Appendix D to California's Proposed Compliance Plan for the Federal Clean Power Plan:

Text of Proposed Emissions Standards and State Measures

This appendix provides the text of the existing and proposed regulations that support this Proposed Compliance Plan. Those components are as follows:

Components of the Proposed Plan

Proposed or Final Regulation	**Summary**	**Status**
Proposed 17 CCR § 95160	Defines source category of affected EGUs for reporting	Proposed state reporting requirement for Proposed Plan
Proposed 17 CCR § 95161	Adopts relevant CPP definitions for reporting	Proposed state reporting requirement for Proposed Plan
Proposed 17 CCR § 95162	Monitoring and recordkeeping requirements for affected EGUs	Proposed state reporting requirement for Proposed Plan
Proposed 17 CCR § 95163	Emissions and data reporting requirements for affected EGUs	Proposed state reporting requirement for Proposed Plan
Proposed and Final 17 CCR § 95859 and Appendix D	Establishes mass-based emission standards within the Cap-and-Trade Regulation and backstop emission standards for affected EGUs, provides interim and final targets, and requires compliance with relevant MRR provisions	Proposed emission standards and federally enforceable reporting requirements
17 CCR §§ 95800-96022 (excluding § 95859 and Appendix D)	State-level Cap-and-Trade Regulations, including definitions of compliance periods.	State measure

This appendix includes the full text of proposed amendments to the Mandatory Reporting Regulation and the Cap-and-Trade Regulation that relate to the CPP (proposed additions are underlined). It also includes the existing text of those regulations. Further proposed amendments to those regulations that do not include the CPP are not included. This appendix may be updated as proposed regulations are finalized.

Proposed Amendments to the Mandatory Reporting Regulation

<u>**Subarticle 6. Reporting Requirements and Calculation Methods for Electricity Generating Units Subject to the Clean Power Plan**</u>

§ 95160. Definition of Source Category and Applicability.

(a) U.S. EPA Clean Power Plan Rule. This subarticle incorporates the following specific provisions of the U.S. EPA Clean Power Plan Final Rule, Subpart UUUU—Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units; 40 Code of Federal Regulations (CFR) Part 60, Subpart UUUU: 40 CFR sections 60.5845, 60.5850, 60.5860, and 60.5880, published in the Federal Register on October 23, 2015.

(b) Each of the provisions of this subarticle become effective starting with 2021 data submitted in 2022, if U.S. EPA has approved, as memorialized by publication in the Federal Register and Code of Federal Regulations, that provision as part of California's plan for compliance with the Clean Power Plan.

(c) For the purposes of this article, the Clean Power Plan electricity generating unit source category consists of any affected EGU, which is a steam generating unit, integrated gasification combined cycle facility (IGCC), or stationary combustion turbine that commenced construction on or before January 8, 2014, and meets the relevant applicability conditions specified in Subpart UUUU of 40 CFR Part 60, §60.5845 paragraphs (b)(1)-(b)(3). EGUs excluded from being affected EGUs are specified in 40 CFR Part 60, §60.5850.

(c) Any affected EGU is also subject to all other applicable requirements of this article, including but not limited to sections 95101 through 95108 and section 95112, except as modified in this subarticle. All affected EGUs are subject to the full verification provisions of this article.

(e) Any affected EGU must comply with the emission estimation provisions of this subarticle, and must not use other emission calculation methods, such as those specified in section 95115.

(f) Any affected EGU must separately monitor and report emissions and other data for each affected EGU, except as provided under section 95162(a)(4) of this subarticle. The provisions allowing unit aggregation specified elsewhere in this article do not apply to affected EGUs.

(g) Affected EGUs remain subject to the provisions of this subarticle unless they undergo a complete and permanent shutdown, with a full cessation of all GHG-emitting processes and operations as specified in section 95101(h).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39602, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§95161. Definitions.

(a) For the purposes of this subarticle, definitions specified in Subpart UUUU of 40 CFR Part 60, §60.5880 shall apply for affected EGUs. Should a conflict exist between definitions of this subpart, and definitions of section 95102 of this article, the definitions identified in this subarticle take precedence for affected EGUs.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39602, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§95162. Monitoring and Record Keeping Requirements

(a) Owners and operators of affected EGUs must follow the applicable monitoring provisions of this section.

(1) Affected EGUs must prepare a monitoring plan as specified in 40 CFR §60.5860(a)(1).

(2) For two or more affected EGUs which share a common exhaust gas stack, and are implementing continuous emissions monitoring per 40 CFR §60.5860(a)(3), and meet the requirements of 40 CFR §60.5860(a)(6), owners or operators may monitor CO_2 emissions at the common stack and calculate hourly net electric output for the common stack as specified in 40 CFR §60.5860(a)(6).

(3) For two or more affected EGUs in which exhaust gases are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), owners or operators must follow the provisions of 40 CFR §60.5860(a)(7).

(4) If two or more affected EGUs serve a common electric generator, owners or operators must comply with the provisions of 40 CFR §60.5860(a)(8).

(b) The owner or operator of an affected EGU must maintain the following records for at least 10 years after the submission of each report, occurrence, measurement, maintenance, corrective action, report, or record, whatever is latest according to U.S. EPA Standards of Performance for New Stationary Sources, 40 Code of Federal Regulations (CFR) Part 60, Subpart A, Section 60.7, July 1, 2012, which is hereby incorporated by reference. The owner or operator of an affected EGU must maintain each record on site for at least 2 years, and may maintain the records off site and electronically for the remaining year(s).

(1) Data as specified under the provisions of 40 CFR §60.5860(b)(1)-(3).

(2) Records as specified by 40 CFR §60.5860(c)(1) and 40 CFR §60.5860(c)(2)(i)-(iii) which includes data collected or used for calculations in applicable sections of 40 CFR §60.5860(a)-(b).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39602, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§95163. Emissions and Data Calculation and Reporting Requirements.

(a) The owner or operator of an affected EGU must determine the CO_2 mass emissions (short tons) for the compliance period as specified under the provisions of 40 CFR §60.5860(b)(1)-(2).

(b) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may determine the hourly CO_2 mass emissions according to 40 CFR §60.5860(a)(4)(i) through (a)(4)(vi).

(c) The owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must comply with all requirements of 40 CFR §60.5860(b)(3) for measurement and calculation of net electric output, useful thermal output, and mechanical output, and determine net energy output.

(d) Each year, any affected EGUs must submit the information specified in 40 CFR §60.5860(d), paragraphs (1) and (3) to the Air Resources Board pursuant to section 95104(e) of this article, under the schedule specified in section 95103(e) of this article.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39602, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

17 CCR §95163. Emissions and Data Calculation and Reporting Requirements.

(a) The owner or operator of an affected EGU must determine the CO_2 mass emissions (short tons) for the compliance period as specified under the provisions of 40 CFR §60.5860(b)(1)-(2).

(b) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may determine the hourly CO_2 mass emissions according to 40 CFR §60.5860(a)(4)(i) through (a)(4)(vi).

(c) The owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must comply with all requirements of 40 CFR §60.5860(b)(3) for measurement and calculation of net electric output, useful thermal output, and mechanical output, and determine net energy output.

(d) Each year, any affected EGUs must submit the information specified in 40 CFR §60.5860(d), paragraphs (1) and (3) to the Air Resources Board pursuant to section 95104(e) of this article, under the schedule specified in section 95103(e) of this article.

Proposed Amendments to the Cap-and-Trade Regulation

§ 95840. Compliance Periods.

Duration of Compliance Periods is as follows:

***

(d) If U.S. EPA has approved California's plan for compliance with the Clean Power Plan, as memorialized by publication in the Federal Register and Code of Federal Regulations, then compliance periods starting January 1, 2021 shall be as follows:

(1) The fourth compliance period starts on January 1, 2021, and ends on December 31, 2022.

(2) The fifth compliance period starts on January 1, 2023, and ends on December 31, 2024.

(3) The sixth compliance period starts on January 1, 2025, and ends on December 31, 2027.

(4) The seventh compliance period starts on January 1, 2028, and ends on December 31, 2029.

(5) The eighth compliance period starts on January 1, 2030, and ends on December 31, 2031.

(6) Each subsequent compliance period after the eighth compliance period has a duration of two calendar years.

(e) If U.S. EPA has not approved California's plan for compliance with the Clean Power Plan by January 1, 2019, including the specified compliance periods in section 95840(d), then the fourth compliance period starts on January 1, 2021, and ends on December 31, 2023, and each subsequent compliance period has a duration of three calendar years.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95859. Federal Clean Power Plan Requirements.

(a) The federal Clean Power Plan (CPP) means Subpart UUUU of 40 CFR Part 60 (40 CFR §§60.5700 to 60.5880) published in the Federal Register on October 23, 2015. The provisions of this section apply only if U.S. EPA has approved each provision as part of California's plan for compliance with the Clean Power Plan, as memorialized by publication in the Federal Register and Code of Federal Regulations.

(b) General Requirements for Electricity Generating Units Subject to CPP (affected EGUs). Beginning January 1, 2021, and thereafter, all entities that own or operate at least one CPP EGU located in California must:

(1) Be registered in the Cap-and-Trade Program pursuant to section 95830 regardless of annual emissions level and remain registered for the duration of CPP regardless of cessation, annual emissions level, or any other factor;

(2) Report and verify emissions pursuant to MRR sections 95160 to 95163; and

(3) Be in compliance with section 95856.

(c) Deadline to Notify U.S. EPA of CPP Backstop Activation. By July 1 of the year after a compliance period ends, the Executive Officer shall compare the applicable aggregate reported emissions and assigned emissions for all affected EGUs for the compliance period to the applicable CPP backstop trigger established in Appendix D. If the applicable aggregate reported emissions and assigned emissions for all affected EGUs for the compliance period is greater than the applicable CPP backstop trigger established in Appendix D, then the Executive Officer shall inform U.S.EPA that the CPP backstop is activated pursuant to 40 CFR § 60.5870(b).

(d) CPP Backstop Activation. By October 24 of the year after a compliance period ends, the Executive Officer shall compare the aggregate reported and verified emissions and assigned emissions for all affected EGUs for the compliance period to the aggregate CPP backstop trigger established in Appendix D. If the aggregate reported and verified emissions and assigned emissions for all affected EGUs for the compliance period is greater than the CPP backstop trigger established in Appendix D, then the CPP backstop is activated; otherwise the CPP backstop is not activated. The CPP backstop will apply to the compliance period *n*+1, the backstop compliance period, which immediately follows a triggering compliance period *n*, the triggering compliance period, in which the aggregate affected EGU emissions exceeded the CPP backstop trigger.

(e) CPP Backstop. If the CPP backstop is activated pursuant to section 95859(d), then sections 95859(e)(1)-(8) shall apply.

(1) Creation of CPP Backstop Account. The accounts administrator will create and maintain a holding account that is under the control of the Executive Officer and known as the CPP Backstop (CPPB) Account:

(A) Into which the Executive Officer will transfer CPP allowances pursuant to section 95859(e)(4); and

(B) From which the Executive Officer may transfer CPP allowances pursuant to sections 95859(e)(5) and (e)(8).

(2) Creation of CPP Allowances. The Executive Officer shall create CPP allowances pursuant to section 95859(e)(4) and place these allowances into the CPPB Account. The Executive Officer shall assign each CPP allowance a unique serial number that indicates the compliance period allowance budget from which the allowance originates. CPP allowances are available only to entities that own or operate at least one affected EGU located in California.

(3) CPP Backstop Compliance Obligation. Entities with at least one CPP EGU incur a CPP backstop compliance obligation for the compliance period *n*+1, the backstop compliance period, that immediately follows the compliance period *n*, the triggering compliance period, in which the aggregate affected EGU sector emissions exceeded the CPP backstop trigger. The CPP backstop compliance obligation in compliance period *n*+1 for an affected EGU equals the affected EGU's emissions for compliance period *n*+1 that are reported and verified pursuant to MRR sections 95160 to 95163 or the emissions for compliance period *n*+1 that are assigned by the Executive Officer.

(4) Quantity of CPP Allowances Created in the CPPB Account. By October 24 of the year following a triggering compliance period, the Executive Officer shall

create a number of CPP allowances calculated by the following equation and place them in the CPPB Account:

$$CPPB_{created,n+1} = T_{CPP,n+1} – (E_{sector,n} − T_{CPP,n})$$

Where:

"$CPPB_{created,n+1}$" is the number of CPP allowances with compliance period vintage n+1 created and transferred to the CPPB Account;

"$E_{sector,n}$" is the aggregate reported and verified emissions and assigned emissions for all affected EGUs, rounded up to the nearest whole metric ton value, for the triggering compliance period n in which the emissions exceeded the CPP backstop trigger;

"$T_{CPP,n}$" is the CPP glidepath target for the triggering compliance period n that is established in Appendix D; and

"$T_{CPP,n+1}$" is the CPP glidepath target for the backstop compliance period n+1 that is established in Appendix D.

(5) Allocation of CPP Allowances. By October 24 of the year following a triggering compliance period, the Executive Officer shall allocate the number of CPP allowances from the CPPB Account to the holding account of each facility with an affected EGU that is calculated by the following equation:

$$A_{facility} = \frac{\sum_i E_{EGU,n,i}}{E_{sector,n}} \times CPPB_{created,n+1}$$

Where:

"$A_{facility}$" is the number of CPP allowances, rounded up to the nearest whole number, transferred from the CPPB Account to the holding account of a facility that owns or operates at least one CPP EGU located in California;

"$E_{EGU,n,i}$" is the reported and verified emissions or the assigned emissions in the triggering compliance period *n* for affected EGU *i* at the facility;

"$E_{sector,n}$" is the aggregate reported and verified emissions and assigned emissions for all CPP EGUs for the triggering compliance period *n* in which the emissions exceeded the CPP glidepath target; and

"$CPPB_{created,n+1}$" is the number of CPP allowances with compliance period vintage *n*+1 created and transferred to the CPPB Account pursuant to section 95859(e)(4).

(6) Trading of CPP Allowances. CPP allowances may only be traded among entities that own or operate affected EGUs located in California and that are registered in the Program. Trading of CPP allowances must be conducted pursuant to section 95921.

(7) Timely Surrender of CPP Allowances. Entities with at least one affected EGU must surrender one CPP allowance for each metric ton of emissions for the CPP backstop compliance obligation in section 95859(e)(3). Each entity must transfer from its holding account to its compliance account a sufficient number of CPP allowances to meet the CPP backstop compliance obligation established pursuant to section 95859(e)(3). Each entity must transfer sufficient CPP allowances to its compliance account to fulfill its CPP backstop compliance obligation by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on November 1 of the calendar year following the final year of the backstop compliance period *n*+1.

(8) Retirement of Remaining CPP Allowances. Any CPP allowances with compliance period vintage *n*+1 remaining in the CPPB Account after the CCP backstop compliance obligation deadline in section 95859(e)(7) shall be transferred to the Retirement Account by the Executive Officer.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 39601, and 39602, Health and Safety Code.

Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Appendix D (to the Cap-and-Trade Regulation): CPP Glidepath Targets and Backstop Triggers from 2021 to 2031

Year	Compliance Period	Annual CPP Glidepath Target[#] ($MMTCO_2e$)	Full Compliance Period CPP Glidepath Target[#] ($MMTCO_2e$)	CPP Backstop Trigger[#] ($MMTCO_2e$)
2021	4	Not applicable	50.0	55
2022		50.0		
2023	5	49.4	98.3	108.2
2024		48.9		
2025	6	48.4	143.4	157.8
2026		47.8		
2027		47.3		
2028	7	46.7	92.9	102.2
2029		46.2		
2030	8	45.6	91.3	100.4
2031		45.6		

[#] For all two-year compliance periods after 2031, the CPP Glidepath Target is 91.3 $MMTCO_2e$ and the CPP Backstop Trigger is 100.4 $MMTCO_2e$.

Attachment A

Current Text of Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

LEGAL DISCLAIMER & USER'S NOTICE

Unofficial electronic version of the
Regulation for the Mandatory Reporting of
Greenhouse Gas Emissions

Unofficial Electronic Version

This unofficial electronic version of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions following this Disclaimer was produced by California Air Resources Board (ARB) staff for the reader's convenience. ARB staff has removed the underline-strikeout formatting which exists in the Final Regulation Order approved by the Office of Administrative Law (OAL) on December 31, 2014 and included the full regulatory text for the regulation; however, the following version is not an official legal edition of title 17, California Code of Regulations (CCR), sections 95100-95158. While reasonable steps have been taken to make this unofficial version accurate, the officially published CCR takes precedence if there are any discrepancies.

Official Legal Edition

The official legal edition of title 17, CCR, sections 95100-95158 is available at the OAL website: http://www.oal.ca.gov/CCR.htm. To access relevant provisions online, click on the following path items from the OAL site:

→ *"Online" link (http://ccr.oal.ca.gov/linkedslice/default.asp?SP=CCR-1000&Action=Welcome)*

→ *"List of CCR Titles"*

→ *"Title 17. Public Health"*

→ *"Division 3. Air Resources"*

→ *"Chapter 1. Air Resources Board"*

→ *"Subchapter 10. Climate Change"*

→ *"Article 2. Mandatory Greenhouse Gas Emissions Reporting"*

→ *then choose the relevant subarticle(s) and section(s).*

For ease of reviewing, once you have selected a section, scroll to the bottom left-hand corner of the page and click on "Docs in Sequence." This will enable easy switching from one section to the next.

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Subchapter 10. Climate Change

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

This table of contents is not part of the official published regulation, and is provided for convenience only.

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Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95101, 95102, 95103, 95104, 95111, 95112, 95113, 95114, 95115, 95119, 95121, 95122, 95124, 95130, 95131, 95132, 95133, 95152, 95153, 95156, 95157, and Appendix A, title 17 California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

§ 95100. Purpose and Scope.

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

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

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

(d) Except as otherwise specifically provided:

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

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

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

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

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

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

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

1. Electricity generation units that report CO_2 mass emissions year round through 40 CFR Part 75;
2. Cement production;
3. Lime manufacturing;
4. Nitric acid production;
5. Petroleum refineries;
6. Geologic sequestration of carbon dioxide;
7. Injection of carbon dioxide.

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

1. Stationary fuel combustion, which includes electricity generating units not subject to 40 CFR Part 75;
2. Glass production;
3. Hydrogen production;
4. Iron and steel production;
5. Pulp and paper manufacturing;
6. Petroleum and natural gas systems;
7. Geothermal electricity generation;
8. Lead production;

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

(D) Carbon dioxide suppliers as specified below in paragraph (c), including CO_2 producers regardless of quantity produced, and CO_2 importers and exporters when bulk imports or exports equal or exceed 10,000 metric tons for 2011 or a later calendar year;

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

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

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

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

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

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

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

(1) For the purpose of computing emissions relative to the 25,000 metric ton CO_2e threshold specified in section 95812 of the 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 any vented and fugitive emissions from the estimate. However, if all the CO_2, CH_4, and N_2O 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 an emissions data 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 refiners delivering petroleum fuels and/or biomass-derived fuels, as described in section 95121;

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

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

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

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

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

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

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

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

(10) Operators of liquefied natural gas production facilities that produce liquefied natural gas products from natural gas received from interstate pipelines, as described in section 95122;

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

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

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

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

(4) Western Area Power Administration (WAPA);

(5) Bonneville Power Administration (BPA).

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

(1) Offshore petroleum and natural gas production facilities;

(2) Onshore petroleum and natural gas production facilities;

(3) Onshore natural gas processing plants;

(4) Onshore natural gas transmission compression facilities;

(5) Underground natural gas storage facilities;

(6) Liquefied natural gas storage facilities;

(7) Liquefied natural gas import and export facilities;

(8) Natural gas distribution facilities.

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

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

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

(3) Fire suppression systems and equipment;

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

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

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

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

(8) Agricultural irrigation pumps.

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

(h) *Cessation of Reporting*. 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 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.

(1) For facilities with source categories in section 95101(a)(1)(A) that are subject to the requirements of this article regardless of emissions level, cessation of reporting provisions in section 95101(h)(1) apply, but the 2011 data year is the earliest year that criteria for cessation can be applied.

If reported emissions are less than 10,000 metric tons of CO_2e per year for three consecutive years, then the owner, operator, or supplier may discontinue complying with this article provided that the owner, operator, or supplier submits a notification to ARB that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification must be submitted no later than March 31 of the year immediately following the third consecutive year in which emissions are less than 10,000 metric tons of CO_2e per year. The owner, operator, or supplier must maintain the corresponding records required under section 95103 for each of the three consecutive years and retain such records for five years following the year that reporting was discontinued. The owner, operator, or supplier must resume reporting if annual emissions in any future calendar year increase to 10,000 metric tons of CO_2e per year or more.

(2) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraph (a)(1) of this section cease to operate or are permanently shut down, the owner, operator, or supplier must submit an emissions data report for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows. The owner, operator, or supplier must submit a notification to ARB that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations no later than March 31 of the year following such changes. Paragraph 95101(h)(2) does not apply to seasonal or other temporary cessation of operations. The owner, operator, or supplier must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting pursuant to section 95101(a)(1).

(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 an emissions data report through the 2014 data year. 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 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 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.

(D) Electric power entities who meet the definition of "retail provider" must always report retail sales for each calendar year. WAPA and DWR must always report pump loads for each calendar year.

(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 CO_2e, including CO_2 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 CO_2e.

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

§ 95102. Definitions.

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

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

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

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

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

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

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

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

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

applies to the adverse emissions data verification statement and the adverse product data verification statement.

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

(10) "Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

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

(12) "API" means the American Petroleum Institute.

(13) "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.

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

(15) "ARB" means the California Air Resources Board.

(16) "ARB ID" means, for the purposes of this article, the unique identification number assigned to each facility, supplier, and electric power entity that reports GHG emissions to the ARB.

(17) "ARB offset credit" is as defined in the cap-and-trade regulation.

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

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

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

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

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

(23) "ASTM" means the American Society of Testing and Materials.

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

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

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

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

(28) "Barrel" means a volume equal to 42 U.S. gallons.

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

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

(31) "Bias" means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

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

(33) "Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under

section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

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

(B) A mono-alkyl ester;

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

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

(E) Derived from nonpetroleum renewable resources.

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

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

(36) "Biogenic portions of CO_2 emissions" means carbon dioxide emissions generated as the result of biomass combustion from combustion units.

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

(38) "Biomass-derived fuels" or "biomass fuels" or "biofuels" or "biomass-based fuels" means fuels derived from biomass.

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

(40) "Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

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

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

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

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

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

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

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

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

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

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

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

(52) "Butane" or "n-Butane" is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

(53) "Butylene" or "n-Butylene" means an olefinic straight-chain hydrocarbon with molecular formula C_4H_8.

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

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

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

(57) "Calendar year" means the time period from January 1 through December 31.

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

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

(60) "California Climate Action Registry" or "CCAR" means the entity established pursuant to former Health and Safety Code Section 42800 et seq.

(61) "California consignee" means the person or entity in California to whom the shipment is to be delivered.

(62) "California Energy Commission" or "CEC" means the California Energy Resources Conservation and Development Commission.

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

(64) "Cap-and-trade regulation" or "cap-and-trade program" means ARB's regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

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

(66) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. For the purposes of this article, global warming potential values listed in Table A-1 of 40 CFR Part 98 are used to determine the CO_2 equivalent of emissions.

(67) "Carbon dioxide supplier" means: (a) facilities with production process units located in the State of California that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture the CO_2 stream in order to utilize it for geologic sequestration where capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process, (b) facilities with CO_2 production wells located in the State of

California that extract or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that extract a CO_2 stream in order to utilize it for geologic sequestration, (c) exporters (out of the State of California) of bulk CO_2 that export CO_2 for the purpose of geologic sequestration, (d) exporters (out of the State of California) of bulk CO_2 that export for purposes other than geologic sequestration, and (e) importers (into the State of California) of bulk CO_2. This source category is focused on upstream supply and is not intended to place duplicative compliance obligations on CO_2 already covered upstream. The source category does not include transportation or distribution of CO_2, purification, compression or processing of CO_2, or on-site use of CO_2 captured on-site.

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

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

(70) "Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(71) "CBOB-summer" or "conventional blendstock for oxygenate blending-summer" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-summer.

(72) "CBOB-winter" or "conventional blendstock for oxygenate blending-winter" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-winter.

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

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

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

(76) "Centrifugal compressor dry seals" mean a series of rings around the compressor shaft where it exits the compressor case that operate

mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

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

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

(79) "Chain of title" means the sequence of historical transfers of title to a fuel from the producer to the reporting entity.

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

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

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

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

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

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

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

(87) “Combustion emissions” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(88) “Combustion source” means a source of emissions resulting from combustion.

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

(90) “Common control” means having common “operational control” as defined herein.

(91) “Compliance instrument” is as defined in the cap-and-trade regulation.

(92) “Compliance obligation” means the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

(93) “Compliance offset protocol” means an offset protocol adopted by the Board.

(94) “Compliance period” means the period for which the compliance obligation is calculated for covered entities pursuant to the cap-and-trade regulation.

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

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

(97) "Compressor" means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas and discharging significantly higher pressure natural gas or CO_2.

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

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

(100) "Consignee" means the same as "California consignee."

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

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

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

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

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

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

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

(108) "Covered emissions" mean all emissions included in a compliance obligation under sections 95852 through 95852.2 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year.

(109) "Covered product data" means all product data included in the allocation of allowances under sections 95870, 95890, and 95891 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year.

(110) "Cracking" means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

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

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

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

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

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

Liquids produced at natural gas processing plants and natural gas fractionating facilities are excluded, unless the produced natural gas liquids are extracted from produced gas, associated gas, and waste gas at a facility and re-injected into barrels of crude oil produced by the same facility. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels;

lubricants; asphalt; ethane, propane, and butane; and many other products used for their energy or chemical content.

(112) "Customer" means a purchaser of electricity not for the purposes of retransmission or resale.

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

(114) "Data year" means the calendar year in which emissions occurred.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(128) "Distillate Fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131℉.

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

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

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

(132) “Dry gas” means a natural gas that is produced from gas wells not associated with the production of crude oil.

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

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

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

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

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

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

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

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

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

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

(143) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

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

(145) "Eligible renewable energy resource" is as defined in section 95802(a) of the cap-and-trade regulation.

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

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

(148) "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by this article. The emissions data report is for the submission of required

data for the calendar year prior to the year in which the report is due. For example, a 2013 emissions data report would cover emissions and product data for the 2013 calendar year and would be reported in 2014.

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

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

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

(152) “Energy Imbalance Market” or “EIM” means the operation of the CAISO’s real-time market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined CAISO and EIM footprint.

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

(154) “Enforceable” means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

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

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

(157) “Enterer” means an entity that imports into California motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel, non-exempt biomass-derived fuel or renewable

fuel and who is the importer of record under federal customs law or the owner of fuel upon import into California if the fuel is not subject to federal customs law. Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.

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

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

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

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

(162) "Ethane" is a paraffinic hydrocarbon with molecular formula C_2H_6.

(163) "Ethanol" is an anhydrous alcohol with molecular formula C_2H_5OH.

(164) "Ethylene" is an olefinic hydrocarbon with molecular formula C_2H_4.

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

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

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

(168) "Exported electricity" means electricity generated inside the state of California and delivered to serve load located outside the state of California. This includes electricity delivered from a first point of receipt inside California, to the first point of delivery outside California, with a final point of delivery outside the state of California. Exported electricity delivered across balancing authority areas is documented on NERC e-Tags with the first point of receipt located inside the state of California and the final point of delivery located outside the state of California. Exported electricity does not include electricity generated inside the state of California then transmitted outside of California, but with a final point of delivery inside the state of California. Exported electricity does not include electricity generated inside the state of California that is allocated to serve the California retail customers of a multi-jurisdictional retail provider, consistent with a cost allocation methodology approved by the

California Public Utilities Commission and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

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

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

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

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

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

(174) "Feedstock" means the raw material supplied to a process.

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

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

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

(178) "First deliverer of electricity" or "first deliverer" means the owner or operator of an electricity generating facility in California or an electricity importer.

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

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

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

(182) "Flare combustion" means unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares.

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

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

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

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

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

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

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

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

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

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

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

(194) "Fluorinated greenhouse gas" means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A, (May 1995), which is hereby incorporated by reference, and substances with vapor pressures of less than 1 mm of Hg absolute at 25℃. With these exceptions , "fluorinated GHG"

includes any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

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

(196) “Forest-derived wood and wood waste” means wood harvested pursuant to the California Forest Practice Rule, Title 14, California Code of Regulations, Chapters 4, 4.5, and 10 or pursuant to the National Environmental Policy Act.

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

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

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

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

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

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

(203) “Fuel combusting electricity generating or cogeneration unit” means an electricity generating unit, which may include a cogeneration or bigeneration unit, that produces electricity from fuel combustion.

(204) "Fuel ethanol" means ethanol that meets ASTM D-4806-08 "*Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel*" (2008), specifications, which is hereby incorporated by reference, for blending with gasolines for use as automotive spark-ignition engine fuel.

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

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

(207) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas including operators of interstate and intrastate pipelines, a supplier of liquefied natural gas, or a supplier of liquid petroleum gas as specified in this article.

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

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

(210) "Fugitive emissions detection" means the process of identifying emissions from equipment, components, and other point sources.

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

(212) "Fugitive source" means a source of fugitive emissions.

(213) "Full verification" means all verification services as provided in section 95131.

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

(215) "Gas conditions" means the actual temperature, volume, and pressure of a gas sample.

(216) "Gas gathering/booster stations" means centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration,

gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

(217) "Gas-to-oil ratio" or "GOR" means the ratio of gas produced from a barrel of crude oil or condensate when cooling and depressurizing these liquids to standard conditions, expressed in terms of standard cubic feet of gas per barrel of oil.

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

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

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

(221) "Generated energy" means electricity or thermal energy generated by the electricity generating, cogeneration, or bigeneration units included in the reporting facility.

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

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

(224) "Geothermal" means heat or other associated energy derived from the natural heat of the earth.

(225) "Global warming potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

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

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

(228) "Greenhouse gas emission reduction" or "GHG emission reduction" or "greenhouse gas reduction" or "GHG reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

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

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

(231) "Greenhouse gas sink" or "GHG sink" means a physical unit or process that removes a GHG from the atmosphere.

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

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

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

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

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

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

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

(239) "High-bleed pneumatic devices" means automatic, continuous or intermittent bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents

continuously or intermittently (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

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

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

(242) "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

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

(244) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

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

(246) "Imported electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the state of California from a facility or unit physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, defined pursuant to this section. Imported electricity does not include electricity imported into the California Independent System Operator (CAISO) balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the state of California. Imported Electricity does not include electricity imported into California by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall include Energy Imbalance Market dispatches designated by the CAISO's optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported to serve retail customers load that are located within the State of California.

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

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

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

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

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

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

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

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

(255) "Intrastate pipeline" means any pipeline or piping system wholly within the state of California that is delivering natural gas to end-users and is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission. For purposes of this article, intrastate pipeline operators that physically deliver gas to end users in California are considered to be Local Distribution Companies. Facilities that receive gas from an upstream LDC

and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.

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

(257) "ISO" means the International Organization for Standardization.

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

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

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

(261) “Jurisdiction” means U.S. state or Canadian province. For purposes of this article, “U.S. state” means U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this article, “province” means any Canadian province or territory.

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

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

(264) “Kiln” means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

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

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

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

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

(269) "Legacy contract" shall have the meaning defined in section 95802(a) of the cap-and-trade regulation.

(270) "Legacy contract transition assistance" means allowances provided under section 95894 of the cap-and-trade regulation to an entity which has applied for allowances on the basis of its legacy contract(s).

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

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

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

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

(275) "Linkage" is as defined in section 95802(a) of the cap-and-trade regulation.

(276) "Linked jurisdiction" means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the cap-and-trade regulation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(293) "MMBtu" means million British thermal units.

(294) "Motor gasoline (finished)" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

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

(296) "Mscf" means thousand standard cubic feet.

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

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

(299) "NAICS" means North American Industry Classification System.

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

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

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

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

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

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

(306) "Natural gas liquid fractionator" means an installation that fractionates natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

(307) "Natural gas supplier" means, for the purposes of this article, the local distribution company or interstate pipeline that owns or operates the distribution pipelines that physically deliver natural gas to end users.

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

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

(310) "Net generation" or "net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(311) "Nitrous oxide" or "N_2O" means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

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

(313) "Non-exempt biomass-derived CO_2" means CO_2 emissions resulting from the combustion of fuel not listed under section 95852.2(a) of the cap-and-trade regulation, or that does not meet the requirements of section 95131(i) of this article.

(314) "Non-exempt biomass-derived fuel" means fuel not listed under section 95852.2(a) of the cap-and-trade regulation, or that does not meet the requirements of section 95131(i) of this article.

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

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

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

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

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

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

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

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

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

(324) "Offshore," for purposes of this article, means all waters within three nautical miles of the California baseline, starting at the California-Oregon border and

ending at the California-Mexico border at the Pacific Ocean, inclusive. For purposes of this definition, "California baseline" means the mean lower low water line along the California Coast.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(339) “Perfluorocarbons” or “PFCs” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

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

(341) “Performance review” means an assessment conducted by ARB of an applicant seeking to become accredited as a verification body, verifier, lead verifier, offset project specific verifier, or sector specific verifier pursuant to section 95132 of this article. Such an assessment may include a review of applicable past sampling plans, verification reports, verification statements,

conflict of interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

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

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

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

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

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

(347) "Pipeline quality natural gas" means, for the purpose of calculating emissions under this article, natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

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

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

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

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

(A) The equipment is attached to a foundation.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(366) "Process gas" means any gas generated by an industrial process such as petroleum refining.

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

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

(369) "Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation.

(370) "Produced water" means the resulting water that is produced as a byproduct of crude oil or natural gas production.

(371) "Producer" means a person who owns, leases, operates, controls or supervises a California production facility.

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

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

(374) "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

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

(376) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(377) "Propylene" is an olefinic hydrocarbon with molecular formula C_3H_6.

(378) "Public utility gas corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(379) "Publicly-owned natural gas utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers

authority that includes one or more of these agencies that furnishes natural gas services to end users.

(380) "Pump" means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

(381) "Pump seal emissions" means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

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

(383) "Purchasing-selling entity" or "PSE" means the entity that is identified on a NERC e-Tag for each physical path segment.

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

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

(386) "QA/QC" means quality assurance and quality control.

(387) "Qualified exports" is as defined in section 95802(a) of the cap-and-trade regulation.

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

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

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

This definition applies to the qualified positive emissions data verification statement and the qualified positive product data verification statement.

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

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

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

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

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

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

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

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

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

(400) “Re-condenser” means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

(401) “Refiner” means, for purposes of this article, an individual entity or a corporate-wide entity that delivers transportation fuels to end users in California that were produced by petroleum refineries owned by that entity or a subsidiary of that entity.

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

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

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

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

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

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

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

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

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

(B) Not a mono-alkyl ester;

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

(D) Derived from nonpetroleum renewable resources.

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

(411) “Renewable Energy Credit” or “REC” has the same meaning defined in the California Energy Commission’s “Renewable Portfolio Standard Eligibility,” 7^{th} edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF.

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

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

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

(415) “Reporting year” or “report year” means data year.

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

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

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

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

(420) “Retail provider” means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public

Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electric cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(421) “Retail sales” means electricity sold to retail end users.

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

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

(424) “Sector” means a broad industrial categorization such as specified in section 95101.

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

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

(427) “Short ton” means a common international measurement for mass, equivalent to 2,000 pounds.

(428) “Shutdown” means the cessation of operation of an emission source for any purpose.

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

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

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

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

(433) "Source" means greenhouse gas source; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(434) "Source category" means categories of emission sources as defined by Tables A-3, A-4, and A-5 of 40 CFR Part 98.

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

(436) "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB.

(437) "SSM" means periods of startup, shutdown and malfunction.

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

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

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

(441) "Steam generator" means equipment that produces steam using an external heat source.

(442) "Stationary" means neither portable nor self-propelled, and operated at a single facility.

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

(444) "Sub-facility" for purposes of reporting data disaggregated pursuant to section 95156(a), means the geographic area, or areas, within a single township or within a group of contiguous or adjacent townships identified in the Public Land Survey System of the United States, where operations and equipment are located. The operator may disaggregate sub-facilities based on contiguous township areas to smaller sub-facilities according to similar operational, geological, or geographical characteristics. Sub-facility disaggregation may be retained from year to year, or may be updated when some of the operations cease or equipment is reconfigured within the

previously designated sub-facilities. Sub-facility disaggregation must be updated from previous reporting years if there are new operations or equipment that lies outside previous township boundaries. The Principal Meridian name, Township and Range designations, and the section numbers that apply to each sub-facility, must be identified in the operator's GHG Monitoring Plan required pursuant to section 95105(c). The operator must also describe in the GHG Monitoring Plan any operational, geological or geographical characteristics used to determine sub-facility boundaries.

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

(446) "Sulfur hexafluoride" or "SF_6" means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

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

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

(449) "Supplier" means a producer, importer, exporter, position holder, interstate pipeline operator, or local distribution company of a fossil fuel or an industrial greenhouse gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(486) “Vegetable oil” means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

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

(488) “Verification” means a systematic, independent and documented process for evaluation of a reporting entity’s emissions data report against ARB’s reporting procedures and methods for calculation and reporting GHG emissions and product data.

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

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

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

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

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

(494) "Verifier" means an individual accredited by ARB to carry out verification services as specified in section 95131.

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

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

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

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

(499) "$VOC_{C3\text{-}C9,}$" for purposes of Appendix B, means Volatile Organic Compounds with three to nine carbon atoms.

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

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

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

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

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

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

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

(507) "Wholesale sales" means sales to other LDCs.

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

(1) “Air dried ton of paper” means paper with 6 percent moisture content.

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

(3) “Aluminum alloy” is an alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.(4)

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

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

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

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

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

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

(10) “Bathroom tissue” means a thin, soft, lightweight, sanitized paper used in bathrooms for personal cleanliness. Bathroom tissue is usually sold as a long strip of perforated paper wrapped around a paperboard core.

(11) “Blending component” means a material blended into a primary refinery product, such as n-butane (EIA product codes 249 and 643), isobutane (EIA product codes 247 and 644), butylene (EIA product code 633), isobutylene (EIA product code 634), pentanes plus (EIA product code 220), ethyl tertiary butyl ether (ETBE) (EIA product code 142), methyl tertiary butyl ether (MTBE) (EIA product code 144), other oxygenates (EIA product code 445), and fuel ethanol (EIA product code 141).

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

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

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

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

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

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

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

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

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

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

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

(23) "Concentrated milk" means the liquid food obtained by partial removal of water from milk. The milkfat and total milk solids contents of the food are not less than 7.5 and 25.5 percent, respectively. It is pasteurized, but is not processed by heat so as to prevent spoilage. It may be homogenized.

(24) "Condensed milk" means the food obtained by partial removal of water only from a mixture of milk and nutritive carbohydrate sweeteners. The finished food contains not less than 8 percent by weight of milkfat, and not less than 28 percent by weight of total milk solids. The quantity of nutritive carbohydrate sweetener used is sufficient to prevent spoilage. The food is pasteurized and may be homogenized.

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

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

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

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

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

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

(31) "Dairy product solids for animal feed" means modified dairy by-products derived from the fluid milk production process that are purposely processed for animal consumption obtained by the removal of water, protein and/or lactose, and/or minerals.

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

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

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

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

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

(37) “Delicate task wiper” means tissue-based wipers used for the delicate cleaning of lenses, surfaces, and equipment in labs, research facilities, hospitals, and manufacturing settings.

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

(39) “Diced Tomatoes” means the food prepared from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum* P. Mill, of red or reddish varieties. The tomatoes are peeled and diced, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

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

(41) “Dolime" is calcined dolomite.

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

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

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

(45) “Facial Tissue” means a class of soft, absorbent, disposable tissue papers that is suitable for use on the face.

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

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

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

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

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

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

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

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

(54) “Gypsum” means a mineral with the chemical formula $CaSO_4 \cdot 2H_2O$.

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

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

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

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

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

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

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

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

(63) “Liquid Color Concentrate” means a fluid extract from fruits and vegetables reduced by driving off water and the use of which is for altering the color of materials and/or food.

(64) “Liquid Hydrogen" means hydrogen in a liquid state.

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

(66) “Nitric acid” means HNO_3 of 100% purity.

(67) "Nonfat dry milk and skimmed milk powder (high heat)" means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of 88 ºC for 30 minutes and includes undenatured whey protein nitrogen content equal to or less than 1.5 mg/g powder.

(68) "Nonfat dry milk and skimmed milk powder (low heat)" means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of milk no higher than 70 ºC for 2 minutes and includes undenatured whey protein nitrogen content equal to or greater than 6 mg/g powder.

(69) "Nonfat dry milk and skimmed milk powder (medium heat)" means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of 70-78 ºC for 20 minutes and includes undenatured whey protein nitrogen content equal to or greater than 1.51 mg/g powder up to 5.99 mg/g powder.

(70) "Non-Aseptic tomato juice" means tomato juice packaged using methods other than aseptic preparation.

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

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

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

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

(75) "Paper Towel" means a disposable towel made of absorbent tissue paper.

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

(77) "Pistachio" means the nuts of the pistachio tree *Pistacia vera*.

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

(79) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.

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

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

(82) “Primary refinery product” means aviation gasoline (EIA product codes 111 and 112), motor gasoline (finished) (EIA product codes 125, 127, 130, 149, and 166), motor gasoline blendstocks (EIA product codes 117, 118, 138, and 139), kerosene-type jet fuel (EIA product code 213), distillate fuel oil (EIA product codes 465, 466, and 467), renewable liquid fuels (EIA product codes 203, 205, and 207), and asphalt (EIA product code 931). For the purpose of calculating this value for each refinery, ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

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

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

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

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

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

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

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

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

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

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

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

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

(95) "Soda ash equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

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

(97) “Stucco” means hemihydrate plaster ($CaSO_4 \bullet ½H_2O$) produced by heating (“calcining”) raw gypsum, thereby removing three-quarters of its chemically combined water.

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

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

(100) “Tissue” means a class of papers which are characteristically gauzy in texture and, in some cases, fairly transparent. They may be glazed, unglazed, or creped, and are used for a variety of purposes. Examples of different types of tissue papers include sanitary grades such as toilet, facial, napkin, towels, wipes, and special sanitary papers.

(101) "Tissue produced adjusted by water absorbency capacity" means the mass of tissue adjusted by water absorbency capacity derived by using the following metric: Tissue produced adjusted by water absorbency capacity = Air dried ton of tissue produced x grams of water absorbed by a gram of tissue product.

(102) “Tomato juice” is the liquid obtained from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum* P. Mill, of red or reddish varieties. Tomato juice may contain salt, lemon juice, sodium bicarbonate, water, spices and/or flavoring. This food shall contain not less than 5.0 percent by weight tomato soluble solids.

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

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

(105) “Tomato soluble solids” (TSS) means the sucrose value as determined by the method prescribed in the “Official Methods of Analysis of the Association of Official Analytical Chemists,” 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. For instances where no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or through the application of the acidified break, determine the percent of such added sodium chloride as specified in the definition of salt. Subtract the percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of “tomato soluble solids.”

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

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

(108) “Water absorption capacity” means the mass of water that is absorbed per unit mass of the test piece using the methodology specified by ISO 12625-8:2010 except for the humidity and temperature conditions, which shall be 50% relative humidity ±2%, and 23 degrees C ±1 degree C.

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

(110) "Whole chicken and chicken parts" means the whole chicken or chicken parts (including breasts, thighs, wings, and drums) that are packaged for wholesale, or retail sales, or transferred to other facilities.

(111) "Whole Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum P*. Mill, of red or reddish varieties. The tomatoes are peeled but kept whole, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

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

(1) "Air separation unit" means a refinery unit which separates air into its components including oxygen utilizing a cryogenic or other method.

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

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

(4) "Aromatic saturation of distillates" means the saturation of aromatic rings over a fixed catalyst bed at low or medium pressure in the presence of hydrogen.

(5) "AROMAX®" means a special application of catalytic reforming for the specific purpose of producing light aromatics.

(6) "Aromatics production" means extraction of light aromatics from reformate and/or hydrotreated pyrolysis gasoline by a solvent.

(7) "Asphalt production" means the processing required to produce asphalts and bitumen, including bitumen oxidation (mostly for road paving). This includes polymer-modified asphalt.

(8) "Atmospheric Crude Distillation" means primary atmospheric distillation of crude oil and other feedstocks. The atmospheric crude distillation unit includes any ancillary equipment such as a crude desalter, naphtha splitting,

gas plant and wet treatment of light streams for mercaptan removal and may have more than one distillation column.

(9) "Benzene saturation" means a selective hydrogenation of benzene in gasoline streams over a fixed catalyst bed at moderate pressure.

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

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

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

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

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

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

(16) "Cumene production" means the alkylation of benzene with propylene.

(17) "Cyclohexane production" means hydrogenation of benzene to cyclohexane over a catalyst at high pressure.

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

(19) "Desalination" means a refinery's desalination of seawater or contaminated water.

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

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

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

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

(24) "Ethylbenzene production" means the process of combining benzene and ethylene to form ethylbenzene.

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

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

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

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

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

(30) "Fluid Coker" means a continuous process where the fluidized powder-like coke is transferred between the cracking reactor and the coke burning vessel

and burned for process heat production. Surplus coke is drawn off as a product.

(31) "Fuel gas sales treating & compression" means treatment and compression of refinery fuel gas for sale to a third party.

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

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

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

(35) "Lube catalytic dewaxing" means the catalytic breakdown of long paraffinic chains in intermediate streams for the manufacture of lube oils.

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

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

(38) "Lube/Wax hydrofining" means the hydrotreating of lube oil fractions and wax for improving the quality of the lube and wax.

(39) "Lubricant hydrocracking" means hydrocracking of heavy feedstocks for the manufacture of lube oils.

(40) "Methanol synthesis" means the recombination of CO_2 and hydrogen to produce methanol. Methanol synthesis is only applicable when a refinery produces hydrogen via partial oxidation.

(41) "Middle distillate dewaxing" means the cracking of long paraffinic chains in gasoils to improve cold flow properties over a fixed catalyst bed at low or medium pressure in the presence of hydrogen. This process includes the desulfurization step.

(42) "Mild Residual FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of 2.25% to 3.5% by weight.

(43) "Naphtha/Distillate Hydrocracker" means a refinery process unit which conducts cracking of a hydrocarbon stream typically consisting of gasoils and

distillates over a fixed catalyst bed, at high pressure and in the presence of hydrogen. The process combines cracking and hydrogenation reactions.

(44) "Naphtha hydrotreater" means a refinery process unit that treats and upgrades naphtha/gasoline and lighter streams using any combination of one or more of the following processes: benzene saturation, desulfurization of C4–C6 feeds, conventional naphtha hydrotreating, diolefin to olefin saturation of gasoline, FCC gasoline hydrotreating with minimum octane loss, olefinic alkylation of thio sulfur, desulfurization of pyrolysis gasoline/naphtha. For naphtha/distillates, selective hydrotreating or the S-Zorb™ process may be used.

(45) "Non-Crude Input" means the total volume of barrels of raw materials processed in process units at the refinery, excluding returns from a lube refiner or a chemical plant within a refining/petrochemical complex and excluding non-processed blendstock.

(45) "Olefinic alkylation of thio sulfur" means a gasoline desulfurization process in which thiophenes and mercaptans are catalytically reacted with olefins to produce higher-boiling sulphur compounds removable by distillation. This process does not utilize hydrogen.

(46) "Other FCC" means early catalytic cracking processes on fixed catalyst beds, including Houdry catalytic cracking and Thermofor catalytic cracking.

(47) "Oxygenates" means ethers that are produced by reacting an alcohol with olefins.

(48) "Paraxylene production" means the physical separation of paraxylene from mixed xylenes.

(49) "Process CWB" means the total complexity-weighted barrels of a refinery excluding those contributed by the process units called total refinery input and non-crude input.

(50) "Propane/Propylene splitter (propylene production)" means a refinery unit that conducts separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC or coker. This unit produces chemical or polymer grade propylene.

(51) "POX syngas for fuel" means the production of synthesis gas by gasification (partial oxidation) of heavy residues. This includes syngas clean-up.

(52) "Reactor for selective hydrotreating" means a special configuration where a distillation/fractionation column contains a solid catalyst that converts diolefins in FCC gasoline to olefins or where the catalyst bed is in a preheat train reactor vessel in front of the column.

(53) "Reformer - including AROMAX" means a refinery unit which increases the octane rating of naphtha by dehydrogenation of naphthenic rings and paraffin isomerisation over a noble metal catalyst at low pressure and high temperature. The process also produces hydrogen.

(54) "Residual FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of greater than or equal to 3.5% by weight.

(55) "Residual hydrotreater" means a refinery unit which conducts desulfurization of residues over a fixed catalyst bed at high pressure and in the presence of hydrogen. It results in a limited degree of conversion of the residue feed into lighter products.

(56) "Residual Hydrocracker" means a refinery unit which conducts hydrocracking of residual feedstocks. Different processes involve continuous or semi-continuous catalyst replenishment. The residual hydrocracker unit must process residuum with a Conradson carbon level of at least 3.5% by weight.

(57) "S-Zorb™ process for kerosene and gasoil" means desulfurization of gasoil using an absorption process. This process does not utilize hydrogen.

(58) "S-Zorb™ process for naphtha/distillates" means desulfurization of naphtha/gasoline streams using a proprietary fluid-bed hydrogenation adsorption process in the presence of hydrogen.

(59) "Selective hydrotreating of C3-C5 streams for alkylation" means selective saturation of diolefins for alkylation over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen, or hydrotreatment of distillates for conversion of diolefins to olefins.

(61) "Solomon Energy Intensity Index®" or "Solomon EII" or "EII" means a petroleum refinery energy efficiency metric that compares actual energy consumption for a refinery with the "standard" energy consumption for a refinery of similar size and configuration. The "standard" energy consumption is calculated based on an analysis of worldwide refining capacity as contained in the database maintained by Solomon Associates. The ratio of a facility's actual energy to the standard energy is multiplied by 100 to arrive at the Solomon EII for a refinery.

(62) "Solomon Energy Review" means a data submittal and review conducted by a petroleum refinery and Solomon Associates. This process uses the refinery energy utilization, throughput and output to determine the Solomon EII of the refinery.

(63) "Solvent deasphalter" means a refinery unit which uses a solvent such as propane, butane or a heavier solvent to remove asphaltines from a residual oil stream and produce asphalt and a deasphalted gasoil.

(64) "Special Fractionation" means fractionation processes excluding solvents, propylene and aromatics fractionation, which are accomplished by a deethanizer, depropanizer, deisobutanizer, debutanizer, deisopentanizer, depentanizer, deisohexanizer, dehexanizer, deisoheptanizer, deheptanizer, naphtha splitter, alkylate splitter or reformate splitter.

(65) "Standard FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of less than 2.25% by weight.

(66) “Sulfur Recovery” means a process where hydrogen sulfide is converted to elemental sulfur.”

(67) “Sulfuric acid regeneration” means a catalytic process in which spent acid is regenerated to concentrated sulfuric acid. The equipment for this process may include the combustor, waste heat boiler, converter, absorber, SO3 recycle, gas cleaning including electrostatic precipitator and amine regenerator.

(68) “Thermal Cracking” means thermal cracking of distillate feedstocks. A thermal cracking unit may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

(69) “Thermofor catalytic cracking” means a method of catalytic cracking in which gravity is used to pass the catalyst through the feedstock or to pass the feedstock through the catalytic reactor bed. The catalyst is not fluidized.

(70) “Toluene disproportionation/transalkylation means a fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen.

(71) “Total Refinery Input” means the total volume of the following brought in to the refinery: crude oil and condensate, excluding basic sediment and water; finished product additives such as dyes, diesel pour point depressants and cetane improvers; antiknock compounds; and other raw materials, including crude diluents, feedstock from outside the refinery which is processed in other process units or blend stock blended into refinery products.

(72) “Vacuum Distillation” means distillation of atmospheric residues under vacuum. Some units may have more than one main distillation column.

(73) “Visbreaker” means a refinery unit which conducts mild thermal cracking of residual feedstocks to produce some distillates and reduce the viscosity of the cracked residue. It may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

(74) “VGO Hydrotreater” means a refinery unit which conducts desulfurization of a hydrocarbon stream typically made up of vacuum gasoils and cracked gasoils, principally destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure in the presence of hydrogen.

(75) “Wax deoiling” means solvent removal of lighter hydrocarbons from wax obtained from lube dewaxing. Different proprietary processes use different solvents, such as MEK/toluene, MEK/MIBK, or propane.

(76) “Xylene isomerization” means isomerization of mixed xylenes to paraxylene.

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

§ 95103. Greenhouse Gas Reporting Requirements.

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this part.

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the 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:

(1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, geographic location, natural gas supplier name, natural gas supplier customer identification number, natural gas supplier service account identification number or other primary account identifier, and annual billed MMBtu (10 therms = 1 MMBtu).

(2) Facility GHG stationary combustion emissions for all stationary fuel combustion units and calculated according to any method in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O. 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.

(3) Total facility GHG process emissions aggregated for all process emissions sources and calculated according to the requirements in the following parts, expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O, as applicable:

(A) 40 CFR §98.143 for glass production;

(B) 40 CFR §98.163 for hydrogen production;

(C) 40 CFR §98.173 for iron and steel production;

(D) 40 CFR §98.273 for pulp and paper manufacturing;

(E) Subarticle 5 of this article for petroleum and natural gas systems.

(4) Identification of the methods chosen for determining emissions.

(5) Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions. Missing fuel use or fuel characteristics data must be substituted according to the requirements of 40 CFR §98.35.

(6) For facilities with on-site electricity generation or cogeneration, the applicable information specified in sections 95112(a)-(b) of this article. Geothermal facilities must also report the information specified in section 95112(e). Operators of hydrogen fuel cells must report the information specified in section 95112(f).

(7) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(8) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year.

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

(10) For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR §98.3(g), except that a written GHG Monitoring Plan is not required.

(11) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

(b)-(d) ***Reserved***

(e) *Reporting Deadlines.* Except as provided in section 95103(a)(7)-(8), each facility operator or supplier must submit an emissions data report no later than April 10 of each calendar year. Each electric power entity must submit an emissions data report no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* The requirements of this paragraph apply to each reporting entity submitting an emissions data report that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, 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(i)(4). 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).

(g) *Non-submitted/Non-verified Emissions Data Reports.* When a reporting entity that holds a compliance obligation under the cap-and-trade regulation fails to submit an emissions data report or fails to obtain a positive emissions data verification statement or qualified positive emissions data verification statement by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the reporting entity as set forth in section 95131(c)(5)(A)-(C).

(h) *Reporting in 2015.* All provisions of the regulation are in full effect for 2014 data reporting in 2015 and beyond, except the following:

(1) Operators of petroleum refineries may use best available methods for reporting 2014 data for primary refinery products and calcined coke pursuant to sections 95113(l)(1) and 95113(l)(2), respectively.

(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.

(1) When reporting solid waste, the reporting entity must separately report the mass, in short tons, of urban waste, agricultural waste, and municipal solid waste.

(2) When reporting the use of forest derived wood and wood waste as identified in section 95852.2(a)(4) of the cap-and-trade regulation and harvested pursuant to any of the California Forest Practice Rules Title 14, California Code of Regulations, Chapters 4, 4.5 and 10 of the Federal National Environmental Policy Act, the reporting entity must report: the bone-dry mass received; information about the supplier, including the name, physical address, mailing address, contact person with phone number and e-mail address; and the corresponding identification number under which the wood was removed.

(3) When reporting biomethane, the operator or supplier who is reporting biomass emissions from biomethane fuel must also report the following information for each contracted delivery:

(A) Name and address of the biomethane vendor from which biomethane is purchased;

(B) Annual MMBtu delivered by each biomethane vendor.

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.

(4) Reporting of fuel consumption from non-exempt biomass-derived fuel is subject to the requirements of section 95103(k) and reporting of emissions from non-exempt biomass-derived fuels is subject to the requirements of sections 95110 to 95158.

(k) *Measurement Accuracy Requirement*. The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements for data used for calculating non-covered emissions and non-covered product data, except as otherwise specified in this paragraph. In addition, the following accuracy requirements apply to data used for calculating covered emissions and covered product data. The operator or supplier with covered product data or covered emissions equal to or exceeding 25,000 metric tons of CO_2e or a compliance obligation under the 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.

(1) Except as otherwise provided in sections 95103(k)(7) through (9), all flow meter and other measurement devices used to provide data for the GHG emissions calculations or covered product data must be calibrated prior to the year data collection is required to begin using the procedures specified in this section, and subsequently recalibrated according to the frequency specified in paragraph (4). Flow meters and other measurement devices that were calibrated prior to January 1, 2012 using procedures specified in previous versions of the Mandatory Reporting Regulation or methods specified in 40 CFR Part 98 must be subsequently recalibrated according to the frequency specified in paragraph (4). A flow meter device consists of a number of individual components which might include a flow constriction component, mechanical component, and temperature and pressure measurement components. Each meter or measurement device must meet the applicable accuracy specification in section 95103(k)(6), however each individual component of a flow meter device is not required to meet the accuracy specifications. The procedures and methods used to quality-assure the data from each measurement device must be documented in the written monitoring plan required by section 95105(c).

(2) All flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be calibrated according to either the manufacturer's recommended procedures or a method specified in an applicable subpart of 40 CFR 98. The calibration method(s) used must be documented in the monitoring plan required under section 95105(c), and are subject to verification under this article and review by ARB to ensure that measurements used to calculate GHG emissions or product data have met the accuracy requirements of this section.

(3) For facilities and suppliers that become subject to this article after January 1, 2012, all flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be installed and calibrated no later than the date on which data collection is required to begin under this article.

(4) Except as otherwise provided in sections 95103(k)(7) through (9), subsequent recalibrations of the flow meter and other measurement devices subject to the requirements of this section must be performed no less frequently than at one of the following time intervals, whichever is shortest:

(A) The frequency specified in a subpart of 40 CFR Part 98 that is applicable under this article.

(B) The frequency recommended by the manufacturer.

(C) Once during every three-year compliance period of the cap-and-trade regulation, with the time between successive calibrations not to be less than 30 months or greater than 48 months.

(D) Immediately upon replacement of a previously calibrated meter.

(E) Immediately upon replacement or repair of a device that is deemed out of calibration as determined in paragraph (6).

(F) If the device manufacturer explicitly states in the product documentation that calibration is required at a period exceeding three years, the operator may follow the procedures in paragraph (9) to obtain Executive Officer approval to relieve the operator from having to comply with provisions (A) and (C) of this subparagraph.

(5) All standards used for calibration must be traceable to the National Institute of Standards and Technology or other similar national government body responsible for measurement standards.

(6) In addition to the specific calibration requirements specified below, and, if applicable, the field accuracy assessment requirements specified below, all flow meter and other measurement devices covered by this part, regardless of type, must be selected, installed, operated, and maintained in a manner to ensure accuracy within ±5 percent.

(A) Perform all mass and volume measurement device calibration as specified in the original equipment manufacturers (OEM) documentation. If OEM documentation is unavailable, calibrate as specified in 40 CFR §98.3(i)(2)-(3), except that a minimum of three calibration points must be used spanning the normal operating conditions. When using the three calibration points, one point must be at or near the zero point, one point must be at or near the upscale point, and one point at or near the mid-point of the devices operating range. If OEM documentation does not specify a method or is unavailable, and calibration methods specified in 40 CFR §98.3(i)(2)-(3) are not possible for a particular device, the procedures in section 95109(b) must be followed to obtain approval for an alternative calibration procedure. Additionally:

1. Pressure differential devices must be inspected at a frequency specified in paragraph (k)(4) of this section. The inspection must be conducted as described in the appropriate part of ISO 5167-2 (2003), or AGA Report No 3 (2003) Part 2, both of which are incorporated by reference, or a method published by an organization listed in 40 CFR §98.7 applicable to the analysis being conducted. If the device fails any one of the tests then the meter shall be deemed out of calibration. If OEM guidance for a particular pressure differential device recommends against disassembly and inspection of the device, disassembly and inspection requirements in this paragraph do not apply. Documentation of OEM guidance must be made available to verifiers and ARB upon request.
   a. Records of all tests must be preserved pursuant to section 95105 and made available to verifiers and ARB upon request.
   b. Where inspection requirements apply, the primary element must also be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe.
2. Devices used to measure total pressure and temperature must be calibrated using methods specified in section 95103(k)(2) and at a frequency specified in section 95103(k)(4).
3. If temperature and/or total pressure measurements are not available or are taken at a remote location, the uncertainty caused by this must be factored into the evaluation of the overall measurement accuracy required under section 95103(k)(6).

(B) Operators and suppliers may conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±5 percent. When performing a field accuracy assessment, the as-found condition must be recorded to ensure the device is measuring with accuracy within ±5 percent. Should a device be found to be operating outside the ±5 percent accuracy bounds, the device shall be deemed out of calibration. Records of all field accuracy assessments must clearly indicate the assessment procedure and the as-found condition, be preserved pursuant to section 95105, and be made available to verifiers and ARB upon request. Device accuracy may be assessed using one of the following options:

1. Engineering analysis;
2. OEM calibration guidance or other OEM recommended methods;
3. Standard industry practices; or
4. Portable instruments.

(C) Pursuant to paragraph (k)(10) of this section, in the event of a failed calibration or recalibration, operators or suppliers who choose not to perform the annual field accuracy assessment specified in paragraph (6)(B) of this section for one or more mass or volume measurement devices must demonstrate data accuracy going back multiple years to the most recent successful calibration. Multiple years of data may be deemed invalid if accuracy cannot be demonstrated by other means, including strap-on meters or engineering methods. For operators and suppliers who conduct the annual field accuracy assessment, and a device is found to be out of calibration, accuracy must be demonstrated back to the most recent successful calibration or the most recent successful field accuracy assessment, whichever is most recent.

(7) The requirements of section 95103(k) do not apply under the following circumstances:

(A) Financial transaction meters are exempted from the calibration requirements of section 95103(k) if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Financial transaction meters where the supplier and the purchaser do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the calibration requirements of section 95103(k) if one of the following is true:

1. The financial transaction meter is also used by other companies that do not share common ownership with the fuel supplier; or

2. The financial transaction meter is sealed with a valid seal from the county sealer of weights and measures or from a county certified designee; or

3. The financial transaction meter is operated by a third party.

(B) Upstream ethanol and additive meters used to ensure proper blendstock percentage for finished gasoline are exempted from the calibration requirements of section 95103(k).

(C) Non-financial transaction meters used by Public Utility Gas Corporations for purposes of reporting natural gas supplier emissions are exempt from the calibration requirements in sections 95103(k)(1)-(6) if the supplier can demonstrate that the meters are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of the California Public Utilities Commission General Order 58A (1992).

(8) For units and processes that operate continuously with infrequent outages, it may not be possible to meet deadlines for the initial or subsequent calibrations of a flow meter or other fuel measurement or sampling device, or inspection of orifice plates without disrupting normal process operation. In such cases, the owner or operator may submit a written request to the Executive Officer to postpone calibration or inspection until the next scheduled maintenance

outage. Such postponements are subject to the procedures of section 95103(k)(9) and must be documented in the monitoring plan that is required under section 95105(c).

(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date. The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to ARB within ten (10) working days of a request by ARB.

(B) The request must include:

1. The date of the required calibration, recalibration, or inspection;

2. The date of the last calibration or inspection;

3. The date of the most recent field accuracy assessment, if applicable;

4. The results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;

5. The proposed date for the next field accuracy assessment, if applicable;

6. The proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.

7. A description of the meter or other device, including at a minimum:

a. make,
b. model,
c. install date,
d. location,
e. annual emissions calculated or annual product data reported using data from the device,
f. sources for which the device is used to calculate emissions or product data,
g. calibration or inspection procedure,
h. reason for delaying calibration or inspection,

i. proposed method to assure the accuracy requirements of section 95103(k)(6) are met,

j. name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.

(10) If the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the required accuracy specification, and the emissions or product data estimated using the data provided by the device represent more than 5 percent of total facility emissions or product data on an annual basis, the operator must demonstrate by other means to the satisfaction of the verifier or ARB that measurements used to calculate GHG emissions and product data still meet the ± 5% accuracy requirements going back to the last instance of successful field accuracy assessment or calibration of the device. Where the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the accuracy specifications, the verifier shall note at a minimum a nonconformance as part of the emissions data verification statement.

(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses the method must be accurate to ±5 percent for the time periods required by this article, including annually for covered product data. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this section. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 95131(b)(12) of this article. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1)-(10) above, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using the following equations:

Fuel consumed (volume or mass) = (inputs during time period – outputs during time period) + (amount stored at beginning of time period) – (amount stored at end of time period)

Product produced (volume or mass) = (outputs during time period - inputs during time period) + (amount stored at end of time period - amount stored at beginning of time period)

(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95124 and 95156 of this article. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data. Covered product data is evaluated for material misstatement and conformance, while the remaining reported product data is evaluated for conformance only. Reporting entities must exclude inaccurate covered product data, and may elect to exclude accurate covered product data. Reporting entities that exclude covered product data must report a description of the excluded data and an estimated magnitude using best available methods. The excluded covered product data will not be used for the material misstatement assessment or for the total covered product data variable described in section 95131(b)(12)(A). Operators of cement plants may not exclude covered product data.

(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, or January 1 of the first data year reporting under this article, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative monitoring or calculation method is approved in advance by the Executive Officer.

(1) The operator or supplier is permitted to permanently improve the emissions or product data monitoring or calculation method after January 1, 2013 through a change to a higher-tier monitoring or calculation method, such as the addition of a continuous emissions monitoring system. Permanent improvements to emissions monitoring or calculation methods do not require approval in advance by the Executive Officer; however, the operator or supplier must notify ARB prior to January 1 of the year the new method is implemented. Permanent changes to a lower-tier emissions monitoring or calculation method, and to all covered product data monitoring or calculation methods, must be approved in advance by the Executive Officer per the requirements in parts 95103(m)(2)-(3).

(2) When proposing a permanent change in a monitoring or calculation method to the Executive Officer, an operator or supplier must indicate why the change in method is being proposed, include a detailed description of what data are affected by the alternate procedure, and include a demonstration of differences in estimated data under the two methods.

(3) When permitted, a change in method must be made after the completion of monitoring for a data year and apply to the start of the subsequent data year, except in the circumstances described in part (m)(4).

(4) The operator or supplier is permitted to temporarily modify the emissions or product data monitoring or calculation method when necessary for the avoidance of missing data or to comply with the missing data provisions of this article. In the event of an unforeseen breakdown in fuel analytical data monitoring equipment or CEMS equipment, operators and suppliers must use the procedures in section 95129(h) and section 95129(i), respectively, for seeking approval of interim data collection procedures. For all other instances that temporary methods are used, ARB must be notified by the reporting deadline of the following information: a description of the temporary method, the affected data, and the duration that the temporary method was used. A temporary method may be used for a period not to exceed 365 days unless the method is submitted and approved by the Executive Officer as a permanent method per the requirements in parts 95103(m)(2)-(3). Operators and suppliers must be able to demonstrate during verification that the temporary method provides data accuracy within ± 5% as specified in section

95103(k)(6). Covered product data that does not meet the required accuracy specification must be excluded using the procedure in section 95103(l) to avoid an adverse verification statement.

(5) When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

(n) *Changes in Ownership or Operational Control*. If a reporting entity undergoes a change of ownership or operational control, the following requirements apply regarding notifications to 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 information 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. Name of a new Designated Representative pursuant to section 95104(b) for the affected entity's account in the California Reporting Greenhouse Gas Reporting Tool (Cal e-GGRT) specified in section 95104(e);

(2) *Reporting Responsibilities.* 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 must not be split or subdivided for the year, based on ownership. A single annual data report must be submitted for the entity by the current owner or operator. This report must represent required data for the entire, calendar year.

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

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

Executive Officer
Attn: Emission Inventory Branch
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

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

§ 95104. Emissions Data Report Contents and Mechanism.

The reporting entities specified in section 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) *General Contents.* In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, geographic location, and indicate whether the reporting entity qualifies for small business status pursuant to California Government Code 11342.610. Electricity generating units must also provide Energy Information Administration and California Energy Commission identification numbers, as applicable. Reporters subject to the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95200 to 95207), must report the official responsible for fees payment and the billing address for fees.

(b) *Designated Representative*. Each reporting entity must designate a reporting representative and adhere to the requirements of 40 CFR §98.4 for this representative and for any named alternate designated representatives.

(c) *Corporate Parent and NAICS Codes.* Each reporting entity must submit information to meet the requirements specified in amendments to 40 CFR Part 98 on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration, as promulgated by U.S. EPA on September 22, 2010.

(d) *Facility Level Energy Input and Output.* The operator must include in the emissions data report information about the facility's energy acquisitions and energy provided or sold as specified below. For the purpose of reporting under this paragraph, the operator may exclude any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility. The operator may also exclude electricity consumed by operations or activities that do not generate any emissions, energy outputs, or products that are covered by this article, and that are neither a part of nor in support of electricity generation or any industrial activities covered by this article. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

(1) Electricity purchases or acquisition from sources outside of the facility boundary (MWh) and the name and ARB identification number of each electricity provider, as applicable.

(2) Thermal energy purchases or acquisitions from sources outside of the facility boundary (MMBtu) and the name and ARB identification number of each energy provider, as applicable. If the operator acquires thermal energy from a PURPA Qualifying Facility and vents, radiates, wastes, or discharges more than 10% of the acquired thermal energy before utilizing the energy in any industrial process, operation, or heating/cooling application, the operator must report the amount of thermal energy actually needed and utilized, in addition to the amount of thermal energy received from the provider.

(3) Electricity provided or sold, as specified in section 95112(a)(4), if applicable.

(4) Thermal energy provided or sold to entities outside of the facility boundary: the operator must report the amount of thermal energy provided or sold (MMBtu), the names and ARB identification number of each end-user as applicable, and the type of unit that generates the thermal energy. If section 95112 applies to the operator, the operator must follow the requirements of section 95112(a)(5) in reporting the thermal energy generated by cogeneration or bigeneration units, and if applicable, also separately report the information required in paragraph 95104(d)(4) for the thermal energy provided or sold that is not generated by cogeneration or bigeneration units.

If the facility boundary includes more than one cogeneration system, boiler, or steam generator, and each unit/system or each group of units produces thermal energy for different particular end-users or on-site industrial processes and operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions, and by the type of thermal energy product provided.

(e) *Reporting Mechanism*. Reporting entities shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's (ARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by ARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation. Reporting entities are not responsible for reporting data required under this article that is not specified for reporting in the reporting tool.

(f) *Increases and Decreases in Facility Emissions*. The operator of a facility identified in section 95101(a)(1)(A)-(B) that is subject to the cap-and-trade regulation must include the following information in the emissions data report:

(1) Whether a change in the facility's operations or status resulted in an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous data year.

(2) Specify which of the following reason(s) would be the cause of the increase or decrease in greenhouse gas emissions:

(A) Change in production;

(B) Changes in facility operations in order to comply with:

1. The cap-and-trade regulation;

2. Other air pollution regulations;

3. Other regulations, not related to air pollution or greenhouse gases;

(C) Changes in efficiency due to:

1. Process or material changes;

2. The addition of control equipment;

3. Other efficiency measures;

(D) Other.

(3) A narrative description of how each reason identified in section 95104(f)(2) caused the increase or decrease in emissions. Include in this description any changes in your air permit status.

(4) This section is not subject to the third-party verification requirements of this article.

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

§ 95105. Recordkeeping Requirements.

Each reporting entity that is required to report greenhouse gases under this article, except as provided in section 95103(a)(9), must keep records as required by 40 CFR §98.3(g)-(h) with the following qualifications.

(a) *Duration*. Reporting entities with a compliance obligation under the cap-and-trade regulation in any year of the current compliance period must maintain all records specified in 40 CFR §98.3(g), and records associated with revisions to emissions data reports as provided under 40 CFR §98.3(h), for a period of ten years from the date of emissions data report certification. The retained documents, including GHG emissions data and input data, must be sufficient to allow for verification of each emissions data report. Reporting entities that do not have a compliance obligation under the cap-and-trade regulation during any year of the current compliance period must maintain such records for a period of five years from the date of certification.

(b) *ARB Requests for Records.* Copies of any records or other materials maintained under the requirements of 40 CFR Part 98 or this article must be made available to the Executive Officer upon request, within twenty days of receipt of such request by the designated representative of the reporting entity.

(c) *GHG Monitoring Plan for Facilities and Suppliers*. Each facility operator or supplier that reports under 40 CFR Part 98, each facility operator or supplier with emissions equal to or exceeding 25,000 $MTCO_2e$ (including biomass-derived CO_2 emissions and geothermal emissions), and each facility operator or supplier with a compliance obligation under the cap-and-trade 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). For facilities, the Plan must also include the following elements, as applicable:

(1) All fuel use measurement devices used for emissions calculations or product data must be clearly identified, and the plan must indicate how data from these devices are incorporated into the emissions data report.

(2) Original equipment manufacturer (OEM) documentation, or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used in the calculation of GHG emissions.

(3) Identification of measurement device location, and the location of any additional devices or sampling ports required for calculating covered emissions and product data (e.g. temperature, total pressure, HHV).

(4) The dates of measurement device calibration or inspection, and the dates of the next required calibration or inspection.

(5) Identification of low flow cutoffs, as applicable.

(6) A listing of the equation(s) used to calculate mass or volume flows, and from which any non-measured parameters are obtained.

(7) Records of the most recent orifice plate inspection performed according to the requirements of ISO 5167-2 (2003), section 5, or AGA Report No 3 (2003) Part 2, which are hereby incorporated by reference.

(8) Training practices for personnel involved in GHG monitoring, including documented training procedures, and training materials.

(9) Copies of methodologies used for all fuel-based emissions analyses, including the standardized methods chosen as specified in section 95109.

(10) At the operator's choosing, a fuel monitoring plan to verify on a regular basis the proper functioning of fuel measurement equipment that is used to determine facility GHG emissions. The operator wishing to preserve the option of using the missing data substitution procedures in section 95129(d)(2) in the event that such procedures become necessary to use, must monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption data at least weekly. The operator exercising this option may fulfill periodic fuel monitoring either through manual monitoring or by using an automatic data acquisition system that electronically records, stores, and identifies measurement device malfunctioning periods. The

records of fuel consumption must be sufficient for the application of the missing data substitution procedure in section 95129(d)(2) if that option is later chosen by the operator.

(d) *GHG Inventory Program for Electric Power Entities that Import or Export Electricity.* In lieu of a GHG Monitoring Plan, electric power entities that import or export electricity must prepare GHG Inventory Program documentation that is maintained and available for verifier review and ARB audit pursuant to the recordkeeping requirements of this section. The following information is required:

(1) Information to allow the verification team to develop a general understanding of entity boundaries, operations, and electricity transactions;

(2) Reference to management policies or practices applicable to reporting pursuant to section 95111;

(3) List of key personnel involved in compiling data and preparing the emissions data report;

(4) Training practices for personnel involved in reporting delivered electricity pursuant to section 95111 and responsible for data report certification, including documented training procedures;

(5) Query of NERC e-Tag source data to determine the quantity of electricity (MWh) imported, exported, and wheeled for transactions in which they are the purchasing-selling entity on the last physical path segment that crosses the border of the state of California, access to review the raw e-Tag data, a tabulated summary, and query description;

(6) Reference to other independent or internal data management systems and records, including written power contracts and associated verbal or electronic records, full or partial ownership, invoices, and settlements data used to document whether reported transactions are specified or unspecified and whether the requirements for adjustments to covered emissions pursuant to sections 95852(b)(1)(B), 95852(b)(4) and 95852(b)(5) of the cap-and-trade regulation are met;

(7) Description of steps taken and calculations made to aggregate data into reporting categories required pursuant to section 95111;

(8) Records of preventive and corrective actions taken to address verifier and ARB findings of past nonconformances and material misstatements;

(9) Log of emissions data report modifications made after initial certification; and

(10) A written description of an internal audit program that includes emissions data report review and documents ongoing efforts to improve the GHG Inventory Program.

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

§ 95106. Confidentiality.

(a) Emissions data submitted to the ARB under this article is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR Part 98 which has been released to the public by U.S. EPA shall be considered public information by ARB.

(b) Any entity submitting information to the Executive Officer pursuant to this article may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

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

§ 95107. Enforcement.

(a) Penalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580. In seeking any penalty amount, ARB shall consider all relevant circumstances, including any pattern of violation, the size and complexity of the reporting entity's operations, and the other criteria in Health and Safety Code section 42403(b).

(b) Each day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate is a single, separate violation. For purposes of this section, "report" means any emissions data report, verification statement, or other document required to be submitted to the Executive Officer by this article.

(c) Each metric ton of CO_2e emitted but not reported as required by this article is a separate violation. ARB will not initiate enforcement action under this subparagraph until after any applicable verification deadline for the pertinent report.

(d) Each failure to measure, collect, record or preserve information in the manner required by this article constitutes a separate violation, except where the reporting entity can demonstrate that the failure results solely from maintenance or calibration required by this article.

(e) The Executive Officer may revoke or modify any Executive Order issued pursuant to this article as a sanction for a violation of this article.

(f) The violation of any condition of an Executive Order that is issued pursuant to this article is a separate violation.

(g) Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38530, 38580, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 38580, 39600 and 41511, Health and Safety Code.

§ 95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

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.

§ 95109. Standardized Methods.

(a) Entities that are required to report greenhouse gas emissions pursuant to this article must use either those standardized methods and materials listed in 40 CFR §98.7, or another similar method published by an organization listed in 40 CFR §98.7 that is applicable to the analysis being conducted. For gaseous fuels, fuel characteristics may be determined using chromatographic analysis as specified in 40 CFR §98.34(a)(6) and §98.34(b)(5). All methods used must be documented in the GHG Monitoring Plan that is as required by section 95105(c).

(b) Alternative test methods that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the methods in section 95109(a) may be used upon written approval by 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.

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

§ 95110. Cement Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart H of 40 CFR Part 98 (§§98.80 to 98.88) in reporting annual stationary combustion and process emissions and other data from cement production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95110(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95110(c)-(d), 95115, and 95129 of this article.

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

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR §98.83(d) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the monthly raw material consumption or monthly clinker production used to calculate emissions, the operator must apply a substitute value according to paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.85(c) or 40 CFR §98.85(d), as applicable.

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum short tons of clinker per day capacity of the system or the maximum short tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* In addition to the information required by 40 CFR §98.86, the operator must report the parameters provided in paragraphs (1)-(4) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity clinker produced (short tons).

(2) Annual quantity clinker consumed (short tons).

(3) Annual quantity of limestone and gypsum (including both natural and synthetic gypsum) consumed for blending (short tons).

(4) Annual quantity of cement substitute consumed, by type (short tons). This parameter is not subject to review for material misstatement under the requirements of section 95131(b)(12).

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

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

The electric power entity who is required to report under section 95101 of this article must comply with the following requirements.

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

(1) *Greenhouse Gas Emissions.* The electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (MT of CO_2e), according to the calculation methods in section 95111(b).

(2) *Delivered Electricity.* The electric power entity must report imported, exported, and wheeled electricity in MWh disaggregated by first point of receipt or final point of delivery, as applicable, and must also separately report imported and exported electricity from unspecified sources and from each specified source. Substitute electricity defined pursuant to section 95102(a) must be separately reported for each specified source, as applicable. First points of receipt (POR) and final points of delivery (POD) must be reported using the standardized code used in NERC e-Tags, as well as the full name of the POR/POD.

(3) *Imported Electricity from Unspecified Sources.* When reporting imported electricity from unspecified sources, the electric power entity must report for each first point of receipt the following information:

(A) Whether the first point of receipt is located in a linked jurisdiction published on the ARB Mandatory Reporting website;

(B) The amount of electricity from unspecified sources as measured at the first point of delivery in California; and

(C) GHG emissions, including those associated with transmission losses, as required in section 95111(b).

(4) *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity. 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:

1. *Measured at Busbar*. The amount of imported electricity from specified facilities or units as measured at the busbar; and

2. *Not Measured at Busbar*. If the amount of imported electricity deliveries from specified facilities or units as measured at the busbar is not provided, report the amount of imported electricity as measured at the first point of delivery in California, including estimated transmission losses as required in section 95111(b), and the reason why measurement at the busbar is not known.

(5) *Imported Electricity Supplied by Asset-Controlling Suppliers.* The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by ARB. The reporting entity must:

(A) Report the asset-controlling supplier standardized PSE acronym or code, full name, and the ARB identification number;

(B) Report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

(C) Report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in the state of California; and,

(D) Report GHG emissions calculated pursuant to section 95111(b), including transmission losses.

(E) *Tagging ACS Power*. To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner.

(6) *Exported Electricity.* The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e for unspecified sources disaggregated by each final point of delivery outside the state of California, and for each specified source disaggregated by each final point of delivery outside the state of California, as well as the following information:

(A) Exported electricity as measured at the last point of delivery located in the state of California, if known. If unknown, report as measured at the final point of delivery outside California.

(B) Do not report estimated transmission losses.

(C) Report whether the final point of delivery is located in a linked jurisdiction published on the ARB Mandatory Reporting website.

(D) Report GHG emissions calculated pursuant to section 95111(b).

(E) Separately report qualified exports as defined in section 95102(a).

(7) *Exchange Agreements.* The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into the state of California under exchange agreements must be reported as imported electricity and electricity delivered out of California under exchange agreements must be reported as exported electricity.

(8) *Electricity Wheeled Through California.* The electric power entity who is the PSE on the last physical path segment that crosses the border of the State of California on the NERC e-tag must separately report electricity wheeled through California, aggregated by first point of receipt, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

(9) *Verification Documentation.* The electric power entity must retain for purposes of verification NERC e-Tags, written power contracts, settlements data, and all other information required to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 95105.

(10) *Electricity Generating Units and Cogeneration Units in California.* Electric power entities that also operate electricity generating units or cogeneration units located inside the state of California that meet the applicability requirements of this article must report GHG emissions to ARB under section 95112.

(11) *Electricity Generating Units and Cogeneration Units Outside California.* Operators and owners of electricity generating units and cogeneration units located outside the state of California who elect to report to ARB under section 95112 must fully comply with the reporting and verification requirements of this article.

(12) Electrical Distribution Utility Sales into CAISO. All electrical distribution utilities (EDU) except IOUs must report the annual MWh of all electricity sold into the CAISO markets for which an EDU has a compliance obligation, beginning with calendar years 2013 and 2014 reported in 2015. EDUs must report MWh by source of generation (if known), of the electricity sold into the CAISO markets and for which the EDU has a compliance obligation, and the emission factor (if known) for each source of generation. This requirement does not apply to EDUs that have had all of their directly allocated allowances allocated for the data year placed in their limited use holding account pursuant to section 95892(b)(2) of the Cap-and-Trade Regulation. Verifiers must contact the Air Resources Board directly to confirm that a specific EDU is not subject to this requirement.

(b) *Calculating GHG Emissions.*

(1) *Calculating GHG Emissions from Unspecified Sources*. For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (MT of CO_2e).

MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.

EF_{unsp} = Default emission factor for unspecified electricity imports.

EF_{unsp} = 0.428 MT of CO2e/MWh

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses between the busbar and measurement at the first point of receipt in California.

(2) *Calculating GHG Emissions from Specified Facilities or Units.* For electricity from specified facilities or units, the electric power entity must calculate emissions using the following equation:

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

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EF_{sp} = 0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

TL = Transmission loss correction factor.

TL = 1.02 to account for transmission losses associated with generation outside of a California balancing authority.

TL = 1.0 if the reporting entity provides documentation that demonstrates to the satisfaction of a verifier and ARB that transmission losses (1) have been accounted for, (2) are supported by a California balancing authority, or (3) are compensated by using electricity sourced from within California.

The Executive Officer shall calculate facility-specific or unit-specific emission factors and publish them on the ARB Mandatory Reporting website using the following equation:

$$EF_{sp} = E_{sp} / EG$$

Where:

E_{sp} = CO_2e emissions for a specified facility or unit for the report year (MT of CO_2e).

EG = Net generation from a specified facility or unit for the report year shall be based on data reported to the Energy Information Administration (EIA).

If order to register a specified unit(s) source of power pursuant to section 95111(g)(1), the reporting entity must provide to ARB unit level GHG emissions consistent with the data source requirements of this section and net generation data as reported to the EIA, along with contracts for delivery of power from the specified unit(s) to the reporting entity, and proof of direct delivery of the power by the reporting entity as an import to California.

(A) For specified facilities or units whose operators are subject to this article or whose owners or operators voluntarily report under this article, E_{sp} shall be equal to the sum of CO_2e emissions reported pursuant to section 95112.

(B) For specified facilities or units whose operators are not subject to reporting under this article or whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} shall be based on GHG emissions reported to U.S. EPA pursuant to 40 CFR Part 98. Emissions from combustion of biomass-derived fuels will be based on EIA data until such time the emissions are reported to U.S. EPA.

(C) For specified facilities or units whose operators are not subject to reporting under this article or whose owners or operators do not voluntarily report under this article, nor are subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} is calculated using heat of combustion data reported to the Energy Information Administration (EIA)

$$E_{sp} = 0.001 \times \Sigma(Q \times EF)$$

Where:

0.001 = conversion factor kg to MT

Q = Heat of combustion for each specified fuel type from the specified facility or unit for the report year (MMBtu). For cogeneration, Q is the quantity of fuel allocated to electricity generation consistent with EIA reporting. For geothermal electricity, Q is the steam data reported to EIA (MMBtu).

EF = O_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu). For geothermal electricity, EF is the estimated CO_2 emission factor published by EIA.

(D) Facilities or units will be assigned an emission factor by the Executive Officer based on the type of fuel combusted or the technology used when a U.S. EPA GHG Report or EIA fuel consumption report is not available, including new facilities and facilities located outside the U.S.

(E) Meter Data Requirement. For verification purposes, electric power entities shall retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered. This provision is applicable to imports from specified sources for which ARB has calculated an emission factor of zero, and for imports from California Renewable Portfolio Standard (RPS) eligible resources, excluding: (1) contract or ownership agreements, known as grandfathered contracts that meet California RPS program requirements in Public Utilities Code Section 399.16(d) or California Code of Regulations, Title 20 Section 3202(a)(2)(A); (2) dynamically tagged power deliveries; (3) untagged power deliveries, including EIM imports; (4) nuclear power; (5) asset controlling supplier power; and (6) imports from hydroelectric facilities for which an entity's share of metered output on an hourly basis is not established by power contract. Accordingly, a lesser of analysis is required pursuant to the following equation:

Sum of Lesser of MWh = ΣHM_{sp} min(MG_{sp}, TG_{sp})

Where:

ΣHM_{sp} = Sum of the Hourly Minimum of MG_{sp} and TG_{sp} (MWh).
MG_{sp} = metered facility or unit net generation (MWh).
S_{sp} = entity's share of metered output.
TG_{sp} = tagged or transmitted energy at the transmission or sub-transmission level imported to California (MWh).

(3) *Calculating GHG Emissions of Imported Electricity Supplied by 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:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from ARB-recognized asset-controlling suppliers (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Asset-Controlling Supplier system emission factor published on the ARB Mandatory Reporting website ($MTCO_2e$/MWh). ARB will assign the system emission factors for all asset-controlling suppliers based on a previously verified GHG report submitted to ARB pursuant to section 95111(f). The supplier-specific system emission factor is calculated annually by ARB. The calculation is derived from data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification statement. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

$$EF_{ACS} = \text{Sum of System Emissions MT of } CO_2e \text{ / Sum of System MWh}$$

$$\text{Sum of System Emissions, MT of } CO_2e = \Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$$

$$\text{Sum of System MWh} = \Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$$

Where:

ΣE_{asp} = *Emissions from Owned Facilities*. Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = *Net Generation from Owned Facilities*. Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to ARB under this article (MWh).

PE_{sp} = *Electricity Purchased from Specified Sources*. Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

PE_{unsp} = *Electricity Purchased from Unspecified Sources*. Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

SE_{sp} = *Electricity Sold from Specified Sources*. Amount of wholesale electricity sold from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) ($MTCO_2e$/MWh).

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) ($MTCO_2e/MWh$).

(4) *Calculating GHG Emissions of Imported Electricity for Multi-jurisdictional Retail Providers.* Multi-jurisdictional retail providers must include emissions and megawatt-hours in the terms below from facilities or units that contribute to a common system power pool. Multi-jurisdictional retail providers do not include emissions or megawatt-hours in the terms below from facilities or units allocated to serve retail loads in designated states pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service. Multi-jurisdictional retail providers must calculate emissions that have a compliance obligation using the following equation:

$$CO_2e = (MWh_R \times TL_R - MWh_{WSP\text{-}CA} - EG_{CA}) \times EF_{MJRP} + MW_{WSP\text{-}notCA} \times TL_{WSP} \times EF_{unsp} - CO_2e_{linked}$$

Where:

CO_2e = Annual CO_2e mass emissions of imported electricity (MT of CO_2e).

MWh_R = Total electricity procured by multi-jurisdictional retail provider to serve its retail customers in California, reported as retail sales for California service territory, MWh.

$MWh_{WSP\text{-}CA}$ = Wholesale electricity procured in California by multi-jurisdictional retail provider to serve its retail customers in California, as determined by the first point of receipt on a NERC e-Tag and pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

$MWh_{WSP\text{-}not\ CA}$ = Wholesale electricity imported into California by multi-jurisdictional retail provider with a final point of delivery in California and not used to serve its California retail customers, MWh.

EF_{MJRP} = Multi-jurisdictional retail provider system emission factor calculated by ARB pursuant to subsection 95111(b)(3) and consistent with a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) ($MTCO_2e/MWh$).

EG_{CA} = Net generation measured at the busbar of facilities and units located in California that are allocated to serve its retail customers in California pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

TL = Transmission loss correction factor.

TL_{WSP}= 1.02 for transmission losses applied to wholesale power .

TL_R = Estimate of transmission losses from busbar to end user reported by multi-jurisdictional retail provider.

CO_2e_{linked} = Annual CO_2e mass emissions recognized by ARB pursuant to linkage under subarticle 12 of the cap-and-trade regulation (MT of CO_2e).

(5) Calculation of Covered Emissions. For imported electricity with covered emissions as defined pursuant to section 95102(a), the electric power entity must calculate and report covered emissions pursuant to the equation in 95852(b)(1)(B) of the cap-and-trade regulation and include the following information:

$CO_2e_{covered}$ = Sum of covered emissions defined pursuant to section 95102(a) and calculated pursuant to the equation in section 95852(b)(1)(B) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{unsp} = Sum of CO_2 equivalent mass emissions from imported electricity from unspecified sources (MT of CO_2e).

CO_2e_{sp} = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources (MT of CO_2e).

$CO_2e_{sp\text{-}not\ covered}$ = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources and is explicitly listed as emissions without a compliance obligation pursuant to section 95852.2 of the cap-and-trade regulation (MT of CO_2e).

$CO_2e_{RPS\ adjust}$ = Sum of CO_2 equivalent mass emissions adjustment is calculated using the following equation for electricity generated by each eligible renewable energy resource located outside the state of California and registered with ARB by the reporting entity pursuant to section 95111(g)(1), but not directly delivered as defined pursuant to section 95102(a). Electricity included in the RPS adjustment must meet the requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation (MT of CO_2e).

$$CO_2e_{RPS\_adjust} = MWh_{RPS} \times EFunsp\ (MTCO_2e/MWh)$$

Where:

MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the state of California, registered with ARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation.

$CO_2e_{QE\ adjust}$ = Sum of CO_2 equivalent mass emissions adjustment for qualified exports as defined in section 95102(a) and that meet the requirements pursuant to section 95852(b)(5) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{linked} = Sum of CO_2e mass emissions recognized by ARB pursuant to linkage under subarticle 12 of the cap-and-trade regulation (MT of CO_2e).

(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 provider who is required only to report retail sales may choose not to apply the verification requirements specified in section 95103, if the retail provider deems the emissions data report non-confidential.

(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.

(3) For facilities or units located outside California in a jurisdiction where a GHG emissions trading system has not been approved for linkage pursuant to subarticle 12 of the 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:

(A) Information required in section 95111(g)(1) in data years with no reported imported electricity from the facility or unit;

(B) The quantity of electricity from the facility or unit sold by the retail provider or on behalf of the retail provider having a final point of delivery outside California, as measured at the busbar.

(C) *High GHG-Emitting Facilities or Units.* For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider, 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:

1. When the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions associated with electricity not imported into California must be reported as

$$CO_2e_{not\ imported} = (EG_{sp}*OS - I_{sp})*EF_{sp.}$$

Where:

EG_{sp} = facility or unit net generation, MWh.
OS = fraction ownership share.
Isp = imported electricity, MWh.
EFsp. = facility or unit-specific emission factor, MT of CO2e/MWh.

2. List the replacement generation sources, locations, and whether

they are new units when I_{sp}< 90% of EG_{sp}*OS and when a facility specified in the previous report year has no imported electricity in the current report year.

(4) Retail providers that report as electricity importers or exporters also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer. In addition, all imported electricity transactions documented by NERC e-Tags where the retail provider is the PSE at the sink must be reported.

(d) *Additional Requirements for Multi-Jurisdictional Retail Providers.* Multi-jurisdictional retail providers that provide electricity into California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

(1) A report of the electricity transactions and GHG emissions associated with the common power system or contiguous service territory that includes consumers in California. This includes the requirements in this section as applicable for each generating facility or unit in the multi-jurisdictional retail provider's fleet;

(2) The multi-jurisdictional retail provider must include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;

(3) Total retail sales (MWh) by the multi-jurisdictional retail provider in the contiguous service territory or power system that includes consumers in California;

(4) Retail sales (MWh) to California customers served in California's portion of the service territory;

(5) GHG emissions associated with the imported electricity, including both California retail sales and wholesale power imported into California from the retail provider's system, according to the specifications in this section;

(6) Multi-jurisdictional retail providers that serve California load must claim as specified power all power purchased or taken from facilities or units in which they have operational control or an ownership share or written power contract;

(7) Multi-jurisdictional retail providers that serve California load may elect to exclude information listed in 95111(g)(1)(E)-(J) when registering claims to specified power from facilities located outside California and participating in the Federal Energy Regulatory Commission's PURPA Qualifying Facility program.

(e) *Additional Requirements for WAPA and DWR.*

(1) In reporting its GHG emissions to ARB, the California Department of Water Resources shall include all applicable information identified in this article for

retail providers, including the amount of electricity used for pump loads, to operate the State Water Project.

(2) In reporting its GHG emissions to ARB, the Western Area Power Agency shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the Central Valley Project.

(f) *Requirements for Asset-Controlling Suppliers.* Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from ARB. Approved asset-controlling suppliers may request that ARB calculate a supplier-specific emission factor pursuant to section 95111(b)(3). To apply for asset-controlling supplier designation, the applicant must:

To apply for asset-controlling supplier designation, the applicant must:

(1) Meet the requirements in this article, including reporting pursuant to section 95112 as applicable for each generating facility or unit in the supplier's fleet;

(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;

(3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;

(4) Provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(5) To apply for and maintain asset-controlling supplier status, the entity shall submit as part of its emissions data report the following information, annually:

(A) General business information, including entity name and contact information;

(B) List of officer names and titles;

(C) Data requirements per section 95111(b)(3);

(D) Data requirements per section 95111(g)(1);

(E) A list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to 95102(a); and,

(F) An attestation, in writing and signed by an authorized officer of the applicant, as follows:

"I certify under penalty of perjury under the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], that [name of entity] meets the definition of an asset-controlling supplier as specified in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, title 17, California Code of Regulations, section 95100 et seq., and that the information submitted herein is true, accurate, and complete."

Asset-controlling suppliers must annually adhere to all reporting and verification requirements of this article, or be removed from asset-controlling supplier designation. Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation.

(g) Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment.

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with 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. If an operator fails to register aspecified source by the June 1 reporting deadline specified in section 95103(e), the operator must use the emission factor provided by ARB for a specified facility or unit in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to subsection 95111(g)(1) in the emissions data report. Prior registration and subsection 95111(g)(2)-(5) do not apply to RPS adjustments. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date.

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(A) The facility names and, for specification to the unit level, the facility and unit names.

(B) For sources with a previously assigned ARB identification number, the ARB facility or unit identification number or supplier number published on ARB's mandatory reporting program website. For newly specified sources, ARB will assign a unique identification number.

(C) If applicable, the facility and unit identification numbers as used for reporting to the U.S. EPA Acid Rain Program, U.S. EPA pursuant to 40 CFR Part 98, U.S. Energy Information Administration, Federal Energy Regulatory Commission's PURPA Qualifying Facility program, California Energy Commission, and California Independent System Operator, as applicable.

(D) The physical address of each facility, including jurisdiction.

(E) Provide names of facility owner and operator.

(F) The percent ownership share and whether the facility or unit is under the electricity importer's operational control.

(G) Total facility or unit gross and net nameplate capacity when the electricity importer is a GPE.

(H) Total facility or unit gross and net generation when the electricity importer is a GPE.

(I) Start date of commercial operation and, when applicable, date of repowering.

(J) GPEs claiming additional capacity at an existing facility must include the implementation date, the expected increase in net generation (MWh), and a description of the actions taken to increase capacity.

(K) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the previous report year that will not be specified in the current report year.

(L) Provide the primary technology or fuel type as listed below:

1. Variable renewable resources by type, defined for purposes of this article as pure solar, pure wind, and run-of-river hydroelectricity;
2. Hybrid facilities such as solar thermal;
3. Hydroelectric facilities ≤ 30 MW, not run-of-river;
4. Hydroelectric facilities > 30 MW;
5. Geothermal binary cycle plant or closed loop system;
6. Geothermal steam plant or open loop system;
7. Units combusting biomass-derived fuel, by primary fuel type;
8. Nuclear facilities;
9. Cogeneration by primary fuel type;
10. Fossil sources by primary fuel type;
11. Co-fired fuels;
12. Municipal solid waste combustion;
13. Other.

(M) Provide the primary facility name, total number of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as

whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that were subsequently withdrawn from the retirement subaccount, or modified the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.

3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.

(2) *Emission Factors.* The emission factor published on the ARB Mandatory Reporting website, calculated by ARB according to the methods in section 95111(b), must be used when reporting GHG emissions for a specified source of electricity.

(3) *Delivery Tracking Conditions Required for Specified Electricity Imports.* Electricity importers may claim a specified source when the electricity delivery meets any of the criteria for direct delivery of electricity defined in section 95102(a), and one of the following sets of conditions:

(A) The electricity importer is a GPE; or

(B) The electricity importer has a written power contract for electricity generated by the facility or unit.

(4) *Additional Information for Specified Sources.* For each claim to a specified source of electricity, the electricity importer must indicate whether one or more of the following descriptions applies:

(A) Deliveries from specified sources previously reported as consumed in California. Specified source of electricity has been reported in a 2009 verified data report and is claimed for the current data year by the same electricity importer, based on a written power contract or status as a GPE in effect prior to January 1, 2010 that remains in effect, or that has been renegotiated for the same facility or generating unit for up to the same share or quantity of net generation within 12 months following prior expiration; or a specified facility for which imported electricity was reported as greater than 80 percent of net generation in the 2009 or 2010 data years;

(B) Deliveries from existing federally owned hydroelectricity facilities by exclusive marketers. Electricity from specified federally owned hydroelectricity facility delivered by exclusive marketers;

(C) Deliveries from existing federally owned hydroelectricity facilities allocated by contract. Specified federally owned hydroelectricity source delivered by electricity importers with a written power contract in effect within 12 months after changes in rights due to federal power allocation or redistribution policies, including acts of Congress, and not related to price bidding, that remains in effect or has been renegotiated for the same facility for up to the same share or quantity of net generation within 12 months following prior contract expiration;

(D) Deliveries from new facilities. Specified source of electricity is first registered pursuant to section 95111(g)(1) and delivered by an electricity importer within 12 months of the start date of commercial operation and the electricity importer making a claim in the current data year is either a GPE or purchaser of electricity under a written power contract;

(E) Deliveries from existing facilities with additional capacity. Specified source of electricity is first registered pursuant to section 95111(g)(1) and delivered by a GPE within 12 months of the start date of an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions.

(5) *Substitute electricity.* Report substitute electricity received from specified and unspecified sources pursuant to the requirements 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.

§ 95112. Electricity Generation and Cogeneration Units.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must report as specified below and comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions and other data from electricity generating and cogeneration units to ARB, except as otherwise provided in this section. Notwithstanding the above, the operator of a facility with total facility nameplate generating capacity of less than 1 MW may elect to follow section 95115 in reporting electricity generating units as general combustion sources, in lieu of the requirements of section 95112. If engineering estimation is used to report disposition of generated energy or energy flow data that are not used directly to determine emissions, facility operators must demonstrate accuracy of the chosen engineering estimation method.

(a) *Information About the Electricity Generating Facility.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. However, facility operators that are applying for or receiving the legacy contract transition assistance under the cap-and-trade regulation, or that are applying for or receiving the limited exemption for emissions from the production of qualified thermal output under the cap-and-trade regulation, must report the information in sections 95112(a)(4)-(6), even if they do not provide or sell any generated energy outside of the facility boundary.

(1) If applicable, facility identification numbers assigned by the California Energy Commission, U.S. Energy Information Administration, Federal Energy Regulatory Commission's PURPA Qualifying Facility program, and California Independent System Operator;

(2) Total facility nameplate generating capacity in megawatts (MW);

(3) Indicate whether the facility is a stand-alone electricity generating facility, an independently operated cogeneration/bigeneration facility co-located with the thermal host, an independently operated and sited cogeneration/bigeneration facility, or an industrial/institutional/commercial facility with electricity generation capacity, as applicable. Also indicate whether the facility is a grid-dedicated facility, a facility that does not provide any generated energy outside of the facility boundary, as applicable.

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

(A) *Generated Electricity For Grid.* Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer;

(B) *Generated Electricity For Other Users.* Generated electricity provided or sold directly to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, and ARB ID if applicable;

(C) *Generated Electricity For On-Site Industrial Applications Not Related to Electricity Generation.* If the facility includes industrial processes or operations that are neither in support of or a part of the power generation system, report the 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 or 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 section 95112(b)(2).

If a facility includes more than one electricity generating unit or cogeneration system, and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated electricity from the group of units is provided to the same destination.

(5) The operator of a cogeneration or bigeneration unit must report the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit ("generated thermal energy"), reported at the facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Thermal Energy For Other Users.* Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user.

(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 section 95112(a)(5)(B) in reporting such use of generated thermal energy.

If a facility includes more than one cogeneration or bigeneration unit/system, and each unit/system or each group of units generate thermal energy for different particular end-users or on-site industrial processes or operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated thermal energy from the group of units is provided to the same destination.

(6) For the first year of reporting, operators of cogeneration or bigeneration units must submit a simplified block diagram depicting the following, as applicable: individual equipment included in the generation system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (a)(4)-(5), (b)(2)-(4) and (b)(7)-(8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements. If the cogeneration or bigeneration system is modified after the initial submission of the diagram, the operator must resubmit an updated diagram to 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).

(1) Basic information about the generating unit, including:

(A) Nameplate generating capacity in megawatts (MW);

(B) Prime mover technology;

(C) For aggregation of units, provide a description of the individual equipment included in the aggregation;

(D) If the unit generates both electricity and thermal energy, indicate whether the unit is a cogeneration or a bigeneration unit. If the unit is a cogeneration unit, indicate whether it is topping or bottoming cycle.

(2) Net and gross power generated, in megawatt hours (MWh). The difference between net generation and gross generation is the parasitic load of electricity generation or cogeneration. The net generation quantity represents the amount of generated electricity that can be provided to the disposition categories in section 95112(a)(4).

(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined in section 95102, that was generated by the unit and can be potentially utilized in other industrial operations that are not electricity generation. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation. The total thermal output quantity represents the amount of generated thermal energy that can be provided to the thermal energy disposition categories in section 95112(a)(5).

(4) Fuel consumption by fuel type, reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids.

(5) If not already required to be reported under 40 CFR §98.36(b) for Subarticle C units and §98.46 for Subarticle D units, annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas.

(6) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(e)(2)(ii)(C) and (iv)(C), report weighted or arithmetic average carbon content and high heat value by fuel type, whichever is used in calculating emissions as specified in 40 CFR §98.33.

(7) For cogeneration systems, where supplemental firing has been applied to support electricity generation or thermal output, report the information in paragraphs (b)(4)-(6). Indicate by fuel type the portion of the total fuel

consumption (MMBtu) that is used for supplemental firing, and indicate the purpose of the supplemental firing.

(8) *Other heat input for electricity generation.* If the electricity generation unit uses additional heat input that is not already accounted for in paragraphs 95112(b)(4)-(6) (for example, if steam or heat is acquired from outside of the electricity generation system boundary or acquired from another facility for the generation of electricity), report the amount of acquired steam or heat (MMBtu). For bottoming cycle cogeneration units only, also report the input steam to the steam turbine (MMBtu) and the output of the heat recovery steam generator (MMBtu).

(c) *Emissions from Fuel Combustion and Sorbent*. When calculating CO_2, CH_4, and N_2O emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 must use a method in 40 CFR §98.33(a)(1)-(4) as specified by fuel type in section 95115 of this article, except that for 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.

(1) The operator of a Subpart D unit must report emissions from fuels combusted within the data year but not reported pursuant to 40 CFR Part 75 requirements, such as prior to initial provisional or monitoring certification of CEMS. The operator must use a method in 40 CFR §98.33(a)(1)-(4) as specified by fuel type in section 95115, or if applicable, according to the *de minimis* provisions in section 95103(i) of this article.

(2) The operator of a Subpart D unit with contractual deliveries of biomethane or biogas is subject to the requirements in section 95131(i) of this article and must follow the procedure in sections 95115(e)(4)-(5) in calculating emissions from biomethane, biogas, and natural gas.

(3) The operator of a Subpart D unit who reports CO_2 emissions using emission calculation methods specified in 40 CFR Part 75, and who operates a unit with a wet flue gas desulfurization system, must indicate the portion of the total reported CO_2 emissions that is generated from sorbent injection for acid gas removal.

(d) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95112(c), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95112, 95115, and 95129 of this article.

(e) *CO_2 and CH_4 Emissions from Geothermal Facilities.* Operators of geothermal generating facilities must report CO_2 and CH_4 emissions from geothermal energy sources, the amount of geothermal steam utilized (MMBtu) if steam quantity is used in calculating emissions, and applicable requirements in section 95112(a)(1)-(4), (b)(1)(A)-(C), and (b)(2).

The operator must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by the ARB. The operator must submit to the Executive Officer a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the Executive Officer, the test procedures in that plan must be performed as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least 20 days in advance of subsequent tests.

(f) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units must include the following information in the annual GHG emissions data report:

(1) Basic information about the generating unit specified in section 95112(b)(1)-(2);

(2) Fuel or feedstock consumption by fuel/feedstock type, reporting in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids;

(3) The provider of each fuel or feedstock, and the user's customer account number;

(4) Cogeneration information in section 95112(b)(3), if applicable.

(5) CO_2 emissions from the hydrogen fuel cell, 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.

(g) *On-site Renewable Electricity Generation*. The requirements in this paragraph apply to facilities that meet the applicability for reporting under section 95101 and are not otherwise exempted from reporting under section 95101(f). If such facility includes non-fuel-based renewable electricity generating units with nameplate generating capacity of greater than 0.5 MW, the operator must report the nameplate generating capacity (MW), gross power generated (MWh) by the non-fuel-based renewable electricity generating units, and the applicable information in 95112(a). For facility operators that do not operate other electricity generating units that are subject to the requirements in paragraphs (a)-(f) of section 95112, reporting of information specified in section 95112(a)(4)(C) and (a)(5)-(6) is optional.

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

(i) *Additional Reporting Requirements for Legacy Contract Applicants*. The additional requirements in section 95112(i) apply to every facility operator that is applying for legacy contract transition assistance under the cap-and-trade regulation. A legacy contract generator with an industrial counterparty and a legacy contract generator without an industrial counterparty must submit a simplified block diagram in every year that the facility operator applies for legacy contract transition assistance. Legends or attachments may be used when labeling the diagram. If any of the amounts requested are sums of measurements made by different devices, the amounts for each device must be shown in the diagram and the summation described in an attachment.

(1) The diagram must depict the following elements:

(A) For the data year, all of the information described in sections 95112(a)(4)-(5), as applicable, regardless of whether the facility operator, or the equipment, is itself otherwise subject to sections 95112(a)(4)-(5). This information reflects electricity and thermal energy flows, including information identifying the recipient(s) of the electricity and/or thermal energy. Also report the quantities of any other products provided or sold under the legacy contract, using the units in which they are reported elsewhere in this regulation, if applicable. The diagram must indicate where each of these energy flows or products is measured. In addition, the following information must be included:

1. Each of the amounts reported under section 95112(i)(1)(A) must be labeled indicating whether or not it was provided under the legacy contract; and
2. All thermal energy products must be labeled with the type of thermal energy product (e.g., steam, hot water, chilled water, distilled water).

(B) The individual equipment included in the system for which the facility operator is applying for legacy contract transition assistance, and other equipment that is not an integral part of that system but produces or consumes energy that is sent to or received from that system and is owned or operated by the facility operator. Boilers, individual generators such as heat recovery steam generators, turbines if separate from generators, ice plants, chillers, purifiers and other equipment that meet these criteria must each be shown separately in the diagram. In addition, label each piece of equipment with the amount of fuel consumed (in MMBtu) by that piece of equipment during the data year, if any, and the resulting greenhouse gas emissions in CO_2e as reported elsewhere under this regulation. The diagram must also indicate the fuel meter where this fuel use was measured, and the amount measured.

(C) An outline showing the boundary of the activities covered by the legacy contract.

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 refiners are considered separate reporting entities for the purposes of this article.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.252(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article. CO_2 emissions from refinery fuel gas combustion must be calculated using a Tier 3 or Tier 4 methodology of subpart C, as specified in 40 CFR §98.252(a).

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95113(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95113(k), 95115, and 95129 of this article.

(c) *Refinery Fuel Gas Sampling.* As required by 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(d) *Calculating CO_2 from Flares.* For periods of normal flare operation, the operator must use Equation Y-1a, Y-1b, or Y-2 as specified in 40 CFR §98.253(b)(ii)(A) or 98.253(b)(ii)(B). For periods of startup, shutdown, and malfunction (SSM) during which the operator was unable to measure the parameters required by Equations Y-1a, Y-1b, or Y-2, the operator must determine the quantity of gas discharged to the flare separately for each SSM, and calculate the CO_2 emissions as specified in the equation shown below. For SSM periods the operator must use engineering calculations and process knowledge to estimate the carbon content of flared gas as required by §98.253(b)(iii)(A). The terms of the equation below are defined as they are for Equation Y-3 in 40 CFR §98.253(b)(iii)(C).

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[44/12 \times (Flare_{SSM})_p \right] \times MW_p / MVC \times CC_p \right)$$

(e) *Calculating CO_2 from FCCUs and Fluid Coking.* The requirements of 40 CFR §98.253(c)(2) apply under this article regardless of the rated capacity of a fluid catalytic cracking unit or a fluid coking unit. The operator may not use Equation Y-8 or the option provided under 40 CFR §98.253(c)(3) for units with rated capacities of 10,000 barrels per stream day or less.

(f) *Uncontrolled Blowdown Systems.* When calculating CH_4 emissions for uncontrolled blowdown systems as required by 40 CFR §98.253(k), the operator must use the methods for process vents in 40 CFR §98.253(j).

(g) *Data Reporting Requirements for Flares.* When the operator has calculated flare emissions for SSM periods using the modified equation specified in section 95113(d), the operator reporting data under the requirements of 40 CFR §98.256(e)(8) must report only the total number of SSM events, the volume of gas flared, and the average molecular weight and carbon content of the flare gas for each SSM event, using the units specified.

(h) *Data Reporting Requirements for FCCUs and Coking Units.* When the operator has calculated CO_2 from fluid catalytic cracking units or fluid coking units consistent with section 95113(e), the operator shall not report the data required by 40 CFR §98.256(f)(9).

(i) *Data Reporting Requirements for Uncontrolled Blowdown Systems.* When the operator has calculated CH_4 from uncontrolled blowdown systems consistent with section 95113(g), the operator must report the information required for process vents in 40 CFR §98.256(l), as applicable, in lieu of the information required by 40 CFR §98.256(m)(2).

(j) *Records that must be retained.* In addition to the requirements of 40 CFR §98.257, for each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in 40 CFR §98.253(j), the operator must maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentrations, and all supporting documentation necessary to demonstrate that the thresholds in 40 CFR §98.253(j) are not exceeded during the data year pursuant to the record keeping requirements of section 95105.

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

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions

monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(l) Additional Product and Process Data.

(1) *Primary refinery products*. The operator must report on-site production quantities of each primary refinery product for the data year by EIA number. The operator must also report for the data year by EIA number the quantity of each primary refinery product and blending component that was produced elsewhere and brought on-site. Liquid products must be reported in barrels, and solid products must be reported in short tons. When reporting the production quantity of a primary refinery product, sales data may be used, but must be adjusted by the change in inventory during the data year to accurately reflect the amount of material actually produced during the data year. Sales data may be used to report quantities of primary refinery product and blending component produced elsewhere and brought on-site. For each primary refinery product and blending component that was produced elsewhere and brought on-site, the operator must designate if any was used for a purpose other than blending into a primary refinery product, such as being used as a fuel or as a process unit feedstock. The quantity of primary refinery product or blending component that is produced elsewhere and brought on-site may not be included in the reported on-site production quantity of primary refinery product, unless the reporter has identified that the quantity of primary refinery product or blending component that is produced elsewhere and brought on-site is used for a purpose other than blending into a primary refinery product.

(2) *Calcined coke*. The operator must report the production quantity for the data year of calcined coke (metric tons). The operator must specify whether the calciner is integrated with the petroleum refinery operation.

(3) *Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR Part 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). These products will not be subject to review for material misstatement under the requirements of section 95131(b)(12). Primary products will be evaluated for conformance and assessment of material misstatement through 2014 data year verifications. Beginning with 2015 data reported in 2016, primary refinery products will be evaluated for conformance only and will not be evaluated for material misstatement.

(4) *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.

(5) *Complexity Weighted Barrel (CWB) Calculation*.

(A) *Reporting CWB Throughputs*. The operator must report the annual throughput for each CWB unit in Table 1 of this section using the appropriate units listed in column 3 of Table 1 of this section. Reported throughputs based on feed must include only fresh feed and exclude recycled streams. The coke-on-catalyst volume percent also must be reported for each catalytic cracking unit. Beginning with data year 2013, CWB is considered covered product data and subject to material misstatement.

(B) *Total facility CWB.* The total facility CWB production must be calculated according to the following formula.

$$CWB_{Total} = CWB_{Process} + CWB_{Off-Sites} + CWB_{Non-Crude\ Sensible\ Heat}$$

Where CWB_{Total} is the total complexity weighted barrels for a petroleum refinery, and $CWB_{Process}$, $CWB_{Off\text{-}Sites}$, and $CWB_{Non\text{-}Crude\ Sensible\ Heat}$ must be calculated as follows:

$CWB_{Process} = \sum(CWB_{Factor} \times Throughput)$

$CWB_{Off\text{-}Sites} = (0.327) \times (Total\ Refinery\ Input$ in thousands of barrels per year$) + (0.0085) \times (CWB_{Process})$

$CWB_{Non\text{-}Crude\ Sensible\ Heat} = (0.44) \times (Non\text{-}Crude\ Input$ in thousands of barrels per year$)$

In these equations, CWB_{Factor} is the CWB Factor for a CWB unit from Table 1 of this section. *Throughput* is the process throughput for each CWB unit identified in Table 1 of this section reported pursuant to section 95113(l)(3)(A). *Total Refinery Input* and *Non-Crude Input* are the annual volumes of raw materials as defined in section 95102(c). Total Refinery Input and Non-Crude Input must each be reported in units of thousands of barrels per year and must exclude hydrogen, natural gas, and any input to a hydrogen production plant.

(C) *Correction to CWB_{Factor} for Fluid Catalytic Cracking*. The following equation must be used to adjust CWB_{Factor} for Fluid Catalytic Cracking (FCC) units and mild residual FCC units that result in coke on the catalyst:

$$CWB_{Factor,FCC} = CWB_{Factor} + (A \times COC)$$

Where:

$CWB_{Factor, FCC}$ = The corrected CWB factor used to calculate the contribution to $CWB_{Process}$ for a fluid catalytic cracking unit.

CWB_{Factor} = The uncorrected CWB factor for a catalytic cracking unit from Table 1 of this section.

A = The coke-on-catalyst factor for a fluid catalytic cracking unit listed in the fourth column of Table 1 of this section.

COC = The coke-on-catalyst volume percent reported to three significant figures and calculated by:

COC = 100 x (Volume of coke consumed in the FCC)/(Volume of fresh feed to the FCC)

(D) *Density.* In cases where a density measurement is needed for purposes of converting a throughput from barrel to mass units, the following applies:

1. For a throughput with a known density, utilize the applicable default value from Section 3-1, Physical Constants of Organic Compounds, of the CRC Handbook of Chemistry and Physics, CRC Press Inc., Boca Raton 83rd Edition, 2002 – 2003, incorporated herein by reference;

2. If the throughput density is not known, it must be determined following the requirements of section 95103(k).

(E) *Measurement Accuracy.* All throughputs must follow the accuracy requirements outlined in sections 95103(k)(1)-(10). No single refinery activity may be reported under more than one CWB function. For 2014 data reported in 2015, postponement requests for a CWB meter or device pursuant to sections 95103(k)(8)-(9) must be received by the 2014 reporting deadline in section 95103(e) instead of the timeframe in section 95103(k)(9)(A).

(m) The operator must report the quantity of:

(1) CARBOB produced and imported, as defined by “California reformulated gasoline blendstock for oxygenate blending” in section 95202 of the AB 32 Cost of Implementation Fee Regulation, for use in California and the designated volume of oxygenate associated with the reported CARBOB;

(2) Finished California gasoline produced and imported, as defined by “California gasoline” in section 95202 of the AB 32 Cost of Implementation Fee Regulation, for use in California; and

(3) California Diesel produced and imported, as defined by “California diesel” in section 95202 of the AB 32 Cost of Implementation Fee Regulation, for use in

California and the volume of biodiesel and/or renewable diesel associated with the reported fuels.

Table 1. CWB Functions and Factors

CWB unit	Throughput Basis	Unit of Measure	CWB Factor	EIA Number	Process Subtypes
Atmospheric Crude Distillation	Feed	thousands of barrels/year	1	401	Mild Crude Unit, Standard Crude Unit
Vacuum Distillation	Feed	thousands of barrels/year	0.91	402	Mild Vacuum Fractionation, Standard Vacuum Column, Vacuum Fractionating Column, Vacuum Flasher Column, Heavy Feed Vacuum Unit
Visbreaker	Feed	thousands of barrels/year	1.6	403	Processing Atmospheric Residual (w/o a Soaker Drum), Processing Atmospheric Residual (with a Soaker Drum), Processing Vacuum Bottoms Feed (w/o a Soaker Drum), Vacuum Bottoms Feed (with a Soaker Drum)
Delayed Coker	Feed	thousands of barrels/year	2.55	405	Delayed Coking
Fluid Coker	Feed	thousands of barrels/year	10.3	404	Fluid Coking
Flexicoker	Feed	thousands of barrels/year	23.6		Flexicoking
Fluid Catalytic Cracking	Feed	thousands of barrels/year	1.150, Coke-on-Catalyst Factor = 1.041	407	Fluid Catalytic Cracking (Feed ConCarbon <2.25 wt%)
Mild Residual FCC	Feed	thousands of barrels/year	0.6593, Coke-on-Catalyst Factor = 1.1075		Mild Residualuum Catalytic Cracking (Feed ConCarbon 2.25-3.5 wt %)
Other FCC	Feed	thousands of barrels/year	4.65		Houdry Catalytic Cracking
Other FCC	Feed				Thermofor Catalytic Cracking
Thermal Cracking	Feed	thousands of barrels/year	2.95	406	Thermal Cracking
Naphtha/Distillate Hydrocracker	Feed	thousands of barrels/year	3.15	439 / 440	Mild Hydrocracking (Normally less than 1,500 psig and consumes between 100 and 1,000 SCF H2/b) Severe Hydrocracking Naphtha Hydrocracking
Residual Hydrocracker (H-Oil; LC-Fining and Hycon)	Feed	thousands of barrels/year	4.4	441	H-Oil LC-Fining™ and Hycon
Naphtha Hydrotreater	Feed	thousands of barrels/year	0.91	420/425/426	Benzene Saturation Desulfurization of C4–C6 Feeds

					Conventional Naphtha Hydrotreating
					Diolefin to Olefin Saturation of Gasoline
					FCC gasoline hydrotreating with minimum octane loss
					Olefinic Alkylation of Thio Sulfur
					Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization
					Pyrolysis Gasoline/Naphtha Desulfurization
					Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization
					Reactor for Selective Hydrotreating
					S-Zorb™ Process
Kerosene Hydrotreater	Feed	thousands of barrels/year	0.75	421	Aromatic Saturation of Kerosene
					Conventional Hydrotreating of Kerosene/Jet Fuel
					High Severity Hydrotreating Kerosene/Jet Fuel
Diesel/Selective Hydrotreater	Feed	thousands of barrels/year	0.9	422 / 423	Aromatic Saturation of Distillates
					Conventional Distillate Hydrotreating
					High Severity Distillate Hydrotreating
					Ultra-High Severity Hydrotreating
					Middle Distillate Dewaxing
					S-Zorb™ Process
					Diolefin to Olefin Saturation of Alkylation Feed
					Selective Hydrotreating of C3-C5 Streams for Alkylation
Residual Hydrotreater	Feed	thousands of barrels/year	1.8	424	Desulfurization of Atmospheric Residual
					Desulfurization of Vacuum Residual
VGO Hydrotreater	Feed	thousands of barrels/year	1	413	Hydrodesulfurization/denitrification
					Hydrodesulfurization
Reformer - including AROMAX	Feed	thousands of barrels/year	3.5	430 / 431	Continuous Regeneration, Cyclic, Semi-Regenerative, and AROMAX
Solvent Deasphalter	Feed	thousands of barrels/year	2.8	432	Conventional Solvent, Supercritical Solvent
Alkylation/Poly/Dimersol	C5+ Alkylate	thousands of barrels/year	5	415	Alkylation with Hydrofluoric Acid
					Alkylation with Sulfuric Acid
	C5+ Product				Polymerization C3 Olefin Feed
					Polymerization C3/C4 Feed
					Dimersol

C4 Isomer Production	Feed	thousands of barrels/year	1.25	615/644	C4 Isomerization
C5/C6 Isomer Production - including ISOSIV	Feed	thousands of barrels/year	1.8	438	C5/C6 Isomerization
					ISOSIV
POX Syngas for Fuel	Product	millions of standard cubic feet/year[1]	2.75		POX Syngas for Fuel
POX Syngas for Fuel					Air Separation Unit
Sulfur Recovery	Product Sulfur	thousands of long tons/year	140	435	sulfur Recovery Unit
					Tail Gas Recovery Unit
	Sulfur Sprung				H2S Springer Unit
Aromatics Production (All)	Feed	thousands of barrels/year	3.3	437	Aromatics Solvent Extraction: Extraction Distillation
					Aromatics Solvent Extraction: Liquid/Liquid Extraction
					Aromatics Solvent Extraction: Liq/Liq w/ Extr. Distillation
					Benzene Column
					Toluene Column
					Xylene Rerun Column
					Heavy Aromatics Column
Hydrodealkylation	Feed	thousands of barrels/year	2.5		Hydrodealkylation
Toluene Disproportionation/ Transalkylation	Feed	thousands of barrels/year	1.9		Toluene Disproportionation / Transalkylation
Cyclohexane production	Cyclohexane Product	thousands of barrels/year	2.8		Cyclohexane
Xylene Isomerization	Feed	thousands of barrels/year	1.9		Xylene Isomerization
Paraxylene Production	Paraxylene Product	thousands of barrels/year	6.5		Paraxylene Adsorption
		thousands of barrels/year			Paraxylene Crystallization
	Feed	thousands of barrels/year			Xylene Splitter
		thousands of barrels/year			Orthoxylene Rerun Column
Ethylbenzene production	Ethylbenzene Product	thousands of barrels/year	1.6		Ethylbenzene Manufacture
	Feed	thousands of barrels/year			Ethylbenzene Distillation
Cumene production	Cumene Product	thousands of barrels/year	5		Cumene
Lubricant solvent extraction	Feed	thousands of barrels/year	2.2	815/854	Extraction: Solvent is Duo-Sol, Furfural, NMP, Phenol, or SO2
Lubricant solvent dewaxing	Feed	thousands of barrels/year	4.55		Dewaxing: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane
Lubricant Catalytic Dewaxing	Feed	thousands of barrels/year	1.6		Catalytic Wax Isomerization and Dewaxing, Selective Wax Cracking
Lubricant Hydrocracking	Feed	thousands of barrels/year	2.5		Lube Hydrocracker with Multi-fraction Distillation, Lube Hydrocracker with Vacuum Stripper
Lubricant Wax Deoiling	Product	thousands of barrels/year	11.8		Deoiling: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane

Lubricant and Wax Hydrofining	Feed	thousands of barrels/year	1.15		Lube Hydrofinishing with Vacuum Stripper
					Lube Hydrotreating with Multi-Fraction Distillation, Lube Hydrotreating Vacuum Stripper
					Wax Hydrofinishing with Vacuum Stripper, Wax Hydrotreating with Multi-Fraction Distillation, Wax Hydrotreating with Vacuum Stripper
Asphalt Production	Total Asphalt Production	thousands of barrels/year	2.7	931	Asphalt Production
Oxygenates	Product	thousands of barrels/year	4.9		Distillation Units
					Extraction Units
					ETBE
					TAME
Methanol Synthesis	Product	thousands of barrels/year	-36		Methanol Synthesis
Desalination	Product (Water)	millions of gallons/year	32.7		Desalination
Special Fractionation	Feed	thousands of barrels/year	0.8		All Special Fractionation ex Solvents, Propylene, and Aromatics
Propane/Propylene Splitter (Propylene Production)	Feed	thousands of barrels/year	2.1		Chemical Grade
					Polymer grade
Fuel Gas Sales Treating & Compression (hp)	Horsepower	hp	0.92		Fuel Gas Sales Treating & Compression
Sulfuric Acid Regeneration	Product	thousands of short tons/year	37.8		Sulfuric Acid Regeneration
Ammonia Recovery Unit	Product	thousands of short tons/year	453		Ammonia Recovery Unit: PHOSAM
Cryogenic LPG Recovery	Feed	millions of standard cubic feet/year	0.25		Cryogenic LPG Recovery
Flare Gas Recovery	Feed	millions of standard cubic feet/year	0.13		Flare Gas Recovery
Flue Gas Desulfurizing	Feed	millions of standard cubic feet/year	0.02		Flue Gas Desulfurizing
CO2 Liquefaction	CO2 product	thousands of short tons/year	-160	.	CO2 liquefaction
					-
					-

[1] Standard cubic feet are dry @ 60°F and 14.696 psi a or 15 °C and 1 atmosphere.

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

§ 95114. Hydrogen Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart P of 40 CFR Part 98 (40 CFR §§98.160 to 98.168) in reporting emissions and other data from molecular hydrogen production to ARB, except as otherwise provided in this section. GHG emissions and output associated with hydrogen production must be reported separately from other emissions and output associated with a petroleum refinery.

(a) *Definition of Source Category*. This source category is defined consistent with 40 CFR §98.160(b) and (c). This category is further defined as a hydrogen production source that produces molecular hydrogen whether sold to other entities or consumed on-site.

(b) *CO_2 from Fossil Fuel Combustion*. When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.162(b)-(c), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(c) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95114(b), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95114(h), 95115, and 95129 of this article.

(d) *CO_2 Process Emissions.* When calculating CO_2 under the fuel and feedstock material balance approach specified at 40 CFR §98.163(b), the operator must apply the weighted average carbon content values obtained (the term CC_n in Equations P-1 through P-3) according to the frequencies specified in section 95114(e).

(e) *Sampling Frequencies.* When monitoring GHG emissions as specified at 40 CFR §98.163, and reporting data as specified at §98.166, the operator must report the following:

(1) Carbon, atomic hydrogen, and molecular hydrogen content for each feedstock using engineering estimates based on measured data as specified below:

(A) For gaseous feedstock the operator must use weighted average carbon content, atomic hydrogen content (excluding hydrogen atoms contained in steam), and molecular hydrogen 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 monthly analysis for other gaseous fuels and feedstocks such as refinery fuel gas;

(B) For liquid feedstock the operator must use weighted average carbon content and atomic hydrogen 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 monthly sampling for other liquid fuels or feedstocks;

(C) For solid feedstock the operator must use weighted average carbon content and atomic hydrogen content from the results of monthly sampling.

(2) When monitoring GHG emissions without a CEMS as specified in 40 CFR §98.163(b), the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below:

(A) When reporting CO_2 emissions for gaseous fuel and feedstock 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 sampling for month n for other gaseous fuels or feedstocks such as refinery fuel gas.

(B) When reporting CO_2 emissions for liquid fuel and feedstock, the operator must use a 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.

(C) When reporting CO_2 emissions for solid fuel and feedstock, the operator must use the weighted average carbon content from the results of monthly sampling 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 solid fuels and feedstock. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

(f) *Weighted Average Sampling.* Where this section requires sampling of a parameter on a more frequent basis than 40 CFR Part 98, the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.

(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by this article.

n = The number of periods j in period E.

V_j = The value of the sample for period j.
M_j = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in the equation above and of the calculation of each weighted average included in the emissions data report, pursuant to the record keeping requirements of section 95105.

(g) *Data Reporting Requirements.* When reporting data as specified in 40 CFR §98.166, the operator must also report the mass of carbon and methane for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation (e.g., carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods specified in this regulation). To avoid double-counting, these emissions must be subtracted from the total facility emissions.

(h) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.165 when substituting for missing data, except for 2013 and later emissions data reports as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems); the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(i) *Transferred CO_2.* The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Refineries and hydrogen production facilities must subtract this reported mass of CO_2 that is captured and sold or transferred off-site from their facility emissions report to avoid double counting.

(j) *Additional Product Data.* Operators must report the annual mass of hydrogen gas produced (metric tons) and liquid hydrogen sold (metric tons). For hydrogen gas produced, annual masses of on-purpose hydrogen gas and by-product hydrogen gas produced must be reported (metric tons). Operators must also specify if the hydrogen plant is an integrated refinery operation. Operators must report all hydrogen sold or otherwise transferred to another facility and include the purchaser (or receiver) and quantity sold or transferred to each facility.

(k) *Methane and nitrous oxide emissions from stationary combustion.* Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively), and CH_4 and N_2O from fuel stationary combustion sources as set-forth in 40 CFR §98.33(c).

(l) Hydrogen producers shall use the methodology found in section 95113(d) to calculate and report CO_2, CH_4, and N_2O emissions from all flaring at their facility.

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

§ 95115. Stationary Fuel Combustion Sources.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart C of 40 CFR Part 98 (§§98.30 to 98.38) in reporting stationary fuel combustion emissions and related data to ARB, except as otherwise provided in this section.

(a) *CO_2 from Steam Producing Units.* The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR §98.33(a)(2)(B)(iii), unless required to use Tier 3 or 4 by 40 CFR Part 98 or Part 75. Operators of steam producing units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 methods.

(b) *CEMS CO_2 Monitoring.* Notwithstanding the allowed use of oxygen concentration monitors in 40 CFR §98.33(a)(4)(iv), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2012, and who reports CO_2 emissions using this system, must install and use a CO_2 monitor. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a Relative Accuracy Test Audit (RATA) for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 95105 and make them available to ARB upon request. The requirements of this paragraph do not apply to facilities for which pipeline natural gas is the only fuel consumed.

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2

emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 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 these emissions are not subject to a compliance obligation under the cap-and-trade, except as limited by section 95115(e).

(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section 95102 of this article, and for distillate fuels listed in Table 1 of this section. Tier 1 may be selected when the fuel supplier is providing pipeline quality natural gas measured in units of therms or million Btu. Equation C-2c of 40 CFR §98.33(a) may be selected for the units specified in paragraph (a) of this section.

(3) The operator may select any calculation method specified in 40 CFR §98.33(a) when calculating emissions that are shown to be *de minimis* under section 95103(i) of this article, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, unless not permitted under 40 CFR §98.33(b).

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume is measured by lot, the term "n" in Equation C-2b is substituted as the number of lots received in the year.

(d) *Source Test Option for N_2O and CH_4.* In lieu of other methods specified in this article, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in title 17, California Code of Regulations, section 95471. For source testing:

(1) The facility operator must submit to the Executive Officer a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved ARB or U.S. EPA test methods. Process rates

during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the Executive Officer, the test procedures in that plan must be repeated as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least ten days in advance of subsequent tests.

(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:

(1) When combusting municipal solid waste (MSW) or any other fuel for which the biomass fraction is not known, the operator must follow the procedures specified in 40 CFR §98.33(e)(3) to specify a biomass fraction.

(2) For the analysis conducted under the requirements of 40 CFR §98.34(e) for partially biogenic fuels other than MSW, the operator may choose to analyze monthly fuel samples. The operator must collect such samples weekly and combine a portion of each weekly sample to form a monthly composite mixture. The monthly composite mixture must be homogenized and well mixed prior to withdrawal of a sample for analysis.

(3) When calculating emissions from a biomethane and natural gas mixture as described in 40 CFR §98.33(a)(2) using the annual MMBtu of fuel combusted in place of the product of Fuel and HHV in Equation C-2a, the operator must calculate emissions based on contractual deliveries of biomethane subject to the requirements of 95131(i), using the natural gas emission factor in the following equations:

$$E_{\text{biomass}} = EF_{\text{natural gas}} \times MMBtu_{\text{biomethane}} \times 0.001$$

Where:

$E_{biomass}$ = The annual biomass CO_2, CH_4 or N_2O emissions from biomethane (metric tons)

$E_{natual\ gas}$ = The annual fossil CO_2, CH_4 or N_2O emissions from natural gas (metric tons)

$EF_{natural\ gas}$ = The natural gas emission factor from Tables C-1 and C-2 of 40 CFR Part 98 (kg/MMBtu)

$MMBtu_{annual}$ = The total delivered MMBtus for the reporting year based on utility bills or meters meeting the accuracy requirements of section 95103(k)

$MMBtu_{biomethane}$ = The total biomethane deliveries subject to the requirements of section 95131(i) for the reporting year based on contractual deliveries

(4) When calculating emissions from a biomethane and natural gas mixture as described in 40 CFR §98.33(a)(4) using a continuous emission monitoring system (CEMS), or when calculating those emissions according to Subpart D of 40 CFR Part 98, the reporting entity must calculate the biomethane

emissions as described in subparagraph (3) of this section, with the remainder of emission being natural gas emissions.

(5) When calculating emissions from a biogas and natural gas mixture using 40 CFR §98.33(a)(4) or the carbon content method described in 40 CFR §98.33(a)(3), or when calculating those emissions according to Subpart D of 40 CFR Part 98, the reporting entity must calculate biogas emissions using a carbon content method as described in 40 CFR §98.33(a)(3), with the remainder of emissions being natural gas emissions.

(f) *Fuel Sampling Frequencies.* The operator who collects and analyzes fuel samples to conduct the monitoring analyses required under 40 CFR §98.34 must sample at the frequencies specified in that section, except in the following cases.

(1) Natural gas that is outside the range of pipeline quality as defined in section 95102 must be sampled and analyzed at least monthly by the reporting entity or the fuel supplier.

(2) Under 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(3) The operator is estimating CO_2 emissions using a CEMS under 40 CFR §98.33(a)(4).

(g) *Fuel Use for CEMS Units.* The operator who estimates and reports CO_2 emissions using a CEMS under 40 CFR §98.33(a)(4) must also report the quantity of each type of fuel combusted in the unit or group of units (as applicable) during the reporting year, in standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone dry short tons for biomass-derived solids. Fuel use monitoring devices for units covered under this paragraph are exempt from the provisions of section 95103(k) of this article.

(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 fuel use by fuel type as a percentage of the aggregated fuel consumption attributed to 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.

(i) *Pilot Lights.* Notwithstanding the exclusion of pilot lights from this source category in 40 CFR §98.30(d), the operator must include emissions from pilot lights in the emissions data report when operated 300 hours or more in the data year. The operator may apply appropriate methods from 40 CFR §98.33 or engineering methods to calculate these emissions when pilot lights are unmetered. Pilot lights fueled from a common fuel source may be aggregated for reporting. Pilot lights may be reported as *de minimis* consistent with the requirements of section 95103(i). Pilot lights are not subject to the measurement device calibration requirements of section 95103, but pilot light emissions calculations are subject to verification.

(j) *Electricity Generating and Cogeneration Units.* The operator of a facility that includes electricity generating and cogeneration units meeting the applicability criteria of section 95101 must meet the requirements specified in section 95112 of this article.

(k) *Natural Gas Supplier Information.* The operator who is reporting emissions from the combustion of natural gas must report the name(s) of the supplier(s) of natural gas to the facility, the operator's natural gas supplier customer account number(s), natural gas supplier service account identification number(s) or other primary account identifier(s), and the annual MMBtu delivered to each account according to billing statements (10 therms = 1 MMBtu), and if the natural gas was received directly from an interstate pipeline supplier. In the case that the natural gas is purchased from an entity other than the natural gas supplier, the operator must report the supplier name and customer or service account identification number, but may report the annual MMBtu delivered based on the seller's billing statement.

(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) *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.

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

(1) The operator of a facility engaged in hot rolling and/or cold rolling of steel must report the quantity of hot rolled steel sheet, pickled steel sheet, cold rolled and annealed steel sheet, galvanized steel sheet, and tin plate produced in the data year (short tons). For cold rolled and annealed steel sheet, the operator must also report a description of the process used to produce the products, such as continuous annealing process or batch annealing.

(2) The operator of a soda ash manufacturing facility must report the quantity of soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, boric acid, and sulfate produced in the data year (short tons).

(3) The operator of a gypsum manufacturing facility must report the quantity of plaster that is sold as a separate finished product and the amount of stucco used to produce saleable plasterboard produced in the data year (short tons)

(4) The operator of a turbine and turbine generator set testing facility must report the nameplate power of the units tested (horsepower tested).

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

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

(7) The operator of a beer brewery must report the production of lager beer in the data year (gallons).

(8) The operator of a snack food manufacturing facility must report the production of fried potato chips, baked potato chips, corn chips, corn curls, and pretzels in the data year (short tons).

(9) The operator of a sugar manufacturing facility must report the production of granulated refined sugar in the data year (short tons)

(10) The operator of a tomato processing facility must report the quantity of aseptic tomato paste (short ton of 31% TSS), aseptic whole and diced tomato (short ton), non-aseptic tomato paste and tomato puree (short ton of 24% TSS), non-aseptic whole and diced tomato (short ton), and non-aseptic tomato juice (short ton) produced in the data year.

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

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

(13) The operator of a facility mining or processing of rare earth minerals must report the production of rare earth oxide equivalents in the data year (short tons).

(14) The operator of a facility mining or processing freshwater diatomite filter aids must report the production of freshwater diatomite filter aids in the data year (short tons).

(15) The operator of a performing forging facility must report the production of seamless rolled ring during the data year (short tons).

(16) The operator of a dairy product facility must report the production of milk, buttermilk, skim milk, cream, butter, condensed milk, buttermilk powder,

intermediate dairy ingredients, dairy product solids for animal feed, lactose, whey protein concentrate (WPC), deproteinized whey, cheese by cheese type, nonfat dry milk and skimmed milk powder by the type of heat treatment (low heat, medium heat, or high heat), and ultrafiltered milk products by product type during the data year (short tons). Butter re-melted and re-introduced to the manufacturing process may be reported as production. Buttermilk powder and nonfat dry milk and skimmed milk powder that is re-constituted and re-introduced to the manufacturing process may be reported as production. The operator must report the production of total WPC and WPC with high protein concentration using diafiltration process during the data year (short tons). The operator must also report the amount of imported protein.

(17) The operator of an almond or pistachio processing facility must report the sum of pistachios hulled and dried and/or flavored and packaged (short tons) where the hulling and drying, flavoring and packaging is a continuous process, and the sum of almonds pasteurized, blanched and/or flavored and dried (short tons) where flavoring and drying is a continuous process.

(18) The operator of a wet corn milling facility must report the production of corn entering wet milling process during the data year (short tons).

(19) The operator of a winery must report the production of distilled spirits (proof gallons), dry color concentrate (short tons), grape juice concentrate (gallons), grape seed extract (short tons), and liquid color concentrate (gallons) during the data year.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	***Default High Heat Value***	***Default CO_2 Emission Factor***
	MMBtu/gallon	*kg CO_2 /MMBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline (finished)	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

[1]Commercially sold as "propane" including grades such as HD5.

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

§ 95116. Glass Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart N of 40 CFR Part 98 (§§98.140 to 98.148) in reporting stationary combustion and process emissions and related data from glass production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95116(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95116(c)-(d), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating 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) For each missing value of the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.145(a).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum short tons per day raw material capacity of the continuous glass melting furnace.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* In addition to the information required by 40 CFR §98.146, the operator must report the additional parameters provided in paragraphs (1)-(3)

below whether or not a CEMS is used to measure CO_2 emissions.

(1) The operator of a flat glass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (short tons).

(2) The operator of a container glass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (short tons).

(3) The operator of a fiberglass manufacturing facility must report the annual quantity of glass pulled from the melting furnace (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.

§ 95117. Lime Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart S of 40 CFR Part 98 (§§98.190 to 98.198) in reporting stationary combustion and process emissions and related data from lime manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4), as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95117(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95117(c)-(d), and 95129 of this article.

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

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) 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 for the reporting year.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

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

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.195(a).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum capacity of the system.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* The operator of a lime manufacturing facility must report the annual quantity of lime and dolime produced (short tons).

(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-site process, reflects CO_2 process emissions generated by the facility that are not released to the atmosphere. The produced CO_2 emissions must be computed as specified in 40 CFR §98.193(b)(2). The method used to determine the amount of CO_2 captured on-site and not emitted must be provided as specified in 40 CFR §98.196(b)(17)(ii), which could include monitoring of system acidity or basicity (pH), analysis of process samples for calcium oxide, or evaluation of the relative quantities of reactants and products in the lime production and CO_2 reabsorption process (i.e., chemical stoichiometry).

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

§ 95118. Nitric Acid Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart V of 40 CFR Part 98 (§§98.220 to 98.228) in reporting stationary combustion and process emissions and related data from nitric acid production to 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 §98.222(b), 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 95118(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 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) 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.

(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 nitric acid manufacturing facility must report the annual production of nitric acid (HNO_3) and calcium ammonium nitrate solution (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.

§ 95119. Pulp and Paper Manufacturing.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA of 40 CFR Part 98 (40 CFR §§98.270 to 98.278) in reporting stationary combustion and process emissions and related data from pulp and paper manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion in a chemical recovery furnace at a kraft or soda facility under 40 CFR §98.273(a)(1), a chemical recovery unit at a sulfite or stand-alone semichemical facility under 40 CFR §98.273(b)(1), a pulp mill lime kiln at a kraft or soda facility under 40 CFR §98.273(c)(1), or other stationary fuel combustion sources, 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 95119(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95119(c)-(d), and 95129 of this article.

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, 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) For each missing value for the use of makeup chemicals (carbonates), the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.275(c).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum metric tons per day capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* In addition to the information required by 40 CFR §98.276, the operator must report the annual production (air dried short tons) of recycled boxboard, recycled linerboard, and recycled medium, and the annual saleable production of tissue (air dried short tons) by type (bathroom tissue, facial tissue, delicate task wipers, and/or paper towels). The operator producing tissue products must also report:

(1) A description of the process used to produce tissue, such as through use of an air dryer.

(2) Water absorption capacity of each bathroom tissue product with a distinct water absorption capacity manufactured in the data year, measured at least once during the data year using the methodology specified by ISO 12625-8:2010, except the humidity and temperature conditions, which shall be 50% relative humidity ±2%, and 23 degrees C ±1 degree C, respectively.

(3) For bathroom tissue, material misstatement shall be assessed using the following equation:

Material misstatement for bathroom tissue =

$$\sum_{i=1}^{n} O_i WAC_i$$

Where:

Oi = annual product output in air dried saleable ton for each tissue product (*i*) with a distinct water absorption capacity; and

WACi = water absorption capacity for each tissue product (*i*) with a distinct water absorption capacity.

All other pulp and paper manufacturing products shall be assessed on the reported air dried 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.

§ 95120. Iron and Steel Production.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Q of 40 CFR Part 98 (40 CFR §§98.170 to 98.188) in reporting stationary combustion and process emissions and related data from iron and steel production to 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 §98.172(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95120(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95120(c)-(d), and 95129 of this article.

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

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If monthly mass or volume of carbon-containing inputs and outputs are missing when using the carbon mass balance procedure in 40 CFR §98.173(b)(1), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value based on the best available estimate based on information used for accounting purposes (such as purchase records).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum throughput capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) Additional Product Data. In addition to the information required by 40 CFR §98.176, the operator must report the annual production of iron and steel products in short tons, a description of the product(s), and, the process used to produce the products, such as use of an electric arc furnace.

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

§ 95121. Suppliers of Transportation Fuels.

Any position holder, refiner, enterer, or biofuel production facility who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting emissions and related data to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.392, all refiners that produce liquefied petroleum gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas sold or delivered, except for fuel for which a final destination outside California can be demonstrated.

(2) Refiners, position holders of fossil fuels and biomass-derived fuels that supply fuel at California terminal racks, enterers that import transportation fuels outside the bulk transfer/terminal system, and biofuel production facilities that produce and deliver biomass-derived fuels outside the bulk transfer/terminal system in California must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section. However, reporting is not required for fuel in which a final destination outside California or where a use in exclusively aviation or marine applications 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. For purposes of this article, CARBOB blendstocks are reported as RBOB blendstocks.

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, enterers that import fuel outside the bulk transfer system, and biofuel production facilities who produce and deliver fuel outside the bulk transfer/terminal system in California must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel. Emissions must be based on the quantity of fuel removed from the rack (for refiners and position holders), fuel imported or produced and not delivered to the bulk transfer/terminal system (by enterers and biofuel production facilities), and fuel sold to unlicensed entities as specified in section 95121(d)(3) (by refiners). For fuels that are blended, emissions must be reported for each individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section separately, and not as motor gasoline (finished), biofuel blends, or other similar finished fuel. Emissions from denatured fuel ethanol must be calculated as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. Emission factors must be taken from column C of 40 CFR 98 Table MM-1 or MM-2 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1), except that the emission factor

for renewable diesel is equivalent to the emission factor for Distillate No. 2. If a position holder in diesel or biodiesel fuel does not have sealed or financial transaction meters at the rack, and the position holder is the sole position holder at the terminal, the position holder must calculate emissions based on the delivering entity's invoiced volume of fuel or a meter that meets the requirements of section 95103(k) either at the rack or at a point prior to the fuel going into the terminal storage tanks.

(2) Refiners that produce liquefied petroleum gas must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel supplied. For calculating the emissions from liquefied petroleum gas, the emissions from the individual components must be summed. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(3) Refiners, position holders at California terminals, and enterers and biofuel production facilities that deliver fuel outside of the bulk transfer/terminal system must estimate and report CH_4 and N_2O emissions using Equation C–8 and Table C-2 as described in 40 CFR §98.33(c)(1), except that the emission factors in Table 1 of this section will be used for each fuel required to be reported in section 95121(a)(2) above.

Table 1. Transportation Fuel CH_4 and N_2O emission factors

Fuel	CH_4 (g/bbl)	N_2O (g/bbl)
Blendstock	20	20
Distillate	2	1
Ethanol	37	27
Biodiesel and Renewable Diesel	2	1

(4) All fuel suppliers in this section must estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.
GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.
n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For the emissions calculation method chosen under section 95121(b), the operator must meet all the monitoring and

QA/QC requirements as specified in 40 CFR §98.394, and the requirements of 40 CFR §98.3(i) as further specified in section 95103 of this article and below.

(1) Position holders are exempt from 40 CFR §98.3(i) calibration requirements except when the position holder and entity receiving the fuel have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR §98.3(i) calibration requirements apply, unless:

(A) The fuel supplier does not operate the fuel billing meter;

(B) The fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or

(C) The fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR §98.394(a)(1)(iii), for fuels that are liquid at 60 degrees Fahrenheit and one standard atmosphere, the volume reported must be temperature- and pressure-adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60 degrees Fahrenheit.

(d) *Data Reporting Requirements.* In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, that is delivered across the rack in California, except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(2) California position holders that are also terminal operators and refiners must report the annual quantity in barrels delivered across the rack of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If there is only a single position holder at the terminal, and only diesel or biodiesel is being dispensed at the rack then the position holder must report the annual quantity of fuel using a meter meeting the requirements of section 95103(k) or billing invoices from the entity delivering fuel to the terminal.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier must report the annual quantity in barrels delivered of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, except for fuel for which a final destination outside California can be demonstrated. Denatured fuel

ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(4) Enterers and biofuel production facilities delivering transportation fuels outside the bulk transfer/terminal system must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in Table 2 of this section, except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. Biodiesel or renewable diesel blends containing no more than one percent petroleum diesel by volume will be reported as 100% biodiesel or renewable diesel.

(5) In addition to the information required in 40 CFR §98.396, refiners must also report the volume of liquefied petroleum gas in barrels supplied in California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for fuel for which a final destination outside California can be demonstrated.

(6) All fuel suppliers identified in this section must also report CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O and CO_2e emissions in metric tons that would result from the complete combustion or oxidation of each petroleum fuel identified in 95121(a)(2), liquefied petroleum gas, or biomass-derived fuel reported in this section, calculated according to section 95121(b).

(7) All fuel suppliers identified in this section, except for refiners that report pursuant to section 95113(m), must report the total quantity of CARBOB, California Gasoline, California diesel fuel, and biodiesel and/or renewable diesel that was imported from outside of California for use in California. In addition, for CARBOB imports, the designated percentage of oxygenate must be reported.

(8) Fuel suppliers identified in this section, except for refiners that report pursuant to section 95113(m), must report the total quantity of biodiesel and/or renewable diesel blended in California diesel for use in California.

(e) *Procedures for Missing Data.* For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR §98.395. The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

Table 2
Blendstocks, Distillate Fuel Oils, and Biomass-Derived Fuels Subject to Reporting under section 95121

CBOB—Summer
Regular
Midgrade
Premium
CBOB—Winter
Regular
Midgrade
Premium
RBOB (CARBOB)—Summer
Regular
Midgrade
Premium
RBOB (CARBOB)—Winter
Regular
Midgrade
Premium
Distillate Fuel Oils
Distillate No. 1
Distillate No. 2
Liquefied Petroleum Gas (LPG)
Ethane
Ethylene
Propane
Propylene
Butane
Butylene
Isobutane
Isobutylene
Pentanes Plus
Biomass-Derived Fuel
Ethanol (100%)
Biodiesel (≥99%, methyl ester)
Renewable Diesel (≥99%)
Rendered Animal Fat
Vegetable Oil

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

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

Any supplier of natural gas or natural gas liquids who is required to report under section 95101 must comply with Subpart NN of 40 CFR Part 98 (§§98.400 to 98.408) in reporting emissions and related data to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.402(a), natural gas liquid fractionators must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of liquefied petroleum gas sold or delivered to others that was produced on-site, except for products for which a final destination outside California can be demonstrated.

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies including intrastate pipelines delivering gas to California end-users must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of the annual volume of natural gas delivered to all entities on their distribution systems in California.

(3) The 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.

(4) Operators of liquefied natural gas production facilities that receive natural gas supply from interstate pipelines must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of all liquefied natural gas sold or delivered to others, except for product for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions.*

(1) Natural gas liquid fractionators must use calculation methodology 2 as specified in 40 CFR §98.403(a)(2) to estimate the CO_2 emissions that would result from the complete combustion of all natural gas liquid products supplied except that Table MM-1 must be used in place of Table NN-2. For calculating the emissions from liquefied petroleum gas, the fractionators must sum the emissions from the individual constituents of liquefied petroleum gas sold or delivered to others that was produced on-site, except for products for which a final destination outside of California can be demonstrated.

(2) For the calculation of CO_{2i} in section 95122(b)(6), local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(3) For the calculation of CO_{2j} in section 95122(b)(6), public utility gas corporations and publicly owned natural gas utilities must estimate annual CO_2 emissions from instate receipts of pipeline quality natural gas from other public utility gas corporations, interstate pipelines and intrastate transmission pipelines, and annual CO_2 emissions from all natural gas redelivered to other public utility gas corporations or interstate pipelines. Annual CO_2 emissions from redelivered natural gas to intrastate pipelines 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:

$$\mathrm{MMBtu_{Total}} = \mathrm{MMBtu_{redelivery}} - \mathrm{MMBtu_{receipts}}$$

Where

$MMBtu_{Total}$	=	Total annual MMBtu used in equation NN-3
$MMBtu_{redelivery}$	=	Total annual MMBtu of natural gas delivered to other companies as specified above
$MMBtu_{receipts}$	=	Total annual MMBtu of natural gas received from other companies as specified above

(4) For the calculation of CO_{2l} in section 95122(b)(6), emissions from receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to Equation NN-5 of 40 CFR §98.403(b)(3) except that CO_{2l} will be calculated as the product of the net annual MMBtu and a default emission factor from Table NN-1 or the product of the net annual MMBtu and a reporter specific emission factor.

(5) Determination of pipeline quality natural gas is based on the annual weighted average HHV, determined according to Equation C-2b of 40 CFR §98.33(a)(2)(ii)(A), for natural gas from a single city gate, storage facility, or connection with an in-state producer, interstate pipeline, intrastate pipeline or local distribution company. If the HHV is outside the range of pipeline quality natural gas, emissions will be calculated using the appropriate subparagraph of section 95122(a) replacing the default emission factor with either a reporter specific emission factor as calculated in 40 CFR §98.404(b)(2) or one determined as follows:

(A) For natural gas or biomethane with an annual weighted HHV below 970 Btu/scf and not exceeding 3% of total emissions estimated under this section, the local distribution company may use the reporter specific weighted yearly average higher heating value and the default emission factor or an emission factor as determined in 40 CFR §98.404(c)(3). If emissions exceed 3% of the total, then the Tier 3 method specified in 40 CFR §98.33(a)(3)(iii) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is below 970 Btu/scf.

(B) For natural gas or biomethane with an annual HHV above 1100 Btu/scf and not exceeding 3% of total emissions estimated under this section, the local distribution company must use the reporter specific weighted yearly average higher heating value and a default emission factor of 54.67 kg CO_2/MMBtu or an emission factor as determined in 40 CFR §98.404(c)(3). If emissions exceed 3% of the total, then the Tier 3 method specified in 40 CFR §98.33(a)(3)(iii) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is above 1100 Btu/scf.

(6) When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2l}$$

Where:

CO_2 = Total emissions.

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

CO_{2j} = Emissions from natural gas received for redistribution to or received from other natural gas transmission companies, calculated pursuant to section 95122(b)(3).

CO_{2l} = Emissions from storage and direct deliveries from producers calculated pursuant to section 95122(b)(4).

(7) Natural gas liquid fractionators and local distribution companies must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR §98.406 and this section. Local distribution companies must use the annual MMBtu determined in paragraphs (2)-(4) above in place of the product of the Fuel and HHV in equation C-8 when calculating emissions.

(8) Local distribution companies must separately and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in the equation in section 95122(b)(6) with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e. CO_2 emissions from biomass-derived fuel are based on the fuel the LDC has contractually purchased on behalf of and delivered to end users. Emissions from contractually purchased biomethane are calculated using the methods for natural gas required by this section, including the use of the emission factor for natural gas found in

40 CFR§98.408, table NN-1. Biomass-derived fuels directly purchased by end users and delivered by the LDC must be reported as natural gas by the LDC.

(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 Part 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 the imported compressed natural gas and liquefied natural gas.

(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).

(11) Operators of liquefied natural gas production facilities described in section 95122(a)(4) must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of the liquefied natural gas sold or delivered in California.

(12) Operators of liquefied natural gas production facilities described in section 95122(a)(4) must estimate and report CH_4 and N_2O emissions based on the MMBtu of liquefied natural gas sold or delivered using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(13) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC requirements specified in 40 CFR §98.404, except as modified in sections 95103, 95115, and below.

(1) All natural gas suppliers must measure required values at least monthly.

(2) All natural gas suppliers must determine reporter specific HHV at least monthly, or if the local distribution company does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.

(3) All natural gas liquid fractionators must sample for composition at least monthly.

(4) All California consignees of liquefied petroleum gas must record composition, if provided by the supplier, and quantity in barrels, corrected to 60 degrees Fahrenheit, for each shipment received.

(d) Data Reporting Requirements.

(1) For the emissions calculation method selected under section 95122(b), natural gas liquid fractionators must report, in addition to the data required by 40 CFR §98.406(a), the annual volume of liquefied petroleum gas, corrected to 60 degrees Fahrenheit, that was produced on-site and sold or delivered to others, except for products for which a final destination outside California can be demonstrated. Natural gas liquid fractionators must report the annual quantity of liquefied petroleum gas produced and sold or delivered to others as the total volume in barrels as well as the volume of the individual components for all components listed in 40 CFR 98 Table MM-1. Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the volume of liquefied petroleum gas reported in 40 CFR §98.406(a)(5) as modified by this regulation, calculated in accordance with section 95122(b).

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

(A) Publicly-owned natural gas utilities that report in-state receipts at the city gate under 40 CFR §98.406(b)(1) must also identify each delivering entity by name and report the annual volumes received in Mscf and the annual energy in MMBtu.

(B) Local distribution companies that report under 40 CFR §98.406(b)(1) through (b)(7) must also report the annual energy of natural gas in MMBtu associated with the volumes.

(C) In addition to the requirements in 40 CFR §98.406(b)(8), local distribution companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR §98.403(a) and (b)(1) through (b)(3) as modified by section 95122(b).

(D) In lieu of reporting the information specified in 40 CFR §98.406(b)(6), local distribution companies, including intrastate pipelines that deliver natural gas to downstream gas pipelines and other 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). These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies including intrastate pipelines must report the annual volumes in Mscf, annual energy in MMBtu, customer information required in 40 CFR §98.406(b)(12), and ARB ID number if available for all end-users registering supply equal to or greater than 188,500 MMBtu during the calendar year. In addition to reporting the information specified in 40 CFR §98.406(b)(13), local distribution companies including intrastate pipelines that deliver to end users must report the annual energy in MMBtu delivered to the following end-use categories: residential consumers; commercial consumers; industrial consumers; electricity generating facilities; and other end-users not identified as residential, commercial, industrial, or electricity generating facilities. Local distribution companies must also report the total energy in MMBtu delivered to all California end-users.

(F) Local distribution companies that report under 40 CFR §98.406(b)(9) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with section 95122(b).

(3) In addition to the information required in 40 CFR §98.3(c), the operator of an interstate pipeline, which is not a local distribution company, must report the customer name, address, and ARB ID along with annual volumes of natural gas, in Mscf, and the annual energy of natural gas in MMBtu for natural gas delivered to each customer, including themselves.

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline that delivers natural gas directly to end users must follow the reporting requirements described under Subpart NN of 40 CFR Part 98 and this section for local distribution companies. In lieu of the city gate information specified by section 95122(b)(2), the intrastate pipeline operator must report the summed 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 required to estimate a value for CO_{2j} as specified in section 95122(b)(3) for natural gas delivered to local distribution companies, interstate pipelines, and other intrastate pipelines. The CO_{2l} parameter as specified in section 95122(b)(4) must have a value of 0 for calculating emissions as required by section 95122(b)(6).

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98

Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b). All California consignees of compressed or liquefied natural gas and liquefied natural gas production facilities as described in section 95122(a)(4) must report the annual quantities imported, or delivered and sold, respectively, in MMBtu, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons separately for compressed natural gas and liquefied natural gas using the calculation methods in section 95122(b).

(6) In addition to the information required in 40 CFR §98.3(c), all local distribution companies that report biomass emissions from biomethane fuel that was contractually purchased by the LDC on behalf of and delivered to end users, and all liquefied natural gas production facilities reporting biomass emission from biomethane, must report, for each contracted delivery, the information specified in section 95103(j)(3).

(e) *Procedures for estimating missing data.* Suppliers must follow the missing data procedures specified in 40 CFR §98.405. The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

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

§ 95123. Suppliers of Carbon Dioxide.

Any supplier of carbon dioxide who is required to report under section 95101 of this article must comply with Subpart PP of 40 CFR Part 98 (§§98.420 to 98.428) in reporting to ARB, except as otherwise provided in this section.

(a) When reporting imported and exported quantities of CO_2 as required in 40 CFR §98.422, the supplier must report quantities of carbon dioxide imported into and exported from the State of California. Exports for purposes of geologic sequestration must be reported separately from exports for other purposes.

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.425 when substituting for missing data, except as otherwise provided below.

(1) For all data required for emissions calculations in this section, the supplier must follow the requirements of paragraphs (A)-(D) below.

(A) If the data capture rate is at least 90 percent for the data year, the supplier must substitute for each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the supplier must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the supplier must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(D) The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

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

§ 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 in 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 §98.185 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 §98.185(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, recycling, recovery, or manufacturing facility must report production of lead and lead alloys during the data year (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.

Subarticle 3. Additional Requirements for Reported Data

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

In lieu of the requirements for estimating missing data in Subparts C and D of 40 CFR Part 98, the operator of a facility who is reporting emissions under section 95115 or 95112 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must follow the applicable procedures of this section for estimating missing or invalid data. The operator must include the substituted data in the GHG emissions data report and maintain all records, calculations, and data used to estimate substituted data according to the requirements of section 95105 and 40 CFR Part 98. Alternatively, under the limited circumstances specified in this section for equipment breakdown, the operator may request approval of an interim data collection procedure as specified in section 95129(h)-(i). For units combusting pure biomass-derived fuels or for *de minimis* sources, the operator who is reporting emissions must follow either the requirements below or the requirements of 40 CFR §98.35. In the event that section 95129 becomes applicable to a source, compliance with the requirements of section 95129 does not relieve the operator from complying with other sections of this article.

(a) *Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.* The operator of a unit that is reporting CO_2 using 40 CFR Part 75 must follow the applicable missing data substitution procedures in Part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content, except as otherwise provided in this section. Paragraphs (b) through (g) of this section do not apply to these units for CO_2 emissions, but do apply for CH_4 and N_2O emissions that are not *de minimis* if data required for calculating CH_4 and N_2O emissions are missing or invalid.

(b) *Missing Data Substitution Procedures for Other Units Equipped with CEMS.* The operator of a stationary combustion unit who monitors and reports emissions and heat input data for that unit under section 95115 of this article using Tier 4 of Subpart C (40 CFR §98.33(a)(4)) must follow the applicable missing data substitution procedures in 40 CFR §75.31 to 75.37 (revised as of July 1, 2009). For the purpose of missing data substitution, for CEMS certified under 40 CFR Part 60, quality-assured data is defined according to the quality assurance/quality control procedures in 40 CFR Part 60. Paragraphs (c) through (h) of this section do not apply to units using Tier 4 for CO_2 emissions, but do apply for CH_4 and N_2O emissions that are not *de minimis* if data required for calculating CH_4 and N_2O emissions are missing or invalid.

(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:

Data capture rate = S / T x 100%

Where:

S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)

T = Total number of fuel samples required by the applicable sampling requirements

(1) If the fuel characteristic data capture rate is at least 90.0 percent for the data year, the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the “after” value has not been obtained by the time that the GHG emissions data report is due, the operator must use the “before” value for missing data substitution.

(2) If the fuel characteristic data capture rate is at least 80.0 percent but not more than 90.0 percent for the data year, the operator must substitute for each missed value with the highest valid value recorded for that type of fuel during the data year as well as the two previous data years.

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

(A) If historical fuel characteristics data are available and kept according to the requirements of section 95105, substitute with the greater of the following:

1. The highest valid value recorded for that type of fuel for all records kept under the requirements of section 95105, or

2. The default value in Table 1 of this section (for carbon content) or Table C-1 of 40 CFR Part 98 (for high heat value). If a substitute value is not available in Table 1 of this section or Table C-1 of 40 CFR Part 98, the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 95105.

(B) For carbon content data, if historical fuel characteristics data are not available and a default value is not listed in Table 1 of this section, use

90% for other liquid and gaseous fuels and 100% for other solid fuels in substituting for missed carbon content data.

Table 1. Default Carbon Content

Parameter	***Missing Data Value***
Anthracite Coal	*90%*
Bituminous	*85%*
Subbituminous/Lignite	*75%*
Oil	*90%*
Natural Gas	*75%*

(d) *Missing Data Substitution Procedures for Fuel Consumption Data.* The operator subject to the requirements of this article must demonstrate every reasonable effort to obtain a total facility fuel consumption data capture rate of 100 percent for each year for each type of fuel. The total facility fuel consumption for the data year can be determined using any combination of meters and/or other fuel measurement devices or methods that individually meet the accuracy requirements of this article, provided that the total amount of fuel consumed at the facility level is completely accounted for during each time period that the facility is in operation. For each fuel type, when the total facility fuel consumption data that meet the accuracy requirements of this article are available during each time period that the facility is in operation, but such data are missing or invalid at the unit level, the operator must either estimate missing unit-level fuel consumption data using other available data parameters that are routinely measured at the facility (e.g., electrical load, steam production, operating hours, production output, or fuel consumption data at other measurement points), or use an applicable missing data substitution procedure from section 95129(d)(1)-(3). If during any time periods that the facility is in operation, a portion of the total facility fuel consumption is missing or cannot be determined at the accuracy required by this article, the operator must use the applicable missing data substitution procedure from section 95129(d)(1)-(3) below, so that the total facility fuel consumption quantity for the missing data periods is reconstructed. If a source is eligible for more than one procedure in section 95129(d)(1)-(3), the operator has the option to choose one of the applicable procedures in section 95129(d)(1)-(3). The requirements in section 95129(d)(1)-(3) are optional for sources that are not required to meet the accuracy standard specified in section 95103(k) and for sources that do not utilize fuel consumption data for emission calculation.

(1) *Continuous Fuel Flow Rate Data Using Load Ranges.* The sources that meet the following criteria are eligible for using the procedures in paragraph (d)(1): the sources combust gaseous or liquid fuels, produce electrical or thermal output, use a fuel flowmeter system to continuously measure fuel flow rate; and are equipped with a data acquisition and handling system (DAHS) that continuously records fuel flow rates and measured electrical or thermal output on an hourly basis, which enables segregation of the fuel flow rate data into bins. The operator of such sources that applies the requirements in this

paragraph must substitute missing fuel flow rate data according to this paragraph.

Whenever quality-assured fuel flow rate data are missing and there is no backup system available to record the fuel flow rate, the operator must use the following procedures to account for the flow rate of fuel combusted at the source for each hour during the missing data period. Before using these procedures, operators must establish load ranges for the affected sources using the procedures in paragraph (f) of this section.

When load ranges are used for estimating missing fuel flow rate data, the operator must create and maintain separate fuel-specific databases for the source. The database for each type of fuel combusted must include the hours in which the fuel is combusted alone at the source and the hours in which it is co-fired with any other fuel types. The database must record fuel flow rate and corresponding electrical output or thermal output, and assign these values into the established load bins. To be eligible to use the missing data procedures in this paragraph, measured electrical output or thermal output must be available for the hour(s) in which fuel flow rate data are missing. If output data are missing, the operator must follow the requirements of paragraph (d)(3).

(A) *Single Fuel Type.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each hour of the missing data period as follows: Substitute the arithmetic average of the hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours in which the source combusted only that same fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, the operator may combine available data with data from higher load ranges if available until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(B) *Multiple Fuel Types.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each hour of the missing data period as follows:

1. Substitute the maximum hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, data from higher load ranges if available may be combined until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator

must substitute the maximum potential fuel flow rate for each hour of the missing data period.

2. If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in subparagraph (d)(1)(B)1. separately for each type of fuel.

3. If the missing data substitution required in subparagraphs (d)(1)(B)1-2 causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input.

(C) *Lookback Period.* In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period. In addition, for sources in operation less than three years (26,280 clock hours), until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in subparagraphs (d)(1)(A) and (d)(1)(B), the methodology in section (d)(3) must be used to determine the appropriate substitute data values.

(2) *Fuel Consumption Data Without Load Ranges.* The sources that meet the following criteria are eligible to use the procedures in this paragraph: the facility operator has established and implemented a fuel monitoring plan as a part of the GHG Monitoring Plan specified in section 95105(c)(5), has monitored fuel measurement equipment and maintained records of its proper operation by recording fuel consumption quantities at least weekly, and has compiled records of fuel consumption that are sufficient for the application of the procedures in this paragraph. For operators that apply the requirements in this paragraph, whenever quality-assured fuel consumption data are missing and there is no backup system available to record the fuel consumption, the operator must use the procedures in this paragraph to account for the consumption of fuel combusted at the unit during the missing data period. For fuels that are combusted less than 180 days in a calendar year, the operator must record fuel consumption at least daily on each day the fuel is combusted. For all other sources or fuels, the operator must record fuel consumption at least weekly.

The data capture rate for the data year must be calculated as follows for each unit with missing fuel consumption data:

Data capture rate = S / T x 100%

Where:

S = Number of fuel monitoring periods (e.g., days or weeks) in the data year for which valid measured fuel consumption data are available. Do not include fuel monitoring periods when the fuel was not combusted at the unit.

T = Total number of fuel monitoring periods (e.g., days or weeks) in the data year that the fuel is combusted at the unit.

(A) *Single Fuel.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows:

1. If the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year, the operator must develop an estimate based on available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, operating hours) or fuel consumption data recorded at other upstream or downstream measurement points.

2. If the fuel consumption data capture rate is equal to or greater than 90.0 percent but less than 95.0 percent during the data year, the operator must calculate substitute data as the 90^{th} percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.

3. If the fuel consumption data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 95^{th} percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.

4. If the fuel consumption data capture rate is less than 80.0 percent during the data year, the operator must apply as substitute data the maximum potential fuel consumption rate.

(B) *Multiple Fuels.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each missing data period as follows:

1. If the fuel consumption data for a single fuel are missing, provide substitute fuel consumption data for the missing data period using the procedures in section 95129(d)(2)(A).

2. If fuel consumption data are missing for two or more of the fuels being combusted, apply the procedures in section 95129(d)(2)(A) (as applicable) separately for each type of fuel.

3. If the missing data substitution required in section 95129(d)(2)(A) causes the reported heat input rate based on the combined fuel usage to exceed the maximum rated heat input of the source, adjust the substitute fuel consumption value(s) so that the reported heat input rate equals the source's maximum rated heat input.

(C) *Prorating Substitute Value.* When applying the procedures in subparagraphs (d)(2)(A)-(B), if an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the specified value for the fuel consumption data monitoring period by the missing data period. For example, for a unit with a missing data period length of one day but weekly fuel consumption monitoring schedule, the operator may divide the substitute value, estimated on a weekly basis, by the number of days the unit operates in a week to obtain the substitute value for the missing data day.

(3) *Alternate Missing Data Procedure for Fuel Consumption Data.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraphs (d)(1) and (d)(2). If fuel consumption data are missing or invalid for a fuel combusting unit, and the total facility fuel consumption data cannot be determined at the accuracy required by this article for the particular missing data period, the operator must substitute for each hour of missing data using the maximum potential fuel consumption rate for the unit. If fuel consumption data at the facility level or at a higher aggregated-units level are available and meet the accuracy requirements of this article, the operator may estimate the missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours) or fuel consumption data recorded at other upstream or downstream measurement points that meet the accuracy requirements of this article.

(e) *Missing Data Substitution Procedures for Steam Production.* The operator of a steam-producing unit who calculates and reports emissions using Equation C-2c in 40 CFR §98.33(a)(2) must apply the procedures in this paragraph to substitute for missing steam production data, unless a backup system to record steam production is available. For sources for which steam production data are not used to calculate emissions, the operator may develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, operating hours) to estimate missing steam production.

If hourly steam production data are not available at the facility, the operator must record steam production data at least weekly and use the weekly records for substituting the missing steam production data. The operator must prorate the steam data using the same procedure in paragraph (d)(2)(C).

The data capture rate for the data year must be calculated as follows for each unit with a missing data period:

Data capture rate = S / T x 100%

Where:

S = Number of monitoring intervals (e.g. hourly, daily, or weekly) with valid measured steam production data.

T = Total number of monitoring intervals that the unit is operated in the data year.

(1) If the steam production data capture rate is at least 90.0 percent during the data year, the operator must develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, and operating hours).

(2) If the steam production data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 90th percentile value of the steam production data recorded for the data year.

(3) If the steam production data capture rate is less than 80.0 percent during the data year, the operator must substitute the highest valid steam production value recorded in all records kept according to section 95105(a).

(f) *Procedure for Establishing Load Ranges.* This paragraph is applicable to units that produce electrical output or thermal output. For a single unit, the operator must establish ten operating load ranges, each defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MW). (Do not use integrated hourly gross load in MWh.) For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity, or for a unit for which hourly average gross load in MW is not recorded separately, the operator must use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia), instead of gross MW.

Beginning with the first hour of unit operation after installation and certification of the fuel flowmeter, for each hour of unit operation the operator must record a number, 1 through 10, that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour. The operator must calculate maximum values and percentile values determined by this procedure using bias adjusted values in the load ranges. When a bias adjustment is necessary for the fuel flowmeter, the operator must apply the adjustment factor to all data values placed in the load ranges. The operator must use the calculated maximum values and percentile values to substitute for missing flow rate according to the procedures in paragraph (d)(1) of this section.

(g) *Executive Officer Approved Load Range.* An operator may petition the Executive Officer for approval to use an alternate load based methodology for substituting missing data to using the procedures in section 95129(d)(1). The operator must be able to prove to the satisfaction of the Executive Officer that there is a direct correlation between fuel consumption and the proposed load metric. At a minimum, the operator will have a system in place that electronically measures and records fuel consumption and load at least hourly. The alternate load metric must be a metric that can be accurately measured, correlated to fuel consumption, and divided into ten operating load ranges. In order to verify the feasibility of the methodology the Executive Officer will require at least three years of fuel consumption and load data and may request up to the maximum years of data required to be retained under section 95105(a).

(h) Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.

(1) In the event of an unforeseen breakdown of the fuel characteristic data monitoring or fuel flow monitoring equipment used to estimate emissions under this article, the Executive Officer may authorize an operator to use an interim data collection procedure under the circumstances specified below. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown may result in a loss of more than 10 percent of a fuel characteristic data element or a fuel usage data element for the data year, and back-up sampling for affected fuel characteristics is unavailable;

(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the usual procedure used by the operator;

(D) A demonstration that the criteria in paragraph (h)(1) are satisfied, and operator certification that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (h)(1) are met.

(4) When reviewing an interim data collection procedure, the Executive Officer shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 95131 of this article. Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in this section.

(5) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(i) Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.

(1) In the event of an unforeseen breakdown of CEMS equipment at a combustion unit where the operator uses the Tier 4 Calculation Methodology (40 CFR §98.33(a)(4)) to monitor and report emissions under this article, the operator may request approval from the Executive Officer to temporarily use the Tier 2 Calculation Methodology (40 CFR §98.33(a)(2)) for pipeline quality natural gas, biomass, or municipal solid waste, or the Tier 3 Calculation Methodology (40 CFR §98.33(a)(3)) for other fuels, to calculate emissions during the equipment breakdown period. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown will result in a loss of more than 10 percent of the concentration, flow rate, or other information used to calculate and report annual emissions for the data year, and that back-up monitoring is unavailable;

(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) The operator must collect fuel samples and comply with all applicable requirements of the Tier 2 or Tier 3 Calculation Methodology in 40 CFR §98.33(a)(2) or (3), as modified by section 95115 of this article, during the equipment breakdown period. Fuel characteristics data provided by the fuel suppliers can be used if available. The operator must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all the following information:

(A) The proposed start date and end date of the interim procedure, including a demonstration that the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning equipment;

(B) A detailed description of what data are affected by the breakdown; and,

(C) An interim monitoring plan that meets the requirements of the Tiers 2 and 3 Calculation Methodologies as applicable by fuel type in section 95115.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (i)(1) are met.

(4) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

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.

The reporting entity who is subject to verification must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this article, as specified in section 95103(f).

(a) Annual Verification.

(1) Reporting entities required to obtain annual verification services as specified in section 95103(f) are subject to full verification requirements in the first year that verification is required in each compliance period. Upon receiving a positive verification statement, or statements, if applicable, under full verification requirements, the reporting entity may choose to obtain less intensive verification services for the remaining years of the compliance period. Reporting entities subject to this section are also required to obtain full verification services if any of the following apply:

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

(B) There has been a change in the verification body;

(C) An adverse verification statement or qualified positive verification statement was issued for the previous year for either emissions data or product data, or both;

(D) A change of operational control of the reporting entity occurred in the previous year.

(E) Nothing in this paragraph shall be construed as preventing a verification body from performing a full verification in instances where there are changes in sources or emissions. The verification body must provide information on the causes of the emission changes and justification in the verification report if a full verification was not conducted in instances where the total reported GHG emissions differ by greater than 25 percent relative to the preceding year's emissions data report.

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifier(s) for a period of more than six consecutive years, which includes any verifications conducted under this article and for the California Climate Action Registry; The Climate Registry; Climate Action Reserve; or other third-party verifications, validations, or audits conducted under impartiality provisions substantively equivalent to section 95133, which may include third-party certification of environmental management systems to the ISO 14001 standard or third-party certification of energy management systems to the ISO 50001 standard. This limitation applies only to those third-party verifications, validations, or audits that include

the scope of activities or operations under the ARB identification number for the emissions data report.

The six year period begins on the date the reporting entity first contracts for any third-party verifications, validations, or audits under any protocols, including ARB verification services, for the scope of activities or operations under the ARB identification number for the emissions data report, and ends on the date the final verification statement is submitted. Even if these services are provided before the verification body or verifiers have received ARB accreditation, the six year period still begins when these services are contracted for, if accreditation is later received.

The six year limit also applies to verification bodies and verifiers providing ARB or any other third-party verifications, validations, or audits that include the scope of activities or operations under the ARB identification number for the emissions data report and does not reset upon a change in reporting entity ownership or operational control.

(3) If a reporting entity is required or elects to contract with another verification body or verifier(s), the reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifier(s) for at least three years.

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

§ 95131. Requirements for Verification Services.

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services.* After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the reporting entity ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten working days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification.

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited as a sector specific verifier when required below:

(A) For providing verification services to an electric power entity, a supplier of petroleum products or biofuels, a supplier of natural gas, natural gas liquids, or liquefied petroleum gas, or a supplier of carbon dioxide, at least one verification team member must be accredited by ARB as a transactions specialist;

(B) For providing verification services to the operator of a petroleum refinery, hydrogen production unit or facility, or petroleum and natural gas system listed in section 95101(e), at least one verification team member must be accredited by ARB as an oil and gas systems specialist;

(C) For providing verification services to the operator of a facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, nitric acid production, or lead production, at least one verification team member must be accredited by ARB as a process emissions specialist.

(3) General information on the reporting entity, including:

(A) The name of the reporting entity and the facilities and other locations that will be subject to verification services, reporting entity contact, address, telephone number, and e-mail address;

(B) The industry sector and the North American Industry Classification System (NAICS) code for the reporting facility;

(C) The date(s) of the on-site visit, if required in section 95130(a)(1), with facility address and contact information;

(D) A brief description of expected verification services to be performed, including expected completion date.

(4) If any of the information under section 95131(a)(1) or 95131(a)(3) changes after the notice is submitted to ARB, the verification body must notify ARB by submitting an updated conflict of interest self-evaluation form as soon as the change is made but at least five working days before the verification services start date. If any information submitted under section 95131(a)(1) or 95131(a)(3) changes during the verification services, the verification body must notify ARB . In either instance, the conflict of interest must be reevaluated pursuant to section 95133(f) and ARB must approve any changes in writing.

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

(1) *Verification Plan*. The verification team shall develop a verification plan based on the following:

(A) Information from the reporting entity. Such information shall include:

1. Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, product data, and electricity or fuel transactions as applicable;

2. Information regarding the training or qualifications of personnel involved in developing the emissions data report;

3. Description of the specific methodologies used to quantify and report greenhouse gas emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

4. Information about the data management system used to track greenhouse gas emissions, product data, electricity and fuel transactions, and associated data as needed to develop the verification plan;

5. Previous verification reports.

(B) Timing of verification services. Such information shall include:

1. Dates of proposed meetings and interviews with reporting facility personnel;

2. Dates of proposed site visits;

3. Types of proposed document and data reviews;

4. Expected date for completing verification services.

(2) *Planning Meetings with the Reporting Entity.* The verification team shall discuss with the reporting entity the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(3) *Site Visits.* At least one accredited verifier in the verification team, including the sector specific verifier, if applicable, shall at a minimum make one site visit, during each year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the reporting entity is a retail provider, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

(A) The verification team member(s) shall check that all sources specified in sections 95110 to 95123, and 95150 to 95157, as applicable to the reporting entity are identified appropriately.

(B) The verification team member(s) shall review and understand the data management systems used by the reporting entity to track, quantify, and report greenhouse gas emissions and, when applicable, product data, and electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

(C) The verification team shall carry out tasks that, in the professional judgment of the team, are needed in the verification process, including the following:

1. Interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;

2. Making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;

3. Assessing conformance with measurement accuracy, data capture, and missing data substitution requirements;

4. Reviewing financial transactions to confirm fuel, feedstock, product data and electricity purchases and sales, and confirming the complete and accurate reporting of required data such as facility fuel suppliers, fuel quantities delivered, and if fuel was received directly from an interstate pipeline.

(4) *Review of Reporting Entity's Operations, Product Data and Emissions.* The verification team shall review facility operations to identify applicable greenhouse gas emissions sources and product data. This shall include a review of the emissions inventory and each type of emission source to ensure that all sources listed in sections 95110 to 95123 and sections 95150 to 95157 of this article are properly included in the emissions data report. This shall also include a review of the product data to ensure that all product data listed in sections 95110 to 95123 and sections 95150 to 95157 of this article are included in the emissions data report as required by this article. The verification team shall also ensure that the reported current NAICS code(s) accurately represents the activities noted in Table 8-1 of the Cap-and-Trade Regulation, as applicable.

(5) *Other Reporting Entity Information.* Reporting entities shall make available to the verification team all information and documentation used to calculate and report emissions, product data, fuels and electricity transactions, and other information required under this article, as applicable.

(6) *Electricity Importers and Exporters.* The verification team shall review the GHG Inventory Program documentation required pursuant to section 95105(d), electricity transaction records, including deliveries and receipts of

power via North American Electric Reliability Corporation (NERC) e-Tags, written power contracts, settlements data, and any other applicable information required to confirm reported electricity procurements and deliveries.

(7) *Sampling Plan.* As part of confirming emissions data, product data, electricity transactions, or fuel transactions, the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for a reporting entity. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of data management systems, and the coordination within the reporting entity's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. The verification team shall also include in the sampling plan a ranking of the product data by units specified in the appropriate section of this article and a ranking of the product data with the largest uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the reporting entity.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95123, 95129, and 95150 to 95157:

1. Data acquisition equipment;
2. Data sampling and frequency;
3. Data processing and tracking;
4. Emissions calculations;
5. Product data;
6. Data reporting;
7. Management policies or practices in developing emissions data reports.

(D) After completing the analyses required by sections 95131(b)(7)(A)-(C), the verification team shall include in the sampling plan a list which includes the following:

1. Emissions sources, product data, and/or transactions that will be targeted for document reviews, and data checks as specified in 95131(b)(8), and an explanation of why they were chosen;
2. Methods used to conduct data checks for each source, product data, or transaction;
3. A summary of the information analyzed in the data checks and document reviews conducted for each emissions source, product data, or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services. The final sampling plan must describe in detail how the identified risks were addressed during the verification.

(E) The verification team shall revise the sampling plan to describe tasks completed by the verification team as information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this article.

(F) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each verification statement. The sampling plan shall be made available to ARB upon request.

(G) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(8) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions, product data and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources, fuel and electricity transactions covered under sections 95110 to 95123, 95129, and 95150 to 95158;

(B) The verification team shall use data checks to ensure the accuracy of product data reported under sections 95110 to 95123, and 95150 to 95158 of this article;

(C) The verification team shall choose data checks for emissions sources, product data, and fuel and electricity transactions data, as applicable, based on their relative contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(D) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reported covered emissions and covered product data are free of material misstatement. At a minimum, data checks must include the following:

1. Tracing data in the emissions data report to its origin;
2. Looking at the process for data compilation and collection;
3. Recalculating emission estimates to check original calculations;
4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and
5. Reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 95103(k).

(E) As applicable, the verification team shall review the following information when conducting data checks for product data:

1. Product inventory and stock records;
2. Product sales records and contracts;
3. Onsite and offsite product delivery records;
4. Purchase and delivery records for inputs to product(s);
5. Product measurement records; and
6. Other information or documentation that provides financial or direct measurement information about total product(s) reported.

(F) The verification team is responsible for ensuring via data checks that there is reasonable assurance that the emissions data report conforms to the requirements of this article. In addition, and as applicable, the verifier's review of conformance must confirm the following information is correctly reported:

1. For facilities that combust natural gas, natural gas supplier customer account number, service account identification number, or other primary account identifier(s) reported pursuant to section 95115(k);
2. For suppliers of natural gas, end-user names, account identification numbers, and natural gas deliveries in MMBtu, reported pursuant to section 95122(d)(4);
3. Energy generation and disposition information reported pursuant to section 95112, if any of the following apply:
   a. The facility belongs to an industry sector listed in Table 8-1 of section 95870 of the cap-and-trade regulation;
   b. The facility is applying for legacy contract transition assistance under the cap-and-trade regulation; or

c. The facility is applying for the limited exemption of emissions from the production of qualified thermal output pursuant to the cap-and-trade regulation.

(G) The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must also include a narrative to indicate which sources, product data, and transactions were checked, the types and quantity of data that were evaluated for each source, product data, and transaction, the percentage of reported emissions covered by the data checks, the percentage of product data covered by the data checks, and any separate discrepancies that were identified in emission data or product data.

(9) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement(s), the reporting entity must fix all correctable errors that affect covered emissions, non-covered 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 covered emissions, non-covered emissions, or covered product data represents a non-conformance with this article but does not, absent other errors, result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

The verification team shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation or rounding or averaging.

If the verification team determines that the reported NAICS code(s) reviewed pursuant to section 95131(b)(4) is inaccurate, and the reporting entity does not submit a revised emissions data report to correct the current NAICS code(s), the result will be an adverse verification statement.

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

(10) *Findings.* To verify that the emissions data report is free of material misstatements, the verification team shall make its own determination of emissions for checked sources and product data for checked data and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement in GHG emissions reported for the reporting entity, on a CO_2 equivalent basis and/or a material misstatement in product data for the reporting entity, using the units required by the applicable parts of this article. To assess conformance with this article the verification team shall review the methods and factors used to develop the

emissions data report for adherence to the requirements of this article and ensure that other requirements of this article are met.

(11) *Log of Issues.* The verification team must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance. The issues log must identify the regulatory section related to the nonconformance, if applicable, and indicate if the issues were corrected by the reporting entity prior to completing the verification. Any other concerns that the verification team has with the preparation of the emissions data report, including with any *de minimis* method calculations, must be documented in the issues log. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both.

(12) *Material Misstatement Assessment.* Assessments of material misstatement are conducted independently on total reported covered emissions and total reported covered product data (units from the applicable sections of this article).

(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

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

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.

"Misreporting" means duplicate, incomplete or other covered emissions the verifier concludes should, or should not, be part of the emissions data report or duplicate or other product data the verifier concludes should not be part of the emissions data report.

"Total reported covered emissions or covered product data" means the total annual reporting entity covered emissions or total reported covered product data for which the verifier is conducting a material misstatement assessment.

(B) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(C) The omissions variable described in section 95131(b)(12)(A) does not apply to excluded covered product data as described in section 95103(l), such that excluded covered product data is not considered in the material misstatement assessment.

(13) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

(A) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.

(B) If 20 percent or less of any single data elements used to calculate emissions are missing, and emissions are correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158 these emissions will be considered accurate and as meeting the reporting requirements for that source.

(C) If greater than 20 percent of any single data element used to calculate emissions are missing or any combination of data elements are missing that would result in more than 5% of a facility's emissions being calculated using missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158, the verifier must include a finding of non-conformance with the required emissions calculation methodology as part of the verification statement.

(D) The verifier must note the date, time and source of any missing data substitutions discovered during the course of verification in the verification report.

(14) *Review of Product Data.* The verifier's review of product data must include the following, where applicable.

(A) Verifiers must confirm that data substitutions were not used for covered product data.

(B) For product data reported by operators of petroleum refineries subject to section 95113:

1. Verifiers must evaluate conformance and material misstatement for 2013 primary refinery products data reported in 2014. For the 2014 data year, the total on-site production quantity of primary refinery

product for a refinery that has not reported a Solomon EII value pursuant to 95113(l)(4) ("non-EII refinery") is covered product data and verifiers must evaluate conformance and material misstatement. For non-EII refineries in the 2014 data year, the quantity of each primary refinery product and blending component produced elsewhere and brought on-site and that is used for a purpose other than blending into a primary refinery product is not covered product data and is not subject to material misstatement. For the 2014 data year and subsequent years, the total on-site production quantity of primary refinery product for a refinery that has reported a Solomon EII value pursuant to 95113(l)(4) ("EII refinery"), and the quantities of primary refinery product and blending component produced elsewhere and brought on-site by an EII refinery, are not covered product data and verifiers only evaluate for conformance. For the 2015 data year and subsequent years, primary refinery product data are not covered product data for any refinery and verifiers only evaluate for conformance.

2. Verifiers must evaluate conformance for Solomon Energy Intensity Index (EII), if applicable, for all data years.
3. Verifiers must separately evaluate conformance and separately assess material misstatement for the total facility complexity weighted barrel beginning with 2013 data reported in 2014
4. Verifiers must submit two product data verification statements for 2013 and 2014 data reports:
    a. A verification statement that includes the evaluation of primary refinery products and the Solomon EII, as applicable, as well as non-covered product data;
    b. A verification statement for the evaluation of complexity weighted barrel.
5. Beginning with 2015 data reported in 2016, only the verification statement for the complexity weighted barrel is submitted. Evaluation of other product data conformance is included in the verification statement for complexity weighted barrel.

(c) Completion of verification services must include:

(1) *Verification Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete an emissions data verification statement and product data verification statement(s), and provide those statements to the reporting entity and 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.

(2) *Independent Review.* The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(A) Errors in planning,

(B) Errors in data sampling, and

(C) Errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents applicable to the verification services provided, and identify any failure to comply with requirements of this article or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement(s) can be issued.

(3) *Completion of Findings and Verification Report.* The verification body is required to provide each reporting entity with the following:

(A) A detailed verification report, which shall at a minimum include:

1. A detailed description of the facility or entity including all emissions and product data sources and boundaries;
2. A detailed description of data acquisition, tracking and emission calculation/product data systems;
3. The verification plan;
4. The detailed comparison of the data checks conducted during verification services for emissions and product data sources;
5. The log of issues identified in the course of verification activities and their resolution;
6. Any qualifying comments on findings during verification services; and
7. The calculation performed in section 95131(b)(12)(A) for emissions and product data.

The verification report shall be submitted to the reporting entity at the same time as or before the final emissions data verification statement and product data verification statement(s) are submitted to ARB. The detailed verification report shall be made available to ARB upon request.

(B) The verification team shall have a final discussion with the reporting entity explaining its findings, and notify the reporting entity of any unresolved issues noted in the issues log before the verification statement(s) are finalized.

(C) The verification body shall provide the verification statement(s) to the reporting entity and the ARB, attesting whether the verification body has found the submitted emissions data report to be free of material misstatements, and whether the emissions data report is in conformance with the requirements of this article. For every qualified positive verification statement, the verification body shall explain the non-conformances contained within the emissions data report and shall cite the section(s) in this article that corresponds to the non-conformance and why the non-conformances do not result in a material misstatement. For every adverse verification statement, the verification body must explain all non-conformances and material misstatements leading to the adverse verification statement and shall cite the section(s) in this article that corresponds to the non-conformance(s) and material misstatements.

(D) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier who has conducted the independent review of verification services and findings shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

1. The lead verifier must attest in the verification statement, in writing, to ARB as follows:

   "I certify under penalty of perjury under the laws of the State of California that the verification team has carried out all verification services as required by this article."

2. The lead verifier independent reviewer who has conducted the independent review of verification services and findings must attest in the verification statement, in writing, to ARB as follows:

   "I certify under penalty of perjury under the laws of the State of California that I have conducted an independent review of the verification services and findings on behalf of the verification body as required by this article and that the findings are true, accurate, and complete."

(4) *Adverse Verification Statement and Petition Process.* Prior to the verification body providing an adverse verification statement for emissions or product data, or both, to 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 verification deadline, even if the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

(A) If the reporting entity and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement or qualified positive verification statement for the emissions or product data because of a disagreement on the requirements of this article, the reporting entity may petition the ARB Executive Officer before the verification deadline and before the verification statement is submitted to make a final decision as to the verifiability of the submitted emissions data report. The reporting entity may petition either emissions or product data, or both. At the same time that the reporting entity petitions the Executive Officer, the reporting entity must submit all information it believes is necessary for the ARB Executive Officer to make a final decision.

(B) The Executive Officer shall make a final decision no later than October 10 following the submission of a petition pursuant to section 95131(c)(4)(A). If at any point ARB requests information from the verification body or the reporting entity, the information must be submitted to ARB within five working days. ARB will notify both the reporting entity and the verification body of its determination, which may also include an assigned emissions level calculated pursuant to section 95131(c)(5), if applicable.

(5) *Assigned Emissions Level.* When a reporting entity fails to receive a verification statement for a data year by the applicable deadline or receives an adverse emissions data verification statement, the Executive Officer shall develop an assigned emissions level for the data year for the reporting entity. Within five working days of a written request by the Executive Officer, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within five working days of a request by the Executive Officer, the reporting entity shall provide the data that is required to calculate GHG emissions for the entity according to the requirements of this article, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the Executive Officer, including the operating days and hours of the reporting entity during the data year. The reporting entity shall also make available personnel who can assist the Executive Officer's determination of an assigned emissions level for the data year.

(A) In preparing the assigned emissions level for the reporting entity, the Executive Officer shall consider at a minimum the following information:

1. The number, types and days and hours of operation of the sources operated by the reporting entity for the emissions data year;

2. Any previous emissions data reports submitted by the reporting entity and verification statements rendered for those reports;

3. The potential maximum fuel and process material input and output capacities for the reporting entity's emissions sources during operating hours;

4. For electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the applicable data year and for previous years;

5. Emissions, electricity transactions, fuel use, or product output information reported to ARB or other State, federal, or local agencies.

(B) In preparing the assigned emissions level for the reporting entity, the Executive Officer may use the following methods, as applicable:

1. The sector specific calculation methodologies in this article;

2. In the event of missing data, the Executive Officer will rely on the missing data provisions of this article; and

3. Any information reported under this article for this data year and past years.

(C) The Executive Officer shall assign the emissions level for the reporting entity using the best information available, including the information in section 95131(c)(5)(A) and methods in section 95131(c)(5)(B), as applicable. The Executive Officer shall include an assigned emissions level in the decision made pursuant to section 95131(c)(4)(B), if applicable.

(d) Upon provision of the verification statement, or statements, if applicable, to ARB, the emissions data report shall be considered final. No changes shall be made to the report as submitted to ARB, notwithstanding the requirements of 40 CFR §98.3(h), and all verification requirements of this article shall be considered complete except in the circumstance specified in section 95131(e).

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days. This paragraph applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by ARB to 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.

(f) Upon request by the Executive Officer, the reporting entity shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 20 working days.

(g) Upon request of the Executive Officer, the verification body shall provide ARB the full verification report given to the reporting entity, as well as the sampling plan, contracts for verification services, and any other supporting documents and calculations, within 20 working days.

(h) Upon written notification by the Executive Officer, the verification body shall make itself and its personnel available for an ARB audit.

(i) *Verifying Biomass-derived Fuels.* In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of subarticle 4 of this article as modified below when verifying biomass-derived fuel:

(1) *General biomass-derived fuel verification requirements.* The following requirements apply to the biomass-derived fuel verification:

(A) *Annual Verification.* Biomass-derived fuel is subject to annual verification as specified in section 95103(f).

(B) *Verification Services for Biomass-derived Fuels.* When a reporting entity reports that biomass-derived fuels are used, the biomass-derived fuels must be considered when providing all verification services required under section 95131(b) of this article. The verification team must:

1. Review the reporting entity's reported biomass-derived fuel emissions to ensure the biomass-derived fuels are properly listed in the emissions data report as required in section 95103(j) of this article and sections 95852.1.1 and 95852.2 of the cap-and-trade regulation.

2. Conduct separate data checks that are consistent with the requirements in 95131(i)(2)(D) for the fuel type being verified using the following documentation, as appropriate: the invoice, nomination, scheduling, storage, in-kind fuel purchase, allocation, transportation and balancing reports or other documents used as evidence of the fuel delivery.

a. The reporting entity may arrange for the documentation to be supplied directly to the verifier if there are confidentiality issues that would prevent these documents from being made available to the reporting entity.

(C) Completion of Verification Services for Biomass-derived Fuels.

1. All information used for the verification of biomass-derived fuels must be included in the independent review as required in section 95131(c)(2) of this article.

2. Conformance for biomass-derived fuels is evaluated against the requirements of this article and sections 95852.1.1 and 95852.2 of the cap-and-trade regulation.

3. Reported carbon dioxide emissions from biomass-derived fuels are considered an omission in the evaluation for material misstatement when:

a. The fuel does not conform with sections 95852.1.1 and 95852.2 of the cap-and-trade regulation and

b. The emissions are listed as exempt biomass-derived CO_2.

(2) Specific biomass-derived fuel verification requirements.

(A) For urban, agricultural and forest derived wood and wood waste, the verifier must determine the reporting entity met the requirements of section 95103(j).

(B) For biodiesel and fuel ethanol, the verifier must determine the reporting entity met the requirements of section 95103(j) and the following requirements:

1. At combustion sources that purchase biomass-derived fuels, verify records to demonstrate that volume purchased equals or exceeds volume reported.

2. At combustion sources that produce their own fuel, verify:

a. that raw material is sufficient to produce the quantity of fuel reported;
b. that the facility has the ability to produce the biomass-derived fuel reported;
c. that the emissions from the fuel are accurately reported and do not lead to the underreporting of fossil fuel emissions.

(C) For municipal solid waste and tires, the verifier must determine the reporting entity met the requirements of section 95103(j).

(D) For biomethane and biogas, the verifier must:

1. Examine all nomination, invoice, scheduling, allocation, transportation, storage, in-kind fuel purchase and balancing reports from the producer to the reporting entity and have reasonable assurance that the reporting entity is receiving the identified fuel;

2. Determine a contract is in place for the purchase of biogas or biomethane that meets all requirements of sections 95852.1.1 and 95852.2 of the cap-and-trade regulation and that no fossil-derived fuel is used to supplement the biomass-derived fuel deliveries except for documented fuel purchases to avoid loss of metered volumes in connection with the transportation of the biomethane to the reporting entity;

3. Ensure any discrepancies in the fuel volumes, heat values and/or energies will be carried over into the evaluation of material misstatement for the reporting entity;

(3) *Assessment.* If the reporting entity is unable to demonstrate that the biomass-derived fuel is consistent with the requirements in sections 95852.1.1 and 95852.2 of the cap-and-trade regulation, the emission data report must be revised to list these biomass CO_2 emissions as non-exempt biomass-derived CO_2.

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

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article and under the cap-and-trade regulation.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall employ and retain at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2).

2. A verification body shall employ and retain at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings, enforcement actions, or administrative actions filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services. Neither general nor umbrella liability policies can be used for the professional liability insurance minimum for the purposes of this provision.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;

2. A detailed organizational chart that includes the verification body, its management structure, and any related entities;

3. The verification body's internal conflict of interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in ARB verifier training on an ongoing basis.

(F) The verification body shall notify ARB within 30 days of when it no longer meets the requirements for accreditation as a verification body in section 95132(b)(1). The verification body may request that the Executive Officer provide additional time to hire additional staff to meet the requirements of this section.

(G) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) *Lead Verifier Accreditation Application*. To apply for accreditation as a lead verifier, the applicant shall submit documentation to the Executive Officer that provides the evidence specified in section 95132(b)(2)(A), and section 95132(b)(2)(B), or (C):

(A) Evidence that the applicant meets the criteria in 95132(b)(3); and,

(B) Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment by ARB for services performed; or,

(C) Evidence that at the time of the verification training examination, the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories; or,

2. As a lead environmental data or financial auditor in the private sector.

(3) *Verifier Accreditation Application.* To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) Evidence demonstrating the minimum education background required to act as a verifier for ARB. Minimum education background means that the applicant has either:

1. A bachelors level college degree or equivalent in science,

technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or

2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of full-time work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant must take an ARB approved general verification training and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course. Training under the previous version of the regulation does not qualify an applicant to retake an exam under this version without first taking the training for this revised regulation.

(5) Sector Specific and Offset Project Specific Verifiers.

(A) *Sector Specific Verifier*. The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take ARB sector specific verification training and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved sector specific verification training.

(B) *Offset Project Specific Verifier*. The applicant seeking to be accredited as an offset project specific verifier as specified in the cap-and-trade regulation must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, meet one of the following requirements:

1. Have at least two years of professional experience related to developing emission inventories, conducting technical analyses, or environmental audits of the offset project type, and take general ARB offset verification training and ARB offset project specific verification training for an offset project type, and receive a passing score of greater than an unweighted 70% on an exit examination. If the

applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the applicable ARB-approved offset verification training; or,

2. Be a verifier in good standing for the Climate Action Reserve prior to October 28, 2011, taken Climate Action Reserve project specific verifier training, have performed at least two project verifications for a project type by October 28, 2011, and have taken general ARB offset verification training, and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general ARB offset verification training and offset project specific verification training.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier, or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) *ARB Accreditation*.

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, verifier, sector specific verifier, or offset project specific verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verification body, verifier, lead verifier, sector specific verifier, or offset project specific verifier is complete, meets all applicable regulatory requirements, and passes a performance review as defined in section 95102(a), the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to issue an Executive Order to grant or withhold accreditation for the verification body, lead verifier, sector specific verifier, offset project specific verifier or verifier.

(4) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, sector specific verifier, offset project specific verifier, or verification body if the applicant has not been subject to ARB enforcement action under this article. All ARB approved general, sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive

Officer. In addition, the performance review requirement set forth in section 95132(c)(2) must be met for accreditation to be renewed by the Executive Officer.

(5) All verification body requirements in section 95132(b)(1) must be met for the Executive Officer to renew the verification body accreditation.

(6) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in subsections 95132(c)(1) or 95132(c)(3), and the applicant may submit additional supporting documentation before a decision has been made by the Executive Officer.

(7) Within 15 working days of being notified of any corrective action in another voluntary or mandatory GHG program, an ARB accredited verification body, lead verifier, sector specific verifier, offset project specific verifier, or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

(8) Verifiers shall take ARB approved training to continue to provide verification services after January 1, 2012. The verifier must receive a passing score of greater than an unweighted 70% on the exit examination.

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier, and Voluntary Withdrawal from the Accreditation Program.* 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.

(1) During suspension or revocation proceedings, the verification body, lead verifier, or verifier may not continue to provide verification services.

(2) Within five working days of suspension or revocation of accreditation, a verification body must notify all reporting entities, offset project operators, or authorized project designees for whom it is providing verification services, or has provided verification services within the past 6 months of its suspension or revocation of accreditation.

(3) A reporting entity, offset project operator, or authorized project designee who has been notified by a verification body of a suspended or revoked accreditation must contract with a new verification body for verification services.

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

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.

(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers.

(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.

(4) A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for a reporting entity.

(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the reporting entity for which it will provide verification services.

(6) A verification body may not use a subcontractor as the independent reviewer.

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

§ 95133. Conflict of Interest Requirements for Verification Bodies.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services for reporting entities. Any individual person or company that is hired by a reporting entity to contract with a verification body on behalf of the reporting entity is subject to the conflict of interest assessment in this article. In such instances, the verification body must assess the potential conflict of interest between itself and the contracting entity as well as between itself and the reporting entity, and must also address the potential conflict of interest between the contracting entity and the reporting entity, including a written assessment provided and signed by the contracting entity.

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

(1) The verification body and reporting entity share any management staff or board of directors membership, or any of the senior management staff of the reporting entity have been employed by the verification body, or vice versa, within the previous five years; or

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

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services;

(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information;

(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the cap-and-trade regulation;

(E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity;

(F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;

(G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting entity;

(H) Appraisal services of carbon or greenhouse gas liabilities or assets;

(I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(J) Directly managing any health, environment or safety functions for the reporting entity;

(K) Bookkeeping or other services related to accounting records or financial statements;

(L) Any service related to development of information systems, including consulting on the development of environmental management systems, such as those conforming to ISO 14001 or energy management systems such as those conforming to ISO 50001, unless those systems will not be part of the verification process;

(M) Appraisal and valuation services, both tangible and intangible;

(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;

(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;

(Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the reporting entity;

(R) Any legal services;

(S) Expert services to the reporting entity, a trade or membership group to which the reporting entity belongs, or a legal representative for the purpose of advocating the reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation.

(T) Verification services that are not conducted in accordance with, or equivalent to, section 95133 requirements, unless the systems and data reviewed during those services, as well as the result of those services, will not be part of the verification process.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to a reporting entity to secure a verification services contract.

(4) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the reporting entity except within the time periods in which the reporting entity is allowed to use the same verification body as specified in section 95130(a).

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

(1) No potential for a high conflict of interest is found pursuant to section 95133(b); and

(2) Any services provided by any member of the verification body or verification team to the reporting entity, within the last five years, are valued at less than 20 percent of the fee for the proposed verification services. Any verification conducted in accordance with, or equivalent to, section 95133 provided by the verification body or verification team outside the jurisdiction of 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 or energy management system under 50001 standards.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95133(b) and 95133(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the reporting entity, and when a conflict of interest self-evaluation is submitted pursuant to section 95133(h).

(1) If a verification body identifies a medium potential for conflict of interest and intends to provide verification services for the reporting entity, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) As provided in section 95133(f)(4), the Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(e) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(1) Before the start of any work related to providing verification services to a reporting entity, a verification body must first be authorized in writing by the Executive Officer to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the verification body, related entities, or any subcontractors performing verification services may have with the reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

(B) Identification of whether the verification body, related entities, or any member of the verification team has previously provided verification services for the reporting entity or related entities and, if so, provide a description of such services and the years in which such services were provided;

(C) Identification of whether any member of the verification team, verification body, or related entity has engaged in services of any nature, other than ARB verification services, with the reporting entity or related entities either within or outside California during the previous five years. If services other than ARB verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the reporting entity or related entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the reporting entity's greenhouse gas emissions pursuant to this article;

2. The nature of past, present or future relationships of any member of the verification team, verification body, or related entities with the reporting entity or related entities including:

   a. Instances when any member of the verification team, verification body, or related entities has performed or intends to perform work for the reporting entity or related entities;
   b. Identification of whether work is currently being performed for the reporting entity or related entities, and if so, the nature of the work;
   c. How much work was performed for the reporting entity or related entities in the last five years, in dollars;
   d. Whether any member of the verification team, verification body, or related entities has contracts or other arrangements to perform work for the reporting entity or a related entity;
   e. How much work related to greenhouse gases the verification team has performed for the reporting entity or related entities in the last five years, in dollars.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(D) A list of names of the staff that would perform verification services for the reporting entity, and a description of any instances of personal or family relationships with management or employees of the reporting entity that potentially represent a conflict of interest; and,

(E) Identification of any other circumstances known to the verification body, or reporting entity that could result in a conflict of interest.

(F) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) *Conflict of Interest Determinations.* The Executive Officer must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within 30 working days of deeming the information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and must so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to section 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the reporting entity and related entities, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, the Executive Officer will authorize the verification body to provide verification services.

(g) Monitoring Conflict of Interest Situations.

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(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 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.

(3) The verification body shall notify the Executive Office, within 30 days, of any emerging conflicts of interest during the time verification services are being provided.

(A) If the Executive Officer determines that a disclosed emerging potential conflict is medium risk and this risk can be mitigated, the verification body is deemed to have met the conflict of interest requirements to continue to provide verification services to the reporting entity and will not be subject to suspension or revocation of accreditation as specified in section 95132(d).

(B) If the Executive Officer determines that a disclosed emerging potential conflict is medium or high risk and this risk cannot be mitigated, the verification body will not be able to continue to provide verification services to the reporting entity, and may be subject to suspension or revocation of accreditation under section 95132(d).

(4) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(5) The Executive Officer may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the reporting entity shall be provided 90 days to complete re-verification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) as provided in section 95132(d).

(h) Specific Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(1) If an air district has provided or is providing any services listed in section 95133(b)(2) as part of its regulatory duties, those services do not constitute non-verification services or a potential for high conflict of interest for purposes of this subarticle;

(2) Before providing verification services, an air district shall either submit a conflict of interest self-evaluation pursuant to section 95133(e) for each reporting entity for which it intends to provide verification services, or shall submit an annual self-evaluation to ARB no later than April 10 of each calendar year containing the information specified in section 95133(e)(1)(A)-(F) for all reporting entities for which it intends to provide verification services;

(3) As part of its conflict of interest self-evaluation submittal under section 95133(e), the air district shall certify that it will prevent conflicts of interests and resolve potential conflict of interest situations pursuant to its policies and mechanisms submitted under section 95132(b)(1)(G);

(4) If an air district hires a subcontractor who is not an air district employee to provide verification services, the air district shall be subject to all of the requirements of section 95133.

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

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

§95150. Definition of the Source Category.

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well-pad or associated with a well pad (including compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations (both thermal and non-thermal), and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Crude oil and associated gas that is piped to an onshore production facility as an emulsion as defined in section 95102(a) must follow the requirements of section 95156(a)(7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the platform.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or

greater. This industry segment also includes all booster stations owned and/or operated by the facility owner/operator.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment. This industry segment also includes all booster stations owned and/or operated by the facility owner/operator.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process or equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage*. LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for regasification of the liquefied natural gas.

(7) *LNG import and export equipment*. LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system in California. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to California.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within California that is regulated by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

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

§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(b) and the reporting thresholds outlined in section 95101(e).

(b) For applying the threshold defined in section 95101(b), natural gas processing facilities must also include owned or operated residue gas compression equipment.

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

§95152. Greenhouse Gases to Report.

(a) The operator of a facility must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (i) of this section, and stationary and portable combustion emissions as applicable and as specified in paragraph (j) of this section.

(b) For offshore petroleum and natural gas production, the operator must report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emissions, and flare emission source types as identified in the data collection and emissions estimation study (Year 2008 Gulfwide Emission Inventory Study (GOADS) (December 2010)) conducted by the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference. Offshore platforms do not need to report portable emissions. In addition, offshore production facilities must report combustion emissions from supply and transportation vessels (e.g., ships and helicopters) used to transport personnel, equipment and products to and from the production facility using methods found in subpart C of 40 CFR Part 98.

(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, associated with a well-pad or associated with equipment to which an emulsion is transferred:

(1) Metered natural gas pneumatic device and pump venting;

(2) Non-metered natural gas pneumatic device venting;

(3) Acid gas removal vents;

(4) Dehydrator vents;

(5) Well venting for liquids unloading;

(6) Gas well venting during well completions and workovers;

(7) Equipment and pipeline blowdowns;

(8) Dump valves;

(9) Well testing venting and flaring;

(10) Associated gas venting and flaring;

(11) Flare stack or other destruction device emissions;

(12) Centrifugal compressor venting;

(13) Reciprocating compressor venting;

(14) EOR injection pump blowdown;

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

(16) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and

(17) The operator must use the methods in section 95153(y) and report under this subarticle the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in section 95150. Stationary or portable equipment includes equipment which is integral to the extraction, processing, and movement of oil and/or natural gas; such as well pad construction equipment, well drilling and completion equipment, equipment used for abandoned well plugging and site reclamation, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Acid gas removal vents;

(2) Dehydrator vents;

(3) Equipment and pipeline blowdowns;

(4) Flare stack or other destruction device emissions;

(5) Centrifugal compressor venting;

(6) Reciprocating compressor venting; and

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Metered natural gas pneumatic device and pump venting;

(2) Non-metered natural gas pneumatic device venting;

(3) Equipment and pipeline blowdowns;

(4) Transmission storage tanks;

(5) Flare stack or other destruction device emissions;

(6) Centrifugal compressor venting;

(7) Reciprocating compressor venting; and

(8) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, the operator must report CO_2, CH_4, and N_2O from the following sources:

(1) Metered natural gas pneumatic device and pump venting;

(2) Non-metered natural gas pneumatic device venting;

(3) Equipment and pipeline blowdowns;

(4) Flare stack or other destruction device emissions;

(5) Centrifugal compressor rod packing venting;

(6) Reciprocating compressor venting; and

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns;

(2) Flare stack or other destruction device emissions;

(3) Centrifugal compressor rod packing venting;

(4) Reciprocating compressor venting; and

(5) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(h) For LNG import and export equipment, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns;

(2) Flare stack or other destruction device emissions;

(3) Centrifugal compressor rod packing venting;

(4) Reciprocating compressor venting; and

(5) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines at above grade transmission-distribution transfer stations;

(2) Equipment leaks at below grade transmission-distribution transfer stations;

(3) Equipment leaks at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations;

(4) Equipment leaks at below grade metering-regulating stations.

(5) Distribution main equipment leaks;

(6) Distribution services equipment leaks;

(7) Report under section 95150 of this article the emissions of CO_2, CH_4, and N_2O from stationary fuel combustion sources following the methods in 95153(y);

(8) Flare stack emissions;

(9) Equipment and pipeline blowdowns;

(10) CO_2 and CH_4 emissions from customer meters (N_2O emissions excluded); and

(11) CO_2 and CH_4 emissions from pipeline dig-ins (N_2O emissions excluded).

(j) Except for facilities under onshore petroleum and natural gas production and natural gas distribution, the operator of a facility must report emissions of CO_2, CH_4, and N_2O for each stationary fuel combustion unit by following the requirements of section 95115 of this article. Operators of onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(k) Operators of facilities must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article (suppliers of carbon dioxide).

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

§ 95153. Calculating GHG Emissions.

The operator of a facility must calculate and report annual GHG emissions as prescribed in this section. The facility operator who is a local distribution company reporting under section 95122 of this article must comply with section 95153 for reporting emissions from the applicable source types in section 95152(i) of this article.

(a) *Metered Natural Gas Pneumatic Device and Pneumatic Pump Venting*. The operator of a facility who is subject to the requirements of sections 95153(a) and (b) must calculate emissions from a natural gas powered continuous high bleed control device and pneumatic pump venting using the method specified in paragraph (a)(1) below when the natural gas flow to the device is metered. By January 1, 2015, natural gas consumption must be metered for all of the operator's pneumatic continuous high bleed devices and pneumatic pumps. The operator may choose to also meter flow to any or all low bleed and intermittent bleed natural gas powered devices. For unmetered devices the operator must use the method specified in section 95153(b). Vented emissions from natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to be reported under paragraph (a) of this section.

(1) The operator must calculate vented emissions for all metered natural gas powered pneumatic devices and pumps using the following equation:

$$E_m = \sum_1^n B_n \qquad \text{(Eq. 1)}$$

Where:

E_m = Annual natural gas emissions at standard conditions, in cubic feet, for all metered natural gas powered pneumatic devices.

n = Total number of meters.

B_n = Natural gas consumption for meter n.

(2) For both metered and unmetered natural gas powered devices, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(b) *Non-metered Natural Gas Pneumatic Device Venting*. The operator must calculate CH_4 and CO_2 emissions from all un-metered natural gas powered pneumatic intermittent bleed and continuous low and high bleed devices using the following method:

$$E_{nm,i,x} = \sum_1^i \sum_1^x EF_i * T_{i,x} \qquad \text{(Eq. 2)}$$

Where:

$E_{nm,i,x}$ = Annual natural gas emissions at standard conditions for all unmetered natural gas powered devices and pumps (in scf).

i = Total number of unmetered component types.

x = Total number of component type i.

EF_i = Population emission factor for natural gas pneumatic device type i (scf/hour/component) listed in Tables 1A, 3, and 4 of Appendix A for onshore petroleum and natural gas production, onshore natural gas transmissions compression, and underground natural gas facilities, respectively.

$T_{i,x}$ = Total number of hours type i component x was in service. Default is 8760 hours.

(1) GHG (CO_2 and CH_4) volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(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 emitted 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.

(1) *Calculation Methodology 1.* If the operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate meter, they must calculate CO_2 emissions under this subarticle by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in section 95115 (stationary fuel combustion sources). Alternatively, the operator may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all the requirements specified for the Tier 4 Calculation Methodology in section 95115 (stationary fuel combustion sources). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) *Calculation Methodology 2*. If CEMS is not available but a vent meter is installed, the operator must use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation 3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \qquad \text{(Eq. 3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_s = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in section 95154(b). Alternatively, the facility operator may follow the manufacturer's instructions for calibration of the vent meter.

Vol_{CO2} = Annual average volumetric fraction of CO_2 content in the vent gas out of the AGR unit as determined in (c)(5) of this section.

(3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, the operator may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations 4A or 4B of this section. If inlet gas flow rate is known, use Equation 4A. If outlet gas flow rate is known, use Equation 4B.

$$E_{\alpha,CO2} = V_{in} * [(Vol_I - Vol_O)/(1-Vol_O)] \quad \text{(Eq. 4A)}$$

$$E_{\alpha,CO2} = V_{out} * [(Vol_I - Vol_O)/(1-Vol_I)] \quad \text{(Eq. 4B)}$$

Where:

$E_{\alpha, CO2}$= Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in}= Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (c)(4) of this section.

V_{out}= Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (c)(4) of this section.

Vol_I= Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.

Vol_o= Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (c)(7) of this section.

(4) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in section 95154(b). If the operator does not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(5) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in section 95154(b).

(6) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in section 95154(b).

(7) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (c)(7) of this section.

(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.

(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).

(C) Use sales line quality specification for CO_2 in natural gas.

(8) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(9) Mass CO_2 emissions shall be calculated from volumetric CO_2emissions using calculations in paragraph (t) of this section.

(10) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emission estimated in paragraphs (c)(1) through (c)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(d) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2, and N_2O emissions using any of the calculation methodologies described in paragraph (d) of this section.

(1) Calculate annual mass emissions from dehydrator vents using a software program which applies the Peng-Robinson equation of state (Equation 38 of section 95154) to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators.

(A) Feed natural gas flow rate.

(B) Feed natural gas water content.

(C) Outlet natural gas water content.

(D) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(E) Absorbent circulation rate.

(F) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(G) Use of stripping gas.

(H) Use of flash tank separator (and disposition of recovered gas).

(I) Hours operated.

(J) Wet natural gas temperature and pressure.

(K) Wet natural gas composition. Determine this parameter by selecting one of the methods described in subparagraphs (1) – (4) below.

1. Use the wet natural gas composition as defined in section 95153(s)(2).

2. If wet natural gas composition cannot be determined using paragraph 95153(s)(2) of this section, select a representative analysis.

3. The facility operator may use an appropriate standard method published by a consensus-based standards organization or the facility operator may use an industry standard practice as specified in section 95154(b) to sample and analyze wet natural gas composition.

4. If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(4) of this section downward by the magnitude of emissions captured.

(3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraph (d)(1) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(4) In the case of dehydrators that use desiccant, operators must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation 5 of this section.

$$E_{s,n} = n(H * D^2 * \pi * \%G * P_2/(4 * P_1)) \qquad \text{(Eq. 5)}$$

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

n = number of fillings in reporting period.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

π = pi (3.1416)

%G = Percent of packed vessel volume that is gas (expressed as a decimal, e.g.,15% = 0.15).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

(5) For glycol dehydrators, both CH_4 and CO_2 mass emissions must be calculated from volumetric GHG_i emissions using calculations in paragraph (t) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(e) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from *well venting* for liquids unloading using one of the calculation methodologies described in paragraphs (e)(1), (e)(2) or (e)(3) of this section.

(1) *Calculation Methodology 1*. Calculate the total emissions for well venting for liquids unloading without plunger lift assist using Equation 6 of this section.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * CD_p^2 * WD_p * SP_p\right) + \sum_{p=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 1.0\right) * Z_{p,q}\right)\right] \quad \text{(Eq. 6)}$$

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of well venting events for liquids unloading for each basin.

0.37×10^{-3} = {3.14(pi)/4}/{14.7x144}(psia converted to pounds per square feet).

p = wells 1 through W with well venting for liquids unloading in the basin.

CD_p = Casing diameter for each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia).

V_p = Number of unloading events per year per well, p.

SFR_p = Average flow-line rate of gas for well p, at standard conditions in cubic feet per hour. Use Equation 29 to calculate the average flow-rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(A) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 7 of this section.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * TD_p^2 * WD_p * SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 0.5\right) * Z_{p,q}\right)\right] \quad \text{(Eq. 7)}$$

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of well venting liquid unloading events at wells using plunger lift assist technology for each basin.

0.37×10^{-3} = {3.14(pi)/4}/{14.7 x 144} (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia).

V_p = Number of unloading events per year for each well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation 29 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5, then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5, then $Z_{p,q}$ is equal to 1.

(3) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(f) *Gas 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 gas well venting during both conventional completions and completions involving hydraulic fracturing in wells and during 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:

$$E_a = V_M - V_{\mathrm{CO2\ or\ N2}} \qquad \text{(Eq. 8)}$$

Where:

E_a = 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).

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

(A) All gas volumes must be corrected to standard temperature and pressure using methods in section(r).

(B) Calculate CO_2 and CH_4 volumetric and mass emissions using the methodologies in sections (s) and (t).

(2) Calculation Methodology 2.

(A) Record the well flowing pressure upstream (P_1) and downstream (P_2) of a well choke, upstream temperature and elapsed time of venting according to methods set forth in section 95154(b) to calculate the well backflow during well completions and workovers.

(B) The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes.

(C) Sonic flow is defined as the flow regime where $P_2/P_1 \leq 0.542$.

(D) Calculate the average flow rate during sonic conditions using Equation 9 of this section:

$$FR_a = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad \text{(Eq. 9)}$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 x K)$.

1.27 x 10^5 = Conversion from m^3/second to ft^3/hour.

(E) Calculate total gas volume vented during sonic flow conditions as follows:

$$V_S = FR_a * T_S \quad \text{(Eq. 10)}$$

Where:

V_s = Volume of gas vented during sonic flow conditions (scf).

T_S = Length of time that the well vented under sonic conditions (hours).

(F) For each of the sets of data points (T_u, P_1, P_2, and elapsed time under subsonic flow conditions) recorded as the well vented under subsonic flow conditions, calculate the instantaneous gas flow rate as follows:

$$FR_a = 1.27 * 10^5 * A * \sqrt{3430 * T_u * [(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]} \quad \text{(Eq. 11)}$$

Where:

FR_a = Instantaneous flow rate in cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 x K)$.

1.27×10^5 = Conversion from m^3/second to ft^3/hour.

(G) Calculate the total gas volume vented during subsonic flow conditions, V_{SS}, as the total volume under the curve of a plot of FR_a and elapsed time under subsonic flow conditions.

(H) Correct V_{SS} to standard conditions using the methodology found in paragraph (r) of this section.

(I) Sum the vented volumes during subsonic and sonic flow and adjust vented emissions for the volume of CO_2 and N_2 injected and the volume of gas recovered to a sales line as follows:

$$E_S = V_S + V_{SS} - V_{\frac{CO2}{N2}} - V_{SG} \qquad \text{(Eq. 12)}$$

Where:

E_s = Total volume of gas vented during the well completion or workover (scf).

V_s = Volume of gas vented during sonic flow conditions for the well completion or workover (scf) (see Eq. 10).

V_{ss} = Volume of gas vented during subsonic flow conditions for the well completion or workover (scf) (see 95153(f)(2)(G) above).

$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during the well completion or workover (scf).

V_{SG} = Volume of gas recovered to a sales line during the well completion or workover (scf).

(3) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures must be measured using an appropriate meter as described in section 95154(b) or using receipts of gas purchases that are used for the energized fracture job.

(A) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section.

(4) Determine if the backflow gas from the well completion or workover is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (*e.g.,* reduced emissions completion or workover).

(A) Use the factor V_{SG} in Equation 8 of this section to adjust the emissions estimated in paragraphs (f)(1) through (f)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(B) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section.

(5) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric total emissions using calculations in paragraphs (s) and (t) of this section.

(g) *Equipment and pipeline blowdowns*. Calculate CO_2 and CH_4 blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraphs (d)(4) of this section) as follows:

(1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimates based on best available data. Engineering estimates based on best available data may also be used to determine the temperature and pressure variables used in the Equations 13 and 14 if monitoring data is unavailable. Equipment blowdowns with a unique physical volume (including pipelines, compressor case or cylinder manifolds, suction bottles, discharge bottles and vessels) of less than 50 cubic feet (cf) between isolation valves are not subject to the requirements of 95153(g).

(2) Calculate the total annual venting emissions for unique volumes using either Equation 13 or 14 of this section.

$$E_{s,n} = N * \left(V\left(\frac{(459.67+T_s)P_a}{(459.67+T_a)P_s}\right) - V * C\right) \quad \text{(Eq. 13)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60˚F).

T_a = Temperature at actual conditions in the unique physical volume (˚F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

$$E_{s,n} = \sum_1^{PV} \sum_1^{N} [V((459.67 + T_S)(P_{(a,b,p)} - P_{(a,e,p)})/(459.67 + T_{a,p})\ P_S)] \quad \text{(Eq. 14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

PV = Number of unique physical volumes blowndown.

N = Number of occurrences of blowdowns for each unique physical volume.

V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown “p”.

T_s = Temperature at standard conditions (60˚F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (˚F).

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown “p”.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown “p”; 0 if blowdown volume is purged using non-GHG gases.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions using calculations in paragraph (s) and (t) of this section.

(4) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined by Equation 13 or 14 and paragraph (g)(3) of this section.

(h) Dump Valves. 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).

(i) *Transmission storage tanks*. For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression and onshore petroleum and natural gas production, the operator of a facility must calculate CH_4, CO_2 and N_2O annual emissions from condensate scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in section 95154(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in section 95154(b) through (d) for a duration of five minutes, or a calibrated bag according to methods in section 95154(b). Or the facility operator may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods in paragraph 95154(a)(5).

(2) If the tank vapors from the vent stack are continuous for five minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (i)(2) of this section to quantify annual emissions:

(A) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in section 95154(b) through (d). If a continuous flow measurement device is not installed, the facility operator may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (i)(1) of this section to detect continuous leakage, this serves as the measurement.

(B) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in section 95154(a)(5).

(C) Use the appropriate gas composition in paragraph (s)(2)(C) of this section.

(D) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (r), (s), and (t) of this section, as applicable to the monitoring equipment used.

(3) If a leaking dump valve is identified, the leak must be counted as having occurred since the beginning of the calendar year, or from the previous test that did not detect leaking in the same calendar year. If the leaking dump valve is fixed following leak detection, the leak duration will end upon being repaired. If the leaking dump valve is identified and not repaired, the leak must be counted as having occurred through the rest of the calendar year.

(4) Calculate annual emissions from storage tanks to flares as follows:

(A) Use the storage tank emissions volume and gas composition as determined in paragraphs (i)(1) through (i)(3) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine storage tank emissions sent to a flare.

(j) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) gas and oil well testing venting and flaring emissions as follows:

(1) Determine the gas-to-oil ratio (GOR) of the hydrocarbon production from all oil well(s) tested. Determine the production rate from all gas well(s) tested.

(2) If GOR cannot be determined from available data, then the facility operator must measure quantities reported in this section according to one of the two procedures in paragraph (j)(2) of this section to determine GOR.

(A) The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists; or

(B) The facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 15 (for oil wells) or Equation 16 (for gas wells) of this section.

$$E_{S,n} = GOR * FR * D \quad \text{(Eq. 15)}$$
$$E_{a,n} = PR * D \quad \text{(Eq. 16)}$$

Where:

$E_{S,n}$ = Annual volume of gas emissions from well(s) testing in cubic feet under actual conditions.

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas-to-oil ratio, for well p in basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Annual average flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the year the well(s) is tested.

(4) For equation 16 calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(6) Calculate emissions from well testing to flares as follows:

(A) Use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine well testing emissions from the flare.

(k) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same basin shall be used.

(2) If GOR cannot be determined from available data, then use one of the two procedures in paragraph (k)(2) of this section to determine GOR.

(A) Use an appropriate standard method published by a consensus-based standards organization if such a method exists, including ARB's sampling methodology and flash liberation test procedure in Appendix B of this regulation; or

(B) The facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 17 of this section.

$$E_{a,n} = \sum_{p=1}^{x} GOR_{p,q} * V_{p,q} \quad \text{(Eq.17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.

$GOR_{p,q}$ = Gas-to-oil ratio, for well p in basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in basin q, in barrels in the calendar year during which associated gas was vented or flared.

x = Total number of wells in the basin that vent or flare associated gas.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(6) Calculate emissions from associated gas to flares as follows:

(A) Use the associated natural gas volume and composition as determined in paragraph (k)(1) through (k)(4) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) *Flare stack or other destruction device emissions.* Calculate CO_2, CH_4 and N_2O emissions from a flare stack or other destruction device as follows:

(1) For the purposes of this reporting requirement, the facility operator must calculate emission from all flares, incinerators, oxidizers and vapor combustion units.

(2) If a continuous flow measurement device is installed on the flare or destruction device, the measured flow volumes must be used to calculate the flare gas emissions. If all of the gas or liquid sent to the flare or destruction device is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If a continuous flow measurement device is not installed on the flare or destruction device, a flow measuring device can be installed on the flare or destruction device or engineering calculations based on process knowledge, company records, or best available data.

(3) If a continuous gas composition analyzer is not installed on gas or liquid supply to the flare or destruction device, use the appropriate gas composition for each stream of hydrocarbons going to the flare as follows:

(A) For onshore natural gas processing, when the stream going to the flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmissions pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(B) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then the facility operator may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(4) Determine flare combustion efficiency from manufacturer specifications. If not available, assume that flare combustion efficiency is 98 percent.

(5) Calculate GHG volumetric emissions at actual conditions using Equations 18 and 19 of this section.

$$E_{a,CH4} = V_a * X_{CH4} * [(1 - \eta) * Z_L + Z_U] \quad \text{(Eq. 18)}$$

$$E_{a,CO2} = V_a * X_{CO2} + \sum_{j=1}^{5} \left(\eta * V_a * Y_j * R_j * Z_L\right) \quad \text{(Eq. 19)}$$

Where:

$E_{a,CH4}$ = Annual CH_4 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO2}$ = Annual CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare.

Z_L = Fraction of the feed gas sent to a burning flare (equal to 1 – Z_U).

Z_U = Fraction of the feed gas sent to an unlit flare determined by engineering estimate and process knowledge based on best available data and operating records.

X_{CO2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, and pentanes-plus).

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.

(6) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(7) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (t) of this section.

(8) Calculate N_2O emissions from flare stacks using Equation 37 in paragraph (y) of this section.

(9) If the facility operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, calculate only CO_2 emissions for the flare. The facility operator must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and record keeping requirements for Tier 4 in section 95115. If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (l)(1) through (l)(8) are not required. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the facility operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in section 95115 of this article (stationary fuel combustion sources).

(10) The flare emissions determined under paragraph (l) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in section 95153 use Equations 18 and 19 of this section, use volume under actual conditions for the parameter, V_a, in these equations.

(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:

(A) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors. For all centrifugal compressor start-ups where natural gas is used as spin-up or starting gas (i.e. not combusted in the compressor), venting of this gas must be quantified and reported as follows:

$$E_{SGi} = \sum_1^n V_{sg}(1 - CF)Y_i \qquad \text{(Eq. 20)}$$

Where:

E_{SGi} = Annual GHG_i (CO_2 and CH_4) vented emissions at standard conditions in cubic feet.

n = number of compressor start-ups using spin gas.

V_{sg} = Volume of spin-up gas in standard cubic feet determined by metering or engineering estimates based on best available data.

CF = Fraction of spin-up gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

Y_i = Mole fraction of GHG_i in the vent gas.

Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(B) Operating mode, wets seal oil degassing vents.

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

1. For the not operating depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the three year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the three year period, it must be measured in the standby depressurized mode.

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.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to section 95154(b) of this section. If a permanent flow meter is not installed, the operator may install a permanent flow meter on the wet seal oil degassing tank vent.

(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.

(4) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.

(5) Estimate annual emissions using the flow measurement and Equation 21 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 21)}$$

Where:

$E_{s,i,m}$ = Annual GHG (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour during operating mode m as described in sections (m)(1)(A) through (m)(1)(C).

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

Y_i = Mole fraction of GHG_i in the vent gas.

CF = Fraction of centrifugal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(6) For each centrifugal compressor with a rated horsepower of less than 250hp covered by sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3), the operator must calculate annual emissions from both wet seal and dry seal centrifugal compressor vents using Equation 22 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 22)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressors (<250hp) in cubic feet.

Count = Total number of centrifugal compressors less than 250hp.

EF_i = Emission factor for GHGi. Use 1.2 x 10^7 standard cubic feet per year per compressor for CH_4 and 5.30 x 10^5 standard cubic feet per year per compressor for CO_2 at 60˚F and 14.7 psia.

(7) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(8) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(A) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (m)(2) through (m)(4) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine degassing vent vapor emissions from the flare.

(n) *Reciprocating compressor venting.* Calculate CH_4 and CO_2, and N_2O (when flared) emissions from all reciprocating compressor vents as follows:

(1) For each reciprocating compressor with a rated horsepower of 250hp or greater covered in sections 95152(c)(13), (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4) the facility operator must conduct an annual measurement for each

compressor in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing 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 as follows:

(A) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(B) Operating mode, reciprocating rod packing emissions.

(C) Not operating depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

1. For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the three year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the three year period, it must be measured in the standby depressurized mode.

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 reciprocating 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.

(2) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line, use one of the following two methods to calculate emissions:

(A) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in sections 95154(c) and 95154(d), respectively.

(B) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in section 95154(b). If a permanent flow meter is not installed, the facility operator may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents such as unit isolation valves on not operating, depressurized compressors, use an acoustic detection device according to methods set forth in section 95154(a).

(3) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(A) The facility operator must use the methods described in section 95154(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(B) Measure emissions found in paragraph (n)(2)(A) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to the methods set forth in sections 95154(b), (c), and (d) respectively.

(4) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.

(5) Estimate annual emissions using the flow measurement and Equation 23 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 23)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

Y_i = Mole fraction of GHG_i in the vent gas.

CF = Fraction of reciprocal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(6) For each reciprocating compressors with a rated horsepower of less than 250hp, the operator must calculate annual emissions using Equation 24 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 24)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the facility operator.

EF_i = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60˚F and 14.7 psia.

(7) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(o) *Leak detection and leaker emission factors.* The operator must use the methods described in section 95154(a) to conduct leak detection(s) of equipment leaks from all components types listed in sections 95152(c)(16), (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1). This paragraph (o) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types 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 this paragraph (o) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (o), calculate equipment leak emissions per component type per reporting facility using Equations 25 or 26 of this section for each component type. Use Equation 25 for industry segments listed in section 95150(a)(1) – (a)(7). Use Equation 26 for natural gas distribution facilities as defined in section 95150(a)(8). Use methods found in section 95153(t) to convert GHG_i volume emissions to GHG_i mass emissions.

$$E_{s,i} = GHG_i * \sum_{p=1}^{x}\left(EF * T_p\right) \quad \text{(Eq. 25)}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t}\sum_{p=1}^{x}\left(EF * T_{p,q}\right) \quad \text{(Eq. 26)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (o)(1) through (o)(8) of this section.

X = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table 1A and 2 through 7 of Appendix A.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (s)(2)(A) of this section; For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

t = Calendar year of reporting.

n = The number of years over which one complete cycle of leak detection is conducted over all the Transmission – Distribution (T-D) transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first (n-1) calendar years of reporting the summation in Equation 26 should be for years that the data is available.

$T_{p,q}$ = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume the component found to be leaking has been leaking since the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

(1) The operator must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Onshore petroleum and natural gas production facilities must use the appropriate default leaker emissions factors listed in Table 1A of Appendix A for all leaks from equipment types in the table.

(3) Onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission facilities shall use the appropriate default leaker emission factors listed in Table 3 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 4 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 5 of Appendix A for equipment leaks detected from valves, pump seals, connectors, and other equipment.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 6 of Appendix A for equipment leaks detected from valves, pump seals, connectors, and other equipment.

(8) Natural gas distribution facilities for above ground transmission-distribution transfer stations, shall use the appropriate default leak emission factors listed in Table 7 of Appendix A for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(A) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility operator chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(p) *Population count and emission factors.* This paragraph applies to emissions sources listed in sections 95152(c)(16), (f)(7), (g)(5), (h)(5), (i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (i)(10) 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.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. 27)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. Underground natural gas storage shall count the components listed for population emission factors in Table 4. LNG storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter/regulator runs and the number of customer meters as described in paragraph (p)(6) of this section.

EF_s = Population emission factor for the specific component type, as listed in Table 1A and Tables 3 through Table 7 of Appendix A. Use appropriate emission factor for operations in Western U.S., according to Table 1(A) – 1(C) of Appendix A. EF for meter/regulator runs at above grade metering-regulator stations is determined in Equation 28 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (s)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1 x 10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1 x 10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

T_s = Total time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data, assume T_s = 8760 hours for section 95152(i)(10).

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(2) Onshore petroleum and natural gas production facilities must use the appropriate default population emission factors listed in Table 1A of Appendix A for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1A of Appendix A and major natural gas equipment in reference to Table 1B of Appendix A. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1A of Appendix A and major crude oil equipment in reference to Table 1C of Appendix A. Where facilities conduct EOR operations the emissions factor listed in Table 1A of Appendix A shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (p)(2). The same methodology must be used for the entire calendar year.

(A) *Component Count Methodology 1*. For all onshore petroleum and natural gas production operations in the facility perform the following activities:

1. Count all major equipment listed in Table 1B and Table 1C of Appendix A. For meters/piping, use one meters/piping per well-pad.

2. Multiply major equipment counts by the average component counts listed in Table 1B and 1C of Appendix A for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 1A of Appendix A for operations in Eastern and Western U.S. according to the mapping in Table 1B of Appendix A.

(B) *Component Count Methodology 2*. Count each component individually for the facility. Use the appropriate factor in Table 1A of Appendix A for operations in the Western U.S.

(3) Underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of Appendix A for equipment leak from connectors, valves, pressure relief valves and open ended lines.

(4) LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of Appendix A for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities must use the appropriate emission factor listed in Table 6 of Appendix A for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities must use the appropriate emission factors as described in paragraph (p)(6) of this section.

(A) Below grade metering-regulating stations; distribution mains; distribution services; and customer meters must use the appropriate default population emission factors listed in Table 7 of Appendix A. Below grade T-D transfer stations must use the emission factor for below grade metering-regulating stations.

(B) Emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) must be calculated by applying the emission factor calculated in Equation 28 and the total count of metering/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation 27. The facility wide emission factor in Equation 28 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation 26 and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (p)(1) of this section. A meter on a regulator run is considered one meter regulator run. Facility operators that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with section 95157(c)(16)(T).

$$EF = E_{s,i}/(8760 * Count) \quad \text{(Eq. 28)}$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade meter/regulator run for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG_i emissions, CO_2 or CH_4, at standard condition from each component type at all above grade T-D transfer stations, from Equation 26.

Count = Total number of meter/regulator runs at all T-D transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (o)(8)(A) of this section.

8760 = Conversion to hourly emissions.

(q) *Offshore petroleum and natural gas production facilities.* Operators must report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimate study (Year 2008 Gulfwide

Emission Inventory Study (GOADS) (December 2010)) conducted by BOEMRE in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference.

(1) Offshore production facilities under BOEMRE jurisdiction must report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimate study published by BOEMRE and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) Gulfwide Offshore Activities Data System (GOADS).

(A) The BOEMRE data is collected and reported every other year. In years where the BOEMRE data is not available, use the previous year's BOEMRE data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEMRE data.

(2) Offshore production facilities that are not under BOEMRE jurisdiction must use monitoring methods and calculation methodologies published by BOEMRE and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) to calculate and report emissions (GOADS).

(A) The BOEMRE data is collected and reported every other year. In years where the BOEMRE data is not available, use the previous year's BOEMRE data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEMRE data.

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore operators must once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either the first or subsequent year of reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle must use the BOEMRE data collection and emissions estimation methods published by BOEMRE and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) (GOADS) to calculate and report.

(r) *Volumetric emissions.* If equation parameters in section 95153 are already at standard conditions, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation 29 of this section.

$$E_{s,n} = E_{a,n} * (459.67 + T_s) * P_a/((459.67 + T_a) * P_s) \quad \text{(Eq. 29)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet except $E_{s,n}$ equals ($FR_{s,p}$) for each well p, when calculating either subsonic or sonic flow rates under section 95153(f).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60˚F).

T_a = Temperature at actual conditions (˚F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation 30 of this section.

$$E_{s,i} = E_{a,i} * (459.67 + T_s) * P_a/((459.67 + T_a) * P_s) \quad \text{(Eq. 30)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard conditions in cubic feet.

Ea,i = GHG i volumetric emissions at actual conditions in cubic feet.

Ts = Temperature at standard conditions (60˚F).

Ps = Absolute pressure at standard conditions (14.7 psia).

Pa = Absolute pressure at actual conditions (Psia).

(3) Facility operators using 68˚F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68˚F to 60˚F.

(s) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (s)(1) and (s)(2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 31 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. 31)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation 31 of this section, the mole fraction, M_i, must be the annual average mole fraction for each basin or facility, as specified in paragraphs (s)(2)(A) through (s)(2)(G) of this section.

(A) GHG mole fraction in produced pipeline quality natural gas for onshore petroleum and natural gas production facilities. If the facility has a continuous gas composition analyzer for produced natural gas, the facility operator must use an annual average of these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then it must use an annual average gas composition based on the most recent available analysis of the facility.

(B) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline system for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If the facility has a continuous gas composition analyzer on feed natural gas, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(C) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(D) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(E) GHG mole fraction in natural gas stored in the LNG storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(F) GHG mole fraction in natural gas stored in the LNG import and export industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(G) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(t) *GHG mass emissions.* Calculate GHG mass emissions by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 32 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. 32)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons GHG_i.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

P_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60˚F and 14.7 psia.

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

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

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

R_c = Density of critical phase EOR injection gas in kg/ft^3. The facility operator may use an appropriate standard method published by a consensus based organization if such a method exists or the facility operator may use an industry standard practice to determine density of super-critical emissions.

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. This reporting requirement includes emissions from hydrocarbon liquids and water produced using EOR operations. Emissions must be reported for crude oil, condensate, and produced water sent to storage tanks, ponds, and holding facilities. The facility operator must also report the volume of produced water in barrels per year.

(1) Calculate CO_2 and CH_4 emissions from crude oil, condensate, and produced water using Equation 33A:

$$E_{CO2/CH4} = (S * V)\big(1 - (VR * CE)\big) \qquad \text{(Eq. 33A)}$$

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 ARB's sampling methodology and flash liberation test procedure entitled "Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems," which is included as Appendix B of this article. The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of crude oil, condensate, or produced water. The test results from the flash liberation test must be submitted to 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:

   a. Measure the annual gas stream volume captured by the vapor recovery system.
   b. Calculate the annual mass of CO_2 and CH_4 in the gas stream using the gas stream volume and mole percentage of CO_2 and CH_4 as determined by a laboratory analysis of an annual gas stream sample.
   c. Calculate S by dividing the total mass of CO_2 and CH_4 in the gas stream by the total volume, in barrels, of the crude oil,

condensate, or produced water throughput of the storage tank system.

d. Vapor recovery system measurements and analyses may include gases from crude oil, condensate, and produced water.

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

(B) Emissions resulting from the destruction of the vapor recovery system gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

(2) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir are exempt from paragraph (v) of this section.

(w) *Pipeline dig-ins.* For reporting pipeline dig-in emissions as specified in section 95152(i)(11), operators may either use measured data or use engineering estimation based on best available data to quantify the volume of natural gas released from pipeline dig-in events. Volumetric emissions must be converted into mass emissions of CO_2 and CH_4 using the applicable methods in paragraphs (r), (s), and (t) of this section.

(x) *Reserved.*

(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 completely consisting of 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). The operator must use the appropriate gas composition for each stream of hydrocarbon going to the combustion unit as specified in paragraph (s)(2) of this section. 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 completely consisting of 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 specified below:

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

(B) If a continuous gas composition analyzer is installed and operational on fuel supply to the combustion unit, the operator must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If a continuous gas composition analyzer is not installed on gas to the combustion unit, the facility operator must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit.

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

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

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

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 month.

Y_{CO2} = Monthly 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 = Monthly 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} = Monthly 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 convert 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 x 10^{-3} MMBtu/scf for HHV.

EF = Use 1.0 x 10^{-4} kg N_2O/MMBtu.

1 x 10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 MMBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 MMBtu/hr (or equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each internal fuel combustion unit.

(5) Calculate sorbent CO_2 emissions from fluidized bed boilers with flue gas desulfurization using methods found in §98.33(d).

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 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 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 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.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR Part 60, appendix A-7, Method 21 (July 1, 2011). If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR Part 60, are not exempt from this subarticle. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, the facility operator must operate the infrared laser beam illuminated instrument to detect the source types required by this subarticle in accordance with the instrument manufacturer's operating instructions.

(4) *Optical gas imaging instrument.* An optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(5) *Acoustic leak detection device*. Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the

acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subarticle in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subarticle in accordance with the instrument manufacturer's operating parameters.

(b) The operator must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in section 95153 according to the procedures in section 95103(k) and the procedures in paragraph (b) of this section. Pursuant to section 95109 of this article, the facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists or use an industry standard practice.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the vent bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer's operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use

anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples by following manufacturer's instructions for calibration.

(e) Peng-Robinson Equation of State means the equation of state defined by Equation 38 of this section.

$$p = \frac{RT}{(V_m - b)} - a\alpha/(V_m^2 + 2bV_m - b^2) \qquad \text{(Eq. 38)}$$

Where:

p = Absolute pressure.
R = Universal gas constant
T = Absolute temperature.
V_m = Molar volume.
$a = 0.45724R^2T_c^2/p_c$
$b = 0.7780RT_c/p_c$

$$\alpha = \left(1 + (0.37464 + 1.54226\omega - 0.26992\omega^2)\left(1 - \sqrt{T/T_c}\right)\right)^2$$

Where:

ω = Acentric factor of the species.
T_c = Critical temperature.
P_c = Critical pressure.

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.

§ 95155. Procedures for Estimating Missing Data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures outlined below:

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data required by this subarticle is missing and additional sampling and/or analysis is not possible, the operator must generate a substitute value as follows:

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

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 to the data reporting requirements in section 95157 in addition to the data reporting requirements specified below. Sales records or sales records with an inventory adjustment are allowable methods to quantify the covered product data required by paragraphs (a)(7)-(10), (b), (c) and (d) of this section, for products that are sold or produced during the data year, if the measurement system meets the criteria in section 95103(k). Any changes in the covered product data reporting method must conform to the requirements in 95103(m). Reporting entities must exclude inaccurate product data pursuant to section 95103(l).

(a) In addition to the data required by section 95157, the operator of an onshore or offshore petroleum and natural gas production facility must report the following data for the facility, disaggregated within the basin by sub-facility :

(1) CO_2e emissions, including CO_2, CH_4, and N_2O as applicable for the source types specified in section 95152(c);

(2) For combustion sources for which emissions are reported, fuel use by fuel type;

(3) For cogeneration sources:

(A) Total thermal output (MMBtu);

(B) Net electricity generation (MWh);

(C) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator);

(4) For steam generator sources:

(A) Total thermal energy generated (MMBtu) and the CO_2e emissions associated with this output;

(B) Thermal energy (MMBtu) not utilized within the facility (i.e., exported offsite or to another facility owner/operator) and the CO_2e emissions associated with this output;

(5) For electricity generation sources not included in section 95156(a)(3):

(A) Net electricity generation (MWh) and the CO_2e emissions associated with this generation;

(B) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) and the portion of CO_2e emissions associated with this generation;

(6) Total steam (MMBtu) utilized but not generated at the facility and the CO_2e emissions associated with this output, if known;

(7) Barrels of crude oil produced using thermal enhanced oil recovery. This means the volume of crude oil produced within the facility boundary during the data year, a volume which may include the crude oil fraction piped as an emulsion as defined in section 95102(a);

(8) Barrels of crude oil produced using non-thermal enhanced oil recovery. This means the volume of crude oil produced within the facility boundary during the data year, a volume which may include the crude oil fraction piped as an emulsion as defined in section 95102(a);

(9) Heat energy (MMBtu) of associated gas produced using thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a). Associated gas may be quantified using production or sales meters as appropriate. Associated gas may also be quantified by multiplying the barrels of crude oil produced during the data year by a representative GOR measurement plus the representative GWR measurement multiplied by the produced water volume. When GOR and GWR measurements are used for quantifying associated gas, these measurements must be the most disaggregated data available (e.g., field or tank farm level). The average HHV of the produced gas must be multiplied by the data year volume to determine the annual heat content in MMBtu. HHV measurements must be collected and averaged consistent with the frequency requirements in 95153(y)(2)(D);

(10) Heat energy (MMBtu) of associated gas produced using non-thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a). Associated gas may be quantified using production or sales meters as appropriate. Associated gas may also be quantified by multiplying the barrels of crude oil produced during the data year by a representative GOR measurement plus the representative GWR measurement multiplied by the annual produced water volume. When GOR

and GWR measurements are used for quantifying associated gas, these measurements must be the most disaggregated data available (e.g., field or tank farm level). The average HHV of the produced gas must be multiplied by the data year volume to determine the annual heat content in MMBtu. HHV measurements must be collected and averaged consistent with the frequency requirements in 95153(y)(2)(D).

(b) For dry gas production, the operator of an onshore petroleum and natural gas production facility must report its annual heat energy of dry gas produced (MMBtu). The average HHV of the produced gas must be multiplied by the data year volume to determine the heat energy in MMBtu. HHV measurements must be collected and averaged consistent with the frequency requirements in 95153(y)(2)(D);

(c) The operator of a natural gas liquid fractionating facility, a natural gas processing facility, or an onshore petroleum and natural gas production facility with a natural gas processing plant that processes less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

(1) Ethane

(2) Ethylene

(3) Propane

(4) Propylene

(5) Butane

(6) Butylene

(7) Isobutane

(8) Isobutylene

(9) Pentanes plus

(10) Natural gasoline

(11) Liquefied petroleum gas

(12) Bulk natural gas liquids not included in 95156(d)(1)-(11)

If a facility extracts natural gas liquids from produced gas, associated gas, or waste gas, and re-injects these natural gas liquids into barrels of crude oil produced at the same facility, the operator of such a facility shall report the amount of any re-injected natural gas liquids as covered product data pursuant to section 95156(a)(7) or (8). All other natural gas liquids produced at the facility should be reported as covered product data pursuant to section 95156(c).

(d) Onshore natural gas processing facilities that have an annual average throughput of 25 MMscf per day or greater must also report the heat energy of associated gas, waste gas, and natural gas processed (MMBtu). The average HHV of the produced gas must be multiplied by the data year volume to determine the heat energy in

MMBtu. HHV measurements must be collected and averaged consistent with the frequency requirements in 95153(y)(2)(D).

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

§95157. Activity Data Reporting Requirements.

In addition to the information required by section 95103, each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions in metric tons per year for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section:

(1) Onshore petroleum and natural gas production.

(2) Offshore petroleum and natural gas production

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) LNG storage.

(7) LNG import and export.

(8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG type. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring of the gas. Both the vented and flared emissions will be reported under respective source types and not under flare source type.

(1) For natural gas pneumatic devices (refer to Equations 1 and 2 of section 95153), report the following:

(A) Actual count and estimated count separately of natural gas pneumatic high bleed devices, as applicable.

(B) Actual count and estimated count separately of natural gas low bleed devices, as applicable.

(C) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices, as applicable.

(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) For natural gas driven pneumatic pumps (refer to Equation 1 and 2 of section 95153), report the following:

(A) Count of natural gas driven pneumatic pumps.

(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all natural gas driven pneumatic pumps combined.

(3) For each acid gas removal unit (refer to Equation 3 and Equations 4A-B of section 95153), report the following:

(A) Total throughput of the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.

(B) For Calculation Methodology 1 and Calculation Methodology 2 of section 95153(c), annual fraction of CO_2 content in the vent from acid gas removal unit (refer to section 95153(c)(6)).

(C) For Calculation Methodology 3 of section 95153(c), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to section 95153(c)(6)).

(D) Report the annual quantity of CO_2, expressed in metric tons that was recovered from the AGR unit and transferred outside the facility, under section 95153.

(E) Report annual CO_2 emissions for the AGR unit, expressed in metric tons.

(F) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.

(G) An indication of which methodology was used for the AGR unit.

(4) For dehydrators, report the following:

(A) For each Glycol dehydrator (refer to section 95153(d)(1)), report the following:

1. Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.
2. Glycol dehydrator absorbent circulation pump type.
3. Whether stripper gas is used in glycol dehydrator.
4. Whether a flash tank separator is used in glycol dehydrator.

5. Type of absorbent.
6. Total time the glycol dehydrator is operating in hours.
7. Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.
8. Concentration of CH_4 and CO_2 in wet natural gas.
9. What vent gas controls are used (refer to sections 95153(d)(3) and (d)(4)).
10. For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
11. For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons for each gas.
12. For the onshore natural gas processing industry segment only, report a unique name or ID number for (each) glycol dehydrator.

(B) For absorbent desiccant dehydrators (refer to Equation 5 of section 95153), report the following:

1. Count of desiccant dehydrators.
2. Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(A) For Calculation Methodology 1 (refer to Equation 6 of section 95153(e)), report the following:

1. Count of wells vented to the atmosphere for liquids unloading.
2. Count of plunger lifts. Whether the well had a plunger lift (yes/no).
3. Cumulative number of unloadings vented to the atmosphere.
4. Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet.
5. Casing pressure, in psia, of each well that does not have a plunger lift.
6. Tubing pressure, in psia, of each well that has a plunger lift.
7. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(B) For Calculation Methodologies 2 (refer to Equation 7 of section 95153(e)), report the following for each basin:

1. Count of wells vented to the atmosphere for liquids unloading.

2. Count of plunger lifts.

3. Cumulative number of unloadings vented to the atmosphere.

4. Average internal casing diameter, in inches, of each well, where applicable.

5. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each GHG gas.

(6) For well completions and workovers, report the following for each basin category:

(A) Total field count of gas well completions and total field count of oil well completions by average depth (in thousands of feet) in calendar year.

1. Total number of gas well completions by average depth (in thousands of feet) using hydraulic fracturing;

2. Total number of oil well completions by average depth (in thousands of feet) using hydraulic fracturing;

(B) Total field count of gas well workovers and total field count of oil well workovers by average depth (in thousands of feet) in calendar year.

1. Total number of gas well workovers by average depth (in thousands of feet) using hydraulic fracturing;

2. Total number of oil well workovers by average depth (in thousands of feet) using hydraulic fracturing;

(C) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.

(D) Report number of workovers employing purposely designed equipment that's separates natural gas from the backflow and the amount of natural gas recovered using engineering estimate based on best available data.

(E) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.

(F) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons for each gas.

(G) The following field average activity data for oil wells:

1. Casing diameter;

2. Tubing diameter;

3. Typical pressure inside the well at the wellhead, immediately prior to removing the wellhead for well work activities;

4. Typical producing temperature inside the well;

5. Time, in hours, to complete well work (workover or completion).

(7) For each equipment and pipeline blowdown event (refer to Equation 13 and Equation 14 of section 95153(g)), report the following:

(A) For each unique physical volume that is blowdown more than once during the calendar year, report the following:

1. Total number of blowdowns for each unique physical volume, expressed in metric tons for each gas.

2. Annual CO_2 and CH_4 emissions for each unique physical blowdown volume, expressed in metric tons for each gas.

3. A unique name or ID number for the unique physical volume.

(B) For all unique volumes that are blow down once during the calendar year, report the following:

1. Total number of blowdowns for all unique physical volumes in the calendar year.

2. Annual CO_2 and CH_4 emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(A) If a wellhead separator dump valve is functioning improperly during the calendar year (refer to section 95153 (i)), report the following:

1. Count of wellhead separators that dump valve factor is applied.

2. Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons for each gas, at the basin level for improperly functioning dump valves.

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

(A) For each vent stack, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.

(B) For each transmission storage tank, report annual CO_2, CH_4 and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons for each gas.

(C) A unique name or ID number for the vent stack monitored according to section 95153(i).

(10) For well testing venting and flaring (refer to Equation 15 or 16 of section 95153(j)), report the following:

(A) Number of wells tested per basin in calendar year.

(B) Average gas-to-oil ratio for each basin.

(C) Average number of days the well is tested in a basin.

(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emissions from well testing venting.

(E) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation 17 of section 95153), report the following for each basin:

(A) Number of wells venting or flaring associated natural gas in a calendar year.

(B) Average gas-to-oil ratio for each basin.

(C) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emission s from associated natural gas venting.

(D) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation 18, 19, and 20 of section 95153(l)), report the following for each flare:

(A) Whether flare has a continuous flow monitor.

(B) Volume of gas sent to flare in cubic feet per year.

(C) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(D) Whether flare has a continuous gas analyzer.

(E) Flare combustion efficiency.

(F) Report CH_4 emissions, in metric tons (refer to Equation 18 of section 95153).

(G) Report CO_2 emissions, in metric tons (refer to Equation 19 of section 95153).

(H) Report N_2O emissions, in metric tons.

(I) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(J) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(13) For each centrifugal compressor:

(A) For compressors with wet seals in operational mode (refer to Equation 21 and 22 of section 95153(m)), report the following for each degassing vent:

1. Number of wets seals connected to the degassing vent.

2. Fraction of vent gas recovered for fuel or sales or flared.

3. Annual throughput in million scf, use an engineering calculation based on best available data.

4. Type of meters used for making measurements.

5. Total time the compressor is operating in hours.

6. Report seal oil degassing vent emissions for compressors measured (refer to Equation 21 of section 95153) and for compressors not measured (refer to Equation 22 of section 95153).

(B) For wet and dry seal centrifugal compressors in operating mode, (refer to Equation 21 and 22 of section 95153(m)), report the following:

1. Total time in hours the compressor is in operating mode.

2. Report blowdown vent emissions when in operating mode (refer to Equation 21 and 22 of section 95153).

(C) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations 21 and 22 of section 95153(m)), report the following:

1. Total time in hours the compressor is in shutdown, depressurized mode.

2. Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equations 21 and 22 of section 95153).

(D) Report total annual compressor emissions from all modes of operation.

(14) For reciprocating compressors:

(A) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

1. Annual throughput in million scf, use an engineering calculation based on best available data.

2. Total time in hours the reciprocating compressor is in operating mode.

3. Report rod packing emissions for compressors measured (refer to Equation 23 of section 95153).

(B) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode, report the following:

1. Total time in hours the compressor is in standby, pressurized mode.

2. Report blowdown vent emissions when in operating and standby modes.

(C) For reciprocating compressors in not operating, depressurized mode report the following:

1. Total time the compressor is in not operating depressurized mode.

2. Facility operator emission factor for isolation valve emissions in not operating mode, depressurized mode in cubic feet per hour.

3. Report the isolation valve leakage emissions in not operating, depressurized mode.

(D) Report total annual compressor emissions from all modes of operation.

(E) For reciprocating compressors in onshore petroleum and natural gas production report the following:

1. Count of compressors.

2. Report emissions collectively.

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to sections 95153(o) and (p).

(A) For equipment leaks found in each leak survey (refer to section 95153(o)), report the following:

1. Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leak emission factor in Tables 2, 3, 4, 5, 6, and 7 of Appendix A.

2. For onshore natural gas processing, range of concentrations of CH_4 and CO_2.

3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(B) For equipment leaks calculated using population counts and factors (refer to section 95153(p)), report the following:

1. For source categories listed in sections 95150(a)(4), (a)(5), (a)(6), and (a)(7), total count for each component type in Tables 2, 3, 4, 5, and 6 of Appendix A for which there is a population emission factor, listed by major heading and component type.

2. For onshore production (refer to section 95150 (a)(2)), total count for each type of major equipment in Table 1B and Table 1C of Appendix A, by facility.

3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(16) For local distribution companies, report the following:

(A) Total number of above grade T-D transfer stations in the facility.

(B) Number of years over which all T-D transfer stations will be monitored at least once.

(C) Number of T-D stations monitored in calendar year.

(D) Total number of below grade T-D transfer stations in the facility.

(E) Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.

(F) Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.

(G) Leak factor for meter/regulator run developed in Equation 28 of section 95153.

(H) Number of miles of unprotected steel distribution mains.

(I) Number of miles of protected steel distribution mains.

(J) Number of miles of plastic distribution mains.

(K) Number of miles of cast iron distribution mains.

(L) Number of unprotected steel distribution services.

(M) Number of protected steel distribution services.

(N) Number of plastic distribution services.

(O) Number of copper distribution services.

(P) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade T-D transfer stations combined.

(Q) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.

(R) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.

(S) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution mains combined.

(T) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution services combined.

(U) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from customer meters serving residential, commercial, and industrial customers, respectively.

(V) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from pipeline dig-ins.

(W) Number of customer meters at residential, commercial, and industrial premises, respectively.

(X) Number of pipeline dig-ins.

(17) For each EOR injection pump blowdown (refer to Equation 33 of section 95153), report the following:

(A) Pump capacity, in barrels per day.

(B) Volume of critical phase gas between isolation valves.

(C) Number of blowdowns per year.

(D) Critical phase EOR injection gas density.

(E) For each EOR pump, report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(18) For crude oil, condensate, and produced water dissolved CO_2 and CH_4 (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.

(B) Report annual CO_2 and CH_4 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(A) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 MMBtu/hr, by type of unit.

(B) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(C) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(D) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(E) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 MMBtu/hr or 130 horsepower, by type of unit.

(F) Report annual CO_2, CH_4 and N_2O emissions from internal fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(G) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 MMBtu/hr or 130 horsepower, by fuel type.

(H) Annual volume of associated gas produced MMBtu) using thermal enhanced oil recovery and non-thermal enhanced oil recovery.

(I) Onshore petroleum and natural gas production facilities may voluntarily report total thermal input (MMBtu) to EOR wells generated using renewable energy source(s) as defined in section 95102(a).

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas-to-oil ratio, and best available estimate of average low pressure separator pressure for each oil basin category.

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.

§95158. Records That Must Be Retained.

The operator shall follow the document retention requirements of section 95105 of this article.

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

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Appendix A

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

Emission Factors and Calculation Data for Petroleum and Natural Gas Systems Reporting

Table 1A
Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
Western U.S. **Population Emission Factors All components, Gas Service:**[1]	
Valve	0.121
Connector	0.017
Open-ended line	0.031
Pressure relief valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors – All Components, Light Crude Service:[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors – All Components, Heavy Crude Service:[6]	
Valve Flange	0.0005 0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emissions factor is in units of “scf/hour/device.”
[3] Emission Factor is in units of “scf/hour/pump.”
[4] Hydrocarbon liquids greater than or equal to 20˚API are considered “light crude.”
[5] “Other” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20˚API are considered “heavy crude.”

Table 1B
Default Average Component Counts for Major Onshore Natural Gas Production Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

Table 1C
Default Average Component Counts for Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Table 2
Default Total Hydrocarbon Emission Factors for Onshore Natural Gas Processing

Onshore natural gas processing	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1] Valves include control valves, block valves and regulator valves.

Table 3
Default Total Hydrocarbon Emission factors for Onshore Natural Gas Transmission Compression

Onshore Natural Gas Transmission compression	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Population Emission Factors – Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves, and regulator valves.
[2] Emission Factor is in units of “scf/hour/component.”

Table 4
Default Total Hydrocarbon Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – Storage Station, Gas Service	
Valve[1]	14.84
Connector	5.659
Open-Ended Line	17.27
Pressure Relief valve	39.66
Meter	19.33
Population Emission Factors – Storage Wellheads, Gas Service	
Connector	0.01
Valve[1]	0.1
Pressure Relief Valve	0.17
Open Ended Line	0.03
Population Emission Factor – Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of “scf/hour/device.

Table 5
Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG storage Components, Gas and Liquids Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] “other” equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of “scf/hour/compressor.”

Table 6
Default Methane Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG Terminals Components, Gas and Liquid Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Terminal Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor."

Table 7
Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors – Above Grade M&R at City Gate Stations[1] Components	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors – Below Grade M&R [2] Components, Gas Service	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population emission Factors – Distribution Mains, Gas Service[4]	
Unprotected steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors – Distribution Services, Gas Service[5]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03
Population Emission Factors – Customer Meters	Emission Factor (scf/meter-hour)
Residential	0.01582
Commercial	0.00547
Industrial	0.00547

[1] City gate stations at custody transfer and excluding customer meters.
[2] Excluding customer meters.
[3] Emission Factor is in units of “scf/hour/station.”
[4] Emission Factor is in units of “scf/hour/mile.”
[5] Emission factor is in units of “scf/hour/number of services.”

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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 Sections 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-to-Oil Ratio or Gas-to-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, all definitions are found in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.).

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-4007-08. 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.

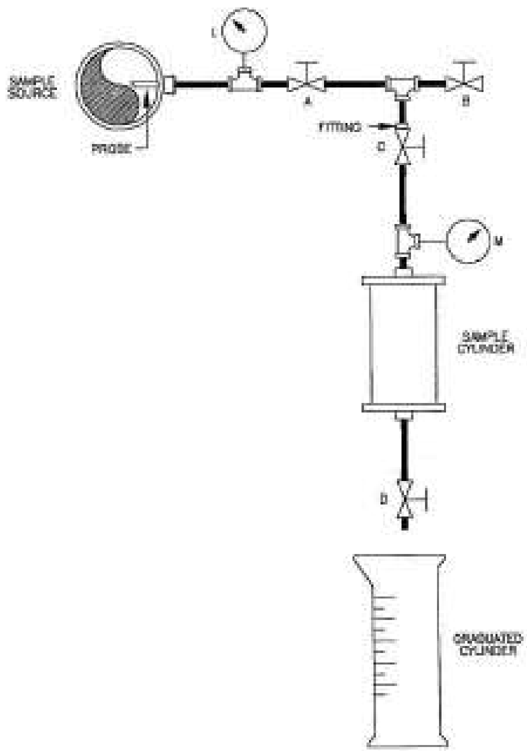
When a liquid sample is gathered, the technician measures the pressure and temperature of the liquid using the calibrated gauges specified and records the vessel and liquid characteristics as reported by the facility operator. The cylinder is then identified with a Cylinder Identification Tag (See Section 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

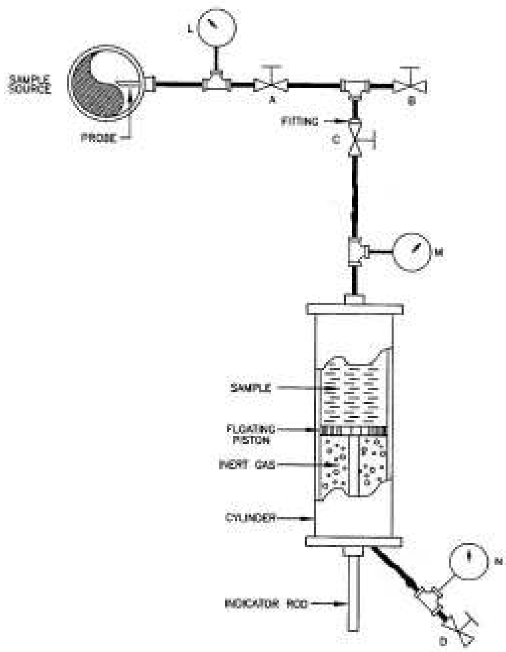
The Produced Water Sampling Method is conducted using a Floating-Piston Cylinder. This allows the sample liquid to be extracted from the cylinder without using laboratory water. The cylinder is provided by a laboratory with the piston pressurized with inert gas to approximately 1,000 psig or greater. 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:

$$Barrels / Day = (1 - Percent\ Water\ Cut)(Throughput)$$ **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:

$$Barrels / Day = (Percent\ Water\ Cut)(Throughput)$$ **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-to-Oil Ratio or Gas-to-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

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

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-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^{0}F

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

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

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

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 $VOC_{C3\text{-}C9}$ 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 2174-93, GPA 2261-00 and GPA 2177-03.

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-1945-03 (Thermal Conductivity Detector), ASTM D-5504-08 (sulfur chemiluminescence detector), and ASTM D-6228-10 (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-1945-03, ASTM D-3588-98(2003), and ASTM D-2597-94(2004)(GC/TCD). Note: This analysis requires all three methods specified. The base method is ASTM D-1945-03, 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-287-92-(2006) using measured result of Specific Gravity. Note: If water is entrained in the sample, measure the API Gravity using ASTM D-287-92 (2006)(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-4052-09, ASTM D-70-09, or ASTM D-5002-99(2010) or calculate using results from ASTM D-287-92(2006).

(f) Molecular Weight of gaseous phase by calculation per ASTM D-3588-98(2003).

(g) Percent Water Cut: evaluate per ASTM D-4007-08 (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-to-Water Ratio (GWR) for produced water; and,

(e) Volumetric Gas-to-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% CO_2, CH_4
WT% C2-C9, C10+
WT% BTEX
WT% O_2
WT% N_2
WT% H_2S
Molecular Weight Total Gaseous Sample
Gas-to-Oil Ratio
Gas-to-Water Ratio

Pre-Flash Liquid Crude Oil or Condensate
API Gravity

13. REFERENCES

ASTM D-70-09 *Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)*

ASTM D-287-92(2006) *Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)*

ASTM D-1945-03 *Standard Test Method for Analysis of Natural Gas by Gas Chromatography*

ASTM D-2597-94(2004) *Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*

ASTM D-3710-95(1999) *Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography*

ASTM D-3588-98(2003) *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*

ASTM D-4007-08 *Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method*

ASTM D-4052-09 *Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter*

ASTM D-5002-99(2010) *Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer*

ASTM D-5504-08 *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence*

ASTM D-6228-10 *Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection*

EPA Method 15 (1996) *Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources*

EPA Method 16 (1996) *Semicontinuous Determination of Sulfur Emissions from Stationary Sources*

EPA Method 8021B (1996)*Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors*

EPA Method 8260B(1996)	*Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)*
EPA Method TO-14(1999)	*Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography*
EPA Method TO-15(1999)	*Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)*
GPA 2174-93	*Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography*
GPA 2177-03	*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*
GPA 2261-00	*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*
GPA 2286-95	*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: ______________________

Attachment B

Current Text of Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

LEGAL DISCLAIMER & USER'S NOTICE

Unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

Unofficial Electronic Version

This unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms following this Disclaimer was produced by California Air Resources Board (ARB) staff for the reader's convenience. ARB staff has removed the underline-strikeout formatting which exists in the Final Regulation Order approved by the Office of Administrative Law (OAL) on October 20, 2015, and included the full regulatory text for the regulation; however, the following version is not an official legal edition of title 17, California Code of Regulations (CCR), sections 95801-96022. The effective date of this regulation is November 1, 2015. While reasonable steps have been taken to make this unofficial version accurate, the officially published CCR takes precedence if there are any discrepancies.

Official Legal Edition

The official legal edition of title 17, CCR, sections 95801-96022 is available at the OAL website: http://www.oal.ca.gov/CCR.htm.

"Online" link (http://ccr.oal.ca.gov/linkedslice/default.asp?SP=CCR-1000&Action=Welcome)

→"Title 17. Public Health"

→ "Division 3. Air Resources"

→ "Chapter 1. Air Resources Board"

→ "Subchapter 10. Climate Change"

→ "Article 5. California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms"

→then choose the relevant subarticle(s) and section(s).

For ease of reviewing, once you have selected a section, scroll to the bottom left-hand corner of the page and click on "Docs in Sequence." This will enable easy switching from one section to the next.

FINAL REGULATION ORDER

ARTICLE 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

§ 95800. Table of Contents.

Subarticle 2: Purpose and Definitions

§ 95801. Purpose.

The purpose of this article is to reduce emissions of greenhouse gases associated with entities identified in this article through the establishment, administration, and enforcement of the California Greenhouse Gas Cap-and-Trade Program by applying an aggregate greenhouse gas allowance budget on covered entities and providing a trading mechanism for compliance instruments.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95802. Definitions.

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(1) “Account Viewing Agent” means an individual authorized by a registered entity to view all the information on the entity’s accounts contained in the tracking system.

(2) “Accounts Administrator” means the entity acting in the capacity to administer the accounts identified in this regulation. This may be ARB, or could be an entity ARB enters into a contract with.

(3) “Activity-Shifting Leakage” means increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project’s boundary to locations outside the offset project’s boundary as a result of the offset project activity.

(4) “Additional” means, in the context of offset credits, greenhouse gas emission reductions or removals that exceed any greenhouse gas reduction or removals otherwise required by law, regulation or legally binding mandate, and that exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative business-as-usual scenario.

(5) "Adjusted Clinker and Mineral Additives Produced" means annual amount of clinker and mineral additives (limestone and gypsum) derived by using the

following metric: Adjusted clinker and mineral additives produced = clinker produced x (1 + (limestone and gypsum consumed)/clinker consumed)).

(6) "Adverse Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement, or that it cannot attest that the Offset Project Data Report conforms to the requirements of this article or applicable Compliance Offset Protocol.

(7) "Air Dried Ton of Paper" means paper with 6 percent moisture content.

(8) "Air Pollution Control District" or "Air Quality Management District" or "Air District" means any district created or continued in existence pursuant to the provisions of Part 3 (commencing with Section 40000) of Division 26 of the Health and Safety Code.

(9) "Allowance" means a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(10) "Almond" means the edible seed of the almond (*Prunus amygdalus*).

(11) "Alternate Account Representative" means an individual designated pursuant to section 95832 to take actions on an entity's accounts.

(12) "Aluminum and aluminum alloy billet" is a solid bar of nonferrous metal, produced by casting molten aluminum alloys, that is suitable for subsequent rolling, casting, or extrusion. Aluminum alloy is an alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.

(13) "Annual Allowance Budget" means the number of California Greenhouse Gas Allowances associated with one year of the Cap-and-Trade Program in subarticle 6.

(14) "ARB Offset Credit" means a tradable compliance instrument issued by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable.

(15) "Aseptic Preparation" is a system in which a product is sterilized before filling into pre-sterilized packs under sterile conditions.

(16) "Aseptic tomato paste" means tomato paste packaged using aseptic preparation. Asceptic paste is normalized to 31% tomato soluble solids (TSS). Asceptic paste normalized to 31% TSS = (%TSS - raw TSS)/(31 - raw TSS).

(17) "Aseptic whole and diced tomatoes" means whole and diced tomatoes packaged using aseptic preparation. Sum of Aseptic Whole and Diced Tomatoes = Whote Tomatoes + (Diced Tomatoes x 1.05).

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

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

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

(21) "Associated Gas" or "Produced Gas" means a natural gas that is produced in association with the production of crude oil.

(22) "Auction" means the process of selling California Greenhouse Gas Allowances, along with allowances from External Greenhouse Gas Emissions Trading Systems with which California has linked its Cap-and-Trade Program pursuant to subarticle 12, by offering them up for bid, taking bids, and then distributing the allowances to winning bidders.

(23) “Auction Purchase Limit” means the limit on the number of allowances one entity or a group of affiliated entities may purchase from the share of allowances sold at a quarterly auction.

(24) “Auction Reserve Price” means a price for allowances below which bids at auction would not be accepted.

(25) “Auction Settlement Price” means the price announced by the Auction Administrator at the conclusion of each quarterly auction. It is the price which all successful bidders will pay for their allowances and also the price to be paid to those entities which consigned allowances to the auction.

(26) “Authorized Project Designee” means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(27) "Aviation Gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications are as stated in MRR, section 95102(a).

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

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

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

(31) “Banking” means the holding of compliance instruments from one compliance period for the purpose of sale or surrender in a future compliance period.

(32) “Barrel of Gas Processed Equivalent," with respect to reporting of onshore natural gas processing as defined in MRR 95150(a)(3), means the volume of associated gas, waste gas, and natural gas processed converted to barrels at 5.8 MMBtu per barrel.

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

(34) “Bathroom tissue” means a thin, soft, lightweight, sanitized paper used in bathrooms for personal cleanliness. Bathroom tissue is usually sold as a long strip of perforated paper wrapped around a paperboard core.

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

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79 (June 27, 1994);

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

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

(E) Derived from nonpetroleum renewable resources.

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

(37) “Biomass” means non-fossilized and biodegradable organic material originating from plants, animals, and microorganisms, including products, by-products, residues, and waste from agriculture, forestry, and related industries as well as the non-fossilized and biodegradable organic fractions of

industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(38) "Biomass-Derived Fuels" or "Biomass Fuels" or "Biofuels" means fuels derived from biomass.

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

(40) "Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

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

(42) "Budget Year" means the calendar year to which an annual allowance budget is assigned pursuant to subarticle 6.

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

(44) "Butter" means the product made by gathering the fat of fresh or ripened milk or cream into a mass that also contains a small portion of other milk constituents.

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

(46) "Buttermilk powder" means milk powder obtained by drying liquid buttermilk that was derived from the churning of butter and pasteurized prior to condensing. Buttermilk powder has a protein content of no less than 30%. It may not contain, or be derived from, nonfat dry milk, dry whey, or products

other than buttermilk, and contains no added preservatives, neutralizing agents, or other chemicals.

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

(48) "Calcium Ammonium Nitrate Solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.

(49) "Calendar Year" means the time period from January 1 through December 31.

(50) "California Balancing Authority" shall have the same meaning ascribed in section 95102(a) of MRR.

(51) "California Electricity Transmission and Distribution System" means the combination of the entire infrastructure within California that delivers electric power from electric generating facilities to end users over single or multiple paths.

(52) "California Greenhouse Gas Emissions Allowance" or "CA GHG Allowance" means an allowance issued by ARB and equal to up to one metric ton of CO_2 equivalent.

(53) "Cap" means the total number of California GHG Allowances that the Executive Officer issues over a given period of time.

(54) "Cap-and-Trade Program" means the requirements of this article.

(55) "Carbon Dioxide" or "CO_2" means the most common of the primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(56) "Carbon Dioxide Equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. Global warming potential values shall be determined consistent with the definition of Carbon Dioxide Equivalent in MRR section 95102(a).

(57) "Carbon Stock" means the quantity of carbon contained in an identified GHG reservoir.

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

(59) "Carbonation" means the process of dissolving carbon dioxide in water.

(60) "Casein" means a group of proteins found in milk which is coagulated by enzymes and acid to form cheese.

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

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

(63) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve onsite generation of electricity and useful

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

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

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

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

(67) "Complexity weighted barrel" or "CWB" means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The CWB value for an individual refinery is calculated using actual refinery throughput to specified process units and emission factors for these process units. The emission factor is denoted as the CWB factor and is representative of the greenhouse gas emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for

production, and for average process emissions of the process units across a sample of refineries. Each CWB factor is expressed as a value weighted relative to crude distillation. A refinery's CWB value for allocation will be its $CWB_{process}$ value adjusted for off-sites and non-crude sensible heat using the following equation: $CWB = 1.0085*CWB_{process} + 0.327*\text{Total Refinery Input} + 0.44*\text{Non-Crude Input}$. This calculation will rely on data submitted under section 95113 of the MRR, the definition of $CWB_{process}$ under section 95113(l) of MRR, and the definitions of Total Refinery Input, and Non-Crude Input given under section 95102(c) of MRR.

(68) "Compliance Account" means an account created by the accounts administrator for a covered entity or opt-in covered entity with a compliance obligation, to which the entity transfers compliance instruments to meet its annual and triennial compliance obligations.

(69) "Compliance Instrument" means an allowance or offset, issued by ARB or by an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

(70) "Compliance Obligation" means the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

(71) "Compliance Offset Protocol" means an offset protocol adopted by the Board.

(72) "Compliance Period" means the three-year period for which the compliance obligation is calculated for covered entities except for the first compliance period. The compliance obligation for the first compliance period only considers emissions from data years of 2013 and 2014.

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

(74) "Concentrated milk" means the liquid food obtained by partial removal of water from milk. The milkfat and total milk solids contents of the food are not

less than 7.5 and 25.5 percent, respectively. It is pasteurized, but is not processed by heat so as to prevent spoilage. It may be homogenized.

(75) "Condensed milk" means the food obtained by partial removal of water only from a mixture of milk and safe and suitable nutritive carbohydrate sweeteners. The finished food contains not less than 8 percent by weight of milkfat, and not less than 28 percent by weight of total milk solids. The quantity of nutritive carbohydrate sweetener used is sufficient to prevent spoilage. The food is pasteurized and may be homogenized.

(76) “Conflict of Interest” means, for purposes of this article, a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial Offset Verification Statement of a potential client’s Offset Project Data Report, or the person or body’s objectivity in performing offset verification services is or might be otherwise compromised.

(77) “Conservative” means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements.

(78) “Consumer Price Index for All Urban Consumers” means a measure that examines the changes in the price of a basket of goods and services purchased by urban consumers, and is published by the U.S. Bureau of Labor Statistics.

(79) "Container Glass Pulled" means the quantity of glass removed from the melting furnace in the container glass manufacturing process where "container glass" is defined as glass products used for packaging.

(80) “Contract Description Code” means the alphanumeric code assigned by an exchange to a particular exchange product that differentiates the product from others traded on the exchange.

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

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

(83) "Counterparty" means the opposite party in a bilateral agreement, contract, or transaction.

(84) "Covered Entity" means an entity within California that has one or more of the processes or operations and has a compliance obligation as specified in subarticle 7 of this regulation; and that has emitted, produced, imported, manufactured, or delivered in 2009 or any subsequent year more than the applicable threshold level specified in section 95812(a) of this rule.

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

(86) "Crediting Baseline" refers to the reduction of absolute GHG emissions below the business-as-usual scenario or reference level across a jurisdiction's entire sector in a sector-based crediting program after the imposition of greenhouse gas emission reduction requirements or incentives.

(87) "Crediting Period" means the pre-determined period for which an offset project will remain eligible to be issued ARB offset credits or registry offset credits for verified GHG emission reductions or GHG removal enhancements.

(88) "Dairy product solids for animal feed" means modified dairy products (permeates and products derived there from) processed for animal consumption obtained by the removal of water, protein and/or lactose, and/or minerals from milk.

(89) "Data Year" means the calendar year in which emissions occurred.

(90) "Deforestation" means direct human-induced conversion of forested land to non-forested land.

(91) "Dehydrated chili pepper" means chili pepper that has been dehydrated to no more than 12 percent water by volume in order to extend the shelf life and to

concentrate the flavor. Chili peppers are the fruit of plants from the genus *Capsicum*, and are members of the nightshade family *Solanaceae*.

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

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

(94) “Dehydrated parsley” means parsley that has been dehydrated to no more than 5 percent water by volume in order to extend the shelf life and to concentrate the flavor. Parsley (Petroselinum crispum) is a species of *Petroselinum* in the family *Apiaceae*.

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

(96) “Delicate task wiper” mean tissue-based wipers used for the delicate cleaning of lenses, surfaces, and equipment in labs, research facilities, hospitals, and manufacturing settings.

(97) “Delivered Electricity” means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

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

(99) "Diced Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum* P. Mill, of red or reddish varieties. The tomatoes are peeled and diced, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

(100) "Diesel Fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and non-taxed fuels.

(101) "Direct Delivery of Electricity" or "directly delivered" has the same meaning as ascribed to MRR section 95102(a).

(102) "Direct GHG Emission Reduction" means a GHG emission reduction from applicable GHG emission sources, GHG sinks, or GHG reservoirs that are under control of the Offset Project Operator or Authorized Project Designee.

(103) "Direct GHG Removal Enhancement" means a GHG removal enhancement from applicable GHG emission sources, GHG sinks, or GHG reservoirs under control of the Offset Project Operator or Authorized Project Designee.

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

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

(106) "Distillate Fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 F.

(107) "Distillate Fuel Oil" means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term "distillate fuel oil" includes kerosene, kerosene-type jet fuel, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(108) "Distilled spirit" means a spirit made from the separation of alcohol and a fermented product.

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

(110) "Dolime" is calcined dolomite.

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

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

(113) "Dry color concentrate" means precipitated solids extract from fruits and vegetables whose uses are for altering the color of materials and/or food.

(114) "Early Action Offset Credit" means a tradable credit issued by an Early Action Offset Program that represents a GHG reduction or GHG removal enhancement equivalent to one metric ton of CO_2e and meets the requirements of section 95990(c).

(115) "Early Action Offset Program" means a program that meets the requirements of section 95990(a) and is approved by ARB.

(116) "Early Action Offset Project" means an offset project that is registered with an Early Action Offset Program, has been issued early action offset credits, with the exception of reforestation offset projects, which must be registered with

an Early Action Offset Program but might not have been issued early action offset credits, and is in good standing with the Early Action Offset Program.

(117) “Early Action Reporting Period” means a reporting period in which GHG reductions and/or GHG removal enhancements are reported under an Early Action Offset Program.

(118) “Early Action Verification Report” means a verification report submitted to an Early Action Offset Program that covers GHG reductions or GHG removal enhancements achieved by an early action offset project over a specific time period.

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

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

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

(122) “Electricity Importers” deliver imported electricity. For electricity that is scheduled with a NERC E-Tag to a final point of delivery inside the state of California, the electricity importer is identified on the NERC E-Tag as the purchasing-selling entity (PSE) on the last segment of the tag’s physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority’s transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility

operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). Electricity Importers include EIM Participating Resource Scheduling Coordinators serving the EIM market whose transactions result in electricity imports into California.

(123) "Eligible Renewable Energy Resource" has the same meaning as defined in Section 399.12 of the Public Utilities Code.

(124) "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids. In the context of offsets, "emissions" means the release of greenhouse gases into the atmosphere from sources and processes within an offset project boundary.

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

(126) "Emissions Efficiency Benchmark" or "GHG emissions efficiency benchmark" means a performance standard used to evaluate GHG emissions efficiency between and amongst similar facilities or operations in the same industrial sector.

(127) "Emulsion" means a mixture of water, crude oil, associated gas, and other components from the oil extraction process that is transferred from an existing platform that is permanently affixed to the ocean floor and that is located outside the distance specified in the "offshore" definition in section 95102 of MRR, to an onshore petroleum and natural gas production facility.

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

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

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

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

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

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

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

(135) “Environmental Impact Assessment” means a detailed public disclosure statement of potential environmental and socioeconomic impacts associated with a proposed project. Such disclosure is a matter of public record and provides detailed information to public agencies and the general public about the effect that a proposed project is likely to have on the environment and ways in which the significant effects of such a project might be minimized, and to indicate alternatives to such a project.

(136) "Evaporated milk" means the liquid food obtained by partial removal of water only from milk. It contains not less than 6.5 percent by weight of milkfat, not less than 16.5 percent by weight of milk solids not fat, and not less than 23 percent by weight of total milk solids. Evaporated milk contains added vitamin D as prescribed by the Code of Federal Regulations, Title 21. It is homogenized. It is sealed in a container and so processed by heat, either before or after sealing, as to prevent spoilage.

(137) “Exchange” means a central marketplace with established rules and regulations where buyers and sellers meet to conduct trades.

(138) “Executive Officer” means the Executive Officer of the California Air Resources Board, or his or her delegate.

(139) “Expected Settlement Date” is a date specified in a transaction agreement on which all requirements in the transaction agreement are expected to be settled, exclusive of any contingencies specified in the agreement.

(140) “Expected Termination Date” is a date specified in a transaction agreement on which all requirements in the transaction agreement are expected to be completed, exclusive of any contingencies specified in the agreement.

(141) “Exported Electricity” shall have the same meaning ascribed in section 95102(a) of MRR.

(142) “External Greenhouse Gas Emissions Trading System” or “External GHG ETS” means an administrative system, other than the California Cap-and-Trade Program, that controls greenhouse gas emissions from sources in its program.

(143) "Facial Tissue" means a class of soft, absorbent, disposable tissue papers that is suitable for use on the face.

(144) (A) "Facility," unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95802(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

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

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

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

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

(147) "First Deliverer of Electricity" or "First Deliverer" means the owner or operator of an electricity generating facility in California or an electricity importer.

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

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

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

(151) "Fluorinated Greenhouse Gas" means sulfur hexafluoride (SF6), nitrogen trifluoride (NF3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82 (May 10, 1995), subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 C. With these exceptions, "fluorinated GHG" includes any hydrofluorocarbon; any perfluorocarbon; any fully fluorinated linear, branched, or cyclic alkane, ether, tertiary amine, or aminoether; any perfluoropolyether; and any hydrofluoropolyether.

(152) "Fluting" means the center segment of corrugated shipping containers, being faced with linerboard (testliner/kraftliner) on both sides. Fluting covers mainly papers made from recycled fiber but this group also holds paperboard that is made from chemical and semichemical pulp.

(153) "Forest Buffer Account" means a holding account for ARB offset credits issued to forest offset projects. It is used as a general insurance mechanism against unintentional reversals, for all forest offset projects listed under a Compliance Offset Protocol.

(154) "Forest Owner" means the owner of any interest in the real (as opposed to personal) property involved in a forest offset project, excluding government agency third party beneficiaries of conservation easements. Generally, a Forest Owner is the owner in fee of the real property involved in a forest offset project. In some cases, one entity may be the owner in fee while another entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the real property are collectively considered the Forest Owners, however, a single Forest Owner must be identified as the Offset Project Operator.

(155) "Fossil Fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

(156) "Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

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

(158) "Fried potato chip" means a thin slice of potato that is deep fried until crunchy.

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

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

(161) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas including operators of interstate and intrastate pipelines, a supplier of liquefied natural gas, or a supplier of liquefied petroleum gas as specified in MRR.

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

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

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

(165) "Gaseous Hydrogen" means hydrogen in a gaseous state.

(166) "Geologic Sequestration" means the process of injecting CO_2 captured from an emissions source into deep subsurface rock formations for long-term storage.

(167) "Global Warming Potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

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

(169) "Grape Juice concentrate" means the liquid from crushed grapes, from the botanical genus *Vitas*, processed to remove water.

(170) "Grape seed extract" means the extract from grape seeds containing concentrations of proanthocyanidin.

(171) "Greenhouse Gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrogen trifluoride (NF_3), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

(172) "Greenhouse Gas Emission Reduction" or "GHG Emission Reduction" or "Greenhouse Gas Reduction" or "GHG Reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

(173) "Greenhouse Gas Emissions Source" or "GHG Emissions Source" means, in the context of offset credits, any type of emitting activity that releases greenhouse gases into the atmosphere.

(174) "Greenhouse Gas Removal" or "GHG Removal" means the calculated total mass of a GHG removed from the atmosphere over a specified period of time.

(175) "Greenhouse Gas Removal Enhancement" or "GHG Removal Enhancement" means a calculated increase in GHG removals relative to a project baseline.

(176) "Greenhouse Gas Reservoir" or "GHG Reservoir" means a physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store, accumulate, or release a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

(177) "Greenhouse Gas Sink" or "GHG Sink" means a physical unit or process that removes a GHG from the atmosphere.

(178) "Gypsum" means a mineral with the chemical formula $CaSO_4 \cdot 2H_2O$.

(179) "HD-5" or "Special Duty Propane" has the same meaning as contained in MRR.

(180) "HD-10" has the same meaning as contained in MRR.

(181) "Hold" in the context of a compliance instrument, is to have the serial number assigned to that instrument registered into an account assigned to an entity that is registered into the California Cap-and-Trade Program or an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, or an account under the control of the Executive Officer.

(182) "Holding Account" or "General Holding Account" means an account created for each covered entity, opt-in covered entity, or voluntarily associated entity to hold compliance instruments.

(183) "Horsepower Tested" means the total horsepower of all turbine and generator set units tested prior to sale.

(184) "Hot Rolled Steel Sheet" means steel produced from the rolling mill that reduces a hot slab into a coil of specified thickness at a relatively high temperature.

(185) "Hydrocarbon" means a chemical compound containing predominantly carbon and hydrogen.

(186) "Hydrofluorocarbon" or "HFC" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

(187) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; it exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(188) "Imported Electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the

first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the state of California from a facility or unit physically located outside the state of California with the first point of interconnection into a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, defined pursuant to MRR section 95102(a). Imported electricity does not include electricity imported into the CAISO balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the state of California. Imported Electricity does not include electricity imported into California by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall include Energy Imbalance Market (EIM) dispatches designated by the CAISO's optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported to serve retail customers load that is located within the State of California.

(189) "Initial Crediting Period" means the crediting period that begins with the date that the first GHG emission reductions or GHG removal enhancements took place according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by ARB.

(190) "Intentional Reversal" means any reversal, except as provided below, which is caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the offset project boundary. A reversal caused by an intentional back burn set by, or at the request of, a local, state, or federal fire protection agency for the purpose of protecting forestlands from an advancing wildfire that began on another

property through no negligence, gross negligence, or willful misconduct of the forest owner is not considered an intentional reversal but, rather, an unintentional reversal.

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

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

(193) "Intrastate Pipeline" means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

(194) "Inventory Position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(195) "Issue" or "Issuance" means, in the context of offset credits, the creation of ARB offset credits or registry offset credits equivalent to the number of verified GHG reductions or GHG removal enhancements for an offset project over a specified period of time. In the context of allowances, issue means the placement of an allowance into an account under the control of the Executive Officer.

(196) "Joint Powers Agency(ies)" or "JPA" means an public agency that is formed and created pursuant to the provisions of Government Code sections 6500. et seq.

(197) "Kerosene" is a light petroleum distillate with a maximum distillation temperature of 400 F at the 10-percent recovery point, a final maximum boiling point of 572 F, a minimum flash point of 100 F, and a maximum freezing point of -22 F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively),

as well as all other grades of kerosene called range or stove oil. Kerosene does not include kerosene-type jet fuel.

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

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

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

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

(202) “Lead Verifier” means, for purposes of this article, a person that has met all of the requirements in section 95132(b)(2) of MRR and who may act as the lead verifier of an offset verification team providing offset verification services or as a lead verifier providing an independent review of offset verification services rendered.

(203) “Lead Verifier Independent Reviewer” or “Independent Reviewer” means, for purposes of this article, a lead verifier within a verification body who has not participated in conducting offset verification services for an Offset Project Developer or Authorized Project Designee for the current Offset Project Data Report and who provides an independent review of offset verification services rendered for an Offset Project Developer or Authorized Project Designee as required in section 95977.1(b)(3)(R). The independent reviewer is not required to also meet the requirements for a sector specific or offset project specific verifier.

(204) “Legacy Contract” means a written contract or tolling agreement, originally executed prior to September 1, 2006, governing the sale of electricity and/or

legacy contract qualified thermal output at a price, determined by either a fixed price or price formula, that does not provide for recovery of the costs associated with compliance with this regulation; the originally executed contract or agreement must have remained in effect and must not have been amended since September 1, 2006 to change or affect the terms governing the California greenhouse gas emissions responsibility, price, or amount of electricity or legacy contract qualified thermal output sold, or the expiration date. For purposes of this regulation, legacy contracts exclude contracts that have been amended to include a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision 10-12-035, with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU). This definition of a "Legacy Contract" does not apply to opt-in covered entities.

(205) "Legacy Contract Counterparty" means an entity that has been identified, pursuant to section 95894, and may also be identified under industrial allocation pursuant to Table 8-1 to receive an allowance allocation, and has a contract to purchase legacy contract qualified thermal output and/or electricity from a legacy contract generator with an industrial counterparty, or from a legacy contract generator without an industrial counterparty, determined by the Executive Officer pursuant to 95894(b) to be eligible for transition assistance under 95894.

(206) "Legacy Contract Emissions" means the covered emissions calculated, based on a positive or qualified positive emissions data verification statement issued pursuant to MRR, by the legacy contract generator with an industrial counterparty or legacy contract generator without an industrial counterparty, that are a result of either electricity and/or legacy contract qualified thermal output sold to a legacy contract counterparty, and calculated pursuant to section 95894 of this regulation.

(207) "Legacy Contract Generator with an Industrial Counterparty" means a covered entity that generates and sells electricity, thermal energy, or both,

subject to a legacy contract with a legacy contract counterparty that is identified as eligible for allowance allocation pursuant to section 95891.

(208) "Legacy Contract Generator without an Industrial Counterparty" means a covered entity that generates and sells electricity, thermal energy, or both, subject to a legacy contract, and does not also sell electricity or thermal energy under the legacy contract to a covered entity eligible for allowance allocation pursuant to section 95891.

(209) "Legacy Contract Qualified Thermal Output" means thermal energy that is sold to a legacy contract counterparty, and reported pursuant to MRR.

(210) "Less Intensive Verification" means, for the purposes of this article, the offset verification services provided in interim years between full verifications of an Offset Project Data Report; less intensive verification of an Offset Project Data Report only requires data checks and document reviews of an Offset Project Data Report based on the analysis and risk assessment in the most current sampling plan developed as part of the most recent full offset verification services. This level of verification may only be used if the offset verifier can provide findings with a reasonable level of assurance.

(211) "Limited Use Holding Account" means an account in which allowances are placed after an entity qualifies for a direct allocation under section 95890(b). Allowances placed in this account can only be removed for consignment to the auction pursuant to section 95831(a)(3).

(212) "Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under this article, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

(213) "Liquid Color Concentrate" means a fluid extract from fruits and vegetables reduced by driving off water and the use of which is for aleraing the colora of materials and/or food.

(214) "Liquid Hydrogen" means hydrogen in a liquid state.

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

(216) "Liquefied Petroleum Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG is primarily mixtures of propane, butane, propene (propylene) and ethane. The most common specification categories are propane grades, HD-5, HD-10, and commercial grade propane. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as propane.

(217) "Listed Industrial Sector" means covered industrial sectors that are eligible for industry assistance specified in Table 8-1 of subarticle 8.

(218) "Long-Term Contract" means a contract for the delivery of electricity entered into before January 1, 2006, for the term of five years or more.

(219) "Mandatory Reporting Regulation" or "MRR" means ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 2 (commencing with section 95100).

(220) "Market Index" means any published index of quantities or prices based on results of market transactions.

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

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

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

(224) "Metric Ton" or "MT" means a common international measurement for mass, equivalent to 2,204.6 pounds or 1.1 short tons.

(225) "Milk" means the lacteal secretion, practically free from colostrum, obtained by the complete milking of one or more healthy cows. Milk that is in final

package form for beverage use shall have been pasteurized or ultrapasteurized, and shall contain not less than 8 1/4 percent milk solids not fat and not less than 3 1/4 percent milkfat. Milk may have been adjusted by separating part of the milkfat from, or by adding cream to, concentrated milk, dry whole milk, skim milk, concentrated skim milk, or nonfat dry milk. Milk may be homogenized.

(226) “Monitoring” means, in the context of offset projects, the ongoing collection and archiving of all relevant and required data for determining the project baseline, project emissions, and quantifying GHG reductions or GHG removal enhancements that are attributable to the offset project.

(227) "Motor Gasoline (finished)" has the same definition as MRR.

(228) “Multi-Jurisdictional Retail Provider” means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

(229) “Municipal Solid Waste” or “MSW” means solid-phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing, and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or

used tires that do not contain hazardous waste identified or listed under 42 U.S.C. §6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

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

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

(232) "Natural gas supplier" or "supplier of natural gas" means any entity that distributes or uses natural gas in California and is described below:

(A) A public utility gas corporation operating in California;

(B) A publicly owned natural gas utility operating in California; or

(C) The operator of an intrastate pipeline not included in section 95811(c)(1) or section 95811(c)(2) that distributes natural gas directly to end users. For the purposes of this article, an interstate pipeline is not a natural gas supplier.

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

(234) "Nitric Acid" means HNO_3 of 100% purity.

(235) “Nonfat dry milk and skimmed milk powder (low heat)” means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of milk no higher than 70 ºC for 2 minutes and includes undenatured whey protein nitrogen content equal to or greater than 6 mg/g powder.

(236) “Nonfat dry milk and skimmed milk powder (medium heat)” means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of 70-78 ºC for 20 minutes and includes undenatured whey protein nitrogen content equal to or greater than 1.51 mg/g powder up to 5.99 mg/g powder.

(237) “Nonfat dry milk and skimmed milk powder (high heat)” means milk powder obtained by removing water from pasteurized skim milk. It contains no more than 5% moisture (by weight) and no more than 1.5% milkfat (by weight). It is derived from cumulative heat treatment of 88 ºC for 30 minutes and includes undenatured whey protein nitrogen content equal to or less than 1.5 mg/g powder.

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

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

(240) “Non-Aseptic whole and diced tomato” means the sum of whole and diced tomatoes packaged using methods other than aseptic preparation. Sum of Non-Aseptic Whole and Diced Tomatoes = Whole Tomatoes + (Diced Tomatoes × 1.05).

(241) "Non-exempt Biomass derived CO_2" means CO_2 emissions resulting from the combustion of fuel not listed under section 95852.2(a), or that is not verifiable under section 95131(i) of MRR.

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

(243) "Notice of Delegation" means a formal notice used to delegate authority to make an electronic submission to the accounts administrator.

(244) "Offset Material Misstatement" means a discrepancy, omission, misreporting, or aggregation of the three, identified in the course of offset verification services that leads an offset verification team to believe that an Offset Project Data Report contains errors resulting in an overstatement of the reported total GHG emission reductions or GHG removal enhancements greater than 5.00 percent. Discrepancies, omissions, or misreporting, or an aggregation of the three, that result in an understatement of total reported GHG emission reductions or GHG removal enhancements in the Offset Project Data Report is not an offset material misstatement.

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

(246) "Offset Project Boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(247) "Offset Project Commencement" means, unless otherwise specified in a Compliance Offset Protocol, the date of the beginning of construction, work, or installation for an offset project involving physical construction, other work at an offset project site, or installation of equipment or materials. For an

offset project that involves the implementation of a management activity, “offset project commencement” means, unless otherwise specified in a Compliance Offset Protocol, the date on which such activity is first implemented.

(248) “Offset Project Data Report” means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a Compliance Offset Protocol.

(249) “Offset Project Operator” means the entity(ies) with legal authority to implement the offset project.

(250) “Offset Project Registry” means an entity that meets the requirements of section 95986 and is approved by ARB that lists offset projects, collects Offset Project Data Reports, facilitates verification of Offset Project Data Reports, and issues registry offset credits for offset projects being implemented using a Compliance Offset Protocol.

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

(252) “Offset Verification” means a systematic, independent, and documented process for evaluation of an Offset Project Operator’s or Authorized Project Designee’s Offset Project Data Report against ARB’s Compliance Offset Protocols and this article for calculating and reporting project baseline emissions, project emissions, GHG reductions, and GHG removal enhancements.

(253) “Offset Verification Services” means services provided during offset verification as specified in sections 95977.1 and 95977.2, including reviewing an Offset Project Operator’s or Authorized Project Designee’s Offset Project Data Report, verifying its accuracy according to the standards specified in this

article and applicable Compliance Offset Protocol, assessing the Offset Project Operator's or Authorized Project Designee's compliance with this article and applicable Compliance Offset Protocol, and submitting an Offset Verification Statement to ARB or an Offset Project Registry.

(254) "Offset Verification Statement" means the final statement rendered by a verification body attesting whether an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report is free of an offset material misstatement, and whether the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

(255) "Offset Verification Team" means all of those working for a verification body, including all subcontractors, to provide offset verification services for an Offset Project Operator or Authorized Project Designee.

(256) "On-purpose hydrogen gas" means molecular hydrogen gas produced as a result of a process or processes dedicated to producing hydrogen (e.g., steam methane reforming).

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

(258) "Operator" means the entity, including an owner, having operational control of a facility, or other entity from which an emissions data report is required under article 2, section 95104, title 17, Greenhouse Gas Emissions Data Report. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(259) "Opt-in Covered Entity" means an entity that meets the requirements of 95811 that does not exceed the inclusion thresholds set forth in section 95812 and may elect to voluntarily opt-in to the Cap-and-Trade Program and be willing to be subject to the requirements set forth in this article.

(260) "Over-the-Counter" means the trading of carbon compliance instruments, contracts, or other instruments not executed or entered for clearing on any exchange.

(261) "Oxidation" means a reaction in which the atoms in an element loe electrons and the valence of the element is correspondingly increased.

(262) "Ozone Depleting Substances" or "ODS" means a compound that contributes to stratospheric ozone depletion.

(263) "Paper Towel" means a disposable towel made of absorbent tissue paper.

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

(265) "Permanent" means, in the context of offset credits, either that GHG reductions and GHG removal enhancements are not reversible, or when GHG reductions and GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions and GHG removal enhancements to ensure that all credited reductions endure for at least 100 years.

(266) "Permanent Retirement Registry" means the publicly available registry in which the Executive Officer will record the retired compliance instruments.

(267) "Petroleum" means oil removed from the earth and the oil derived from tar sands, and/or shale.

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

(269) "Pickled Steel Sheet" means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides, and includes both

finished pickled steel, and steel produced by the facility as an intermediate product for further processing.

(270) "Pipeline Quality Natural Gas" means, for the purpose of calculating emissions under MRR, natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent (90%) methane by volume, and which is less than five percent (5%) carbon dioxide by volume.

(271) "Pistachio" means the nuts of the pistachio tree *Pistacia vera*.

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

(273) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.

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

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

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

(A) The equipment is attached to a foundation;

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months;

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

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

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

(278) “Positive Emissions Data Verification Statement” means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of MRR. For purposes of this definition, ‘material misstatement’ shall have the same meaning as ascribed to it in section 95102(a) of MRR.

(279) “Positive Offset Verification Statement” means an Offset Verification Statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement and that the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

(280) “Positive Product Data Verification Statement” means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and that the product data conforms to the requirements of MRR. For purposes of this definition,

'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

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

(282) "Power" means electricity, except where the context makes clear that another meaning is intended.

(283) "Power contract" shall have the same meaning ascribed in section 95102(a) of MRR.

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

(285) "Primary Account Representative" means an individual authorized by a registered entity through the registration process outlined in section 95832 to make submissions to the Executive Officer and the tracking system in all matters pertaining to this article that legally bind the authorizing entity.

(286) "Primary Refinery Products" means aviation gasoline (EIA product codes 111 and 112), motor gasoline (finished) (EIA product codes 125,127,130,149, and 166), motor gasoline blendstocks (EIA product codes 117, 118, 138, and 139), kerosene-type jet fuel (EIA product code 213), distillate fuel oil (EIA product codes 465, 466, and 467), renewable liquid fuels (EIA product codes 203, 205, and 207), and asphalt (EIA product code 931). For the purpose of calculating this value for each refinery, ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

(287) "Primary Residence" means the property an individual uses as a residence the majority of the time during the year or as the principal place of abode of the individual's family members. The primary residence may be documented by the address listed on the individual's federal and state tax returns, driver's license, automobile registration, or voter registration card.

(288) "Proceeds" means monies generated as a result of an auction or from sales from the Allowance Price Containment Reserve.

(289) "Process" means the intentional or unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

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

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

(292) "Producer" means a person who owns leases, operates, controls, or supervises a California production facility.

(293) "Product Data Verification Statement" means the final statement rendered by a verification body attesting whether a reporting entity's product data in their covered emissions data report is free of material misstatement, and whether the product data conforms to the requirements of the MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

(294) "Professional Judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(295) "Project Baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or

GHG removal enhancements for the offset project's GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

(296) "Project Emissions" means any GHG emissions associated with the implementation of an offset project that must be accounted for in the Offset Project Data Report.

(297) "Proof Gallons" means one liquid gallon of distilled spirits that is 50% alcohol at 60 degrees F.

(298) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(299) "Property Right" means any type of right to specific property whether it is personal or real property, tangible or intangible.

(300) "Protein meal and fat" means meal, feather meal, and fat rendered product from poultry tissues including meat, viscera, bone, blood, and feathers.

(301) "Public Service Facility" means:

(A) a facility that is a covered entity or opt-in covered entity owned by a local government as defined in Government Code section 53720(a) that provides steam or chilled water to buildings and facilities owned by the local government, and may also provide steam or electricity to other buildings or to an electrical distribution utility other than the local government; or

(B) a covered entity that provides steam or chilled water to a publicly-owned university that is an educational facility pursuant to Education Code section 94110(e).

(C) Facilities operated by electrical distribution utilities are excluded from this definition.

(302) "Public Utility Gas Corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(303) "Publicly Owned Natural Gas Utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(304) "Public Wholesale Water Agency" means a covered entity that is owned and operated as a special district, as defined in Statutes of 1960, Ch. 209 (California Water Code appendix § 109), that uses electricity to convey wholesale water supplies and has a compliance obligation for each data year from 2013 to 2020.

(305) "Purchase Limit" means the maximum percentage of allowances that may be purchased by an entity of a group of affiliated entities at an allowance auction.

(306) "Purchasing-Selling Entity" or "PSE" means the same meaning as ascribed in MRR.

(307) "Qualified Export" means electricity that is exported in the same hour as imported electricity and documented by NERC E-tags. When imports are not documented on NERC E-tags, because a facility or unit located outside the state of California has a first point of interconnection with a California balancing authority area, the reporting entity may demonstrate hourly electricity delivery consistent with the record keeping requirements of the California balancing authority area, including records of revenue quality meter data, invoices, or settlements data. Only electricity exported within the same hour and by the same importer as the imported electricity is a qualified export. It is not necessary for the imported and exported electricity (as defined in the MRR) to enter or leave California at the same intertie. Qualified exports shall not result in a negative compliance obligation for any hour.

(308) "Qualified Positive Emissions Data Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9) of MRR, but the emissions data may include one or more other nonconformance(s) with requirements of MRR which do not result in a material misstatement. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

(309) "Qualified Positive Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement, but the Offset Project Data Report may include one or more nonconformance(s) with the quantification, monitoring, or metering requirements of this article and applicable Compliance Offset Protocol which do not result in an offset material misstatement. Nonconformance, in this context, does not include disregarding the explicit requirements of this article or applicable Compliance Offset Protocol and substituting alternative requirements not approved by the Board.

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

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

(312) "Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements

relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks, or GHG reservoirs included within the offset project boundary, while accounting for uncertainty and activity-shifting leakage and market-shifting leakage.

(313) “Quantitative Usage Limit” means a limit on the percentage of an entity’s compliance obligation that may be met by surrendering offset credits, sector-based credits, or other compliance instruments designated to be subject to the limit under this article.

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

(315) “Radiative Forcing” means the change in the net vertical irradiance at the atmospheric boundary between the troposphere and the stratosphere due to an internal change or a change in the external forcing of the climate system such as a change in the concentration of carbon dioxide or the output of the Sun.

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

(317) “Real” means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate, and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

(318) “Reasonable Assurance” means a high degree of confidence that submitted data and statements are valid.

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

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

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

(322) "Reference Level" means the quantity of GHG emission equivalents that have occurred during the normal course of business or activities during a designated period of time within the boundaries of a defined sector and a defined jurisdiction.

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

(324) "Register," in the context of a compliance instrument, means the act of assigning the serial number of a compliance instrument into an account.

(325) "Registrant" or "Registered Entity" means an entity that has completed the process for registration.

(326) "Registry Offset Credit" means a credit issued by an Offset Project Registry for a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable and may only be issued for offset projects using Compliance Offset Protocols. Pursuant to section 95981.1, ARB may determine that a registry offset credit may be removed, retired, or cancelled from the Offset Project Registry system and issued as an ARB offset credit.

(327) "Registry Services" means all services provided by an ARB approved Offset Project Registry in section 95987.

(328) "Renewable diesel" means a motor vehicle fuel or fuel additive that is all of the following:

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

(B) Not a mono-alkyl ester;

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

(D) Derived from nonpetroleum renewable resources.

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

(330) “Renewable Energy Credit” or “REC” has the same meaning as defined in the California Energy Commission’s “Renewable Portfolio Standard Eligibility, 7th edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF.

(331) "Renewable Liquid Fuels" means fuel ethanol, biomass-based diesel fuel, other renewable diesel fuel and other renewable fuels.

(332) “Reporting Period” means, in the context of offsets, the period of time for which an Offset Project Operator or Authorized Project Designee quantifies and reports GHG reductions or GHG removal enhancements covered in an Offset Project Data Report. The first reporting period for an offset project in an initial crediting period may consist of 6 to 24 consecutive months; all subsequent reporting periods in an initial crediting and all reporting periods in any renewed crediting period must consist of 12 consecutive months. For offset projects developed using the Compliance Offset Protocol in section 95973(a)(2)(C)1., there may only be one Reporting Period per offset project. The Reporting Period may not be longer than 12 months and there is no minimum timeframe imposed for the Reporting Period.

(333) “Reporting Year” means data year.

(334) “Reserve Price” see “Auction Reserve Price.”

(335) “Reserve Sale Administrator” means the operator of sales from the Allowance Price Containment Reserve account, which may be the Executive Officer or an entity designated by the Executive Officer.

(336) "Resource Shuffling" means any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).

(337) "Retail Provider" means an entity that provides electricity to retail end users in California and is an electrical corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(338) "Retire" or "Retired" or "Retirement" means that the serial number for a compliance instrument is registered into the Retirement Account under the control of the Executive Officer. Compliance instruments registered into this account cannot be removed.

(339) "Reversal" means a GHG emission reduction or GHG removal enhancement for which an ARB offset credit or registry offset credit has been issued that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance.

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

(341) "Seamless rolled ring" means a metal product manufactured by punching a hole in a thick, round piece of metal, and then rolling and squeezing (or in

some cases, pounding) it into a thin ring. Ring diameters can be anywhere from a few inches to 30 feet.

(342) "Sector" or "Sectoral," when used in conjunction with sector-based crediting programs, means a group or subgroup of an economic activity, or a group or cross-section of a group of economic activities, within a jurisdiction.

(343) "Sector-Based Crediting Program" is a GHG emissions-reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that jurisdiction. A program's performance is based on achievement toward an emissions reduction target for the particular sector within the boundary of the jurisdiction.

(344) "Sector-Based Offset Credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached.

(345) "Self-Generation of Electricity" means electricity dedicated to serving an electricity user on the same location as the generator. The system may be operated directly by the electricity user or by an entity with a contractual arrangement.

(346) "Serial Number" means a unique number assigned to each compliance instrument for identification.

(347) "Sequestration" means the removal and storage of carbon from the atmosphere in GHG sinks or GHG reservoirs through physical or biological processes.

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

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

(350) "Soda Ash Equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

(351) "Solomon Energy Intensity Index®" or "Solomon EII" or "EII" means a petroleum refinery energy efficiency metric that compares actual energy consumption for a refinery with the "standard" energy consumption for a refinery of similar size and configuration. The "standard" energy is calculated based on an analysis of worldwide refining capacity as contained in the database maintained by Solomon Associates. The ratio of a facility's actual energy to the standard energy is multiplied by 100 to arrive at the Solomon EII for a refinery. "Solomon Energy Review" means a data submittal and review conducted by a petroleum refinery and Solomon Associates. This process uses the refinery energy utilization, throughput and output to determine the Solomon EII of the refinery.

(352) "Source" means greenhouse gas source; or any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

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

(354) "Specified Source of Electricity" or "Specified Source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract as defined in MRR section 95102(a) to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by ARB.

(355) "Stand-Alone-Electricity Generating Facility" has the same meaning in this regulation as in section 95102(a) of MRR.

(356) "Standing Live Carbon Stocks" means the above ground carbon in live tree biomass. Live trees include the bole, stem, branches, roots, and leaves or needles.

(357) "Stationary" means neither portable nor self-propelled, and operated at a single facility.

(358) "Steel Produced Using an Electric Arc Furnace" means steel produced by electric arc furnace or "EAF". EAF means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes.

(359) "Stucco" means hemihydrate plaster ($CaSO_4 \cdot ½H_2O$) produced by heating ("calcining") raw gypsum, thereby removing three-quarters of its chemically combined water.

(360) "Supplier" means a producer, importer, exporter, position holder, interstate pipeline operator, or local distribution company of a fossil fuel or an industrial greenhouse gas.

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

(362) "Testliner" means types of paperboard that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made. Testliner is made primarily from fibers obtained from recycled fibers.

(363) "Thermal enhanced oil recovery" or "thermal EOR" means the process of using injected steam to increase the recovery of crude oil from a reservoir.

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

(365) "Tissue" means a class of papers which are characteristically gauzy in texture and, in some cases, fairly transparent. They may be glazed, unglazed, or creped, and are used for a variety of purposes. Examples of different types of tissue papers include sanitary grades such as toilet, facial, napkin, towels, wipes, and special sanitary papers.

(366) "Tissue produced adjusted by water absorbency capacity" means the mass of tissue adjusted by water absorbency capacity derived by using the following metric: Tissue produced adjusted by water absorbency capacity = Air dried ton of tissue produced x grams of water absorbed by a gram of tissue product.

(367) "Tomato Juice" is the liquid obtained from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum* P. Mill, of red or reddish varieties. Tomato juice may contain salt, lemon juice, sodium bicarbonate, water, spices and/or flavoring. This food shall contain not less than 5.0 percent by weight tomato soluble solids.

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

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

(370) "Tomato soluble solids" (TSS or NTSS) means the sucrose value as determined by the method prescribed in the "Official Methods of Analysis of the Association of Official Analytical Chemists," 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. For instances where no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or through the application of the acidified break, determine the percent of such added sodium chloride as specified in the definition of salt. Subtract the

percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of "tomato soluble solids."

(371) "Tracking System" means the Compliance Instrument Tracking System Service where ARB compliance instruments are issued, traded, and retired.

(372) "Transaction," when referring to an arrangement between registered entities regarding compliance instruments, means an understanding among registered entities to transfer the control of a compliance instrument from one entity to another, either immediately or at a later date.

(373) "Transfer" of a compliance instrument means the removal of a compliance instrument from one account and placement into another account.

(374) "Transfer Request" means the communication by an authorized account representative or an alternate authorized account representative to the accounts administrator to register into the tracking system the transfer of allowances between accounts.

(375) "Transferred ARB Project" means an offset project which has been transferred from one Offset Project Registry, where it was previously listed, to another Offset Project Registry. The Offset Project Registry to which the offset project is transferred will indicate the applicable offset project status from the following list: "Proposed Project," "Active ARB Project," "Active Registry Project," "Proposed Renewal," "Active ARB Renewal," and "Active Registry Renewal."

(376) "Tribe" means a federally-recognized Indian tribe and any entity created by a federally-recognized Indian Tribe.

(377) "True-up allowance amount" is a quantity of California GHG allowances allocated for changes in production or allocation not properly accounted for in prior allocations pursuant to 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c), or 95894(d).

(378) "Ultrafiltered milk" means raw or pasteurized milk or nonfat milk that is passed over one or more semipermeable membranes to partially remove water,

lactose, minerals, and water-soluble vitamins without altering the casein-to-whey protein ratio of the milk or nonfat milk and resulting in a liquid product.

(379) “Unintentional Reversal” means any reversal, including wildfires or disease that is not the result of the forest owner’s negligence, gross negligence, or willful intent.

(380) “University Covered Entity” means a facility that meets the definition of an educational facility pursuant to Education Code section 94110(e) and is either a covered entity, or opt-in covered entity as of January 1, 2015.

(381) “Unspecified Source of Electricity” or “Unspecified Source” means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity.

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

(383) “Verifiable” means that an Offset Project Data Report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

(384) “Verification Body” means a firm accredited by ARB, which is able to render an offset verification statement and provide offset verification services for Offset Project Operators or Authorized Project Designees subject to providing an Offset Project Data Report under this article.

(385) “Verifier” or “offset verifier” means an individual accredited by ARB to carry out offset verification services as specified in sections 95977.1 and 95977.2.

(386) “Vintage Year” means the budget year to which an individual Californian GHG allowance is assigned pursuant to subarticle 6.

(387) “Voluntarily Associated Entity” or “General Market Participant” means any entity which does not meet the requirements of section 95811 or 95813 in this article and that intends to purchase, hold, sell, or voluntarily retire compliance instruments or an entity operating an offset project or early action offset

project that is registered with ARB pursuant to subarticle 13 or 14 in this article.

(388) "Voluntary Renewable Electricity" or "VRE" means electricity produced or RECs associated with electricity, produced by a voluntary renewable electricity generator, and which has not and will not be sold or used to meet any other mandatory requirements in California or any other jurisdiction.

(389) "Voluntary Renewable Electricity Aggregator" or "VRE Aggregator" means the entity that is aggregating systems for the purpose of allowance retirement pursuant to section 95841.1.

(390) "Voluntary Renewable Electricity Generator" means any entity that produces renewable electricity and applies for allowance retirement pursuant to section 95841.1.

(391) "Voluntary Renewable Electricity Participant" or "VRE Participant" means a voluntary renewable electricity generator, a REC marketer, or entity that purchases voluntary renewable electricity or RECs as an end-user or on behalf of an end-user and is seeking allowance retirement pursuant to section 95841.1.

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

(393) "Waste-to-Energy Facility" means a facility located in California that combusts eligible municipal solid waste. The facility must operate in accordance with a current permit issued by the local Air Pollution Control District or Air Quality Management District to generate and distribute electricity over the electric power grid for wholesale or retail customers of the grid located in California.

(394) "Water absorption capacity" means the mass of water that is absorbed per unit mass of the test piece using the methodology specified by ISO 12625-8:2010 except for the humidity and temperature conditions, which shall be 50% relative humidity +/- 2%, and 23 degrees C +/- 1 degree C.

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

(396) "Whole chicken and chicken parts" means whole chicken or chicken parts (including breasts, thighs, wings, and drums) that are packaged for wholesale or retail sale, or transferred to other facilities.

(399) "Whole Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum* P. Mill, of red or reddish varieties. The tomatoes are peeled but kept whole, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

(b) For the purposes of sections 95801 through 96023, the following acronyms apply:

(1) "AB 32" means Assembly Bill 32, the California Global Warming Solutions Act of 2006.

(2) "ARB" means the California Air Resources Board.

(3) "BAU" means business as usual.

(4) "BPA" means Bonneville Power Administration.

(5) "C" means Centigrade

(6) "CAISO" means the California Independent System Operator.

(7) "CAR" means Climate Action Reserve.

(8) "CEC" means California Energy Commission.

(9) "CFR" means Code of Federal Regulations.

(10) "CH_4" means methane.

(11) "CO_2" means carbon dioxide.

(12) "CO_2e" means carbon dioxide equivalent.

(13) "DWR" means California Department of Water Resources.

(14) "EII" means the Solomon Energy Instensity Index®

(15) "ETS" means Emission Trading System

(16) "F" means Fahrenheit.

(17) "GHG" means greenhouse gas.

(18) "GHG ETS" means greenhouse gas emissions trading system.

(19) "GWP" means global warming potential.

(20) "HFC" means hydrofluorocarbon.

(21) "LPG" means liquefied petroleum gas.

(22) "MMBtu" means one million British thermal units.

(23) "MRR" means the Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(24) "Mscf" means one thousand standard cubic feet.

(25) "MWh" means megawatt-hour.

(26) "MT" means metric tons.

(27) "NAICS" means North American Industry Classification System.

(28) "NGLs" means natural gas liquids.

(29) "NERC" means North American Electric Reliability Corporation.

(30) "N_2O" means "nitrous oxide."

(31) "PFC" means perfluorocarbon.

(32) "PSE" means purchasing-selling entity.

(33) "PUC" means the Public Utilities Commission.

(34) "QE" means Qualified Export as defined in section 95802(a)

(35) "REC" means Renewable Energy Credit.

(36) "REDD" means reducing emissions from deforestation and degradation.

(37) "RPS" means the Renewable Portfolio Standard

(38) "SCF" means standard cubic foot.

(39) "SF_6" means sulfur hexafluoride.

(40) "TEAP" means the Technology and Economic Assessment Panel of the Montreal Protocol.

(41) "WAPA" means Western Area Power Administration.

(42) "WREGIS" means Western Renewable Energy Generation Information System.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 3: Applicability

This article applies to all of the entities identified in this subarticle.

§ 95810. Covered Gases.

This article applies to the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogen trifluoride (NF_3), and other fluorinated greenhouse gases.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95811. Covered Entities.

This article applies to all of the following entities with associated GHG emissions pursuant to section 95812:

(a) Operators of Facilities. The operator of a facility within California that has one or more of the following processes or operations:

(1) Cement production;

(2) Cogeneration;

(3) Glass production;

(4) Hydrogen production;

(5) Iron and steel production;

(6) Lead Production;

(7) Lime manufacturing;

(8) Nitric acid production;

(9) Petroleum and natural gas systems, as specified in section 95852(h);

(10) Petroleum refining;

(11) Pulp and paper manufacturing;

(12) Self-generation of electricity; or

(13) Stationary combustion.

(b) First Deliverers of Electricity.

(1) Electricity generating facilities: the operator of an electricity generating facility located in California; or

(2) Electricity importers.

(c) Suppliers of Natural Gas. An entity that distributes or uses natural gas in California as described below:

(3) A public utility gas corporation operating in California;

(4) A publicly owned natural gas utility operating in California; or

(5) The operator of an intrastate pipeline not included in section 95811(c)(1) or section 95811(c)(2) that distributes natural gas directly to end users.

(d) Suppliers of RBOB and Distillate Fuel Oil. A position holder of one or more of the following fuels, or an enterer that imports one or more of the following fuels into California:

(6) RBOB;

(7) Distillate Fuel Oil No. 1; or

(8) Distillate Fuel Oil No. 2.

(e) Suppliers of Liquefied Petroleum Gas.

(9) The operator of a refinery that produces liquid petroleum gas in California;

(10) The operator of a facility that fractionates natural gas liquids to produce liquid petroleum gas; or

(11) A consignee of liquefied petroleum gas into California as defined under MRR.

(f) Sections 95811(c), (d), and (e) apply to suppliers of blended fuels that contain the fuels listed above.

(g) Suppliers of Liquefied Natural Gas.

(1) Operators of liquefied natural gas production facilities that produce liquefied natural gas products from natural gas received from interstate pipelines as described in section 95122 of MRR;

(2) Importers of liquefied natural gas.

(h) Carbon dioxide suppliers.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95812. Inclusion Thresholds for Covered Entities.

(a) The inclusion threshold for each covered entity is based on the subset of greenhouse gas emissions that generate a compliance obligation for that entity as specified in section 95852. The entity must report and verify annual emissions pursuant to sections 95100 through 95157 of MRR.

(b) If an entity's reported or reported and verified annual emissions in any data year from 2009 through 2012 from the categories specified in section 95852(a) or (b) equal or exceed the thresholds identified below, that entity is classified as a covered entity as of January 1, 2013, and for all future years until any requirement set forth in section 95812(e) is met.

(c) The requirements apply as follows:

(1) Operators of Facilities. The applicability threshold for a facility is 25,000 metric tons or more of CO_2e per data year.

(2) First Deliverers of Electricity.

(A) Electricity Generating Facilities. The applicability threshold for an electricity generating facility is based on the annual emissions from which the electricity originated. The applicability threshold for an electricity generating facility is 25,000 metric tons or more of CO_2e per data year.

(B) Electricity importers. The applicability threshold for an electricity importer is based on the annual emissions from each of the electricity importer's sources of delivered electricity.

1. All emissions reported for imported electricity from specified sources of electricity that emit 25,000 metric tons or more of CO_2e per year are considered to be above the threshold.

2. All emissions reported for imported electricity from unspecified sources are considered to be above the threshold.

(3) Carbon Dioxide Suppliers. The applicability threshold for a carbon dioxide supplier is 25,000 metric tons or more of CO_2e per year. For purpose of comparison to this threshold, the supplier must include the sum of the CO_2 that it captures from its production process units for purposes of supplying CO_2 for commercial applications or that it captures from a CO_2 stream to utilize for geologic sequestration, and the CO_2 that it extracts or produces from a CO_2 production well for purposes of supplying for commercial applications or that it extracts or produces to utilize for geologic sequestration.

(4) Petroleum and Natural Gas Facilities. The applicability threshold for a petroleum and natural gas facility 25,000 metric tons or more of CO_2e per data year. This threshold is applied for each facility type specified in section 95852(h).

(d) If an entity's annual, assigned, or reported and verified emissions from any data year between 2011-2014 equal or exceed the thresholds identified below from the categories specified in sections 95851(a), (b), and (d) then that entity is classified as a covered entity as of January 1, 2015, for the year in which the threshold is reached and for all future years until any requirement set forth in section 95812(e) is met.

(1) Fuel Suppliers. The threshold for a fuel supplier is 25,000 metric tons or more of CO_2e annually from the emissions of GHG that would result from full combustion or oxidation of the quantities of the fuels, identified in section 95811(c) through (g), which are imported and/or delivered to California.

(2) Electricity importers. The threshold for an electricity importer of specified source of electricity is zero metric tons of CO_2e per year and for unspecified sources is zero MWhs per year as of January 1, 2015.

(3) Waste-to-Energy-Facilities. If a waste-to-energy facility's annual, assigned, or reported and verified emissions from any data year between 2011-2015 equal or exceed 25,000 metric tons or more of CO_2e annually, then that entity is classified as a covered entity as of January 1, 2016, for the year in which the

threshold is reached and for all years until the requirement set forth in section 95812(e) is met.

(e) Effect of Reduced Emissions on an Entity's Compliance Obligation. A covered entity continues to have a compliance obligation for each data year of a compliance period, until the subsequent compliance period after one of the following conditions occurs:

(1) Annual reports demonstrate GHG emissions less than 25,000 metric tons of CO_2e per year during one entire compliance period; or

(2) A covered entity has ceased reporting and shuts down all processes, units, and supply operations subject to reporting, and has followed the requirements of section 95101(h) of MRR.

(f) If a covered entity or opt-in covered entity ceases all operation or "shuts down," the following shall apply:

(1) The entity must comply with MRR cessation of reporting provisions per 95101(h).

(2) Within 30 days of shut down, the entity must inform ARB in writing that it has shut down. If not part of a consolidated tracking system account, the entity will become a voluntarily associated entity. If part of a consolidated tracking system account, the entity that has shut down will become a voluntarily associated entity within the consolidated tracking system account.

(3) For a formerly covered or opt-in covered entity, within 30 days of fulfilling its compliance obligation for its final year of operations, the entity must request (in writing) permission from ARB to:

(A) remain in the tracking system account as a voluntarily associated entity pursuant to 95814(a)(1), or

(B) close its tracking system account (if not part of a consolidated tracking system account), or remove the covered entity or opt-in covered entity from its tracking system account (if part of a consolidated tracking system account).

(4) Return of future free allocation. If an entity received allocation of a vintage subsequent to the calendar year that the facility ceased operation, the facility

shall return to the Executive Officer the number of allowances equal to the directly allocated allowances for the corresponding budget years in which it had no production. The submission of request to return allowances must occur within five days of settlement of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is later, and for which the registration deadline has not passed at the time of the final compliance obligation for its final year of operation. The returned allowances will be auctioned pursuant to section 95910.

(5) Prorated final free allocation. In calendar year following shut down, if a facility receives allocation that includes a true-up pursuant to sections 95852(k), 95870(e), 95870(f), 95891(b), 95891(c), 95891(d), 95891(e), or 95894(c) only the true-up shall be calculated. This value shall include any previous negative balance of allowance allocation pursuant to 95870(i).

(A) If true-up is positive, the calculated true-up amount shall be directly distributed to the facility in the vintage of the calendar year following shut down.

(B) If true-up is negative, the facility shall return to the Executive Officer the number of allowances equal to the negative amount in the vintage of or before the calendar year following shut down. The submission for retirement must occur within five days of settlement of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is later, and for which the registration deadline has not passed at the time of the final compliance obligation for its final year of operation. The Executive Officer will auction the returned allowances pursuant to section 95910.

(6) If the entity requests that ARB close its account in the tracking system and there are compliance instruments remaining in the entity's accounts, ARB will auction the allowances pursuant to 95831(c)(4).

(g) Change of Entity Type. At the end of any compliance period, a covered entity may apply to change its entity type in the program, if its annual emission levels for each year in the compliance period remain below the inclusion thresholds set forth in section 95812. This application must be made to the Executive Officer by September 1 of the last calendar year of the compliance period. If an entity does not apply to the Executive Officer, the facility will automatically become an voluntarily associated entity pursuant to 95812(g)(2). A covered entity that applies to change its entity type may choose one of the following:

(1) Remain in the Cap-and-Trade Program as an opt-in covered entity pursuant to 95813;

(2) Remain in the Cap-and-Trade Program as a voluntarily associated entity pursuant to 95814;

(A) If the entity has a negative balance of allowance allocation pursuant to 95870(i), the entity shall submit to the Executive Officer for the retirement of the number of allowances equal to the negative amount in the vintage of or before the final calendar year of the compliance period. The submittal for retirement must occur within five days of settlement of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is later, and for which the registration deadline has not passed at the time of the final compliance obligation for its final year of operation.

(3) Opt out of the Cap-and-Trade Program.

(A) An entity choosing to opt out of the program must continue to report pursuant to MRR in the calendar year following the final year of a compliance period and fulfill its compliance obligations as required pursuant to 95856.

(B) If the entity has a negative balance of allowance allocation pursuant to 95870(i), the entity shall return to the Executive Officer the number of allowances equal to the negative amount in the vintage of or before the final calendar year of the compliance period. The submittal for retirement must occur within five days of settlement of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is later, and for which the registration deadline has not passed at the time of the final compliance obligation for its final year of operation.

(C) If the entity closes its account in the tracking system and there are compliance instruments remaining in the entity's accounts, ARB will auction the allowances pursuant to 95831(c)(4).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95813. Opt-In Covered Entities.

(a) An entity that meets the requirements of section 95811, but does not exceed the inclusion thresholds set forth in section 95812 may elect to voluntarily opt-in to the Cap-and-Trade Program.

(b) An entity that voluntarily elects to participate in this program under this section must submit its request to the Executive Officer for approval pursuant to section 95830(c) by March 1 of the calendar year immediately preceding the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to this section. The Executive Officer shall evaluate such applications and designate approved applicants as opt-in covered entities.

(c) An entity that voluntarily elects to participate in this program under this section may rescind its request to opt in to the program by October 1 of the calendar year prior to the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to section 95813.

(d) An opt-in covered entity is subject to all reporting, verification, enforcement, and compliance obligations that apply to covered entities. An opt-in covered entity's first reporting and verification year shall be the calendar year immediately preceding the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to this section.

(e) An opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles 8 and 9.

(f) Opt-in participation shall not affect the allowance budgets set forth in subarticle 6.

(g) Opting out. At the end of any given compliance period, an opt-in covered entity may choose to opt out of the program provided its annual emission levels for any data year remain below the inclusion thresholds set forth in section 95812. An entity choosing to opt out of the program must either fulfill its compliance obligations as required pursuant to subarticle 7 or surrender allowances equivalent to all the directly allocated allowances it has received from the budget years for the compliance period in question. An opt-in covered entity that wishes to opt-out of this program must apply to the Executive Officer by September 1 of the last year of a compliance period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95814. Voluntarily Associated Entities and Other Registered Participants.

(a) Voluntarily Associated Entities (VAE). An entity not identified as a covered entity or opt-in covered entity that intends to hold California compliance instruments may apply to the Executive Officer pursuant to section 95830(c) for approval as a voluntarily associated entity.

(1) The following entities may qualify as voluntarily associated entities:

(A) An individual, or an entity that does not meet the requirements of sections 95811 and 95813, that intends to purchase, hold, sell, or voluntarily retire compliance instruments;

(B) An entity operating an offset project or early action offset project that is registered with ARB pursuant to subarticles 13 or 14; or

(C) An entity providing clearing services in which it takes only temporary possession of compliance instruments for the purpose of clearing transactions between two entities registered with the Cap-and-Trade Program. A qualified entity must be a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C § 1a(9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. § 7a-1(a)).

(2) An individual registering as a voluntarily associated entity must have a primary residence in the United States.

(3) An individual employed by an entity providing consulting services as described in section 95923 for a covered entity, opt-in covered entity, or voluntarily associated entity who chooses to register as a voluntarily associated entity in the tracking system, must provide a notarized letter from the individual's employer stating the employer is aware of the employee's plans to apply as a voluntarily associated entity in the Cap-and-Trade Program and that the employer has conflict of interest policies and procedures in place which prevent the employee from using information gained in the course of employment as an employee of the company and using it for personal gain in the Cap-and-Trade Program.

(4) An individual who meets the requirements of section 95814(a)(3) and is already registered in the tracking system must provide the notarized letter from his/her employer no later than October 1, 2014. Failure to provide such a letter by the deadline will result in suspension, modification, or revocation of his/her tracking system account.

(5) An entity registering as a voluntarily associated entity must be located in the United States, according to the registration information reported pursuant to section 95830(c).

(6) Individuals identified by registered entities pursuant to sections 95830(c)(1)(B),(C),(I), and (J) are not eligible to register as voluntarily associated entities.

(7) An individual employed by an entity subject to the requirements of MRR or the Cap-and-Trade Program is not eiligible to register as a voluntarily associated entity.

(b) Restrictions on Other Registered Participants. The following entities do not qualify to hold compliance instruments and do not qualify as a Registered Participant:

(1) An offset verifier accredited pursuant to section 95978;

(2) A verification body accredited pursuant to section 95978;

(3) Offset Project Registries;

(4) Early Action Offset Programs approved pursuant to subarticle 14; or

(5) A MRR verifier accredited pursuant to the MRR.

(c) A registered entity that has had its holding account revoked pursuant to section 95921(g)(3) may not hold compliance instruments or register with the accounts administrator in the Cap-and-Trade Program in any capacity.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 4: Compliance Instruments

§ 95820. Compliance Instruments Issued by the Air Resources Board.

(a) California Greenhouse Gas Emissions Allowances.

(1) The Executive Officer shall create California GHG allowances pursuant to the schedule set forth in subarticle 6.

(2) The Executive Officer shall assign each California GHG allowance a unique serial number that indicates the annual allowance budget from which the allowance originates.

(3) The Executive Officer shall place these allowances into a holding account under the control of the Executive Officer pursuant to section 95831(b).

(b) Offset Credits Issued by ARB.

(1) The Executive Officer shall issue and register ARB offset credits pursuant to the requirements of subarticles 13 and 14.

(2) Surrender of ARB offset credits shall be subject to the quantitative usage limit set forth in section 95854.

(c) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. No provision of this article may be construed to limit the authority of the Executive Officer to terminate or limit such authorization to emit. A compliance instrument issued by the Executive Officer does not constitute property or a property right.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95821. Compliance Instruments Issued by Approved Programs.

The following compliance instruments may be used to meet a compliance obligation under this article:

(a) Allowances specified in section 95942(b) and issued by a program approved by ARB pursuant to section 95941;

(b) Offset credits specified in section 95942(c) and issued by a program approved by ARB pursuant to section 95941;

(c) ARB offset credits issued for purposes of early action pursuant to section 95990;

(d) Sector-based offset credits recognized pursuant to subarticle 14; and

(e) Compliance instruments specified in sections 95821(b) through (d) are subject to the quantitative usage limit set forth in section 95854.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 5: Registration and Accounts

§ 95830. Registration with ARB.

(a) The Executive Officer shall serve as accounts administrator or may contract with an entity to serve as accounts administrator.

(b) Eligibility and Restrictions:

(1) An entity must qualify for registration in the tracking system pursuant to section 95811, 95813, or 95814. If an entity is registering pursuant to section 95811 or 95813, the facility operator, fuel or CO_2 supplier, electric power entity, or operator of petroleum and natural gas systems, as applicable and as identified in section 95101(a)(1) of MRR must register pursuant to this section

and meet all applicable requirements of this article. Alternatively, if the entity chooses to consolidate accounts pursuant to Section 95833, then at least one facility operator, fuel or CO_2 supplier, electric power entity, or operator of petroleum and natural gas systems, as applicable, of the entities in the direct corporate association must register pursuant to this section and meet all applicable requirements of this article for all entities included in the consolidated account.

(2) An entity qualified to register cannot apply for more than one Registration in the tracking system.

(3) An entity cannot hold a compliance instrument until the Executive Officer approves the entity's registration with ARB and an account in the tracking system.

(4) An entity seeking to list an offset project situated on the categories of land in section 95973(d) must demonstrate the existence of a limited waiver of sovereign immunity entered into pursuant to section 95975(l) prior to registering pursuant to this section.

(c) Requirements for Registration.

(1) An entity must complete an application to register with ARB for an account in the tracking system that contains the following information:

(A) Name, physical and mailing addresses, and contact information, type of organization, date and place of incorporation;

(B) Names and addresses of the entity's directors and officers;

(C) Names and contact information for persons controlling over 10 percent of the voting rights attached to all the outstanding voting securities of the entity;

(D) A business number, if one has been assigned to the entity by a California state agency;

(E) A U.S. Federal Tax Employer Identification Number, if assigned;

(F) Data Universal Numbering System number, if assigned;

(G) Statement of basis for qualifying for registration pursuant to sections 95811, 95813, or 95814; and

(H) Identification of all other entities with whom the entity has a direct corporate association or indirect corporate association that must be reported pursuant to section 95833(d), and a brief description of the association. When identifying direct corporate associations pursuant to section 95833(d) that are not registered in the Cap-and-Trade Program or in a GHG ETS to which California has linked pursuant to subarticle 12, an entity may opt to limit this identification by disclosing only those unregistered direct corporate associated entities that participate in a market related to the Cap-and-Trade Program in accordance with section 95830(c)(1)(H)1. Notwithstanding this option of a more limited disclosure, a registered entity that has a direct or indirect corporate association with another registered entity must always disclose the identity of all entities involved in the line of direct or indirect corporate associations between the two registered entities, even if such entities are not registered. An entity completing an application to register with ARB and for an account in the tracking system, or updating its information pursuant to sections 95833 and 95830(f)(1), must provide all applicable information required by section 95833(d)(1)-(2), or, for unregistered direct corporate associations only, the entity may opt to comply by disclosing unregistered direct corporate associations in accordance with section 95830(c)(1)(H)1.

1. As an alternative to disclosing all unregistered direct corporate associations pursuant to section 95833(d), an entity may disclose those unregistered direct corporate associated entities that trade, sell, or purchase for resale any natural gas, oil, electricity, or greenhouse gas emission instrument, or natural gas, oil, electricity, or greenhouse gas emission instrument derivative or swap on exchanges. To disclose unregistered direct corporate associations, an entity also may submit the most recent information submitted to another government agency in the United States on one or more of the following official governmental forms or documentation as

needed to meet the required disclosure: (1) Exhibit 21 of the Form 10-K submitted to the Securities and Exchange Commission by the registrant or an affiliate of the registrant; (2) the application for market-based rate authority, or update to such application, submitted by the registrant or an affiliate of the registrant to the Federal Energy Regulatory Commission pursuant to 18 CFR Part 35 and Order 697; (3) the application for registration with the National Futures Association, or update to such application, submitted by the registrant or an affiliate of the registrant as required by the Commodity Futures Trading Commission pursuant to the Commodity Exchange Act; (4) Form 40 or Form 40S filed by the registrant or an affiliate of the registrant in accordance with the Commodity Futures Trading Commission's reporting rules; and/or (5) Part 1A of a Form ADV filed with the Securities and Exchange Commission by a registered investment advisor responsible for managing the registrant.

(I) Names and contact information for all persons employed by the entity with knowledge of the entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions).

(J) Information required under section 95923 for individuals serving as Cap-and-Trade Consultants and Advisors for entities participating in the Cap-and-Trade Program.

(2) Applicants may be denied registration in the tracking system: 1. based on information provided; or 2. if the Executive Officer determines the applicant has provided false or misleading information; or 3. if the Executive Officer determines the applicant has withheld information material to its application.

(3) Any individual listed by the registering entity in its registration application in a capacity requiring access to the tracking system must comply with the Know-Your-Customer requirements pursuant to section 95834 before access to the tracking system will be granted.

(4) An entity must designate a primary account representative, at least one and up to four alternate account representatives pursuant to section 95832. An individual registering as a voluntarily associated entity may elect to serve as both primary and alternate account representatives or designate additional persons.

(5) An individual registering as a voluntarily associated entity and having a primary residence in the United States, but not located in California, must designate an agent for service of process in California. The agent may be an individual who resides in California, or a corporation, that has previously filed a certificate pursuant to California Corporations Code section 1505.

(6) An entity applying for registration that is not an individual or an entity supplying exchange clearing services pursuant to section 95814(a)(1)(C) must designate, pursuant to section 95832, either:

(A) A primary account representative or at least one alternate account representative with a primary residence in California; or

(B) An agent for service of process in California. For entities registering into California, the agent may be an individual who resides in California, or a corporation, that has previously filed a certificate pursuant to California Corporations Code section 1505.

(7) Any individual who requires access to the tracking system, including the primary account representative, alternate account representatives, or account viewing agents must first register as a user in the tracking system.

(A) An individual qualified to register as a user in the tracking system cannot apply for more than one user registration.

(B) An individual cannot be designated in a capacity requiring access to the tracking system until the Executive Officer approves the user's registration in the tracking system. This prohibition includes all primary account representatives, alternate account representatives, and account viewing agents.

(C) An individual registering in the tracking system must provide all applicable information required by sections 95832, 95833, and 95834.

(D) An individual registering in the tracking system must agree to the terms and conditions contained in Appendix B of this article.

(8) An individual may be denied registration:

(A) Based on the information provided;

(B) If the Executive Officer determines the individual has provided false or misleading information;

(C) If the Executive Officer determines the individual has withheld information material to his/her registration;

(D) If an individual fails to comply with section 95834 Know-Your-Customer Requirements; or

(E) If the individual is already registered and has a user account under the same or a different name. This provision applies to individuals registered in an approved external linked GHG emissions trading system.

(d) Registration Deadlines.

(1) An entity that meets or exceeds the inclusion thresholds in section 95812 or an opt-in covered entity must register with the accounts administrator pursuant to this section:

(A) Within 30 calendar days of the reporting deadline contained in MRR if the entity is not a covered entity as of January 1, 2013; or

(B) By January 31, 2012 or within 30 calendar days of the effective date of this regulation, whichever is later, for an entity that exceeds the inclusion thresholds in section 95812 for any data year 2009 through 2012.

(2) Any voluntarily associated entity that intends to hold an ARB-issued compliance instrument must register with the accounts administrator prior to acquiring such compliance instruments.

(e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts administrator of the approval.

(f) Updating Registration Information.

(1) When there is a change to the information registrants have submitted pursuant to section 95830(c), registrants must update the registration information within 30 calendar days of the change unless otherwise specified below. Updates of information provided pursuant to section 95830(c)(1)(I) may be updated within one year of the change instead of within 30 calendar days of the change. If changes in information submitted pursuant to section 95830(c)(1)(H) are related to entities registered in the Cap-and-Trade Program or in a GHG ETS to which California has linked pursuant to subarticle 12, the information must be updated within 30 calendar days of the change. If changes in information submitted pursuant to section 95830(c)(1)(H) are related to entities which are not registered in the Cap-and-Trade Program or in a GHG ETS to which California has linked pursuant to subarticle 12, and which are not involved in the line of direct or indirect corporate associations between two registered entities, the information must be updated within one year of the change, instead of within 30 calendar days of the change.

(2) Information may be directly entered into the tracking system operated by the accounts administrator or, if that is not available, submitted to the accounts administrator by the entity.

(3) Pursuant to section 95921(g)(3), registration may be revoked or suspended if an entity does not update its registration as required in section 95830(f)(1).

(g) Information Confidentiality. The following information collected about individuals during the registration process will be treated as confidential by the Executive Officer and the accounts administrator to the extent possible, and except as needed in the course of oversight, investigation, enforcement and prosecution:

(1) Information collected pursuant to section 95830(c)(1)(B), (C), (I) and (J);

(2) Information collected about individuals pursuant to section 95834; and

(3) Information collected about individuals pursuant to section 95832.

(h) Linking. When California links to an External GHG ETS, each entity must register into a jurisdiction based on the physical location information the entity must provide pursuant to section 95830(c)(1)(A).

(1) An entity located in California or in a jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12 must register with the jurisdiction in which they are located.

(2) An entity located in the United States may only register with California to participate in its Cap-and-Trade Program.

(3) California will recognize the registration of an entity that registers into an External GHG ETS to which California has linked pursuant to subarticle 12 and allow that entity to participate in the California Cap-and-Trade Program.

(i) Change of ownership. When the ownership of a facility changes, the following information must be submitted to ARB within 30 days of finalization of ownership change:

(1) A description of the acquisition and the effective date of the change of ownership including if the acquisition is the purchase of a facility or facilities from another entity or the purchase of an entity that owns a facility or facilities;

(2) Both the legal and operating names and the tracking system entity IDs of the entities owning the facility or facilities prior to the change of ownership;

(3) Both the legal and operating names and the tracking system entity ID of the purchasing entity, if any;

(4) Written direction whether the purchased facility or facilities will be added to a consolidated entity account or whether the purchased facility or facilities will be associated with an entity that will opt-out of account consolidation pursuant to section 95833(f);

(5) Original signatures by a Director or Officer from the entities being purchased and the purchasing entity, notifying ARB of the change of ownership.

(6) Any changes or new information pursuant to section 95833.

(7) Written direction regarding the disposition of compliance instruments that must be transferred by the jurisdiction to the purchasing entity. Compliance instruments can be transferred only to the same account type, i.e., from a Compliance Account to a Compliance Account.

(8) If the change of ownership results in the closure of the tracking system account of the entity owning the facility or facilities prior to the change in

ownership, the Executive Officer will close the account within 10 days of the change in ownership. It is the responsibility of the entities participating in the change of ownership to transfer any compliance instruments from tracking system accounts they control prior to closure.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95831. Account Types.

(a) Accounts Created for Registered Entities.

(1) The Executive Officer shall not create more than one holding account, one limited use holding account, one compliance account, one Annual Allocation Holding Account, or one exchange clearing holding account for each entity registered pursuant to 95830.

(2) Holding Accounts. When the Executive Officer approves a registration for a covered entity, an opt-in covered entity, or a voluntarily associated entity, the accounts administrator will create a holding account for the registrant.

(3) Limited Use Holding Accounts. When an entity qualifies for a direct allocation under section 95890(b) the accounts administrator will create a limited use holding account for the entity that shall be subject to the following restrictions:

(A) The entity may not transfer compliance instruments from other accounts into the limited use holding account; and

(B) The entity may not transfer compliance instruments from the limited use holding account to any account other than the Auction Holding Account.

(4) Compliance Accounts. When the Executive Officer approves a registration for a covered entity or opt-in covered entity, the accounts administrator will create a compliance account for the entity.

(A) A covered entity or opt-in covered entity may transfer compliance instruments to its compliance account at any time.

(B) A compliance instrument transferred into a compliance account may not be removed by the entity.

(C) The Executive Officer may transfer compliance instruments into a compliance account. The Executive Officer may remove compliance instruments to satisfy a compliance obligation, or when closing an account.

(5) Exchange Clearing Holding Accounts. When the Executive Officer approves registration for an entity identified as a voluntarily associated entity pursuant to section 95814(a)(1)(C), then the accounts administrator will create an exchange clearing holding account for the entity.

(A) Entities may transfer compliance instruments to exchange clearing accounts only for the purpose of transferring control of the instruments to the entity performing the clearing function.

(B) The clearing entity may only transfer the compliance instruments in its exchange clearing holding account to the account designated by the entity receiving the allowances under the transaction being cleared.

(6) Annual Allocation Holding Account. When an entity qualifies for a direct allocation under section 95870, the accounts administrator will create an annual allocation holding account for the entity.

(A) Except for allowances to be placed in limited use holding accounts, the Executive Officer will place allowances allocated to an entity on a date prior to the vintage year of the allowances into the entity's annual allocation holding account.

(B) Entities may only transfer allowances from an annual allocation holding account to their compliance account. No other transfer of allowances from an annual allocation holding account is permitted.

(C) Allowances transferred from an annual allocation holding account to an entity's compliance account will be subject to the holding limit pursuant to section 95920(c).

(D) Allowances received by an entity through allocations pursuant to section 95870(d) will be transferred on January 1 of the vintage year of the allowances to the compliance accounts designated in the determination made by the entity pursuant to 95892(b)(2)(A).

(E) Allowances received by an entity through allocations pursuant to section 95870(h) will be transferred on January 1 of the vintage year of the allowances to the entity's compliance account pursuant to 95893(b)(1)(B).

(F) Allowances received through allocations pursuant to section 95870(e), (f), and (g) will be transferred to the entity's holding account on January 1 of the vintage year of the allowances.

(b) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer:

(1) A holding account to be known as the Allocation Holding Account into which the serial numbers of compliance instruments will be registered when the compliance instruments are created.

(2) A holding account to be known as the Auction Holding Account into which allowances are transferred to be sold at auction from:

(A) The Allocation Holding Account;

(B) The holding accounts of those entities for which allowances are being auctioned on consignment pursuant to section 95921(g)(3);

(C) The limited use holding accounts of those entities consigning allowances to auction pursuant to section 95910; and

(D) The compliance accounts of entities fulfilling an untimely surrender obligation pursuant to section 95857(d)(1)(A).

(3) A holding account to be known as the Retirement Account to which the Executive Officer will transfer compliance instruments from compliance accounts or from holding accounts under the control of the Executive Officer for the purpose of permanently retiring them. Alternatively, entities may voluntarily retire compliance instruments by transferring the compliance instruments to the Retirement Account.

(A) When compliance instruments are registered into the Retirement Account, these compliance instruments cannot be returned to any other holding or compliance account.

(B) When compliance instruments are registered into the Retirement Account, any External GHG ETS to which California links pursuant to subarticle 12 will be informed of the retirements.

(C) The Executive Officer will record the retired instruments in a publicly available Permanent Retirement Registry.

(4) A holding account to be known as the Allowance Price Containment Reserve Account:

(A) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve pursuant to section 95870(a) will be transferred; and

(B) From which the Executive Officer will authorize the withdrawal of allowances for sale to covered entities pursuant to section 95913.

(5) A holding account to be known as the Forest Buffer Account:

(A) Into which ARB will place ARB offset credits pursuant to section 95983(a); and

(B) From which ARB may retire ARB offset credits pursuant to sections 95983(b)(2), (c)(3), and (c)(4) and place them into to the Retirement Holding Account.

(6) A holding account to be known as the Voluntary Renewable Electricity Reserve Account, which will be closed when it is depleted of the following originally allocated allowances:

(A) Into which the Executive Officer will transfer allowances allocated pursuant to section 95870(c); and

(B) From which the Executive Officer may retire allowances pursuant to section 95841.1.

(c) Account Closure.

(1) A registered entity's accounts will be closed after the Executive Officer receives a report that an entity has ceased operation pursuant to MRR section 95101(h).

(2) A voluntarily associated entity's accounts may be closed if no compliance instruments are transferred into or out of the accounts for a period of three years.

(3) Compliance instruments needed to fulfill the entity's compliance obligation will be drawn first from the entity's Compliance Account and then from the entity's Holding Account if the Compliance Account does not contain sufficient compliance instruments to meet the compliance obligation.

(4) Compliance instruments remaining in accounts closed by the Executive Officer and not needed to fulfill a compliance obligation will be consigned to auction pursuant to section 95910(d) on behalf of the registered entity.

(d) Additional accounts may be created by the Executive Officer to implement the Cap-and-Trade Program.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95832. Designation of Representatives and Agents.

(a) An application for registration into the California Cap-and-Trade Program for an account must designate a single primary account representative and at least one but no more than four alternate account representatives. Any communication between the accounts administrator and an alternate account representative must also be addressed to the primary account representative. A complete application for an account shall be submitted to the accounts administrator and shall include the following elements:

(1) Name, business and primary residence addresses, email addresses, and phone numbers, of the primary account representative and any alternate account representatives and account viewing agents;

(2) Name of the organization designating the primary account representative or any alternate account representative to represent its ownership interest with respect to the compliance instruments held in the account;

(3) The primary account representative and any alternate account representative must attest, in writing, to ARB as follows: "I certify under penalty of perjury under the laws of the State of California that I was selected as the primary account representative or the alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to compliance instruments held in the account. I certify that I have all the necessary authority to carry out the duties and responsibilities contained in title 17, article 5, sections 95800 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account";

(4) An attestation verifying the selection of the primary account representative, alternate account representatives, and account viewing agents, signed by the officer of the entity who is responsible for the conduct of the primary account representative, alternate account representatives, and account viewing agents, and is one of the officers disclosed pursuant to section 95830(c)(1)(B);

(5) The signature of the primary account representative and any alternate account representative and the dates signed; and

(6) An attestation as follows: "I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. I certify under penalty of perjury of the laws of the State of

California that the statement of information submitted to ARB is true, accurate, and complete."

(b) Unless otherwise required by the Executive Officer, documents of agreement referred to in section 95832(a) in the application for an account shall not be submitted to the accounts administrator. The accounts administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(c) Authorization of primary account representative. Upon receipt by the accounts administrator of a complete application for an account under section 95830(c):

(1) The accounts administrator will establish an account or accounts for the person or persons for whom the application is submitted pursuant to section 95831.

(2) The primary account representative and any alternate account representative for the account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each entity that owns compliance instruments held in the account in all matters pertaining to this article, notwithstanding any agreement between the primary account representative or any alternate account representative and such entity.

(3) Any such entity shall be bound by any decision or order issued to the primary account representative or any alternate account representative by the Executive Officer or a court regarding the account. Any representation, action, inaction, or submission by any alternate account representative shall be deemed to be a representation, action, inaction, or submission by the primary account representative or any alternate account representative.

(d) Each submission concerning the account shall be submitted, signed, and attested to by the primary account representative or any alternate account representative for the entity that owns the compliance instruments held in the account. Each such submission shall include the following attestation statement by the primary account representative or any alternate account representative: "I certify under penalty of perjury under the laws of the State of California that I am authorized to make this submission on behalf of the entity that owns the compliance instruments held in the account. I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify under penalty of perjury under the laws of the State of California that the statements and information submitted to ARB are true, accurate, and complete." I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(e) The accounts administrator will accept or act on a submission concerning the account only if the submission has been made, signed, and attested to in accordance with this section.

(f) Changing primary account representative and alternate account representative.

(1) The primary account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous primary account representative, or the previous alternate account representative prior to the time and date when the accounts administrator receives the superseding application for an account shall be binding on the new primary account representative and the entity that owns the compliance instruments in the account.

(2) The alternate account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous primary account representative, or the previous alternate account representative, prior to the time and date when the accounts administrator

receives the superseding application for an account shall be binding on the new alternate account representative and the entity that owns the compliance instruments in the account.

(g) Objections Concerning Account Representatives.

(1) Once a complete application for an account under section 95830(c) has been submitted and received, the accounts administrator will rely on the application unless and until a superseding complete application for an account under section 95830(c) is received by the accounts administrator.

(2) Except as provided in section 95832(f)(1), no objection or other communication submitted to the accounts administrator concerning the authorization, or any representation, action, inaction, or submission of the primary account representative or any alternate account representative for an account shall affect any representation, action, inaction, or submission of the primary account representative or any alternate account representative or the finality of any decision or order by the accounts administrator under this article.

(3) The accounts administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the primary account representative or any alternate account representative for an account, including private legal disputes concerning the proceeds of compliance instrument transfers.

(h) Delegation by primary account representative and alternate account representatives.

(1) A primary account representative or an alternate account representative for a registered entity may authorize up to five natural persons per account that may view all information contained in the tracking system involving the entity's accounts, information, and transfer records (account viewing authority). The persons delegated shall not have authority to take any other action with respect to an account on the tracking system.

(2) In order to delegate account viewing authority in accordance with section 95832(h)(1) the primary account representative or alternate account

representative, as appropriate, must submit to the accounts administrator a notice of delegation, that includes the following elements:

(A) The name, address, email address, and telephone number of such primary account representative or alternate account representative;

(B) The name, address, email address, and telephone number of each such natural person, herein referred to as "account viewing agent;" and

(C) An attestation verifying the selection of the account viewing agent, signed by the officer of the entity who is responsible for the conduct of the account viewing agent, and is one of the officers disclosed pursuant to section 95830(c)(1)(B).

(3) A notice of delegation submitted under section 95832(h)(2) shall be effective, with regard to the accounts identified in such notice, upon receipt of such notice by the accounts administrator and until receipt by the accounts administrator of a superseding notice of delegation by such primary account representative or alternate account representative as appropriate. The superseding notice of delegation may replace any previously identified account viewing agent, add a new account viewing agent, or eliminate entirely any delegation of authority.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95833. Disclosure of Corporate Associations.

(a) Criteria for Determining Corporate Associations.

(1) An entity has a corporate association with another entity, regardless of whether the second entity is subject to the requirements of this article, if either one of these entities:

(A) Holds more than 20 percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than 20 percent of common directors of the other entity;

(C) Holds more than 20 percent of the voting power of the other entity;

(D) In the case of a partnership other than a limited partnership, holds more than 20 percent of the interests of the partnership;

(E) In the case of a limited partnership, controls the general partner; or

(F) In the case of a limited liability corporation, owns more than 20 percent of the other entity regardless of how the interest is held.

(2) An entity has a "direct corporate association" with another entity, regardless of whether the second entity is subject to the requirements of this article, if either one of these entities:

(A) Holds more than 50 percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than 50 percent of common directors of the other entity;

(C) Holds more than 50 percent of the voting power of the other entity;

(D) In the case of a partnership other than a limited partnership, holds more than 50 percent of the interests of the partnership;

(E) In the case of a limited partnership, controls the general partner; or

(F) In the case of a limited liability corporation, owns more than 50 percent of the other entity regardless of how the interest is held.

(3) An entity has a "direct corporate association" with a second entity, regardless of whether the second entity is subject to the requirements of this article, if the two entities are connected through a line of more than one direct corporate association.

(A) An entity (A) has a "direct corporate association" with another entity (B) if the two entities share a common parent that is not registered into the California Cap-and-Trade Program and that parent has a direct corporate association with each entity (A and B) when applying the indicia of control contained in section 95833(a)(2).

(B) An entity with a "direct corporate association" with a second registered entity has a direct corporate association with any registered entity with whom the second registered entity has a direct corporate association.

(4) An entity has an "indirect corporate association" with another entity if the two entities are both registered in the Cap-and-Trade Program and:

(A) The two entities do not have a direct corporate association; and

(B) The controlling entity's percentage of ownership or other indicia of control under section 95833(a)(1)(A), (B), (C), (D), or (F) of the indirectly controlled entity is more than 20 percent but less than or equal to 50 percent, or in the case of a limited partnership, the controlling entity controls the general partner. If the two entities are connected through a chain of more than one corporate association, the indicia of control under section 95833(a)(1)(A), (B), (C), (D), (E) or (F) is calculated by multiplying the percentages at each link in the chain of corporate associations.

(C) For the purposes of the calculation in section 95833(a)(4)(B), if the condition specified in section 95833(a)(2)(E) applies to a link in the chain of corporate associations the indicia of control for that link in the chain of corporate associations will be set to 100%.

(5) A publicly-owned electric utility or joint powers agency that is the operator of an electricity generating facility in California has a direct corporate association with the operator of another electricity generating facility in California if the same entity operates both generating facilities. A publicly-owned electric utility or joint powers agency that is the operator of an electricity generating facility in California has a direct corporate association with an electricity importer if the same entity operates the generating facility in California and is the entity importing electricity.

(b) If California links to one or more GHG ETS pursuant to subarticle 12, then entities shall disclose direct and indirect corporate associations with entities registered with those linked programs.

(c) Any registered entity subject to affiliate compliance rules promulgated by state or federal agencies shall not be required to disclose information or take other action that violates those rules.

(d) If a registered entity has a direct or indirect corporate association with another entity involved in determinations made pursuant to section 95833(a)(2), (3), (4) or (5), it must disclose the following information for each associated entity, unless, for unregistered direct corporate associated enitites only, the registered entity discloses via official documentation pursuant to section 95830(c)(1)(H)1.:

(1) Information to identify the associated entity, including:

(A) Name, contact information, and physical address of the entity;

(B) Whether the entity is parent or subsidiary;

(C) Holding account number, if applicable;

(D) Primary account representative, if applicable;

(E) Data Universal Numbering System number, if assigned;

(F) A U.S. federal tax Employer Identification Number, if assigned; and

(G) Place and Date of Incorporation, if applicable;

(2) The type of corporate association and a brief description of the association, to include information sufficient to explain the entity's evaluation of the measures contained in section 95833(a) used to determine the type of corporate association disclosed.

(e) The entity must disclose the information pursuant to section 95833(d) to the Executive Officer:

(1) When registering pursuant to section 95830;

(2) At any time after registering when a direct or indirect corporate association is created or exists;

(3) Within at least one year of the change, for any changes to the information disclosed on direct and indirect corporate associations, pursuant to section 95830(f)(1); and

(4) No later than the auction registration deadline established in section 95912 when reporting a change to the information disclosed if the changes relate to

another entity registered in the Cap-and-Trade Program, otherwise the entity may not participate in that auction.

(f) Consolidation of Accounts for Corporate Associations.

(1) By January 1, 2013, the Executive Officer will consolidate the accounts held by entities registered into the California Cap-and-Trade Program pursuant to section 95830 that are part of a direct corporate association into a consolidated set of accounts.

(2) By October 1, 2012, the primary account representative or alternate account representative for all entities that are part of a direct corporate association and intend to have their accounts consolidated must provide to the Executive Officer:

(A) Confirmation of the corporate association if not already provided;

(B) Confirmation of the entity's intent to have its account consolidated with that of the other entities within the corporate association; and

(C) A change of primary account representative and alternate account representative to new representatives that will serve as the primary account representative and alternate account representatives for the consolidated accounts.

(3) To opt out of consolidation of accounts, the primary account representative or alternate account representative for an entity within the corporate association must provide to the Executive Officer:

(A) Confirmation of the corporate association if not already provided;

(B) An attestation, signed by the officer of the entity who is responsible for the conduct of the account viewing agent and is one of the officers disclosed pursuant to section 95830(c)(1)(B), that the entity seeks exclusion of its account from the consolidated set of accounts to be created; and

(C) Confirmation of the opt-out decision by the primary account representative or alternate account representative for any entity opting out of consolidation, as well as the primary account representative or alternate account representative designated for any entities remaining in the corporate association consolidated account pursuant to section 95833(f)(2)(C).

1. This confirmation must include an allocation of shares of the holding limit between the consolidated corporate association and any associated entities opting out of consolidation.

2. This confirmation must include an allocation of shares of the purchase limit between the consolidated corporate association and any associated entities opting out of consolidation.

(4) If an entity registered in the California Cap-and-Trade Program has a direct corporate association with an entity(ies) registered in an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, the entity registered in the California Cap-and-Trade Program must opt out of consolidation with the entity(ies) registered in an External Greenhouse Gas Emissions Trading System and meet all the requirements of section 95833(f)(3).

(5) To consolidate the accounts for a corporate association the Executive Officer shall instruct the accounts administrator to:

(A) Create a single consolidated set of accounts for members of a corporate association that accept consolidation;

(B) Include a compliance account only for a corporate association with at least one member entity that accepts consolidation that is eligible for a compliance account;

(C) Include a limited use holding account only for a corporate association with at least one member entity that accepts consolidation that is eligible for a limited use holding account;

(D) Complete all valid transfer requests in the system involving any accounts for the members of the corporate association;

(E) Transfer all compliance instruments in the existing accounts held by the member entities to the appropriate corporate association accounts; and

(F) Close the accounts held by the individual member entities of the corporate association that have not opted out.

(6) Entities with a direct corporate association may change their decision to consolidate accounts or opt-out of consolidation only once each year.

(7) If some or all of the primary and alternate account representatives who are employees of a registered entity have primary responsibility for developing and executing procurement, transfer, and surrender of compliance instruments of another registered entity or other registered entities within the tracking system, the entities will be considered to have a direct corporate association and the requirements in section 95833(f) apply. If any primary account representative or alternate account representative of a registered entity has access to the market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions) for multiple registered entities and is not disclosed pursuant to section 95923, and can use that market position information without restriction to inform the development and execution of procurement, transfer, and surrender of compliance instruments for any registered entity, the entities for which the primary account representative or alternate account representative has access to the market position will be considered to have a direct corporate association and the requirements in section 95833(f) apply.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95834. Know-Your Customer Requirements.

(a) General Requirements.

(1) The accounts administrator cannot provide access to the tracking system to an individual until the Executive Officer has determined the individual applying for participation has complied with the requirements of this section.

(2) The requirements of this section are in addition to any requirements contained elsewhere in this article that apply to the functions the individual will undertake in the tracking system.

(3) All documents submitted to the Executive Officer pursuant to this section shall be in English.

(4) Individuals with a criminal conviction in the five previous years constituting a felony in the United States are ineligible for registration and participation in the Cap-and-Trade Program.

(b) The individual must provide documentation of the following:

(1) Name;

(2) The address of the primary residence of the applicant, which may be shown by any of the following:

(A) A valid identity card issued by a state with an expiration date;

(B) Any other government-issued identity document containing an individual’s primary address; or

(C) Any other document that is customarily accepted by the State of California as evidence of the primary residence of the individual;

(3) Date of birth;

(4) Employer name, contact information, and address;

(5) Either a passport number or driver’s license number, if one is issued;

(6) An open bank account in the United States;

(7) Employment or other relationship to an entity that has registered or has applied to register with the California Cap-and-Trade Program if the individual is listed by an entity registering pursuant to section 95830;

(8) A government-issued document providing photographic evidence of identity of the applicant which may include:

(A) A valid identity card or driver’s license issued by a state with an expiration date and date of birth; or

(B) A passport; and

(9) Any criminal conviction during the previous five years constituting a felony in the United States. This disclosure must include the type of violation, jurisdiction, and year.

(c) Verification of information.

(1) Any copy of a document submitted pursuant to section 95834 must be notarized by a notary public no more than three months before submittal.

(2) The Executive Officer may re-verify all documents required pursuant to Section 95834 every two years. To allow verification, upon request and within ten days, the individual must provide updated documentation required pursuant to 95834(b).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 6: California Greenhouse Gas Allowance Budgets

§ 95840. Compliance Periods.

Duration of Compliance Periods is as follows:

(a) The first compliance period starts on January 1, 2013, and ends on December 31, 2014.

(b) The second compliance period starts on January 1, 2015, and ends on December 31, 2017.

(c) The third compliance period starts on January 1, 2018, and ends on December 31, 2020.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95841. Annual Allowance Budgets for Calendar Years 2013-2020.

The California GHG Allowance Budgets are set as described in Table 6-1.

Table 6-1: California GHG Allowances Budgets

	Budget Year	Annual Allowance Budget (Millions of CA GHG Allowances)
First Compliance Period	2013	162.8
	2014	159.7
Second Compliance Period	2015	394.5
	2016	382.4
	2017	370.4
Third Compliance Period	2018	358.3
	2019	346.3
	2020	334.2

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95841.1 Voluntary Renewable Electricity.

(a) Program Requirements: The end-user, or VRE participant acting on behalf of the end-user, must meet the requirements of this section. Generation must be new and not have served load prior to July 1, 2005. Allowance retirement for purposes of voluntary renewable electricity will begin in 2014 for 2013 generation, and will continue in the same manner for subsequent years. Voluntary renewable electricity must be directly delivered to California. RECs must represent generation that occurred during the year for which allowance retirement is requested. The RECs shall be retired before the submittal of the request to retire allowances pursuant to this section.

(b) Reporting Requirements. The end-user, or the VRE participant acting on behalf of the end-user, requesting allowance retirement for eligible generation must meet the following requirements for the period in which allowance retirement is being requested:

(1) By July 1 of each year, provide a written request for allowance retirement for the previous year's generation or REC purchases. Request must meet the requirements below:

(A) Report to ARB the quantity of renewable electricity in MWhs and/or the number of RECs generated during the previous year from an eligible renewable electricity generator that meets the requirements of 95841.1(b)(2) or (3), as applicable;

(B) Generator of the renewable electricity or RECs must be certified as RPS eligible by the California Energy Commission, or must meet design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs in effect for the year in which the system received incentive approval:

1. first edition, December 2007;
2. second edition, December 2008;
3. third edition, June 2010;
4. fourth edition, July 2011; or
5. fifth edition, January 2013

(C) An approval of incentive claim must be submitted by end-users, or the VRE participants acting on behalf of the end-user choosing to meet (B) above by meeting the California Energy Commission's design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs in effect for the year in which the system was installed:

1. first edition, December 2007;
2. second edition, December 2008;
3. third edition, June 2010;
4. fourth edition, July 2011; or
5. fifth edition, January 2013;

(D) Contract, tracking system data, or settlement data for the purchase of the electricity or RECs associated with the generation of the electricity;

(E) Contract, tracking system data, or settlement data for sale of the electricity or RECs associated with the generation of the electricity to the end-user or entity purchasing on behalf of the end-user; and

(F) Submit the following attestations:

1. Attest, in writing, to ARB as follows: "I certify under penalty of perjury of the laws of the State of California that I have not authorized use of, or sold, any renewable electricity credits or any claims to the emissions, or lack of emissions, for electricity for which I am seeking ARB allowance retirement, in any other voluntary or mandatory program."

2. Attest, in writing, to ARB as follows: "I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, Cal. Code of Regs. article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this voluntary renewable electricity program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes."

(2) VRE Participants seeking allowance retirement for renewable electricity generation from an eligible facility > 200 KW nameplate capacity must submit the following with the report required in this section, for which the VRE participant is seeking allowance retirement:

(A) Provide the generator's RPS certification identification number, as determined by the California Energy Commission, or proof that each facility or system has met design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs in effect for the year in which the system received incentive approval:

1. first edition, December 2007;
2. second edition, December 2008;
3. third edition, June 2010;
4. fourth edition, July 2011; or

5. fifth edition, January 2013;

(B) MWhs of renewable electricity generated designated for VRE retirement;

(C) Number of RECs designated for VRE retirement, as applicable; and

(D) WREGIS REC Retirement Compliance Report, as applicable.

(3) VRE participants seeking allowance retirement for renewable electricity generating from an eligible facility ≤ 200 KW nameplate capacity must submit the following with the report required in this section. Applicants may aggregate eligible systems, but must submit one application under one entity:

(A) Provide the generator's RPS certification identification number, as determined by the California Energy Commission, or must meet design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs in effect for the year in which the system received incentive approval:

1. first edition, December 2007;
2. second edition, December 2008;
3. third edition, June 2010;
4. fourth edition, July 2011; or
5. fifth edition, January 2013;

(B) MWhs of renewable electricity generated;

(C) Number of RECs, as applicable; and

(D) WREGIS REC Retirement Compliance Report, as applicable.

(c) The allowances requested to be retired, calculated as follows:

$$\text{Number of MT } CO_2e = \text{MWh x EF}$$

Where:

"Number of MT CO_2e," rounded down to the nearest whole ton, is the number of allowances to be retired from the Voluntary Renewable Electricity Reserve Account;

"MWh" is the MWh of voluntary renewable electricity claimed and generated from a generator that meets the requirements of this article; and

"EF" is the CO_2e emissions factor equivalent to the default emission factor for unspecified power, pursuant to section 95111 of MRR.

ARB shall determine the actual MWh of voluntary renewable electricity purchases that occurred during the period indicated in the documentation. ARB shall retire allowances from the Voluntary Renewable Electricity Reserve Account in an amount up to the number of MT CO_2e represented by actual voluntary renewable electricity purchases, based on actual MWh purchases and the emissions factor determined pursuant to this section.

(d) Once a voluntary renewable electricity tracking system is approved by the Executive Officer and it is in place, a voluntary renewable electricity generator or REC marketer which meets the requirements in section 95841.1(b) will always be considered to have satisfied section 95841.1(b), if they participate in the tracking system.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 7: Compliance Requirements for Covered Entities

§ 95850. General Requirements.

(a) Reporting Requirements. Each covered entity identified in section 95811 is subject to MRR.

(b) An entity's compliance obligation is based on the emissions number for the emissions subject to a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive emissions data verification statement is issued, rounded to the nearest whole ton, or for which there are assigned emissions pursuant to MRR.

(c) Record Retention Requirements. Each entity must retain all of the following records for at least 10 consecutive years and must provide such records within 20 calendar days of receiving a written request from ARB, including:

(1) Copies of all data and reports submitted under this article and section 95105 of MRR;

(2) Records used to calculate a compliance obligation as specified in section 95853;

(3) Emissions data and product data verification statements as required pursuant to section 95103(f) of MRR; and

(4) Detailed verification reports as required pursuant to section 95131 of MRR.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95851. Phase-in of Compliance Obligation for Covered Entities.

(a) Operators of facilities and first deliverers of electricity specified in sections 95811(a) and (b) and carbon dioxide suppliers specified in section 95811(h) that meet or exceed the annual emissions threshold in section 95812(c) have compliance obligations beginning with the first compliance period.

(b) Suppliers of natural gas, suppliers of RBOB and distillate fuel oils, suppliers of liquefied petroleum gas, and suppliers of liquefied natural gas specified in sections 95811(c), (d), (e), (f), and (g) that meet or exceed the annual threshold in section 95812(d) will have a compliance obligation beginning with the second compliance period.

(c) Operators of cogeneration facilities and district heating facilities that have been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j), that meet or exceed the annual threshold in section 95812(c) will have no compliance obligation and are not covered entities during the first, second, and third compliance periods. The compliance obligation for these exempt facilities will be held by the upstream natural gas supplier. Facilities that are not approved by the

Executive Officer for a limited exemption of emissions will have a compliance obligation.

(d) Operators of eligible Waste-to-Energy Facilities, pursuant to section 95852(k), that meet or exceed the annual threshold in section 95812(d), will have a compliance obligation beginning in 2016.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852. Emission Categories Used to Calculate Compliance Obligations.

(a) Operators of Facilities.

(1) An operator of a facility covered under sections 95811(a) and 95812(c)(1) has a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive emissions data verification statement is issued per section 95131 of MRR, including process emissions, stationary combustion emissions and vented emissions. If ARB has assigned emissions for the sources subject to a compliance obligation pursuant to this section, the facility will have a compliance obligation equal to the value of every metric ton of CO_2e assigned emissions. The entity's compliance obligation will be assessed at the facility level unless otherwise noted under section 95812(c).

(2) Beginning in 2015, combustion emissions resulting from burning RBOB, distillate fuel oils, or natural gas liquids are not included when calculating an operator's compliance obligation.

(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for every metric ton of CO_2e emissions calculated pursuant to section 95852(b)(1) for which a positive or qualified positive emissions data verification statement is issued pursuant to MRR, or for which there are assigned emissions, when such emissions are from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12.

(1) Calculation of emissions for compliance obligation.

(A) For first deliverers that are operators of an electricity generating facility in California, the calculation for compliance obligation includes all emissions reported and verified or assigned pursuant to MRR, except emissions without a compliance obligation pursuant to section 95852.2.

(B) For first deliverers that are electricity importers, emissions with a compliance obligation are calculated using the following equation:

$$CO_2e_{covered} = CO_2e_{unspecified} + \left(CO_2e_{specified} - CO_2e_{specified-not\ covered}\right) - CO_2e_{RPS\_adjustment} - CO_2e_{QE\_adjustment} - CO_2e_{linked}$$

Where:

$CO_2e_{covered}$ = Annual metric tons of CO_2e with a compliance obligation.

$CO_2e_{unspecified}$ = Annual metric tons of CO_2e from unspecified imported electricity calculated pursuant to MRR 95111(b)(1).

$CO_2e_{specified}$ = Annual metric tons of CO_2e from imported electricity from specified sources that meet the requirements of MRR section 95111(b)(1).

$CO_2e_{specified\text{-}not\ covered}$ = Annual metric tons of CO_2e without a compliance obligation pursuant to section 95852.2. from specified sources that meet the requirements in MRR section 95111(b)(1).

$CO_2e_{RPS\_adjustment}$ = Annual metric tons of CO_2e calculated pursuant to MRR that meets the requirements of section 95852(b)(4).

$CO_2e_{QE\_adjustment}$ = Annual metric tons of CO_2e from qualified exports pursuant to MRR section 95111 that meet the requirements of section 95852(b)(5).

CO_2e_{linked} = Annual metric tons of CO_2e from electricity with a first point of receipt located in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12.

(C) All deliveries of electricity not meeting the requirements for specified sources pursuant to MRR will have emissions calculated using the default emission factor for unspecified electricity pursuant to section MRR 95111(b)(1).

(2) Resource shuffling is prohibited and is a violation of this article.

(A) The following substitutions of electricity deliveries from a lower emission resource for electricity deliveries from a higher emission resource shall not constitute resource shuffling:

1. Electricity deliveries that are caused by the procurement of electricity eligible to be counted towards and purchased for Renewable Portfolio Standard (RPS) compliance in California.
2. Electricity deliveries made for the purpose of compliance with state or federal laws and regulations, including the Emission Performance Standard (EPS) rules established by CEC and the CPUC pursuant to public utilities code section 8340 et. seq.
3. Electricity deliveries made for the purpose of compliance with requirements related to maintaining reliable grid operations, such as North American Electric Reliability Corporation (NERC) Reliability Standards, and Reliability Coordinator directives, including the provision of electricity between balancing authorities or load-serving entities when required to alleviate emergency grid conditions.

4. Electricity deliveries made for the purpose of compliance with either a judicially approved settlement of litigation or a settlement of a transaction dispute pursuant to the dispute resolution terms and conditions of a contract for reasons other than reducing GHG compliance obligations.
5. Electricity deliveries that substitute for power previously supplied by a specified source that has been retired.
6. Electricity deliveries that substitute for deliveries that have been discontinued because of termination of a contract or divestiture of resources for reasons other than reducing a GHG compliance obligation.
7. Electricity deliveries that are necessitated by early termination of a contract for, or full or partial divestiture of, resources subject to the EPS rules.
8. Electricity deliveries that are necessitated by expiration of a contract.
9. Electricity deliveries pursuant to contracts for short-term delivery of electricity with terms of no more than 12 months, for either specified or unspecified power, linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electrical Distribution Utility has a contract, or in which a California Electrical Distribution Utility has an ownership share, and based on economic decisions including congestion costs but excluding implicit and explicit GHG costs. In evaluating these short-term deliveries of electricity, ARB will consider the levels of past sales and purchases from similar resources of electricity, among other factors, to judge whether the activity is resource shuffling.
10. Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time

market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11., 12., or 13. below.

11. Electricity deliveries that are necessitated by operational emergencies or transmission or distribution constraints, including constraints caused by the inability to obtain or retain transmission rights, transmission curtailments or outages, or emergencies.

12. Electricity deliveries that are necessitated because a First Deliverer has more than enough electricity to meet demand as a result of the First Deliverer being required to take electricity from specific generating units, including requirements due to electricity contracts with “must-take” or “must-run” provisions.

13. Deliveries of electricity that are required to make up for transmission losses associated with electricity deliveries in California.

(B) Prohibited substitutions of electricity deliveries from a higher emission resource with electricity deliveries from a lower emission resource include:

1. Substituting relatively lower emission electricity to replace electricity generated at a high emission power plant procured by a First Deliverer under a long-term contract or ownership arrangement, when the power plant does not meet California’s EPS, and the substitution is made to reduce a First Deliverer’s compliance obligation.

2. Assigning a long-term contract for high emission electricity specified in section 95852(b)(2)(B)1. directly above to a third party, for the purpose of reducing a compliance obligation.

(3) The following criteria must be met for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor or asset controlling supplier emission factor.

(A) Electricity deliveries must be reported to ARB and emissions must be calculated pursuant to MRR section 95111.

(B) The electricity importer must be the facility operator or have right of ownership or a written power contract, as defined in MRR section 95102(a), to the amount of electricity claimed and generated by the facility or unit claimed;

(C) The electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid; and

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the REC serial numbers must be reported and verified pursuant to MRR.

(4) RPS adjustment. Electricity procured from an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the RPS adjustment:

(A) The electricity importer must have:

1. Ownership or contract rights to procure the electricity and the associated RECs generated by the eligible renewable energy resource; or

2. A contract with an entity subject to the California RPS that has ownership or contract rights to the electricity and associated RECs generated by the eligible renewable energy resource, as verified pursuant to MRR.

(B) The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the California RPS, and party to the contract in

95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25, and designated as retired for the purpose of compliance with the California RPS program within 45 days of the reporting deadline specified in section 95111(g) of MRR for the year for which the RPS adjustment is claimed.

(C) The quantity of emissions included in the RPS adjustment is calculated as the product of the default emission factor for unspecified sources, pursuant to MRR, and the reported electricity generated (MWh) that meets the requirements of this section, 95852(b)(4).

(D) No RPS adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered.

(E) No RPS adjustment may be claimed for electricity generated by an eligible renewable energy resource in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12.

(F) Only RECs representing electricity generated after 12/31/2012 are eligible to be used towards the RPS adjustment.

(5) QE adjustment. An adjustment to the compliance obligation pursuant to the calculation in 95852(b)(1) may be made for exported and imported electricity during the same hour by the same PSE. Emissions included in the QE adjustment for qualified exports claimed by a first deliverer must meet the following requirements:

(A) During any hour in which an electricity importer claims qualified exports and corresponding imports, the maximum amount of QE adjustment for the hour shall not exceed the product of:

1. The lower of either the quantity of exports or imports (MWh) for the hour; multiplied by

2. The lowest emission factor of any portion of the qualified exports or corresponding imports for the hour.

(B) Emissions and MWhs included in the QE adjustment must be reported and verified or assigned pursuant to MRR, and must be documented by hourly import and export data pursuant to MRR.

(c) Suppliers of Natural Gas. A supplier of natural gas covered under sections 95811(c) and 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California contained in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned, less the fuel that is delivered to covered entities, as follows:

(1) Suppliers of natural gas shall report the total metric tons CO_2e of GHG emissions delivered to all end users in California pursuant to section 95122 of MRR;

(2) ARB shall calculate the metric tons CO_2e of GHG emissions for natural gas delivered to covered entities which are customers of the supplier. The emissions will be calculated using the reported deliveries (in MMBtu) contained in natural gas supplier emissions data reports that received a positive or qualified positive emissions data verification statement. Natural gas received data (in MMBtu) contained in covered facility emissions data reports that received positive or qualified positive emissions data verification statements will be used to cross check delivery data reported by natural gas suppliers, and will serve as a second source of data in instances of missing supplier data. In the event that a natural gas supplier receives an adverse verification statement, ARB will use the provisions described in section 95131(c)(5) of the MRR to calculate the supplier's assigned emission level;

(3) ARB shall provide the supplier of natural gas a listing of all customers and aggregate natural gas (in MMBtu) and emissions calculated from the supplier's natural gas delivered to covered entities; and

(4) The Executive Officer shall calculate the metric tons CO_2e for which the supplier will be required to hold a compliance obligation based on the supplier's reported emissions less ARB's calculated emissions from deliveries

to covered entities which are customers of the supplier. The Executive Officer shall provide this value to the supplier of natural gas within 30 days of the verification deadline in section 95103 of MRR.

(d) Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under sections 95811(d) or 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities of the following fuels that are removed from the rack in California, sold to entities not licensed by the California Board of Equalization as a fuel supplier, or imported into California and not directly delivered to the bulk-transfer/terminal system as defined in section 95102 of MRR, except for products for which a final destination outside California can be demonstrated:

(1) RBOB;

(2) Distillate Fuel Oil No. 1; and

(3) Distillate Fuel Oil No. 2.

(e) Suppliers of Liquefied Petroleum Gas:

(1) A producer of liquefied petroleum gas covered under sections 95811(e) and 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of all fuel sold, distributed, or otherwise transferred for consumption in California; and

(2) An importer consignee, as defined under MRR, of liquefied petroleum gas covered under section 95811(e) has a compliance obligation for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of all fuel imported into California.

(f) Suppliers of Blended Fuels. An entity that supplies any of the fuels covered under sections 95811(f) and 95812(d) as blended fuels has an aggregated compliance obligation for every metric ton of CO_2e of GHG emissions based on the separate constituents of the blend included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the fuel.

(g) Carbon Dioxide Suppliers. An entity that supplies carbon dioxide, "Carbon Dioxide Supplier" or CO_2 Supplier", covered under sections 95811(h) and 95812(c)(3) has an aggregated compliance obligation based on the sum of MT CO_2 included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned minus exported CO_2 that is not geologically sequestered, and minus CO_2 verified to be geologically sequestered through use of a Board-approved carbon capture and geologic sequestration quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable. Emissions of CO_2 already covered with a compliance obligation upstream are not included.

(h) Petroleum and Natural Gas Systems. Operators of the facilities specified in section 95101(e)(2)-(5) of MRR have a compliance obligation for every metric ton of CO_2e from the source types specified in sections 95152(c)-(f) of MRR, except as specified in section 95852.2 of this article, that is contained in an emissions data report that has received a positive or qualified positive emissions data report, or for which emissions have been assigned.

(i) The compliance obligation for sources specified in sections 95852(a) through (h), and 95852(l) is calculated based on the sum of the following, as applicable:

(1) Emissions of CO_2, CH_4, and N_2O which resulted from combustion of fossil fuel;

(2) Emissions of CH_4 and N_2O which resulted from combustion of all biomass-derived fuel;

(3) Emissions of CO_2 which resulted from combustion of biomass-derived fuels that do not meet the requirements in section 95852.2(a);

(4) Emissions of CO_2 which resulted from combustion of biomass-derived fuels pursuant to section 95852.1; and

(5) All process and vented emissions of CO_2, CH_4, and N_2O as specified in the MRR except for those listed in section 95852.2(b).

(j) Limited Exemption of Emissions from the Production of Qualified Thermal Output During the First, Second, and Third Compliance Periods. During the first, second, and third compliance periods, emissions from the production of qualified thermal output from a district heating facility or a facility with a cogeneration unit that meets the requirements of this section and has been approved by the Executive Officer for an emissions exemption shall not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(c)(1). A facility that qualifies for this limited exemption shall not be a covered entity during the first, second, and third compliance periods.

(1) A facility with a cogeneration unit may apply for the emissions exemption if it meets the following two conditions for each year from 2008-2013, starting with the first year that a cogeneration unit was operational at the facility, and will remain eligible until the year in which either condition is not met, based on data reported pursuant to MRR:

(A) The facility's annual covered emissions as defined in MRR associated with the production of qualified thermal output, calculated using the following equation, are less than 25,000 metric tons of CO_2e:

$$GHG_{QTO} = Q_{produced} * 0.06244$$

Where:

"GHG_{QTO}" is the annual covered emissions for each calendar year, in metric tons of CO_2e, associated with the production of qualified thermal output;

$Q_{produced}$ is the annual amount of qualified thermal output produced for each calendar year, from fuels that result in covered emissions, measured in MMBtu, at the cogeneration facility. If $Q_{produced}$ is produced from a cogeneration unit that burns both fuels that result in covered emissions and fuels that result in emissions without a compliance commission pursuant to Subarticle 7, then $Q_{produced}$ is calculated as total qualified thermal output multiplied by the ratio of the MMBtus of fuel that produces covered emissions divided by the total MMBtus of all fuels combusted in the unit; and,

(B) The facility's remaining covered emissions, calculated pursuant to the following equation, are less than 25,000 metric tons of CO_2e:

$$GHG_R = GHG_{Total} - GHG_{QTO}$$

Where:

"GHG_R" is the annual remaining covered emissions, in metric tons of CO_2e.

"GHG_{Total}" is total annual covered emissions, in metric tons of CO_2e.

(2) A district heating facility may apply for the qualified thermal output emissions exemption if the annual emissions associated with qualified thermal output distributed to each single facility on its system do not exceed 25,000 $MTCO_2$e for each year from 2008 to 2013, and will remain eligible until the year in which this condition is not met:

(A) Emissions associated with a single facility are calculated using the following equation:

$$GHG_{sf} = Q_{sf} * 0.06244$$

Where:

"GHG_{sf}" is the emissions associated with a single facility.

"Q_{sf}" is the amount of Qualified Thermal Output provided to a single facility, measured in MMBtu.

(3) Data Sources. The Executive Officer may employ all available data reported to ARB under MRR for data years 2008-2013 to determine a facility's initial eligibility for the limited exemption of emissions from the production of qualified thermal output.

(4) A facility with a cogeneration unit or a district heating facility must apply to the Executive Officer for the emissions exemption by providing the following data by September 2, 2014:

(A) Annual qualified thermal output for each year from 2008 to 2013, in MMBtu.

(B) A district heating facility must provide the amount of qualified thermal output provided to each single facility it serves.

(C) The application must include the following attestation:
"I certify under penalty of perjury of the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], and that the information submitted herein is true, accurate, and complete."

(D) Operators of facilities that meet the requirements of this section must register in the tracking system pursuant to section 95830.

(E) Operators of facilities that meet the requirements of this section must report and verify emissions pursuant to MRR.

(k) Limited Exemption of Emissions for Waste-to-Energy Facilities. Emissions reported and verified in the first compliance period and in data year 2015 for the direct combustion of municipal solid waste in a waste-to-energy facility that had started operations before 2009 and that meets the requirements of this section do not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(d)(3). The exempted waste-to-energy facility must meet the following criteria:

(1) Operators of Waste-to-Energy Facilities must register in the tracking system pursuant to section 95830;

(2) Report and verify emissions pursuant to MRR;

(3) Must be operating under a current permit issued by the local Air Pollution Control District or Air Quality Management District; and

(4) Fuel must be derived from municipal solid waste, as defined in the section 95802 of this article and MRR.

(5) The Executive Officer will place the number of true-up allowances equal to the facility's reported, verified, and covered emissions from municipal solid waste for the 2013, 2014, and 2015 data years into their compliance account. These allowances will be used to meet the facility's 2013, 2014, and 2015 compliance obligations. The 2015 vintage true-up allowances will be deposited by October 24, 2014 for the 2013 data year's reported and verified emissions. The 2016 vintage true-up allowances will be deposited by October 24, 2015 for the 2014 year's reported and verified emissions. The 2017 vintage true-up allowances will be deposited by October 24, 2016 for the 2015 data year's reported and verified emissions. The Executive Officer will retire the allowances placed into the account according to the surrender dates in section 95856.

(l) Suppliers of Liquefied Natural Gas. A supplier of liquefied natural gas covered under sections 95811(g) or 95812(d) has a compliance obligation for every metric ton CO_2e of GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities on liquefied natural gas or compressed natural gas imported into California, except for products for which a final destination outside California can be demonstrated.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.1. Compliance Obligations for Biomass-Derived Fuels.

An entity that has emissions from combustion of biomass-derived fuels is required to report and verify its emissions pursuant to MRR and has a compliance obligation for every metric ton of CO_2e emissions:

(a) From combustion of fuel types that are not listed under section 95852.2; or

(b) From combustion of fuels that do not meet the requirements of section 95852.1.1; or

(c) That are reported as non-exempt biomass derived CO_2 under MRR.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.1.1. Eligibility Requirements for Biomass-Derived Fuels.

(a) Biomass-derived fuel procured under contracts for biogas and biomethane must meet one of the following criteria. Only the portion of the fuel that meets one of these criteria will be considered a biomass-derived fuel. Emissions from combustion of this fuel will not be subject to a compliance obligation when reported as Biomass CO_2 in an emissions data report that has received a positive or qualified positive emissions data verification statement and determined as exempt pursuant to section 95852.2 and 95131(j) of MRR.

(1) The contract for purchasing any biomass-derived fuel must be executed prior to January 1, 2012 and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. The delivery of the fuel under the contract must commence by one of the following dates to be eligible under this provision:

(A) 90 days after the execution date of the signed contract; or

(B) January 1, 2012; or

(C) 10 days after the date on which the CEC provides notice that the operator's electricity generating facility is certified as eligible for California's Renewables Portfolio Standard for the contracted biomass-derived fuel, or cannot be so certified, provided that the application for certification was submitted to the CEC before January 1, 2012.

(2) If the biomass-derived fuel does not meet the requirements of 95852.1.1(a)(1) then the biomass-derived fuel must meet one of the following requirements and the entity claiming the biomass-derived fuel must be the first entity to contract for the biomass-derived fuel:

(A) An increase in the biomass derived fuel production capacity, at a particular site, where an increase is considered any amount over the average production at that site over the last three years; or

(B) Recovery of the fuel at a site where the fuel was previously being vented or destroyed for at least three years or since commencement of fuel recovery operations, whichever is shorter, without producing useful energy transfer.

(3) If the biogas or biomethane is used at the site of production, and not transferred to another operator, thus not requiring a contract, the operator must demonstrate one of the following:

(A) The fuel has been combusted in California prior to January 1, 2012; or

(B) The fuel was not previously used to produce useful energy transfer for at least three years or since commencement of fuel recovery operations, whichever is shorter.

(4) The fuel being provided under a contract is for a fuel that was previously eligible under sections 95852.1.1(a)(1), (2) or (3), and the verifier is able to track the fuel to the previously eligible contract.

(b) An entity may not sell, trade, give away, claim, or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would, when combined with the CO_2 emissions from complete combustion of the fuel, result in more CO_2e emissions than would have occurred in the absence of the fuel production. In the case of biomethane or biogas produced from digesters or landfills, the resulting credit for avoided methane emissions may not exceed the global warming potential as listed in MRR for methane plus 2.75 in metric tons of

CO_2e per ton of captured methane. This includes any credit received by an entity in the Carbon Intensity calculation under the Low Carbon Fuel Standard Regulation (title 17, California Code of Regulations (CCR), sections 95480-95490) for methane capture. All calculations of CO_2e emissions are based on the 100-year global warming potentials included in MRR. Generation of Renewable Energy Credits is excluded from this analysis and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.2. Emissions without a Compliance Obligation.

Emissions from the following source categories and from the combustion of the following fuel types count toward applicable reporting thresholds, as applicable in MRR, but do not count toward a covered entity's compliance obligation set forth in this article unless those emissions are reported as non-exempt biomass-derived CO_2 under MRR. Emissions without a compliance obligation include:

(a) CO_2 emissions from combustion of the following biomass-derived fuels:

(1) The biogenic fraction of solid waste materials as reported under MRR;

(2) Waste pallets, crates, dunnage, manufacturing and construction wood wastes, tree trimmings, mill residues, and range land maintenance residues;

(3) All agricultural crops or waste;

(4) Wood and wood wastes identified to follow all of the following practices:

(A) Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan; and

(B) Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(5) Biodiesel:

(A) Agri-biodiesel derived solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, sunflower seeds, cottonseeds, canola, cramble, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats.

(B) Biodiesel is defined as monoalkyl esters of long chain fatty acids derived from the following plant or animal matter that meets the requirements of the American Society of Testing Materials (ASTM) D6751:

1. Waste oils;

2. Tallow; or

3. Virgin oils.

(6) Fuel ethanol (including denaturant):

(A) Cellulosic biofuel produced from lignocellulosic or hemicellulosic material that has a proof of at least 150 without regard to denaturants;

(B) Corn starch; or

(C) Sugar cane.

(7) The biogenic fraction of municipal solid waste as reported under MRR, including MSW directly combusted or converted to a cleaner-burning fuel;

(8) Biomethane and biogas from the following sources:

(A) All animal, plant and other organic waste; or

(B) Landfills and wastewater treatment plants;

(9) Renewable diesel.

(b) The following additional process, vented, and fugitive emissions:

(1) Emissions from geothermal generating units and geothermal facilities, including geothermal geyser steam or fluids;

(2) Emissions from natural gas hydrogen fuel cells;

(3) Vented and fugitive emissions from storage tanks used in petroleum and natural gas production and natural gas transmission;

(4) Vented and fugitive emissions reported under sections 95152(e) and (i) of MRR by local distribution companies that report under section 95122 of MRR;

(5) Vented and fugitive emissions from natural gas transmission storage tanks used in petroleum and natural gas production and natural gas transmission, and from produced water;

(6) Emissions reported by petroleum refineries from asphalt blowing operations, equipment leaks, storage tanks, and loading operations;

(7) Emissions from low bleed pneumatic devices;

(8) Emissions from high bleed pneumatic devices reported prior to January 1, 2015;

(9) Vented emissions from well-site centrifugal and reciprocating compressors with a rated horsepower less than 250hp;

(10) Sources for which fugitive emissions are estimated using leak detection and leaker emission factors, as required by section 95153(o) of MRR, and sources for which vented and fugitive emissions are estimated using a population count and emissions factors, as required by section 95153(p) of MRR;

(11) Sources for which emissions originate from offshore petroleum and natural gas production facilities, as provided in section 95153(q) of MRR;

(12) Carbon dioxide that is exported for purposes other than geologic sequestration or enhanced oil recovery; and

(13) Carbon dioxide used in the carbonation process during sugar production in facilities with NAICS code 311313.

(c) Other Exemptions. The operators of facilities with any of the following activities are exempt from compliance with this article:

(1) NAICS Code 92811.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95853. Calculation of Covered Entity’s Triennial Compliance Obligation.

(a) A covered entity that exceeds the threshold in section 95812 in any of the four data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions with a compliance obligation that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR from all data years of the compliance period.

(b) A covered entity that initially exceeds the threshold in section 95812 in the first year of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR from all data years of the compliance period.

(c) A covered entity that initially exceeds the threshold in section 95812 in the second year of the second or subsequent compliance period is a covered entity for the second and third years of this compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR for the second and third data years of the compliance period.

(d) A covered entity that initially exceeds the threshold in section 95812 in the second year of the first compliance period or the third year of a later compliance period has a compliance obligation for its emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR for that year, but the entity's triennial compliance obligation for the current compliance period is not due the following year. Instead the entity's reported and verified or assigned emissions for this year will be added to the entity's triennial obligation for the subsequent compliance period.

(e) For a covered entity that meets all the criteria set forth in 95853(e)(1) through 95853(e)(3), the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under an energy-based methodology annually using the following formula. All subsequent allocation shall be calculated pursuant to 95891.

$$TA_{2015} = A_{EB,2015} + TrueUp_{2014} + TrueUp_{2013}$$

Where:

"TA_{2015}" is the total amount of California GHG allowances directly allocated to the operator of an industrial facility from budget year 2015;

"$A_{EB,2015}$" is the amount of California GHG allowances calculated under the Energy-Based Allocation Methodology from budget year 2015 pursuant to 95891(c); and

"$TrueUp_t$" is the amount of true-up allowances allocated to account for allocation not properly accounted for in prior allocations. This value of allowances from budget year 2015 shall be allowed to be used for compliance for budget year 2013 and subsequent years pursuant to 95856(h)(1)(D) and 95856(h)(2)(D). This value is calculated using the following formula:

$$TrueUp_t = A_{EB,2015} * \frac{c_{a,t}}{c_{a,2015}} \frac{AF_{a,t}}{AF_{a,2015}}$$

Where:

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to each activity "a" as specified in Table 8-1; and

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to each activity "a" as specified in Table 8-1.

(1) The facility emissions exceeded the program inclusion threshold prior to 2012 pursuant to pursuant to 95812(c)(1);

(2) The facility conducted an activity that was not listed in Table 8-1 prior to 2014; and

(3) The facility is eligible to receive an allowance allocation under the energy-based allocation methodology pursuant to 95891(c) for budget year 2015.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95854. Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits.

(a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation for a compliance period must conform to the following limit:

$$O_O/S \text{ must be less than or equal to } L_O$$

In which:

O_O = Total number of compliance instruments identified in section 95854(a) submitted to fulfill the entity's compliance obligation for the compliance period.

S = Covered entity's compliance obligation.

L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

(c) The number of sector-based offset credits that each covered entity may surrender to meet the entity's compliance obligation for a compliance period must not be greater than 0.25 of the L_O for the first and second compliance periods and not more than 0.50 of the L_O for subsequent compliance periods.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95855. Annual Compliance Obligation.

(a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the condition specified in section 95853(d); and

(b) The annual compliance obligation for a covered entity equals 30 percent of emissions with a compliance obligation reported from the previous data year that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

(a) A covered entity must surrender one compliance instrument for each metric ton of CO_2e of GHG emissions for the annual and triennial compliance obligations calculated pursuant to this subarticle beginning with the emissions data report for 2013 emissions and each subsequent year in which the covered entity has a compliance obligation.

(b) Compliance Instruments Valid for Surrender.

(1) A compliance instrument listed in subarticle 4 may be used to satisfy a compliance obligation.

(2) To fulfill a compliance obligation, a compliance instrument issued pursuant to sections 95820(a) and 95821(a) must be issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated or the last year of a compliance period for which a triennial compliance obligation is calculated, unless:

(A) The allowance was purchased from an Allowance Price Containment Reserve Sale pursuant to section 95913 or compliance instruments pursuant to section 95821(a);

(B) The allowance is used to satisfy an excess emissions obligation; or

(C) The allowance is eligible for compliance use pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D).

(c) A covered entity must transfer from its holding account to its compliance account a sufficient number of valid compliance instruments to meet the compliance obligation set forth in sections 95853 and 95855.

(d) Deadline for Surrender of Annual Compliance Obligations. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation:

(1) By November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the year for which the obligation is calculated if the entity reports by April 10 pursuant to section 95103 of MRR; or

(2) By November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the year for which the obligation is calculated if the entity reports by June 1 pursuant to section 95103 of MRR.

(3) In years 2015, 2018, and 2021 there is no annual compliance obligation for the preceding compliance period, only a triennial compliance obligation.

(4) Transfers to compliance accounts may be restricted during the time the tracking system is processing the surrender of the annual compliance obligation.

(e) Determination of Triennial Compliance Obligation.

(1) When a positive or qualified positive emissions data verification statement or assigned emissions for any year is received by ARB, then those emissions for the source categories in section 95852 equal the triennial compliance obligation pursuant to section 95853.

(2) If a positive or qualified positive emissions data verification statement for any year of the compliance period is not received by ARB by the applicable verification deadline as set forth in MRR, ARB will assign emissions according to the requirements set forth in section 95103(g) of MRR for the emissions for

the source categories in section 95852. The assigned emissions value then equals the compliance obligation.

(f) Surrender of Triennial Compliance Obligation.

(1) The covered entity must transfer sufficient valid compliance instruments to its compliance account to fulfill its triennial compliance obligation by November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the final year of the compliance period. Transfers to compliance accounts may be restricted during the time the tracking system is processing the surrender of the triennial compliance obligation.

(2) The total number of compliance instruments submitted to fulfill the triennial compliance obligation is subject to the quantitative use limit pursuant to section 95854.

(3) The surrender of compliance instruments must equal the triennial compliance obligation calculated pursuant to section 95853 less compliance instruments surrendered to fulfill the annual compliance obligation for the years in the compliance period.

(g) In determining whether the covered entity has fulfilled its compliance obligations, the Executive Officer shall:

(1) In the case of annual and triennial compliance obligations, determine the status of compliance with the annual or triennial compliance obligation by evaluating the number and types of compliance instruments in the Compliance Account; and

(A) Retire the compliance instruments surrendered; and

(B) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

(h) Annual and Triennial Compliance Instrument Requirements

(1) When a covered entity or opt-in covered entity surrenders compliance instruments to meet its annual compliance obligation pursuant to section 95856(d), the Executive Officer will retire them from the Compliance Account in the following order:

(A) Offset credits specified in section 95820(b) and sections 95821(b) through (d), up to eight percent of the emissions with a compliance obligation pursuant to section 95855;

(B) Allowances purchased from a California Allowance Price Containment Reserve sale followed by Allowance Price Containment Reserve Allowances and then other non-vintage allowances issued by a program approved by ARB pursuant to section 95941 as specified in section 95821(a);

(C) Allowances specified in section 95820(a) and 95821(a) with earlier vintage allowances retired first; and

(D) The current calendar year's vintage allowances and allowances allocated just before the annual surrender deadline up to the True-up allowance amount as determined in sections 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c) or 95894(d) if an entity was eligible to receive true up allowances pursuant to sections 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c) or 95894(d).

(2) When a covered entity or opt-in covered entity surrenders compliance instruments to meet its triennial compliance obligation pursuant to section 95856(f), the Executive Officer will retire them from the Compliance Account in the following order:

(A) Offset credits specified in section 95820(b) and sections 95821(b) through (d) with oldest credits retired first and subject to the quantitative usage limit set forth in section 95854:

(B) Allowances purchased from a California Allowance Price Containment Reserve sale followed by Allowance Price Containment Reserve Allowances and then other non-vintage allowances issued by a program approved by ARB pursuant to section 95941 as specified in section 95821(a);

(C) Allowances specified in section 95820(a) and 95821(a) with earlier vintage allowances retired first; and

(D) The current calendar year's vintage allowances and allowances allocated just before the triennial surrender deadline up to the true-up allowance amount as determined in section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c) or 95894(d) if an entity was eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c) or 95894(d).

(3) An entity that is not eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c) or 95894(d), cannot use the current calendar year's vintage allowances or allowances allocated just before the current surrender deadline to meet the timely surrender of compliance instrument requirements in section 95856.

(4) An electric distribution utility will not be in violation of section 95892(d)(5) when the Executive Officer retires compliance instruments, if the electric distribution utility has a sufficient quantity of eligible compliance instruments not allocated pursuant to section 95870(d) in its compliance account, at the time the timely surrender of compliance instruments by a covered entity is due pursuant to section 95856, that is at least equal to its compliance obligation for any transactions for which the use of allocated allowance value is prohibited under section 95892(d)(5).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

(a) Applicability.

(1) A covered entity or opt-in covered entity that does not meet the compliance deadline for surrendering its annual or triennial compliance obligation pursuant to section 95856 is subject to the compliance obligation for untimely surrender as described in this section; and

(2) The compliance obligation for untimely surrender ("excess emissions") will not apply to a covered entity or opt-in covered entity which is determined to have transferred insufficient instruments to meet the compliance obligations of section 95856 solely because of the invalidation of an ARB offset credit by the Executive Officer pursuant to section 95985 until six months after notice of invalidation.

(b) Calculation of the Untimely Surrender Obligation.

(1) The quantity of excess emissions is the difference between the compliance obligation calculated pursuant to this section and any compliance instruments timely surrendered by the entity;

(2) The entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions;

(3) At least three-fourths of an entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances or allowances issued by a GHG ETS pursuant to subarticle 12;

(4) Up to one-fourth of an entity's compliance obligation for untimely surrender may be fulfilled with ARB offset credits or compliance instruments listed in sections 95821(b), (c), and (d);

(5) The quantitative usage limit provided in section 95854 will apply to the compliance instruments listed in section 95857(b)(4) for the compliance period for which the untimely surrender obligation applies; and

(6) The untimely surrender obligation is due within five days of settlement of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed. Future vintage allowances are eligible for complying with the untimely surrender obligation.

(c) If an entity with an untimely surrender obligation fails to satisfy this obligation pursuant to section 95857(b)(6) then:

(1) ARB will determine the number of violations pursuant to section 96014;

(2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(6) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and

(3) The calculation of the untimely surrender obligation shall only apply once for each untimely surrender of compliance instruments per annual or triennial compliance obligation.

(d) When the covered entity or opt-in covered entity meets its untimely surrender obligations pursuant to sections 95857(a) through (c), the Executive Officer shall:

(1) Transfer the compliance instruments used to fulfill the untimely surrender obligation in the following manner:

(A) At least three fourths of the compliance instruments to the Auction Holding Account. The three fourths of the compliance instruments transferred to the Auction Holding Account shall only be comprised of allowances; and

(B) The remaining one fourth of compliance instruments to the Retirement Account.

(2) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95858. Compliance Obligation for Under-Reporting in a Previous Compliance Period.

If, after an entity has surrendered its compliance instruments for a compliance period pursuant to section 95856, the Executive Officer determines, through an audit or other information, that the entity under-reported its emissions under MRR for any emissions sources that form the basis for entity's the compliance obligation, then the following shall apply:

(a) If the difference between the emissions used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by the Executive Officer to be under-reported for the sum of those emissions is less than five percent of the emissions number used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856, then the entity is not required to take any further action.

(b) If the difference between the emissions used to calculate the compliance obligation and subsequently calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by the Executive Officer to be under-reported for the sum of those emissions is more than five percent of the emissions number used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856, then the entity must surrender compliance instruments in the following amount:

$$\mathrm{Cla} = \mathrm{EMd} - \mathrm{CO} - (\mathrm{CO} * 0.05)$$

Where:

'Cla' is the number of additional compliance instruments that must be surrendered to ARB to cover under-reported emissions;

'CO' is the emissions number used to determine the compliance obligation surrendered pursuant to section 95856 for any previous compliance period; and

'EMd' is the number of the emissions determined by the Executive Officer for the sum of the emissions sources subject to a compliance obligation;

(c) The entity will have six months from the time of notification by the Executive Officer to surrender additional compliance instruments for under-reporting emissions under MRR for the previous compliance period as determined pursuant to this section. The provisions of sections 95857 and 96014 shall not apply during these six months. The entity may use compliance instruments from subsequent compliance periods to meet these requirements. The entity may only use CA GHG allowances or allowances issued by a GHG ETS approved pursuant to subarticle 12 to meet the requirements of this section.

(d) Any determination that an entity under-reported its emissions for a previous compliance period shall be made by the Executive Officer no later than eight years from the applicable verification deadline for the emissions data report which contained the under-reporting of emissions.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 8: Disposition of Allowances

§ 95870. Disposition of Allowances.

(a) Allowance Price Containment Reserve. Upon creation of the Allowance Price Containment Reserve Account, the Executive Officer shall transfer allowances to the Allowance Price Containment Reserve, as follows:

(1) One percent of the allowances from budget years 2013-2014;

(2) Four percent of the allowances from budget years 2015-2017; and

(3) Seven percent of the allowances from budget years 2018-2020.

(b) Advance Auction. Upon creation of the Auction Holding Account, the Executive Officer shall transfer 10 percent of the allowances from budget years 2015-2020 to the Auction Holding Account.

(1) These allowances will be eligible to be sold pursuant to section 95913(f)(5).

(2) All Advance Auction allowances not sold pursuant to section 95913(f)(5) will be auctioned pursuant to section 95910.

(3) The proceeds from the sale of these allowances will be deposited into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8, and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq. and consistent with the requirements of Chapter 4.1 (commencing with Section 39710) of Part 2 of Division 26 of the California Health and Safety Code and Article 9.7 (commencing with Section 16428.8) of Chapter 2 of Part 2 of Division 4 of Title 2 of the Government Code.

(c) Upon creation of the Voluntary Renewable Electricity Reserve Account, the Executive Officer shall transfer allowances to the Voluntary Renewable Electricity Reserve Account, as follows:

(1) 0.5 percent of the allowances from budget years 2013-2014; and

(2) 0.25 percent of the allowances from budget years 2015-2020.

(d) Electricity Related Allocation.

(1) Electrical Distribution Utility Sector Allocation. Allowances available for allocation to electrical distribution utilities each budget year shall be 97.7 million metric tons multiplied by the cap adjustment factor in Table 9-2 for each budget year 2013-2020. The Executive Officer will allocate to electrical distribution utilities on September 14, 2012 for vintage 2013 allowances and October 24, or the first business day thereafter, of each calendar year from 2013-2019 for allocations from 2014-2020 annual allowance budgets.

(2) Allocation to Public Wholesale Water Agencies. The Executive Officer will place an annual individual allocation in the compliance account of a public wholesale water agency on or before October 24, or the first business day thereafter, of each calendar year from 2014-2019 for allocations from 2015-2020 annual allowance budgets.

(e) Allocation to Industrial Covered Entities. Allowances allocated for the purposes of industry assistance shall be transferred to annual allocation holding accounts for industrial sectors listed in Table 8-1. Allowances in the annual allocation holding account are transferred to the Holding Account on January 1 of the vintage year of the allowances.

(1) The Executive Officer will allocate allowances from 2015-2020 annual allowance budgets to each eligible covered entity on or before October 24, or the first business day thereafter, of each calendar year 2014-2019 for allocations from 2015-2020 annual allowance budgets.

(2) Allocation to eligible covered entities shall be conducted using the assistance factors specified for each listed industrial activity found in Table 8-1 and the methodology set forth in section 95891.

(A) First Compliance Period Refining Sector Allocation. Allowances available for allocation to petroleum refineries from the 2013-2014 allowance budgets shall be calculated using the following equation. Individual petroleum refiners will receive a portion of this sector allocation under the method calculated pursuant to section 95891(d).

$$SA_t = O_{t-2} * B_R * AF_{R,t} * c_t$$

Where:

"SA_t" is the allocation to the refining sector from budget year "t";

"O_{t-2}" is the output of primary refinery products, in barrels, from the refining sector in year "t-2";

"B_R" is the benchmark for primary products produced by the refining sector, equal to 0.0462 metric tons of allowances per barrel of primary refinery product;

"$AF_{R,t}$" is the assistance factor for budget year "t" assigned to petroleum refining as specified in Table 8-1; and

"c_t" is the cap adjustment factor for budget year "t" assigned to petroleum refining to account for cap decline as specified in Table 9-2 in section 95891.

(B) Second and Third Compliance Period Refining Sector Allocation. For budget years 2015-2020, allowances available for allocation to individual petroleum refineries shall be calculated using the product output-based allocation calculation methodology in section 95891(b).

(3) The total amount of allowances allocated for the purposes of industry assistance shall not exceed the available amount of allowances after accounting for allocations made pursuant to section 95870(a) through (d). If the amount calculated under the methodology set forth in section 95891 exceeds the amount of allowances available, the number of allowances available will be prorated equally across all eligible industrial covered entities. The proration will be calculated using the share of allowances available after accounting for all allocations made pursuant to sections 95870(a) through (d) compared to total allowances that would be distributed according to the methodology set forth in section 95891.

(4) Industrial entities that purchase electricity or legacy contract qualified thermal output pursuant to a legacy contract and who receive allocation under this section shall have their allocation reduced as specified in section 95891(f).

(5) If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) did not receive any industrial allocation for budget year 2013, the Executive Officer shall place in its compliance account, by October 24, 2014, the amount of true-up allowances equal to the facility's reported, verified, and covered emissions (pursuant to MRR) for the 2013 data year, less the amount of allowances in its compliance account as of October 23, 2014. The Executive Officer will place in the facility's holding account the amount of allowances equivalent to the allowances in its compliance account as of October 23, 2014. If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) did not receive any industrial allocation for budget year 2014, the Executive Officer shall place in its compliance account, by October 24, 2015, the amount of true-up allowances equal to the facility's reported, verified, and covered emissions for the 2014

data year. The Executive Officer shall retire the amount of allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years, as applicable, according to the surrender dates in section 95856 . A facility that has been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to 95852(j) shall not receive any allocation of allowances for the second and third compliance periods unless it ceases to be eligible for the limited exemption and qualifies for an allocation pursuant to sections 95870, 95890, 95891, or 95894.

(6) If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) received an industrial allocation for budget year 2013, it must place allowances equal to the amount received in 2013 into its compliance account. If the amount of allowances equal to the facility's reported, verified, and covered emissions (pursuant to MRR) for the 2013 data year exceeds the amount received through industrial allocation for budget year 2013, by October 24, 2014, the Executive Officer will place in the facility's compliance account true-up allowances equal to the difference between the facility's reported, verified, and covered emissions and the amount of industrial allocation received for budget year 2013. If the allowances received for budget year 2013 exceeds the amount of the facility's reported, verified, and covered emissions for the 2013 data year, the facility will have its "budget year 2016 true-up allocation" reduced by the amount that the industrial allocation amount received for budget year 2013 exceeds the reported, verified, and covered emissions for the 2013 data year. If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) received an industrial allocation for budget year 2014, it must place allowances equal to the amount received through industrial allocation for the 2014 budget year into its compliance account. Budget year 2016 true-up allocation: If the amount of allowances equal to the facility's reported, verified, and covered emissions for the 2014 data year exceeds the amount of allowances received for industrial allocation

for budget year 2014, by October 24, 2015, the Executive Officer will place in the facility's compliance account true-up allowances equal to the difference between the facility's reported, verified, and covered emissions for the 2014 data year and the amount of allowances received through industrial allocation for budget year 2014; this amount will be reduced by the amount that the industrial allocation amount received for budget year 2013 exceeded the reported, verified, and covered emissions for the 2013 data year, if applicable. If the allowances received for budget year 2014 exceeds the amount of the facility's reported, verified, and covered emissions for the 2014 data year, the facility shall return to the Executive Officer the number of allowances equal to the difference between the industrial allocation for budget year 2014 and the facility's reported, verified, and covered emissions for the 2014 data year. The submission of a request to return allowances must occur within five days of settlement of the first auction or reserve sale conducted by ARB following the October 24, 2015 allocation, whichever is later, and for which the registration deadline has not passed at the time of the October 24, 2015 allocation. The returned allowances will be auctioned pursuant to section 95910. The Executive Officer shall retire the amount of allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years, as applicable, according to the surrender dates in section 95856. A facility that has been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to 95852(j) shall not receive any allocation of allowances for the second and third compliance periods unless it ceases to be eligible for the limited exemption and qualifies for an allocation pursuant to sections 95870, 95890, 95891, or 95894.

(f) Allocation to University Covered Entities and Public Service Facilities. The Executive Officer will place an annual individual allocation from budget year 2015 in the annual allocation holding account of each eligible university covered entity and public service facility for calendar years 2013, 2014, and 2015 by October 24, 2014 or the first business day thereafter. The Executive Officer will place an annual individual allocation in the annual allocation holding account of each eligible university covered entity and public service facility on or before October 24, or the first business day thereafter, of each calendar year from 2015-2019 for allocations from 2016-2020 annual allowance budgets. A public service facility providing steam to a publicly-owned educational facility is not eligible for any allocation of allowances provided under other provisions of this regulation. In the event a publicly-owned educational facility that receives qualified thermal output from a public service facility becomes an opt-in covered entity and receives allowances for the emissions from qualified thermal output sold to the university by the public service facility pursuant to section 95891(e), the publicly-owned educational facility shall unconditionally transfer to the public service facility allowances relating to the qualified thermal output provided by such public service facility. So long as the publicly-owned educational facility remains an opt-in covered entity and provides such allowances to the public service facility, such public service facility will not be eligible for any disposition of allowances provided under this section.

(g) Allocation to Legacy Contract Generators.

(1) Allowances will be allocated to legacy contract generators without an industrial counterparty for budget years 2013 through 2017 for transition assistance. The Executive Officer will transfer allowance allocations into each eligible generator's annual allocation holding account by October 24 for eligible legacy contract emissions pursuant to the methodology set forth in section 95894 each year through 2017.

(2) Allowances will be allocated to legacy contract generators with an industrial counterparty pursuant to section 95894 for the term of the contract. The Executive Officer will transfer allowance allocations into each eligible generator's annual allocation holding account by October 24 each for eligible legacy contract emissions pursuant to the methodology set forth in section 95894.

(h) Natural Gas Supplier Sector Allocation. Allowances available for allocation to natural gas suppliers each budget year shall be calculated as set forth in section

95893. The Executive Officer will allocate to natural gas suppliers on October 24, or the first business day thereafter, of each calendar year from 2014 through 2019 for allocations from 2015 through 2020 annual allowance budgets.

(i) Auction Proceeds for AB 32 Statutory Objectives.

(1) Beginning in 2015, 10 percent of all remaining allowances from each vintage not allocated for uses specified in section 95870(a) are eligible to be sold pursuant to section 95913(f)(5).

(2) All remaining allowances not allocated for uses specified in sections 95870(a) through (h) or section 95870(i)(1) will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8, and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq. and consistent with the requirements of Chapter 4.1 (commencing with Section 39710) of Part 2 of Division 26 of the California Health and Safety Code and Article 9.7 (commencing with Section 16428.8) of Chapter 2 of Part 2 of Division 4 of Title 2 of the Government Code.

(j) Negative Allocation. If the calculation of an entity's annual allowance allocation is negative pursuant to 95891, that negative amount shall be applied to the entity's allowance allocation that is distributed the following calendar year.

Table 8-1: Industry Assistance

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
				2013-2014	2015-2017	2018-2020
High	Crude Petroleum and Natural Gas Extraction	211111	Thermal EOR Crude Oil Extraction	100%	100%	100%
			Non-Thermal Crude Oil Extraction	100%	100%	100%
			Natural Gas Processing >25 MMscf/day	100%	100%	100%
	Natural Gas Liquid Extraction	211112	Natural Gas Liquid Processing	100%	100%	100%
	All Other Metal Ore Mining	212299	Rare Earth Production	100%	100%	100%
	Potash, Soda, and Borate Mineral Mining	212391	Mining and Manufacturing of Soda Ash and Related	100%	100%	100%
	All Other Nonmetallic Mineral Mining	212399	Diatomaceous Earth Mining	100%	100%	100%
			Freshwater Diatomite Filter Aids Manufacturing	100%	100%	100%
	Paper (except Newsprint) Mills	322121	Bathroom Tissue Manufacturing	100%	100%	100%
			Facial Tissue Manufacturing	100%	100%	100%
			Delicate Task Wipers Manufacturing	100%	100%	100%
			Paper Towel Manufacturing	100%	100%	100%
	Paperboard Mills	322130	Recycled Boxboard Manufacturing	100%	100%	100%
			Recycled Linerboard (Testliner) Manufacturing	100%	100%	100%
			Recycled Medium (Fluting) Manufacturing	100%	100%	100%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
	All Other Petroleum and Coal Products Manufacturing	324199	Coke Calcining	100%	100%	100%
	All Other Basic Inorganic Chemical Manufacturing	325188	All Other Basic Inorganic Chemical Manufacturing	100%	100%	100%
	All Other Basic Organic Chemical Manufacturing	325199	All Other Basic Organic Chemical Manufacturing	100%	100%	100%
	Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production	100%	100%	100%
			Calcium Ammonium Nitrate Solution Production	100%	100%	100%
	Flat Glass Manufacturing	327211	Flat Glass Manufacturing	100%	100%	100%
	Glass Container Manufacturing	327213	Container Glass Manufacturing	100%	100%	100%
	Cement Manufacturing	327310	Cement Manufacturing	100%	100%	100%
	Lime Manufacturing	327410	Dolime Manufacturing	100%	100%	100%
	Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	100%	100%	100%
	Iron and Steel Mills	331111	Steel Production Using an Electric Arc Furnace	100%	100%	100%
	Rolled Steel Shape Manufacturing	331221	Hot Rolled Steel Sheet Production	100%	100%	100%
Medium	Food Manufacturing	311	Food Manufacturing	100%	100%	75%
	Fruit and vegetable canning	311421	Aseptic Tomato Paste Processing	100%	100%	75%
			Aseptic Whole and Diced Tomato Processing	100%	100%	75%
			Non-Aseptic Tomato Paste and Tomato Puree Processing	100%	100%	75%
			Non-Aseptic Whole and Diced Tomato Processing	100%	100%	75%
			Non-Aseptic Tomato Juice Processing	100%	100%	75%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
	Poultry Processing	311615	Whole Chicken and Chicken Parts Processing	100%	100%	75%
			Poultry Deli Product Processing	100%	100%	75%
			Protein Meal and Fat Processing	100%	100%	75%
	Dried and Dehydrated Food Manufacturing	311423	Dehydrated Garlic Processing	100%	100%	75%
			Dehydrated Onion Processing	100%	100%	75%
			Dehydrated Chili Pepper Processing	100%	100%	75%
			Dehydrated Spinach Processing	100%	100%	75%
			Dehydrated Parsley Processing	100%	100%	75%
	Dairy Product Manufacturing	31151	Milk, Buttermilk, Skim Milk, and Ultrafiltered Milk Processing	100%	100%	75%
			Cream processing	100%	100%	75%
			Butter processing	100%	100%	75%
			Condensed Milk Processing	100%	100%	75%
			Nonfat Dry Milk and Skimmed Milk Powder (Low Heat) Processing	100%	100%	75%
			Nonfat Dry Milk and Skimmed Milk Powder (Medium Heat and High Heat) Processing	100%	100%	75%
			Buttermilk Powder Processing	100%	100%	75%
			Dairy Product Solids for Animal Feed Processing	100%	100%	75%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
			Intermediate Dairy Ingredients Processing	100%	100%	75%
			Cheese Processing	100%	100%	75%
			Lactose Processing	100%	100%	75%
			Whey Protein Concentrate Processing	100%	100%	75%
			Deproteinized Whey Processing	100%	100%	75%
	Roasted Nuts and Peanut Butter Manufacturing	311911	Pistachio Processing	100%	100%	75%
			Almond Processing	100%	100%	75%
	Snack Food Manufacturing	31191	Fried Potato Chips Processing	100%	100%	75%
			Baked Potato Chips Processing	100%	100%	75%
			Corn Chips Processing	100%	100%	75%
			Corn Curls Processing	100%	100%	75%
			Pretzel Processing	100%	100%	75%
	Beet sugar manufacturing	311313	Beet sugar manufacturing	100%	100%	75%
	Cut and Sew Apparel Manufacturing	3152	Cut and Sew Apparel Manufacturing	100%	100%	75%
	Breweries	312120	Brewing	100%	100%	75%
			Lager Beer Manufacturing	100%	100%	75%
	Wineries	312130	Distilled Spirits Production	100%	100%	75%
			Dry Color Concentrate Production	100%	100%	75%
			Grape Juice Concentrate Production	100%	100%	75%
			Grape Seed Extract Production	100%	100%	75%
			Liquid Color Concentrate Production	100%	100%	75%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
	Petroleum Refineries	324110	Petroleum Refining	100%	100%	75%
	Asphalt Paving Mixture and Block Manufacturing	324121	Asphalt Paving Mixture and Block Manufacturing	100%	100%	75%
	Industrial Gas Manufacturing	325120	On-Purpose Hydrogen Gas Production	100%	100%	75%
			Liquid Hydrogen Production	100%	100%	75%
	Ethyl Alcohol Manufacturing	325193	Ethyl Alcohol Manufacturing	100%	100%	75%
	Biological Product (Except Diagnostic) Manufacturing	325414	Biological Product (Except Diagnostic) Manufacturing	100%	100%	75%
	Gypsum Product Manufacturing	327420	Plaster Manufacturing	100%	100%	75%
			Stucco Manufacturing	100%	100%	75%
	Rolled Steel Shape Manufacturing	331221	Pickled Steel Sheet Production	100%	100%	75%
			Cold Rolled and Annealed Steel Sheet Production	100%	100%	75%
			Galvanized Steel Sheet Production	100%	100%	75%
			Tin Steel Plate Production	100%	100%	75%
	Secondary Smelting and Alloying of Aluminum	331314	Aluminum and Aluminum Alloy Billet Manufacturing	100%	100%	75%
	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (Except Copper and Aluminum)	331492	Lead Acid Battery Recycling	100%	100%	75%
	Iron Foundries	331511	Iron Foundries	100%	100%	75%
			Ductile Iron Pipe Manufacturing	100%	100%	75%
	Hardware Manufacturing	332510	Hardware Manufacturing	100%	100%	75%
	Turbine and Turbine Generator Set Units	333611	Testing of Turbines and Turbine Generator Sets	100%	100%	75%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity (a)	Industry Assistance Factor (AF_a) by Budget Year		
Low	Pharmaceutical and Medicine Manufacturing	325412	Pharmaceutical and Medicine Manufacturing	100%	100%	50%
	Nonferrous Forging	332112	Nonferrous Metal Forging	100%	100%	50%
			Seamless Rolled Ring	100%	100%	50%
	Aircraft Manufacturing	336411	Aircraft Manufacturing	100%	100%	50%
	Guided Missile and Space Vehicle Manufacturing	336414	Guided Missile and Space Vehicle Manufacturing	100%	100%	50%
	Support Activities for Air Transportation	4881	Support Activities for Air Transportation	100%	100%	50%

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code and Section 16428.8, Government Code.

Subarticle 9: Direct Allocations of California GHG Allowances

§ 95890. General Provisions for Direct Allocations.

(a) Eligibility Requirements for Industrial Facilities. A covered entity or opt-in covered entity from the industrial sectors listed in Table 8-1 shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive product data verification statement for the prior year pursuant to MRR.

(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility that is a covered entity shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.

(c) Electrical Distribution Utilities that are not covered entities but are listed in Table 9-3 must register pursuant to section 95830 to receive allowances.

(d) Eligibility Requirements for University Covered Entities and Public Service Facilities. A University Covered Entity or public service facility that is not an opt-in covered entity shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR and if it had a compliance obligation in 2013 or 2014. A university or public service facility that is an opt-in covered entity shall be eligible for direct allocation of California GHG allowances only if it submits a request to opt-in to the Cap-and-Trade Program pursuant to section 95813 no later than July 31, 2014 and if it has complied with the requirements of MRR section 95103 and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR section 95103(f). A university or public service facility shall not be eligible for any direct allocation of allowances for any data year for which it is not a covered entity or an opt-in covered entity.

(e) Eligibility Requirements for Legacy Contract Generators. A legacy contract generator with an industrial counterparty that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of this regulation shall be eligible for direct allocation of allowances if it has complied with the requirements of MRR and has obtained a positive or a qualified positive emissions data verification statement pursuant to MRR. A legacy contract generator without an industrial counterparty that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of this regulation shall be eligible for direct allocation of allowances if it has complied with the requirements of MRR and has obtained a positive or a qualified positive emissions data verification statement pursuant to MRR.

(f) Eligibility Requirements for Natural Gas Suppliers. A natural gas supplier that is a covered entity shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.

(g) Eligibility Requirements for Public Wholesale Water Agencies. A public wholesale water agency shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of MRR, and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.

(h) No facility receiving allowances pursuant to section 95870(f) may also receive allowances pursuant to section 95870(g).

(i) No facility that qualifies for a limited exemption pursuant to section 95852(j) may also receive allowances pursuant to sections 95870, 95890, 95891, or 95894 for the same budget year.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95891. Allocation for Industry Assistance.

(a) The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the product output-based allocation calculation methodology specified in section 95891(b) if the entity conducts an activity listed in both Table 8-1 and Table 9-1. The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the energy-based allocation calculation methodology specified in section 95891(c) if the entity conducts an activity listed in Table 8-1 but not listed in Table 9-1.

(1) First Compliance Period Refining Sector Allocation Exception. For budget years 2013-2014 petroleum refineries shall receive their allocation of allowances pursuant to the methodology stated in section 95891(d).

(2) Second and Third Compliance Period Refining Sector Allocation. For budget years 2015-2020, petroleum refineries shall receive their allocation of allowances pursuant to the product output-based allocation calculation methodology stated in section 95891(b), using the complexity weighted barrel definition detailed in 95802(a).

(3) New Entrant Industrial Allocation Without Leakage Risk. Covered facilities that had emissions below the inclusion threshold as outlined in 95812(c) prior to 2012 and do not have a leakage risk in Table 8-1 are eligible to receive allocated allowances under the new entrant energy-based allocation methodology pursuant to 95891(c)(3) if the first three digits of the facility NAICS code matches a NAICS code in Table 8-1. The leakage risk classification shall be low until a leakage risk classification is added for that sector. Food processors that are only classified by a three digit NAICS code are exempt from this classification.

(b) Product Output-Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under a product output-based methodology annually using the following formula:

$$A_t = \left(\sum_{a=1}^{n} O_{a,t-2} * B_a * AF_{a,t} * c_{a,t}\right) + TrueUp_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"a" is each eligible activity as defined in Table 9-1;

"n" is the number of eligible activities at a facility;

"$O_{a,\ t-2}$" will be calculated by the Executive Officer as the output in year "t-2" as reported to ARB.

"B_a" is the emissions efficiency benchmark per unit of output for each eligible activity defined in Table 9-1;

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to each activity "a" as specified in Table 8-1;

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to each activity "a" to account for cap decline as specified in Table 9-2; and

"$trueup_t$" is the amount of true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations. This value shall only be calculated if the entity was covered under the Cap-and-Trade Program in year "t-2." Entities allocated to under 95891(d) for budget years 2013 and 2014 will not be allocated true-up allowances under this methodology for hydrogen production in those data years. This value of allowances for budget year "t" shall be allowed to be used for compliance for budget year "t-2" or subsequent budget years pursuant to 95856(h)(1)(D) and 95856(h)(2)(D). This value is calculated using the following formula:

$$TrueUp_t = \left(\sum_{a=1}^{n} O_{a,t-2} * B_a * AF_{a,t-2} * c_{a,t-2}\right) - A_{t-2,no\ trueup}$$

Where:

"$O_{a,\ t-2}$" will be calculated by the Executive Officer as the output in year "t-2" as reported to ARB;

"$A_{t-2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities from budget year "t-2" not including the true-up for that budget year;

"$AF_{a,\ t-2}$" is the assistance factor for budget year "t-2" assigned to each activity "a" as specified in Table 8-1; and

"$c_{a,t-2}$" is the adjustment factor for budget year "t-2" assigned to each activity.

Table 9-1: Product-Based Emissions Efficiency Benchmarks

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Crude Petroleum and Natural Gas Extraction	211111	Thermal EOR Crude Oil Extraction	0.0811	Allowances / Barrel of Oil Eqv. Produced Using Thermal EOR
		Non Thermal Crude Oil Extraction	0.0076	Allowances / Barrel of Non Thermal Crude Oil Eqv.
		Natural Gas Processing ≥ 25 MMscf/day	0.0220	Allowances / Barrel of Gas Processed Eqv.
Natural Gas Liquid Extraction	211112	Natural Gas Liquid Processing	0.0118	Allowances / Barrel of Natural Gas Liquids Produced
Potash, Soda, and Borate Mineral Mining	212391	Mining and Manufacturing of Soda Ash and Related Products	0.948	Allowances / Short Ton of Soda Ash Equivalent (Soda Ash, Biocarb, Borax, V-Bor, DECA, PYROBOR, Boric Acid, and Sulfate)
All Other Nonmetallic Mineral Mining	212399	Freshwater Diatomite Filter Aids Manufacturing	0.418	Allowances / Short Ton of Freshwater Diatomite Filter Aids

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Fruit and vegetable canning	311421	Aseptic Tomato Paste Processing	0.353	Allowances / Short Ton of 31% NTSS Aseptic Tomato Paste
		Aseptic Whole and Diced Tomato Processing	0.179	Allowances / Short Ton of Aseptic Whole and Diced Tomatoes
		Non-Aseptic Tomato Paste and Tomato Puree Processing	0.315	Allowances / Short Ton of 24% NTSS Non-Aseptic Tomato Paste and Tomato Puree
		Non-Aseptic Whole and Diced Tomato Processing	0.135	Allowances / Short Ton of Non-Aseptic Whole and Diced Tomatoes
		Non-Aseptic Tomato Juice Processing	0.163	Allowances / Short Ton of Non-Aseptic Tomato Juice
Poultry Processing	311615	Whole Chicken and Chicken Parts Processing	0.0330	Allowances / Short Ton of Whole Chicken and Chicken Parts
		Poultry Deli Product Processing	0.0353	Allowances / Short Ton of Poultry Deli Product
		Protein Meal and Fat Processing	0.396	Allowances / Short Ton of Protein Meal and Fat
Dried and Dehydrated Food Manufacturing	311423	Dehydrated Garlic Processing	0.824	Allowances / Short Ton of Dehydrated Garlic
		Dehydrated Onion Processing	1.01	Allowances / Short Ton of Dehydrated Onion
		Dehydrated Chili Pepper Processing	1.29	Allowances / Short Ton of Dehydrated Chili Pepper

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Dehydrated Spinach Processing	5.56	Allowances / Short Ton of Dehydrated Spinach
		Dehydrated Parsley Processing	3.21	Allowances / Short Ton of Dehydrated Parsley
Dairy Product Manufacturing	31151	Milk, Buttermilk, Skim Milk, and Ultrafiltered Milk Processing	0.0147	Allowances / Short Ton of Milk, Buttermilk, Skim Milk, and Ultrafiltered Milk
		Cream processing	0.0153	Allowances / Short Ton of Cream
		Butter processing	0.0391	Allowances / Short Ton of Butter
		Condensed Milk Processing	0.0368	Allowances / Short Ton of Condensed Milk
		Nonfat Dry Milk and Skimmed Milk Powder (Low Heat) Processing	0.380	Allowances / Short Ton of Nonfat Dry Milk and Skimmed Milk Powder (Low Heat)
		Nonfat Dry Milk and Skimmed Milk Powder (Medium Heat and High Heat) Processing	0.425	Allowances / Short Ton of Nonfat Dry Milk and Skimmed Milk Powder (Medium Heat and High Heat)
		Buttermilk Powder Processing	0.501	Allowances / Short Ton of Buttermilk Powder
		Dairy Product Solids for Animal Feed Processing	0.0241	Allowances / Short Ton of Dairy Product Solids for Animal Feed
		Intermediate Dairy Ingredients Processing	0.0808	Allowances / Short Ton of Intermediate Dairy Ingredients

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Cheese Processing	0.114	Allowances / Short Ton of Cheese
		Lactose Processing	0.272	Allowances / Short Ton of Lactose
		Whey Protein Concentrate Processing	1.28	Allowances / Short Ton of Whey Protein Concentrate
		Deproteinized Whey Processing	0.764	Allowances / Short Ton of Deproteinized Whey
Roasted Nuts and Peanut Butter Manufacturing	311911	Pistachio Processing	0.221	Allowances / Short Ton of Pistachios
		Almond Processing	0.0714	Allowances / Short Ton of Almonds
Snack Food Manufacturing	31191	Fried Potato Chips Processing	0.834	Allowances / Short Ton of Fried Potato Chips
		Baked Potato Chips Processing	0.517	Allowances / Short Ton of Baked Potato Chips
		Corn Chips Processing	0.580	Allowances / Short Ton of Corn Chips
		Corn Curls Processing	0.446	Allowances / Short Ton of Corn Curls
		Pretzel Processing	0.633	Allowances / Short Ton of Pretzels
Beet sugar manufacturing	311313	Beet sugar manufacturing	0.611	Allowances / short ton Granulated-Refined Sugar

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Breweries	312120	Lager Beer Manufacturing	0.178	Allowances / Thousand Gallons of Lager Beer
Wineries	312130	Distilled Spirits Production	1.13×10^{-3}	Allowances / Proof Gallons of Distilled Spirits
		Dry Color Concentrate Production	12.0	Allowances / Short ton of Dry Color Concentrate
		Grape Juice Concentrate Production	1.59×10^{-3}	Allowances / Gallons of Grape Juice Concentrate
		Grape Seed Extract Production	9.48	Allowances / Short ton of Grape Seed Extract
		Liquid Color Concentrate Production	6.95×10^{-3}	Allowances / Gallons of Liquid Color Concentrate
Paper (except Newsprint) Mills	322121	Bathroom Tissue Manufacturing	0.108	Allowances / Air Dried Short Ton of Bathroom Tissue produced adjusted by water absorption capacity

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Facial Tissue Manufacturing	1.32	Allowances / Air Dried Short Ton of Facial Tissue
		Delicate Task Wipers Manufacturing	1.32	Allowances / Air Dried Short Ton of Delicate Task Wipers
		Paper Towel Manufacturing	1.54	Allowances / Air Dried Short Ton of Paper Towel
Paperboard Mills	322130	Recycled Boxboard Manufacturing	0.516	Allowances / Air Dried Short Ton of Recycled Boxboard
		Recycled Linerboard (Testliner) Manufacturing	0.562	Allowances / Air Dried Short Ton of Recycled Linerboard
		Recycled Medium (Fluting) Manufacturing	0.392	Allowances / Air Dried Short Ton of Recycled Medium
Petroleum Refineries	324110	Petroleum Refining	3.89	Allowances / Complexity Weighted Barrel
All Other Petroleum and Coal Products Manufacturing	324199	Coke Calcining	0.632	Allowances/ Metric Ton Calcined Coke
Industrial Gas Manufacturing	325120	On–Purpose Hydrogen Gas Production	8.94	Allowances / Metric Ton of On–Purpose Hydrogen Gas

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Liquid Hydrogen Production	11.9	Allowances / Metric Ton of Liquid Hydrogen Sold
Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production	0.349	Allowances / Short ton of nitric acid (HNO_3 100%)
		Calcium Ammonium Nitrate Solution Production	0.0902	Allowances / Short ton of Calcium Ammonium Nitrate Solution
Flat Glass Manufacturing	327211	Flat glass Manufacturing	0.495	Allowances / Short Ton of Flat Glass Pulled
Glass Container Manufacturing	327213	Container Glass Manufacturing	0.270	Allowances / Short Ton of Container Glass Pulled
Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	0.394	Allowances / Short Ton of Fiberglass Pulled
Cement Manufacturing	327310	Cement Manufacturing	0.742	Allowances / Short ton of adjusted clinker and mineral additives produced
Lime Manufacturing	327410	Dolime Manufacturing	1.40	Allowances / Short Ton of Dolime Produced
Gypsum Product Manufacturing	327420	Plaster Manufacturing	0.0454	Allowances / Short Ton of Plaster Sold as a Separate Finished Product

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Stucco Manufacturing	0.134	Allowances / Short Ton of Stucco used to produce saleable plasterboard
Iron and Steel Mills	331111	Steel Production Using an Electric Arc Furnace	0.170	Allowances / Short ton of Steel produced using EAF
Secondary smelting and alloying of aluminum	331314	Aluminum and Aluminum Alloy Billet Manufacturing	0.371	Allowances / Short ton of Aluminum and Aluminum alloy Billet
Secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum)	331492	Lead Acid Battery Recycling	0.403	Allowances / Short Ton of Lead and Lead Alloys
Iron Foundries	331511	Ductile Iron Pipe Manufacturing	0.561	Allowances / Short ton of Ductile Iron Pipes
Nonferrous Forging	332112	Seamless Rolled Ring	3.14	Allowances / Short ton of Seamless Rolled Ring
Rolled Steel Shape Manufacturing	331221	Hot Rolled Steel Sheet Production	0.0843	Allowances / Short ton of hot rolled steel sheet
		Pickled Steel Sheet Production	0.0123	Allowances / Short ton of pickled steel sheet
		Cold Rolled and Annealed Steel Sheet Production	0.0520	Allowances / Short ton of cold rolled and annealed steel sheet

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Galvanized Steel Sheet Production	0.0504	Allowances / Short ton of galvanized steel sheet
		Tin Steel Plate Production	0.111	Allowances / Short ton of tin plate
Turbine and Turbine Generator Set Units Manufacturing	333611	Testing of Turbines and Turbine Generator Sets	0.00782	Allowances / Horsepower tested

(c) Energy-Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_t = \left(S_{Consumed} * B_{Steam} + F_{Consumed} * B_{Fuel} - e_{Sold} * B_{Electricity}\right) * AF_{a,t} * c_{a,t}$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"$S_{Consumed}$" is the historical baseline annual arithmetic mean amount of steam consumed, measured in MMBtu, at the industrial facility for any industrial process, including heating or cooling applications. This value shall exclude any steam used to produce electricity. This value shall exclude steam produced from an onsite cogeneration unit;

"B_{Steam}" is the emissions efficiency benchmark per unit of steam, 0.06244 California GHG Allowances/MMBtu Steam;

"$F_{Consumed}$" is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (October 20, 2009). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit. This value shall exclude energy to generate the steam accounted for in the "$S_{Consumed}$" term;

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"e_{Sold}" is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWhs;

"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to the facility for activity "a" as specified in Table 8-1; and

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to the facility for activity "a" to account for cap decline as specified in Table 9-2.

(1) Data Sources.

(A) In determining the appropriate baseline values, the Executive Officer may employ all available data reported to ARB under MRR for data years 2008-2010. If necessary, the Executive Officer will solicit additional data to establish a representative baseline allocation.

(B) Recognition of California Climate Action Registry membership. If a facility reported facility level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2000-2007, the Executive Officer may consider these years in determining the representative annual baseline value. If necessary the Executive Officer will solicit additional data for these data years.

(2) Maximum Free Allocation. The Executive Officer shall ensure that the annual amount of California GHG Allowances directly allocated under the energy-based methodology to a covered entity for operations at a facility shall not exceed 110% of the maximum annual level of greenhouse gas emissions, adjusted for steam purchases and sales and electricity sales, emitted during

the historical data years used in establishing the baseline allocation for the facility in question.

(3) New Entrants. For covered facilities whose emissions exceeded the inclusion threshold pursuant to 95812(c) in 2012 or subsequent years, or opted into the program in 2012 or subsequent years, and are eligible for free allocation under the energy-based methodology, allowances shall be determined by the Executive Officer using the following methodology.

(A) Opt-In Covered Entities without Historical Baseline Emissions Data. For opt-in covered entities of facilities that have no historical emissions data reported to ARB under MRR, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_{a,t} = \left(F_{Consumed,est} * B_{Fuel} - e_{sold,est} * B_{Elect}\right) * AF_{a,t} * c_{a,t}$$

Where:

"$A_{a,t}$" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility for activity "a" with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"$F_{Consumed,est}$" is the estimated amount of energy produced due to fuel combustion at a given facility, measured in MMBtu. This value shall exclude fuel used to produce steam that is provided or sold offsite. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (December 17, 2010). The Executive Officer shall calculate this value utilizing any available data on the design of the facility and equipment;

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"$e_{Sold,est}$" is the estimated amount of electricity sold or provided for off-site use, measured in MWh. The Executive Officer shall calculate this value utilizing any available data on the design of the facility and equipment;

"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to the facility activity "a" as specified in Table 8-1; and

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to the facility activity "a" to account for cap decline as specified in Table 9-2.

(B) Entities with Transitional Emissions Data. For covered entities or opt-in covered entities that are classified as transitional in the stability formula in 95891(c)(3)(D), the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_{a,t} = \left(F_{t-2} * 0.05307 + \left(S_{Purchased,t-2} - S_{Sold,t-2}\right) * 0.06244 - e_{sold,t-2} * 0.431\right) * AF_{a,t} * c_{a,t} + TrueUp_t$$

Where:

"$A_{a,t}$" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility with activity "a" with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"F_{t-2}" is the annual amount of energy produced due to fuel combustion at a given facility for year "t-2", measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (November 29, 2013). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t-2}$" is the annual amount of steam purchased for year "t-2" by the facility in MMBtu as reported to ARB under MRR;

"$S_{Sold,t-2}$" is the annual amount of steam provided or sold for year "t-2" from the facility in MMBtu as reported to ARB under MRR;

"$e_{Sold,t-2}$" is the annual amount of electricity sold for year "t-2" from the facility in MWh as reported to ARB under MRR;

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to the facility activity "a" as specified in Table 8-1;

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to the facility activity "a" to account for cap decline as specified in Table 9-2; and

"$trueup_t$" is the amount of true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations. This value shall only be calculated if the entity was covered under the Cap-and-Trade Program in year "t-2". This value of allowances for budget year "t" shall be allowed to be used for compliance for budget year "t-2" or subsequent budget years pursuant to section 95856(h)(1)(D) and 95856(h)(2)(D). This value is calculated using the following formula:

$$TrueUp_t = (BE_{t-2} * AF_{a,t-2} * c_{a,t-2} - A_{a,t-2,no\ trueup})$$

Where:

"$A_{a,t\text{-}2,no\ trueup}$" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility for activity "a" with an energy-based allocation from budget year "t-2" not including the true-up for that budget year;

"t-2" is the year two years prior to year "t";

"$AF_{a,t\text{-}2}$" is the assistance factor for budget year "t-2" assigned to the facility activity "a" as specified in Table 8-1;

"$c_{a,t\text{-}2}$" is the adjustment factor for budget year "t-2" assigned to the facility activity "a" to account for cap decline as specified in Table 9-2;

"$BE_{t\text{-}2}$" is the baseline annual greenhouse gas emissions for year "t-2" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_{t-2} = F_{t-2} * 0.05307 + (S_{Purchased,t-2} - S_{Sold,t-2}) * 0.06244 - e_{sold,t-2} * 0.431$$

Where:

"F_t" is the annual amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (November 29, 2013). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t-2}$" is the annual amount of steam purchased for year "t-2" by the facility in MMBtu;

"$S_{Sold,t-2}$" is the annual amount of steam sold for year "t-2" from the facility in MMBtu; and

"$e_{Sold,t-2}$" is the annual amount of electricity sold for year "t-2" from the facility in MWh.

(C) Entities with Stable Emissions Data. For covered entities or opt-in covered entities classified as stable in the stability formula in 95891(c)(3)(D), the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the methodology in 95891(c). The allocation for all subsequent years shall be determined using this methodology.

(1) Data Years. The data years used in determining the appropriate baseline values shall match "t-2", "t-3", and "t-4" used in the stability formula when the emissions were first classified stable. The Executive Officer may employ all available data reported to ARB under MRR. If necessary, the Executive Officer will solicit additional data to establish a representative baseline allocation.

(D) Stability Formula for New Entrants. The following formula classifies the allocation methodology for budget year "t":

$$0.10 \geq \frac{BE_{t-2} - \frac{BE_{t-4} + BE_{t-3}}{2}}{BE_{t-2}} \quad \text{(Stable)}$$

$$0.10 < \frac{BE_{t-2} - \frac{BE_{t-4} + BE_{t-3}}{2}}{BE_{t-2}} \quad \text{(Transitional)}$$

Where:

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"t-3" is the year three years prior to year "t";

"t-4" is the year four years prior to year "t"; and

"BE_t" is the baseline annual greenhouse gas emissions for year "t" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_t = F_t * 0.05307 + \left(S_{Purchased,t} - S_{Sold,t}\right) * 0.06244 - e_{sold,t} * 0.431$$

Where:

"F_t" is the annual amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98 (November 29, 2013). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t}$" is the annual amount of steam purchased for year "t" by the facility in MMBtu;

"$S_{Sold,t}$" is the annual amount of steam sold for year "t" from the facility in MMBtu; and

"$e_{Sold,t}$" is the annual amount of electricity sold for year "t" from the facility in MWh.

(4) Facility Closures. Covered entities that are no longer subject to the Cap-and-Trade Program due to reduced emissions or facility closure as determined pursuant to section 95812(e) shall no longer be eligible to receive allowances.

(d) First Compliance Period Refining Sector Allocation Calculation Methodology. For the budget years 2013-2014, the Executive Officer shall calculate the amount of California GHG allowances allocated to an individual petroleum refinery annually using the following methodology.

(1) Facilities without an EII value. For refineries that did not participate in the 2008 Solomon Energy Review, or that do not have a representative EII value as determined by the Executive Officer, allowances will be allocated using the following approach:

(A) Initial allocations for 2013 and 2014 vintage allowances will be allocated using the following equations:

If: $O_{X,t-2} * B_R * c_t * AF_{R,t} \leq BE_X * c_t * AF_{R,t}$

Then: $A_{X,t} = O_{X,t-2} * B_R * c_t * AF_{R,t}$

If: $\mathrm{O}_{\mathrm{X},t-2} * \mathrm{B}_\mathrm{R} * \mathrm{c}_\mathrm{t} * \mathrm{AF}_{\mathrm{R,t}} > \mathrm{BE}_\mathrm{X} * \mathrm{c}_\mathrm{t} * \mathrm{AF}_{\mathrm{R,t}}$

Then: $A_{X,t} = BE_X * c_t * AF_{R,t}$

Where:

"$A_{X,t}$" is the allocation to refinery "X" without an EII value for year "t";

"$O_{X,t-2}$" is the output of primary refinery products, in barrels, from refinery "X" in year "t-2";

"B_R" is the benchmark for primary products produced by the refining sector, equal to 0.0462 metric tons of allowances per barrel of primary product;

"$AF_{R,t}$" is the assistance factor for budget year "t" assigned to petroleum refining as specified in Table 8-1; and

"c_t" is the adjustment factor for budget year "t" assigned to petroleum refining to account for cap decline as specified in Table 9-2.

"BE_X" is the baseline average annual greenhouse gas emissions for refinery "X" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_X = GHG + (S_{Purchased} - S_{Sold}) * 0.06244 - e_{Sold} * 0.431$$

"GHG" is the annual arithmetic mean amount of greenhouse gas emissions from the refinery;

"$S_{Purchased}$" is the annual arithmetic mean amount of steam purchased by the refinery in MMBtu;

"S_{Sold}" is the annual arithmetic mean amount of steam sold from the refinery in MMBtu;

"e_{Sold}" is the annual arithmetic mean amount of electricity sold from the refinery in MWh;

To calculate these values, the Executive Officer may employ data reported to ARB for data years 2008-2010. If the facility reported facility-level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2006-2007, the Executive Officer may consider these years in determining representative baseline values. If necessary, the Executive Officer will solicit data to establish a representative baseline.

(B) Trueup. In calendar years 2014 and 2015, allowance values as calculated for petroleum refineries in Section 95891(b) will be adjusted to account for actual 2013 and 2014 product output. If the entity received initial allowances based on output then the following equation will he used to calculate the true up using actual output:

$$TrueUp_{X,t} = (O_{X,t-2} * B_R * c_{\,t-2} * AF_{R,t-2}) - A_{X,t-2}$$

Where:

"$TrueUp_{X,t}$" is the amount true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations for refinery "X". This value of allowances for budget year "t" shall be allowed to be used for compliance for budget year "t-2" and subsequent years pursuant to 95856(h)(1)(D) and 95856(h)(2)(D).

"$A_{X,t-2}$" is the allocation to refinery "X" without an EII value for year "t-2."

If the entity received initial allocation based on emissions the following true-up equation will be used:

If: $(AE_{X,t-2}) < BE_X * 0.8$

Then: $TrueUp_{X,t} = (AE_{X,t-2} * c_{\,t-2} * AF_{R,t-2}) - A_{X,t-2}$

Where:

"$AE_{X,t-2}$" is the covered greenhouse gas emissions for refinery "X" for the data two years before budget year "t," adjusted for steam purchases and sales and electricity sales using the following equation:

$$AE_{X,t-2} = GHG_{t-2} + (S_{Purchased,t-2} - S_{Sold,t-2}) * 0.06244 - e_{Sold,t-2} * 0.431$$

"GHG_{t-2}" is the covered greenhouse gas emissions from the refinery in year "t-2";

"$S_{Purchased,t-2}$" is the amount of steam purchased by the refinery in year "t-2" in MMBtu;

"$S_{Sold,t-2}$" is the amount of steam sold from the refinery in year "t-1" in MMBtu;

"$e_{Sold,t-2}$" is the amount of electricity sold from the refinery in year "t-2" in MWh;

(2) Facilities with an EII® value. For refineries that participated in the 2008 Solomon Energy Review and have a representative EII® value, allowances will be allocated using the following approach:

(A) Initial Allocations. 2013 and 2014 vintage allowances will be allocated using the following equation:

$$A_{Y,t} = BE_Y * DF_{Y,t} * F_t$$

Where:

"$A_{Y,t}$" is the initial allocation to refinery "Y" that has an EII® value for year "t";

"BE_Y" is the baseline average annual greenhouse gas emissions for refinery "Y" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_Y = GHG + (S_{Purchased} - S_{Sold}) * 0.06244 - e_{Sold} * 0.431$$

"GHG", for the purposes of this calculation, is the annual arithmetic mean amount of greenhouse gas emissions from the refinery;

"$S_{Purchased}$" is the annual arithmetic mean amount of steam purchased by the refinery in MMBtu;

"S_{Sold}" is the annual arithmetic mean amount of steam sold from the refinery in MMBtu;

"e_{Sold}" is the annual arithmetic mean amount of electricity sold from the refinery in MWh;

To calculate these values, the Executive Officer may employ data reported to ARB for data years 2008-2010. If the facility reported facility level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2006-2007, the Executive Officer may consider these years in determining representative baseline values. If necessary, the Executive Officer will solicit data to establish a representative baseline allocation;

"$DF_{Y,t}$" is a distribution factor calculated as:

$$DF_{Y,t} = ((Avg / EII_Y) + Adj_t) / (1 + Adj_t)$$

"Avg" is the weighted average EII for all facilities with EII values calculated as:

$$Avg = \frac{\sum BE_Y}{\sum (BE_Y/EII_Y)}$$

"EII_Y" is the Solomon Energy Intensity Index (EII) for facility Y for 2008, 2009 or 2010 as determined to be representative by the Executive Officer. For the purposes of this calculation, EII values shall be rounded to one digit after the decimal;

"Adj" is an adjustment factor designed to provide the facility with the best EII the most allowances relative to its baseline level:

$$Adj_t = ((Avg/EII_{Best}) * F_t - 1) / (1 - F_t)$$

"EII_{Best}" is the EII of most efficient facility (lowest EII in sector);

"F_t" is a fraction calculated as:

$$F_t = \frac{SA_t - \sum A_{X,t}}{\sum BE_Y}$$

"SA_t" is the allocation to refining sector for year "t" specified in section 95870(e)(2)(A);

(B) True-up Debit. If actual 2013 and 2014 emissions are less than the amount of allowances allocated, the entity's allocation of budget year 2016 allowances under 95891(b) will be reduced according to the following equation:

If: $(AE_{Y,2013} + AE_{Y,2014}) < (\mathrm{A}_{Y,2013} + \mathrm{A}_{Y,2014})$

Then:

$$\mathrm{TrueUp}_{Y,Debit,2016} = 0.8 * \left[(AE_{Y,2013} + AE_{Y,2014}) - (\mathrm{A}_{Y,2013} + \mathrm{A}_{Y,2014})\right]$$

Where:

"$AE_{Y,t}$" = Actual GHG emissions from a facility in year "t" adjusted for heat sales and purchases and electricity sales.

"$TrueUp_{Y,Debit,2016}$" = the amount true-up allowances allocated from budget year 2016 to account for changes in production or allocation not properly accounted for in prior allocations for refinery "Y".

(C) True-up Credit. If actual 2013 and 2014 emissions are greater than the assumed baseline emissions, a true-up allocation will be conducted using 2016 vintage allowances and the following equation:

If: $$(2 * BE_Y) < (AE_{Y,2013} + AE_{Y,2014})$$

Then:

$$\text{TrueUp}_{Y,Credit,2016} = (AE_{Y,2013} * DF_{Y,2013} * F_{2013} * AF_{2013} + AE_{Y,2014} * DF_{Y,2014} * F_{2014} * AF_{2014}) - (\text{A}_{Y,2013} + \text{A}_{Y,2014})$$

Where:

"$TrueUp_{Y,Credit,2016}$"is the amount of true-up allowances from budget year 2016 allocated to account for changes in production or allocation not properly accounted for in prior allocations for refinery "Y". This value of allowances for budget year 2016 shall be allowed to be used for compliance for budget year 2013 and subsequent years pursuant to 95856(h)(1)(D) and 95856(h)(2)(D).

(e) Allocation to University Covered Entities and Public Service Facilities. The Executive Officer shall calculate the amount of allowances directly allocated to a University or a public service facility using the following formulas:

(1) Budget Year 2015 Allocation. For budget year 2015, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated to eligible University Covered Entities or Public Service Facilities using the following formula.

$$A_{2015} = \left(F_{consumed} * B_{Fuel} - Q_{sold} * 0.06244 - e_{sold} \times B_{electricity}\right) * c_t + \sum_{t=2013}^{2014} TrueUp_t$$

Where:

"A_{2015}" is the amount of California GHG allowances directly allocated to a university or public service facility from budget year 2015;

"$F_{consumed}$" is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at the facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit. For a university opt-in covered entity that purchases qualified thermal output from a public service facility, "$F_{consumed}$" includes the emissions associated with qualified thermal output purchased, calculated as MMBtu of qualified thermal output purchased multiplied by 0.06244.

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"Q_{sold}" is the quantity of qualified thermal output sold or provided to an entity other than the university or local government which owns the facility, or takes service from the Public Service Facility;

"e_{Sold}" is the historical baseline annual arithmetic mean amount of electricity sold or provided to an entity other than the university or local government which owns or takes service from the Public Service Facility, measured in MWhs;

"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"c_t" is the adjustment factor for budget year "t" to account for cap decline as specified in Table 9-2.

"$TrueUp_t$" is the amount of true-up allowances allocated to account for changes in allocation not properly accounted for in prior allocations. This value of allowances for budget year 2015 shall be allowed to be used for compliance for budget year 2013 and subsequent years pursuant to section 95856(h)(1)(D) and 95856(h)(2)(D). This value shall only be calculated for years in which the entity was covered under the Cap-and-Trade Program. This value is calculated using the following formula:

$$TrueUp_t = \left(F_{consumed} * B_{Fuel} - Q_{sold} * .06244 - e_{sold} * B_{electricity}\right) * c_t$$

Where:

"t" is the calendar year for which the trueup is providing a correction, 2013 and 2014.

(2) Budget Years 2016 to 2020 Allocation. For budget years 2016 to 2020, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated to eligible University Covered Entities or Public Service Facility using the following formula.

$$A_t = \left(F_{consumed} * B_{Fuel} - Q_{sold} * .06244 - e_{sold} * B_{electricity}\right) * c_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to a university or public service facility for budget years "t" from 2016 to 2020.

(3) Data Sources. In determining the appropriate baseline values, the Executive Officer may employ all available data reported to ARB under MRR for data years 2008 through 2013.

(4) Reporting on the Use of Allowance Value. No later than June 30, 2016, and each calendar year thereafter, each university and public service facility shall submit a report to the Executive Officer describing the disposition of any allowance value from allowances from the previous budget year, and how the allowance value was used to achieve additional environmental and economic benefits for California. This report shall include:

(A) The monetary value of allowances received by the university or public service facility. The university or public service facility shall calculate the value of these allowances based on the average market clearing price of the four Current Auctions held in the same budget year from which the allowances are allocated; and

(B) How the university or public service facility's disposition of the monetary value of allowances complies with the requirements of California Health and Safety Code sections 38500 et seq.

(f) Adjustment of Allowance Allocation to a Legacy Contract Counterparty. Industrial entities that receive an allowance allocation pursuant to section 95891 and are designated as a legacy contract counterparty shall have an adjustment to their allowance allocation. The Executive Officer shall subtract the allowances from the number of California GHG Allowances directly allocated to the legacy contract counterparty pursuant to 95891(b) through 95891(d). If the legacy contract counterparty was not eligible for allocation pursuant to sections 95891(b) through (d) and the legacy contract counterparty has a direct corporate association pursuant to section 95833 with any other covered or opt-in entity that was eligible for allocation pursuant to sections 95891(b) through (d) then the entity with a direct corporate association who received industrial allocation pursuant to sections 95891(b) through (d) shall have its allowance allocation adjusted by the equations in this section.

(1) For budget year 2015, the allocation adjustment formula is as follows:

$$Adj_{2015} = \sum_{t=2013}^{2015} A_{LC,t}$$

Where:

"Adj_{2015}" is the allocation adjustment for budget year 2015. This number shall be subtracted from the number of California GHG allowances directly allocated to a legacy contract counterparty or direct corporate associated entity for budget year 2015.

"$A_{LC,t}$" is the allocation amount supplied to the legacy contract generator with an industrial counterparty calculated pursuant to section 95894;

(2) For each budget year after 2015, the allocation adjustment formula is as follows:

$$Adj,_t = A_{LC,t}$$

"Adj_t" is the allocation adjustment for budget year "t". This number shall be subtracted from the number of California GHG allowances directly allocated to the Legacy Contract Counterparty or the entity with a direct corporate association for budget year "t";

"$A_{LC,t}$" is the allocation received by the legacy contract generator with an industrial counterparty in year "t" pursuant to section 95894.

(3) If the allocation adjustment is greater than the number of California GHG Allowances directly allocated to a legacy contract counterparty pursuant to sections 95891(b) through (d), then the legacy contract counterparty will have its allowance allocation adjusted to zero. If the legacy contract counterparty has a direct corporate association pursuant to section 95833 with any other covered or opt-in covered entity that was eligible for allocation pursuant to

sections 95891(b) through (d), then the entity with the direct corporate association that received allocation pursuant to section 95891(b) through (d) shall have its allowance allocation adjusted by the remainder of the adjustment as calculated earlier in this section.

Table 9-2: Cap Adjustment Factors for Allowance Allocation

Budget Year	Cap Adjustment Factor (c) for All Other Direct Allocation	Cap Adjustment Factor (c) for Sectors with Process Emissions Greater Than 50%		
		Sector	NAICS	Activity
		Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production
				Calcium Ammonium Nitrate Solution Production
		Cement manufacturing	327310	Cement manufacturing
		Lime manufacturing	327410	Dolime Manufacturing
2013	0.981	0.991		
2014	0.963	0.981		
2015	0.944	0.972		
2016	0.925	0.963		
2017	0.907	0.953		
2018	0.888	0.944		
2019	0.869	0.935		
2020	0.851	0.925		

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.

(a) Allocation to Individual Electrical Distribution Utilities. The allowances allocated to each electrical distribution utility from each budget year shall be the electrical distribution utility sector allocation calculated pursuant to section 95870(d) for the budget year multiplied by the percentage allocation factors specified in Table 9-3, or the quantity of allowances in Table 9-3A. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of retail ratepayers of each such electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(b) Transfer to Utility Accounts.

(1) Investor Owned Utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical corporation.

(2) Publicly Owned Electric Utilities or Electrical Cooperatives. When a publicly owned electric utility or electrical cooperative is eligible for a direct allocation, it shall inform the Executive Officer of the amounts to be placed:

(A) In the compliance account of an electrical generating facility operated by a publicly owned electric utility, an electrical cooperative, or a Joint Powers Agency in which the electrical distribution utility or electrical cooperative is a member and with which it has a power purchase agreement; or

(B) In the publicly owned electric utility's or electrical cooperative's limited use holding account.

(3) Publicly owned electric utilities or electrical cooperatives receiving a direct allocation must inform the Executive Officer by September 1, or the first business day thereafter, of the accounts in which the allocations are to be placed. If an entity fails to submit its distribution preference by September 1, ARB will automatically place all directly allocated allowances for the following budget year in the entity's Limited Use Holding Account.

(c) Monetization Requirement.

(1) In 2012 an electrical distribution utility must offer one third of the allowances placed in its limited use holding account in 2012 for sale at the auction scheduled for 2012.

(2) Within each calendar year after 2012, an electrical distribution utility must offer for sale at auction all allowances in its limited use holding account that were issued:

(A) From budget years that correspond to the current calendar year; and

(B) From budget years prior to the current calendar year.

(d) Limitations on the Use of Auction Proceeds and Allowance Value.

(1) Proceeds obtained from the monetization of allowances directly allocated to a publicly owned electric utility shall be subject to any limitations imposed by the governing body of the utility and to the additional requirements set forth in sections 95892(d)(3-5) and 95892(e).

(2) Proceeds obtained from the monetization of allowances directly allocated to investor owned utilities shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional requirements set forth in sections 95892(d)(3-5) and 95892(e).

(3) Auction proceeds and allowance value obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(4) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.

(e) Reporting on the Use of Auction Proceeds and Allowance Value. No later than June 30, 2014, and each calendar year thereafter, each electrical distribution utility shall submit a report to the Executive Officer describing the disposition of any auction proceeds and allowance value received in the prior calendar year. This report shall include:

(1) The monetary value of auction proceeds received by the electrical distribution utility;

(2) How the electrical distribution utility's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.;

(3) The monetary value of allowances received by the electrical distribution utility which were deposited directly into electrical generating facility compliance accounts. The electrical distribution utility shall calculate the value of these allowances based on the average market clearing price of the four quarterly auctions held in the same calendar year that the allowances are allocated; and

(4) How the electrical distribution utility's disposition of the monetary value of allowances, deposited directly into compliance accounts, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.

Table 9-3: Percentage of Electric Sector Allocation Allocated to Each Utility

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
PG&E	IOU	26.02909%	26.34522%	26.01510%	26.21500%	27.21147%	26.91164%	27.21091%	27.22981%
LADWP	POU	14.18332%	14.18925%	14.00829%	14.43473%	14.91438%	15.28169%	14.96326%	14.04837%
SCE	IOU	34.01733%	33.58115%	34.04480%	32.69831%	30.32124%	29.84140%	29.46661%	29.71342%
SDG&E	IOU	7.21940%	6.96087%	6.96792%	7.08933%	7.29010%	7.24815%	7.28721%	7.38964%
SMUD	POU	3.28172%	3.28283%	3.21338%	3.30147%	3.44817%	3.57259%	3.70519%	3.83415%
City of Anaheim	POU	2.07532%	2.12074%	2.11355%	2.19270%	2.20963%	2.27089%	2.30639%	2.35434%
City of Azusa (Azusa Light & Water)	POU	0.18055%	0.18489%	0.18858%	0.19402%	0.20119%	0.20555%	0.21082%	0.21761%
City of Banning	POU	0.09772%	0.10169%	0.10327%	0.10646%	0.11074%	0.11334%	0.11631%	0.12050%
City of Burbank	POU	0.65354%	0.66027%	0.66532%	0.67128%	0.68296%	0.68319%	0.68787%	0.69354%
City of Cerritos	POU	0.01827%	0.01887%	0.01945%	0.02004%	0.02090%	0.02128%	0.02186%	0.02240%
City of Colton	POU	0.24485%	0.25185%	0.25876%	0.26535%	0.27437%	0.27891%	0.28559%	0.29302%
City of Glendale (Water and Power)	POU	0.65850%	0.66238%	0.66100%	0.67150%	0.69049%	0.69592%	0.68391%	0.70039%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Pasadena (Pasadena Water and Power)	POU	0.80141%	0.80710%	0.80920%	0.82057%	0.83784%	0.86949%	0.87876%	0.89190%
City of Riverside	POU	1.12865%	1.13669%	1.13121%	1.17999%	1.20482%	1.24829%	1.27103%	1.30954%
City of Vernon	POU	0.41385%	0.42014%	0.42987%	0.43256%	0.44276%	0.44174%	0.42961%	0.42477%
Imperial Irrigation District	POU	1.77241%	1.81456%	1.82936%	1.90056%	1.97281%	2.00476%	2.05350%	2.11597%
Modesto ID	POU	1.26426%	1.28335%	1.27289%	1.30523%	1.34388%	1.35267%	1.36746%	1.40098%
City of Alameda	POU	0.05321%	0.05746%	0.05675%	0.06140%	0.06253%	0.07244%	0.07403%	0.07561%
City of Biggs	POU	0.00680%	0.00729%	0.00674%	0.00681%	0.00733%	0.00711%	0.00710%	0.00721%
City of Gridley	POU	0.01517%	0.01551%	0.01571%	0.01601%	0.01650%	0.01657%	0.01654%	0.01666%
City of Healdsburg	POU	0.03290%	0.03271%	0.03126%	0.03325%	0.03567%	0.03777%	0.03889%	0.04195%
City of Lodi	POU	0.16616%	0.16780%	0.16385%	0.16740%	0.17419%	0.17518%	0.17494%	0.17995%
City of Lompoc	POU	0.04956%	0.04985%	0.04887%	0.05136%	0.05400%	0.05438%	0.05442%	0.05635%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Palo Alto	POU	0.35530%	0.35717%	0.34944%	0.35460%	0.36639%	0.36628%	0.36537%	0.37403%
City of Redding	POU	0.44750%	0.50262%	0.50106%	0.51053%	0.52983%	0.54582%	0.54607%	0.55913%
City of Roseville	POU	0.48831%	0.50123%	0.50861%	0.53058%	0.55609%	0.54800%	0.54623%	0.55111%
City of Ukiah	POU	0.03536%	0.03503%	0.03265%	0.03550%	0.03905%	0.04202%	0.04340%	0.04460%
Plumas-Sierra Rural Electric Cooperation	COOP	0.06414%	0.06559%	0.06670%	0.06763%	0.06929%	0.06923%	0.06894%	0.06892%
Port of Oakland	POU	0.03277%	0.03345%	0.03411%	0.03438%	0.03491%	0.03467%	0.03451%	0.03432%
Silicon Valley Power	POU	1.13125%	1.14819%	1.13895%	1.20823%	1.29624%	1.33330%	1.33645%	1.38438%
Truckee-Donner Public Utility District	POU	0.12089%	0.12415%	0.12749%	0.13067%	0.13480%	0.13722%	0.14051%	0.14406%
Turlock Irrigation District	POU	0.94012%	0.97157%	0.98772%	1.01291%	1.05443%	1.06803%	1.06840%	1.08659%
Anza Electric Cooperative, Inc.	COOP	0.02028%	0.02102%	0.04803%	0.04922%	0.05093%	0.05159%	0.05284%	0.05386%
Golden State Water Company	IOU	0.00006%	0.00006%	0.00006%	0.00007%	0.00007%	0.00007%	0.00007%	0.00007%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Needles	POU	0.01027%	0.01086%	0.01148%	0.01183%	0.01248%	0.01250%	0.01284%	0.01316%
City of Rancho Cucamonga	POU	0.02559%	0.02653%	0.02753%	0.02822%	0.02928%	0.02961%	0.03034%	0.03104%
City and County of San Francisco	POU	0.09929%	0.11620%	0.13435%	0.15375%	0.17430%	0.19643%	0.22009%	0.24157%
City of Shasta Lake (Shasta Dam Area Public Utility District)	POU	0.05182%	0.05360%	0.05499%	See Table 9-3A for absolute value of allocation				
Lassen Municipal Utility District	POU	0.05079%	0.05279%	0.05492%	0.05638%	0.05866%	0.05927%	0.06075%	0.06219%
Merced Irrigation District	POU	0.17105%	0.17687%	0.18268%	0.18770%	0.19525%	0.19791%	0.20285%	0.20835%
Moreno Valley Utilities	POU	0.03929%	0.04073%	0.04227%	0.04334%	0.04495%	0.04547%	0.04657%	0.04765%
Kirkwood Meadows Public Utility District	POU	0.00306%	0.00317%	0.00329%	0.00337%	0.00350%	0.00354%	0.00362%	0.00369%
Port of Stockton	POU	0.00538%	0.00558%	0.00579%	0.00594%	0.00616%	0.00623%	0.00638%	0.00648%
Power and Water Resource Pooling Authority	POU	0.06650%	0.06899%	0.07018%	0.07365%	0.07980%	0.08118%	0.08378%	0.08727%
California Pacific Electric Company	IOU	0.22625%	0.23453%	0.24340%	0.24957%	0.25888%	0.26194%	0.26839%	0.27259%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
Surprise Valley Electrical Corporation	COOP	0.05381%	0.05578%	0.03167%	0.03251%	0.03384%	0.03419%	0.03505%	0.03541%
Trinity Public Utility District	POU	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
WAPA	POU	0.33271%	0.35496%	0.37846%	0.39096%	0.41612%	0.41522%	0.42716%	0.43040%
Valley Electric Association, Inc.	COOP	0.00012%	0.00012%	0.00013%	0.00013%	0.00014%	0.00014%	0.00014%	0.00014%
Victorville Municipal	POU	0.02385%	0.02472%	0.02566%	0.02631%	0.02729%	0.02761%	0.02829%	0.02873%
Hercules	POU	0.00656%	0.00674%	0.00687%	0.00711%	0.00747%	0.00761%	0.00782%	0.00813%
City of Industry	POU	0.00910%	0.00945%	0.00982%	0.01008%	0.01047%	0.01058%	0.01085%	0.01101%
Corona	POU	0.06050%	0.06248%	0.06438%	0.06621%	0.06897%	0.06999%	0.07176%	0.07331%
Pittsburg Power (Island)	POU	0.00407%	0.00429%	0.00452%	0.00466%	0.00492%	0.00494%	0.00507%	0.00513%
Eastside	POU	0.00487%	0.00522%	0.00558%	0.00577%	0.00616%	0.00613%	0.00631%	0.00635%
PacifiCorp	IOU	0.75511%	0.77388%	0.79208%	0.81600%	0.84143%	0.86742%	0.89439%	0.92339%
(1) IOU = Investor Owned Electric Utility, POU = Publicly Owned Electric Utility, COOP = Rural Electric Cooperative									

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code

Table 9-3A: Quantity of Allowances Allocated to City of Shasta Lake (Shasta Dam Area Public Utiltiy District)

Utility Name	Utility Type (1)	Annual Allowances to Utility				
		2016	2017	2018	2019	2020
City of Shasta Lake (Shasta Dam Area Public Utility District)	POU	129,197	72,923	72,523	72,814	73,697

§ 95893. Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers.

(a) Allocation to Individual Natural Gas Suppliers. For each budget year, each natural gas supplier's allocation will be calculated as follows. Any allowances allocated to natural gas suppliers must be used exclusively for the benefit of retail ratepayers of each such natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

$$A_{S,t} = E_{2011} * c_{a,t}$$

Where:

"$A_{S,t}$" is the amount of California GHG allowances directly allocated to the natural gas supplier "S" from budget year "t";

"E_{2011}" is the emissions for natural gas supplier "S" for data year 2011, as calculated using the compliance obligation calculation methods under section 95852(c);

"$c_{a,t}$" is the adjustment factor for budget year "t" to account for cap decline as specified in Table 9-2; and

(b) Transfer to Natural Gas Supplier Accounts.

(1) When a natural gas supplier as defined in section 95811(c) is eligible for a direct allocation, it shall inform the Executive Officer by September 1, or the first business day thereafter of the amount of allowances to be placed into its Compliance and Limited Use Holding Account with the following constraints. If an entity fails to submit its distribution preference by this deadline, ARB will automatically place all directly allocated allowances for the following budget year in the entity's Limited Use Holding Account:

(A) The quantity of allowances placed into the Limited Use Holding Account will equal at least the amount of allowances provided in section 95893(a) multiplied by the applicable percentage in Table 9-4, rounded down to the nearest whole allowance.

(B) The remaining allowances from the allowances allocated in section 95893(a) which are not placed into the Limited Use Holding Account will be placed into the Compliance Account.

(c) Monetization Requirement. Within each calendar year beginning in 2015 and after, a natural gas supplier must offer for sale at auction all allowances in its limited use holding account that were issued from budget years that correspond to the current calendar year and from budget years prior to the current calendar year.

(d) Limitations on the Use of Auction Proceeds and Allowance Value.

(1) Proceeds obtained from the monetization of allowances directly allocated to a publicly owned natural gas utility shall be subject to any limitations imposed by the governing body of the utility and to the additional requirements set forth in sections 95893(d)(3) through 95893(d)(5) and 95893(e).

(2) Proceeds obtained from the monetization of allowances directly allocated to public utility gas corporations shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional requirements set forth in sections 95893(d)(3) through 95893(d)(5) and 95893(e).

(3) Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. Any revenue returned to ratepayers must be done in a non-volumetric manner.

(4) Public utility gas corporations shall ensure equal treatment of their procurement and delivery customers and delivery-only customers.

(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to a natural gas supplier, other than for the benefit of retail ratepayers consistent with the goals of AB 32, is prohibited.

(e) Reporting on the Use of Auction Proceeds and Allowance Value. No later than June 30, 2016, and each calendar year thereafter, each natural gas supplier shall submit a report to the Executive Officer describing the disposition of any auction proceeds and allowance value from allowances from the previous budget year. This report shall include:

(1) The monetary value of auction proceeds received by the natural gas supplier. The natural gas supplier shall calculate the value of these allowances based on the average market clearing price of the four Current Auctions held in the same budget year from which the allowances are allocated;

(2) How the natural gas supplier's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.;

(3) The monetary value of allowances received by the natural gas supplier which were deposited directly into its compliance account. The natural gas supplier shall calculate the value of these allowances based on the average market clearing price of the four Current Auctions held in the same budget year from which the allowances are allocated; and

(4) How the natural gas supplier's disposition of the monetary value of allowances, including those deposited directly into its compliance account, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.

Table 9-4: Percentage Consignment Requirements for Natural Gas Utilities by Year

Compliance Period	2			3		
Year	2015	2016	2017	2018	2019	2020
Percent Consigned	25%	30%	35%	40%	45%	50%

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95894. Allocation to Legacy Contract Generators for Transition Assistance.

(a) Demonstration of Eligibility. Opt-in covered entities are not eligible for transition assistance due to legacy contract emissions. To be eligible to receive a direct allocation of allowances under this section, the primary or alternate account representative of a legacy contract generator with an industrial counterparty or legacy contract generator without an industrial counterparty shall submit the following in writing via certified mail to the Executive Officer by September 2 of each year as applicable:

(1) A letter to ARB stating covered entity's name and ARB ID, identification of legacy contract counterparty, and statement requesting transition assistance for the previous data year's legacy contract emissions.

(A) Previous data year's legacy contract emissions, pursuant to section 95894(c); and

(B) 2012 data year's legacy contract emissions, pursuant to section 95894(d).

(2) Copy of the following portions from the legacy contract for which it is seeking an allocation;

(A) Dates of effective commencement and cessation of terms of contract.

(B) Terms governing price per unit of product.

(C) Signature page.

(3) An attestation under penalty of perjury under the laws of the State of California that:

(A) Each legacy contract does not allow the covered entity to recover the cost of legacy contract emissions from the legacy contract counterparty purchasing electricity and/or legacy contract qualified thermal output from the unit or facility;

(B) The legacy contract was originally executed prior to September 1, 2006, remains in effect, and has not been amended since that date to change the terms governing the price or amount of electricity or legacy contract qualified thermal output sold, the GHG costs, or the expiration date;

(C) The operator of the legacy contract generator with an industrial counterparty or the legacy contract generator without an industrial counterparty made a good faith effort, but was unable to renegotiate the legacy contract with the counterparty to address recovery of the costs of compliance with this regulation.

(4) Data requested pursuant to Section 95894.

(5) If, subsequent to the submittal of the foregoing information and supporting documentation, there is any material change in the information and statements provided to the Executive Officer, the party who submitted such information and statements shall submit a supplemental attestation and supporting materials addressing any such material change to the Executive Officer within 30 days after the change occurs.

(b) Determination of Eligibility. Upon receipt of the information required by paragraph (a) of this section, the Executive Officer shall determine whether the party submitting such information has demonstrated that it is eligible to receive a direct allocation of allowances pursuant to this section and shall notify that party by October 10 each year if it is eligible to receive an allocation calculated pursuant to section 95894(c) or 95894(d) for the following compliance year.

(c) Allocation to Legacy Contract Generators with an Industrial Counterparty. If the counterparty (or entity in a direct corporate association with the counterparty) is a covered entity or opt-in covered entity that is in a sector listed in Table 8-1, the following formulae apply based on the type of generation facility:

(1) For stand-alone generation facilities that are legacy contract generators with an industrial counterparty, the following equations apply:

$$TrueUp_{2015} = \left(EEm_{lc} * AF_{lcc,2013} * c_{2013}\right) + \left(EEm_{lc} * AF_{lcc,2014} * c_{2014}\right) + (EEm_{lc} * AF_{lcc,2015} * c_{2015})$$

Where

"$TrueUp_{2015}$" is the amount of true up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years, pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"$EEm_{lc,}$" is the emissions reported, in $MTCO_2e$, associated with electricity sold under the legacy contract in 2013;

"$AF_{lcc,2013}$," "$AF_{lcc,2014}$," and "$AF_{lcc,2015}$" are the assistance factors associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget years 2013, 2014, and 2015, respectively; and

"c_{2013}," "c_{2014}," and "c_{2015}," are the cap adjustment factors for the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget years 2013, 2014, and 2015, respectively, as specified in Table 9-2.

From budget year 2016 forward, the following equation applies:

$$A_t = \left(EEm_{lc,t-2} * c_{a,t} * AF_{lcc,t}\right) + TrueUp_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the legacy contract generator with an industrial counterparty for legacy contract emissions from budget year "t". This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 94894(a) and 95894(b), and is covered under the Cap-and-Trade Program during the second compliance period;

"$EEm_{lc,t-2,}$" is the emissions reported, in $MTCO_2e$, associated with electricity sold under the legacy contract in the data years two years before year "t";

"$c_{a,t}$" is the cap adjustment factor for the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget year "t";

"$AF_{lcc,t}$" is the assistance factor associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget years "t"; and

$$TrueUp_t = \left(EEm_{lc,t-2} * c_{a,t-2} * AF_{lcc,t-2}\right) - A_{t-2,no\ trueup}$$

Where:

"$TrueUp_t$" is the amount of true-up allowances allocated to account for the emissions reported for data year "t" and allowed to be used for compliance for the budget year two years prior to year "t" and subsequent years pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"$EEm_{lc,t-2,}$" is the emissions reported, in $MTCO_2e$, associated with electricity sold under the legacy contract in the data years two years before year "t";

"$c_{a,t-2}$" is the cap adjustment factor for the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for the ~~budget~~ year two years prior to year "t";

"$AF_{lcc,t-2}$" is the assistance factor associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for two years before budget year "t";

"$A_{t-2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the legacy contract generator with an industrial counterparty for legacy contract emissions from the budget year two years prior to year "t," not including the true-up for that budget year.

(2) For legacy contract generators with an industrial counterparty, subject to 95894(c) but not covered in 95894(c)(1), the following equations apply:

$$TrueUp_{2015} = \left((Q_{lc} * B_s + E_{lc} * B_e) * AF_{lcc,2013} * c_{2013}\right) + ((Q_{lc} * B_s * E_{lc} * B_e) * AF_{lcc,2014} * c_{2014}) + ((Q_{lc} * B_s + E_{lc} * B_e) \times AF_{lcc,2015} * c_{2015})$$

Where:

"$TrueUp_{2015}$" is the amount of true-up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"$Q_{lc,}$" is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in data year 2013, as reported to MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract in data year 2013;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of legacy contract qualified thermal output, 0.06244 California GHG Allowances/MMBtu thermal;

"$AF_{lcc,2013}$," "$AF_{lcc,2014}$," and "$AF_{lcc,2015}$" are the assistance factors associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget years 2013, 2014, and 2015, respectively; and

"c_{2013}," "c_{2014}," and "c_{2015}," are the cap adjustment factors for the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget years 2013, 2014, and 2015, respectively, as specified in Table 9-2.

From budget year 2016 forward, the following formula applies:

$$A_t = ((Q_{lc,t-2} * B_s + E_{lc,t-2} * B_e) * AF_{lcc,t} * c_t) + TrueUp_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the legacy contract generator with an industrial counterparty for legacy contract emissions from budget year "t". This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 94894(a), and 95894(b), and is covered under the Cap-and-Trade Program during the second compliance period.

"$Q_{lc,t-2}$" is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in the data year two years prior to year "t," as reported under MRR;

"$E_{lc,t-2}$" is the electricity, in MWh, sold under the legacy contract in the data year two years prior to year "t," as reported under MRR;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of legacy contract qualified thermal output, 0.06244 California GHG Allowances/MMBtu thermal;

"$AF_{lcc,t}$" is the assistance factor associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget year "t";

"c_t" is the cap adjustment factor for the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty for budget year "t" as specified in table 9-2; and

$$TrueUp_t = \left(\left(Q_{lc,t-2} * B_s + E_{lc,t-2} * B_e\right) * AF_{lcc,t-2} * c_{t-2}\right) - A_{t-2,no\ trueup}$$

"$TrueUp_t$" is the amount of true-up allowances allocated to account for the emissions reported for data year "t" and allowed to be used for compliance for the budget year two years prior to year "t" and subsequent years pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"$Q_{lc,\ t-2}$" is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in the data year two years prior to year "t," as reported under MRR;

"B_s" is the emissions efficiency benchmark per unit of legacy contract qualified thermal output, 0.06244 California GHG Allowances/MMBtu thermal;

"$E_{lc,t-2}$" is the electricity, in MWh, sold under the legacy contract in the data year two years prior to year "t," as reported under MRR;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"$AF_{lcc,t-2}$" is the assistance factor associated with the legacy contract counterparty or entity in a direct corporate association with the legacy contract counterparty in the budget year two years prior to year "t";

"c_{t-2}" is the is the cap adjustment factor for the budget year two years prior to year "t" as specified in Table 9-2.

"$A_{t-2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the legacy contract generator with an industrial counterparty for legacy contract emissions from the budget year two years prior to year "t," not including the true-up for that budget year;

(d) Allocation to Legacy Contract Generators without an Industrial Counterparty. For legacy contracts not covered in 95894(c), the following formulae shall apply:

(1) For stand-alone generation facilities that are legacy contract generators without an industrial counterparty:

$$TrueUp_{2015} = (EEm_{lc} * c_{2013}) + (EEm_{lc} * c_{2014}) + (EEm_{lc} * c_{2015})$$

Where:

"$TrueUp_{2015}$" is the amount of true up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years, pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"$EEm_{lc,}$" is the emissions reported, in $MTCO_2e$, associated with electricity sold under the legacy contract in 2012; and

"c_{2013}," "c_{2014}," and "c_{2015}," are the cap adjustment factors for budget years 2013, 2014, and 2015, respectively, as specified under the "Cap Adjustment Factor (c) for All Other Direct Allocation" column in Table 9-2.

For budget years 2016 and 2017 the following equation applies:

$$A_t = (EEm_{lc} * c_t)$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the legacy contract generator without an industrial counterparty for legacy contract emissions from budget year "t." This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 95894(a) and 95894(b), and is covered under the Cap-and-Trade Program during the second compliance period.

EEm_{lc}," is the emissions reported, in $MTCO_2e$, associated with electricity sold under the legacy contract in 2012; and

"c_t" is the adjustment factor for budget year "t," as specified under the "Cap Adjustment Factor (c) for All Other Direct Allocation" column in Table 9-2.

(2) For legacy contract generators without an industrial counterparty not covered in 95894(c) or 95894(d)(1):

$$TrueUp_{2015} = \left((Q_{lc} * B_s + E_{lc} * B_e) * c_{2013}\right) + ((Q_{lc} * B_s + E_{lc} * B_e) * c_{2014}) + ((Q_{lc} * B_s + E_{lc} * B_e) * c_{2015})$$

Where:

"$TrueUp_{2015}$" is the amount of true-up allowances allocated from budget year 2015 and allowed to be used for compliance for budget years 2013 and 2014 and subsequent years pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"Q_{lc}," is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in data year 2012, as reported to MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract in data year 2012;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of legacy contract qualified thermal output, 0.06244 California GHG Allowances/MMBtu thermal; and

"c_{2013}," "c_{2014}," and "c_{2015}" are the cap adjustment factors for budget years 2013, 2014, and 2015, respectively, as specified under the "Cap Adjustment Factor (c) for All Other Direct Allocation" column in table 9-2.

For budget years 2016 and 2017, the following equation applies:

$$A_t = \left((Q_{lc} * B_s + E_{lc} * B_e) * c_t\right)$$

Where:
"A_t" is the amount of California GHG allowances directly allocated to the legacy contract generator without an industrial counterparty, for legacy contract emissions from budget year "t." This value shall only be calculated if the entity meets the eligibility requirements, pursuant to section 95894(a) and 95894(b), and is covered under the Cap-and-Trade Program during the second compliance period;

"$Q_{lc,}$" is the legacy contract qualified thermal output in MMBtu sold under a legacy contract in data year 2012, as reported to MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract in data year 2012;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of legacy contract qualified thermal output, 0.06244 California GHG Allowances/MMBtu thermal; and

"c_t" is the cap adjustment factor for budget year "t" as specified under the "Cap Adjustment Factor (c) for All Other Direct Allocation" column in table 9-2.

(e) Data Sources. In determining the appropriate values for section 95894(c) and 95894(d), the Executive Officer may employ all available data reported to ARB under MRR and all other relevant data, including invoices, that demonstrate the amount of electricity and legacy contract qualified thermal output sold or provided for off-site use does not include a carbon cost in the budget year for which it is seeking an allocation. If necessary, the Executive Officer will solicit additional data to establish a representative allocation. The operator of the legacy contract generator with an industrial counterparty and the operator of a legacy contract generator without an industrial counterparty, must provide the additional data upon request by the Executive Officer.

(f) Contract Expiration or Generator Closure. Once a legacy contract expires or the legacy contract generator with an industrial counterparty or a legacy contract generator without an industrial counterparty closes operations, the generator will no longer be eligible for free allocation pursuant to 95890(e), and allocation will be prorated for the time in which the contract was eligible.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95895. Allocation to Public Wholesale Water Agencies for Protection of Water Ratepayers.

(a) Allocation to Public Wholesale Water Agencies. The allowances allocated to each public wholesale water agency from each budget year from 2015 through 2020 shall be the amount specified in Table 9-5.

Table 9-5: Allocation to Each Public Wholesale Water Agency

Agency Name	Annual Allocation					
	2015	2016	2017	2018	2019	2020
Metropolitan Water District	182,499	133,065	57,180	42,323	41,502	40,723

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 10: Auction and Sale of California Greenhouse Gas Allowances

§ 95910. Auction of California GHG Allowances.

(a) Timing of the Allowance Auctions.

(1) In 2012, an auction will held on November 14.

(2) Beginning in 2013 and through 2014, the auctions shall be conducted on the twelfth business day in California or a jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12 of the second month of each calendar quarter.

(3) Beginning in 2015, auctions shall be conducted on the schedule pursuant to Appendix C. The schedule may be adjusted by a maximum of 4 days from the dates listed in Appendix C.

(b) General Requirements.

(1) Allowances allocated to the Auction Holding Account pursuant to section 95870(b)(1)-(2) and (i) will be designated to specific auctions pursuant to section 95910(c).

(2) An allowance may be designated for auction prior to or after its vintage year.

(c) Allowances from future vintages will be auctioned separately from allowances from current and previous vintages each quarter.

(1) Auction of Allowances from the Current and Previous Budget Years.

(A) This auction will be known as the Current Auction.

(B) Beginning in 2013, one quarter of the allowances allocated for auction from the current calendar year's budget and the allowances designated pursuant to Section 95911(f)(3)(D) will be designated for sale at each Current Auction.

(C) The Current Auction will include allowances consigned to auction pursuant to section 95910(d).

(D) The Current Auction may include allowances from the current and previous budget years which remained unsold at previous auctions and which are designated for auction pursuant to section 95911(f)(3).

(2) Auction of Allowances from Future Budget Years.

(A) This auction will be known as the Advance Auction.

(B) At the one Advance Auction taking place in 2012, the Executive Officer will designate for sale all of the allowances allocated for Advance Auction from the 2015 budget.

(C) Beginning in 2013, one quarter of the allowances allocated for Advance Auction from the budget year three years subsequent to the current calendar year will be designated for sale at each Advance Auction.

(D) The Advance Auction will include allowances which were returned to the Auction Holding Account following an Advance Auction which resulted in unsold allowances, and which are designated for auction pursuant to section 95911(f)(3).

(d) Auction of Consigned Allowances.

(1) An entity may consign allowances to the Executive Officer for sale at the quarterly auctions only from a limited use holding account.

(2) When the Executive Officer withdraws compliance instruments from accounts closed pursuant to section 95831(c), accounts containing allowances in excess of the holding limit pursuant to section 95920(b)(5), or accounts suspended or revoked pursuant to section 95921(g)(3):

(A) Allowances shall be consigned to the next auction;

(B) If, after review, the Executive Officer determines the withdrawn ARB offset credits are valid, the Executive Officer will retire them, withdraw a similar number of allowances from the Auction Holding Account, and consign those allowances to auction in place of the retired ARB offset credits.

(3) Each consigning entity agrees to accept the auction settlement price for allowances sold at auction.

(4) Deadline for Consignment.

(A) For the auction conducted in 2012, allowances designated for consignment pursuant to section 95892(c) must be transferred to the Auction Holding Account at least 10 days before the auction.

(B) Beginning in 2013 and through 2014, allowances consigned to auction through a transfer to the Auction Holding Account at least 75 days prior to the regular quarterly auction will be offered for sale at that auction.

(C) Beginning in 2015, allowances designated for consignment pursuant to sections 95892(c) and 95893(c) must be transferred to the Auction Holding Account at least 75 days before the auction as scheduled in Appendix C.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95911. Format for Auction of California GHG Allowances.

(a) Auction Bidding Format.

(1) The auction will consist of a single round of bidding.

(2) Bids will be sealed.

(3) Bid quantities must be submitted as multiples of 1,000 California GHG allowances.

(4) Entities registered into the California Cap-and-Trade Program must submit bids in whole U.S. dollars and whole cents.

(5) The allowances for auction in section 95911(a)(3) will also include allowances from a jurisdiction operating an External GHG ETS system to which California has linked pursuant to subarticle 12.

(b) Auction Reserve Price Schedule.

(1) Each auction will be conducted with an auction reserve price.

(2) No allowances will be sold at bids lower than the auction reserve price.

(c) Method for Setting the Auction Reserve Price.

(1) The Auction Reserve Price for vintage 2013 allowances auctioned in 2012 will be $10 per allowance. For Advance Auctions conducted in 2012, the Reserve Price shall be $10 per allowance for vintage 2015 allowances.

(2) Beginning in 2012, and each year thereafter, the Auction Administrator will announce the Auction Reserve Price for auctions to be conducted the following calendar year on the first day in December that is a business day in California. The Reserve Price shall be stated in U.S. dollars.

(3) The Auction Administrator will calculate the Auction Reserve Price using the following procedure:

(A) The Auction Reserve Price in U.S. dollars shall be the U.S. dollar Auction Reserve Price for the previous calendar year increased annually by 5 percent plus the rate of inflation as measured by the most recently available twelve months of the Consumer Price Index for All Urban Consumers.

(B) Prior to the opening of the auction window on the day of the auction, the Auction Administrator shall announce the Auction Reserve Price.

(C) The auction administrator shall set the exchange rate as the most recently available noon daily buying rate for U.S. and Canadian dollars as published by the Bank of Canada, and shall announce the exchange rate prior to the opening of the auction window.

(D) The Auction Reserve Price in Canadian dollars shall be the Canadian dollar Auction Reserve Price for the previous calendar year increased annually by 5 percent plus adjusted in the manner provided for in section 83.3 of the Financial Administration Act (R.S.Q., c. A-6.001) of Quebec.

(E) The auction administrator will use the announced exchange rate to convert to a common currency the Auction Reserve Prices previously calculated separately in U.S. and Canadian dollars. The auction administrator will set the Auction Reserve Price equal to the higher of the two values.

(4) The Auction Reserve Price will be announced prior to the opening of the auction window at 10 a.m. Pacific Standard Time (or Pacific Daylight Time when in effect) on the day of the auction, and will be in effect until the window closes at 1 p.m. Pacific Standard Time (or Pacific Daylight Time when in effect). The opening of the bidding window may be delayed or paused for no more than one hour by the Executive Officer due to technical systems failures.

(5) The Auction Reserve Price in section 95911(c)(2) will be announced on the first day in December that is a business day in California and in any jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12 and the Reserve Price shall also

be stated in the currency (or currencies) used in an External GHG ETS to which California has linked pursuant to subarticle 12.

(d) Auction Purchase Limit.

(1) The auction purchase limit is the maximum number of allowances offered at each quarterly auction which can be purchased by any entity or group of entities with a direct corporate association pursuant to section 95833.

(2) The auction purchase limit in section 95911(d)(4) will apply to auctions conducted from January 1, 2012 through December 31, 2014.

(3) For the Advance Auction of future vintage allowances conducted pursuant to section 95910(c)(2) the purchase limit is 25 percent of the allowances offered for auction.

(4) For the auction of current vintage allowances conducted pursuant to section 95910(c)(1):

(A) The purchase limit for covered entities and opt-in covered entities will be 15 percent of the allowances offered for auction, except for the last auction in 2014 where the purchase limit for covered and opt-in covered entities will be 20 percent of allowances offered for auction;

(B) The purchase limit for electrical distribution utilities will be 40 percent of the allowances offered for auction; and

(C) The purchase limit for all other auction participants is four percent of the allowances offered for auction.

(5) The auction purchase limit for auctions conducted from January 1, 2015 through December 31, 2020 will be 25 percent of the allowances offered in the Current Auction and 25 percent of the allowances offered in the Advance Auction for covered entities, opt-in entities, and electrical distribution utilities or direct corporate associations pursuant to section 95833.

(6) The auction purchase limit for auctions conducted from January 1, 2015 through December 31, 2020 will be 4 percent of the allowances

offered in the Current Auction and 4 percent of the allowances offered in the Advance Auction for voluntarily associated entities or group of voluntarily associated entities with a direct corporate association pursuant to section 95833. The total purchase limit assigned to voluntarily associated entites within a direct corporate association including covered entities, opt-in entities, or electrical distribution utilities must be less than or equal to 4 percent. The purchase limit to be divided among the covered entities, opt-in entities, and electrical distribution utilities in the association is the purchase limit assigned to the corporate association less the value assigned to the voluntarily associated entities within the corporate association.

(e) Determination of Winning Bidders and Settlement Price. The following process shall be used to determine winning bidders, amounts won, and a single auction settlement price:

(1) Each bid will consist of a price and the quantity of allowances, in multiples of 1,000 CA GHG Allowances, desired at that price.

(2) Each bidder may submit multiple bids.

(3) Beginning with the highest bid price, bids from each bidder will be considered in declining order by price, and the auction operator shall reject a bid for a bundle of 1,000 allowances:

(A) If acceptance of the bid would result in violation of the purchase limit pursuant to sections 95911(d) and 95914;

(B) If acceptance of the bid would result in violation of the holding limit pursuant to section 95920(b); or

(C) If acceptance of the bid would result in a total value of accepted bids for an auction participant greater than the value of the bid guarantee submitted by the auction participant pursuant to section 95912(j).

(4) Bids from all bidders will be ranked from highest to lowest by price. Beginning with the highest bid and proceeding to successively lower bids, entities submitting bids at each price will be sold allowances until:

(A) The next lower bid price is less than the auction reserve price, in which case the current price becomes the auction settlement price; or

(B) The total quantity of allowances contained in the bids at the next lower bid price is greater than or equal to the number of allowances yet to be sold, in which instance, the next lower bid price becomes the auction settlement price and the procedure for resolution of tie bids in section 95911(e)(5) shall apply.

(5) Resolution of tie bids. If the quantity of allowances contained in the bids placed at the auction settlement price is greater than the quantity of allowances available to be sold at that price, then:

(A) The auction administrator will calculate the share of the remaining allowances to be distributed to each entity bidding at the auction settlement price by dividing the quantity bid by that entity and accepted by the auction administrator by the total quantity of bids at the settlement price which were accepted by the auction administrator;

(B) The auction administrator will calculate the number of allowances distributed to each bidding entity by multiplying the bidding entity's share calculated in section 95911(e)(5)(A) above by the number of allowances remaining, rounding the number down to the nearest whole number; and

(C) To distribute any remaining allowances, the auction administrator will assign a random number to each entity bidding at the auction settlement price. Beginning with the lowest random number, the auction administrator will assign one allowance to the last bundle purchased by each entity until the remaining allowances have been assigned.

(f) If the quantity of bids accepted by the Auction Administrator is less than the number of allowances offered for sale then some allowances will remain unsold.

(1) If allowances remain unsold at auction, the Auction Administrator will fulfill winning bids with allowances from consignment sources in the following order:

(A) Allowances consigned to auction pursuant to section 95910(d)(2);

(B) Allowances consigned from limited use holding accounts pursuant to section 95910(d)(1);

(C) Allowances redesignated to the auction pursuant to section 95911(f)(3); and

(D) Allowances designated by ARB for auction pursuant to section 95910(c)(1)(B) and (c)(2)(B) and (C).

(2) When there are insufficient winning bids to exhaust the allowances from a consignment source in section 95911(f)(1), the auction operator will sell an equal proportion of allowances from each consigning entity in that source.

(3) Disposition of Allowances Designated by ARB for Auction Which Remain Unsold.

(A) Allowances designated by ARB pursuant to section 95910(c)(1)(B) and (c)(2)(B) and (c)(2)(C) for an auction which remain unsold shall be kept in the Auction Holding Account for later auction.

(B) Allowances designated by ARB for auction which remain unsold will be re-designated for auction after two consecutive auctions have resulted in an auction settlement price above the Auction Reserve Price. If future vintage allowances remain unsold at the end of the calendar year for which they were designated for sale at Advance Auction, they will remain in the Auction Holding Account until their vintage year. They will then be designated for the Current Auction.

(C) The number of allowances re-designated to a subsequent current or Advance Auction will not exceed 25 percent of allowances already designated by ARB for that auction. Allowances which remain unsold above that level will be held in the Auction Account for later auction.

(D) Allowances designated for Advance Auction which remain unsold until their vintage year equals the current calendar year will be designated for Current Auction pursuant to section 95910(c)(1)(B).

(4) Disposition of Consigned Allowances Remaining Unsold at Auction.

(A) Allowances consigned to auction from limited use holding accounts that remain unsold at auction will be held in the Auction Holding Account until the next auction.

(B) Allowances consigned to auction pursuant to section 95921(g)(3) that remain unsold at auction will be held in the Auction Holding Account until the next auction.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95912. Auction Administration and Participant Application.

(a) Administration of the Auctions.

(1) The Executive Officer may serve as auction administrator or designate an entity to serve as auction administrator.

(2) The Executive Officer may serve as financial services administrator or may designate a qualified financial services administrator to conduct all financial transactions required by this article.

(b) The Executive Officer may direct that the California GHG allowances designated for auction be offered through an auction conducted jointly with other jurisdictions to which California links pursuant to subarticle 12, provided the joint auction conforms to this article.

(c) Auction Notification. At least 60 days prior to each auction, the auction administrator shall publish the following information:

(1) The date and time of the auction;

(2) Auction application requirements and instructions;

(3) The form and manner for submitting bids;

(4) The procedures for conducting the auction;

(5) The administrative requirements for participation; and

(6) The number of allowances from California that will be available at the auction.

(7) For the announcement of the first quarter auction, the number of allowances to be available for sale during the calendar year and the Auction Reserve Price in effect for the calendar year pursuant to section 95911(c).

(8) If California has linked to a jurisdiction operating an External GHG ETS pursuant to subarticle 12, the number of allowances in section 95912(c)(6) will also include the allowances made available by the linked jurisdiction.

(d) Auction Participation Application Requirements.

(1) The Executive Officer must approve an entity's auction participant application before that entity may participate in an auction.

(2) An entity applying for approval as an auction participant must be registered into the Cap-and-Trade Program as provided in section 95830.

(3) An entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction. An individual associated pursuant to section 95830, 95832, and 95833 with an entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction.

(4) An entity will be required to complete an auction participant application at least 30 days prior to an auction in which it intends to participate. The entity must provide information and documentation including:

(A) Information and documentation regarding the corporate identity, ownership, and capital structure of the applicant;

(B) The existence of any direct or indirect corporate associations pursuant to sections 95833 and 95914(d);

(C) An allocation of the purchase limit among associated entities as defined in section 95833, or a change in the existing allocation of the purchase limit among associated entities, if applicable;

(D) An allocation of the holding limit among associated entities as defined in section 95833, or a change in the existing allocation of the holding limit among associated entities, if applicable;

(E) An attestation disclosing the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 that participate in a carbon, fuel, or electricity market. The attestation must be updated to reflect any change in the status of an investigation that has occurred since the most recent auction application attestation was submitted; and

(F) The applicant's holding account number.

(5) An entity with any changes to the auction application information listed in subsection 95912(d)(4) within 30 days prior to an auction may be denied participation in the auction. For the purposes of changes to indirect and direct corporate associations, this section only applies to those corporate associates with entities registered in the tracking system.

(6) Prior to participating in an auction, any primary or alternate account representative that will be submitting bids on behalf of entities eligible to participate in an auction must have already:

(A) Complied with the Know-Your-Customer requirements of section 95834; and

(B) Submitted the additional information required by the financial services administrator contained in Appendix A of this subarticle.

(e) Maintenance and Modification of Auction Participation Approval.

(1) Once the Executive Officer has approved an entity's auction participant application, the entity need not complete another application for subsequent auctions unless there is a material change to the information contained in the approved application pursuant to section 95912(d)(4) there is a material change in the entity's Cap-and-Trade Program registration pursuant to section 95830, or the Executive Officer has made a determination restricting an entity's auction participation pursuant to section 95914.

(2) An entity approved for auction participation must inform the Auction Administrator at least 30 days prior to an auction when reporting a change to the information disclosed, otherwise the entity may not participate in that auction. The change should be reported by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the 30th day before an auction.

(f) Auction Intent to Bid Notification Requirements. An entity that intends to participate in an auction must inform the Auction Administrator at least 30 days prior to an auction of its intent to bid in an auction, otherwise the entity may not participate in that auction.

(g) An entity approved for auction participation may not communicate information on auction participation with any entity that is not part of an association disclosed pursuant to section 95914, except as requested by the Auction Administrator to remediate an auction application.

(h) Protection of Confidential Information. To the extent permitted by state law, the Executive Officer, the Auction Administrator, and the financial services administrator will treat the information contained in the auction application and not listed for release pursuant to section 95912(k)(5) as confidential business information.

(i) All bids will be considered binding offers for the purchase of allowances under the rules of the auction.

(j) Auction participants must provide a bid guarantee to the financial services administrator at least 12 days prior to the auction.

(1) The bid guarantee must be in one or a combination of the following forms:

(A) Cash in the form of a wire transfer; or

(B) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(C) A bond issued by a financial institution with a United States banking license; or

(D) A Surety Bond issued by an institution named in the current list of “Surety Companies Acceptable in Federal Bonds” as published in the Federal Register by the Audit Staff Bureau of Accounts, U.S. Treasury Department.

(2) The bid guarantee submitted by any entity registered with California will be in U.S. dollars.

(3) A bid guarantee submitted in any form other than cash must be payable within three business days of payment request.

(4) The bid guarantee will be in the currency used by the jurisdiction with which the entity has registered.

(5) The amount of the bid guarantee must be greater than or equal to the maximum value of the bids to be submitted.

(A) The value of a set of bids equals the cumulative quantity of bids submitted at or above a price times that price. The value of the set of bids is calculated at each price at which the bidder will submit a bid.

(B) The maximum value of a set of bids is the highest value of a set of bids calculated at each price at which the bidder will submit a bid.

(C) The auction participant submits a single bid guarantee to cover bids in both the Current and Advance Auctions and the amount of the single bid guarantee must be greater than or equal to the combined maximum value of the Current and Advance Auction bids to be submitted.

(6) The bid guarantee will be made payable to the financial services administrator.

(7) The bid guarantee will expire no sooner than 26 days after the auction date.

(8) The financial services administrator will evaluate the bid guarantee and inform the auction administrator of the value of the bid guarantee once it is found to conform to this section and is accepted by the Executive Officer.

(9) If an entity has submitted more than one form of bid guarantee then the financial services administrator will apply the instruments to the unpaid balance in the order the instruments are listed in section 95912(j)(1).

(10) If the auction participant submits a single bid guarantee instrument to cover bids in both the Current and Advance Auctions, the auction administrator will apply the value of the bid guarantee to the Current Auction first when accepting bids pursuant to section 95911(e)(3). The remaining value of the bid guarantee will be used to determine acceptance of bids into the Advance Auction.

(k) After the auction administrator has notified the Executive Officer of the results of the auction the Executive Officer will:

(1) Review the conduct of the auction by the auction administrator, then certify whether the auction met the requirements of this article;

(2) After certification, direct the financial services administrator to:

(A) Notify each winning bidder of the auction settlement price, the number of allowances purchased, the total purchase cost, and the deadline and method for submitting payment;

(B) Collect cash payments from winning bidders within seven days of notifying them of the auction results;

(C) Use the bid guarantee to cover payment for allowance purchases by any entity that fails to make cash payment within seven days after bidders are notified of results and place the proceeds into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8;

(D) Deposit auction proceeds from sales of ARB allowances sold at auction into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8;

(E) Distribute auction proceeds to entities that consigned allowances for auction pursuant to section 95910(d); and

(F) Return any unused bid guarantee.

(3) Upon determining that the payment for allowances has been deposited into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8, or transferred to entities that consigned allowances, transfer the allowances purchased into each winning bidder's Holding Account, or to its Compliance Account if needed to comply with the holding limit;

(4) Inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances purchased at auction; and

(5) Following the auction, the Executive Officer will publish at www.arb.ca.gov the following information:

(A) The names of the bidders;

(B) Auction settlement price; and

(C) Aggregated or distributional information on purchases with the names of the entities withheld.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code and Section 16428.8, Government Code.

§ 95913. Sale of Allowances from the Allowance Price Containment Reserve.

(a) The Executive Officer may serve as reserve sale administrator to conduct sales from the Allowance Price Containment Reserve (Reserve) or designate an entity to serve as reserve sale administrator. The financial services administrator designated by the Executive Officer pursuant to section 95912(a) will conduct the financial transactions required to operate sales from the Reserve.

(b) Entities registered in an External GHG ETS to which California has linked pursuant to subarticle 12 are not eligible to purchase from the California Reserve.

(c) Only entities registered into the California GHG Cap-and-Trade Program as provided in sections 95811 or 95813 shall be eligible to purchase allowances from the Reserve. Prior to participating in a Reserve sale, any primary or alternate account representative that will be submitting bids on behalf of entities eligible to participate in Reserve sales must have already:

  (1) Complied with the Know-Your-Customer requirements of section 95834; and

  (2) Submitted the additional information required by the financial services administrator contained in Appendix A of this subarticle.

(d) Timing of Reserve Sales.

  (1) The first Reserve sale will be conducted on March 8, 2013.

  (2) Subsequent Reserve sales through 2014 shall be conducted on the first business day six weeks after each quarterly allowance auction scheduled pursuant to section 95910.

(3) Beginning in 2015, Reserve sales shall be conducted pursuant to the schedule in Appendix C.

(4) The Reserve sale administrator shall provide all eligible participants with notice of the number of allowances available for sale and the terms of the sale at least 30 days prior to the sale.

(5) The subsequent Reserve sales in section 95913(d)(2), shall be conducted on the first day six weeks after each quarterly allowances auction scheduled pursuant to section 95910 that is also a business day in California and any linked jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12.

(6) Section 95913(d)(5) will not apply after January 1, 2015.

(e) Reserve Sale Intent to Bid Notification Requirements

(1) An entity that intends to participate in a reserve sale must be registered in the tracking system and must inform the Reserve Sale Administrator at least 20 days prior to a reserve sale of its intent to bid in that reserve sale, otherwise the entity may not participate in that reserve sale.

(2) An entity with any auction application information listed in subsection 95912(d)(4) that changes 20 days prior to a reserve sale, may be denied participation in a reserve sale.

(f) Reserve Tiers.

(1) Creation of Reserve Tiers. Prior to the first Reserve sale, the Executive Officer shall divide allowances allocated to the Reserve from section 95870(a) into three equal-sized tiers.

(2) The Reserve sale administrator shall offer all of the allowances in the Reserve at each Reserve sale.

(3) Reserve Tier Prices. Sales of Reserve allowances in calendar year 2013 shall be conducted at the following prices:

(A) Allowances from the first tier shall be offered for $40 per allowance;

(B) Allowances from the second tier shall be offered for $45 per allowance; and

(C) Allowances from the third tier shall be offered for $50 per allowance.

(4) Increase in Reserve Tier Prices. In calendar years subsequent to 2013, allowances from each tier shall be offered at prices equal to the tier prices from the previous calendar year increased by five percent plus the rate of inflation as measured by the most recently available twelve month value of the Consumer Price Index for All Urban Consumers.

(5) This provision only applies to the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1. Pursuant to section 95870(i)(1), allowances will be made available at the highest price tier of the Allowance Price Containment Reserve if the amount of accepted bids at the highest price tier exceeds the number of allowances in that tier.

(A) The allowances will be made available no sooner than the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1, 2015.

(B) If the quantity of allowances from section 95870(a) allocated to the highest price tier plus the allowances defined in section 95870(i)(1) is equal to or greater than the quantity of accepted bids in the highest price tier then all accepted bids for the highest price tier will be filled.

(C) If the quantity of accepted bids at the highest price tier exceeds the allowances from section 95870(a) plus the allowances defined in section 95870(i)(1), allowances will be sold through the procedure outlined in section 95913(h)(5).

(D) The accepted bids at the highest price tier will be filled first with allowances from section 95870(a) allocated to the highest price tier if available.

(E) The allowances defined in section 95870(i)(1) will be sold beginning with the latest vintage and then the preceding vintages, from latest to most recent, until all accepted bids at the highest price tier are filled or until all the allowances defined in section 95870(i)(1) have been sold. The allowances defined in section 95870(i)(1) sold pursuant to this section shall first reduce the quantity of allowances defined in section 95870(b) if available and then will reduce the quantity of allowances defined in section 95870(i)(2).

(F) Allowances sold pursuant to this section will be surrendered as allowances purchased from an Allowance Price Containment Reserve sale as specified in section 95856(b)(2)(A) and section 95856(h).

(g) At least 12 days before the scheduled sale, an entity intending to participate in a Reserve sale must submit to the financial services administrator a bid guarantee, payable to the financial services administrator, in an amount greater than or equal to the sum of the maximum value of the bids to be submitted by the entity.

(1) The maximum value of a set of bids is the quantity bid at each tier times the tier price, summed across the three tiers.

(2) The bid guarantee must be in one or a combination of the following forms:

(A) Cash in the form of a wire transfer; or

(B) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(C) A bond issued by a financial institution with a United States banking license; or

(D) A Surety Bond issued by an institution named in the current list of "Surety Companies Acceptable in Federal Bonds" as published in the Federal Register by the Audit Staff Bureau of Accounts, U.S. Treasury Department.

(3) A bid guarantee submitted in any form other than cash must be payable within three business days of payment request.

(4) The bid guarantee will be made payable to the financial services administrator.

(5) The bid guarantee will expire no sooner than 26 days after the Reserve sale.

(6) The financial services administrator will evaluate the bid guarantee and inform the Reserve sale administrator of the value of the bid guarantee once it is found to conform to this section and is accepted by the Executive Officer.

(7) The Executive Officer may revise the timing of reserve sales intent to bid notification requirements in subsection 95913(e) and bid guarantee submittal requirements in subsection 95913(g) to ensure a minimum of four business days is available between the intent to bid notification and bid guarantee submittal due dates.

(h) Purchase Determinations.

(1) The reserve sale administrator will conduct sales from each tier in succession, beginning with the lowest priced tier and proceeding to the highest priced tier.

(A) The Reserve sale will continue until either all allowances made available pursuant to section 95870(a) are sold from the Reserve or all the accepted bids are filled.

(B) Pursuant to section 95913(f)(5), the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1 will continue until all accepted highest price tier bids are filled or the allowances made available pursuant to section 95870(i)(1) are sold pursuant to section 95913(f)(5).

(2) The Reserve sales window will open at 10 a.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the day of the sale, and bids may be submitted until the window closes at 1 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect).

(A) Each bid will consist of the price, in U.S. dollars, equal to one of the three tiers and a quantity of allowances in multiples of 1,000 allowances.

(B) An entity may submit multiple bids.

(3) The reserve sale administrator will only accept a bid for a bundle of 1,000 allowances:

(A) If acceptance of the bid would not result in violation of the holding limit pursuant to section 95920(b);

(B) If acceptance of the bid would not result in a total value of accepted bids for a covered entity greater than the value of the bid guarantee submitted by the covered entity pursuant to section 95913(g); or

(C) If the bid entered by an entity for a tier is for a quantity less than or equal to the number of allowances available for sale in that tier.

(4) If the sum of bids at the tier price which are accepted by the reserve sale administrator is less than or equal to the number of allowances in the tier, then:

(A) The reserve sale administrator will sell to each covered entity the number of allowances for which the entity submitted bids for that tier which were accepted by the reserve sale administrator; and

(B) If allowances remain in the tier after the sales pursuant to section 95913(h)(4)(A) are completed, the reserve sale administrator will assign a random number to each bundle of 1,000 allowances for which entities submitted a bid for the tier above the current tier being sold. Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the reserve sale administrator shall sell allowances to the bidder assigned the random number until the remaining allowances in the tier are sold or all accepted bids have been fulfilled. The price for the allowances sold under this procedure will be the price for the tier from which they are sold, not the bid placed.

(5) If the sum of bids accepted by the reserve sale administrator for a tier is greater than the number of allowances in the tier, the reserve sale administrator will determine the total amount to be distributed from the tier to each covered entity using the following procedure:

(A) The reserve sale administrator will calculate the share of the tier to be distributed to each bidding entity by dividing the quantity bid by that entity and accepted by the reserve sale administrator by the total quantity of bids which were accepted by the reserve sale administrator; and

(B) The reserve sale administrator will calculate the number of allowances distributed to each bidding entity from the tier by multiplying the bidding entity's share calculated in section 95913(h)(5)(A) above by the number of allowances in the tier, rounding the number down to the nearest whole number.

(6) After completing the sales for each tier the reserve sale administrator will repeat the processes in sections 95913(h)(4) and (h)(5) above for the next highest price tier until all bids have been filled or until the Reserve is depleted. At that time the reserve sale administrator will inform the Executive Officer of the sales from the Reserve to each participant.

(i) Resolution of Sales.

(1) After reviewing the conduct of the sale by the Reserve sale administrator, the Executive Officer will certify whether the Reserve sale met the requirements of this article.

(2) Upon certification of the sale results, the Executive Officer will authorize the financial services administrator to:

(A) Notify Reserve sale participants of their purchases and total purchase cost;

(B) Process cash payments from participants and deposit proceeds into the Greenhouse Gas Reduction Fund created pursuant to Government Code 16428.8 up to seven days after bidders are notified of results;

(C) Use the bid guarantee to cover payment for allowance purchases by any entity that fails to make cash payment within seven days after bidders are notified of results and place the proceeds into the Greenhouse Gas Reduction Fund created pursuant to Government Code 16428.8. If an entity has submitted more than one form of bid guarantee then the financial services administrator will apply the instruments to the unpaid balance in the order the instruments are listed in section 95913(g)(2); and

(D) Return any unused bid guarantee.

(3) Upon determining that the financial services administrator has deposited the payment for allowances into the Greenhouse Gas Reduction Fund created pursuant to Government Code 16428.8, the Executive Officer shall transfer the allowances purchased from the Allowance Price Containment Reserve sale into each winning bidder's compliance account.

(4) The Executive Officer shall inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances sold; and

(5) The Executive Officer shall publish the sale results at www.arb.ca.gov.

(j) Entities registered in an External GHG ETS to which California has linked pursuant to subarticle 12 are not eligible to purchase from the Reserve.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95914. Auction Participation and Limitations.

(a) The Executive Officer may cancel or restrict a previously approved auction participation application or reject a new application if the Executive Officer determines that an entity has:

(1) Provided false or misleading facts;

(2) Withheld material information from its application or account application information listed in section 95830, with material meaning information that could influence a decision by the Executive Officer, the Board, or the Board's staff;

(3) Violated any part of the auction rules pursuant to subarticle 10;

(4) Violated the registration requirements pursuant to subarticle 5; or

(5) Violated the rules governing trading pursuant to subarticle 11.

(b) If the Executive Officer determines an entity has committed any of the violations listed in section 95914(a), then:

(1) The Executive Officer may instruct the auction administrator to cancel a previously approved auction application or to not accept auction applications from the entity;

(2) The Executive Officer may instruct the auction administrator to restrict the auction application approval for any corporate associate of the entity to prevent the purchase of allowances at auction for subsequent transfer to the violator;

(3) Any cancellation or restriction imposed by the Executive Officer may be permanent or for a specified number of auctions; and

(4) The cancellation or restriction imposed by the Executive Officer shall be in addition to any other penalties, fines, and additional remedies available at law.

(c) Non-disclosure of Bidding Information.

(1) Except as provided in section 95914(c)(2), all entities registered into the Cap-and-Trade program pursuant to section 95830, their direct and indirect corporate associations, or consultants and advisors as identified in section 95923 shall not release any of the following

information regarding auction participation or reserve sale participation, as applicable:

(A) Intent to participate, or not participate, at auction, auction approval status, maintenance of continued auction approval;

(B) Bidding strategy;

(C) Bid price or bid quantity information; and

(D) Information on the bid guarantee it provided to the financial services administrator.

(2) Auction participation information listed in section 95914(c)(1) may be released under the following conditions:

(A) When the release is to other members of a direct corporate association not subject to auction participation restriction or cancellation pursuant to section 95914(b),

(B) When the release is to a Cap-and-Trade Consultant or Advisor who has been disclosed to the Executive Officer pursuant to section 95914(c)(3).

(C) When the release is made by a publicly-owned utility only as required by public accountability rules, statute, or rules governing participation in generation projects operated by a Joint Powers Authority or other publicly-owned utilities.

(D) When the release is by an entity regulated by an agency that has regulatory jurisdiction over privately owned utilities in the State of California of information regarding compliance instrument cost and acquisition strategy and other disclosures specifically required or authorized by the regulatory agency pursuant to any of its applicable rules, orders, or decisions. In the event of a disclosure pursuant to this section, the entity regulated by the agency must provide to the Executive Officer within 10 business days, the statutory or regulatory reference or the general order, decision, or ruling to ARB that requires the disclosure of the specific information related to bidding strategy.

(3) If an entity participating in an auction has retained the services of a Cap-and-Trade Consultant or Advisor, as defined in section 95923, regarding auction bidding strategy, then:

(A) The entity must ensure against the Consultant or Advisor transferring information to other auction participants or coordinating the bidding strategy among participants;

(B) The entity will inform the Consultant or Advisor of the prohibition of sharing information to other auction participants and ensure the Consultant or Advisor has read and acknowledged the prohibition under penalty of perjury;

(C) The Consultant or Advisor must provide the Executive Officer the following information:

1. Names of the entities participating in the Cap-and-Trade Program that are being advised;

2. Description of advisory services being performed; and

3. Assurance under penalty of perjury that advisor is not transferring to or otherwise sharing information with other auction participants.

(D) The information must be physically received by the Executive Officer at least 15 days prior to an auction.

(d) Application of the Corporate Association to the Auction Purchase Limit.

(1) The total number of compliance instruments which may be purchased in a single auction by a group of entities with a direct corporate association is limited pursuant to section 95911(d).

(2) Entities that are part of a direct corporate association must allocate shares of the purchase limit amongst themselves. This allocation of shares of the purchase limit must be provided pursuant to section 95833. Each entity will then have a specified percentage share of the association's purchase limit. The sum of the shares allocated among the entities must sum to one. Each associated entity's allocated

purchase limit share times the auction purchase limit assigned to the association becomes the purchase limit for that entity.

(3) If a corporate association consists of entities with a compliance obligation and voluntarily associated entities, then the following additional restrictions apply:

(A) For Current Auctions, the total purchase limit for the association is 15 percent, unless some of the included covered entities are electrical distribution utilities, in which case the purchase limit is 40 percent. For the last auction in 2014, the auction purchase limit for associations with covered entities or opt-in covered entites will be 20 percent of current vintage allowances offered for sale. The auction purchase limit for Current Auctions conducted from January 1, 2015 through December 31, 2020 will be 25 percent for corporate associations that include only electrical distribution utilities, covered entities, and opt-in covered entities. For Advance Auctions, the purchase limit for corporate associations containing covered entities, opt-in entities, or electrical distribution utilities is 25 perecent of allowances offered for auction.

(B) Corporate associations containing only voluntarily associated entites have a purchase limit for both Current Auction and Advance Auction or 4 percent. For voluntarily associated entites that are part of a corporate association containing covered entities, opt-in entites, or electrical distribution utilites, the total purchase limit assigned to voluntarily associated entities within the corporate association must be less than or equal to 4 percent.

(C) The purchase limit to be divided among the covered or opt-in entities is the purchase limit assigned to the corporate association less the value assigned to the voluntarily associated entities within the corporate association.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 11: Trading and Banking

§ 95920. Trading.

(a) The holding limit is the maximum number of California GHG allowances that may be held by an entity or jointly held by a group of entities with a direct corporate association, as defined in section 95833 at any point in time.

(b) Application of the Holding Limit.

(1) The holding limit will apply to each entity registered as a covered, opt-in covered, or voluntarily associated entity pursuant to section 95830.

(2) The holding limit calculation will not include allowances contained in limited use holding accounts or exchange clearing holding accounts created pursuant to section 95831.

(3) Application of the Holding Limit to Exchange Clearing Holding Accounts. Compliance instruments transferred out of an exchange clearing holding account will count against the holding limit of the destination account listed in the transfer request submitted by an exchange clearing holding account at the time the transfer request is confirmed.

(4) If the Executive Officer determines that a reported transfer request not yet recorded into the tracking system would result in an entity's holdings exceeding the applicable holding limit, then the Executive Officer shall not approve the transfer request pursuant to section 95921(a)(1).

(5) If the violation is not discovered until after a transfer request is recorded, or the holding limit is exceeded at the beginning of a compliance year when allowances purchased at Advance Auction now

fall under the current vintage holding limit pursuant to section 95920(c)(1)(C), then:

(A) The accounts administrator will inform the violator; and

(B) The violator will have five business days to bring its account balances within the holding limit. After that, the Executive Officer may transfer allowances in excess of the holding limit to the Auction Holding Account for consignment to auction pursuant to section 95910(d).

(C) Allowances transferred to the Auction Holding Account for consignment will be drawn first from the entity's Holding Account and, if necessary, from the entity's Compliance Account. The order for removing allowances for consignment will be the opposite of the retirement order in section 95856(h)(1).

(6) Penalties may be applied whenever the holding limit is exceeded or transfer requests are filed with the accounts administrator that would violate the holding limit.

(c) The holding limit will be separately calculated to holdings of:

(1) Allowances including:

(A) Allowances with a vintage year corresponding to the current or previous calendar years;

(B) Allowances from any vintage purchased from the Allowance Price Containment Reserve pursuant to section 95913;

(C) Allowances originally purchased at the Advance Auction but of a vintage year equal or prior to the current calendar year; and

(D) Allowances issued by a GHG ETS program approved by ARB pursuant to section 95941 that have no vintage;

(2) Allowances that were purchased at the Advance Auction and still have a vintage year greater than the current calendar year.

(d) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(1) as the sum of:

(1) The number given by the following formula:

Holding Limit = 0.1×Base + 0.025×(Annual Allowance Budget - Base)

In which:

"Base" equals 25 million metric tons of CO_2e.

"Annual Allowance Budget" is the number of allowances issued for the current budget year.

(2) Limited Exemption from the Holding Limit.

(A) The limited exemption from the holding limit (limited exemption) is the maximum number of allowances which can be held in an entity's compliance account that will not be included in the holding limit calculated pursuant to section 95920(c)(1). To qualify for inclusion within the limited exemption, allowances must be placed in the entity's Compliance Account.

(B) On July 1, 2014 the limited exemption will be calculated as the sum of the annual emissions data reports received in 2012 and 2013 that have received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to section 95851(a). On November 2, 2014 the limited exemption will be increased by the amount of emissions contained in the emissions data report received in 2014 that have received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to section 95851(a).

(C) On January 1, 2015 the limited exemption will be increased by the amount of emissions that generate a compliance obligation pursuant to section 95851(b), (c), and (d) that are included in the emissions data report received in 2014 that have received a positive or qualified positive emissions data verification statement.

(D) Beginning in 2015, the limited exemption will be increased on November 2 of each year by the amount of emissions that generate a compliance obligation pursuant to section 95851(a), (b), (c), and (d) that are included in the emissions data report received that year that have received a positive or qualified positive emissions data verification statement.

(E) If ARB has assigned emissions to an entity, for any year, in the absence of a positive or qualified positive emissions data verification statement the calculation of the limited exemption will be calculated using the assigned emissions. If the emission reports scheduled to be used to increase the Limited Exemption are not available at the time of a scheduled increase and ARB has not assigned emissions to the entity the Limited Exemption will be increased by the amount of the most recently received report that has received a positive or qualified positive emissions data verification statement. If this procedure is used, the Limited Exemption will not be adjusted using data in the reports scheduled to be received that year until the next scheduled change in the Limited Exemption.

(F) Beginning in 2015, on November 2 of the calendar year following the end of a compliance period, the limited exemption will be reduced by the sum of the entity's compliance obligation over that compliance period.

(G) Allowances allocated pursuant to section 95870(e), (f), and (g), which are transferred to the receiving entity's annual allocation holding account in a year preceding their vintage year, will not count against the Holding Limit or limited exemption until January 1 of their vintage year.

(3) Petition to Adjust the Limited Exemption.

(A) Prior to October 1 of any year, a covered entity may submit to the Executive Officer evidence demonstrating an increase in emissions for that year over the previous year and request a temporary increase in the limited exemption until verified data for that year are available.

(B) The amount of the increase must be at least 250,000 metric tons CO_2e on an annualized basis.

(C) The Executive Officer will review the evidence and determine whether an adjustment is needed.

(D) If an adjustment is granted, then the limited exemption for that covered entity will be increased immediately by the amount determined by the Executive officer.

(E) When the verified emissions data are received for the year for which an adjustment was granted, the Executive Officer will use the verified emissions value when calculating the limited exemption.

(e) The holding limit will be calculated separately for each vintage year for allowances qualifying pursuant to section 95920(c)(2) as the number given by the following formula:

$$\text{Holding Limit} = 0.1\times\text{Base} + 0.025\times(\text{Annual Allowance Budget} - \text{Base})$$

In which:

"Base" equals 25 million metric tons of CO_2e.

"Annual Allowance Budget" is the number of California GHG allowances issued for a budget year.

(f) Application of the Corporate Association Disclosure to the Holding Limit.

(1) The total number of allowances held by a group of entities with a direct corporate association pursuant to section 95833 must sum to less than or equal to the holding limits pursuant to sections 95920(d) and (e).

(2) The limited exemption for each entity which is part of a direct corporate association is the same as defined in section 95920(d).

(3) Entities that are part of a direct corporate association that choose to opt out of account consolidation pursuant to section 95833(f)(3) must allocate shares of the holding limit among themselves. This holding limit allocation results in each entity having a specified percentage share of the group's holding limit. The sum of the shares allocated among the entities must sum to one.

(A) The primary account representatives or alternate account representatives of each of the associated entities must inform the accounts administrator of the allocation of the holding limit when registering pursuant to section 95833.

(B) The holding limit allocation will remain in effect until the primary account representatives or alternate account representatives of each of the associated entities informs the accounts administrator of subsequent changes to the allocation of the holding limit.

(g) The holding limit in section 95920(a) shall include holdings of any allowances issued by a jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12.

(h) The "Annual Allowance Budget" in section 95920(d) is calculated as the sum for the current budget year of the annual compliance budgets of California and all External GHG ETS programs to which California has linked pursuant to subarticle 12. The "Annual Allowance Budget" in section 95920(e) is calculated as the sum for a budget year of the annual compliance budgets of California and all External GHG ETS programs to which California has linked pursuant to subarticle 12.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95921. Conduct of Trade.

(a) Transfers of Compliance Instruments Between Accounts.

(1) Except when a transfer is undertaken by the Executive Officer, the accounts administrator will not register a transfer of compliance instruments between accounts into the tracking system until the administrator receives a transfer request that the Executive Officer has determined meets the requirements of this article.

(A) To initiate the process, the primary account representative or an alternate account representative of the source account for the transfer must submit a transfer request to the accounts administrator.

(B) The primary account representative or another alternate account representative for the same entity must confirm the transfer request to the accounts administrator within two days of the initial submission of the transfer request.

(C) The primary account representative or an alternate account representative for the destination account must confirm the transfer request to the accounts administrator within the time remaining in the three days following the initial submission of the transfer request in section 95921(a)(1)(A).

(D) The Executive Officer must determine whether the transfer request and the transaction for which the transfer request was submitted meet the requirements of this article based on the information available at the time of approval.

(2) The following transfers do not require confirmation by an account representative of the destination account pursuant to section 95921(a)(1)(C).

(A) Transfers initiated by the Executive Officer.

(B) Transfers between a single entity's holding and compliance accounts.

(3) Through December 31, 2014 the parties to a transfer will be in violation and penalties may apply if the above process is completed:

(A) More than three days after the initial submission of the transfer request; or

(B) More than three days after the expected settlement date of the transaction agreement for which the transfer request is submitted.

(4) Beginning January 1, 2015 the parties to a transfer will be in violation and penalties may apply if the above process is completed:

(A) More than three days after the initial submission of the transfer request; or

(B) More than three days after the expected termination date of the transaction agreement for which the transfer request is submitted.

(5) An entity may not submit a transfer request to another registered entity without an existing written or recorded oral transaction agreement with that party authorizing a transfer.

(b) Information Requirements for Transfer Requests Beginning on January 1, 2015. Parties to the transfer request agree to provide documentation about the transaction agreement for which the transfer request was submitted upon the request of the Executive Officer. The following information must be reported to the accounts administrator as part of a transfer request before any transfer of allowances can be recorded on the tracking system:

(1) The following information must be entered into the tracking system for all transfer requests:

(A) Holding account number of the source account and identification of two individuals who are the primary account representative and/or alternate account representatives initiating the transfer request.

(B) Account number of destination account.

(C) Type, quantity, and vintage of compliance instrument.

(2) The transfer request must identify the type of transaction agreement for which the transfer request is being submitted, selecting one of the following three types:

(A) Over-the-counter agreement for the sale of compliance instruments for which delivery will take place no more than three days from the date the parties enter into the transaction agreement.

(B) Over-the counter agreement for the sale of compliance instruments for which delivery is to take place more than three days from the date the parties enter into the transaction agreement or that involve multiple transfers of compliance instruments over time or the bundled sale of compliance instruments with other products.

(C) Exchange agreements for the sale of compliance instruments through any contract arranged through an exchange or Board of Trade.

(3) A transfer request submitted for an over-the-counter agreement for the sale of compliance instruments for which delivery will take place no more than three days from the date the parties enter into the transaction agreement must provide the following information:

(A) Date the entity entered into the transaction agreement.

(B) Expected Termination Date of the transaction agreement. If completion of the transfer request process is the last term of the transaction agreement to be completed, the date the transfer request is submitted should be entered as the Expected Termination Date. If there are financial, contingency, or other terms to be settled after the transfer request is completed, the date those terms are expected to be settled should be entered as the Expected Termination Date. If the transaction agreement does not specify a date for the settlement of financial, contingency, or other terms that would be completed after the transfer request is completed, the entity may enter the Expected Termination Date as "Not Specified".

(C) Price of the compliance instrument in U.S. dollars or Canadian dollars.

(4) A transfer request submitted for an over-the-counter agreement for the sale of compliance instruments for which delivery is to take place more than three days from the date the parties enter into the transaction agreement or that involves multiple transfers of compliance instruments over time or incorporates compliance instrument requirements with other product sales or purchases, must provide the following information:

(A) Date the entity entered into the transaction agreement.

(B) Expected Termination Date of the transaction agreement. If completion of the transfer request process is the last term of the transaction agreement to be completed, the date the transfer request is submitted should be entered as the Expected Termination Date. If there are financial, contingency, or other terms to be settled after the transfer request is completed, the date those terms are expected to be settled should be entered as the Expected Termination Date. If the transaction agreement does not specify a date for the settlement of financial, contingency, or other terms that would be completed after the transfer request is completed, the entity may enter the Expected Termination Date as "Not Specified".

(C) Whether the transaction agreement provides for further compliance instrument transfers after the current transfer request is completed.

(D) Whether the transaction agreement provides for transfers of other products.

(E) If the transaction agreement specifies a fixed price for the compliance instruments, provide the price in U.S. dollars or Canadian dollars.

(F) If the transaction agreement sets the price as a cost base plus a margin, then provide the cost base and the margin.

(G) If the transaction agreement does not specify the price using one of the above formats, provide a brief description of the pricing method.

(5) A transfer request submitted for an Exchange Agreement must provide the following information:

(A) Identify the exchange where the transaction is conducted.

(B) Identify the contract description code assigned by the exchange to the contract.

(C) Date of close of trading for the contract.

(D) Price at close of trading for the contract.

(6) If the transaction agreements do not contain a price for compliance instruments, entities may enter a price of zero into the transfer request if the transfer request is submitted to fulfill one of the following transaction agreement types and the entity discloses the agreement type in the transfer request.

(A) The proposed transfer is between entities with a direct corporate association.

(B) The proposed transfer is from an entity's holding account to its compliance account.

(C) The proposed transfer is from a publicly-owned utility to an entity or a Joint Powers Authority operating a generation facility as a joint venture with the utility.

(D) The proposed transfer is from a public utility to a federal power authority to cover emissions associated with imported power.

(E) The proposed transfer is from an electric distribution utility to an entity operating a generation facility under a tolling agreement or other long-term power purchase agreement that does not specify a price or cost basis for the sale of the compliance instruments alone.

(F) The proposed transfer results from a transaction agreement that incorporates compliance instrument requirements with other product sales or purchases, and does not specify a price or cost basis for the sale of the compliance instruments alone.

(G) The proposed transfer is from a publicly-owned utility to an entity (including a Joint Powers Authority of which that utility is a member, or an operating agent acting on behalf of such a Joint Powers Authority) operating a generation facility from which the utility obtains electricity.

(H) The proposed transfer is to satisfy a transaction agreement that requires the production of a new ARB-issued offset credit or a transaction agreement to transition an early action offset credit into an ARB-issued offset credit and the transaction agreement does not specify a price for the ARB-issued offset credit.

(c) Information Requirements for Transfer Requests Through December 31, 2014. Parties to the transfer request agree to provide documentation about the transaction agreement for which the transfer request was submitted upon the request of the Executive Officer. The following information must be reported to the accounts administrator as part of a transfer request before any transfer of allowances can be recorded on the tracking system:

(1) Holding account number of the source account and identification of two individuals who are the primary account representative and/or alternate account representatives initiating the transfer request;

(2) Holding account number of destination account;

(3) Date of the transaction agreement for which the transfer request is submitted;

(4) Expected settlement date. If completion or confirmation of the transfer request process is the last action required by the agreement, the date the transfer request is submitted should be entered as the expected settlement date. If there are financial, contingency, or other terms to be settled after the transfer request is completed, the date those terms are to be settled should be entered as the expected settlement date. If the transaction agreement does not specify a date for the settlement of financial, contingency, or other terms that would be completed after the transfer request is completed the entity may enter its best estimate of the expected settlement date as long as the date is later than the date the transfer request is submitted.

(5) Price of the compliance instrument in U.S. or Canadian dollars.

(6) If the transaction agreement does not contain a price for compliance instruments, entities may enter a price of zero into the transfer request if the transfer request is submitted to fulfill one of the following transaction agreement types.

(A) The proposed transfer is between entities with a direct corporate association.

(B) The proposed transfer is from an entity's holding account to its compliance account.

(C) The proposed transfer is from a publicly-owned utility to an entity or a Joint Powers Authority operating a generation facility as a joint venture with the utility.

(D) The proposed transfer is from a public utility to a federal power authority to cover emissions associated with imported power.

(E) The proposed transfer is from an electric distribution utility to an entity operating a generation facility under a tolling agreement or other long-term power purchase agreement that does not specify a price or cost basis for the sale of the compliance instruments alone.

(F) The proposed transfer results from a transaction agreement that incorporates compliance instrument requirements with other product sales or purchases, and does not specify a price or cost basis for the sale of the compliance instruments alone.

(G) The proposed transfer is from a publicly-owned utility to an entity (including a Joint Powers Authority of which that utility is a member, or an operating agent acting on behalf of such a Joint Powers Authority) operating a generation facility from which the utility procures electricity.

(c) Intentionally Omitted

(d) Transfers Involving Exchange Clearing Holding Accounts.

(1) A request to transfer compliance instruments to an exchange clearing holding account will list the exchange clearing holding account as the destination account.

(2) All of the compliance instruments received by an exchange clearing holding account must be transferred to one or more destination accounts within five days of receiving them.

(3) A request to transfer compliance instruments to or from an exchange clearing holding account does not require confirmation by an account representative of the destination account pursuant to section 95921(a)(1)(C).

(4) A request to transfer compliance instruments from an exchange clearing holding account does not require confirmation by a second account.

(e) Protection of Confidential Information. The Executive Officer will protect confidential information to the extent permitted by law by ensuring that the accounts administrator:

(1) Releases information on the transfer price and quantity of compliance instruments in a manner that is timely and maintains the confidentiality of the parties to a transfer;

(2) Except as needed for market oversight and investigation by the Executive Officer, protects as confidential all other information obtained through transfer requests;

(3) Protects as confidential the quantity and serial numbers of compliance instruments contained in holding accounts; and

(4) Releases information on the quantity of compliance instruments contained in compliance accounts in a timely manner.

(f) General Prohibitions on Trading.

(1) An entity may purchase and hold compliance instruments for later transfer to members of a direct corporate association. However, an entity cannot acquire allowances and hold them in its own holding account on behalf of another entity, including the following restrictions:

(A) An entity may not hold allowances in which a second entity has any ownership interest.

(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity's accounts, or control over the acquisition of allowances by the first entity. Provisions specifying a date to deliver a specified quantity of compliance instruments, or specifying a procedure to determine a quantity of compliance instruments for delivery and/or a delivery date, do not violate the prohibition.

(2) A trade involving, related to, or associated with any of the following are prohibited:

(A) Any manipulative or deceptive device in violation of this article;

(B) A corner or an attempt to corner the market for a compliance instrument;

(C) Fraud, or an attempt to defraud any other entity;

(D) A false, misleading or inaccurate report concerning information or conditions that affects or tends to affect the price of a compliance instrument;

(E) An application, report, statement, or document required to be filed pursuant to this article which is false or misleading with respect to a material fact, or which omits to state a material fact necessary to make the contents therein not misleading; or

(F) Any trick, scheme, or artifice to falsify or conceal a material fact, including use of any false statements or representations, written or oral, or documents made by or provided to an entity on or through which transactions in compliance instruments occur, are settled, or are cleared.

(G) A fact is material if it could probably influence a decision by the Executive Officer, the Board, or the Board's staff.

(g) Restrictions on Registered Entities. If an entity registered pursuant to section 95830 violates any provision specified in this article the Executive Officer may:

(1) Reduce the number of compliance instruments a covered entity or opt-in covered entity may have in its holding account below the amount allowed by the holding limit pursuant to section 95920;

(2) Increase the annual surrender obligation for a covered entity or an opt-in covered entity to a percentage of its reported and verified or assigned emissions above the 30% obligation pursuant to section 95855;

(3) Suspend or revoke the registration of opt-in covered entities, voluntarily associated entities, and other entities registered pursuant to section 95830;

(A) If registration is revoked or suspended the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation; and

(B) If registration is revoked or suspended and the entity fails to sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation, the accounts administrator will transfer the remaining instruments into the Auction Holding

Account for sale at auction on behalf of the entity pursuant to section 95910(d);

(4) Limit or prohibit transfers in or out of the holding account; or

(5) All of the above.

(h) Information Reporting By Holders of Exchange Clearing Holding Accounts.

(1) Holders of exchange clearing holding accounts must make the transaction records available to ARB within 10 calendar days of a request from the Executive Officer.

(2) Holders of exchange clearing holding accounts must retain transaction records containing the information listed in 95921(b) for 10 years.

(3) Holders of exchange clearing holding accounts are not required to include the information listed in 95921(b)(3), (4), and (6), and 95921(c)(3), (4), (5) and (6) in transfer requests to the accounts administrator.

(i) Transfer Request Deficiencies

(1) If the accounts administrator detects a deficiency in a transfer request before it is recorded into the tracking system:

(A) The accounts administrator will inform the entities submitting the request that the transfer request is deficient and inform the Executive Officer of the deficiency;

(B) The accounts administrator will inform the entity responsible for the deficiency of the specific problem to be remedied.

(C) The entities submitting the transfer request may resubmit the request with the deficiency corrected within the time limit set pursuant to sections 95921(a)(1)(C), 95921(a)(3), or 95921(a)(4); and

(D) If the entities fail to submit an acceptable transfer request within the time limit, then they must either withdraw the transfer request or submit a new transfer request. Penalties may still apply pursuant to sections 95921(a)(3) or (a)(4).

(2) If the accounts administrator detects a deficiency in a transfer request after it is recorded into the tracking system:

(A) The accounts administrator will inform the entities submitting the request that the transfer request is deficient and inform the Executive Officer of the deficiency;

(B) If the deficiency is based on the information submitted by the representative of the source account, the Executive Officer will inform the submitting representative of the specific deficiency;

(C) If the deficiency is a violation of the holding limit, the Executive Officer will inform the primary account representative for the account listed on the transfer request as the destination account of the deficiency; and

(D) If the entities that submitted the transfer request cannot correct the deficiency within five business days after notification by the accounts administrator, the Executive Officer may instruct the accounts administrator to reverse the transfer.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95922. Banking, Expiration, and Voluntary Retirement.

(a) Allowances Issued for a Current or Previous Compliance Period. A CA GHG allowance or an allowance issued by an approved GHG ETS pursuant to subarticle 12 may be held ("banked") by an entity registered pursuant to section 95830.

(b) Allowances Issued for a Future Compliance Period. A CA GHG Allowance or an allowance approved pursuant to subarticle 12 issued from an allowance budget year within a future compliance period may be held by an entity registered pursuant to section 95830.

(c) Expiration of Compliance Instruments. A California compliance instrument does not expire and is not retired in the tracking system until:

(1) It is surrendered by a covered entity or opt-in covered entity and retired by the Executive Officer;

(2) An entity voluntarily submits the instrument to the Executive Officer for retirement; or

(3) The instrument is retired by an approved external GHG emissions trading system to which the Cap-and-Trade Program is linked pursuant to subarticle 12.

(d) Voluntary Retirement of Compliance Instruments.

(1) An entity registered pursuant to section 95830 may voluntarily submit any compliance instrument for retirement.

(2) To voluntarily retire a compliance instrument, the registered entity submits a transaction report to the accounts administrator listing its account number, the type and number of instruments to be retired, and the ARB Retirement Account as the destination account.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95923. Disclosure of Cap-and-Trade Consultants and Advisors.

(a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is providing the services listed in section 95979(b)(2) of the Cap-and-Trade Regulation or section 95133(b)(2) of the Mandatory Reporting Regulation in relation to the Cap-and-Trade Program or MRR and specifically for the entity registered in the Cap-and-Trade Program, regardless if the Consultant or Advisor is acting in the capacity of an offset or MRR verifier.

(b) An entity employing Cap-and-Trade Consultants or Advisors defined pursuant to 95923(a) must disclose the following information for each Cap-and-Trade Consultant or Advisor:

(1) Information to identify the Cap-and-Trade Consultant or Advisor, including:

(A) Name;

(B) Contact information;

(C) Physical work address of the Cap-and-Trade Consultant or Advisor; and

(D) Employer, if applicable.

(c) The entity must disclose the information pursuant to section 95923(b) to the Executive Officer:

(1) When registering pursuant to section 95830;

(2) Within 30 days of entering into a contract with a Cap-and-Trade Consultant or Advisor pursuant to section 95923(a);

(3) Within 30 days of a change to the information disclosed on Consultants or Advisors.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 12: Linkage to External Greenhouse Gas Emissions Trading Systems

§ 95940. General Requirements.

A compliance instrument issued by an external greenhouse gas emissions trading system (GHG ETS) may be used to meet the requirements of this Article if the external GHG ETS and the compliance instrument have been approved pursuant to this section and section 95941.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95941. Procedures for Approval of External GHG ETS.

The Board may approve a linkage with an external GHG ETS after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code sections 11340 et seq.). Provisions set forth in this Article shall specify which compliance instruments issued by a linked GHG ETS may be used to meet a compliance obligation under this Article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95942. Interchange of Compliance Instruments with Linked External Greenhouse Gas Emissions Trading Systems.

(a) Once a linkage is approved, a compliance instrument issued by the approved external GHG ETS, as specified in this section, may be used to meet a compliance obligation under this Article.

(b) An allowance issued by an approved external GHG ETS and specified in this section is not subject to the quantitative usage limit specified in section 95854.

(c) An offset credit or sector-based credit issued by an external GHG ETS is subject to the quantitative usage limit specified in section 95854, when used to meet a compliance obligation under this Article.

(d) Once a linkage is approved, a compliance instrument issued by California may be used to meet a compliance obligation within the approved External GHG ETS.

(e) Once a linkage is approved, a compliance instrument issued by the linked jurisdiction may be used to meet a compliance obligation in California.

(f) The administrator of the approved External GHG ETS must agree to inform the Executive Officer of any of the serial numbers of California compliance instruments that the External GHG ETS accepts for compliance.

(g) The Executive Officer will agree to inform the appropriate official in the approved External GHG ETS of any of the serial numbers of compliance instruments accepted by California for compliance.

(h) The Executive Officer will register into the Retirement Account compliance instruments issued by California that are used for compliance within the approved External GHG ETS, along with information identifying the External GHG ETS actually retiring the compliance instruments.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95943. Linked External GHG ETS.

Covered or opt-in entities may use compliance instruments issued by the following programs to meet their compliance obligation under this article:

(a) Government of Quebec (effective January 1, 2014).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 13: ARB Offset Credits and Registry Offset Credits

§ 95970. General Requirements for ARB Offset Credits and Registry Offset Credits.

An Offset Project Operator or Authorized Project Designee must ensure the requirements for ARB offset credits and registry offset credits are met as follows:

(a) A registry offset credit must:

(1) Represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable;

(2) Result from the use of a Compliance Offset Protocol that meets the requirements of section 95972 and is adopted by the Board pursuant to section 95971;

(3) Result from an offset project that meets the requirements specified in section 95973;

(4) Result from an offset project that is listed pursuant to section 95975;

(5) Result from an offset project that follows the monitoring, reporting and record retention requirements pursuant to section 95976;

(6) Result from an offset project that is verified pursuant to sections 95977 through 95978; and

(7) Be issued pursuant to section 95980.1 by an Offset Project Registry approved pursuant to section 95986.

(b) An ARB offset credit must meet the requirements in sections 95970(a)(1) through (a)(6) and:

(1) Be issued pursuant to section 95981.1;

(2) Be registered pursuant to section 95982; and

(3) When used for compliance under this article, be subject to the quantitative usage limit pursuant to section 95854.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95971. Procedures for Approval of Compliance Offset Protocols.

(a) The Board shall provide public notice of and opportunity for public comment prior to approving any Compliance Offset Protocols, including updates or modifications to existing Compliance Offset Protocols.

(b) All Compliance Offset Protocols shall be reviewed and periodically revised, if needed, in compliance with the California Administrative Procedure Act, if applicable.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95972. Requirements for Compliance Offset Protocols.

(a) To be approved by the Board, a Compliance Offset Protocol must:

(1) Accurately determine the extent to which GHG emission reductions and GHG removal enhancements are achieved by the offset project type;

(2) Establish data collection and monitoring procedures relevant to the type of GHG emissions sources, GHG sinks, and GHG reservoirs for that offset project type;

(3) Establish a project baseline that reflects a conservative estimate of business-as-usual performance or practices for the offset project type;

(4) Account for activity-shifting leakage and market-shifting leakage for the offset project type, unless the Compliance Offset Protocol stipulates eligibility conditions for use of the Compliance Offset Protocol that eliminate the risk of activity-shifting and/or market-shifting leakage;

(5) Account for any uncertainty in quantification factors for the offset project type;

(6) Ensure GHG emission reductions and GHG removal enhancements are permanent;

(7) Include a mechanism to ensure permanence of GHG removal enhancements for sequestration offset project types;

(8) Establish the length of the crediting period pursuant to section 95972(b) for the relevant offset project type; and

(9) Establish the eligibility and additionality of projects using standard criteria, and quantify GHG reductions and GHG removal enhancements using standardized baseline assumptions, emission factors, and monitoring methods.

(b) Crediting Periods. The crediting period for a non-sequestration offset project must be no less than 7 years and no greater than 10 years, unless specified otherwise in a Compliance Offset Protocol. The crediting period for a sequestration offset project must be no less than 10 years and no greater than 30 years.

(c) Geographic Applicability. A Compliance Offset Protocol must specify where the protocol is applicable. The geographic boundary must be within the United States, United States Territories, Canada, or Mexico.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Projects. To qualify under the provisions set forth in this article, an Offset Project Operator or Authorized Project Designee must ensure that an offset project:

(1) Meets all of the requirements in a Compliance Offset Protocol approved by the Board pursuant to section 95971;

(2) Meets the following additionality requirements, as well as any additionality requirements in the applicable Compliance Offset Protocol, as of the date of Offset Project Commencement:

(A) The activities that result in GHG reductions and GHG removal enhancements are not required by law, regulation, or any legally binding mandate applicable in the offset project's jurisdiction, and would not otherwise occur in a conservative business-as-usual scenario;

(B) The Offset Project Commencement date occurs after December 31, 2006, unless otherwise specified in the applicable Compliance Offset Protocol, except as provided in section 95973(c); and

(C) The GHG reductions and GHG removal enhancements resulting from the offset project exceed the project baseline calculated by the applicable version of the Compliance Offset Protocol under which the offset project has been listed pursuant to section 95975 or under which the offset project has been transitioned to pursuant to section 95973(a)(2)(D) for that offset project type as set forth in the following:

1. Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011, and Compliance Offset Protocol

Ozone Depeleting Substances Projects, November 14, 2014, which are hereby incorporated by reference;

2. Compliance Offset Protocol Livestock Projects, October 20, 2011, and Compliance Offset Protocol Livestock Projects, November 14, 2014, which are hereby incorporated by reference;
3. Compliance Offset Protocol Urban Forest Projects, October 20, 2011, which is hereby incorporated by reference;
4. Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, Compliance Offset Protocol U.S. Forest Projects, November 14, 2014, and Compliance Offset Protocol U.S. Forest Projects, June 25, 2015, which are hereby incorporated by reference;
5. Compliance Offset Protocol Mine Methane Capture Projects, April 25, 2014, which is hereby incorporated by reference; and
6. Compliance Offset Protocol Rice Cultivation Projects, June 25, 2015, which is hereby incorporated by reference.

(D) The Offset Project Operator or Authorized Project Designee may transition an offset project to the most recently incorporated version of the Compliance Offset Protocol by updating the listing information in an Offset Project Data Report pursuant to section 95976. Projects may only transition at the initial submission of the Offset Project Data report for a reporting period to ARB or the Offset Project Registry. An offset projects that transitions to a new version of the Compliance Offset Protocol during a crediting period will continue in the same crediting period and not start a new crediting period.

(E) The offset project must meet all the requirements in this Regulation for the applicable version of the Compliance Offset Protocol under which the offset project has been listed pursuant to 95975 or under which the offset project has been transitioned to pursuant section 95973(a)(2)(D).

(F) The applicable version of the Compliance Offset Protocol is the version under which the offset project has been listed pursuant to section 95975 or transitioned to pursuant section 95973(a)(2)(D).

(3) Is located in the United States, United States Territories, Canada, or Mexico.

(b) Local, Regional, and National Regulatory and Environmental Impact Assessment Requirements. An Offset Project Operator or Authorized Project Designee must fulfill all local, regional, and national requirements on environmental impact assessments that apply based on the offset project location. In addition, an offset project must also fulfill all local, regional, and national environmental and health and safety laws and regulations that apply based on the offset project location and that directly apply to the offset project, including as specified in a Compliance Offset Protocol. The project is out of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period. An offset project is not eligible to receive ARB or registry offset credits for GHG reductions or GHG removal enhancements for the entire Reporting Period if the offset project is not in compliance with regulatory requirements directly applicable to the offset project during the Reporting Period.

(c) Early Action Offset Project Commencement Date. Offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k) may have an Offset Project Commencement date before December 31, 2006.

(d) Any Offset Project Operator or Authorized Project Designee seeking to list an offset project situated on any of the following categories of land must demonstrate the existence of a limited waiver of sovereign immunity between ARB and the governing body of the Tribe entered into pursuant to section 95975(l):

(1) Land that is owned by, or subject to, an ownership or possessory interest of the Tribe;

(2) Land that is "Indian lands" of the Tribe, as defined by 25 U.S.C, §81(a)(1); or

(3) Land that is owned by any person, entity, or tribe, within the external borders of such Indian lands.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95974. Authorized Project Designee.

(a) General Requirements for Designation of Authorized Project Designee. An Offset Project Operator may designate an entity as an Authorized Project Designee at the time of offset project listing or any time after offset project listing as long as it meets the requirements of section 95974(b).

(1) The Offset Project Operator may assign ownership rights of ARB offset credits or registry offset credits to the following entities at the time of registry offset credit or ARB offset credit issuance pursuant to sections 95980.1 and 95981, respectively:

(A) Authorized Project Designee; or

(B) Any other third party not otherwise prohibited by this article.

(2) The Offset Project Operator may delegate responsibility to the Authorized Project Designee for performing or meeting all the requirements of sections 95975, 95976, 95977, 95977.1, 95977.2, 95980, 95980.1, 95981, 95981.1, and, where the Authorized Project Designee is specifically identified, the requirements in sections 95983, 95985, and 95990, on behalf of the Offset Project Operator.

(A) If an Authorized Project Designee is designated, the Authorized Project Designee will be responsible for performing all activities to meet the requirements in section 95974(a)(2) and will be the main point of contact with regard to the offset project for the Offset Project Registry and ARB. The Offset Project Operator, however, is ultimately responsible for ensuring compliance with the requirements of this article and the applicable Compliance Offset Protocol. In addition, the Offset Project Operator retains its ability to perform any activities required under this article, including signing documents and attestations.

(B) If an Authorized Project Designee is designated, the Offset Project Operator must designate an individual of the Authorized Project Designee as a Primary Account Representative or Alternate Account Representative on the Offset Project Operator's tracking system account before the Authorized Project Designee may act on behalf of the Offset Project Operator or submit any documentation to the Offset Project Registry and ARB. Only an individual authorized on the Offset Project Operator's tracking system account may sign any documents or attestations to ARB on behalf of the Offset Project Operator for an offset project.

(C) Consultants. An Offset Project Operator or Authorized Project Designee may use a consultant to prepare documents for submittal by the Offset Project Operator or Authorized Project Designee to the Offset Project Registry or ARB. However, a consultant may not sign any documents or attestations on behalf of the Offset Project Operator or Authorized Project Designee. A consultant may only communicate with ARB or the Offset Project Registry in conjunction with the Offset Project Operator or Authorized Project Designee, and the Offset Project Operator or Authorized Project Designee must be included in all communications, whether written or verbal, between ARB or the

Offset Project Registry and the consultant regarding the offset project.

(b) Modifications to Authorized Project Designee and Activities. An Offset Project Operator may modify or change an Authorized Project Designee, or any other third party authorized pursuant to section 95974(a)(1) for a listed offset project once within each calendar year after the offset project has been listed by ARB or an Offset Project Registry by submitting a request, in writing, to ARB or an Offset Project Registry.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95975. Listing of Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Project Operators or Authorized Project Designees Who Are Submitting an Offset Project for Listing. Before an offset project can be listed by ARB or an Offset Project Registry the Offset Project Operator and its Authorized Project Designee, if applicable, must:

(1) Register with ARB pursuant to section 95830; and

(2) Not be subject to any Holding Account restrictions imposed pursuant to section 96011.

(b) If the offset project is not listed by ARB, it must be listed by an Offset Project Registry approved pursuant to section 95986.

(c) General Requirements for Offset Project Listing. For offset projects being listed by ARB or an Offset Project Registry in an initial or renewed crediting period, the Offset Project Operator and any Authorized Project Designees approved pursuant to section 95974 must:

(1) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the GHG reductions and/or GHG removal enhancements for [project] from [date] to [date] will be measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB is true, accurate, and complete.";

(2) Attest, in writing, to ARB as follows:

"I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes arising from the enforcement of provisions in this article.";

(3) Attest in writing to ARB as follows:

"I understand that the offset project activity and implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety laws and regulations that apply to the offset project location. I understand that offset projects are not eligible to receive ARB or registry offset credits for GHG reductions and GHG removal enhancements that are not in compliance with the requirements of the cap-and-trade program.";

(4) Provide all documentation required pursuant to section 95975(e) to ARB or an Offset Project Registry; and

(5) Disclose GHG reductions and GHG removal enhancements issued credit by any voluntary or mandatory programs for the same offset project being listed or any GHG reductions and GHG removal enhancements used for any GHG mitigation requirement.

(d) The attestations in section 95975(c)(1), 95975(c)(2), and 95975(c)(3) must be provided to an Offset Project Registry with the listing information, if being listed with an Offset Project Registry, or to ARB if being listed with ARB.

(e) Offset Project Listing Information Requirements. Before an offset project is publicly listed for an initial or renewed crediting period the Offset Project Operator or Authorized Project Designee must provide the listing information in the most recent version of a Compliance Offset Protocol for that offset project type as set forth in and incorporated by reference:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, November 14, 2014;

(2) Compliance Offset Protocol Livestock Projects, November 14, 2014;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011;

(4) Compliance Offset Protocol U.S. Forest Projects, June 25, 2015;

(5) Compliance Offset Protocol Mine Methane Capture Projects, April 25, 2014; and

(6) Compliance Offset Protocol Rice Cultivation Projects, June 25, 2015.

(f) Review of Offset Project Listing Information. ARB and/or the Offset Project Registry will review the offset project listing information submitted pursuant to section 95975(e) for completeness.

(g) Notice of Completeness for Offset Project Listing Information. The Offset Project Operator or Authorized Project Designee will be notified after review by ARB or the Offset Project Registry, within 30 calendar days of receiving the complete and accurate listing information, that the offset project may be listed. If ARB or the Offset Project Registry determine that the information submitted pursuant to section 95975(e) is incomplete or that a denial of the listing information is required, ARB or the Offset Project Registry will notify the Offset Project Operator or Authorized Project Designee of this determination within 30 calendar days of receiving the listing information from the Offset Project Operator or Authorized Project Designee.

(h) Timing for Offset Project Listing in an Initial Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(e) to ARB or an Offset Project Registry no later than the date at which the Offset Project Operator or Authorized Project Designee submits its required Offset Project Data Report for its first Reporting Period under a Compliance Offset Protocol to ARB or an Offset Project Registry pursuant to section 95976. For offset projects with an Offset Project Commencement date on or after January 1, 2015, the Offset Project Operator or Authorized Project Designee must submit the listing information in section 95975(e) to ARB or an Offset Project Registry within one year of Offset Project Commencement, or within one year of meeting the requirements of section 95975(l), whichever is later. If, after January 1, 2015, the Offset Project Operator or Authorized Project Designee does not submit the listing information in section 95975(e) for the offset project to ARB or an Offset Project Registry within one year of Offset Project Commencement, or within one year of meeting the requirements of section 95975(l), whichever is later, it will be ineligible to be listed under a Compliance Offset Protocol and will not be issued registry offset credits and ARB offset credits pursuant to sections 95980 and 95981.

(i) Listing Status of Offset Projects in an Initial Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in an initial crediting period and the required documentation pursuant to section 95975(e), and ARB or the Offset Project Registry has reviewed the offset project listing information for completeness, the offset project listing status will be “Proposed Project.” If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final determination if the offset project meets the requirements in section 95975 to be listed for an initial crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(j) Timing for Offset Project Listing in a Renewed Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(e) for a renewed crediting period to ARB or an Offset Project Registry no earlier than 18 months and no later than 9 months before conclusion of the initial crediting period or a previous renewed crediting period.

(k) Listing Status of Offset Projects in a Renewed Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in a renewed crediting period and the required documentation pursuant to section 95975(e), and ARB or the Offset Project Registry has reviewed the offset project listing information for completeness, the offset project listing status will be "Proposed Renewal." The verification body must assess that the offset project meets the additionality requirements in section 95973(a)(2)(A) and 95973(a)(2)(C) as of the date of the commencement of the renewed crediting period when conducting offset verification services for the first Reporting Period of a renewed crediting period. If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final determination if the project meets the requirements in section 95975 to be listed for a renewed crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(l) Additional Offset Project Listing Requirements for Tribes. In addition to meeting the listing requirements in sections 95975(c)(1) through (5), Tribes must meet the following requirements before offset projects located on the categories of land specified in section 95973(d) can be listed with ARB or an Offset Project Registry pursuant to this section. The requirements of this article apply regardless of the category of land on which the offset project is located.

(1) The governing body of the Tribe must enter into a limited waiver of sovereign immunity with ARB related to its participation in the requirements of the Cap-and-Trade Program for the duration required by the applicable Compliance Offset Protocol(s). This waiver must include a consent to suit by the State of California, Air Resources

Board, in the courts of the State of California, with respect to any action in law or equity commenced by the State of California, Air Resources Board to enforce the obligations of the Tribe with respect to its participation in the Cap-and-Trade Program, irrespective of the form of relief sought, whether monetary or otherwise, except for purposes of relief under this limited waiver, Tribes shall be treated in the same manner as a California public entity under California Government Code sections 818 and 818.8.

(2) The Tribe must provide ARB with documentation demonstrating that the limited waiver of sovereign immunity entered into pursuant to section 95975(l)(1) has been properly adopted in accordance with the Tribe's Constitution or other organic law, by-laws and ordinances, and applicable federal laws.

(3) For offset projects located on Indian lands, as defined in 25 U.S.C. §81(a)(1), the Tribe must also provide ARB with proof of federal approval of the Tribe's participation in the requirements of the Cap-and-Trade Program, or documentation from the U.S. Department of the Interior, Bureau of Indian Affairs that federal approval is not required.

(m) Once ARB or an Offset Project Registry approves an offset project for listing, the listing information is considered final, and may not be changed unless the Offset Project Operator changes during the crediting period.

(1) If the Offset Project Operator changes during the crediting period the new Offset Project Operator or Authorized Project Designee must submit updated listing information for the information that pertains to the Offset Project Operator and Authorized Project Designee, if applicable, to ARB or OPR within 30 calendar days of the change.

(2) If the Offset Project Operator changes during the crediting period the new Offset Project Operator or Authorized Project Designee must submit the information required pursuant to section 95975(c) to ARB OPR within 30 calendar days of the change.

(n) Limitations for Crediting Period Renewals. A crediting period may be renewed if the offset project meets the requirements for additionality pursuant to section 95973(a)(2) and in the applicable Compliance Offset Protocol.

(1) The crediting period for non-sequestration offset projects may be renewed twice for the length of time identified by the Compliance Offset Protocol.

(2) Sequestration offset projects are not subject to any renewal limits.

(o) Transferring an Offset Project to Another Offset Project Registry. If the Offset Project Operator or Authorized Project Designee transfers an offset project listed with an Offset Project Registry to another Offset Project Registry:

(1) The Offset Project Registry that originally listed the offset project must change the offset project listing status on its registry system to "Transferred ARB Project."

(A) If the only action taken by the Offset Project Operator or the Authorized Project Designee was to have the listing documentation for the offset project approved by the original Offset Project Registry, the original Offset Project Registry must retain the information related to the offset project on its website for the duration of one year before it is removed from the registry system. If the listing documentation was only submitted by the Offset Project Operator or Authorized Project Designee, but not approved by the original Offset Project Registry, the original Offset Project Registry does not need to retain the submitted listing documentation.

(B) If a verification body submitted an Offset Verification Statement, the original Offset Project Registry must retain the information related to the offset project on its website for the duration of the offset project life.

(C) The new Offset Project Registry must retain the listing date and all listing information as approved by the original Offset Project Registry. If the offset project has not undergone initial verification, the Offset Project Commencement date may change as a result of verification activities only.

(2) The Offset Project Operator or Authorized Project Designee must submit the original listing documentation reviewed and accepted by the original Offset Project Registry pursuant to this section to the new Offset Project Registry. The Offset Project Operator or Authorized Project Designee may only make changes to the listing documentation pursuant to section 95975(m).

(3) The Offset Project Operator or Authorized Project Designee may not transfer an offset project to another Offset Project Registry once a Notice of Offset Verification Services has been submitted for a Reporting Period(s) pursuant to section 95977.1(b)(1) or during the course of offset verification services for a Reporting Period(s). Once a Notice of Offset Verification Services has been submitted, the offset verification services must be completed for the applicable Reporting Period(s) before the Offset Project Operator or Authorized Project Designee may transfer the offset project to another Offset Project Registry. Once the offset verification services are completed for the applicable Reporting Period(s), the Offset Project Operator or Authorized Project Designee may transfer the offset project to another Offset Project Registry.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95976. Monitoring, Reporting, and Record Retention Requirements for Offset Projects.

(a) General Requirements for Monitoring Equipment for Offset Projects. The Offset Project Operator or Authorized Project Designee must employ the procedures in the Compliance Offset Protocol for monitoring measurements and project performance for offset projects. All required monitoring equipment must be maintained and calibrated in a manner and at a frequency required by the equipment manufacturer, unless otherwise specified in the applicable Compliance Offset Protocol. All modeling, monitoring, sampling, or testing procedures must be conducted in a manner consistent with the applicable procedure.

(b) The Offset Project Operator or Authorized Project Designee must use the missing data methods as provided in a Compliance Offset Protocol for that offset project type, if provided and applicable.

(c) An Offset Project Operator or Authorized Project Designee must put in place all monitoring equipment or mechanisms required by the applicable version of the Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011 and Compliance Offset Protocol Ozone Depleting Substances Projects, November 14, 2014;

(2) Compliance Offset Protocol Livestock Projects, October 20, 2011 and Compliance Offset Protocol Livestock Projects, November 14, 2014;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011;

(4) Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, Compliance Offset Protocol U.S. Forest Projects, November 14, 2014 and Compliance Offset Protocol U.S. Forest Projects, June 25, 2015;

(5) Compliance Offset Protocol Mine Methane Capture Projects, April 25, 2014; and

(6) Compliance Offset Protocol Rice Cultivation Projects, June 25, 2015.

(d) Offset Project Reporting Requirements. An Offset Project Operator or Authorized Project Designee shall submit an Offset Project Data Report to ARB or an Offset Project Registry for each Reporting Period as defined in section 95802. Each Offset Project Data Report must cover a single Reporting Period. Reporting Periods must be contiguous; there must be no gaps in reporting once the first Reporting Period has commenced. For projects developed under the Compliance Offset Protocol in section 95973(a)(2)(C)1., there may be one Offset Project Data Report submitted for each offset project and the Offset Project Data Report may cover up to a maximum of 12 months of data. The Offset Project Operator or Authorized Project Designee must submit an Offset Project Data Report to ARB or an Offset Project Registry within 24 months of listing their offset project pursuant to section 95975. The Offset Project Data Report shall contain the information required by the applicable version of the Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011 and Compliance Offset Protocol Ozone Depleting Substances Projects, November 14, 2014;

(2) Compliance Offset Protocol Livestock Projects, October 20, 2011 and Compliance Offset Protocol Livestock Projects, November 14, 2014;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011;

(4) Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, Compliance Offset Protocol U.S. Forest Projects, November 14, 2014, and Compliance Offset Protocol U.S. Forest Projects, June 25, 2015;

(5) Compliance Offset Protocol Mine Methane Capture Projects, April 25, 2014; and

(6) Compliance Offset Protocol Rice Cultivation Projects, June 25, 2015.

(7) The Offset Project Operator or Authorized Project Designee must attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the GHG reductions and/or GHG removal enhancements for [project] from [date] to [date] are measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB in the Offset Project Data Report is true, accurate, and complete."

This attestation must be provided to an Offset Project Registry with the Offset Project Data Report if the offset project is listed with an Offset Project Registry, or to ARB if the offset project is listed with ARB.

(8) All Offset Project Data Reports must be submitted within four months after the conclusion of each Reporting Period.

(9) If an Offset Project Data Report is not submitted to ARB or an Offset Project Registry by the applicable reporting deadline, the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to be issued ARB offset credits pursuant to section 95981.

(e) Requirements for Record Retention for Offset Projects. An Offset Project Operator or Authorized Project Designee must meet the following requirements:

(1) The Offset Project Operator or Authorized Project Designee must retain the following documents:

(A) All information submitted as part of the Offset Project Data Report;

(B) Documentation of the offset project boundary, including a list of all GHG emissions sources, GHG sinks, and GHG reservoirs included in the offset project boundary and the project baseline, and the calculation of the project baseline, project emissions, GHG emission reductions, and GHG removal enhancements;

(C) Fuel use and any other underlying measured or sampled data used to calculate project baseline emissions, GHG emission reductions, and GHG removal enhancements for each source, categorized by process and fuel, or material type;

(D) Documentation of the process for collecting fuel use or any other underlying measured or sampled data for the offset project and its GHG emissions sources, GHG sinks, and GHG reservoirs for quantifying project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(E) Documentation of all project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(F) All point of origin and chain of custody documents required by a Compliance Offset Protocol, if applicable;

(G) All chemical analyses, results, and testing-related documentation for material and sources used for inputs to project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(H) All model inputs or assumptions used for quantifying project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(I) Any data used to assess the accuracy of project baseline emissions, GHG emission reductions, and GHG removal enhancements from each offset project GHG emissions source, GHG sink, and GHG reservoir, categorized by process;

(J) Quality assurance and quality control information including information regarding any measurement gaps, missing data substitution, calibrations or maintenance records for monitoring equipment, or models providing data for calculating project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(K) A detailed technical description of any offset project continuous measurement/monitoring system, including documentation of any findings and approvals by federal, state, and local agencies;

(L) Raw and aggregated data from any measurement system;

(M) Documentation of any changes over time and the log book on tests, down-times, calibrations, servicing, and maintenance for any measurement/monitoring equipment providing data for project baseline calculations, project emissions, GHG emission reductions, and GHG removal enhancements;

(N) For sequestration offset projects, documentation of inventory methodologies and sampling procedures including all calculation methodologies and equations used, and any data related to plot sampling; and

(O) Any other documentation or data required to be retained by a Compliance Offset Protocol, if applicable.

(2) Documents listed in section 95976(e)(1) associated with the preparation of an Offset Project Data Report shall be retained in paper, electronic, or other usable format for a minimum of 15 years following the issuance of ARB offset credits related to that Offset Project Data Report. All other documents shall be retained in paper, electronic, or other usable format for a minimum of 15 years.

(3) The documents retained pursuant to this section must be sufficient to allow for the verification of each Offset Project Data Report.

(4) Upon request by ARB or an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide to ARB or an Offset Project Registry all documents pursuant to this section, including data used to develop an Offset Project Data Report within 10 calendar days of the request.

(f) General Procedure for Interim Gas or Fuel Analytical and Monitoring Equipment Data Collection. This section only applies if a Compliance Offset Protocol does not already include methods for collecting or accounting for data in the event of missing data due to an unforeseen breakdown of gas or fuel analytical monitoring data equipment.

(1) In the event of an unforeseen breakdown of offset project data monitoring equipment and gas or fuel flow monitoring devices required for the GHG emission reductions and GHG removal enhancement estimation, ARB may authorize an Offset Project Operator or

Authorized Project Designee to use an interim data collection procedure if ARB determines that the Offset Project Operator or Authorized Project Designee has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's gas or fuel data for the year covered by an Offset Project Data Report;

(B) The gas or fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting the offset project operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the gas or fuel analytical data monitoring equipment.

(2) An Offset Project Operator or Authorized Project Designee seeking approval of an interim data collection procedure must, within 30 calendar days of the monitoring equipment breakdown, submit a written request to ARB that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the Offset Project Operator's or Authorized Project Designee's usual equipment-based method; and

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) ARB may limit the duration of the interim data collection procedure or include other conditions for approval.

(4) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with a Compliance Offset Protocol. When approving an interim data collection procedure, ARB shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible offset material misstatement under section 95977.1(b)(3)(Q) of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977. Verification of GHG Emission Reductions and GHG Removal Enhancements from Offset Projects.

(a) General Requirements. An Offset Project Operator or Authorized Project Designee must obtain the services of an ARB-accredited verification body for the purposes of verifying Offset Project Data Reports submitted under this article.

(b) Schedule for Verification of Non-Sequestration Offset Projects. The verification of GHG emission reductions for non-sequestration offset projects that produce greater than or equal to 25,000 metric tons of GHG reductions must be performed on a 12-month rolling basis and cover the Reporting Period for which the most recent Offset Project Data Report was submitted unless otherwise specified in a Compliance Offset Protocol. For Reporting Periods in which an Offset Project Data Report for a non-sequestration offset project shows that the offset project produced fewer than 25,000 metric tons of GHG reductions in a Reporting Period, the Offset Project Operator or Authorized Project Designee may choose to perform verification that covers two consecutive Reporting Periods, even if for the subsequent Reporting Period the offset project produced greater than or equal to 25,000 metric tons of GHG reductions. If an Offset Project Data Report results in zero GHG emission reductions, the Offset Project Operator or Authorized Project Designee may defer verification until the offset project produces an Offset Project Data Report that no longer results in zero GHG emission reductions.

(c) Schedule for Verification of Sequestration Offset Projects. An initial verification of GHG emission reductions and GHG removal enhancements for all sequestration offset projects must be performed following the first Reporting Period and cover one Reporting Period. After the first Reporting Period, verification must be conducted at least once every six years and may cover up to six Reporting Periods for which Offset Project Data Reports were submitted. After an initial verification with a Positive Offset Verification Statement, reforestation offset projects and urban forest offset projects that meet the requirements of the applicable Compliance Offset Protocol may defer the second verification for twelve years, but verification of Offset Project Data Reports must be performed at least once every six years thereafter.

(d) Timing for Submittal of Offset Verification Statements to ARB or an Offset Project Registry. Any Offset Verification Statement must be received by ARB or an Offset Project Registry within eleven months after the conclusion of the Reporting Period for which offset verification services were performed. If the Offset Verification Statement is not submitted to ARB or an Offset Project Registry by the verification deadline, the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to be issued ARB offset credits or registry offset credits. The verification body must issue one Offset Verification Statement for each Offset Project Data Report that it verifies for the Offset Project Operator or Authorized Project Designee.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977.1. Requirements for Offset Verification Services.

(a) Rotation of Verification Bodies. An offset project shall not have more than six consecutive Reporting Periods verified by the same verification body or offset verification team member(s), unless otherwise specified in section 95977.1(a)(1) or (a)(2). An Offset Project Operator or Authorized Project Designee may contract with a previous verification body or offset verification team member(s) only if at least three consecutive Reporting Periods have been verified by a different verification body or offset verification team member(s) before the previous verification body or offset verification team member(s) is selected again, unless otherwise specified in section 95977.1(a)(1) or (a)(2). The rotation requirements in this section are applied between the Offset Project Operator, Authorized Project Designee, if applicable, and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, if applicable, and the verification body and offset verification team member(s) on an offset project basis.

(1) For offset projects developed under the Compliance Offset Protocol in section 95973(a)(2)(C)(1.), the following shall apply: Neither a verification body nor offset verification team member may conduct offset verification services for an Offset Project Operator, Authorized Project Designee, or any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, for more than six consecutive offset projects developed under the Compliance Offset Protocol in section 95973(a)(2)(C)(1.). After a verification body or offset verification team member(s) has conducted offset verification services for up to six consecutive offset projects developed under the Compliance Offset Protocol in section 95973(a)(2)(C)(1.) for an Offset Project Operator, Authorized Project Designee, or any technical

consultant(s) used by the Offset Project Operator or Authorized Project Designee, the verification body or offset verification team member(s) may conduct offset verification services for the Offset Project Operator, Authorized Project Designee, or any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, only after the Offset Project Operator, Authorized Project Designee, or any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, has had a minimum of three offset projects developed under the Compliance Offset Protocol in section 95973(a)(2)(C)(1.) verified by another verification body(ies) and offset verification team member(s). For this provision an offset project is defined by any activities reported in an Offset Project Data Report, and is applied to offset projects listed by the Offset Project Operator and Authorized Project Designee, if applicable.

(2) For reforestation offset projects developed under, and that meet the requirements of, the Compliance Offset Protocol in section 95973(a)(2)(C)(4.), and urban forest offset projects developed under, and that meet the requirements of, the Compliance Offset Protocol in section 95973(a)(2)(C)(3.), the following shall apply: An Offset Project Operator or Authorized Project Designee that has deferred the second verification for 6 to 12 years may have up to 13 Offset Project Data Reports verified by the same verification body and offset verification team member(s). If an Offset Project Operator or Authorized Project Designee has not deferred the second verification for more than 6 years, the requirements in section 95977.1(a) for rotation of verification bodies and offset verification team member(s) shall apply. An Offset Project Operator or Authorized Project Designee may contract with a previous verification body or offset verification team member(s) only if at least three consecutive Offset Project Data Reports for the offset project have been verified by a different

verification body(ies) and offset verification team member(s) before the previous verification body and offset verification team member(s) is selected again. When rotating verification bodies and offset verification team members under this provision, the rotation requirements must also apply to any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, if applicable.

(3) All early action reporting periods for which regulatory verification was conducted for an early action offset project pursuant to section 95990(f) may count as one Reporting Period for the purposes of determining rotation of verification bodies and offset verification team members.

(4) Each early action reporting period for which early action verification was conducted under an Early Action Offset Program prior to transitioning the offset project to a Compliance Offset Protocol must be used in determining the rotation of verification bodies and offset verification team member pursuant to this section. Each early action reporting period verified under the Early Action Offset Program is considered a separate Reporting Period for purposes of this section.

(b) Offset Verification Services. Offset Verification Services shall be subject to the following requirements.

(1) Notice of Offset Verification Services for Offset Projects. Before offset verification services, as defined in section 95977.1(b)(3), may begin, the verification body must submit a Notice of Offset Verification Services to ARB and an Offset Project Registry, if applicable. The verification body may begin offset verification services for the Offset Project Operator or Authorized Project Designee 30 calendar days after the Notice for Offset Verification Services is received by ARB and the Offset Project Registry, or earlier, if approved by ARB in writing. The Notice of Offset Verification Services must include the following information:

(A) The name of the offset project type, including the length of the offset project crediting period, and title of the Compliance Offset Protocol used to implement the offset project;

(B) A list of staff who will be designated to provide offset verification services as part of an offset verification team, including the names of each designated staff member, the lead verifier, independent reviewer, all subcontractors, and a description of the roles and responsibilities each team member will have during the offset verification process;

(C) Documentation that the offset verification team has the skills required to provide offset verification services for the Offset Project Operator or Authorized Project Designee. At least one offset verification team member must be accredited by ARB as an offset project specific verifier for an offset project of that type; and

(D) General information on the Offset Project Operator or Authorized Project Designee, including:

1. The name of the Offset Project Operator or Authorized Project Designee, including contact information, address, telephone number, and email address;

2. The locations that will be subject to offset verification services;

3. The date(s) of on-site visits, with address and contact information; and

4. A brief description of expected offset verification services to be performed, including expected completion date.

(2) If any information submitted pursuant to sections 95977.1(b)(1)(B) and 95977.1(b)(1)(D) changes after the Notice for Offset Verification Services is submitted to ARB and the Offset Project Registry, if applicable, and before offset verification services begin, the verification body must notify ARB and the Offset Project Registry by submitting an

updated Notice of Offset Verification Services as soon as the change is made, but, at least five working days prior to the start of offset verification services, unless otherwise approved by ARB in writing. If any information submitted pursuant to sections 95977.1(b)(1)(B) and 95977.1(b)(1)(D) changes during offset verification services, the verification body must notify ARB and the Offset Project Registry, if applicable, within 10 working days. In either instance, the Notice of Offset Verification Services must be resubmitted to ARB and the Offset Project Registry, as applicable. If ARB and the Offset Project Registry, if applicable, request revisions to the Notice of Offset Verification Services, the verification body must resubmit the revised Notice of Offset Verification Services within 10 working days of such request, or if there is a reason the verification body cannot submit the revisions within 10 working days, the verification body must communicate to ARB and the Offset Project Registry in writing as to the reasons why and get approval from the Offset Project Registry or ARB for an extension.

(3) Offset verification services must include the following:

(A) Offset Verification Plan. The Offset Project Operator or Authorized Project Designee must submit the following information necessary to develop an Offset Verification Plan to the offset verification team:

1. Information to allow the offset verification team to develop a general understanding of offset project boundaries, operations, project baseline emissions, and annual GHG reductions and GHG removal enhancements;

2. Information regarding the training or qualifications of personnel involved in developing the Offset Project Data Report;

3. The name and date of the Compliance Offset Protocol used to quantify and report project baselines, GHG reductions,

GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol; and

4. Information about any data management system, offset project monitoring system, and models used to track project baselines, GHG reductions, GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol.

(B) Timing of Offset Verification Services. The Offset Verification Plan submitted pursuant to section 95977.1(b)(3)(A) shall also include the following information:

1. Dates of proposed meetings and interviews with personnel related to the offset project;
2. Dates of proposed site visits;
3. Types of proposed document and data reviews; and
4. Expected date for completing offset verification services.

(C) Planning Meetings with the Offset Project Operator or Authorized Project Designee. The offset verification team must discuss with the Offset Project Operator or Authorized Project Designee the scope of the offset verification services and request any information and documents needed for initiating offset verification services. The offset verification team must review the documents submitted and plan and conduct a review of original documents and supporting data for the Offset Project Data Report. Information regarding planning meetings may be included in the offset verification plan, but is not required. Any discussions or meetings to secure an offset verification services contract or collect preliminary project documents to bid the offset verification services may occur prior to submitting the Notice of Offset Verification Services pursuant to section 95977.1(b)(1).

(D) Site Visits for Offset Projects. For a non-sequestration offset project, at least one accredited offset verifier in the offset verification team, including the offset project specific verifier, must make at least one site visit for each Reporting Period that an Offset Project Data Report is submitted, except for those non-sequestration offset projects for which the Offset Project Data Reports qualify for a two-year offset verification period pursuant to section 95977(b). In this case, at least one offset verifier in the offset verification team, including the offset project specific verifier, must make a site visit each time offset verification services are performed; offset verification services for non-sequestration offset projects would include one or two Reporting Periods, depending on whether verification is eligible to be deferred pursuant to section 95977(b). For a forest or urban forest offset project, at least one accredited offset verifier in the offset verification team, including the offset project specific verifier, must make a site visit every year that offset verification services are provided, except for those offset projects approved for less intensive verification, for which a site visit must be performed at least once every six years. A site visit is also required after the first Reporting Period of an offset project under a Compliance Offset Protocol and after the first Reporting Period for each renewed crediting period under a Compliance Offset Protocol. Any site visit performed under this section must be conducted after the Offset Project Operator or Authorized Project Designee submits its Offset Project Data Report to ARB or an Offset Project Registry. During the required site visit, the offset verification team member(s) must conduct the following, and document or explain how each requirement was checked and fulfilled in the detailed verification report:

1. During the initial site visit conducted following the first Reporting Period of the crediting period the offset verification team members must:
   a. Assess offset project eligibility and that the offset project meets the requirements for additionality according to section 95973 and the applicable Compliance Offset Protocol;
   b. Review the information submitted for listing pursuant to section 95975 and determine if it is complete and accurate;
   c. Confirm that the offset project boundary is appropriately defined;
   d. Review project baseline calculations and modeling;
   e. Assess the operations, functionality, data control systems, and review GHG measurement and monitoring techniques; and
   f. Confirm that all applicable eligibility criteria to design, measure, establish the chain of custody, and monitor the offset project conforms to the requirements of the applicable Compliance Offset Protocol.
   g. All criteria pertaining to the eligibility of the offset project must be assessed during the first site visit in the first Reporting Period of each crediting period. All eligibility criteria must be met and are not subject to sampling. If any of the eligibility criteria are not met, the project would be ineligible for crediting and receive an Adverse Offset Verification Statement.
2. During the initial site visit conducted following the first Reporting Period of the crediting period and each subsequent site visit the offset verification team must:

a. Check that all offset project boundaries, GHG emissions sources, GHG sinks, and GHG reservoirs in the applicable Compliance Offset Protocol are identified appropriately;

b. Review and understand the data management systems used by the Offset Project Operator or Authorized Project Designee to track, quantify, and report GHG reductions, GHG removal enhancements, or other data required as applicable in the Compliance Offset Protocol. This includes reviewing data collection processes and procedures, sampling techniques and metering accuracy, quality assurance/quality control processes and procedures, and missing data procedures. The offset verification team member(s) must evaluate the uncertainty and effectiveness of these systems;

c. Interview key personnel involved in collecting offset project data and preparing the Offset Project Data Report;

d. Make direct observations of equipment for data sources and equipment supplying data for GHG emission sources in the sampling plan determined to be high risk;

e. Collect and review other information that, in the professional judgment of the team, is needed in the offset verification process;

f. Confirm the offset project conforms with all local, state, or federal environmental regulatory requirements pursuant to section 95973(b), including health and safety regulations; and

g. Review all chain of custody documents as required in the Compliance Offset Protocol, if applicable.

h. If the offset project is found by the offset verification team to not meet the requirements of section 95977.1(b)(3)(D)(2.)(f.), the offset project is ineligible to receive ARB offset credits or registry offset credits for GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report.

i. The activities performed pursuant to sections 95977.1(b)(3)(D)(2.)(f.) through (b)(3)(D)(2.)(h.) may be included in a site visit or, alternatively, may be conducted as part of a desk review.

(E) The offset verification team must review offset project operations to identify applicable GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs required to be included and quantified in the Offset Project Data Report as required by the applicable Compliance Offset Protocol. This must include a review of each type of GHG emissions source, GHG sink, and GHG reservoir to ensure that all GHG emissions sources, GHG sinks, and GHG reservoirs required to be reported for the offset project are properly included in the Offset Project Data Report.

(F) An Offset Project Operator or Authorized Project Designee must make available to the offset verification team all information and documentation used to calculate and report project baseline and project GHG emissions, GHG reductions, and GHG removal enhancements and other information required by the applicable Compliance Offset Protocol.

(G) Sampling Plan for Offset Project Data Reports. As part of confirming the Offset Project Data Report, the offset verification team must develop a sampling plan that meets the following requirements:

1. The offset verification team must develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale, and complexity of the offset verification services for an Offset Project Operator or Authorized Project Designee. The analysis must review the inputs for the development of the submitted Offset Project Data Report, the rigor and appropriateness of the GHG data management systems, and the coordination within an Offset Project Operator's or Authorized Project Designee's organization to manage the operation and maintenance of equipment and systems used to develop the Offset Project Data Reports;
2. The offset verification team must include a ranking of GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary by amount of contribution to total CO_2e emissions, GHG reductions, and GHG removal enhancements, and a ranking of GHG emissions sources, GHG sinks, or GHG reservoirs with the largest calculation uncertainty; and
3. The offset verification team must include a qualitative narrative of uncertainty risk assessment in the following areas as applicable to the Compliance Offset Protocol:
    a. Data acquisition equipment;
    b. Data sampling and frequency;
    c. Data processing and tracking;
    d. Project baseline and project GHG emissions, GHG reductions, and GHG removal enhancement calculations;
    e. Data reporting; and

f. Management policies or practices in developing Offset Project Data Reports.

(H) After completing the analysis in section 95977.1(b)(3)(G), the offset verification team must include in the sampling plan a list which includes the following:

1. GHG emissions sources, GHG sinks, and GHG reservoirs that will be targeted for document reviews to ensure conformance with the Compliance Offset Protocol and data checks as specified in section 95977.1(b)(3)(L) and an explanation of why they were chosen;

2. Methods used to conduct data checks for each GHG emissions source, GHG sink, and GHG reservoir; and

3. A summary of the information analyzed in the data checks and document reviews conducted for each GHG emissions source, GHG sink, and GHG reservoir.

(I) The sampling plan list, prepared pursuant to section 95977.1(b)(3)(H), must be updated and finalized prior to the completion of offset verification services. The final sampling plan must describe in detail how the GHG emissions sources, GHG sinks, and GHG reservoirs with identified risk, subject to data checks, were reviewed for accuracy.

(J) The offset verification team must revise the sampling plan to describe tasks completed or needed to be completed by the offset verification team as relevant information becomes available and potential issues emerge of offset material misstatement or nonconformance with the requirements of the Compliance Offset Protocol and this article.

(K) The verification body must retain the sampling plan in paper, electronic, or other format for a period of not less than 15 years following the submission of each Offset Verification Statement. The sampling plan must be made available at any time during offset verification services to ARB or the Offset Project Registry within 10 calendar days upon request. The verification body must also retain all material received, reviewed, or generated to render an Offset Verification Statement for an Offset Project Operator or Authorized Project Designee for 15 years following the submittal of each Offset Verification Statement. The documentation must allow for a transparent review of how a verification body reached its conclusion in the detailed verification report and Offset Verification Statement.

(L) Data Checks for Offset Project Data Reports. To determine the reliability of the submitted Offset Project Data Report, the offset verification team must use data checks. Such data checks must focus first on the largest and most uncertain estimates of project baseline GHG emissions, project emissions, GHG reductions, and GHG removal enhancements, and the offset verification team must:

1. Use data checks to ensure that the appropriate methodologies and GHG emission factors have been applied in calculating the project baseline and annual GHG emissions, project emissions, GHG reductions, and GHG removal enhancements calculations in the Compliance Offset Protocol;
2. Choose GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs for data checks based on their relative sizes and risks of offset material misstatement or nonconformance as indicated in the sampling plan;
3. Use professional judgment in the number of data checks required for the offset verification team to conclude with reasonable assurance whether the Offset Project Operator's or Authorized Project Designee's total reported GHG reductions and GHG removal enhancements are free of

offset material misstatement and the Offset Project Data Report otherwise conforms to the requirements of the Compliance Offset Protocol and this article. At a minimum a data check must include the following:

a. Tracing data in the Offset Project Data Report to its origin;

b. Looking at the process for data compilation and collection;

c. Reviewing all GHG inventory designs for GHG sources, GHG sinks, and GHG reservoirs, and sampling procedures, if applicable;

d. Recalculating baseline GHG emissions, project emissions, GHG reductions, and GHG removal enhancements estimates to check original calculations;

e. Reviewing calculation methodologies used by the Offset Project Operator or Authorized Project Designee for conformance with the Compliance Offset Protocol and this article;

f. Reviewing meter and fuel analytical instrumentation calibration, if applicable; and

g. Reviewing the quantification from models approved for use in the Compliance Offset Protocol, if applicable; and

4. Compare its own calculated results for the data checks conducted with the reported offset project data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be identified in the issues log. The comparison of data checks must also include a narrative to indicate which GHG emissions sources, GHG sinks, and GHG reservoirs were checked, the types and quantity of

data that were evaluated for each GHG emissions source, GHG sink, and GHG reservoir, how the data checks were conducted including calculations, and any discrepancies that were identified.

(M) Offset Project Data Report Modifications. As a result of review by the offset verification team and prior to completion of an Offset Verification Statement, the Offset Project Operator or Authorized Project Designee must make any possible improvements and fix any correctable errors to the submitted Offset Project Data Report, and a revised Offset Project Data Report must be submitted to ARB or the Offset Project Registry. If the Offset Project Operator or Authorized Project Designee does not make all possible improvements and fix any correctable errors to the Offset Project Data Report, the verification body must issue an Adverse Offset Verification Statement. The offset verification team shall use professional judgment in the determination of correctable errors, including whether differences are not errors but result from truncation or rounding. The offset verification team must document in the issues log the source of any difference identified, including whether the difference results in a correctable error. Documentation for all Offset Project Data Report submittals must be retained by the Offset Project Operator or Authorized Project Designee for the length of time specified in section 95976(e)(2).

(N) To verify that the Offset Project Data Report is free of offset material misstatement, the offset verification team must make its own determination of GHG reductions or GHG removal enhancements relative to the project baseline using the data check conducted pursuant to section 95977.1(b)(3)(L), and must determine whether there is reasonable assurance that the

Offset Project Data Report does not contain an offset material misstatement for the Offset Project Operator or Authorized Project Designee, on a CO_2e basis. To assess conformance with this article and the Compliance Offset Protocol the offset verification team must review the methods and factors used to develop the Offset Project Data Report for adherence to the requirements of this article and the Compliance Offset Protocol and ensure that other requirements of this article are met.

(O) Issues Log. The offset verification team must keep a log of any issues identified in the course of offset verification services that may affect determinations of offset material misstatement and nonconformance. The issues log must identify the section of this article or Compliance Offset Protocol related to the nonconformance, if applicable, and indicate whether the issues were corrected by the Offset Project Operator or Authorized Project Designee prior to completing the offset verification services. Any other concerns that the offset verification team has with the preparation of the Offset Project Data Report must be documented in the issues log. The issues log must indicate whether the issues could have any bearing on offset material misstatement or conformance.

(P) An assessment of offset material misstatement is conducted for net GHG reductions and GHG removal enhancements achieved in a given Reporting Period relative to the project baseline in that Reporting Period in metric tons of CO_2e.

(Q) The offset verification team must determine whether the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report contain an offset material misstatement using the following equation:

$$Percent\ error = \frac{[\sum Discrepancies + \sum Omissions\ + \sum Misreporting]\ \times 100\%}{Total\ Reported\ Emission\ Reductions\ and\ Removal\ Enhancements}$$

Where:

"Discrepancies" means any differences between the reported GHG value for sources, sinks, and reservoirs for the project baseline or project, and the verifier calculated GHG value for a data source subject to data checks in 95977.1(b)(3)(L) calculated by the offset verification team. Any discrepancies identified must include the positive or negative impact of the GHG source, sink, or reservoir on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Omissions" means any GHG emissions or removal enhancements associated with required sources, sinks, and reservoirs for the project baseline or project emissions, that the offset verification team concludes must be part of the Offset Project Data Report, but were not included by the Offset Project Operator or Authorized Project Designee in the Offset Project Data Report. Any omissions found by the offset verification team must include the positive or negative impact of the omission on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Misreporting" means duplicative, incomplete, or other GHG emissions or removal enhancements for required sources, sinks, and reservoirs in the project baseline or project emissions, the offset verification team concludes should, or should not, be part of the Offset Project Data Report. Any misreporting found by the offset verification team must include the positive or negative impact of the misreporting on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Total reported emission reductions and removal enhancements" means net GHG reductions and GHG removal enhancements reported by the Offset Project Operator or Authorized Project Designee for an Offset Project Data Report relative to the project baseline for that Offset Project Data Report in metric tons CO_2e.

(R) Completion of offset verification services must include:

1. Offset Verification Statement. Upon completion of the offset verification services conducted pursuant to section 95977.1(b)(3), the verification body must complete an Offset Verification Statement for each Offset Project Data Report for which offset verification services were conducted and provide it to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry by the verification deadline pursuant to section 95977(d). Before the Offset Verification Statement is completed, the verification body must have the offset verification services and findings of the offset verification team independently reviewed within the verification body by an independent reviewer not involved in offset verification services for that offset project. The independent reviewer may not be the offset project specific verifier, and may not accompany the offset verification team on a site visit. The independent reviewer may conduct a separate site visit, if necessary.

2. The independent reviewer shall serve as the final check of the offset verification team's work to identify any significant concerns, including:
   a. Errors in planning;
   b. Errors in data sampling; and
   c. Errors in judgment by the offset verification team that are related to the draft offset verification statement.
3. The independent reviewer must maintain independence from the offset verification services by not making specific recommendations about how the offset verification services should be conducted. The independent reviewer will review documents applicable to the offset verification services provided and identify any failure to comply with the requirements of this article or with the verification body's internal policies and procedures for providing offset verification services. The independent reviewer must concur with the offset verification findings before the Offset Verification Statement can be issued.
4. When the offset verification team completes its findings:
   a. The verification body must provide to the Offset Project Operator or Authorized Project Designee a detailed verification report for each Offset Project Data Report for which offset verification services were conducted. The detailed verification report must at a minimum include the Offset Verification Plan, the detailed comparison of the data checks conducted during offset verification services pursuant to section 95977.1(b)(3)(L), including the required narrative, the issues log identified in the course of offset verification activities and the issue resolutions, and any qualifying comments on findings during offset verification

services. The detailed verification report must also include the calculations performed in 95977.1(b)(3)(Q) with enough detail to understand the relationships between the data checks and the offset material misstatement evaluation, and be made available to ARB within 10 calendar days upon request. If the Offset Verification Statement is being submitted to an Offset Project Registry, then the verification body must submit the detailed verification report to the Offset Project Registry with the Offset Verification Statement. The detailed verification report must be submitted to the Offset Project Operator or Authorized Project Designee at the same time or before the Offset Verification Statement is submitted to ARB or the Offset Project Registry.

b. The verification body must provide the Offset Verification Statement to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry, attesting to ARB whether the verification body has found the submitted Offset Project Data Report to be free of offset material misstatement, and whether the Offset Project Data Report is in conformance with the requirements of this article and the Compliance Offset Protocol.

c. A Compliance Offset Protocol may restrict the use of a Qualified Positive Offset Verification Statement for certain project types, in which case the verification body must submit either a Positive Offset Verification Statement or an Adverse Offset Verification Statement. In the case of a Qualified Positive Offset Verification Statement, when not restricted by a

Compliance Offset Protocol, the verification body will qualify the Offset Verification Statement to indicate any nonconformances allowed for a qualified Positive Offset Verification Statement as defined in section 95802 contained within the Offset Project Data Report and that these nonconformances do not result in an offset material misstatement.

d. The offset verification team must have a final discussion with the Offset Project Operator or Authorized Project Designee explaining their findings and notifying the Offset Project Operator or Authorized Project Designee of any unresolved issues noted in the issues log before the Offset Verification Statement is finalized and submitted to the Offset Project Registry or ARB.

e. The lead verifier in the offset verification team must attest to ARB in the Offset Verification Statement that the offset verification team has carried out all offset verification services as required by this article, and the lead verifier who has conducted the independent review of offset verification services and findings must attest to his or her independent review on behalf of the verification body and his or her concurrence with the offset verification findings.

f. The lead verifier must attest in the Offset Verification Statement, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California that the offset verification team has carried out all offset verification services as required by sections 95977.1, 95977.2, and the applicable Compliance Offset Protocol and the findings are true, accurate, and complete and have been independently reviewed by an independent reviewer as required under sections 95977.1(b)(3)(R)(1.) through 95977.1(b)(3)(R)(3.)."

5. Prior to the verification body providing an Adverse Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must be provided at least 10 working days to modify the Offset Project Data Report to correct any offset material misstatement or nonconformance found by the offset verification team. The modified Offset Project Data Report and Offset Verification Statement must be submitted to ARB or the Offset Project Registry by the applicable verification deadline, unless the Offset Project Operator or Authorized Project Designee makes a request to ARB pursuant to section 95977.1(b)(3)(R)(6.).

6. If the Offset Project Operator or Authorized Project Designee and the verification body cannot reach agreement on modifications to the Offset Project Data Report that result in a Positive Offset or Qualified Positive Offset Verification Statement due to a disagreement on the requirements of this article or Compliance Offset Protocol, the Offset Project Operator or Authorized Project Designee may petition ARB to make a decision as to the verifiability of the submitted Offset Project Data Report.

7. If ARB determines that the Offset Project Data Report does not meet the standards and requirements specified in this article, the Offset Project Operator or Authorized Project Designee must provide any additional information within 30 calendar days of the ARB determination. ARB will review the new information and notify the Offset Project Operator or

Authorized Project Designee and verification body of its final decision. In re-verifying a revised Offset Project Data Report, the verification body and offset verification team shall be subject to the requirements in sections 95977.1(b)(3)(R)1. through 95977.1(b)(3)(R)4. and must submit the revised Offset Verification Statement to ARB or the Offset Project Registry within 15 calendar days.

(S) Upon submission of the Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Data Report must be considered final and no further changes may be made by the verification body unless the Offset Project Registry or ARB requests any changes as part of their review. Once ARB offset credits are issued for the Offset Project Data Report, all offset verification requirements of this article shall be considered complete for the applicable Offset Project Data Report.

(T) If the Executive Officer finds a high level of conflict of interest existed between a verification body and an Offset Project Operator or Authorized Project Designee pursuant to section 95979(b)(3) and section 95979(b)(4), or an Offset Project Data Report that received a Positive Offset or Qualified Positive Offset Verification Statement fails an ARB audit, the Executive Officer may set aside the Positive Offset or Qualified Positive Offset Verification Statement submitted by the verification body and require the Offset Project Operator or Authorized Project designee to have the Offset Project Data Report re-verified by a different verification body within 90 calendar days of this finding.

(U) Upon request by ARB or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide the data used to generate an Offset Project Data Report, including all data available to the offset verification team in the conduct of offset verification services, within 10 working days of the request.

(V) Upon request by ARB or the Offset Project Registry the verification body must provide ARB or the Offset Project Registry the detailed verification report given to the Offset Project Operator or Authorized Project Designee, as well as the sampling plan, contracts for offset verification services, and any other supporting documentation. All documentation must be provided by the verification body to ARB or the Offset Project Registry within 10 working days of the request.

(W) Upon written notification by ARB the verification body and its staff must be available for an offset verification services audit when providing offset verification services for an offset project listed with ARB or an Offset Project Registry using a Compliance Offset Protocol.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977.2. Additional Project Specific Requirements for Offset Verification Services.

In addition to meeting the offset verification requirements in sections 95977 and 95977.1, Offset Project Operators or Authorized Project Designees must ensure the GHG emission reductions and GHG removal enhancements resulting from an offset project meet any additional verification requirements in the Compliance Offset Protocol, if applicable, for an offset project of that type.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95978. Offset Verifier and Verification Body Accreditation.

(a) An offset verifier or verification body must meet the accreditation requirements in section 95132 of MRR to provide offset verification services to verify GHG emission reductions and GHG removal enhancements for offset projects listed pursuant to this article. Accreditation of verification bodies and offset verifiers for verifying Offset Project Data Reports under this article must be achieved separately from accreditation for verifying reports submitted under the MRR.

(b) For purposes of this article, the subcontractor requirements in section 95132(e) of the MRR must be applied to the Offset Project Operator and/or Authorized Project Designee and not a reporting entity.

(c) An ARB accredited verification body must make itself and its personnel available for an ARB audit.

(d) An ARB-accredited offset verification body may employ or contract with technical experts not accredited by ARB to assist with offset verification services.

  (1) All technical experts must be listed on the Notice of Offset Verification Services as required in section 95977.1(b) and must be included in the evaluation for conflict of interest as required in section 95979.

  (2) Technical experts must be under the direct supervision of an ARB-accredited offset verifier while performing verification activities.

  (3) Technical experts may assist in underlying offset verification tasks, but may not be responsible for completing any offset verification services as defined in 95802(a).

(e) “Direct supervision,” for purposes of this section, means daily, on-site, close contact with an ARB-accredited verifier acting as a supervisor, who is able to respond to the needs of the technical expert. The supervisor must be physically present, or within 4 hours travel time and available to respond to the needs of the technical expert.

(f) “Technical expert,” for purposes of this section, means a person, who is not an ARB-accredited verifier, and has demonstrated expertise in a particular technical area for which the person hired by the verification body to assist with underlying offset verification task(s) that require a particular expertise. A technical expert may be an employee of the verification body working to get the required experience to become an ARB-accredited verifier.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95979. Conflict of Interest Requirements for Verification Bodies and Offset Verifiers for Verification of Offset Project Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and offset verifiers accredited by ARB to perform offset verification services for Offset Project Operators, and Authorized Project Designees, if applicable, as well as any other member of the offset verification team and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, if applicable.

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

(1) The verification body and Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) share any senior management staff or board of directors membership, or any of the senior management staff of the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) have been employed by the verification body, or vice versa, within the previous three years; or

(2) Within the previous five years, any staff member of the verification body or any related entity or any member of the offset verification team has provided to the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) any of the following non-offset verification services:

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or offset project information or data management system for air emissions, unless the review was part of providing GHG offset verification services;

(B) Developing GHG emission factors or other GHG-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) GHG analysis that includes offset project specific information;

(C) Designing energy efficiency, renewable power, or other projects which explicitly identify GHG reductions and GHG removal enhancements as a benefit;

(D) Designing, developing, implementing, internally auditing, consulting, or maintaining an offset project resulting in GHG emission reductions and GHG removal enhancements;

(E) Owning, buying, selling, trading, or retiring shares, stocks, or ARB offset credits or registry offset credits from the offset project;

(F) Dealing in or being a promoter of ARB offset credits or registry offset credits on behalf of an Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s);

(G) Preparing or producing GHG-related manuals, handbooks, or procedures specifically for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s);

(H) Appraisal services of carbon or GHG liabilities or assets;

(I) Brokering in, advising on, or assisting in any way in carbon or GHG-related markets;

(J) Directly managing any health, environment or safety functions for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s);

(K) Bookkeeping or other services related to the accounting records or financial statements;

(L) Any service related to information systems, including International Organization for Standardization 14001 Certification for Environmental Management (ISO 14001 Certification), unless those systems will not be reviewed as part of the offset verification process;

(M) Appraisal and valuation services, both tangible and intangible;

(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the information reviewed in formulating the Offset Verification Statement will not be reviewed as part of the offset verification services;

(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(P) Any internal audit service that has been outsourced by the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) that relates to the Offset Project Operator's, Authorized Project Designee's, if applicable, and their technical consultant(s) internal accounting controls, financial systems, or financial statements, unless the systems and data reviewed during those services, as well as the result of those services will not be part of the offset verification process;

(Q) Acting as a broker-dealer (registered or unregistered), promoter, or underwriter on behalf of the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s);

(R) Any legal services;

(S) Expert services to the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) or a legal representative for the purpose of advocating the

Offset Project Operator's, Authorized Project Designee's, if applicable, and their technical consultant(s) interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony; and

(T) Third-party certification of a facility to meet the requirements set forth by the United Nations Environment Programme Ozone Secretariate's Technology and Assessment Panel (TEAP) for ozone depleting substances destruction.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities.

"Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest will be deemed to be high when any member of the verification body provides any type of incentive to an Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) to secure an offset verification services contract.

(4) The potential for a conflict of interest will also be deemed to be high where any member of the verification body has provided offset verification services for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) except within the time periods in which the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) is allowed to use the same verification body as specified in section 95977.1(a).

(c) The potential for a conflict of interest must be deemed to be low where no potential for a conflict of interest is found under section 95979(b) and any non-offset verification services provided by any member of the verification body to the Offset Project Operator, Authorized Project Designee, if applicable, and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee within the last five years are valued at less than 20 percent of the fee for the proposed offset verification, except where medium conflict of interest related to personal or family relationships is identified pursuant to section 95979(d).

(d) The potential for a conflict of interest must be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95979(b) and 95979(c), or where there are any instances of personal or familial relationships between the verification body and management or employees of the Offset Project Operator or, Authorized Project Designee, if applicable, and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee and when a conflict of interest self-evaluation is submitted pursuant to section 95979(g). If a verification body identifies a medium potential for conflict of interest and intends to provide offset verification services for the Offset Project Operator, Authorized Project Designee, if applicable, and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee for an offset project listed with ARB or an Offset Project Registry, the verification body must submit, in addition to the submittal requirements specified in section 95979(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan must include:

(1) A demonstration that any members with potential conflicts have been removed and insulated from the project;

(2) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested

or moved into an independent entity or any subcontractor with potential conflicts has been removed; and

(3) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(e) Conflict of Interest Submittal Requirements for Accredited Verification Bodies. Before providing any offset verification services, the verification body must submit to the Offset Project Operator, and Authorized Project Designee, if applicable, ARB and the Offset Project Registry, a self-evaluation of the potential for any conflict of interest that the verification body, its staff, its related entities, or any subcontractors performing offset verification services may have with the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) for which it will perform offset verification services. Offset verification services shall not commence prior to approval of the conflict of interest self-evaluation by ARB or the Offset Project Registry pursuant to section 95979(f). The submittal must include the following:

(1) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95979(b), (c), and (d);

(2) Identification of whether any member of the offset verification team has previously provided offset verification services for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s), and, if so, the years in which such offset verification services were provided; and

(3) Identification of whether any member of the offset verification team or related entity has engaged in any non-offset verification services of any nature with the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) either within or outside California during the previous five years. If non-offset verification services have previously been provided, the following information must also be submitted:

(A) Identification of the nature and location of the work performed for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) and whether the work is similar to the type of work to be performed during offset verification;

(B) The nature of past, present, or future relationships with the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s), including:

1. Instances when any member of the offset verification team has performed or intends to perform work for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s);
2. Identification of whether work is currently being performed for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s), and if so, the nature of the work;
3. How much work was performed for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) in the last five years, in dollars;
4. Whether any member of the offset verification team has any contracts or other arrangements to perform work for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) or a related entity; and
5. How much work related to GHG reductions and GHG removal enhancements the offset verification team has performed for the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) or related entities in the last five years, in dollars;

(C) Explanation of how the amount and nature of work previously performed is such that any member of the offset verification team's credibility and lack of bias should not be under question;

(D) A list of names of the staff that would perform offset verification services for the Offset Project Operator, and Authorized Project Designee, if applicable, and a description of any instances of personal or family relationships with management or employees of the Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) that potentially represent a conflict of interest;

(E) Identification of any other circumstances known to the verification body, or Offset Project Operator, Authorized Project Designee, if applicable, and their technical consultant(s) that could result in a conflict of interest; and

(F) Attest, in writing, to ARB as follows:
"I certify under penalty of perjury of the laws of the State of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) Approval of Conflict of Interest Submittals. ARB or the Offset Project Registry must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform the offset verification services for the Offset Project Operator and Authorized Project Designee, if applicable.

(1) ARB or the Offset Project Registry has 30 calendar days to make a determination whether to accept or deny the conflict of interest submittal and notify the verification body whether it may proceed with the offset verification services for the Offset Project Operator and Authorized Project Designee, if applicable.

(A) If ARB or an Offset Project Registry requests revisions to the conflict of interest self evaluation prior to approval, the verification body must resubmit the revised conflict of interest self evaluation within 10 working days of such request, or if there is a reason the verification body cannot submit the revisions within 10 working days, the verification body must communicate to ARB and the Offset Project Registry, in writing, as to the reasons why and get approval from ARB or the Offset Project Registry for an extension.

(B) If ARB or the Offset Project Registry determines that the verification body or any member of the offset verification team meets the criteria in section 95979(b), ARB or the Offset Project Registry shall find a high potential conflict of interest and offset verification services may not proceed.

(C) If ARB or the Offset Project Registry determines that there is a low potential conflict of interest, offset verification services may proceed.

(D) If ARB or the Offset Project Registry determines that the verification body or any member of the offset verification team have a medium potential for conflict of interest, ARB or the Offset Project Registry shall evaluate the conflict of interest mitigation plan submitted by the verification body pursuant to section 95979(d), and may request additional information from the applicant to complete the determination. In determining whether offset verification services may proceed, ARB or the Offset Project Registry may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the Offset Project Operator and Authorized Project Designee, if applicable, and any technical consultant(s) used by the Offset Project Operator or Authorized Project Designee, and related entities, and the cost of the offset verification services to be performed. If ARB or the Offset Project Registry determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, ARB or the Offset Project Registry will authorize the verification body to provide offset verification services.

(2) If the offset project was listed with an Offset Project Registry, the conflict of interest self-evaluation acceptance or denial notification will be given by the Offset Project Registry.

(g) Monitoring Conflict of Interest Situations.

(1) After commencement of offset verification services, the verification body must monitor and immediately make full disclosure, in writing, to ARB and the Offset Project Registry regarding any potential for a conflict of interest situation that arises for an offset project using a Compliance Offset Protocol. This disclosure must include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body must continue to monitor arrangements or relationships that may be present for a period of one year after the completion of offset verification services for an offset project using a Compliance Offset Protocol. During that period, within 30 days of the verification body or any verification team member entering into any contract with the Offset Project Operator, and Authorized Project Designee, if applicable, for which the verification body has provided offset verification services, the verification body must notify ARB and the Offset Project Registry of the contract and the nature of the work to be performed. ARB or the Offset Project Registry, within 30 working days, will determine the level of conflict using the criteria in sections 95979(a) through (d), if the Offset Project Operator, and Authorized Project Designee, if applicable, must re-verify their Offset Project Data Report, and if accreditation revocation is warranted by ARB.

(3) The verification body must notify ARB and the Offset Project Registry within 30 calendar days, of any emerging conflicts of interest during the time offset verification services are being provided for an offset project using a Compliance Offset Protocol.

(A) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium risk, and this risk can be mitigated, then the verification body meets the conflict of interest requirements to continue to provide offset verification services for the Offset Project Operator, and Authorized Project Designee, if applicable, and will not be subject to suspension or revocation of accreditation as specified in section 95132(d) of MRR.

(B) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium or high risk, and this risk cannot be mitigated, then the verification body will not be able to continue to provide offset verification services for the Offset Project Operator, and Authorized Project Designee, if applicable, and may be subject to the suspension or revocation of accreditation by ARB under section 95132(d) of MRR.

(4) The verification body must report to ARB and the Offset Project Registry, if applicable, any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of offset verification services.

(5) ARB may void a Positive Offset or Qualified Positive Offset Verification Statement received in section 95981 if it discovers a potential conflict of interest has arisen for any member of the offset verification team. In such a case, the Offset Project Operator, and Authorized Project Designee, if applicable, shall be provided 90 calendar days to complete re-verification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section 95132(d) of MRR.

(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 95979(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 article;

(2) Before providing offset verification services, an air district must submit a conflict of interest self-evaluation pursuant to 95979(e) for each Offset Project Operator, and Authorized Project Designee, if applicable, for which it intends to provide offset verification services. As part of its conflict of interest self-evaluation submittal under section 95979(e), the air district shall certify that it will prevent conflicts of interests and resolve potential conflict of interest situations pursuant to its policies and mechanisms submitted under section 95132(b)(1)(G) of MRR;

(3) If an air district hires a subcontractor who is not an air district employee to provide offset verification services, the air district shall be subject to all of the requirements of section 95979.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95979.1 Additional Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(a) The following requirements will apply to air districts that meet the requirements under section 95978 to become accredited as an offset verification body and/or the requirements under section 95986 to meet the requirements as an approved Offset Project Registry:

(1) The air district may:

(A) Register with ARB pursuant to section 95830; and

(B) Hold compliance instruments as a voluntarily associated entity pursuant to section 95814.

(2) The air district may not:

(A) Be an Offset Project Operator or Authorized Project Designee for any offset project for which it provides offset verification services pursuant to sections 95977, 95977.1, and 95977.2, and for which the air district will subsequently request the issuance of ARB offset credits pursuant to section 95981;

(B) Be an Offset Project Operator or Authorized Project Designee for any offset project for which it provides registry services pursuant to section 95987, and for which the air district will subsequently request the issuance of ARB offset credits pursuant to section 95981; and

(C) Be an offset verification body for any offset project developed using a Compliance Offset Protocol for which it would provide registry services pursuant to section 95987.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95980. Issuance of Registry Offset Credits.

(a) One registry offset credit, which represents one metric ton of CO_2e for a direct GHG emission reduction or direct GHG removal enhancement, will be issued pursuant to section 95980.1 only if:

(1) An Offset Project Registry has listed the offset project pursuant to section 95975;

(2) The GHG emission reductions or GHG removal enhancements were issued a Positive Offset or Qualified Positive Offset Verification Statement pursuant to section 95977.1 and 95977.2; and

(3) An Offset Project Registry has received a Positive Offset or Qualified Positive Offset Verification Statement issued and attested to by an ARB-accredited verification body for the Offset Project Data Report for which registry offset credits would be issued.

(b) An Offset Project Registry will determine whether the GHG emission reductions and GHG removal enhancements meet the requirements of section 95980(a), the information submitted pursuant to section 95980(a) is complete, and the Positive Offset or Qualified Positive Offset Verification Statement meets the requirements of sections 95977, 95977.1, and 95977.2 within 45 calendar days of receiving it.

(c) Determination for Timing and Duration of Initial Crediting Periods for Offset Projects Submitted Through an Offset Project Registry. The initial crediting period will begin with the date that the first verified GHG emission reductions and GHG removal enhancements occur, according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by an Offset Project Registry, unless otherwise specified in the applicable Compliance Offset Protocol. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

(d) Determination for Timing and Duration of Renewed Crediting for Offset Projects Submitted through an Offset Project Registry. A renewed crediting period will begin the day after the conclusion of the prior crediting period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95980.1 Process for Issuance of Registry Offset Credits.

(a) An Offset Project Registry may issue a registry offset credit that meets the requirements of sections 95980(a) and (b) to an Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator to receive registry offset credits, no later than 15 calendar days after an Offset Project Registry makes a determination pursuant to section 95980(b).

(b) Change of Listing Status at the Offset Project Registry. When an Offset Project Registry issues a registry offset credit for an offset project, the listing status for that offset project will be changed to either "Active Registry Project" or "Active Registry Renewal" at the Offset Project Registry and ARB.

(c) Notice of Determination of Issuance of Registry Offset Credits. Not later than 15 calendar days after an Offset Project Registry issues a registry offset credit, an Offset Project Registry will notify the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator of the issuance.

(d) Requests for Additional Information. An Offset Project Registry may request additional information for offset projects seeking issuance of registry offset credits from the Offset Project Operator, Authorized Project Designee or verification body.

(1) An Offset Project Registry may request any additional information from the Offset Project Operator, Authorized Project Designee, if applicable, or the verification body within the timeframe specified in section 95980(b) before issuing registry offset credits for an offset project that meets the requirements of sections 95980(a) and (b).

(2) If an Offset Project Registry determines the information submitted pursuant to sections 95980(a), 95980(b), and 95980.1(d)(2) does not meet the requirements for issuance of registry offset credits, an Offset Project Registry must deny issuance of registry offset credits. The

Offset Project Operator or Authorized Project Designee may petition an Offset Project Registry within 10 days of denial for a review of the information submitted pursuant to sections 95980(a), 95980(b), and 95980.1(d)(2) and respond to any issues that prevent the issuance of registry offset credits.

(3) An Offset Project Registry must make a final determination within 30 calendar days of receiving the Offset Project Operator's or Authorized Project Designee's request in section 95980.1(d)(2) and may request additional information from the Offset Project Operator, Authorized Project Designee, if applicable, or verification body.

(4) If an Offset Project Registry determines not to issue registry offset credits, the Offset Project Registry must submit a detailed report to ARB that describes why they came to a negative determination.

(5) If an Offset Project Registry determines not to issue registry offset credits, the Offset Project Operator or Authorized Project Designee may request that ARB make a final determination on whether the GHG reductions or removal enhancements achieved by the offset project meet the requirements for registry offset credit issuance. In making this determination, ARB may consult with the Offset Project Operator, Authorized Project Designee, if applicable, verification body, and Offset Project Registry before making the final determination.

(6) If after reviewing all of the information, ARB determines that the GHG reductions or removal enhancements meet the requirements for registry offset credit issuance, the Offset Project Registry will issue registry offset credits in the amount of GHG reductions or removal enhancements verified to have been achieved by the offset project for the applicable Reporting Period(s).

(e) At the time of issuance or after notifying the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator to receive registry offset credits, of the issuance, the Offset Project Registry will create a unique serial number for each registry offset credit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95981. Issuance of ARB Offset Credits.

(a) One ARB offset credit, which represents one metric ton of CO_2e for a direct GHG emission reduction or direct GHG removal enhancement, will be issued only if:

(1) ARB or an Offset Project Registry has listed the offset project pursuant to section 95975;

(2) The GHG emission reductions and GHG removal enhancements were issued a Positive Offset or Qualified Positive Offset Verification Statement pursuant to sections 95977.1 and 95977.2; and

(3) ARB or an Offset Project Registry has received a Positive Offset or Qualified Positive Offset Verification Statement issued and attested to by an ARB-accredited verification body for the Offset Project Data Report for which registry offset credits were issued pursuant to section 95980.1, if the offset project was submitted for listing with an Offset Project Registry, or for which ARB offset credits would be issued pursuant to section 95981.1.

(b) Requirements for Offset Projects Submitted Through an Offset Project Registry Seeking Issuance of ARB Offset Credits. If an Offset Project Operator or Authorized Project Designee provides information for listing pursuant to section 95975, monitors and reports pursuant to section 95976, and has their offset project verified pursuant to sections 95977, 95977.1, and 95977.2 through an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide the following information to ARB for issuance of ARB offset credits pursuant to section 95981.1:

(1) The attestations required in sections 95975(c)(1), 95975(c)(2), 95975(c)(3), 95976(d)(7), 95977.1(b)(3)(R)4.b., 95977.1(b)(3)(R)4.e., 95977.1(b)(3)(R)4.f., and any in the applicable Compliance Offset Protocol;

(2) Offset project listing information submitted to an Offset Project Registry pursuant to sections 95975(c) and (e);

(3) The original and final Offset Project Data Reports submitted to an Offset Project Registry pursuant to sections 95976(d), 95977.1(b)(3)(M), and 95977.1(b)(3)(R)5.; and

(4) Offset Verification Statements submitted pursuant to section 95977.1(b)(3)(R)4.b..

(5) The Offset Project Operator, or Authorized Project Designee, if applicable, must submit a request for issuance of ARB offset credits to ARB for each Offset Project Data Report for which they are seeking issuance of ARB offset credits.

(A) If the ARB offset credits are only being issued into the Holding Account that belongs to the Offset Project Operator, the Authorized Project Designee may submit the request for issuance of ARB offset credits to ARB. If the ARB offset credits will be issued into any other Holding Account(s) other than the Holding Account that belongs to the Offset Project Operator, only the Offset Project Operator may submit the request for issuance of ARB offset credits to ARB.

(B) The request for issuance of ARB offset credits must identify which Holding Accounts the ARB offset credits should be placed into and how many ARB offset credits will be placed into each Holding Account. Consistent with section 95974, the Offset Project Operator may request that ARB offset credits are placed into the Holding Account of the Authorized Project Designee, or another third party not prohibited to hold compliance instruments under this Article. Any party receiving ARB offset credits at the time of ARB offset credit issuance must have a tracking system account with ARB.

(C) An Offset Project Operator or Authorized Project Designee may request that only a portion of the eligible GHG reductions and removal enhancements for the applicable Reporting Period be issued ARB offset credits in the request for issuance.

(D) The request for issuance of ARB offset credits may be provided to ARB when the Offset Project Operator or Authorized Project Designee, if applicable, submits the information in sections 95981(b)(1) through (4) but must be provided to ARB before it will issue ARB offset credits pursuant to section 95981.1. If the offset project was listed by an Offset Project Registry, the request for issuance of ARB offset credits may not be provided to ARB until the Offset Project Registry has issued registry offset credits for the applicable Offset Project Data Report(s).

(c) ARB will determine whether the GHG emission reductions and GHG removal enhancements meet the requirements of section 95981(a), the information submitted in sections 95981(b) and (c) is complete, and the Positive Offset or Qualified Positive Offset Verification Statement meets the requirements of sections 95977, 95977.1, and 95977.2 within 45 calendar days of receiving complete and accurate information.

(d) Before ARB issues an ARB offset credit pursuant to section 95981.1 for GHG reductions and GHG removal enhancements achieved by an offset project in a Reporting Period, the Offset Project Operator or Authorized Project Designee must provide the following attestations, in writing, to ARB:

(1) “I certify under penalty of perjury under the laws of the State of California the GHG reductions or GHG removal enhancements for [project] from [date] to [date] have been measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB is true, accurate, and complete.”;

(2) "I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes arising from the enforcement of provisions in this article.";

(3) "I understand that the offset project activity and implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety regulations that apply based on the offset project location. I understand that offset projects are not eligible to receive ARB or registry offset credits for GHG reductions and GHG removal enhancements that are not in compliance with the requirements of this Article.";

(4) "I certify under penalty of perjury under the laws of the State of California all information provided to ARB for issuance of ARB offset credits is true, accurate, and complete."; and

(5) "I certify under penalty of perjury under the laws of the State of California that the GHG reductions and GHG removal enhancements for which I am seeking ARB Offset Credits have not been issued any offset credits or been used for any GHG mitigation requirements in any other voluntary or mandatory program, except, if applicable, an Offset Project Registry pursuant to section 95980.1."

(e) Determination for Timing and Duration of Initial Crediting Periods for Offset Projects Submitted Through ARB. The initial crediting period will begin with the date that the first verified GHG emission reductions and GHG removal enhancements occur, according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by ARB, unless otherwise specified in a Compliance Offset Protocol. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

(f) Determination for Timing and Duration of Renewed Crediting for Offset Projects Submitted Through ARB. A renewed crediting period will begin the day after the conclusion of the prior crediting period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95981.1 Process for Issuance of ARB Offset Credits.

(a) ARB will issue an ARB offset credit for GHG reductions and removal enhancements achieved in a Reporting Period for an offset project that meets the requirements of sections 95981(a) and (b) to the ARB Issuance Account , no later than 15 calendar days after ARB makes a determination pursuant to section 95981(c), as long as all attestations required in section 95981(d) have been received by ARB prior to its determination.

(b) Change of Listing Status at ARB. When ARB issues an ARB offset credit for an offset project, the listing status for that offset project will be changed from “Active Registry Project” to “Active ARB Project” or “Active Registry Renewal” to “Active ARB Renewal” at the Offset Project Registry and ARB.

(c) Notice of Determination of Issuance of ARB Offset Credits. Not later than 15 calendar days after ARB determines to issue an ARB offset credit pursuant to section 95981(c), ARB will notify the Offset Project Operator, Authorized Project Designee, or any other third party requested by the Offset Project Operator pursuant to section 95981(b)(5)(B) to receive ARB offset credits, of its intent to issue ARB offset credits.

(d) Requests for Additional Information. ARB may request additional information for offset projects submitted through an Offset Project Registry seeking issuance of ARB offset credits.

(1) ARB will notify the Offset Project Operator, Authorized Project Designee, or other third party identified in section 95981(b)(5)(B) within 15 calendar days of its determination pursuant to section 95981(c) if

the information submitted pursuant to section 95981(b), (c), and (d) is incomplete and request additional specific information.

(2) ARB may request any additional information from the Offset Project Operator, Authorized Project Designee, Offset Project Registry, or verification body before issuing ARB offset credits for an offset project that meets the requirements of section 95981. The Offset Project Operator, Authorized Project Designee, Offset Project Registry, or verification body must submit the requested information to ARB within 10 calendar days of ARB's request.

(3) If ARB determines the information submitted in sections 95981(b), 95981(c), and 95981.1(d)(2) does not meet the requirements for issuance of ARB offset credits, then ARB may deny issuance of ARB offset credits. The Offset Project Operator or Authorized Project Designee may petition ARB within 10 days of denial for a review of submitted information in sections 95981(b), 95981(c), and 95981.1(d)(2) and respond to any issues that prevent the issuance of ARB offset credits.

(4) ARB must make a final determination within 30 calendar days of receiving the request in section 95981.1(d)(3) and may request additional information from the Offset Project Operator or Authorized Project Designee, verification body, or Offset Project Registry. This determination made by the Executive Officer is final.

(e) A registry offset credit issued pursuant to section 95980.1(a) must be removed or cancelled by the Offset Project Registry within 10 calendar days of ARB notification, such that the registry offset credit is no longer available for transaction on the Offset Project Registry system. Registry offset credits must be removed or cancelled by the Offset Project Registry before ARB issues an ARB offset credit pursuant to this section. The Offset Project Registry must provide proof to ARB that the registry offset credits have been permanently removed or cancelled from the registry system.

(f) Receipt of ARB Offset Credits. ARB will transfer ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or any other third party requested by the Offset Project Operator pursuant to section 95981(b)(5)(B) to receive ARB offset credits, within 15 working days of the notice of determination pursuant to sections 95981.1(c) and (d)(4).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95982. Registration of ARB Offset Credits.

An ARB offset credit will be registered by:

(a) Creating a unique ARB serial number; and

(b) Transferring the ARB offset credits to the Holding Account of the listed Offset Project Operator, Authorized Project Designee, or another third party as requested by the Offset Project Operator pursuant to section 95981(b)(5)(B) to receive ARB offset credits, unless otherwise required by section 95983.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95983. Forestry Offset Reversals.

(a) For forest sequestration projects, a portion of ARB offset credits issued to the forest offset project will be placed by ARB into the Forest Buffer Account.

(1) The amount of ARB offset credits that must be placed in the Forest Buffer Account shall be determined as set forth in the applicable version of the Compliance Offset Protocol in section 95973(a)(2)(C)4.

(2) ARB offset credits will be transferred to the Forest Buffer Account by ARB at the time of ARB offset credit registration pursuant to section 95982.

(3) If a forest offset project is originally submitted through an Offset Project Registry an equal number of registry offset credits must be removed or cancelled by the Offset Project Registry, such that the registry offset credit is no longer available for transaction on the Offset Project Registry system, and issued by ARB for placement in the Forest Buffer Account.

(4) The ARB offset credits placed into the Forest Buffer Account must correspond to the Reporting Period for which the ARB offset credits are issued.

(b) Unintentional Reversals. If there has been an unintentional reversal, the Offset Project Operator or Authorized Project Designee must notify ARB and the Offset Project Registry, in writing, of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery.

(1) In the case of an unintentional reversal the Offset Project Operator or Authorized Project Designee shall provide in writing to ARB and an Offset Project Registry, if applicable, a completed verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal. To determine the verified estimate of current carbon stocks a full regulatory verification must be conducted pursuant to sections 95977 through 95978, including a site visit. The verified estimate may be submitted as a separate offset verification services, or incorporated into a chapter of the detailed verification report submitted pursuant to section 95977.1 when offset verification services are conducted for an Offset Project Data Report.

(2) If ARB determines that there has been an unintentional reversal, and ARB offset credits have been issued to the offset project, ARB will

retire a quantity of ARB offset credits from the Forest Buffer Account according to section 95983(b)(2)(A) or (B), as applicable.

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, ARB will retire ARB offset credits in the amount of metric tons CO_2e reversed for each Reporting Period.

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, ARB will retire ARB offset credits from the Forest Buffer Account according to the following equation, calculated for each Reporting Period, rounded up to the nearest whole metric ton CO_2e:

$$ARB_{Retire} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"ARB_{Retire}" is the number of ARB offset credits that must be retired from the ARB Forest Buffer Account to compensate for the unintentional reversal for the Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer

Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Reporting Period.

(c) Intentional Reversals. Requirements for intentional reversals are as follows:

(1) If an intentional reversal occurs, the Offset Project Operator or Authorized Project Designee shall, within 30 calendar days of the intentional reversal:

(A) Give notice, in writing, to ARB and the Offset Project Registry, if applicable, of the intentional reversal; and

(B) Provide a written description and explanation of the intentional reversal to ARB and the Offset Project Registry, if applicable.

(2) Within one year of the occurrence of an intentional reversal, the Offset Project Operator or Authorized Project Designee shall submit to ARB and the Offset Project Registry, if applicable, a completed verified estimate of current carbon stocks within the offset project boundary. To determine the verified estimate of current carbon stocks a full regulatory verification must be conducted pursuant to sections 95977 through 95978, including a site visit. The verified estimate may be submitted as a separate offset verification services, or incorporated into a chapter of the detailed verification report submitted pursuant to section 95977.1 when offset verification services are conducted for an Offset Project Data Report.

(3) If an intentional reversal occurs from a forest offset project, and ARB offset credits have been issued to the offset project, the forest owner must submit to ARB for placement in the Retirement Account a quantity of valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4 within six months of notification by

ARB in the amount determined pursuant to sections 95983(c)(3)(A) or (B), as applicable:

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, the forest owner must turn in valid compliance instruments in the amount of metric tons CO_2e reversed for each Reporting Period.

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, the forest owner must turn in valid compliance instruments according to the following equation, calculated for each Reporting Period, rounded up to the nearest metric ton CO_2e:

$$FO_{Replace} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"$FO_{Replace}$" is the number of valid compliance instruments that the forest owner must turn in to compensate for the intentional reversal for the Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer

Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Offset Project Data Report year.

(C) Notification by ARB will occur after the verified estimate of carbon stocks referred to in section 95983(c)(2) has been submitted to ARB, or after one year has elapsed since the occurrence of the reversal if the Offset Project Operator or Authorized Project Designee fails to submit the verified estimate of carbon stocks.

(D) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments in the amount required pursuant to sections 95983(c)(3)(A) or (B) to ARB within six months of notification by ARB, ARB will retire a quantity of ARB offset credits equal to the difference between the number of metric tons of CO_2e determined pursuant to sections 95983(c)(3)(A) or (B) and the number of retired approved compliance instruments from the Forest Buffer Account and the forest owner will be subject to enforcement action and each ARB offset credit retired from the Forest Buffer Account will constitute a separate violation pursuant to section 96014.

(4) Early Project Terminations. If an early project termination, as defined in the Compliance Offset Protocol in section 95973(a)(2)(C)(4.), occurs from a forest offset project, and ARB offset credits have been issued to the offset project, the forest owner must submit to ARB for placement in the Retirement Account a quantity of valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4 in the amount determined pursuant to sections 95983(c)(4)(A), (B), or (C), whichever applies, for each Offset Project Data Report year:

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, the forest owner must turn in valid compliance instruments to cover the number of ARB offset credits issued to the offset project for each Reporting Period, except for improved forest management projects. If the project is an improved forest management project, the amount of metric tons CO_2e reversed must be multiplied by the compensation rate in the Compliance Offset Protocol in section 95973(a)(2)(C)(4.).

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, the forest owner must turn in valid compliance instruments according to the following equation, calculated for each Reporting Period, except for improved forest management projects:

$$FO_{Replace} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"$FO_{Replace}$" is the number of valid compliance instruments that the forest owner must turn in to compensate for the early project termination for each Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Offset Project Data Report year.

(C) For an improved forest management project that transitioned into the program originally from an Early Action Offset Program, the forest owner must replace ARB offset credits in the amount calculated pursuant to section 95983(c)(4)(B) multiplied by the compensation rate in the Compliance Offset Protocol in section 95973(a)(2)(C)4..

(D) ARB will notify the forest owner of how many ARB offset credits must be replaced with valid compliance instruments.

(E) The forest owner must submit to ARB for placement in the Retirement Account a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 for each ARB offset credit required to be replaced within six months of ARB's retirement.

(F) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments to ARB in the amount required pursuant to sections 95983(c)(4)(A) or (B) within six months of ARB's retirement, ARB will retire a quantity of ARB offset credits equal to the difference between the number of metric tons of CO_2e determined pursuant to sections 95983(c)(4)(A) or (B) and the number of retired approved compliance instruments from the Forest Buffer Account and they will be subject to enforcement action and each ARB offset credit retired from the Forest Buffer Account will constitute a separate violation pursuant to section 96014.

(d) Disposition of Forest Sequestration Projects After a Reversal. If a reversal lowers the forest offset project's actual standing live carbon stocks below its project baseline standing live carbon stocks, the forest offset project will be terminated by ARB or an Offset Project Registry.

(1) If the forest offset project is terminated due to an unintentional reversal, ARB will retire from the Forest Buffer Account a quantity of ARB offset credits equal to the total number of ARB offset credits issued pursuant to section 95981, and where applicable, all ARB offset credits issued to the offset project pursuant to section 95990(i) for early action, over the preceding 100 years.

(2) If the forest offset project is terminated due to an unintentional reversal, another offset project may be initiated and submitted to ARB or an Offset Project Registry for listing within the same offset project boundary.

(3) If the forest offset project has experienced an unintentional reversal and its actual standing live carbon stocks are still above the approved baseline levels, it may continue without termination as long as the unintentional reversal has been compensated by the Forest Buffer Account. The Offset Project Operator or Authorized Project Designee must continue contributing to the Forest Buffer Account in future years as quantified in section 95983(a)(1).

(4) If the forest offset project is terminated due to any reason except an unintentional reversal, new offset projects may not be initiated within the same offset project boundary, unless otherwise specified in a Compliance Offset Protocol.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95984. Ownership and Transferability of ARB Offset Credits.

(a) Initial ownership of an ARB offset credit will be with the registered Offset Project Operator, Authorized Project Designee, or another third party as requested by the Offset Project Operator pursuant to section 95981(b)(5)(B) to receive ARB offset credits, unless otherwise required by section 95983. An ARB offset credit may be sold, traded, or transferred, unless:

(1) It has been retired, surrendered for compliance, or used to meet any GHG mitigation requirements in any voluntary or regulatory program;

(2) It resides in the Forest Buffer Account pursuant to section 95983; or

(3) It has been invalidated pursuant to section 95985.

(b) An ARB offset credit may only be used:

(1) To meet a compliance obligation under this article, except if used by a covered entity in a program approved for linkage pursuant to subarticle 12; or

(2) By a Voluntarily Associated Entity for purposes of voluntary retirement.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95985. Invalidation of ARB Offset Credits.

(a) An ARB offset credit issued under this article will remain valid unless invalidated pursuant to this section.

(b) Timeframe for Invalidation. ARB may invalidate an ARB offset credit pursuant to this section within the following timeframe if a determination is made pursuant to section 95985(f):

(1) Within eight years of issuance of an ARB offset credit, if the ARB offset credit is issued for early action pursuant to section 95990(h), or within eight years of the date that corresponds to the end of the Reporting Period for which the ARB offset credit is issued, if the ARB offset credit

is issued pursuant to section 95981.1, unless one of the following requirements is met:

(A) The Offset Project Operator or Authorized Project Designee for an offset project developed under the Compliance Offset Protocol in section 95973(a)(2)(C)1. or an early action quantification methodology approved pursuant to section 95990(c)(5) for the same project type, does the following:

1. Has a different verification body that has not verified the Offset Project Data Report for the issuance of ARB offset credits, and meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a), conduct a second independent regulatory verification pursuant to sections 95977 through 95978, except for section 95977.1(b)(3)(M), for the same Offset Project Data Report, or as provided in sections 95990(l)(3)(B) and (l)(4) for projects developed under an approved early action quantification methodology. Although the requirements in section 95977.1(b)(3)(M) do not need to be met under this section, any misreporting, discrepancies, and omissions found during the full offset verification services must be included in the offset material misstatement calculation performed pursuant to section 95977.1(b)(3)(Q); and

2. The second regulatory verification must be completed within three years of the issuance of the ARB offset credits through the submittal of an Offset Verification Statement pursuant to section 95977.1(b)(3)(R)1., and the Offset Project Operator or Authorized Project Designee must receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same Offset Project Data Report, or as provided in section 95990(l)(3)(B) and (l)(4) for projects

developed under an approved early action quantification methodology.

a. If the offset project is listed with an Offset Project Registry, the verification body must submit the detailed verification report and Offset Verification Statement for the second regulatory verification to the Offset Project Registry and ARB.

b. The Offset Project Registry must review the offset verification documents pursuant to section 95987(e)(1)(E) and submit a report to ARB that includes the details and findings of the Offset Project Registry's review. During its review, the Offset Project Registry may request additional information from the verification body and Offset Project Operator or Authorized Project Designee, if applicable, and may request clarifications and revisions to the materials, if necessary.

c. The Offset Project Registry has 45 calendar days to review the offset verification information once complete and accurate verification documents are received from the verification body.

d. The Offset Project Registry has an additional 15 working days to submit its report to ARB. ARB will review the Offset Project Registry report and determine based on the report and all the information submitted by the verification body and Offset Project Operator or Authorized Project Designee, if applicable, if the invalidation timeframe will be reduced. During its review, ARB may request additional information, clarifications, and revisions to the materials, if necessary.

3. If the requirements in sections 95985(b)(1)(A)1. and 2. are met, the ARB offset credits issued under the Offset Project Data Report may only be subject to invalidation according to the following timeframes:

   a. Within three years of the date that corresponds to the end of the Reporting Period for which the ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95981; and

   b. Within three years of the date for which ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95990(h); or

(B) The Offset Project Operator or Authorized Project Designee for an offset project developed under one of the protocols listed in section 95985(b)(1)(B)5. does the following:

1. Has a subsequent Offset Project Data Report verified pursuant to sections 95977 through 95978 by a different verification body than the one which conducted the most recent verification, and that meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a), or as provided in section 95990(l)(3)(A) for projects developed under an approved early action quantification methodology; and

2. The verification conducted by a different verification body for the subsequent Offset Project Data Report and used to reduce the invalidation timeframe of any ARB offset credits must be completed through the submittal of an Offset Verification Statement pursuant to section 95977.1(b)(3)(R)1. within, at a maximum, three years from the date that corresponds to the last time ARB offset credits were issued to the offset project, or as provided in section

95990(l)(3)(A) for projects developed under an approved early action quantification methodology. The verification of the subsequent Offset Project Data Report must result in a Positive or Qualified Positive Offset Verification Statement from the new verification body.

3. If the requirements in sections 95985(b)(1)(B)1. and 2. are met, the ARB offset credits issued for no more than three Reporting Periods prior to the Reporting Period for which the subsequent Offset Project Data Report was verified by a different verification body, may only be subject to invalidation according to the following timeframes:

   a. Within three years of the date that corresponds to the end of the Reporting Period for which the ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95981; and

   b. Within three years of the date for which ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95990(h).

4. If an offset project developed under one of the Compliance Offset Protocols listed in section 95985(b)(1)(B)5. is in the last year of a crediting period, and will not have a renewed crediting period, the statute of limitations may be reduced from eight years to three years if the following requirements are met for the last Offset Project Data Report of the crediting period:

   a. The Offset Project Operator or Authorized Project Designee has a different verification body than has verified the last Offset Project Data Report of the crediting period for the issuance of ARB offset credits for the Reporting Period and that meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a) conduct a second independent regulatory verification pursuant to sections 95977 through 95978, except for section 95977.1(b)(3)(M), for the last Offset Project Data Report of the crediting period. Although the requirements in section 95977.1(b)(3)(M) do not need to be met under this section, any misreporting, discrepancies, and omissions found during the full offset verification services must be included in the offset material misstatement calculation performed pursuant to section 95977.1(b)(3)(Q); and

b. The second regulatory verification must be completed within three years of the issuance of the ARB offset credits through the submittal of an Offset Verification Statement pursuant to section 95977.1(b)(3)(R)1. and the Offset Project Operator or Authorized Project Designee must receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same last Offset Project Data Report.

i. If the offset project is listed with an Offset Project Registry, the verification body must submit the detailed verification report and Offset Verification Statement for the second regulatory verification to the Offset Project Registry and ARB.

ii. The Offset Project Registry must review the offset verification documents pursuant to section 95987(e)(1)(E) and submit a report to ARB that includes the details and findings of the Offset Project Registry's review. During its review, the Offset Project Registry may request additional information from the verification body and Offset Project Operator or Authorized Project Designee, if applicable, and may request clarifications and revisions to the materials, if necessary.

iii. The Offset Project Registry has 45 calendar days to review the offset verification information once complete and accurate verification documents are received from the verification body.

iv. The Offset Project Registry has an additional 15 working days to submit its report to ARB. ARB will review the Offset Project Registry report and determine based on the report and all the information submitted by the verification body and Offset Project Operator or Authorized Project Designee, if applicable, and may request additional information, clarifications, and revisions to the materials, if necessary.

5. The provisions in sections 95985(b)(1)(B)1. through 4. apply if an offset project is developed under one of the following Compliance Offset Protocols, and the provisions in sections 95985(b)(1)(B)1. through 3. apply for any early action quantification methodologies approved pursuant to section 95990(c)(5) for the same project types, as well as any applicable provisions in section 95990(l)(3)(A):

a. The Compliance Offset Protocols in section 95973(a)(2)(C)2.;

b. The Compliance Offset Protocols in section 95973(a)(2)(C)3.;

c. The Compliance Offset Protocols in section 95973(a)(2)(C)4.;

d. The Compliance Offset Protocols in section 95973(a)(2)(C)5.; or

e. The Compliance Offset Protocol in section 95973(a)(2)(C)6.

(c) Grounds for Initial Determination of Invalidation. ARB may determine that an ARB offset credit is invalid for the following reasons:

(1) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than 5.00 percent;

(A) If ARB finds that there has been an overstatement by more than 5.00 percent, ARB shall determine how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period. Within 10 calendar days of this determination, ARB will notify the verification body that performed the offset verification and the Offset Project Operator or Authorized Project Designee. Within 25 calendar days of receiving the written notification by ARB, the verification body shall provide any available offset verification services information or correspondence related to the Offset Project Data Report. Within 25 calendar days of receiving the written notification by ARB, the Offset Project Operator or Authorized Project Designee shall provide data that is required to calculate GHG reductions and GHG removal enhancements for the offset project according to the requirements of this article, the detailed offset verification report prepared by the verification body, and other information requested by ARB. The Offset Project Operator or Authorized Project Designee shall also make available personnel who can assist ARB's determination of how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period.

1. ARB will determine the actual GHG reductions and GHG removal enhancements achieved by the offset project for the applicable Reporting Period based on, at a minimum, the following information:
   a. The GHG sources, GHG sinks, and GHG reservoirs within the offset project boundary for that Reporting Period; and
   b. Any previous Offset Project Data Reports submitted by the Offset Project Operator or Authorized Project Designee, and the Offset Verification Statements rendered for those reports.
2. In determining how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period, ARB may use the following methods, as applicable:
   a. The applicable Compliance Offset Protocol;
   b. In the event of missing data, ARB will rely on the missing data provisions pursuant to section 95976, and, if applicable, the Compliance Offset Protocol; and
   c. Any information reported under this article for this Reporting Period and past Reporting Periods.
3. ARB shall determine how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period using the best information available, including the information in section 95985(c)(1)(A)(1.) and methods in section 95985(c)(1)(A)(2.), as applicable.

(B) If ARB determines that an overstatement has occurred pursuant to section 95985(c)(1), ARB shall determine the amount of ARB offset credits that correspond to the overstatement using the following equation, rounded to the nearest whole ton:

If: $I_{ARBOC} > R_{OPDR} \times 1.05$

Then: $O_R = I_{ARBOC} - R_{OPDR}$

Where:

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements for the applicable Offset Project Data Report, rounded to the nearest whole ton;

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"R_{OPDR}" is the number of GHG reductions and GHG removal enhancements determined by ARB pursuant to section 95985(c)(1) for the applicable Offset Project Data Report;

(2) The offset project activity and implementation of the offset project was not in accordance with all local, state, or national environmental and health and safety regulations during the Reporting Period for which the ARB offset credit was issued; or

(3) ARB determines that offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary and for the same Reporting Period in which ARB offset credits were issued for GHG reductions and GHG removal enhancements.

(4) The following shall not be grounds for invalidation:

(A) An update to a Compliance Offset Protocol will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol; or

(B) A reversal that occurs under a forest offset project. If such a reversal occurs the provisions in section 95983 apply.

(d) Suspension of Transfers. When ARB makes an initial determination pursuant to section 95985(c) it will immediately block any transfers of ARB offset credits for the applicable Offset Project Data Report. Once ARB makes a final determination pursuant to section 95985(f) the block on transfers for any valid ARB offset credits will be cancelled.

(e) Identification of Affected Parties. If ARB makes an initial determination that one of the circumstances listed in section 95985(c) has occurred, ARB will identify the following parties:

(1) The current holders that hold any ARB offset credits in their Holding and/or Compliance Accounts from the applicable Offset Project Data Report;

(2) The entities for which ARB transferred any ARB offset credits from the applicable Offset Project Data Report into the Retirement Account; and

(3) The Offset Project Operator and Authorized Project Designee, and, for forest offset projects the Forest Owner(s).

(f) Final Determination and Process of Invalidation. ARB will notify the parties identified in section 95985(e) of its initial determination pursuant to section 95985(c), and provide each party an opportunity to submit additional information to ARB prior to making its final determination, as follows:

(1) ARB will include the reason for its initial determination in its notification to the parties identified in section 95985(e).

(2) After notification the parties identified in section 95985(e) will have 25 calendar days to provide any additional information to ARB.

(3) ARB may request any information as needed in addition to the information provided under this section.

(4) The Executive Officer will have 30 calendar days after all information is submitted under this section to make a final determination that one or

more conditions listed pursuant to section 95985(c) has occurred and whether to invalidate ARB offset credits.

(A) The parties identified pursuant to section 95985(e) will be notified of ARB's final determination of invalidation pursuant to this section.

(B) Any approved program for linkage pursuant to subarticle 12 will be notified of the invalidation at the time of ARB's final determination pursuant to this section.

(g) Removal of Invalidated ARB Offset Credits from Holding and/or Compliance Accounts. If the Executive Officer makes a final determination pursuant to section 95985(f) that an ARB offset credit is invalid, then:

(1) ARB offset credits will be removed from any Holding or Compliance Account, as follows;

(A) If an ARB offset credit is determined to be invalid due to the circumstance listed in section 95985(c)(1), then:

1. ARB will determine which ARB offset credits will be removed from the Compliance and/or Holding Accounts of each party identified in section 95985(e)(1) according to the following equation, truncated to the nearest whole ton:

$$H_{ARBOC} = \left|\frac{TOT_{Holding}}{I_{ARBOC}}\right| O_R$$

Where:

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements for the applicable Offset Project Data Report calculated pursuant to section 95985(c)(1);

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"$TOT_{Holding}$" is the total number of ARB offset credits currently being held in a Compliance and/or Holding Account by each party identified in section 95985(e)(1) for the applicable Offset Project Data Report;

"H_{ARBOC}" is the total number of ARB offset credits, rounded to the nearest whole ton, that will be removed from the Holding and/or Compliance Account of each party identified in section 95985(e)(1).

2. ARB will determine the quantity of ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(g)(1)(A) and remove a quantity of ARB offset credits from any Holding and/or Compliance Account of the parties identified in section 95985(e)(1).

(B) If an ARB offset credit is determined to be invalid due to the circumstances listed in sections 95985(c)(2) or (c)(3), ARB will remove all ARB offset credits issued under the applicable Offset Project Data Report from any Holding and/or Compliance Account of the parties identified in section 95985(e)(1).

(2) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were removed from any Compliance and/or Holding Accounts.

(3) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were removed from any Compliance and/or Holding Accounts.

(h) Requirements for Replacement of ARB Offset Credits.

(1) If an ARB offset credit that is issued to a non-sequestration offset project or an urban forest offset project, or that is issued to a U.S. forest offset project on or afterJuly 1, 2014, and is in the Retirement Account, and it is determined to be invalid pursuant to section 95985(f) for only the circumstance listed in section 95985(c)(1), then:

(A) Each party identified in section 95985(e)(2) must replace ARB offset credits in the amount calculated for the individual party according to the following equation, truncated to the nearest whole ton:

$$R_{ARBOC} = \left|\frac{TOT_{Retired}}{I_{ARBOC}}\right| O_R$$

Where:

"R_{ARBOC}" is the calculated total number of retired ARB offset credits for the applicable Offset Project Data Report, rounded to the nearest whole ton, that must be replaced by each individual party identified in section 95985(e)(2);

"$TOT_{Retired}$" is the total number of ARB offset credits for which ARB transferred the ARB offset credits from the applicable Offset Project Data Report into the Retirement Account for the individual party specified in section 95985(e)(2);

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements calculated pursuant to section 95985(c)(1) for the applicable Offset Project Data Report.

(B) Each party identified in section 95985(e)(2) must replace ARB offset credits in the amount calculated pursuant to section 95985(h)(1)(A) with valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(C) If each party identified in section 95985(e)(2) does not replace each invalid ARB offset credit in the amount calculated pursuant to section 95985(h)(1)(A) within six months of notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that party pursuant to section 96014.

1. If the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2) of MRR, ARB will require the Offset Project Operator to replace each invalidated ARB offset credit and will notify the Offset Project Operator that they must replace them.

2. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(1)(C)1., the Offset Project Operator must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(h)(1)(C)1.

3. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(1)(C)1., and the Offset Project Operator does not replace each invalid ARB offset credit within six months of notification by ARB pursuant to section 95985(h)(1)(C)1., each unreplaced invalidated ARB offset credit will constitute a violation for that Offset Project Operator pursuant to section 96014.

(D) ARB will determine the quantity of ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(h)(1)(A) and invalidate that quantity of ARB offset credits.

(E) The parties identified pursuant to section 95985(e) will be notified of the quantity of ARB offset credits that were invalidated.

(F) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(2) If an ARB offset credit that is issued to a non-sequestration offset project or an urban forest project, or that is issued to a U.S. forest offset project on or after July 1, 2014, and is in the Retirement Account, and it is determined to be invalid pursuant to section 95985(f) for any circumstance listed in sections 95985(c)(2) and (c)(3), then:

(A) The party identified in section 95985(e)(2) must replace each ARB offset credit it requested ARB to transfer into the Retirement Account for the applicable Offset Project Data Report with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(B) If the party identified in section 95985(e)(2) does not replace each invalid ARB offset credit within six months of the notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that party pursuant to section 96014.

1. If the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2) of MRR ARB will require the Offset Project Operator to replace each invalidated ARB offset credit and will notify the Offset Project Operator that they must replace them.

2. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(2)(B)1., the Offset Project Operator must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(h)(2)(B)(1.).

3. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(2)(B)1., and the Offset Project Operator does not replace each invalid ARB offset credit within six months of notification by ARB pursuant to section 95985(h)(2)(B)1., each unreplaced invalidated ARB offset credit will constitute a violation for that Offset Project Operator pursuant to section 96014.

(C) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were invalidated.

(D) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(i) Requirements for Replacement of ARB Offset Credits for U.S. Forest Offset Projects Issued on or prior to July 1, 2014.

(1) If an ARB offset credit that is issued on or prior to July 1, 2014 is in the Retirement Account from a U.S. forest offset project and it is determined to be invalid pursuant to section 95985(f) for only the circumstance listed in section 95985(c)(1), then:

(A) The Forest Owner identified in section 95985(e)(3) must replace ARB offset credits in the amount calculated according to the following equation, truncated to the nearest whole ton:

$$RF_{ARBOC} = \left|\frac{TF_{Retired}}{IF_{ARBOC}}\right| OF_R$$

Where:

"RF_{ARBOC}" is the total number of retired ARB offset credits for the applicable U.S. forest offset project's Offset Project Data Report, rounded to the nearest whole ton, that must be replaced by the Forest Owner;

"$TF_{Retired}$" is the total number of ARB offset credits issued for the applicable U.S. forest offset project's Offset Project Data Report for which ARB transferred any ARB offset credits from into the Retirement Account;

"IF_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report for the U.S. forest offset project pursuant to section 95981.1 or 95990(i);

"OF_R" is the amount of overstated GHG reductions and GHG removal enhancements calculated pursuant to section 95985(c)(1) for the U.S. forest offset project for the applicable Offset Project Data Report.

(B) The Forest Owner identified in section 95985(e)(3) must replace ARB offset credits in the amount calculated pursuant to section 95985(i)(1)(A) with valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(C) If the Forest Owner identified in section 95985(e)(3) does not replace each invalid ARB offset credit in the amount calculated pursuant to section 95985(i)(1)(A) within six months of notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that Forest Owner pursuant to section 96014.

(D) ARB will determine the lowest serial numbers assigned to ARB offset credits issued under the applicable Offset Project Data

Report in the amount calculated pursuant to section 95985(i)(1)(A) and invalidate those serial numbers.

(E) The Forest Owner identified pursuant to section 95985(e)(3) will be notified of which serial numbers were invalidated.

(F) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(2) If an ARB offset credit issued on or prior to July 1, 2014 in the Retirement Account from a U.S. forest offset project is determined to be invalid pursuant to section 95985(f) for any circumstance listed in sections 95985(c)(2) and (c)(3):

(A) The Forest Owner must replace each ARB offset credit transferred by ARB into the Retirement Account for the applicable Offset Project Data Report with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(B) If the Forest Owner does not replace each invalid ARB offset credit within six months of the notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that Forest Owner pursuant to section 96014.

(C) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were invalidated.

(D) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(j) Nothing in this section shall limit the authority of the State of California from pursuing enforcement action against any parties in violation of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95986. Executive Officer Approval Requirements for Offset Project Registries.

(a) The approval requirements specified in this subarticle apply to all Offset Project Registries that will operate to provide registry services under this article.

(b) The Executive Officer may approve Offset Project Registries that meet and maintain the requirements specified in this section.

(1) Offset Project Registry Approval Application. To apply for approval as an Offset Project Registry, the applicant shall submit the following information to the Executive Officer:

(A) Name of applicant;

(B) Name of president or chief executive officer;

(C) List of all board members, if applicable;

(D) Addresses of offices located in the United States;

(E) Documentation that the applicant carries at least five million U.S. dollars of professional liability insurance; and

(F) List of any judicial proceedings and administrative actions filed against the applicant within the previous five years, with a detailed explanation as to the nature of the proceedings.

(2) The applicant must submit, in writing, the procedures to screen and address internal conflicts of interest. The applicant must provide the following information to the Executive Officer:

(A) A staff, management, and board member conflict of interest policy where there are clear criteria for what constitutes a conflict of interest. The policy must:

1. Identify specific activities and limits on monetary and non-monetary gifts staff, management, or board members must not conduct or accept to meet the Offset Project Registry's internal policies of conflict of interest policy, or alternatively provide a comprehensive policy on the applicant's

requirements for the reporting of any and all conflicts based on internal policies that guard against conflict of interest; and

2. Include a requirement for annual disclosure by each staff, management, or board member of any items or instances that are covered by the applicant's conflict of interest policy on an ongoing basis or for the previous calendar year.

3. The applicant must have appropriate conflict of interest and confidentiality requirements in place for any of its contractors;

(B) List of all service types provided by the applicant;

(C) The industrial sectors the applicant serves;

(D) Locations where services are provided; and

(E) A detailed organizational chart that includes the applicant and any parent, subsidiary, and affiliate companies.

(F) If the applicant under section 95986 is going to designate a subdivision of its organization to provide registry services, then the prohibition in section 95986(c)(1) on serving as an offset project consultant shall apply at the subdivision level and the applicant must provide the following general information for its self:

1. General types of services; and

2. General locations where services are provided.

(3) The applicant has the following capabilities for registration and tracking of registry offset credits issued under this article:

(A) A comprehensive registration requirement for all registry participants;

(B) Tracking ownership and transactions of all registry offset credits it issues at all times; and

(C) Possesses a permanent repository of ownership information on all transactions involving all registry offset credits it issues under this article from the time they are issued to the time they are retired or cancelled.

(c) The applicant's primary business must be operating an Offset Project Registry for voluntary or regulatory purposes and meet the following business requirements:

(1) The applicant may not act as an Offset Project Operator, Authorized Project Designee, or offset project consultant for offset projects registered or listed on its own Offset Project Registry and developed using a Compliance Offset Protocol once approved as an Offset Project Registry. The applicant must annually disclose to ARB any non-offset project related consulting services it provides to an Offset Project Operator or Authorized Project Designee who lists a project using a Compliance Offset Project with the applicant as part of the information included in the annual report required in section 95987(j);

(2) The applicant may not act as a verification body or provide offset verification services pursuant to sections 95977.1 and 95977.2 once approved as an Offset Project Registry;

(3) If the applicant designates a subdivision of its organization to provide registry services, the applicant may not be an Offset Project Operator or Authorized Project Designee for offset projects listed at the subdivision's registry, act as a verification body, or be a covered entity or opt-in covered entity;

(4) The applicant must demonstrate experience in the continuous operation of a registry serving an Environmentally-focused Market for a minimum of two years in a regulatory and/or voluntary market. For the purposes of this section, an "Environmentally-focused Market" means a market that includes the trading of carbon-emissions based commodities. In the context of Air Quality Management Districts or Air Pollution Control Districts, "Environmentally-focused Market" includes a market for air emission reduction credits; and

(5) The applicant's primary incorporation or other business formation and primary place of business, or the primary place of business of the designated subdivision, if the applicant designates a subdivision to provide registry services pursuant to this section, must be in the United States of America.

(d) The Offset Project Registry must continue to maintain the professional liability insurance required in section 95986(b) while it provides registry services to Offset Project Operators or Authorized Project Designees who are implementing offset projects using Compliance Offset Protocols.

(e) If any information submitted pursuant to sections 95986(b) through (d) changes after the approval of an Offset Project Registry, the Offset Project Registry must notify the Executive Officer within 30 calendar days and provide updated information consistent with that required in sections 95986(b) through (d).

(f) The Offset Project Registry must attest, in writing, to ARB as follows:

(1) "As the authorized representative for this Offset Project Registry, I understand that the Offset Project Registry is voluntarily participating in the California Cap-and-Trade Program under title 17, article 5, and the Offset Project Registry is now subject to all regulatory requirements and enforcement mechanisms of this program.";

(2) "All information generated and submitted to ARB by the Offset Project Registry related to an offset project that uses a Compliance Offset Protocol will be true, accurate, and complete.";

(3) "All information provided to ARB as part of an ARB audit of the Offset Project Registry will be true, accurate, and complete.";

(4) "All registry services provided will be in accordance with the requirements of section 95987.";

(5) "The Offset Project Registry is committed to participating in all ARB training related to ARB's compliance offset program or Compliance Offset Protocols."; and

(6) The authorized representative of the Offset Project Registry must attest in writing, to ARB: "I certify under penalty of perjury under the laws of the State of California I have authority to represent the Offset Project Registry and all information provided as part of this application is true, accurate, and complete.".

(g) At least two of the management staff at the Offset Project Registry must take ARB provided training on ARB's compliance offset program and pass an examination upon completion of training.

(h) The Offset Project Registry must have staff members who have collectively completed ARB training and passed an examination upon completion of training in all Compliance Offset Protocols.

(i) The Offset Project Registry must have at least two years of demonstrated experience in, and requirements for, direct staff oversight and review of offset projects, project listing, offset verification, and registry offset credit issuance.

(j) ARB Approval.

(1) Within 60 calendar days of receiving an application for approval as an Offset Project Registry and completion by all management staff of the training required in section 95986(g), the Executive Officer will inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) The applicant may be allowed to submit additional supporting documentation before a decision is made by the Executive Officer.

(3) Within 60 calendar days following completion of the application process, the Executive Officer shall approve an Offset Project Registry if evidence of qualification submitted by the applicant has been found to meet the requirements of section 95986 and issue an Executive Order to that effect.

(4) The Executive Officer and the applicant may mutually agree, in writing, to longer time periods than those specified in subsections 95986(j)(1) and 95986(j)(3).

(5) The Executive Officer approval for an Offset Project Registry is valid for a period of 10 years, whereupon the applicant may re-apply. At the time of re-application, the Offset Project Registry must:

(A) Demonstrate it consistently met all of the requirements in section 95986;

(B) Pass a performance review, which, at a minimum shows the Offset Project Registry consistently:

1. Demonstrates knowledge of the ARB compliance offset program and Compliance Offset Protocols;

2. Meets all regulatory deadlines; and

3. Provides registry services in accordance with the requirements of this article; and

(C) Not have been subject to enforcement action under this article.

(k) Modification, Suspension, and Revocation of an Executive Order Approving an Offset Project Registry. The Executive Officer may review, and, for good cause, modify, suspend, or revoke an Executive Order providing approval to an Offset Project Registry.

(1) During revocation proceedings, the Offset Project Registry may not continue to provide registry services for ARB.

(2) Within five working days of suspension or revocation of approval, an Offset Project Registry must notify all Offset Project Operators or Authorized Project Designees for whom it is providing registry services, or has provided registry services within the past 12 months, of its suspension or revocation of approval.

(3) An Offset Project Operator or Authorized Project Designee who has been notified by an Offset Project Registry of a suspended or revoked approval must re-submit its offset project information with a new Offset Project Registry or ARB. An offset project listed at ARB or a new

Offset Project Registry will continue to operate under its originally approved crediting period, provided that ARB may extend the crediting period or the relevant deadline in section 95977(d) for one year if ARB determines that such extension is necessary to provide time for re-submission of information to the new Offset Project Registry or ARB.

(m) If the applicant under section 95986 is going to designate a subdivision of its organization to provide registry services, all the requirements of section 95986 may be applied at the designated subdivision level.

(n) An approved Offset Project Registry must make itself and its personnel available for an ARB audit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95987. Offset Project Registry Requirements.

(a) The Offset Project Registry shall use Compliance Offset Protocols approved pursuant to section 95971 to determine whether an offset project may be listed with the Offset Project Registry for issuance of registry offset credits. The Offset Project Registry may list projects under non-Compliance Offset Protocols, but must make it clear any GHG emission reductions and GHG removal enhancements achieved under those protocols are not eligible to be issued registry offset credits or ARB offset credits.

(b) The Offset Project Registry must make the following information publicly available for each offset project developed under a Compliance Offset Protocol:

(1) Within 10 working days of the offset project listing requirements being deemed complete in section 95975(f):

(A) Offset project name;

(B) Offset project location;

(C) Offset Project Operator and, if applicable, the Authorized Project Designee;

(D) Type of offset project;

(E) Name and date of the Compliance Offset Protocol used by the offset project;

(F) Date of offset project listing submittal and Offset Project Commencement date; and

(G) Identification if the offset project is in an initial or renewed crediting period;

(2) Within 10 working days of the Offset Project Registry making a determination of registry offset credit issuance pursuant to section 95980(b):

(A) Annual verified project baseline emissions;

(B) Annual verified GHG reductions and GHG removal enhancements achieved by the offset project;

(C) The unique serial numbers of registry offset credits issued to the offset project for the applicable Offset Project Data Report;

(D) Total verified GHG reductions and GHG removal enhancements for the offset project by Reporting Period for when an Offset Project Data Report was submitted;

(E) The final Offset Project Data Report for each Reporting Period; and

(F) Offset Verification Statement for each year the Offset Project Data Report was verified; and

(3) Clear identification of which offset projects are listed and submitting Offset Project Data Reports using Compliance Offset Protocols.

(c) Conflict of Interest Review by Offset Project Registries. The Offset Project Registry must apply the conflict of interest requirements in section 95979 when making a conflict of interest determination for a verification body proposing to conduct offset verification services under sections 95977.1 and 95977.2. The Offset Project Registry must review and make sure the conflict of interest submittal in section 95979(e) is complete. When an Offset Project Operator or Authorized Project Designee submits its information pursuant to section 95981(b) to ARB, the Offset Project Registry must provide ARB with the information and attestation identified in section 95979(e) within 15 calendar days.

(d) The Offset Project Registry may provide guidance to Offset Project Operators, Authorized Project Designees, or offset verifiers for offset projects using a Compliance Offset Protocol, if there is no clear requirement for the topic in a Compliance Offset Protocol, this article, or an ARB guidance document, after consulting and coordinating with ARB.

(1) An Offset Project Registry must maintain all correspondence and records of communication with an Offset Project Operator, Authorized Project Designee, or offset verifier when providing clarifications or guidance for an offset project using a Compliance Offset Protocol.

(2) Before providing such guidance, the Offset Project Registry may request ARB to provide clarification on the topic.

(3) Any Offset Project Operator or Authorized Project Designee requests for clarifications or guidance must be documented and the Offset Project Registry response must be submitted on an ongoing monthly basis to ARB beginning with the date of approval as an Offset Project Registry.

(e) The Offset Project Registry must audit at least 10 percent of the annual full offset verifications developed for offset projects using a Compliance Offset Protocol.

(1) The audit must include the following checks:

(A) Attendance with the offset verification team on the offset project site visit;

(B) In-person or conference call attendance for the first offset verification team and Offset Project Operator or Authorized Project Designee meeting;

(C) In-person or conference call attendance to the last meeting or discussion between the offset verification team and Offset Project Operator or Authorized Project Designee;

(D) Documentation of any findings during the audit that cause the Offset Project Registry to provide guidance to, or require corrective action with, the offset verification team, including a list of issues noted during the audit and how those were resolved;

(E) A review of the detailed verification report and sampling plan to ensure that it meets the minimum requirements in sections 95977.1 and 95977.2 and documentation of any discrepancies found during the review; and

(F) An investigative review of the conflict of interest assessment provided by the verification body, which includes the following:

1. Discussions with both the lead verifier who submitted the conflict of interest assessment form and the Offset Project Operator or Authorized Project Designee to confirm the information on the conflict of interest assessment form is true, accurate, and complete;

2. An internet-based search to ascertain the existence of any previous relationship between the verification body and the Offset Project Operator or Authorized Project Designee, and if so the nature and extent; and

3. Any other follow up by the Offset Project Registry to have reasonable assurance that the information provided on the conflict of interest assessment form is true, accurate, and complete.

(2) All information related to audits of offset projects developed using a Compliance Offset Protocol must be provided to ARB within 10 calendar days of an ARB request.

(3) The audits must be selected to provide a representative sampling of geographic locations of all offset projects, representative sampling of

verification bodies, representative sampling of lead verifiers, representative sampling of offset project types, and representative sampling of offset projects by size.

(4) The Offset Project Registry must provide an annual report to ARB by January 31 for its previous year's audit program of offset projects developed using Compliance Offset Protocols that includes:

(A) A list of all offset projects audited;

(B) Locations of all offset projects audited;

(C) Verification bodies associated with each offset project and names of offset verification team members;

(D) Dates of site visits;

(E) Offset Project Registry staff that conducted the audit; and

(F) Audit findings as required in section 95987(e)(1)(D) through (F).

(f) The Offset Project Registry must review each detailed verification report provided in section 95977.1(b)(3)(R)(4.)(a.) for completeness and accuracy and to ensure it meets the requirements of section 95977.1(b)(3)(R)(4.)(a.) before accepting the associated Offset Verification Statement for the Offset Project Data Report and issuing registry offset credits.

(g) The Offset Project Registry must provide all information in its possession, custody, or control related to a listed offset project under a Compliance Offset Protocol within 10 calendar days of request by ARB.

(h) The Offset Project Registry must make its staff and all information related to listed offset projects under Compliance Offset Protocols by the Offset Project Registry available to ARB during any audits or oversight activities initiated by ARB to ensure the requirements in section 95987 are being carried out as required by this article.

(i) The Offset Project Registry must remove or cancel any registry offset credits issued for an offset project using a Compliance Offset Protocol, such that the registry offset credits are no longer available for transaction on the Offset Project Registry system, once notified by ARB that the offset project is eligible to be issued ARB offset credits.

(j) The Offset Project Registry must provide an annual report by January 31 of the previous year's offset projects that are listed using a Compliance Offset Protocol. The report must contain the name of the offset project, type of offset project and applicable Compliance Offset Protocol, name of Offset Project Operator or Authorized Project Designee, location of offset project, status of offset project, associated verification body, crediting period, amount of any registry offset credits issued to date, amount of any registry offset credits retired or cancelled for the offset project by the Offset Project Registry to date.

(k) The Offset Project Registry may choose to offer insurance or other products to cover the risk of invalidation of ARB offset credits, but purchase or use of the insurance or other invalidation risk mechanisms will be optional for all entities involved with registry offset credits and ARB offset credit transactions.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95988. Record Retention Requirements for Offset Project Registries.

All information submitted, and correspondence related to, listed offset projects under Compliance Offset Protocols by the Offset Project Registry must be maintained by the Offset Project Registry for a minimum of 15 years.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 14: Recognition of Compliance Instruments from Other Programs

§ 95990. Recognition of Early Action Offset Credits.

(a) Approval of Early Action Offset Programs. To qualify as an Early Action Offset Program, either the Executive Officer shall issue an Executive Order pursuant to section 95986(j) or the program must demonstrate to ARB that it meets the following requirements:

(1) The program must provide documentation that it carries at least one million U.S. dollars of professional liability insurance.

(2) The program must have the following capabilities for registration and tracking of offset credits:

(A) A registration requirement for all registry participants;

(B) A system for tracking ownership and transactions of all early action offset credits it issues under the quantification methodologies listed pursuant to section 95990(c)(5) at all times; and

(C) A permanent repository of ownership information on all transactions involving all early action offset credits that have been or will be issued for any early action offset project until they are retired or cancelled.

(3) The program's primary business (or that of the designated subdivision, if the Early Action Offset Program applicant designates a subdivision to provide services as an Early Action Offset Program pursuant to this section) is operating a registry for issuing offset credits for voluntary or regulatory purposes and must meet the following business requirements:

(A) The Early Action Offset Program may not act as an Offset Project Operator, Authorized Project Designee, or offset project consultant for early action offset projects registered on its own registry system and developed under protocols approved pursuant 95990(c)(5). The Early Action Offset Program applicant may act as an offset project consultant for early action offset projects as long as these are registered with an Early

Action Offset Program or an Offset Project Registry unaffiliated with the applicant;

(B) The applicant may not act as a verification body and provide offset verification services pursuant to section 95990(f);

(C) If the applicant designates a subdivision of its organization to provide registry services, the applicant may not be an Offset Project Operator or Authorized Project Designee for offset projects listed at the subdivision's registry, act as a verification body, or be a covered entity or opt-in covered entity; and

(D) The applicant's primary incorporation or other business information and primary place of business, or the primary place of business of the designated subdivision, if the applicant designates a subdivision to be an Early Action Offset Program pursuant to this section, must be in the United States of America.

(4) The program must agree to submit to ARB the original documentation submitted by an Offset Project Operator or Authorized Project Designee or third-party verifier regarding the early action offset project, including registration documentation, sampling plans, and Early Action Verification Reports.

(5) The program must agree to retire, and not allow for further use, any early action offset credits it issues when retired or used in any voluntary or regulatory program, including when ARB requests retirement for ARB offset credit issuance pursuant to section 95990(i).

(6) An authorized representative of the Early Action Offset Program must attest in writing, to ARB, as follows:

"I certify under penalty of perjury under the laws of the State of California the information provided in demonstrating this program meets the requirements in section 95990(a) and is true, accurate, and complete."

(b) ARB shall accept early action offset credits from early action offset projects registered with Early Action Offset Programs approved pursuant to section 95990(a), if the early action offset credits meet the criteria set forth in this section.

(c) Criteria for Approval of Early Action Offset Credits Issued by Early Action Offset Programs. An early action offset credit may be issued an ARB offset credit pursuant to section 95990(i) if the early action offset credit results from a GHG reduction or GHG removal enhancement which:

(1) Occurred between January 1, 2005 and December 31, 2014 or between January 1, 2005 and December 31, 2015 for projects developed under any of the offset quantification methodologies in section 95990(c)(5)(H);

(2) Is verified pursuant to section 95990(f);

(3) Results from an early action offset project that is listed or registered with an Early Action Offset Program prior to the following:

(A) Early action offset projects developed under any of the offset quantification methodologies in sections 95990(c)(5)(A) through (D) must be listed with an Early Action Offset Program prior to January 1, 2014;

(B) Early action offset projects developed under any of the offset quantification methodologies in sections 95990(c)(5)(E) through (G) must be listed with an Early Action Offset Program prior to January 1, 2015; and

(C) Early action offset projects developed under any of the offset quantification methodologies in section 95990(c)(5)(H) must be listed by January 1, 2016.

(4) Results from an early action offset project located in the United States; and

(5) Results from the use of one of the following offset quantification methodologies and relied on the most recent version thereof at the time of offset project submittal:

(A) Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0;

(B) Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1;

(C) Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0;

(D) Climate Action Reserve Forest Project Protocol versions 2.1 and 3.0 through 3.2, if the early action offset project contributes early action offset credits into a buffer account based on its reversal risk calculated according to the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4;

(E) Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1;

(F) Verified Carbon Standard VMR0001 Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology, v1.0;

(G) Verified Carbon Standard VMR0002 Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0; or

(H) American Carbon Registry Voluntary Emission Reductions in Rice Management Systems Parent Methodology, version 1.0:

1. American Carbon Registry Voluntary Emission Reductions in Rice Management Systems – California Module, version 1.0; and

2. American Carbon Registry Voluntary Emission Reductions in Rice Management Systems – Mid-South Module, version 1.0.

(d) The following parties must register with ARB pursuant to section 95830 before ARB offset credits may be issued pursuant to section 95990(i):

(1) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(2) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(d)(3):

(A) A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);

(B) An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A), (C), (E), (F), and (G).

(3) The holder of early action offset credits, if the holder lists the early action offset project pursuant to section 95990(e) or seeks the issuance of ARB offset credits pursuant to section 95990(i) and provides ARB with the attestations required pursuant to section 95990(h)(6).

(e) Listing of Early Action Offset Projects. Before ARB can evaluate conflict of interest and any verification related information submitted pursuant to section 95990(f), and issue ARB offset credits pursuant to section 95990(i):

(1) The following parties must submit the information listed in section 95990(e)(2) to ARB:

(A) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(B) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(e)(1)(C);

1. A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);
2. An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A), (C), (E), (F), and (G).

(C) If the Offset Project Operator or Authorized Project Designees identified in section 95990(e)(1)(B) do not list the early action offset project, the holder of early action offset credits may list the early action offset credit by submitting the information listed in section 95990(e)(2), as long as the following conditions are met:

1. The holder registers with ARB pursuant to section 95990(d); and
2. The holder has made at least one written request to the Offset Project Operator or Authorized Project Designee to confirm that the Offset Project Operator or Authorized Project Designee will not list the applicable early action reporting periods for the early action offset project, and has provided proof of this request, and response, or at least 30 days has passed since the request to ARB.

(2) The parties identified in section 95990(e)(1) must submit the following information to ARB:

(A) Early action offset project name;

(B) Early action offset project location;

(C) Offset Project Operator, or if applicable, the Authorized Project Designee;

(D) Name and date of protocol used by the early action offset project, including, if applicable, a version number;

(E) Date of early action offset project listing or registration date and Offset Project Commencement Date; and

(F) The name of any verification bodies which have conducted verification for the early action offset project under the Early Action Offset Program.

(G) For early action offset projects developed under the Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0, each early action reporting period, and/or destruction event may be considered an independent project, or may be listed as a single project with multiple early action reporting periods.

(3) The parties identified in section 95990(e)(1) may submit one or more early action reporting period(s) for the early action offset project for listing. The parties are not required to list all early action reporting periods associated with the early action offset project. The party that submits the listing information pursuant to this section must ensure that the GHG reductions and removal enhancements credited in the applicable early action reporting period are permanent as defined in section 95802, including reporting and verification to ensure permanence. An early action reporting period may not be listed with ARB pursuant to this section until after the Early Action Offset Program has approved or registered the early action offset credits for the early action reporting period in its system. Early action reporting periods must be listed with ARB no later than January 1, 2016.

(4) The Early Action Offset Program must make the following information available on a publicly available website and clearly indicate which early action offset projects and early action reporting periods qualify for early action under this article:

(A) Early action offset project name;

(B) Early action offset project location;

(C) Offset Project Operator, or if applicable, the Authorized Project Designee;

(D) Name and date of protocol used by the early action offset project, including, if applicable, a version number;

(E) Date of early action offset project listing or registration date and Offset Project Commencement Date; and

(F) The name of any verification bodies associated with the early action offset project.

(f) Regulatory Verification of Early Action Offset Credits. Any early action offset credit issued by an Early Action Offset Program must be verified under the following requirements before being issued an ARB offset credit pursuant to section 95990(i):

(1) The project must be verified by an ARB-accredited verification body that meets the accreditation requirements in section 95978. The verification body performing regulatory verification pursuant to this section must be different than any verification body that conducted offset verification services for the early action offset project under the Early Action Offset Program. The offset verification team must include an offset project specific verifier for the applicable offset project type. Verification bodies performing regulatory verification pursuant to this section may verify more than 6 early action reporting periods.

(2) Conflict of interest must be assessed against parties identified pursuant to section 95990(g) and the conflict of interest assessment must meet the requirements of section 95979.

(3) A verification body must conduct a desk review for each early action reporting period eligible and applicable pursuant to section 95990(c)(1) for each early action offset project that generates early action offset credits under the quantification methodologies listed in section 95990(c)(5), unless the Offset Project Operator, Authorized Project Designee, or holder(s) follows the provisions in section 95990(f)(3)(G). The desk review of all early action reporting periods eligible and applicable pursuant to section 95990(c)(1) for each early action offset project may be applied as one single desk review. A desk review

pursuant to section 95990(f)(3) may be conducted only once for each early action reporting period. The desk review must include the following:

(A) Review of the early action offset project original documentation, including the Early Action Verification Reports and Offset Verification Statements submitted to the Early Action Offset Program, to ensure that the previously provided offset verification services were sufficient to render a reasonable assurance to support the issuance of early action offset credits by the Early Action Offset Program;

(B) Review and recalculation of the data checks conducted by the original verification body for the Early Action Offset Program to ensure they were calculated correctly;

(C) If the verification body concludes with reasonable assurance that they concur that a positive verification statement should have been issued based on the Early Action Verification Report and the Offset Verification Statement submitted to the Early Action Offset Program for the applicable early action reporting period, the verification body must submit the attestation in section 95990(f)(3)(D) to ARB, and provide ARB with a report detailing the findings of the desk review. The Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, must submit the related early action reporting periods for the early action offset project for listing pursuant to section 95990(e) prior to the verification body submitting any findings pursuant to this section.

(D) The verification body must attest, in writing, to ARB as follows: “I certify under penalty of perjury under the laws of the State of California that I have conducted a desk review in accordance with the requirements of section 95990(f)(3) and concur with the issuance of a positive verification statement based on the Early

Action Verification Report and Offset Verification Statement that was submitted to the Early Action Offset Program for the applicable early action reporting period."

(E) For each early action offset project the Offset Project Operator or Authorized Project Designee must provide the Early Action Verification Report(s) for all early action reporting periods eligible and applicable pursuant to section 95990(c)(1) to the offset verification team to assist in offset verification services and desk review.

(F) ARB will review the desk review findings submitted by the desk review verification body and determine whether to accept or reject the findings. ARB may consult with the OPO, APD, holder(s), Early Action Offset Program, and the verification body, as needed when making its determination. ARB will notify the verification body, Offset Project Operator, Authorized Project Designee, or holder(s) that listed the early action offset project of its determination. If ARB does not agree with a positive desk review finding, ARB will require that the reporting information provided by the Offset Project Operator or Authorized Project Designee to the original verification body be subject to full offset verification services pursuant to section 95990(f)(6).

(G) If the desk review verification body is unable to obtain the original verification body's data checks calculations or information used by the original verification body required to be reviewed pursuant to section 95990(f)(3)(A) or (B), the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, may opt out of the desk review by having the verification body prepare a report to ARB explaining the circumstances for not completing the desk review process, and contract with a verification body to conduct full offset verification services pursuant to section 95990(f)(6).

(4) If during the desk review performed pursuant to section 95990(f)(3) the verification body cannot conclude with reasonable assurance that a positive verification statement should have been issued based on the Early Action Verification Report and the Offset Verification Statement submitted to the Early Action Offset Program for the applicable early action reporting period then the verification body must prepare a report for ARB and explain the reasons for this conclusion.

(5) ARB will review the information submitted by the verification body pursuant to section 95990(f)(4) and may request additional information from, and consult with, the Early Action Offset Program or the verification body as necessary.

(6) If ARB finds that the GHG reductions or removal enhancements reported to the Early Action Offset Program for a given early action reporting period should not have been issued a positive verification statement after reviewing the information submitted by the desk review verification body, the reporting information provided by the Offset Project Operator or Authorized Project Designee to the original verification body must be verified and full offset verification services pursuant to sections 95977.1 and any additional verification requirements in the applicable protocol identified in section 95990(c) must be conducted. The full offset verification services will be conducted based on the early action quantification methodology under which the OPO or APD of the early action offset project originally reported. The Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, may determine to not move forward with the full offset verification services and the early action offset credits would no longer be eligible to transition to ARB offset credits. If the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, determine to move forward with the full offset verification services, the offset verification services for each early action reporting period may be done by the same verification body that performed the

desk review and may be applied as one single offset verification service and meet the following requirements:

(A) If the early action offset project is still in operation, the verification body must conduct a site visit as required in section 95977.1(b)(3)(D).

(B) If the early action offset project is no longer in operation, the verification body must conduct a desk review of the original documentation to confirm any previous verification findings related to the types of offset verification services required in section 95977.1(b)(3)(D).

(C) The sampling plan in section 95977.1(b)(3)(G) must cover all serialized early action offset credits issued to the early action offset project for all years eligible and applicable pursuant to section 95990(c)(1);

(D) The data checks in section 95977.1(b)(3)(L) must include checks across the sources identified in the sampling plan, covering all serialized early action offset credits issued to the early action offset project for all years eligible and applicable pursuant to section 95990(c)(1); and

(E) The verification body must submit an Offset Verification Statement pursuant to section 95977.1(b)(3)(R) to ARB covering all serialized early action offset credits issued to the early action offset project for all early action reporting periods eligible and applicable pursuant to section 95990(c)(1). For non-forestry offset projects, the verification body may submit a Positive, Qualified Positive, or Adverse Offset Verification Statement. Forestry Offset projects may only receive a Positive or Adverse Offset Verification Statement.

(7) Once ARB offset credits have been issued for an early action reporting period pursuant to section 95990(i) subsequent offset verification services provided for additional early action reporting periods for the

same early action offset project will not trigger a desk review of those early action reporting periods for which ARB offset credits have already been issued pursuant to section 95990(i).

(g) Conflict of Interest Requirements for Early Action. For each early action reporting period for which a verification body provides regulatory verification pursuant to section 95990(f), the verification body must assess conflict of interest according to the following requirements against each party identified in section 95990(g)(2). The conflict of interest assessment for each early action reporting period must be submitted to ARB before ARB issues an ARB offset credit pursuant to section 95990(i). Conflict of interest self-evaluations for multiple early action reporting periods for one early action offset project may be combined into one evaluation. The Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, must submit the related early action reporting periods for the early action offset project for listing pursuant to section 95990(e), and the listing must be approved, prior to the verification body submitting the conflict of interest assessment pursuant to this section.

(1) The verification body is subject to the conflict of interest requirements in section 95979.

(2) The conflict of interest requirements in section 95979 must be assessed against the following parties at the time that offset verification services are conducted pursuant to section 95990(f):

(A) The Offset Project Operator and Authorized Project Designee or holder(s), if applicable, for the project; and

(B) Any party that holds greater than 30 percent of the early action offset credits issued to an early action offset project for each individual early action reporting period reviewed as part of offset verification services conducted pursuant to section 95990(f).

(h) Issuance of ARB Offset Credits for Early Action. ARB will issue ARB offset credits pursuant to section 95990(i) for early action if the following requirements are met:

(1) The early action offset credits meet the requirements of section 95990(c);

(2) The GHG reduction or GHG removal enhancement occurred by December 31, 2014;

(3) The GHG reduction or GHG removal enhancement was determined to meet the requirements for regulatory verification pursuant to section 95990(f) and verification under the Early Action Offset Program was completed with the submittal of an Offset Verification Statement to an Early Action Offset Program by September 30, 2015 for GHG reductions or GHG removal enhancements eligible to be issued ARB offset credits;

(4) The early action offset project has been listed pursuant to section 95990(e); and

(5) The following parties must submit the attestations listed in section 95990(h)(6) to ARB:

(A) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(B) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(h)(5)(C):

1. A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);

2. An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A), (C), (E), (F), and (G).

(C) The holder of early action offset credits may seek issuance of ARB offset credits pursuant to section 95990(i), as long as the holder provides ARB the attestations required pursuant to section 95990(h)(6).

(6) The parties identified in section 95990(h)(5) must submit the following information to ARB:

(A) Attest, in writing, to ARB as follows:
"I certify under penalty of perjury under the laws of the State of California the GHG reductions and GHG removal enhancements for [project] from [date] to [date] have been measured in accordance with the [appropriate Early Action Offset Program offset protocol] and all information required to be submitted to ARB is true, accurate, and complete.";

(B) Attest, in writing, to ARB as follows:
"I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes."; and

(C) Attest in writing to ARB as follows:
"I understand that the offset project activity and the implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety regulations that apply based on the offset project location. I understand that offset projects are not eligible to receive ARB offset credits for GHG reductions or GHG removal enhancements that are not in compliance with the requirements of this Article."

(7) An ARB offset credit may not be issued for an early action offset credit that has been retired, canceled, used to meet a surrender obligation, used to meet a voluntary commitment, or used to meet any GHG mitigation requirements in any voluntary or regulatory system.

(i) Process for Issuance of ARB Offset Credits for Purposes of Early Action. ARB will issue an ARB offset credit that meets the requirements of section 95990(h) in the amount calculated pursuant to section 95990(i)(1):

(1) ARB offset credits will be issued according to the following schedule:

(A) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1;

(B) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0;

(C) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0; and

(D) ARB offset credits will be issued for early action offset credits generated under Climate Action Reserve Forest Project Protocol version 2.1 and versions 3.0 through 3.2, pursuant to the following:

1. If any ARB offset credits are being issued to an early action forest offset project pursuant to this section, ARB will notify the Early Action Offset Program of the quantity of early action offset credits that must be removed or canceled from its buffer account for forest projects for that project such that they are no longer available on the Early Action Offset Program's system.

a. The early action offset credits being removed or canceled from the Early Action Offset Program's buffer account for forest projects must meet the criteria of this section. Early action offset credits that do not meet the criteria of this section may not be used to meet ARB's Forest Buffer Account requirements.

b. If ARB offset credits were placed in the Forest Buffer Account for purposes of transitioning early action offset credits to ARB offset credits, and the early action offset credits were removed or canceled from the Early Action Offset Program's buffer account for forest projects pursuant to sections 95990(i)(1)(D)1.b.i. or ii., ARB will remove or cancel the ARB offset credits from the Forest Buffer Account so that they may be transferred permanently to the Early Action Offset Program's buffer account for forest offset projects:

i. The early action offset credits did not meet the criteria in section 95990(c); or

ii. The early action offset credits removed from the Early Action Offset Program's buffer account for forest projects were removed in excess of the amount of early action offset credits required by this section.

2. A specified number of the issued ARB offset credits must be placed in the Forest Buffer Account for each early action reporting period eligible and applicable pursuant to section 95990(c)(1) using the following equation:

$$ARB_{Buffer} = ARB_{Issue} \times Max[RR_{EAOP}, RR_{COP}]$$

Where:

"ARB_{Buffer}" is the number of ARB offset credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in sections 95990(i)(1)(D)3.a., b. or c. below, as applicable;

"Max" is the larger of the two values [RR_{EAOP}, RR_{COP}];

"RR_{EAOP}" is the reversal risk rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits placed in the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period; and

"RR_{COP}" is the reversal risk rating percentage that must be applied to an early action forest offset project pursuant to the project-specific reversal risk rating calculation in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4., for an early action reporting period.

a. ARB will calculate the reversal risk rating percentage for RR_{COP} for the early action reporting period for the early action offset project according to the requirements in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4.

b. When calculating the reversal risk rating percentage using the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4., ARB will use the maximum value for each risk category in the Compliance Offset Protocol unless the original early action verification included a review of the criteria for determining the risk and verified the requirements for calculating the risk category.

c. Qualified Conservation Easements cannot be retroactively applied to the reversal risk rating percentage calculations for the purposes of early action. Once the forest project transitions to a Compliance Offset Protocol pursuant to section 95990(k), it may use a Qualified Conservation Easement to reduce its reversal risk rating on a forward basis.

3. ARB will determine the number of ARB offset credits that may be issued to the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, for each early action reporting period for which ARB offset credits are issued as follows:

a. If the following condition applies, and no early action offset credits have yet been canceled or retired from the Early Action Offset Program's buffer account for forest projects for the early action reporting period, then ARB will issue one ARB offset credit for each early action offset credit that meets the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits, plus an amount of ARB offset credits equal to the associated credits transferring over from the Early Action Offset Program's buffer account for forest projects, for an early action reporting period:

If: $RR_{EAOP} \geq RR_{COP}$

Then:

$$ARB_{Issue} = \frac{ARB_{Request}}{(1 - RR_{EAOP})}$$

Where:

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period, based on the amount of ARB offset credits for which the party is seeking issuance;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for an early action reporting period;

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period; and

"RR_{COP}" is the reversal risk rating percentage that must be applied to the early action forest offset project pursuant to the project-specific reversal risk rating calculation in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4. for an early action reporting period.

i. The Early Action Offset Program must retire or cancel early action offset credits from its buffer account for forest projects for the early action reporting period equal to the following:

$$EAOP_{BufferRetire} = ARB_{Issue} \times RR_{EAOP}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for the early action reporting period;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)3.a. above; and

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period.

ii. ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)3.a. above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)2. above.

b. If the Early Action Offset Program's reversal risk rating percentage is less than the reversal risk rating calculated using the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4., and no early action offset credits have yet been canceled or retired from the Early Action Offset Program's buffer account for forest projects for the early action reporting period, the following equation will determine the number of ARB offset credits to be issued for each early action reporting period:

If: $RR_{EAOP} < RR_{COP}$

Then:

$$ARB_{Issue} = \frac{ARB_{Request}}{(1 - RR_{EAOP})}$$

Where:

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period, based on the amount of ARB offset credits for which the party is seeking issuance;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for an early action reporting period;

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period; and

"RR_{COP}" is the reversal risk rating percentage that must be applied to the early action forest offset project pursuant to the project-specific reversal risk rating calculation in the Compliance Offset Protocol in section 95973(a)(2)(C)4., for an early action reporting period.

i. The Early Action Offset Program must retire or cancel early action offset credits from its buffer account for forest projects for the early action reporting period equal to the following:

$$EAOP_{BufferRetire} = ARB_{Issue} \times RR_{EAOP}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)3.b. above; and

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period.

ii. ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following, for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)3.b. above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)2. above.

c. If early action offset credits have already been canceled or removed from the Early Action Offset Program's buffer account for forest projects for an early action reporting period due to a reversal or retirement prior to issuance of ARB offset credits, the following will apply for any early action reporting period regardless of ARB's or the Early Action Offset Program's reversal risk rating calculation:

i The number of early action offset credits the Early Action Offset Program must cancel from its buffer account for forest projects for the early action reporting period is as follows:

$$EAOP_{BufferRetire} = \frac{\frac{ARB_{Request}}{(1 - RR_{EAOP})}}{EAOP_{Issue}} \times EAOP_{BufferActive}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period;

"$EAOP_{Issue}$" is the total number of early action offset credits that were issued, for the early action reporting period by the Early Action Offset Program including early action offset credits placed in the buffer account for forest projects;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for the early action reporting period;

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period; and

"$EAOP_{BufferActive}$" is the number of active early action offset credits remaining in the Early Action Offset Program buffer account for forest projects for the early action reporting period after the reversal or retirement.

ii The number of early action offset credits ARB will issue is as follows:

$$ARB_{Issue} = ARB_{Request} + EAOP_{BufferRetire}$$

Where:

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for each early action reporting period; and

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period, as calculated pursuant to section 95990(i)(1)(D)3.c.i. above;

iii ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed in the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s), for an early action reporting period as calculated in section 95990(i)(1)(D)3.c.ii. above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)2. above.

d. When ARB requests retirement or cancellation of early action offset credits from an Early Action Offset

Program's buffer account for forest projects for the purpose of placement in ARB's Forest Buffer Account, ARB will request proof from an Early Action Offset Program that it has retired the early action offset credits from its buffer account for forest offset projects. The Early Action Program must provide proof to ARB of its retirement of the early action offset credits from its buffer account for forest projects within 10 calendar days of a request by ARB.

4. If there is an unintentional reversal for any early action forest offset project, even after it transitions to ARB's Compliance Offset Protocol in section 95973(a)(2)(C)4., the provisions in section 95983(b) and (d) apply.

5. If there is an intentional reversal for any early action forest offset project, even after it transitions to ARB's Compliance Offset Protocol in section 95973(a)(2)(C)4., the provisions in section 95983(c) and (d) apply.

(E) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1;

(F) ARB offset credits will be issued for early action offset projects generated under Verified Carbon Standard VMR0001 Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology, v1.0 or VMR0002 Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0 according to the following:

1. One ARB offset credit will be issued for one early action offset credit for each early action reporting period that did not include emissions from the production of power, heat or

supply to gas grid replaced by the project activity in the baseline (identified as $BE_{Use,y}$ in ACM0008); or

2. No ARB offset credits will be issued for GHG emission reductions credited by an Early Action Offset Program based on data reported by the Offset Project Operator or Authorized Project Designee that included emissions from the production of power, heat or supply to gas grid replaced by the project activity in the baseline (identified as $BE_{Use,y}$ in ACM0008);

(G) For early action offset credits issued for mine methane capture projects developed under an approved early action quantification methodology no ARB offset credits will be issued for GHG emission reductions credited by an Early Action Offset Program based on data reported by the Offset Project Operator or Authorized Project Designee that included emission reductions from the destruction of methane by a destruction device that would be classified as a non-qualifying destruction device in the Compliance Offset Protocol in section 95973(a)(2)(C)5.; and

(H) ARB offset credits will be issued for early action offset projects generated under the offset quantification methodology in section 95990(c)(5)(H) according to the following:

1. One ARB offset credit will be issued for one early action offset credit for each early action reporting period that did not include emissions reductions from nitrous oxide (N_2O), soil organic carbon (SOC), reduced fossil fuel consumption and activities ineligible under the Compliance Offset Protocol in section 95973(a)(2)(C)6.; and

a. Early action offset projects must take the single run output of the De-Nitrification De-Composition (DNDC) model and use equations 5.2.1 and 5.3.1 of the

Compliance Offset Protocol in section 95973(a)(2)(C)6. to calculate the baseline and project N_2O, SOC and CH_4.

b. Early action offset projects must then take the results of equations 5.2.1 and 5.3.1 and use them to calculate the primary source GHG emission reductions from one run of DNDC using the equation for $PER_{i,j}$ from equation 5.4.1 of the Compliance Offset Protocol in section 95973(a)(2)(C)6.

c. Early action offset projects must substitute the results of $PER_{i,j}$ for $BE_{y,i}$ - $PE_{y,i}$ (incorrectly identified as $PE_{y,i}$ - $BE_{y,i}$ and subsequently corrected in errata and clarifications) in equations 7 and 8 of the offset quantification methodology in section 95990(c)(5)(H) to calculate project emission reductions.

d. If modification to the parent methodology identified in the module in section 95990(c)(5)(H)2. results in project energy use emissions (E_{fe} in equation 3) being less than the baseline energy use, both the project and baseline energy use emissions must be set to zero (0). If project energy use emissions are greater than baseline energy use emissions, the actual values must be used.

e. If activities ineligible under the Compliance Offset Protocol in section 95973(a)(2)(C)6. were employed during an early action reporting period, the relevant cropping parameters from the early action reporting period being considered must be used in place of the baseline parameters for the ineligible activities when running DNDC.

2. No ARB offset credits will be issued for GHG emission reductions credited by an Early Action Offset Program based on a baseline set applying data from the common practice in the rice growing region rather than data specific to a project's fields.

(I) If an early action offset project is issued ARB offset credits pursuant to section 95990(i)(1)(D) and transitions from Climate Action Reserve Forest Project Protocol version 2.1 to the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4. pursuant to section 95990(k) the early action offset project may calculate its project baseline pursuant to section 95990(k)(1)(D) and use the following method to determine if it could qualify for additional early action offset credits:

1. Based on the project baseline calculated in section 95990(k)(1)(D), the early action offset project must calculate and sum the net GHG emission reductions and GHG removal enhancements it achieves following all the provisions of the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4. and the requirements in this article, from the date of offset project commencement under the Early Action Offset Program through the date the early action offset project applies for transition pursuant to section 95990(k).

2. The early action offset project must subtract the number of early action offset credits issued by the Early Action Offset Program for the period from the date of offset project commencement through the time the early action offset project applies for transition pursuant to section 95990(k) from the number of sum determined pursuant to section 95990(i)(H)1.:

a. If the difference is positive, ARB will issue ARB offset credits equivalent to the difference at the time of offset project transition pursuant to section 95990(k) for the timeframe specified in section 95990(i)(1)(H)1. ARB will transfer ARB offset credits to the Forest Buffer Account in the amount calculated pursuant to section 95990(i)(1)(D)2. and will transfer the remaining ARB offset credits to the Offset Project Operator or Authorized Project Designee.

b. If the difference is negative, ARB will only issue ARB offset credits pursuant to section 95990(i)(D)1. for the timeframe specified in section 95990(i)(1)(H)1.

3. Section 95990(i)(1)(H) does not apply to holders of early action offset credits.

(2) ARB will notify the Early Action Offset Program within 10 calendar days of ARB's determination of issuance of ARB offset credits pursuant to this section.

(3) Early action offset credits must be permanently removed or canceled by the Early Action Offset Program within 10 calendar days of ARB notification, such that the early action offset credits are no longer available for transaction on the Early Action Offset Program registry system.

(4) Not later than 15 calendar days after ARB issues an ARB offset credit for purposes of early action, ARB will notify the Offset Project Operator, Authorized Project Designee, and holder(s) of the original early action offset credits, if applicable, of the issuance.

(j) Registration and Transfer of ARB Offset Credits for Purposes of Early Action. An ARB offset credit issued pursuant to section 95990(i) will be registered by creating a unique ARB serial number. ARB will transfer the serial numbers into Holding Accounts as follows within 15 working days of the notice of issuance pursuant to section 95990(i)(4), unless otherwise required in section 95990(i)(1)(D):

(1) If the Offset Project Operator or Authorized Project Designee was issued additional ARB offset credits pursuant to section 95990(i)(1)(H)2.a. ARB will transfer the ARB offset credit into the Holding Account of the Offset Project Operator or Authorized Project Designee and the Forest Buffer Account, as required.

(2) For an ARB offset credit issued pursuant to sections 95990(i)(1)(A) through (G) ARB will transfer the ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) of the early action offset credits.

(A) The Offset Project Operator, Authorized Project Designee, or holder(s) must prove ownership of the original early action offset credits, including the original serial numbers issued by the Early Action Offset Program, and submit a request for issuance to ARB for the issuance of ARB offset credits, before ARB will transfer the ARB offset credits into the Holding Account. Offset Project Operators, Authorized Project Designees, and Forest Owners may also be considered holders if they can prove ownership of the original early action offset credits.

(B) Before any party is issued ARB offset credits into a Holding Account, the party must be registered with ARB pursuant to section 95830 and be approved for a Holding Account.

(C) ARB will make publicly available on its webpage which early action offset credits qualify to be issued ARB offset credits based on the early action reporting period in which the early action offset credits were issued.

(D) An Offset Project Operator, Authorized Project Designee, or holder(s) may request that only a portion of the eligible GHG reductions and removal enhancements for the applicable

Reporting Period be issued ARB offset credits in the request for issuance of ARB offset credits.

(k) Transition of Early Action Offset Projects to the Compliance Program.

(1) Early Action Offset Project Transition to ARB Compliance Offset Protocols. Early action offset projects must transition to ARB Compliance Offset Protocols no later than February 28, 2015, or by February 28, 2016 for projects developed under any of the offset quantification methodologies in section 95990(c)(5)(H), by submitting listing information required pursuant to section 95975 to ARB or an Offset Project Registry and having that listing approved:

(A) Early action offset projects using Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0 must use and meet all the requirements in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)2.;

(B) Early action offset projects using Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1 must use and meet all the requirements in Compliance Offset Protocol Urban Forest Projects, October 20, 2011;

(C) Early action offset projects using Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0 must use and meet all the requirements in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)1.;

(D) Early action offset projects using Climate Action Reserve Forest Project Protocol version 2.1 must use and meet all the requirements in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4. At the time of transition the early action offset project must calculate its project baseline according to all the provisions in the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4., and the requirements in this article over the period of time from the date of offset project commencement under the Early Action Offset Program to the date the early action offset project applies for transition pursuant to section 95990(k), plus one-hundred years. This project baseline will remain valid for the duration of the offset project life. Registry offset credits and ARB offset credits issued for the first Reporting Period after the early action offset project is listed pursuant to section 95975 using the most recent version of the Compliance Offset Protocol in secion 95973(a)(2)(C)4., will only be for the increased carbon stocks beyond what was already issued early action offset credits in the last year before the early action offset project transitioned to a Compliance Offset Protocol pursuant to this section;

(E) Early action offset projects using Climate Action Reserve Forest Project Protocol versions 3.0 through 3.2 must use the most recent version of the Compliance Offset Protocol in section 95973(a)(2)(C)4. and subtract from the project baseline any carbon stocks from any optional pools that are excluded in the Compliance Offset Protocol beginning with the last reporting period under the Early Action Offset Program. Decreases will not constitute a reversal;

(F) Early action offset projects using Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1, Verified Carbon Standard VMR0001 Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology version 1.0, and Verified Carbon Standard VMR0002 Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology version 1.0 must use and meet all the requirements in the Compliance Offset Protocol in section 95973(a)(2)(C)5.; and

(G) Early action offset projects using American Carbon Registry Voluntary Emission Reductions in Rice Management Systems Parent Methodology, version 1.0 must use and meet all the requirements in the Compliance Offset Protocol in section 95973(a)(2)(C)6.

(2) Crediting Periods for Early Action Offset Projects. When an early action offset project transitions to a Compliance Offset Protocol pursuant to section 95990(k)(1), it will begin an initial crediting period. The initial crediting period will begin with the date that the first verified GHG emission reductions or GHG removal enhancements occur using a Compliance Offset Protocol approved pursuant to section 95971.

(3) Listing Requirements for Transition of Early Action Offset Projects. At the time an early action offset project transitions to a Compliance Offset Protocol pursuant to section 95990(k)(1), the Offset Project Operator or Authorized Project Designee must:

(A) Meet the requirements for offset projects pursuant to section 95973; and

(B) List the offset project pursuant to section 95975.

(C) To transition an early action offset project to the ARB compliance offset program, the offset project must be listed with ARB or an Offset Project Registry by February 28, 2015, but, if applicable, has until September 30, 2015 to complete the verification of any GHG reductions and GHG removal enhancements under the Early Action Offset Program that were achieved between 2005 and 2014 with the submittal of an Offset Verification Statement to the Early Action Offset Program.

(D) To transition an early action offset project developed under any of the offset quantification methodologies in section 95990(c)(5)(H) to the ARB compliance offset program, the offset project must be listed with ARB or an Offset Project Registry by February 28, 2016, but, if applicable, has until April 30, 2016 to complete the verification of any GHG reductions and GHG removal enhancements under the Early Action Offset Program that were achieved between 2005 and 2015 with the submittal of an Offset Verification Statement to the Early Action Offset Program.

(4) After an early action offset project lists with ARB pursuant to section 95990(k)(3), it must meet the following requirements:

(A) Monitoring, reporting, and record retention requirements pursuant to section 95976;

(B) GHG reduction and GHG removal enhancement verification requirements pursuant to sections 95977 through 95978;

(C) Be issued a registry offset credit pursuant to section 95980.1 or an ARB offset credit pursuant to section 95981.1 for any GHG reductions or GHG removal enhancements it achieves.

(5) ARB will not issue ARB offset credits after August 31, 2016 for any GHG reductions or GHG removal enhancements achieved through 2014 and issued early action offset credits by an Early Action Offset Program and after December 31, 2016 for projects developed under any of the offset quantification methodologies in section 95990(c)(5)(H) for any GHG reductions or GHG removal enhancements achieved through 2015 and issued early action offset credits by an Early Action Offset Program.

(l) An ARB offset credit issued pursuant to section 95990(i) may be invalidated pursuant to section 95985 as follows:

(1) An ARB offset credit issued to a non-sequestration project or an urban forest project, or a U.S. forest offset project issued on or after July 1, 2014, may be invalidated pursuant to sections 95985(a) through (h) and section 95985(j) and as follows:

(A) If an Offset Project Operator or Authorized Project Designee was issued offset credits pursuant to section 95990(i) and the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2), the provisions in sections 95985(h)(1)(C)1. through 3. and sections 95985(h)(2)(B)1. through 3. still apply to the Offset Project Operator; or

(B) If the holder of early action offset credits was issued ARB offset credits pursuant to section 95990(i) and the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2), the provisions in sections 95985(h)(1)(C)1. through 3. and sections 95985(h)(2)(B)1. through 3. apply to the holder that was issued ARB offset credits pursuant to section 95990(i) and not the Offset Project Operator.

(2) An ARB offset credit issued to a U.S. forest offset project on or prior to July 1, 2014, may be invalidated pursuant to sections 95985(a) through (g) and sections 95985(i) and (j).

(3) For an early action offset project developed under one of the quantification methodologies in sections 95990(c)(5)(A), (B), (D), (E), (F), or (G) the invalidation timeframe will remain at eight years, unless one of the following applies and are met to reduce the statute of limitations to three years:

(A) If an Offset Project Operator or Authorized Project Designee transitions an early action offset project to a Compliance Offset Protocol pursuant to section 95990(k):

1. An ARB-accredited verification body must verify a subsequent Offset Project Data Report generated under a Compliance Offset Protocol. The verification must meet the requirements pursuant to sections 95985(b)(1)(B)1., (b)(1)(B)2., and (b)(1)(B)4.b.

2. The ARB-accredited verification body must be a different verification body than the one that conducted any regulatory verification services of the early action offset project pursuant to section 95990(f) or that verified the early action offset project under the Early Action Offset Program, and

must meet the requirements for conflict of interest pursuant to section 95979 and for the rotation of verification bodies pursuant to section 95977.1(a); and

3. If the requirements in sections 95990(l)(3)(A) through (l)(3)(A)2. are met, the invalidation timeframe would be as specified in section 95985(b)(1)(B)3.b.; or

(B) If an Offset Project Operator or Authorized Project Designee does not transition an early action offset project to a Compliance Offset Protocol pursuant to section 95990(k), or the Offset Project Operator or Authorized Project Designee chooses to reduce the invalidation timeframe prior to the verification of a subsequent Offset Project Data Report being verified pursuant to section 95990(l)(3)(A) above:

1. An ARB-accredited verification body must conduct full offset verification services pursuant to sections 95977.1 and 95978, except for section 95977.1(b)(3)(M), based on the original data report and/or reporting information submitted to the Early Action Offset Program for the original offset verification conducted under the Early Action Offset Program for the applicable early action reporting period. Although the requirements in section 95977.1(b)(3)(M) do not need to be met under this section, any misreporting, discrepancies, and omissions found during the full offset verification services must be included in the offset material misstatement calculation performed pursuant to section 95977.1(b)(3)(Q). The full offset verification services must be in addition to any regulatory verification services conducted for the early action offset project pursuant to section 95990(f). The verification body must submit the verification materials pursuant to section 95985(b)(1)(A)2.a. and the Offset Project Registry

and ARB must review the verification materials pursuant to sections 95985(b)(1)(A)2.b. through d.;

2. The ARB-accredited verification body must meet the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a), and be a different verification body than the one that conducted any regulatory verification services of the applicable early action reporting period for the early action offset project pursuant to section 95990(f) or that verified the the applicable early action reporting period for the early action offset project under the Early Action Offset Program; and

3. The new ARB-accredited verification body must complete the full offset verification services, by submitting an Offset Verification Statement pursuant to section 95977.1(b)(3)(R)1., within a maximum of three years following the issuance of ARB offset credits for the early action reporting period as a result of the regulatory verification services performed pursuant to section 95990(f), and the Offset Project Operator or Authorized Project Designee must receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same early action reporting period. The full offset verification services must include a site visit to the offset project location, and any other sites as specified in the applicable early action quantification methodology. The site visit must be performed only once for all qualifying early action reporting periods.

4. If the requirements of sections 95990(l)(3)(B) through (l)(3)(B)3. are met, the invalidation timeframe would be as specified in section 95985(b)(1)(A)3.b.

(4) For an early action offset project developed under the quantification methodology in sections 95990(c)(5)(C), the statute of limitations will remain at eight years, unless the following criteria are met to reduce the invalidation timeframe to three years:

(A) An ARB-accredited verification body must conduct full offset verification services pursuant to sections 95977.1 and 95978, except for section 95977.1(b)(3)(M), based on the original data report and/or reporting information submitted to the Early Action Offset Program for the original offset verification conducted under the Early Action Offset Program for the applicable early action reporting period. Although the requirements in section 95977.1(b)(3)(M) do not need to be met under this section, any misreporting, discrepancies, and omissions found during the full offset verification services must be included in the offset material misstatement calculation performed pursuant to section 95977.1(b)(3)(Q). The full offset verification services must be in addition to any regulatory verification services conducted for the early action offset project pursuant to section 95990(f). The verfication body must submit the verification materials pursuant to section 95985(b)(1)(A)2.a. and the Offset Project Registry and ARB must review the verification materials pursuant to sections 95985(b)(1)(A)2.b. through d.;

(B) The ARB-accredited verification body must meet the requirements for conflict of interest pursuant to section 95979 and the rotation of verification bodies pursuant to section 95977.1(a), and be a different verification body than the one that conducted any regulatory verification services of the applicable early action reporting period for the early action offset project pursuant to section 95990(f) or that verified the applicable early action reporting period for the early action offset project under the Early Action Offset Program; and

(C) The new ARB-accredited verification body must complete the full offset verification services, by submitting an Offset Verification Statement pursuant to section 95977.1(b)(3)(R)1., within a maximum of three years following the issuance of ARB offset credits for the early action reporting period as a result of the regulatory verification services performed pursuant to section 95990(f) and the Offset Project Operator or Authorized Project Designee must receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same early action reporting period. The full offset verification services must include a site visit to the offset project location, and any other sites as specified in the applicable early action quantification methodology. The site visit must only be performed once for all qualifying early action reporting periods.

(D) If the requirements of sections 95990(l)(4) through (l)(4)(C) are met the invalidation timeframe would be as specified in section 95985(b)(1)(A)3.b.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95991. Sector-Based Offset Credits.

Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by, a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries, except as specified in subarticle 13.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95992. Procedures for Approval of Sector-Based Crediting Programs.

The Board may approve a sector-based crediting program in an eligible jurisdiction after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code section 11340 et seq.). Provisions set forth in this article shall specify which compliance instruments issued by an approved sector-based crediting program may be used to meet a compliance obligation under this Article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95993. Sources for Sector-Based Offset Credits.

Sector-based credits may be generated from:

(a) Reducing Emissions from Deforestation and Forest Degradation (REDD) Plans.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95994. Requirements for Sector-Based Offset Crediting Programs.

(a) General Requirements for Sector-Based Crediting Programs. The Board may consider for approval a sector-based crediting program which may include the following sectoral requirements:

(1) Sector Plan. The host jurisdiction has established a plan for reducing emissions from the sector.

(2) Monitoring, Reporting, Verification, and Enforcement. The program includes a transparent system that regularly monitors, inventories,

reports, verifies, and maintains accounting for emission reductions across the program's entire sector, as well as maintains enforcement capability over its reference activity producing credits.

(3) Offset Criteria. The program has requirements to ensure that offset credits generated by the program are real, additional, quantifiable, permanent, verifiable and enforceable.

(4) Sectoral Level Performance. The program includes a transparent system for determining and reporting when it meets or exceeds its crediting baseline(s), and evaluating the performance of the program's sector during each program's crediting period relative to the business as usual or other emissions reference level.

(5) Public Participation and Participatory Management Mechanism. The program has established a means for public participation and consultation in the program design process.

(6) Nested Approach. If applicable, the program includes:

(A) Offset project-specific requirements that establish methods to inventory, quantify, monitor, verify, enforce, and account for all project-level activities

(B) A system for reconciling offset project-based GHG reductions in sector-level accounting from the host jurisdiction.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95995. Quantitative Usage Limit.

Sector-based offset credits approved by ARB for compliance pursuant to section 95821(d) are subject to the quantitative usage limit specified in section 95854.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 15: Enforcement and Penalties

§ 96010. Jurisdiction.

Any of the following actions shall conclusively establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California:

(a) Registration with ARB pursuant to subarticle 5;

(b) The purchase or holding of a compliance instrument issued by ARB, unless the entity holding the compliance instrument is registered in an approved External GHG ETS pursuant to subarticle 12;

(c) Receipt of compensation of any kind, including sales proceeds and commissions, from any transfers of allowances or offset credits issued by ARB pursuant to subarticle 13 or recognized by ARB pursuant to subarticle 14; or

(d) Verification of an offset credit to be issued by ARB.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96011. Authority to Suspend, Revoke, or Modify.

(a) The Executive Officer may suspend, revoke, or place restrictions on the Holding Account of a voluntarily associated entity determined to be in violation of any provision of this article.

(b) The Executive Officer may place restrictions on a Holding Account of a covered entity or an opt-in covered entity determined to be in violation of any provision of this article or of article 2 of this subchapter.

(c) The Executive Officer may suspend, revoke, or modify any Executive Order issued under this article or under article 2 of this subchapter, including an order accrediting a verifier, for a violation of any provision of this article.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96012. Injunctions.

Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96013. Penalties.

Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article as specified in section 96014. In determining any penalty amount, ARB shall consider all relevant circumstances, including the criteria in Health and Safety Code section 42403(b).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96014. Violations.

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each required compliance instrument that has not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).

(b) A separate violation accrues every 45 days after the end of the Untimely Surrender Period pursuant to section 95857 for each required compliance instrument that has not been surrendered.

(c) It is a violation to submit any record, information or report required by this article that:

(1) Falsifies, conceals, or covers up by any trick, scheme or device a material fact;

(2) Makes any false, fictitious or fraudulent statement or representation;

(3) Makes or uses any false writing or document knowing the same to contain any false, fictitious or fraudulent statement or entry; or

(4) Omits material facts from a submittal or record.

(5) A fact is material if it could probably influence a decision by the Executive Officer, the Board, or the Board's staff.

(d) The violations stated in section 96014(c) are additional to violations of any obligations of any entity subject to this regulation under other provisions of this article requiring submissions to ARB to be true, accurate and complete.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 16: Other Provisions

§ 96020. Severability, Effect of Judicial Order.

Each provision of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96021. Confidentiality.

(a) Emissions data submitted to ARB under this article is public information and shall not be designated as confidential.

(b) Any entity submitting information to the Executive Officer pursuant to this subarticle may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Record Act (Government Code, section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in California Code of Regulations, title 17, sections 91000 to 91022.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 96022. Jurisdiction of California.

(a) Any party that participates in the Cap-and-Trade Program is subject to the jurisdiction of the State of California unless the party is subject to the jurisdiction of an External GHG ETS to which California has linked its Cap-and-Trade Program pursuant to section 95830(h) and subarticle 12.

(b) Notwithstanding section 96010, subsection 96022(a) or any other jurisdictional provision in this article, this article shall not be construed to abridge the rights and protections afforded foreign sovereigns, including the right of removal to federal court, pursuant to the Foreign Sovereign Immunities Act, Public Law 94-583, as amended and codified at 28 U.S.C. sections 1330, 1332, 1391(f), 1441(d), and 1602-1611.

(c) A party that has rights and protections under the Foreign Sovereign Immunities Act consents to civil enforcement of the laws, rules and regulations pertaining to this article in California's courts, subject to the rights and protections afforded to entities subject to the Foreign Sovereign Immunities Act, including removal to federal court.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Appendix A

Entity Information
Legal Name
Operating Name
U.S. Federal Tax Employer Identification Number
Value Added Tax Identification Number
Data Universal Numbering System Number
Date of incorporation
Place of Incorporation
Country of Incorporation
Business Number (Assigned by California Agency)
Physical Address (City, State, postal Code)
Mailing Address (City, State, postal Code)
Country
Contact Information (Name, address, phone, email)
Website Address
Type of Organization

Individual Information
First Name
Middle Name
Last Name
Personal Residence Address
Phone number
Email
Social Security Number
Date of Birth
Citizenship
Employer Name
Employer Address
Copy of a valid identity card issued by a state or province with an expiration date
Copy of a government-issued identity document
Copy of a Passport
Documentation of an open bank account
Documentation of any felony convictions during the previous five years

Appendix B

CITSS User Terms and Conditions

ACCESS AGREEMENT AND TERMS OF USE FOR THE CITSS
SIGN THE BOTTOM OF THE PAGE TO INDICATE YOUR ACCEPTANCE OF THIS AGREEMENT.

Access to the Compliance Instrument Tracking System Service (CITSS) is subject to the terms and conditions set forth in this Access Agreement and Terms of Use (Agreement). You must accept this Agreement in order to access the CITSS application. Violation of this agreement may result in loss of access to CITSS and, if warranted, civil or criminal prosecution under state, provincial, or federal law.

This Agreement is between the State of California, Air Resources Board (ARB) and each registered California user of Compliance Instrument Tracking System Service (User). The Agreement sets forth the terms of use of CITSS. ARB provides User with access to the CITSS software application, for registering entities and holding compliance instrument. User understands and agrees that CITSS is provided "AS IS" and without any warranty, as set forth below in greater detail.

1. CITSS Use

1.1 ARB and WCI, Inc. hereby grant to User, and User hereby accepts, subject to the terms and conditions set forth in this Agreement, a non-exclusive and non-transferable right to access CITSS via the world-wide-web or the internet at times when the software and servers are available and operating.

1.2 User further acknowledges that it is not authorized to and may not possess or distribute any or all parts of the CITSS software, including its source codes and program components. User is not authorized to install, run or operate CITSS on User's or third-party computers or servers.

1.3 User is solely responsible for ensuring that all information, data, text, or other materials that User provides to ARB or WCI, Inc. through use of CITSS (Content) are true, accurate, and complete and comply with ARB's requirements for the compliance with the cap-and-trade program under the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms (Regulation) (Title 17, California Code of Regulations (CCR), Sections 98000 et sq.).

1.4 User understands that ARB will retain and use the Content consistent with the applicable Regulation(s) and may disclose Content to the public to the extent the disclosure is required by California law or legal process, or to the extent that disclosure is not prohibited by California law.

1.5 ARB has included (as part of CITSS) security features including password protection to prevent a person other than the User from obtaining access through CITSS to User's Content. User understands that these security features depend on User protecting its password from disclosure to unauthorized persons. User also understands and acknowledges that despite security measures to prohibit unauthorized access to the Content through CITSS, unauthorized access could occur and in the event it does, ARB or WCI, Inc. may not be held liable for the unauthorized release of information, data, text or other materials that have been submitted to ARB using CITSS.

1.6 ARB does not endorse or provide support for software or web-based interfaces offered by third parties for purposes of submitting data to ARB. Use of a third-party interface or software product in order to access CITSS does not relieve the user of the need to ensure that information required by the applicable Regulation has been properly submitted to ARB and received by the applicable deadline and that all certifications required for use of CITSS have been submitted.

1.7 User is responsible for maintaining a copy of all data submitted to CITSS. The loss of electronic information, data, text, or other materials during use of CITSS or the unavailability of the CITSS system does not excuse User from the requirements in the applicable Regulation.

2. CITSS User Agreement
The permission granted in Section 1 above is expressly made subject to and limited by the following restrictions, in addition to the limitations and restrictions set forth in other sections of the Agreement:

2.1 User agrees not to access CITSS by any means other than using internet browsers.

2.2 User further agrees that it shall NOT:
a. Deliberately attempt to access any data, documents, email correspondence, or programs contained on systems for which User does not have authorization;
b. Engage in activity that may harass, threaten or abuse others, or intentionally access, create, store or transmit material which may be deemed offensive, indecent or obscene, or that is illegal according to local, state, provincial, or federal law;
c. Engage in activity that may degrade the performance of CITSS;
d. Deprive an authorized user access to CITSS;
e. Obtain extra resources or login privileges beyond those authorized;
f. Circumvent CITSS security measures;
g. Violate copyright law of copyrighted material;
h. Attempt to disassemble, decompile or reverse engineer CITSS;
i. Attempt to create derivative works based on CITSS;
j. Attempt to copy, reproduce, distribute or transfer CITSS;
k. Provide access to CITSS to any third parties for any improper purpose;

l. Obtain for personal benefit, or engage in political activity, unsolicited advertising, unauthorized fund raising, or solicit performance of any activity that is prohibited by any local, state, or federal law.

2.3 User's right to access CITSS automatically terminates upon User's violation of any provisions of this Agreement.

2.4 User further agrees that it will immediately inform ARB or the CITSS administrator by emailing help@wci-citss.org or calling at 1-866-682-7561 if any of the following occurs:
a. User observes any unauthorized access or misuse of CITSS;
b. User has any reason to believe that the security of their User ID, password, or security question(s) has been compromised;
c. User has any reason to believe that weaknesses in computer security, including unexpected software or system behavior, may result in unintentional disclosure of information or exposure to security threats.

2.5 User further agrees that:
a. User will maintain the security of their CITSS User ID, password, and security questions for use of the CITSS;
b. User will not disclose their CITSS User ID, password, and security questions information to anyone;
c. User will maintain an active email account listed in the CITSS at which User can receive important notifications of changes related to User's personal information or transfers involving any general account or compliance account that User represents as a Primary Account Representative, Alternate Account Representative, Account Viewing Agent, or other CITSS User;
d. Any submission User makes using the CITSS has and will have the same legal effect as if it were made in hardcopy form certified by User's handwritten signature.

2.6 If, at any time, User determines it is no longer able or willing to abide by the terms of this Agreement, User shall immediately cease all use of the CITSS and promptly notify ARB or the CITSS administrator in writing of its determination so that ARB or the CITSS administrator may formally suspend or revoke the User's access to the CITSS.

3. Disclaimer of Warranties
EXCEPT AS REQUIRED BY APPLICABLE LAW, THIS SERVICE IS MADE AVAILABLE ON AN "AS IS" BASIS, WITHOUT WARRANTIES OF ANY KIND. ARB SPECIFICALLY DISCLAIMS ALL WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, BUT NOT LIMITED TO, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO THE SOFTWARE, OR ANY WARRANTIES REGARDING THE CONTENTS OR ACCURACY OF THE SOFTWARE.

4. Limitation on Liability

4.1 Except to the extent required by applicable law, in no event is ARB or WCI, Inc. liable to User on any legal theory for damages of any kind arising from the use of or the inability to use the CITSS, even if ARB or WCI, Inc. has been advised of the possibility of such damages. The unavailability of, or problems with the use of CITSS, does not excuse User from the reporting and compliance deadlines in the applicable Regulation.

5. Copyright and Proprietary Information

5.1 User shall not permit any person who is not registered as a User to access the CITSS and shall not copy, reproduce or distribute, or allow any other person to copy, reproduce or distribute, the CITSS, in whole or in part, without ARB's prior written consent.

6. Term

This Agreement commences upon User's acceptance of this Agreement and access to the CITSS for the first time. The Agreement shall terminate upon User's written notification to ARB under Section 2.5 of this Agreement or upon other termination or discontinuation of User's access to the CITSS, except that Sections 3, 4 and 5 survive any termination of this Agreement. ARB reserves the right to terminate this Agreement at any time, subject to the exception that Sections 3, 4 and 5 survive any termination of this Agreement.

7. Governing Law and General Provisions

This Agreement shall be governed by and construed in accordance with the laws of the State of California. The failure of ARB to exercise or enforce any right or provision of this Agreement shall not constitute a waiver of such right or provision. If any provision of this Agreement is found by a court of competent jurisdiction to be invalid, the parties agree that the court should endeavor to give effect to the parties' intentions as reflected in the provisions, and the other provisions of the Agreement remain in full force and effect.

This Agreement is not intended to modify and cannot modify any provision in the applicable Regulation, including the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms. If any part of this Agreement is found to conflict with any provision(s) in the applicable Regulation(s), the applicable Regulation(s) shall control.

This Agreement constitutes the entire agreement between User and ARB with respect to use of the CITSS. There are no understandings, agreements or representations with respect to the software program that are not specified in this Agreement.

This Agreement may only be modified in a writing signed by User and the Executive Officer of the ARB.

Appendix C: Quarterly Auction and Reserve Sale Dates

	2015	2016	2017	2018	2019	2020
Q1 Auction	Wednesday, February 18	Wednesday, February 17	Wednesday, February 22	Wednesday, February 21	Wednesday, February 20	Wednesday, February 19
Q1 Reserve Sale	Wednesday, April 1	Tuesday, March 29	Tuesday, April 4	Tuesday, April 3	Tuesday, April 2	Wednesday, April 1
Q2 Auction	Tuesday, May 19	Tuesday, May 17	Tuesday, May 16	Tuesday, May 15	Tuesday, May 14	Tuesday, May 19
Q2 Reserve Sale	Tuesday, June 30	Tuesday, June 28	Tuesday, June 27	Tuesday, June 26	Tuesday, June 25	Tuesday, June 30
Q3 Auction	Tuesday, August 18	Tuesday, August 16	Tuesday, August 15	Tuesday, August 14	Tuesday, August 20	Tuesday, August 18
Q3 Reserve Sale	Tuesday, October 6	Tuesday, October 4	Tuesday, October 3	Tuesday, October 2	Tuesday, October 8	Tuesday, October 6
Q4 Auction	Tuesday, November 17	Tuesday, November 15	Tuesday, November 14	Wednesday, November 14	Tuesday, November 19	Tuesday, November 17
Q4 Reserve Sale	Tuesday, December 29	Friday, December 30	Friday, December 29	Friday, December 28	Tuesday, December 31	Tuesday, December 29