a)(3), except that the thresholds for reporting in California are 10,000 metric tons of CO_2e and an aggregate maximum heat input capacity of 12 MMBtu/hr or greater.

(4) Notwithstanding 40 CFR §98.2(b)(2), 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 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 refiner~~i~~es delivering petroleum fuels and/or biomass-derived fuels, as described in section 95121;

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(5) California consignees of imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas, as described in section 95122;

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

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~~(8) The emissions source categories specified in 40 CFR Part 98, Subparts E, F, G, I, K, L, O, R, T, X, Z, BB, CC, DD, EE, FF, GG, II, LL, OO, QQ, SS and TT. However, a reporting entity who after the effective date of this article commences an industrial process identified in one of these subparts must notify the Executive Officer within 90 days of beginning that new process;~~

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(h) *Cessation of Reporting*. A facility operator or supplier who is not subject to the cap-and-trade regulation, whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply with the requirements specified in ~~this paragraph~~ section 95101(h). A reporting entity that is subject to the cap-and-trade regulation must follow the requirements in section 95812 and continue to comply with all reporting requirements until there is no longer a compliance obligation. If the compliance obligation ceases, the reporting entity must still follow the requirements in section 95101(h) before ceasing to comply with the reporting requirements of this Article. The operator or supplier must provide the letter notifications specified below to the address indicated in section 95103 of this article.

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~~(3) The verification requirements of this article do not apply to the first full year of non-operation following a permanent shutdown, but continue to apply to prior emissions data reports.~~

(~~4~~3) Electric power entities must comply with the following requirements for cessation of reporting:

(A) Electric power entities that import or export electricity in 2011 or 2012 must continue to submit~~,~~ and certify~~, and verify~~ an emissions data report through the 2014 data year~~, the end of the first compliance period~~. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(B) Electric power entities that import or export electricity in any year of a subsequent compliance period must continue to submit~~,~~ and certify~~, and verify~~ an emissions data report through the end of the same compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(C) Electric power entities no longer importing or exporting electricity at the beginning of a subsequent compliance period are not required to submit, and certify~~, and verify~~ an emissions data report demonstrating that they have no imports or exports pursuant to this article, but must notify the Executive Officer in writing of the reason(s) for cessation of reporting. The notification must be submitted no later than March 31 of the year following the last year that the electric power entity is required to submit an emissions data report.

***

(i) *Cessation of Verification*. A facility operator, supplier, or electric power entity who wishes to cease annual verification must comply with the requirements specified in section 95101(i) and notify ARB by the applicable reporting deadline if the reporting entity has met the cessation criteria and intends to no longer obtain verification services. A reporting entity that is subject to the cap-and-trade regulation must follow the requirements in section 95812 and continue to comply with all verification requirements until there is no longer a compliance obligation. If the compliance obligation ceases, the reporting entity must still follow the requirements in section 95101(i) before ceasing to comply with the verification requirements of this Article.

(1) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraph 95101(a)(1) of this section cease to operate or are permanently shut down, the owner, operator, or supplier 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 or supplier's GHG-emitting processes and operations ceased to operate. Verification is not required for the emissions data report of the first full year of non-operation that follows.

(2) If the operations of an electric power entity are changed such that the entity ceases to import and export electricity, the electric power entity 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 imports and exports ceased. Verification is not required for the emissions data report of the first full year of

non-operation that follows.

(3) A facility operator or supplier whose emissions decrease to less than 25,000 metric tons of CO2e, including CO2 from biomass-derived fuels and geothermal sources, must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the first year in which the facility or supplier's emissions are less than 25,000 metric tons of CO2e.

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. [Definitions are not included here, but will be added to the proposed 45-day rulemaking package]

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.

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(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 cap-and-trade 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 2011 and each subsequent 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:

***

(2) ~~Total f~~Facility GHG stationary combustion emissions ~~aggregated~~ 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. If the 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 the 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.

***

(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 must report the information specified in section 95112(f).

***

(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. ~~This requirement begins in 2012 for facilities who were required to report GHG emissions to ARB in 2011, and begins in 2013 for facilities not previously reporting to ARB~~.

(9) Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted ~~only~~ if an error is discovered after the submission of the emissions data report. If the cumulative errors are found to exceed 5 percent of total CO_2e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, ~~in which case~~ a report that meets the full requirements of this article must be submitted within ninety days of discovery.

***

(e) *Reporting Deadlines.* Except as provided in section 95103(a)(7)-(8), each facility operator or supplier must submit an emissions data report ~~for the previous calendar year~~ no later than April 10 of each calendar year. Each electric power entity must submit an emissions data report ~~for the previous calendar year~~ 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 ~~for the previous calendar year~~ that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, or each reporting entity that has or has had a compliance obligation under the cap-and-trade regulation in any year of the current compliance period. The requirements of this paragraph also apply to electric power entities that are electricity importers or exporters that have not met the requirements for cessation in section 95101(~~h~~i). 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 September 1 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). If a reporting entity omits any covered product data, they must report a description of the omission and an estimated magnitude of the omission.

***

(i) *Calculation and Reporting of* De Minimis *Emissions*. A facility operator or supplier 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 or supplier 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 provided in Table A-1 of 40 CFR Part 98.

(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 cap-and-trade 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 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 cap-and-trade regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the cap-and-trade regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements of section 95852.1.1 of the cap-and-trade 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 of the cap-and-trade regulation.

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(3) When reporting biomethane, the operator or supplier who is reporting biomass emissions from biomethane fuel must also report, 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.

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 ARB review to demonstrate the receipt of eligible biomethane.

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(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 cap-and-trade 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.

***

(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~~ except in 2012, where the postponement request must be received by the reporting deadline in section 95103(e)~~. 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 ARB within ten (10) working days of a request by ARB.

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(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 or supplier must make this choice by January 1, 2013, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

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(3) When making~~proposing~~ a change in a monitoring or calculation method, an operator or supplier must indicate why the change in method is being proposed, and include~~provide~~ a demonstration of differences in estimated emissions under the two methods.

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(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 ARB and reporting responsibilities.

(1) *ARB 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 via email to ARB. Required information must be submitted to the ARB email account: ghgreport@arb.ca.gov

(A) The previous owner or operator must notify ARB 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 ARB 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. New Designated Representative for the California Reporting Greenhouse Gas Reporting Tool (Cal e-GGRT) account for the affected entity;

(2) *Reporting Responsibilities.* 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) 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) If an ownership change takes place during the calendar year, reported data will not be split or subdivided for the year, based on ownership. A single annual data report will be submitted for the entity by the current owner or operator. This report will represent required data for the entire, calendar year. Existing reporting accounts will be used unless it is infeasible.

(B) Previous owners or operators are required to provide data and records to new owners or operators that is necessary and required for preparing annual data reports required by this article.

(o~~n~~)*Addresses*. The following address shall be substituted for the addresses provided in 40 CFR §98.9 for both U.S. mail and package deliveries:

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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.

§ 95104. Emissions Data Report Contents and Mechanism.

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(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.

***

(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.

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.

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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.

§ 95105. Recordkeeping Requirements.

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(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 ~~covered~~ emissions equal to or exceeding 25,000 MT CO_2e (including biomass-derived CO_2 emissions), and each facility operator or supplier with a compliance obligation under the cap-and-trade regulation in any year of the current compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5), regardless of whether the facility operator or supplier is required to report under 40 CFR Part 98. For facilities, the Plan must also include the following elements, as applicable:

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(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 ~~is~~ are hereby incorporated by reference.

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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.

Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

§ 95110. Cement Production.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

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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.

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

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(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

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(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. 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 cap-and-trade regulation. 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:

***

2. If the amount of imported electricity deliveries from specified facilities or units as measured at the busbar is ~~not known~~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.
3. Supporting documentation must be provided for busbar claims.

(5) *Imported Electricity Supplied by Asset-Controlling Suppliers.* The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by ARB. The asset-controlling supplier must be identified on the physical path of NERC e-Tags as the PSE at the first point of receipt, regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path. The reporting entity must:

***

(B) ~~Report delivered electricity as specified and not as unspecified;~~Report Asset-Controlling Supplier power that was not properly acquired as specified power, as unspecified power;

***

(D) Report GHG emissions calculated pursuant to section 95111(b), ~~including~~using the transmission loss~~es~~ factor of 1.02 in all instances.

To claim power from an asset-controlling supplier, power must originate from the asset-controlling supplier system, as evidenced by the first line of the physical path table in the NERC e-tag which must specify the generation control area of the asset-controlling supplier, with the exception of path outs. Path outs are excess power, originally procured as part of a U.S. federal mandate to serve the operational or reliability needs of a U.S. federal system but which are no longer required due to changes in demand or system conditions.

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(b) *Calculating GHG Emissions*.

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(3) *Calculating GHG Emissions of Imported Electricity Supplied by Specified Asset-Controlling Suppliers.* Based on annual reports submitted to ARB pursuant to section 95111(f), ARB will calculate and publish on the ARB Mandatory Reporting website the system emission factor for all asset-controlling suppliers recognized by the ARB. The reporting entity must calculate emissions for electricity supplied using the following equation:

$$CO_2e = MWh \times TL \times EF_{ACS}$$

Where:

***

~~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.~~

***

(5) For system power imports above the default emission factor for unspecified electricity imports, electricity that is not tagged as originating from unique specified sources of generation but is instead tagged as system power cannot be claimed as an unspecified source. ARB shall calculate system power emission factors and publish them on the ARB Mandatory Reporting website using the following equation:

$EF_{sy} = E_{sy} / EG_{sy}$

Where:

E_{sy} = CO2e emission factor for system power recognized by ARB for the report year (MT of CO_2e/MWh).

E_{sy} = CO_2e emissions for a system for the report year (MT of CO_2e).

EG_{sy} = Net generation from a system for the report year (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 California retail sales. A retail ~~providers~~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.

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(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 cap-and-trade 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 ARB or U.S. EPA, the retail provider must include:

***

(C) *High GHG-Emitting Facilities or Units.* For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider through actual as opposed to implied ownership, 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 ARB or to U.S.EPA, the retail provider must report the following information:

***

(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 ARB pursuant to subsection 95111(g)(1) and by February 1 following each data year to obtain associated emission factors calculated by ARB for use 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 section 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 cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to section 95111(g)(1) in the emissions data report. Prior registration and section 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 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:

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(N) For verification purposes, 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~~.

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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.

§ 95112. Electricity Generation and Cogeneration Units.

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(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.

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(4) The disposition of generated electricity in MWh, reported at the facility-level, including <u>for each of the following disposition categories, if applicable</u>:

(A) <u>*Generated Electricity For Grid.*</u> 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) <u>*Generated Electricity For Other Users.*</u> 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;

(C) <u>*Generated Electricity For On-Site Industrial Applications Not Related to Electricity Generation.*</u> If the facility includes industrial processes or operations that are neither in support of or a part of the power generation system, report the amount of generated electricity used by those on-site industrial processes or operations.

Separately report the amount of generated electricity that is used to produce cooling energy if:

1. the facility provides cooling energy (e.g., chilled water) to a particular end-user outside of the facility boundary; or
2. the facility includes on-site industrial processes or operations that are neither in support of nor a part of the power generation system, and a portion of the generated electricity is used to produce cooling energy for such on-site industrial process or operations.

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 paragraph 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) Operators of a cogeneration or bigeneration unit. Report ~~T~~the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit (“generated thermal energy”)~~, if applicable~~, 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.

(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, NO_x 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 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.

Separately report the amount of generated thermal energy that is used to produce cooling energy or distilled water if:

1. the facility provides cooling energy (e.g., chilled water) or distilled water to a particular end-user outside of the facility boundary, or
2. the facility includes on-site industrial processes or operations that are neither in support of or a part of the power generation system, and a portion of the generated thermal energy is used to produce cooling energy or distilled water for such on-site industrial process or operations.

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 paragraph 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 ~~in 2012 or later~~, 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 ~~in 2012~~, the operator must resubmit an updated diagram to ARB.

***

(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 ARB. 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 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).

***

(2) Net and gross power generated, in megawatt hours (MWh). <u>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).</u>

(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 <u>and can be potentially utilized in other industrial operations that are not electricity generation</u>. 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. <u>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).</u>

***

(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 CO2 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.

***

(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.

***

(f) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units ~~that produce hydrogen on-site must report information on the fuels or feedstocks used in hydrogen production. The operator~~ must include the following information in the annual GHG emissions data report:

***

(4) Cogeneration information in section 95112(b)(3), if applicable.
(5) CO_2 emissions from the hydrogen fuel cell, 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 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.

$$CO_2\ (MT/year) = H\ (MMBtu/year) \times EF\ (kg\ CO_2/MMBtu) \times 0.001\ (MT/kg)$$

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.

***

(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 ~~40 CFR §98.35 when reporting in 2012, and~~ section 95129 of this article ~~when reporting in 2013 and later years~~. 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.

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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.

§ 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 petroleum refineries to ARB, except as otherwise provided in this section. Petroleum refinery operators and the refiners who are suppliers of transportation fuels reported by the associated petroleum refinery are considered separate reporting entities for the purposes of this Article.

***

(k) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.255 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

(l) *Additional Product and Process Data*.

(1) *Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR 98, each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, barrels for liquid products, short tons for solid products), and calcined coke (short tons). For calcined coke, specify whether the calciner is integrated with the petroleum refinery operation. Among the products reported, only calcined coke and primary

refinery products will be subject to review for material misstatement under the requirements of section 95131(b)(12). Verifiers must evaluate reasonable assurance of conformance and reasonable assurance of material misstatement for primary refinery products through 2014 data verifications. Beginning with 2015 data reported in 2016, verifiers will evaluate primary refinery products for reasonable assurance of conformance, and will not evaluate reasonable assurance of material misstatement.

(A) ~~For calcined coke, the operator may voluntarily report the annual short tons of calcined coke for calendar years 2011 and 2012. If the operator chooses to report this 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, t~~The operator must report and verify the annual short tons of calcined coke.

(2) *Energy Intensity Index.* For refineries that participate in the Solomon Energy Reviews, the operator must report its most current Solomon EII values for the applicable data year. Each refinery operator must demonstrate to the verifier that the Solomon EII value reported is the correct value by providing documentation from Solomon & Associates.

(3) *CO_2 Weighted Tonne (CWT) Calculation.*

(A) *Reporting of CWT Throughput Functions.* ~~For data years 2013 and later t~~The operator must report values for the CWT functions listed in Table 1 of this section. Report quantities of net fresh feed (F), reactor feed (R, includes recycle), product Feed (P), or synthesis gas production for POX units (SG) as indicated. Beginning with data year 2013, CWT is considered covered product data and subject to material misstatement.

***

(C) *Units and Accuracy.* Report annual volume in both barrels and mass, in thousands of metric tons, unless other basis units are indicated in column 3 of Table 1 of this section. In order to meet the desired accuracy for CWT, throughput values reported in thousands of metric tons per year must use a certain number of decimals depending on the magnitude of the CWT factor:

~~(i)~~1.	For factors up to 1.99:	0 decimals
~~(ii)~~2.	For factors between 2.00 and 19.99:	1 decimal
~~(iii)~~3.	For factors between 20.00 and 99.99:	2 decimals
~~(iv)~~4.	For factors above 100.00:	3 decimals

(D) *Density Measurements.* Measure the density of each throughput on an annual basis for purposes of converting each throughput from barrel to mass units. The measurements must follow the requirements of section 95103(k).

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.

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(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 hydrogen whether sold to other entities or consumed on-site.

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(e) *Sampling Frequencies.* When monitoring GHG emissions without a CEMS as specified at 40 CFR §98.164(b)(2), and reporting data as specified at §98.166, the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.

(1) When reporting CO_2 emissions using a CEMS as specified in 40 CFR §98.163(a), the reporter must calculate and report the annual CO_2 emissions from each fuel and feedstock separately. The reporter may use engineering calculations to estimate these separate fuel and feedstock emissions. For each feedstock, reporters must report data specified below.

(A) For each gaseous feedstock, report the monthly volume used (in scf) and the weighted average carbon and hydrogen content from the results of one or more analyses for that month for natural gas or a standardized feedstock specified in Table 1 of section 95115, or from daily analysis for other gaseous feedstocks such as refinery fuel gas.

(B) For each liquid feedstock, report the monthly volume used (in gallons) and the weighted average carbon and hydrogen content from the results of one or more analyses for that month for a standardized feedstock specified in Table 1 of section 95115, or from daily sampling for that moth for other liquid feedstocks. Daily liquid samples may be combined to generate a monthly composite sample for carbon and hydrogen analysis.

(C) For each solid feedstock, report the monthly mass used (in kg) and the weighted average carbon and hydrogen content from the results of daily sampling for that month. Daily solid samples may be combined to generate a monthly composite sample for carbon and hydrogen analysis

(~~1~~2) When reporting CO_2 emissions for gaseous fuel and feedstock as specified in

40 CFR §98.163(b)(1), the reporter must calculate and report the annual CO_2 emissions from each gaseous fuel and feedstock separately according to Equation P-1 of this section. The reporter may use engineering calculations to estimate these separate fuel and feedstock emissions. ~~t~~The operator must use a weighted average carbon content from the results of one or more analyses for month n for natural gas or a standardized fuel or feedstock specified in Table 1 of section 95115, or from daily analysis for other gaseous fuels and feedstocks such as refinery fuel gas~~;~~. For each feedstock, reporters must report carbon and hydrogen content using a weighted average from the results of one or more analyses for month n for natural gas or a standardized feedstock specified in Table 1 of section 95115, or from daily analysis for other gaseous feedstocks such as refinery fuel gas.

(~~2~~3) When reporting CO_2 emissions for liquid fuel and feedstock as specified in 40 CFR §98.163(b)(2), the reporter must calculate and report the annual CO_2 emissions from each liquid fuel and feedstock separately according to Eq. P-2 of this section. The reporter may use engineering calculations to estimate these separate fuel and feedstock emissions. T~~t~~he operator must use weighted average carbon content from the results of one or more analyses for month n for a standardized fuel or feedstock specified in Table 1 of section 95115, or from daily sampling for month n for other liquid fuels or feedstocks. Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis~~;~~. For each feedstock, reporters must report carbon and hydrogen content from the results of one or more analyses from month n for a standardized feedstock specified in Table 1 of section 95115, or from daily sampling for month n for other liquid feedstocks. Daily liquid samples may be combined to generate a monthly composite sample for carbon and hydrogen analyses.

(~~3~~4) When reporting CO_2 emissions for solid fuel and feedstock as specified in 40 CFR §98.163(b)(3), the reporter must calculate and report the annual CO_2 emissions from each solid fuel and feedstock separately according to Eq. P-3 of this section. T~~t~~he operator must use weighted average carbon content from the results of daily sampling for month n. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis. For each feedstock, reporters must report carbon and hydrogen content from the results of daily sampling for month n. Daily solid samples may be combined a generate a monthly composite sample for carbon and hydrogen analysis

***

(g) *Data Reporting Requirements.* When reporting data as specified at 40 CFR §98.166, the operator m~~ay~~ust also report the mass~~amount~~ of carbon dioxide and methane ~~in unconverted feedstock and CO_2~~ 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 provided in this regulation). To avoid double-counting, ~~such carbon may~~ these emissions must be subtracted from the total ~~carbon~~facility emissions ~~in the feedstock~~. ~~For example, 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 provided in this regulation, may be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.~~

***

(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 h~~H~~ydrogen production facilities must~~should adjust~~ subtract these reported emissions ~~for~~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 annual mass of hydrogen gas and liquid hydrogen produced (metric tons) and specify if the hydrogen plant is an integrated refinery operation. Hydrogen producers must also report the mass of on-purpose hydrogen and by-product hydrogen produced at their facility. The operator must also report the mass of hydrogen produced and sold as a transportation fuel and contract quantities and purchase entities for all hydrogen sold.

(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 emissions from fuel stationary combustion sources as set-forth in 40 CFR §98.33(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.

§ 95115. Stationary Fuel Combustion Sources.

***

(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 1 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 ~~their~~these emissions are not subject to a compliance obligation under the cap-and-trade, except as limited by section 95115(e) ~~regulation and which are not mixed prior to combustion with fuel that has emissions with a compliance obligation~~.

***

(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~~it~~ measured by lot, the term “n” in Equation C-2b is substituted as the number of lots received in the year.

***

(e) *Procedures for Biomass CO_2 Determination.* Reporting entities must use the following procedures when calculating emissions from biomass-derived fuels that are intermixed with fossil fuels~~ prior to measurement~~:

***

(h) *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B) and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to 40 CFR 98 Subpart C that are associated with one source category must not be grouped with other Subpart C units associated with another source category, except when 40 CFR §98.36(c)(2) applies. Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). Units subject to section 95112 must use the criteria for aggregation in section 95112(b). Facility operators that choose to aggregate units according to the common stack provision in 40 CFR §98.36(c)(2) may report emissions according to 40 CFR §98.36(c)(2), but they must separately report the ~~heat input (MMBtu)~~fuel use by fuel type as a percentage of the aggregated fuel consumption attributed to~~for~~ each individual unit or each group of units of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this paragraph.

***

(l) *Information on Natural Gas Supplied to Downstream Users*. The operator who is reporting emissions from the combustion of natural gas must report whether any of the natural gas reported pursuant to section 95115(k) was supplied to downstream users outside of the operator's facility boundary. If so, the operator must report the name of the facility and the annual MMBtu delivered to each user according to billing statements or financial records.

(m~~l~~) *Procedures for Missing Data*. To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129~~ beginning with the 2013 emissions data report. For reporting of 2011 emissions in 2012, the operator must use the applicable missing data substitution requirements of 40 CFR Part 98~~.

(n) *Additional Product Data.* Operators of the following types of facilities must also report the production quantities indicated below.

***

(5) The operator of a poultry processing facility must report the quantity of whole chicken and chicken parts, poultry deli products, and protein meal produced in the data year (lbs).

(6) The operatory of a facility that manufactures dehydrated flavors must report the production of dried onion, dried garlic, dried chili peppers, dried parsley, and dried spinach in the data year (lbs).

(7) The operator of a brewery must report the quantity of ethanol produced associated with ale production, and the annual quantity of ethanol produced associated with lager production in the data year (hectoliter (hL) of ethanol).

(8) The operator of a snack food manufacturing facility must report the quantity of the following products produced in the data year: fried potato chips, baked potato chips, corn chips, fried corn curls, coated pretzels, pretzels, Cheetos, Funyuns, Nacho Cheese Doritos (short tons).

(9) The operator of a sugar manufacturing facility must report the quantity of granulated refined sugar (white sugar that is 99.9% sucrose) produced in the data year (short tons)

(10) The operator of a tomato processing facility must report the quantity of the following products produced in the data year: asceptic paste, asceptic whole/diced, canned paste, canned whole/diced (short tons (equivalent)). The operator must also report canned juice and canned non-tomato additive produced in the data year (short tons).

(11) The operator of a pipe foundry must report the production of ductile iron pipe produced in the data year (short tons).

(12) The operator of a facility producing aluminum billets must report the production of iron billets in the data year (short tons).

(13) The operator of a facility involved in the mining or processing of rare earth minerals must report the production of rare earth oxide equivalents (short tons).
(14) The operator of a facility involved in the mining or processing of diatomaceous earth must report TBD (short tons).
(15) The operator of a forging facility must report TBD (short tons).
(16) The operator of a lead production, recycling, recovery, or manufacturing facility must report TBD (short tons).

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.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in-paragraphs (1)-(3) below.

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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.

§ 95117. Lime Manufacturing.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.195 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values 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 <u>for the reporting year</u>.

***

(3) For each missing value of the quantity of lime produced (by lime type) and quantity of lime byproduct/waste produced and sold <u>used to calculate emissions pursuant to 40 CFR §98.193</u>, the operator must~~, when calculating emissions,~~ apply a substitute value according to the procedures in paragraphs (A)-(B) below.

***

<u>(e) *Produced CO_2 Used On-Site*. If a CEMS is not used to measure CO_2 emissions, the facility operator shall report data required by 40 CFR §98.196(b)(17), with the clarification that the referenced: Annual amount of CO_2 captured for use in the on-</u>

site process, reflects CO_2 process emissions generated by the facility that is not released to the 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.

§ 95118. Nitric Acid Production.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

***

(2) For each missing value of nitric acid production used to calculate emissions pursuant to 40 CFR §98.223, the operator must substitute the missing data values according to the procedures in paragraphs (A)-(B) below.

***

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

***

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

***

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

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.175 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

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.

***

(a) *GHGs to Report.*

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(2) Refiners, position holders of fossil fuels and biomass-derived fuels that supply fuel at California terminal racks, and enterers outside the bulk transfer/terminal system of fossil fuels 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 of this section. However, reporting is not required for fuel in which a final destination outside California <u>or where a use in exclusively aviation or marine applications</u> can be demonstrated. 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 of 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.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, Liquefied Petroleum Gas, Compressed Natural Gas, and Liquefied Natural Gas.

***

(a) *GHGs to Report.*

***

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies ~~and~~ <u>including</u> intrastate pipelines <u>delivering gas to</u>

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 ~~provided~~ delivered to all entities on their distribution systems in California

(3) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural 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 liquefied petroleum gas, compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside California can be demonstrated

(b) *Calculating GHG Emissions.*

***

(2) For the calculation of CO_{2i} in 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 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 or publicly owned natural gas utilities must be estimated only if emissions from the redelivered natural gas equals or exceeds 25,000 $MTCO_2e$ 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:

***

(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_{2i} = Emissions from natural gas received at the state border or city gate, calculated pursuant to 95122(b)(2).

CO_{2j} = Emissions from natural gas received for redistribution to or received from other natural gas transmission companies, calculated pursuant to 95122(b)(3).
CO_{2l} = Emissions from storage and direct deliveries from producers calculated pursuant to 95122(b)(4).

***

(9) The California consignee for imported liquefied petroleum gas 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 98 must be used in place of Table NN-2. For liquefied petroleum gas, the consignee must 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 consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98. The California consignee for compressed natural gas or liquefied natural gas 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 natural gas received.

(10) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas 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).

***

(d) *Data Reporting Requirements.*

***

(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:

***

(D) ~~For each publicly-owned natural gas utility to which a local distribution company~~ In lieu of reporting the information specified in 40 CFR §98.406(b)(6), local distribution companies, including intrastate pipelines that deliver~~s~~ natural gas to downstream gas pipelines and other local distribution companies,~~ the local distribution companies~~ must report the annual volumes in Mscf, annual energy in MMBtu, and the information required in 40 CFR §98.406(b)(12)~~, including EIA number~~. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) ~~For each customer,~~In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies including intrastate pipelines ~~that report under 40 CFR §98.406 (b)(7)~~ must report the annual volumes in Mscf, annual energy in MMBtu, ~~and~~ 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.

***

(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~~, local distribution companies, interstate pipelines or other intrastate pipelines~~ 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 volumes (Mscf) and 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 ~~not~~ required to estimate a value~~s~~ for CO_{2j} ~~and CO_{2l}~~ 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) ~~and (b)(4) and~~ must ~~use~~ have a value of 0 for ~~both when~~ calculating emissions as required by §95122(b)(6).

***

(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 purchased by the LDC on behalf of and delivered to end users must also report, for each contracted delivery, the information specified in section 95103(j)(3).

***

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.

***

(a) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.425 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided below.

***

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 ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.182(d), 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 95124(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95118(c)-(d), and section 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 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 the annual mass or carbon content of carbon-containing inputs are missing when using the process emissions calculation procedure in 40 CFR §98.183(b)(2), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.225(a) and the number of days per month.

(B) 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 maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for estimating missing data pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* The operator of a lead production facility must report the annual production of TBD.

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

§ 95129. Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

***

(c) *Missing Data Substitution Procedures for Fuel Characteristic Data.* When the applicable emissions estimation methods of this article require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight) the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each data year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR §98.34(a)(2)-(3), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in section 95129(c)(1)-(3). The data capture rate for the data year must be calculated as follows for each type of fuel and each fuel characteristic parameter:

***

(3) If the operator is unable to obtain fuel characteristic data such that less than 80.0 percent of ~~emissions from a source~~a fuel characteristic data element are directly accounted for, the operator must then substitute for each missed data point the greater of the following:

***

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 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.

***

(a) *Annual Verification.*

***

(A) The emissions data report is for the 2011 data year;

***

(D) A change of ~~ownership~~ <u>operational control</u> of the reporting entity occurred in the previous year.

***

(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, or Climate Action Reserve<u>. This limitation applies to individual ARB ID's subject to annual verification. The six year period is considered to have begun on the date the verification body first provided verification services to the reporting entity and ends on the date the final verification statement is submitted.</u>

***

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.

***

***

(b) Verification services shall include, but are not limited to, the following*:*

***

(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:

***

(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 emissions and product data are free of material misstatement ~~and the emissions data report otherwise conforms to the requirements of this article~~. At a minimum, data checks must include the following:

***

~~4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and~~

***

(F) The verification team is responsible for ensuring via data checks that the emissions data report conforms to the requirements of this article. The verifier's review of conformance must include, as applicable, but is not limited to:

1. Ensuring the accuracy of natural gas provider and annual volume of natural gas delivered reported pursuant to section 95115(k) by facilities that combust natural gas.
2. Ensuring the completeness and accuracy of end-users information and natural gas deliveries reported pursuant to section 95122(d)(4)(D) by suppliers of natural gas.
3. Ensuring the completeness and accuracy of electricity provider and natural gas provider information, including provider name and account identification number, pursuant to sections 95104(d)(1) and 95115(k).

***

(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 ~~make any possible improvements or corrections to~~ emissions or covered product data in the submitted emissions data report, and submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. Failure to fix correctable errors that do not affect emissions or covered product

data represents a non-conformance with this article but do 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 result from truncation or rounding or averaging.

The verification team should document the source of any difference identified, including whether the difference results in a correctable error.

***

(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 parts of this article).

(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):

$$Percent\ error\ (emissions) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{Total\ reported\ covered\ emissions}$$

or

$$Percent\ error\ (product\ data) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{\cancel{Total}\ covered\ product\ data}$$

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. This variable does not apply to covered product data, except in the case of covered product data reported by the cement sector in section 95110(d).

***

"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

***

(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 ~~a~~ product data verification statement(s), and provide those statements to the reporting entity and ARB 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.

***

(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 ARB, the verification body shall notify the reporting entity and the reporting entity shall be provided at least ten working days to modify the emissions data report to correct any material misstatements or nonconformance found by the verification team. The verification body must also provide notice to ARB of the potential for an adverse verification statement(s) at the same time it notifies the reporting entity. The modified report and verification statement(s) must be submitted to ARB before the ~~applicable~~ verification deadline, ~~unless~~even if the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

***

(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 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 that does not affect the emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement.

***

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.

***

(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 ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

***

2. A verification body shall ~~have~~ <u>employ</u> and retain at least five total full-time staff.

***

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.* The Executive Officer may review and, for good cause, including any violation of subarticle 4 of this article or any similar action in an analogous GHG system, modify, suspend, or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

***

<u>4) *Withdrawal of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.*</u>

(A) An accredited verification body or individual verifier may request to withdraw voluntarily its accreditation by providing a written notice to the Executive Officer.

***

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.

***

(b) The potential for a conflict of interest must be deemed to be high where:

***

(2) Within the previous five years, any ~~staff member~~ employee of the verification body or any related entity or a subcontractor who is a member of the verification team has provided to the reporting entity any of the following services:

***

(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, unless those systems will not be part of the verification process;

***

(T) Verification services that are not conducted in accordance with, or equivalent to, section 95133.

***

(4) Any individual person or company that is hired by a reporting entity, and which in turn contracts with a verification body to conduct verification services on behalf of reporting entity, is also considered in the conflict of interest assessment in this article.

~~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).~~

(c) The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

***

(2) Any ~~non-verification~~ 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 independent greenhouse gas emissions verification conducted in accordance with, or equivalent to, section 95133 provided by the verification body or verification team outside the jurisdiction of ARB is excluded from this financial assessment but must be disclosed to ARB in accordance with section 95133(e).

(3) Non-ARB 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 standards.

***

(g) *Monitoring Conflict of Interest Situations.*

***

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the reporting entity or related entity for which the body has provided verification services, the verification body shall notify the Executive Officer of the contract and the nature of the work to be performed, and revenue received. The Executive Officer, within 30 working days, will determine the level of~~or~~ conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

***

(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;

***

Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems.

***

§95151. Reporting Threshold.

(a) The operator of a facility must report GHG emissions under this subarticle if the facility contains petroleum and natural gas systems and the facility meets the requirements of sections 95101~~(a)~~ (b) and the reporting thresholds outlined in section 95101(e). ~~Facilities with source categories listed in section 95150 must report emissions if their stationary combustion and process emission sources emit 10,000 metric tons of CO_2 equivalent or more per year, or their stationary combustion, process, fugitive and vented emissions equal or exceed 25,000 metric tons of CO_2 equivalent or more per 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.

§95152. Greenhouse Gases to Report.

***

(c) For an onshore petroleum and natural gas production facility, the operator must report CO_2, CH_4, and N_2O emissions from the following source types on a well-pad or associated with a well-pad:

***

(6) Crude oil or g~~G~~as well venting during well completions and workovers;

***

(15) Crude oil, ~~and,~~ condensate and produced water CO_2 and CH_4;
~~(16) Produced water CO_2 and CH_4;~~

***

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.

***

(c) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (e.g. permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in paragraphs (c)(1)-(c)(10) below.

***

(7) Determine volume fraction of CO_2content in natural gas out of the AGR unit using one of the methods specified in paragraph (c)(7) of this section.

~~1.~~A. If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the operator may install a continuous gas analyzer.

~~2.~~B. If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in section 95154(b).

~~3.~~C. Use sales line quality specification for CO_2 in natural gas.

***

(f) Crude oil and g~~G~~*as well venting during well completions and well workovers*. Using one of the calculation methodologies in this paragraph (f)(1) through (f)(5) below, operators must calculate CH_4, CO_2 and N_2O (when flared) annual emissions from crude oil and gas well venting during both conventional completions and completions involving hydraulic fracturing in wells and both conventional well workovers and well workovers involving hydraulic fracturing.

(1) *Calculation Methodology 1*. Measure total gas flow with a recording flow meter (analog or digital) installed in the vent line ahead of a flare or vent id used. The facility operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{\mathrm{CO2}\cancel{/}\mathrm{or\ N2}} - V_{SG} \quad \text{(Eq. 8)}$$

Where:

E_a = Natural gas emissions during the well completion or workover at actual conditions (m^3).

V_M= Volume of vented gas measured during well completion or workover (m^3).

$V_{\mathrm{CO2}\cancel{/}\mathrm{or\ N2}}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).

***

(h) ~~Dump Valves~~Onshore production and storage tanks. Calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using the method found in 95153(i).

***

(m) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor with a rated horsepower of 250hp or greater covered by sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3) the operator must conduct an annual measurement in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement:

***

(C) Not operating depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

***

~~(D)~~2. An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

***

(3) For blowdown valve leakage and isolation valve leakage to open ended vents, use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in sections 95154(c) and 95154(d), respectively. For through valve leakage, such as isolation valves, the facility operator may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

***

(p) *Population count and emission factors.* This paragraph applies to emissions sources listed in sections 95152(c)(16), (f)(5), (g)(3), (h)(3), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (p) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 27 of this section.

***

(u) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection as follows:

$$Mass_{CO2} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. 33)}$$

Where:

***

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.
GHG_i = Mass fraction of GHG_i in critical phase injection gas.
$1x\ 10^{-3}$ = Conversion factor from kilograms to metric tons.

(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. 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:

$E_{CO2/CH4}$ = 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 a sampling methodology and ~~a~~ ARB's flash liberation test ~~such as~~ 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.~~Determination of Methane, Carbon Dioxide, and Volatile Organic Compounds from Crude Oil and Natural Gas Separation and Storage Tank Systems". adopted Gas Processor Association, American Society for Testing and Materials, or U.S. EPA standards.~~ 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 ARB as part of the emissions data report.

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:

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e. The vapor recovery system method is included in Appendix B.

***

(y) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C of 40 CFR Part 98, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (y)(1)(A). If the fuel combusted is natural gas and is of pipeline quality specification, use the calculation methodology described in paragraph (y)(1)(A) and the facility

operator may use the emission factor provided for natural gas as listed in Subpart C, Table C-1. If the fuel is natural gas, and is not pipeline quality calculate emissions according to paragraph (y)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (y)(2).

(A) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1 of Subpart C, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in section 95115.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality, calculate combustion emissions as <u>specified in section 95115(c)(4) and as</u> follows:

(A) The operator may use company records, <u>which includes the common pipe method,</u> to determine the volume of fuel combusted in the unit during the reporting year.

***

(C) Calculate GHG volumetric emissions at actual conditions using Equations 35 and 36 of this section:

$$\underline{E_{a,CO2} = \sum_{n=1}^{12}\left[(V_a * Y_{CO2}) + \eta \sum_{j=1}^{5} V_a * Y_j * R_j\right]} \qquad \text{(Eq. 35)}$$

$$E_{a,CH4} = \cancel{V_a * (1 - \eta) * Y_{CH4}} \sum_{n=1}^{12}[V_a * (1 - \eta) * Y_{CH4}] \qquad \text{(Eq. 36)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the year.

Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using an engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Concentration of gas hydrocarbon constituent j (such as methane, ethane, propane, butane and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.

n = Month of the year

Calculate CO_2 and CH_4, volumetric emissions at standard conditions using the provisions of section 95153(r). Use the provisions in sections 95153(s) and (t) to covert volumetric gas emissions to GHG volumetric and GHG mass emissions respectively.

(D) Calculate N_2O mass emissions using Equation 37 of this section.

$$Mass_{N2O} = (1 \, x \, 10^{-3}) * Fuel * HHV * EF \qquad \text{(Eq. 37)}$$

Where:
$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons N_2O).
Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV = For the higher heating value for field gas or process vent gas, use either a weighted average of quarterly measurements of HHV or a default value of 1.235×10^{-3} mmBtu/scf for HHV.
EF = Use 1.0×10^{-4} kg N_2O/mmBtu.
1×10^{-3} = Conversion factor from kilograms to metric tons.

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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.

§ 95154. Monitoring and QA/QC Requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable and as specified in this section. Offshore petroleum and natural gas production facilities must adhere to the monitoring and QA/QC requirements as set forth in 30 CFR §250 (July 1, 2011), which is hereby incorporated by reference.

(a) Facility operators must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in sections 95153(i), (m), (n) and (o) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument*. Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR Part 60, subarticle A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subarticle A, Table 1: *Detection Sensitivity Levels*; §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and

§60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records (July 1, 2011, which is hereby incorporated by reference). Any emissions detected by the optical gas ~~imagining~~ imaging instrument is a leak unless screened with Method 21 (40 CFR Part 60, appendix A-7 (July 1, 2011), which is hereby incorporated by reference) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, facility operators must operate the optical gas ~~imagining~~ imaging instrument to image the source types required by this subarticle in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas ~~imagining~~ imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than two meters above a support surface.

***

~~(f) *Special reporting provisions: best available monitoring methods*. Best available monitoring methods will be allowed for the reporting of 2012 data as described in paragraphs (1)-(4). Beginning with collection of data on January 1, 2013, best available monitoring methods will no longer be allowed.~~

~~(1) ARB will allow owners or operators to use best available monitoring methods for certain parameters in section 95153 as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:~~

~~(A) Monitoring methods currently used by the facility operator that do not meet the specifications of this subarticle.~~
~~(B) Supplier data.~~
~~(C) Engineering estimation.~~
~~(D) Other company records.~~

~~(2) Operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subarticle, and only where required measurements cannot be duplicated due to technical limitations after December 31, 2012. These well-related sources are:~~

~~(A) Gas well venting during well completions and workovers as specified in section 95153(f).~~
~~(B) Well testing venting and flaring as specified in section 95153(e).~~

~~(3) Operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subarticle, specifically for events that generate data that can be collected in 2012 and cannot be duplicated after December~~

~~31, 2012. These sources are:~~

~~(A) Cumulative hours of venting, days, or times of operation in sections 95153 (d), (e), (f), (j), (m), (n), (o), and (p).~~
~~(B) Number of blowdowns, completions, workovers, or other events in sections 95153(e), (f), (g), and (u).~~
~~(C) Cumulative volume produced, volume input or output, or volume of fuel used in sections 95153(c), (d), (h), (i), (j), (k), (l), and (y).~~

~~(4) Operators may use best available monitoring methods for sources requiring leak detection and/or measurement. These sources include:~~

~~(A) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152 (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4).~~
~~(B) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152(d)(5), (e)(6), (f)(5), (g)(3), and (h)(3).~~
~~(C) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in sections 95152(c)(3) and (d)(4).~~
~~(D) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in sections 95152(c)(17) (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1).~~

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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.

§ 95156. Additional Data Reporting Requirements.

Operators must conform with the data reporting requirements in section 95157 except as specified below.

(a) In addition to the data required by section 95157, the operator of an onshore and offshore petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

***

(11) ~~The operator of an onshore petroleum and natural gas production facility may voluntarily report the annual product data information in sections 95156(a)(9)-(10) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(a)(9)-(10).~~

(b) For dry gas production, the operator of an onshore petroleum and natural gas production facility <u>must</u>~~may voluntarily~~ report its annual volume of dry gas produced (~~Mscf~~MMBtu) ~~for calendar years 2011 and 2012~~. ~~If the operator chooses to report the 2011 and 2012 dry gas produced, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the volume of dry natural gas produced (MscfMMBtu).~~

~~(c) For underground natural gas storage, the operator must report the volume of natural gas extracted (Mscf).~~

***

~~(e) The operator of a natural gas liquid fractionating facility or a natural gas process facility may voluntarily report the annual product data information in sections 95156(d)(1)-(12) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(d)(1)-(12).~~

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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.

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(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.

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(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:

***

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 ~~sub-~~basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas ~~imagining~~ imaging instrument pursuant to section 95154(a) (refer to section 95153(i)), or acoustic leak detection of scrubber dump valves, report the following:

***

(18) For EOR hydrocarbon liquids dissolved CO_2 (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.
~~(B) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.~~
(~~C~~B) Report annual CO_2 and CH_4 emissions at the basin level.

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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.

Appendix B

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

TEST PROCEDURE

Flash Emissions of Greenhouse Gases and
Other Compounds from Crude Oil and Natural Gas
Separator and Tank Systems

Test Procedure

Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems

1. PURPOSE AND APPLICABILITY

This procedure is used to determine annual emission rates of Greenhouse Gases and other compounds from crude oil and natural gas separator and tank systems. This procedure is conducted by gathering one sample of crude oil or condensate and one sample of produced water from a pressurized vessel and having the liquids analyzed by a laboratory to determine the composition and volume of gas released from the liquids while they change from reservoir to standard atmospheric conditions. The laboratory results are used in conjunction with throughput to calculate the emission rates per year. The sampling and lab analyses may also be conducted to evaluate emissions from Flowback Fluids used to stimulate or hydraulically fracture a crude oil or natural gas well if they are handled by a separation and tank system. An alternative methodology is included for determining the specified emissions rates using measured vapor recovery system parameters provided the system meets the requirements specified in Section 9.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

The sampling and laboratory methods specified in this procedure are used to take samples of liquids and conduct a Flash Analysis on crude oil or natural gas separator and tank systems and are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (EPA), and Gas Processor Association (GPA) methods and standards. The alternative vapor recovery system methodology described in Section 9 and 10.2 is based on common industry practices.

Samples must be taken from a primary vessel located in a separator and tank system using the sampling methods specified in this procedure. Non-pressurized tanks or secondary vessels may not be used for sampling. Typical sampling points are from pressurized Two-Phase or Three-Phase Separators or vessels used to measure Percent Water Cut (e.g., Automatic Well Tester). The liquids found in these vessels contain gases that will flash from the liquids as vapor when the liquids flow into lower pressure secondary vessels. This procedure is used to measure both the volume and composition of this flashed gas vapor. Liquid samples of a crude oil-produced water emulsion do not contain enough crude oil to be evaluated by a laboratory and are not applicable to this procedure.

Two sampling methods are specified: The first is a displacement method used for gathering crude oil or condensate. The second is for gathering produced water. Both methods are specified due to the nature of the laboratory analyses and the design of the sampling cylinders. Produced water cannot be displaced from a Double-Valve Cylinder using laboratory grade water and heavy crude oil may solidify and cause problems with a Floating-Piston Cylinder.

The laboratory methods are used to measure the composition and volume of gas that flash from liquids while they cool or depressurize to standard atmospheric conditions. This includes the molecular weight and weight percent of the gaseous compounds and a Gas-Oil-Ratio or Gas-Water-Ratio. The laboratory results are applied to the annual liquid production rates to calculate Greenhouse Gas and other compound emission rates per year.

3. DEFINITIONS

For the purposes of this procedure, the following definitions apply:

3.1 "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.

3.2 “BTEX” means gaseous compounds of benzene, toluene, ethyl benzene, and xylenes.

3.3 “Condensate” means hydrocarbon liquid, separated from crude oil or natural gas, that condenses due to changes in temperature, pressure, or both, and which remains in liquid form under standard conditions.

3.4 “Crude Oil” means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbon ranging from one to hundreds of carbon atoms in straight and branched chain rings.

3.5 “Double-Valve Cylinder” 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.

3.6 “Emulsion” means any mixture of crude oil, condensate, or produced water in any proportion.

3.7 “Flashing” 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.

3.8 “Flash Analysis” 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.

3.9 “Flash Vapor” means the resulting quantity of hydrocarbon vapor and carbon dioxide that is emitted from the liquid when the liquid changes temperature and pressure.

3.10 “Floating-Piston Cylinder” 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.

3.11 “Flowback Fluid” means chemicals, fluids, or proppants 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.

3.12 “Flowback Period” means the time it takes for an equivalent volume of injected chemicals, fluids, or proppants injected into a crude oil or natural gas well to flow from the well and be processed by a tank system.

3.13 “Gas-Oil-Ratio (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.

3.14 “Gas-Water-Ratio (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.

3.15 “Graduated Cylinder” 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.

3.16 “Greenhouse Gases” means Carbon Dioxide and Methane for the purposes of this Test Procedure.

3.17 “Operating Pressure” 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.

3.18 “Operating Temperature” means the temperature that characterizes the conditions of crude oil, condensate, or produced water inside a particular process, pipeline, vessel or tank.

3.19 “Percent Water Cut” means the percentage of water by volume, of the total emulsion throughput as measured using ASTM D-4007. The percent water cut is expressed as a percentage.

3.20 “Primary Vessel” 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.

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

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

3.23 “Secondary Vessel” 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.

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

3.25 “Sump” 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.

3.26 “Tank” means a container, constructed primarily of non-earthen materials, used for holding or storing crude oil, condensate, produced water, or emulsion.

3.27 “Tentatively Identified Compound List” means a list of target compounds that laboratories can use to evaluate uncommon gaseous compounds when performing a Gas Chromatograph/ Mass Spectrometry analysis.

3.28 "Three-Phase Separator" means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil, produced water and gases.

3.29 "Two-Phase Separator" means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil and produced water that still contain entrained gases.

3.30 "Throughput" 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 between those liquids and the produced water.

3.31 "Vapor Recovery System" means equipment installed on vessels including piping, connections, and if necessary, flow-inducing devices, designed to capture, control, or treat gaseous emissions, or for routing gas into a process as a product, as a fuel source, or for subsequent thermal destruction.

3.32 "Vessel" means any container, constructed primarily of non-earthen materials, used to separate or store crude oil, condensate, natural gas, produced water, or emulsion.

3.33 "VOC_{C3-C9}" means Volatile Organic Compounds with three to nine carbon atoms.

3.34 "VOC_{C10+}" means Volatile Organic Compounds with 10 or more carbon atoms. This value is needed for laboratory and quality control purposes.

4. BIASES AND INTERFERENCES

4.1 The sampling methods specified in this procedure have an impact on the laboratory methods and the final results reported. All samples must be gathered in adherence with the minimum procedures and specifications identified in this procedure.

4.2 A representative sampling point must be selected to ensure that pressurized gases remain suspended in liquid during sampling. Obtaining samples from a non-pressurized vessel or a vessel connected to a vapor recovery system will produce non-representative results.

4.3 All pressure and temperature measurements must be acquired using calibrated instruments as described in Section 5. Un-calibrated equipment, including pressure or temperature gauges installed on vessels, may produce non-representative results. This may result in data errors when analyzing samples in a laboratory.

4.4 The analytical portion of this procedure must be conducted by laboratories experienced with laboratory instrumentation, analytical methods, and the laboratory methods specified in this procedure.

5. EQUIPMENT SPECIFICATIONS

5.1 A pressure gauge capable of measuring liquid pressure less than 200 pounds per square inch pressure within +/-10% accuracy.

5.2 A pressure gauge capable of measuring liquid pressure greater than 200 pounds per square inch pressure within +/- 5% accuracy.

5.3 A temperature gauge capable of reading liquid temperature to within +/- 2^{o}F. The range of the gauge must be at least 32 to 200^{o}F.

5.4 A volume meter with a minimum of +/- 5% accuracy over the entire range of flow rates for which the meter is used. Volume meters must be calibrated annually against a NIST traceable standard.

6. TEST EQUIPMENT

6.1 A Double-Valve Cylinder filled with laboratory grade water for crude oil or condensate or a Floating-Piston Cylinder for produced water.

6.2 A Graduated Cylinder to measure displaced laboratory grade water from a Double-Valve Cylinder.

6.3 A waste container suitable for capturing and disposing sample liquid.

6.4 High-pressure rated components and control valves that can withstand pressure under the same operating conditions as the vessel sampled.

6.5 A low-pressure and a high-pressure measuring device with minimum specifications listed in Section 5.

6.6 A temperature measuring device with minimum specifications listed in Section 5.

6.7 A calibrated volume meter with temperature and pressure gauges each with minimum specifications listed in Section 5 for measuring collected vapor recovery gas volume as described in Section 9.

6.8 A stainless steel hand pump equipped with one-way check valves suitable for pumping low API gravity crude oil into a Double-Valve Cylinder per Section 7.3. Stainless steel is required to prevent sample contamination.

7. SAMPLING METHODS

Pre-Sampling Requirements

Prior to gathering liquid samples, the sampling technician must be provided with the vessel description, Throughput, Percent Water Cut, Days of Operation, and a description of the vapor recovery system on downstream vessels by the facility operator as indicated in Table 1 and on Form 1. If required, the Percent Water Cut may be measured using ASTM D-4007. For sampling liquids that may contain proprietary compounds, such as those used in hydraulic fracturing liquids, a Tentatively Identified Compound List must also be provided prior to gathering liquid samples. All of this information specified is required to calculate and report the results of this test procedure. The results of this test procedure may be nullified without the specified information.

Background

The sampling method used for this procedure depends on the type of liquid to be sampled. Crude oil or condensate is collected using the Crude Oil or Condensate Sampling Method specified in Section 7.1. Produced water is collected using the Produced Water Sampling Method specified in Section 7.2. Low API gravity crude oil that will not flow into a sampling cylinder may be collected using the method specified in Section 7.3.

Liquid samples must only be taken from separated liquids. This is accomplished by taking samples from different levels in a pressurized separator, which may be a permanent or temporarily installed vessel. Liquid samples of emulsions cannot be evaluated by a laboratory and are therefore not applicable to this procedure. To gather a liquid sample, the sample vessel must be pressurized. Samples must not be taken from tanks or separators open to atmosphere.

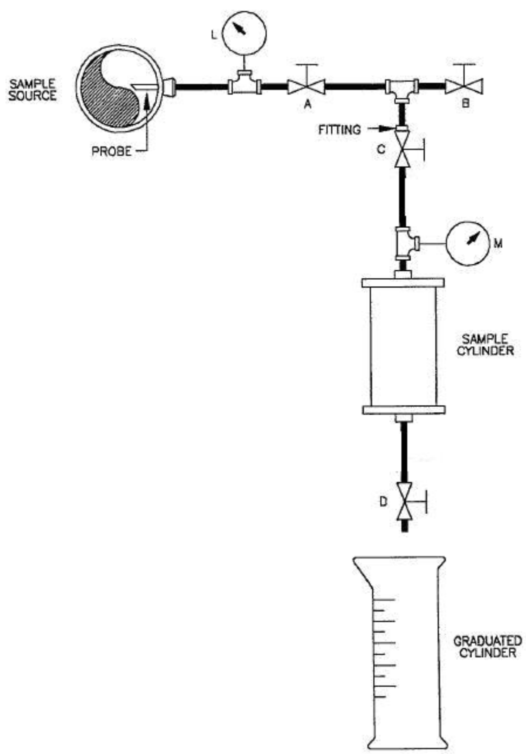
When a liquid sample is gathered, the technician measures the pressure and temperature of the liquid using the calibrated gauges specified and records the vessel and liquid characteristics as reported by the facility operator. The cylinder is then identified with a Cylinder Identification Tag (See Section 8) and sent to a laboratory for analysis. The laboratory heats and pressurizes the liquid to the same conditions recorded at the time of sampling and performs a Flash Analysis which measures the rate and composition of gas evolved from the liquid while it cools and depressurizes to specified atmospheric conditions.

7.1 CRUDE OIL OR CONDENSATE SAMPLING METHOD

The Crude Oil or Condensate Sampling Method is conducted by displacing laboratory grade water with pH between 5 and 7 from a Double-Valve Sampling Cylinder. Figure 1 illustrates a Double-Valve Cylinder sampling train. The configuration shows a cylinder outfitted with high-pressure rated components that can be used for controlling the flow of liquid. Calibrated temperature (Gauge L) and pressure (Gauge M) gauges are included for conducting field measurements. Sample liquid enters the cylinder when water is displaced into a graduated cylinder. The amount of sample liquid contained in the cylinder is equal to the amount of laboratory grade water measured in the graduated cylinder.

Figure 1

Double-Valve Cylinder Sampling Train



(a) If samples are to be shipped to a laboratory, calculate 90% of the cylinder volume, which will be the volume of sample to gather. As an example, 90% of a 500ml cylinder is 0.9 x 500 ml = 450 ml. This also represents the amount of water to displace with sample liquid. The cylinder must retain 10% of the laboratory grade water to allow for flashing during shipping and to prevent an explosive situation from occurring. If samples are not going to be shipped to a laboratory, this step does not need to be performed. Instead, fill the entire cylinder with sample liquid after purging with three cylinder volumes of liquid as described in (f).

(b) Connect the sampling train to a sampling point on the pressurized vessel. Bushings or reducers may be required.

(c) Purge the sample line: with Valves C and D closed, route the outlet of Valve B into a suitable waste container to purge sample liquid. Slowly open Valve B. Slowly open Valve A and allow air and liquid to purge. Continue purging until a consistent, steady stream of liquid is observed and gas pockets subside. Close Valve B.

(d) With Valve C and D closed, slowly open Valve A to the full-open position and then slowly open Valve C to the full-open position.

(e) Slowly open Valve D to allow a slow discharge of water into the graduated cylinder at a rate of approximately 60 milliliters per minute (1 drip per second).

(f) Record the temperature from Gauge L and pressure from Gauge M while the liquid is filling the cylinder. Do not take temperature or pressure measurements on stagnant liquid. If the sample is to be shipped as described in (a), continue displacing the laboratory grade water from the cylinder until 90% of the water is displaced. If the cylinder is not going to be shipped, continue filling the cylinder with sample liquid until three cylinder volumes of liquid have passed through the sampling cylinder.

(g) Close Valves D, C, and A in that order.

(h) Purge the line pressure: slowly open Valve B and allow pressurized liquid to drain into the waste container.

(i) Disconnect the Double-Valve Cylinder from the sampling train and disconnect the sampling train from the pressurized vessel.

(j) Check Valves C and D for leaks. If either Valve C or D is leaking, drain the cylinder into a suitable waste container and use a different cylinder to obtain a new sample.

(k) Wrap the threaded connections of the cylinder with Teflon tape and cap using threaded metal caps to protect the threads and ensure the cylinder is securely sealed for shipping.

(l) Identify the sample cylinder as specified in Section 8.

7.2 PRODUCED WATER SAMPLING METHOD

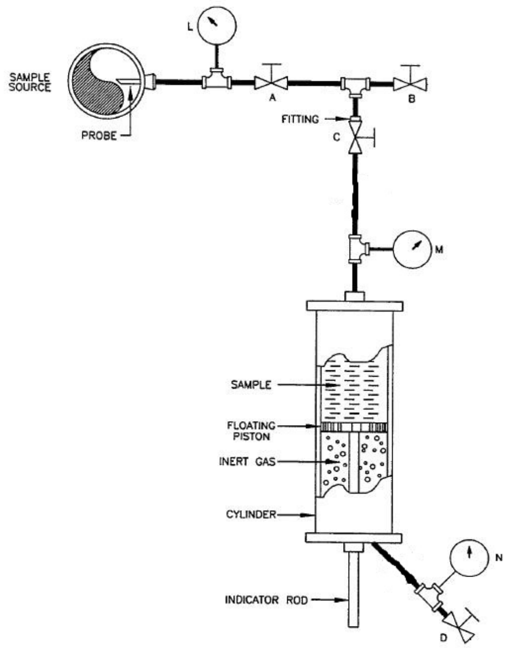
The Produced Water Sampling Method is conducted using a Floating-Piston Cylinder. This allows the sample liquid to be extracted from the cylinder without using laboratory water. The cylinder is provided by a laboratory with the piston pressurized with inert gas to approximately 1,000 psig or greater. Note: produced water may be gathered using a Double-Valve Cylinder as described in Section 7.1 provided that the laboratory can displace the produced water from the cylinder without commingling the sample liquid with laboratory grade water.

Prior to gathering a sample, the technician first measures the vessel pressure and temperature using the calibrated gauges specified. The technician then bleeds off excess pressure from the piston to at least 10 psig greater than the vessel to be sampled. Sample liquid is gathered by slowly bleeding off additional pressure from the piston. The rate at which liquid is gathered must not exceed 60 milliliters per minute in order to prevent the liquid from flashing gases within the sample cylinder.

Figure 2 shows a Floating-Piston Cylinder sample train outfitted with high-pressure rated components. Calibrated temperature (Gauge L) and pressure (Gauge M and N) gauges are included for conducting the required vessel measurements.

Figure 2

Floating-Piston Cylinder Sampling Train



(a) Connect the sampling train to a sampling point on the pressurized vessel. Bushings or reducers may be required.

(b) Purge the sample line: with Valves C and D closed, route the outlet of Valve B into a suitable waste container to purge sample liquid. Slowly open Valve A to the full-open position. Slowly open Valve B and allow liquid to purge. Continue purging until a consistent, steady stream of liquid is observed and gas pockets subside. Close Valve B.

(c) Slowly open Valve C to the full-open position.

(d) Slowly open Valve D to release inert gas pressure until the pressure indicated on Gauge N is equal to Gauge M. When both gauges read equal pressure, close Valve D and prepare to gather sample liquid.

(e) Slowly open Valve D and allow liquid to enter the cylinder at a slow rate of approximately 60 ml per minute to prevent liquid from flashing within the sampling cylinder. Use the measurement scale located on the sampling cylinder and a stopwatch to measure the rate at which liquid is gathered.

(f) Record the temperature from Gauge L and pressure from Gauge M while liquid is gathered. Do not take measurements on stagnant liquid.

(g) Continue gathering liquid until the cylinder is 80% full as indicated on the cylinder scale. The rate at which liquid enters the cylinder, and the volume of liquid in the cylinder, are indicated on the sample cylinder. No outage is required when using a Floating-Piston Cylinder.

(h) Close valves D, C, and A in that order.

(i) Purge the line pressure: slowly open Valve B and allow pressurized liquid to drain into the waste container.

(j) Disconnect the Floating-Piston Cylinder from the sampling train and disconnect the sampling train from the pressurized vessel.

(k) Check Valves C and D for leaks. If either Valve C or D is leaking, drain the cylinder into a suitable waste container and use a different cylinder to obtain a new sample.

(l) Wrap the threaded connections of the cylinder with Teflon tape and cap using threaded metal caps to protect the threads and ensure the cylinder is securely sealed for shipping.

(m) Identify the sample cylinder as specified in Section 8.

7.3 LOW API GRAVITY CRUDE OIL SAMPLING METHOD

In some cases, low API gravity crude oil may not flow into a sampling cylinder. This could be due to the viscosity, temperature, or pressure of the oil. In these cases, a stainless steel hand pump is used to assist with the collection of liquid. The pump must be outfitted with one-way check valves to ensure that liquid flows in only one direction. The difference between the Displacement Method and this method is that the hand pump is used in place of system pressure.

(a) Install the stainless steel hand pump equipped with one-way check valves as described in Section 6 at the inlet of the Double-Valve Cylinder Sampling Train.

(b) Using the hand pump to slowly force the flow of liquid, collect a liquid sample following the sample procedures described in Section 7.1.

8. CYLINDER IDENTIFICATION TAG

8.1 Identify the cylinder with a Cylinder Identification Tag. Both the tag and a copy of Form 1 must be completed prior to sampling using information provided by the facility operator and must include the following minimum information:

(a) Date and time;

(b) Unique sample ID number or cylinder number;

(c) Sample type (crude oil, condensate, or produced water);

(d) Sample pressure and temperature during sampling;

(e) Vessel description;

(f) Vessel throughput of emulsion or liquid in barrels per day;

(g) Percent Water Cut;

(h) Days of Operation per Year;

(i) Facility name and location of where sample was gathered; and,

(j) Attach a completed copy of Form 1.

8.2 Package the cylinder with the information tag and a copy of Form 1.

9. ALTERNATIVE METHODOLOGY FOR CALCULATING EMISSION RATES USING MEASURED VAPOR RECOVERY SYSTEM PARAMETERS IN LIEU OF GATHERING AND EVALUATING LIQUID SAMPLES

This methodology is used to measure the specified emission rates using a vapor recovery system in lieu of gathering and evaluating liquid samples. This methodology requires that all gases flashed from liquid are collected and measured, and that a vapor recovery system is installed on a minimum of the primary and secondary vessels, and that intermediate vessels be covered and controlled using a pressure/vacuum valve, at minimum, so that the vessels are not open to atmospheric pressure. This methodology is an alternative to gathering and evaluating liquid samples and may be used for systems that handle emulsions or single liquids.

The Greenhouse Gas and other compound emission rates are calculated using the measured annual vapor recovery gas volume metered by the system and an annual gas composition analysis. The annual measured gas volume is adjusted to account for capture efficiency of the vapor recovery system.

(a) Measure the annual gas volume recovered by the vapor recovery system using the calibrated meter outfitted with temperature and pressure gauges as described in Section 6.

(b) Obtain an annual gas sample of the vapor recovery gas and evaluate it for all gaseous compounds, the molecular weight, and the weight percent of Greenhouse Gases and other compounds.

(c) Calculate the annual emission rates as described in Section 10.2.

10. CALCULATING RESULTS

10.1 Flash Emission Calculation Methodology for Liquid Samples

The following is used in conjunction with vessel information and a laboratory analysis to calculate metric tons of Greenhouse Gases (CO_2 and CH_4) or short tons of other compounds ($VOC_{C3\text{-}C9}$ or BTEX). The same formulas may be applied to crude oil, condensate, and produced water.

(a) If required, calculate the barrels per day of crude oil or condensate in emulsion using the Percent Water Cut:

$$Barrels / Day = (1 - Percent\ Water\ Cut)(Throughput) \qquad \textbf{Equation 1A}$$

Where:

Barrels/Day = barrels per day crude oil or condensate

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

(b) If required, calculate the barrels per day of produced water in emulsion using the Percent Water Cut:

$$Barrels / Day = (Percent\ Water\ Cut)(Throughput) \qquad \textbf{Equation 1B}$$

Where:

Barrels/Day = barrels per day produced water

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

(c) Calculate the total volume of gas produced per year:

$$Ft^3 / Year = (G)\left(\frac{Barrels}{Day}\right)\left(\frac{Days}{Year}\right)$$ **Equation 2**

Where:

Ft^3/Year = standard cubic feet of gas produced per year

G = Gas-Oil-Ratio or Gas-Water-Ratio (from lab analysis)

Barrels/Day = barrels per day crude oil, condensate, or produced water (Eq. 1A/1B)

Days/Year = days of operation per year

(d) Convert the total gas volume to pounds:

Equation 3

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year}\right)\left(\frac{gram}{gram-mole}\right)\left(\frac{gram-mole}{23.690\,l}\right)\left(\frac{28.317\,l}{Ft^3}\right)\left(\frac{lb}{454\,grams}\right)$$

Where:

$Mass_{Gas}$/Year = pounds of gas per year

Ft^3/Year = cubic feet of gas produced per year (Eq. 2)

Gram/Gram-Mole = Molecular Weight of gas sample (from lab analysis)

23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60^0F

(e) Calculate the mass of GHG or other compound:

$$Mass_{GHG} / Year = \left(\frac{WT\%\,GHG}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\,lb}\right)$$ **Equation 4**

$$Mass_{Compound} / Year = \left(\frac{WT\%\,Compound}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{ton}{2000\,lb}\right)$$ **Equation 5**

Where:

Mass $_{GHG}$ /Year = metric tons of CO_2 or CH_4 (Eq. 4)

Mass $_{Compound}$ /Year = tons of other compound (Eq. 5)

Mass $_{Gas}$ /Year = pounds of gas per year (Eq. 3)

WT% GHG = Weight % of CO_2 or CH_4 (from lab analysis)

WT% Compound = Weight % of $VOC_{C3\text{-}C9}$ or BTEX (from lab analysis)

(f) If a vapor recovery system is installed on the separator and tank system, adjust the annual emission rate as follows:

$$Emissions_{GHG/Compound} = (Mass_{GHG/Compound} / Year)(1 - CE)$$ **Equation 6**

Where:

Emissions $_{GHG/Compound}$ = controlled GHG or other compound emissions

Mass $_{GHG/Compound}$ /Year = uncontrolled GHG or other compound emissions per year (Eq. 4 or 5)

CE = capture and control efficiency of vapor recovery system

10.2 Emission Calculation Methodology Using Measured Vapor Recovery System Parameters

(a) Convert the total volume of vapor measured using the calibrated meter and average annual vapor temperature and pressure to standard conditions:

$$Ft^3 / Year = V\left(\frac{519.67}{T}\right)\left(\frac{P + 14.696}{14.696}\right)$$ **Equation 7**

Where:

Ft^3/Year = annual cubic feet of gas corrected to standard conditions (scf)

V = annual volume of gas going to the vapor recovery system, measured by the calibrated meter (cubic feet)

T = average annual vapor temperature measured at the meter (degrees R)

P = average annual gauge pressure measured at the meter (psig)

(b) Convert the total gas volume to pounds:

Equation 8

$$Mass_{Gas}/Year = \left(\frac{Ft^3}{Year}\right)\left(\frac{gram}{gram-mole}\right)\left(\frac{gram-mole}{23.690\,l}\right)\left(\frac{28.317\,l}{Ft^3}\right)\left(\frac{lb}{454\,grams}\right)$$

Where:

$Mass_{Gas}$/Year = pounds of gas per year

Ft^3/Year = cubic feet of gas produced per year (Eq. 6)

Gram/Gram-Mole = Molecular Weight of gas sample (from lab analysis)

23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60^0F

(c) Calculate the mass of GHG or other compound:

$$Mass_{GHG}/Year = \left(\frac{WT\%\,GHG}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\ lb}\right)$$ **Equation 9**

$$Mass_{Compound}/Year = \left(\frac{WT\%\,Compound}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{ton}{2000\ lb}\right)$$ **Equation 10**

Where:

$Mass_{GHG}$ /Year = metric tons of CO_2 or CH_4 (Eq. 9)

$Mass_{Compound}$ /Year = tons of other compound (Eq. 10)

$Mass_{Gas}$ /Year = pounds of gas per year (Eq. 8)

WT% GHG = Weight % of CO_2 or CH_4 (from lab analysis)

WT% Compound = Weight % of VOC_{C3-C9} or BTEX (from lab analysis)

(d) Adjust the annual emission rate as follows:

Equation 11

$$Emissions_{GHG/Compound} = \left(Mass_{GHG/Compound}/Year\right)\left(\frac{1-CE}{CE}\right)$$

Where:

$Emissions_{GHG/Compound}$ = uncaptured GHG or other compound emissions

$Mass_{GHG/Compound}$ /Year = captured GHG or other compound emissions per year (Eq. 9 or 10)

CE = capture efficiency of vapor recovery system.

11. REPORTING RESULTS

The results of this procedure are used to estimate or report emission rates of Greenhouse Gases or other compounds from separator and tank systems used in onshore crude oil or natural gas production, processing, or storage. All results shall be reported to at least three significant figures. All supporting information used to derive the emission estimates, including sample information, laboratory results, and calculations must be maintained by the reporting entity for a minimum of three years in order to reproduce the estimated or reported results. The following information must be maintained by the reporting entity:

11.1 Crude Oil, Condensate, or Produced Water (Section 10.1)

(a) Laboratory results specified in Section 12;

(b) All calculations and calculated results;

(c) A completed copy of Form 1;

(d) Annual emission rates of Greenhouse Gases and other compounds;

(e) Annual production of crude oil, condensate, and produced water; and

(f) API Gravity of crude oil or condensate.

11.2 Emulsion or Liquids under Vapor Recovery (Section 10.2)

(a) Laboratory results of an annual gas composition analysis or an average of multiple, more frequent samples within the year;

(b) Measured annual vapor recovery system gas throughput;

(c) All calculations and calculated results;

(d) Annual emission rates of Greenhouse Gases and other compounds; and,

(e) API Gravity of crude oil or condensate.

12. ANALYTICAL LABORATORY METHODS

12.1 Sample Preparation

(a) Prior to extracting liquid from a sample cylinder, the cylinder must be heated to the same temperature as measured at the time of sampling. The laboratory apparatus must be temperature and pressure controlled by a means that allows cooling and depressurizing liquid from sampling conditions to the standard temperature and pressure while precisely measuring liquid and gas volumes.

(b) Sample gases shall be collected in a closed system with a means of precisely measuring liquid and gas volume. Sample preparation guidance can be found in GPA 2174, GPA 2261 and GPA 2177.

12.2 Laboratory Methods

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water. All methods and quality control requirements shall be conducted as specified in each method.

(a) Hydrogen Sulfide (Low-Level): Evaluate using EPA Method 15 and EPA Method 16 or use ASTM D-1945M (Thermal Conductivity Detector), ASTM D-5504 (sulfur chemiluminescence detector), and ASTM D-6228 (flame photometric detector) as alternate methods.

(b) Oxygen, Nitrogen, Carbon Dioxide, Hydrogen Sulfide (High-Level), Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane, Hexanes, Heptanes, Octanes, Nonanes, and Decanes+: Evaluate per ASTM D-1945, ASTM D-3588, and ASTM D-2597 (GC/TCD). Note: This analysis requires all three methods specified. The base method is ASTM D-1945, which is modified to extend the hydrocarbon analysis range based on information from the other two methods.

(c) BTEX: Evaluate per EPA 8021 B (GC/FID) or use ASTM D-3170, GPA 2286, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.

(d) API Gravity of liquid phase crude oil or condensate at 60 degrees Fahrenheit (60^{o}F): Evaluate per ASTM D-287 using measured result of Specific Gravity. Note: If water is entrained in the sample, measure the

API Gravity using ASTM D-287 (API Hydrometer) and calculate the Specific Gravity using the measured API Gravity.

(e) Specific Gravity of pre-flash liquid phase crude oil or condensate: Evaluate per ASTM D-4052, ASTM D-70, or ASTM D-5002 or calculate using results from ASTM D-287.

(f) Molecular Weight of gaseous phase by calculation per ASTM D-3588.

(g) Percent Water Cut: evaluate per ASTM D-4007 (Basic Sediment and Water).

12.3 Laboratory Reports

Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. The laboratory results must be reported as specified in Section 11. A laboratory report that provides the following minimum information described below and in Table 1 must be provided to the facility operator so they can calculate and report the results specified in Sections 10 and 11:

(a) The gaseous phase WT% of CO_2, CH_4, the gaseous phase WT% of C2 through C9 and C10+, the gaseous phase WT% of BTEX, and the gaseous phase WT% of O_2, N_2, and H_2S;

(b) The gaseous phase Gram Molecular Weight of the total gas sample;

(c) The liquid phase API Gravity of crude oil or condensate at 60^oF;

(d) Volumetric Gas-Water-Ratio (GWR) for produced water; and,

(e) Volumetric Gas-Oil-Ratio (GOR) for crude oil or condensate.

Table 1

Flash Analysis Sampling and Laboratory Requirements

Sampling Technician Needs to Obtain from Operator Before Sampling Can Occur:
Vessel Description
Vessel Throughput (Barrels/Day)
Percent Water Cut
Number of Days in Operation
Vapor Recovery System Information (downstream vessels) • Presence of VR System • Vapor Processing & Type • Vapor End Use(s)
Tentatively Identified Compound List (if sampling proprietary compounds)

Gas Evolved from Crude Oil, Condensate, or Produced Water
WT% CO2, CH4
WT% C2-C9, C10+
WT% BTEX
WT% O2
WT% N2
WT% H2S
Molecular Weight Total Gaseous Sample
Gas-Oil-Ratio
Gas-Water-Ratio

Pre-Flash Liquid Crude Oil or Condensate
API Gravity

<u>13. REFERENCES</u>

ASTM D-70	*Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)*
ASTM D-287	*Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)*
ASTM D-1945M	*Standard Test Method for Analysis of Natural Gas by Gas Chromatography*
ASTM D-2597	*Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*
ASTM D-3710	*Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography*
ASTM D-3588	*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*
ASTM D-4007	*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method*
ASTM D-4052	*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter*
ASTM D-5002	*Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer*
ASTM D-5504	*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence*
ASTM D-6228	*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection*
EPA Method 15	*Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources*
EPA Method 16	*Semicontinuous Determination of Sulfur Emissions from Stationary Sources*

EPA Method 8021B	*Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors*
EPA Method 8260B	*Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)*
EPA Method TO-14	*Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography*
EPA Method TO-15	*Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)*
GPA 2174	*Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography*
GPA 2177	*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*
GPA 2261	*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*
GPA 2286	*Extended Gas Analysis Utilizing a Flame Ionization Detector*

Form 1
Crude Oil, Condensate, and Produced Water Sampling Field Data Sheet

(report measured results to at least three significant figures)

Facility Contact Information:

Facility Name: ______________________
Address: ______________________
City: ______________ State: ________
Zip: ______________ Phone: ______________
Facility Contact: ______________________

Sampling Company:

Company Name: ______________________
Address: ______________________
City: ______________ State: ________
Zip: ______________ Phone: ______________
Sampling Technician: ______________

Sample Information:

Sample Type: ______________ (crude oil, condensate, produced water)
Date: ______________
Time: ______________ Sample Temperature: ________ Deg. F
Cylinder Number: ______________ Sample Pressure: ________ PSI
Field Name: ______________ (field from where sample was taken)

Separator Information:

Separator Type: ______________________ (e.g., heater/treater)
Separator Throughput: ________ (barrels/day)
Percentage Water Cut ________ % Days in Operation/Year: ________

Vapor Recovery (VR) System (downstream of sample vessel):

VR System Installed: Yes No
Vapor Processing & Type: Yes No List Type(s): ______________
(Sulfa Treat, Amine, etc.)
Vapor End Use(s) (list): ______________________
(sales gas, flare, engine, boiler, etc.)

Shipping Information:

Shipping Company: ______________________
Tracking Number: ______________________