FINAL REGULATION ORDER

Note: The pre-existing regulation text is set forth below in normal type. The proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. Portions of the regulation that are nonsubstantively changed with renumbering are indicated by [Nonsubstantive changes to indicate renumbering]. The symbol "***" means that intervening text not proposed for amendment is not shown.

Subchapter 10. Climate Change

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

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95101, 95102, 95103, 95104, 95105, 95110, 95111, 95112, 95113, 95114, 95115, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, title 17 California Code of Regulations; Proposed adoption of new section 95124, new Appendix B, 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

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§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

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

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8. Lead production;

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(G) Any California reporting entity subject to subparts E, F, G, I, K, L, O, R, T, 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 ~~that fits~~ in~~to~~ one or more of the categories in subsection (a)(1) above ~~for calendar year 2011 or later~~ must submit an annual emissions data report ~~for that year and for subsequent calendar years~~, except as provided in the ~~report~~ cessation provisions of 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.

~~(3)~~(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 ~~industrial~~ facilities for which an emissions-based applicability threshold is specified in section 95101(a)(1), the operator must calculate emissions for comparison to applicable thresholds ~~using the requirements of 40 CFR §98.2(b)-(c), except~~ as specified below:

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

(2) For the purpose of computing emissions relative to the 10,000 metric ton CO_2e threshold for reporting applicability specified in section 95101(a), operators must include emissions of CO_2, CH_4 and N_2O from stationary combustion sources and process emissions, but may exclude 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).

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

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

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

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

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(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;

***

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

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

(~~9~~8) Agricultural irrigation pumps.

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

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

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

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

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

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

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(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 ~~following~~ 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.

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(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 ~~and is in conformance with section 95131(b)(9) for the emissions data~~.

(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 ~~and is in conformance with section 95131(b)(9) for the product data~~.

(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 ~~and is in conformance with section 95131(b)(9)~~. This definition applies to the adverse emissions data verification statement and the adverse product data verification statement.

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~~(10) “Air dried ton of paper” means paper with 6 percent moisture content.~~

(~~11~~10) “Air Injected Flare” ***

(~~12~~11) “Annual” ***

(~~13~~12) “API” ***

(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” ~~means~~ 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” ***

(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.

(~~16~~17) “ARB offset credit” ***

(~~17~~18) “Artificial island” ***

(~~18~~19) “Asphalt” ***

(~~19~~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.

(~~20~~21) “Assigned emissions level” ***

(~~21~~22) “Associated gas” ***

(~~22~~23) “ASTM” ***

(~~23~~24) “Authorized project designee” ***

(~~24~~25) “Aviation gasoline” ***

(~~25~~26) “Balancing authority” ***

(~~26~~27) “Balancing authority area” ***

(~~27~~28) “Barrel” ***

(~~28~~29) "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.

(~~29~~30) “Basin” ***

(~~30~~31) “Best available data and methods” ***

(~~31~~32) “Bias” ***

(~~32~~33) “Bigeneration unit” ***

(~~33~~34) “Biodiesel” ***

(~~34~~35) “Biogas” ***

(~~35~~36) “Biogenic portions of CO_2 emissions” ***

(~~36~~37) “Biomass” ***

(~~37~~38) “Biomass-derived fuels” ***

(~~38~~39) “Biomethane” ***

(~~39~~40) “Blendstocks” ***

(~~40~~41) “Blowdown” ***

(~~41~~42) “Blowdown vent stack emissions” ***

(~~42~~43) “Boiler” ***

(~~43~~44) “Bone dry short ton” ***

(~~44~~45) “Bottom ash” ***

(~~45~~46) “Bottoming cycle” ***

(~~46~~47) “British thermal unit” ***

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

(~~47~~49) “Bulk transfer/terminal system” ***

(~~48~~50) “Bushbar” ***

(~~49~~51) “Business-as-usual scenario” ***

(~~50~~52) “Butane” ***

(~~51~~53) “Butylene” or “n-Butylene” ***

(~~52~~54) “Bybass dust” ***

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

(~~53~~56) “Calcination” ***

(~~54~~57) “Calcine” ***

(~~55~~58) “Calcined coke” ***

~~(56) "Calcium ammonium nitrate solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.~~

(~~57~~59) “Calendar year” ***

(~~58~~60) “Calibrated bag” ***

(~~59~~61) “California balancing authority” ***

(~~60~~62) “California Climate Action Registry” ***

(~~61~~63) “California consignee” ***

(~~62~~64) “California Energy Commission” ***

(~~63~~65) “Cap-and-trade regulation” ***

(~~64~~66) “Carbon dioxide” or “CO_2” ***

(~~65~~67) “Carbon dioxide equivalent” or “CO_2 equivalent” ***

(~~66~~68) “Carbon dioxide supplier” ***

~~(67) “Carbon dioxide weighted tonne” or “CO_2 weighted tonne” or “CWT” means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes, stated in units of metric tons. The CWT 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 CWT 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 CWT factor is expressed as a value weighted relative to crude distillation.~~

(~~68~~69) “Carbonate” ***

(~~69~~70) “Carbonate-based raw material” ***

(~~70~~71) “Catalyst” ***

(~~71~~72) “CBOB-summer” ***

(~~72~~73) “CBOB-winter” ***

(~~73~~74) “Cement” ***

(~~74~~75) “Cement kiln dust” ***

(~~75~~76) “Centrifugal compressor” ***

(~~76~~77) “Centrifugal compressor dry seals” ***

(~~77~~78) “Centrifugal compressor wet seal degassing vent emissions” ***

(~~78~~79) “Centrification” or “certify” ***

(~~79~~80) “Chain of title” ***

(~~80~~81) “City gate” ***

~~(81) “Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.~~

(82) “Coal” ***

~~(83) “Coal bed methane” or “CBM” means natural gas which is extracted from underground coal deposits or “beds.”~~

(~~84~~83) “Cogeneration” ***

(~~85~~84) “Cogeneration system” ***

(~~86~~85) “Cogeneration unit” ***

(~~87~~86) “Coke (petroleum)” ***

~~(88) "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.~~

~~(89) "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.~~

(~~90~~87) “Combustion emissions” ***

(~~91~~88) “Combustion source” ***

(~~92~~89) “Commercial propane” ***

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

(~~93~~91) “Compliance instrument” ***

(~~94~~92) “Compliance obligation” ***

(~~95~~93) “Compliance offset protocol” ***

(~~96~~94) “Compliance period” ***

(~~97~~95) “Component” ***

(~~98~~96) “Compressed natural gas” or “CNG” ***

(~~99~~97) “Compressor” ***

(~~100~~98) “Condensate” ***

(~~101~~99) “Conflict of interest” ***

(~~102~~100) “Consignee” ***

~~(103) “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.~~

(~~104~~101) “Continuous bleed” ***

(~~105~~102) “Continuous emissions monitoring system” ***

(~~106~~103) “Continuous physical transmission path” ***

(~~107~~104) “Conventional-summer” ***

(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.

(~~108~~106) “Conventional-winter” ***

~~(109) “Conventional wells” mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.~~

(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.

(~~110~~108) “Covered emissions” ***

(~~111~~109) “Covered product data” ***

(~~112~~110) “Cracking” ***

(~~113~~111) “Crude oil” ***

(~~114~~112) “Customer” ***

(~~115~~113) “Data year” ***

(~~116~~114) “De minimis” ***

(~~117~~115) “Dehydrator” ***

(~~118~~116) “Dehydrator vent emissions” ***

(~~119~~117) “Delayed cooking”***

(~~120~~118) “Delivered electricity” ***

(~~121~~119) “Dementhanizer” ***

(~~122~~120) “Desiccant” ***

(~~123~~121) “Designated representative” ***

(~~124~~122) “Diesel fuel” ***

(~~125~~123) “Direct delivery of electricity” or “directly delivered” ***

(~~126~~124) “Distillate fuel oil” ***

(~~127~~125) “Distillate Fuel No. 1” ***

(~~128~~126) “Distillate Fuel No. 2” ***

(~~129~~127) “Distillate Fuel No. 4” ***

(~~130~~128) “Distribution pipeline” ***

~~(131) “Dolime" is calcined dolomite.~~

(129) “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.

(130) "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~~131) "Dry gas" ***

(~~133~~132) "E&P Tank" ***

(~~134~~133) "EIA" ***

(~~135~~134) "Electric arc furnace" or "EAF" ***

(~~136~~135) "Electric Power Entity" or "EPE" ***

(~~137~~136)"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.

(~~138~~137) "Electricity generating facility" ***

(~~139~~138) "Electricity generating unit" ***

(~~140~~139)"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.

(~~141~~140) "Electricity transaction" ***

(~~142~~141) "Electricity wheeled through California" or "wheeled electricity" ***

(~~143~~142) “Eligible renewable energy resource” ***

(~~144~~143) “Emission factor” ***

(~~145~~144) “Emissions” ***

(~~146~~145) “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.

(~~147~~146) “Emissions data verification statement” ***

(147) “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.

(148) “End user” ***

(149) “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.

(150) “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.

(~~149~~151) “Enforceable” ***

(~~150~~152) “Engineering estimation” ***

(~~151~~153) “Enhanced oil recovery” or “EOR” ***

(~~152~~154) “Enterer” ***

(~~153~~155) “Entity” ***

(~~154~~156) “Equipment” ***

(~~155~~157) “Equipment leak” ***

(~~156~~158) “Equipment leak detection” ***

(~~157~~159) “Ethane” ***

(~~158~~160) “Ethanol” ***

(~~159~~161) “Ethylene” ***

(~~160~~162) “Exchange agreement” ***

(~~161~~163) “Exclusive marketer” ***

(~~162~~164) “Executive Officer” ***

(~~163~~165) “Exported electricity” ***

(~~164~~166) “External combustion” ***

(~~165~~167) “Facility,” unless otherwise specified in relation ***

(~~166~~168) “Facility,” with respect to natural gas distribution ***

(~~167~~169) “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~~, 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 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.

(~~168~~170) “Farm taps” ***

(~~169~~171) “Feedstock” ***

~~(170) "Fiberglass glass 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.~~

(~~171~~172) "Field," ***

(~~172~~173) "Field accuracy assessment" ***

(~~173~~174) "Final point of delivery" ***

(~~174~~175) "First deliverer of electricity" or "first deliverer" ***

(~~175~~176) "First point of delivery in California" ***

(~~176~~177) "First point of receipt" ***

(~~177~~178) "Flare" ***

(~~178~~179) "Flare combustion" ***

(~~179~~180) "Flare combustion efficiency" ***

(~~180~~181) "Flare stack emissions" ***

(~~181~~183) "Flash point" ***

~~(182) "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.~~

(182) "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.

(184) "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.

(185) "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.

(~~183~~186) "Flow meter" ***

(~~184~~187) "Flow monitor" ***

(188) "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.

(~~185~~189) "Fluid catalytic cracking unit" ***

(~~186~~190) "Fluid coking" ***

(~~187~~191) "Fluorinated greenhouse gas" ***

(~~188~~192) "Forced extraction of natural gas liquids" ***

(~~189~~193) "Forest-derived wood and wood waste" ***

(~~190~~194) "Fossil fuel" ***

(~~191~~195) "Fractionates" ***

(~~192~~196) "Fractionator" ***

(~~193~~197) "Fuel" ***

(~~194~~198) "Fuel analytical data" ***

(~~195~~199) "Fuel characteristic data" ***

(~~196~~200) "Fuel combusting electricity generating or cogeneration unit" ***

(~~197~~201) "Fuel ethanol" ***

(~~198~~202) "Fuel flowmeter system" ***

(~~199~~203) "Fuel production facility" ***

(~~200~~204) "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.

(~~201~~205) "Fuel transaction" ***

(~~202~~206) "Fugitive emissions" ***

(~~203~~207) "Fugitive emissions detection" ***

(~~204~~208) “Fugitive equipment leak” ***

(~~205~~209) “Fugitive source” ***

(~~206~~210) “Full verification” ***

~~(207) "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.~~

(~~208~~211) “Gas” ***

(~~209~~212) “Gas conditions” ***

(~~210~~213) “Gas gathering/booster stations” ***

(~~211~~214) “Gas to oil ratio” or “GOR” ***

(215) “Gas to water ratio (GWR),” for purposes of Appendix B, 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.

(~~212~~216) “Gas well” ***

(~~213~~217) “Generated electricity” ***

(~~214~~218) “Generated energy” ***

(~~215~~219) “Generating unit” ***

(~~216~~220) “Generation providing entity” or “GPE” ***

(~~217~~221) “Geothermal” ***

(~~218~~222) “Global warming potential” ***

(223) “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.

(~~219~~224) “Greenhouse gas” or “GHG” ***

(~~220~~225) “Greenhouse gas” emission reduction” ***

(~~221~~226) “Greenhouse gas removal enhancement” ***

(~~222~~227) “Greenhouse gas reservoir” or GHG reservoir” ***

(~~223~~228) “Greenhouse gas sink” or “GHG sink” ***

(~~224~~229) “Grid” ***

(~~225~~230) “Grid-dedicated facility” ***

(~~226~~231) “Gross generation” or “gross power generated” ***

(~~227~~232) “HD-5” ***

(~~228~~233) “HD-10” ***

(~~229~~234) “Heat input rate” ***

(~~230~~235) “Heavy crude oil” ***

(~~231~~236) “High-bleed pneumatic devices” ***

(~~232~~237) “High heat value” or “HHV” ***

(~~233~~238) “Horizontal well” ***

~~(234) "Horsepower tested" means the total horsepower of all turbine and generator set units tested prior to sale.~~

~~(235) "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.~~

(~~236~~239) “Hydrocarbons” ***

(~~237~~240) “Hydrofluorocarbons” or “HFCs” ***

(~~238~~241) “Hydrogen” ***

(~~239~~242) “Hydrogen plant” ***

(~~240~~243)“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.

(~~241~~244) "Importer of record" ***

(~~242~~245) "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.

(~~243~~246) "Independently operated cogeneration/bigeneration facility co-located with the thermal host" means a cogeneration or bigeneration facility that is located on the same ~~facility~~property footprint as its thermal host but has different operational control and different ownership than the thermal host.

(~~244~~247) "Independent reviewer" ***

(~~245~~248) "Industrial/institutional/commercial facility with electricity generation capacity" ***

(~~246~~249) "Intermittent bleed pneumatic devices" ***

(~~247~~250) "Internal combustion" ***

(~~248~~251) "Interstate pipeline" ***

(~~249~~252)"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.

(~~250~~253) “Inventory position” ***

(~~251~~254) “ISO” ***

(~~252~~255) “Isobutane” ***

(~~253~~256) “Isobutylene” ***

(~~254~~257) “Isopentane” ***

(~~255~~258) “Jurisdiction” ***

(~~256~~259) “Kerosene” ***

(~~257~~260) “Kerosene-type jet fuel” ***

(~~258~~261) “Kiln” ***

(~~259~~262) “Kilowatt hour” or “kWh ***

(~~260~~263) “Last point of delivery in California” ***

(~~261~~264) “Lead verifier” ***

(~~262~~265) “Lead verifier independent reviewer” or “independent reviewer” ***

(~~263~~266) “Less intensive verification” ***

(~~264~~267) “Light Crude Oil” ***

(~~265~~268) “Liquefied natural gas” or “LNG” ***

(~~266~~269) “Liquefied petroleum gas” or “LPG” ***

(~~267~~270) “Liquid hydrogen” ***

(~~268~~271) “Linkage” ***

(~~269~~272) “Linked jurisdiction” ***

(~~270~~273) “LNG boiloff gas” ***

(~~271~~274)“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.

(~~272~~275) “Lookback period” ***

(~~273~~276) “Low-bleed pneumatic devices” ***

(~~274~~277) “Low Btu gas” ***

(~~275~~278) “Marketer” ***

(~~276~~279) “Market-shifting leakage,” ***

(~~277~~280) “Material misstatement” ***

(~~278~~281) “Maximum potential fuel flow rate” ***

(~~279~~282) “Megawatt hour” or “MWh” ***

(~~280~~283) “Meter/regulator run” ***

(~~281~~284) “Metering/regulating station” ***

(~~282~~285) “Methane” or “CH_4” ***

(~~283~~286) “Metric ton” or “MT” ***

(~~284~~287) “Midgrade gasoline” ***

(~~285~~288) “Missing data period” ***

~~(286) "Mixed crude oil" means a mix of both heavy and light crude oil.~~

(~~287~~289) “MMBtu” ***

(~~288~~290) “Motor gasoline (finished)” ***

(~~289~~291) “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, ~~alcohol,~~ or racing fuel.

(~~290~~292) “Mscf” ***

(~~291~~293) “Multi-jurisdictional retail provider” ***

(~~292~~294) “Municipal solid waste” or “MSW” ***

(~~293~~295) “NAICS” ***

(~~294~~296) “Nameplate generating capacity” ***

(~~295~~297) “Naphthas” ***

(~~296~~298) “Natural gas” ***

(~~297~~299) “Natural gas distribution facility” ***

(~~298~~300) “Natural gas driven pneumatic pump” ***

(~~299~~301) “Natural gas liquids” or “NGLs”***

(~~300~~302) “Natural gas liquid fractionator” ***

(303) “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.

(~~301~~304) “Natural gasoline” ***

(~~302~~~~30~~5) “NERC e-Tag” ***

(~~303~~306) “Net generation” or “net power generated” ***

~~(304) “Nitric acid” means HNO_3 of 100% purity.~~

(~~305~~307) “Nitrous oxide” or “N_2O” ***

(~~306~~308) “Nonconformance” ***

(~~307~~309) “Non-exempt biomass-derived CO_2” ***

(~~308~~310) ““Non-exempt biomass-derived fuel” ***

(~~309~~311) “Non-fuel based renewable electricity generating unit” ***

(~~310~~312) “Non-submitted/non-verified emissions data report” ***

(~~311~~313) “North American Industry Classification System (NAICS) code(s)” ***

(~~312~~314) “Offset project” ***

(~~313~~315) “Offset project boundary” ***

(~~314~~316) “Offset project data report” ***

(~~315~~317) “Offset project operator” ***

(~~316~~318) “Offset project specific verifier” ***

(~~317~~319) ""Offset protocol" ***

(~~318~~320) "Offshore" ***

(~~319~~321) "Oil well" ***

(~~320~~322) "Oil and gas systems specialist" ***

(323) "On-purpose hydrogen" means hydrogen produced as a result of a process or processes dedicated to producing hydrogen (e.g., steam methane reforming).

(~~321~~324) "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 ~~hydrocarbon~~ 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.

(~~322~~325) "Onshore petroleum and natural gas production owner or operator" ***

(~~323~~326) "On-site" or "onsite" ***

(~~324~~327) "Operating pressure" ***

(~~325~~328) "Operational control" ***

(~~326~~329) "Operator" ***

(330) "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.

(~~327~~331) "Outside of the facility boundary" ***

(332) "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.

(~~328~~333) “Particular end-user” ***

(~~329~~334) “Pentane” ***

(~~330~~335) “Pentane plus” or “C5+” ***

(~~331~~336) “Perfluorocarbons” or PFCs” ***

(337) “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.

(~~332~~338) “Performance review” ***

(~~333~~339) “Petroleum” ***

(~~334~~340) “Petroleum coke” ***

(~~335~~341) “Petroleum refinery” or “refinery” ***

(~~336~~342) “Physical address” ***

~~(337) “Pickled steel sheet” means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides.~~

(~~338~~343) “Pipeline quality natural gas” ***

~~(339) "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.~~

~~(340) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.~~

(~~341~~344) “Point of delivery” or “POD” ***

(~~342~~345) “Point of receipt” or “POR” ***

(~~343~~346) “Point source” ***

(~~344~~347) “Portable” ***

(~~345~~348) “Portland cement” ***

(~~346~~349) “Position holder” ***

(~~347~~350) “Positive emissions data verification statement” ***

(~~348~~351) “Positive product data verification statement” ***

(~~349~~352) “Positive verification statement” ***

(~~350~~353) “Power” ***

(~~351~~354) “Power contract” or “written power contract” ***

(~~352~~355) “Premium grade gasoline” ***

(~~353~~356) “Primary fuel” ***

(~~354~~357)“Primary refinery products” means aviation gasoline, motor gasoline (finished), motor gasoline blendstocks, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. 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.

(358) “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.

(~~355~~359) “Prime mover” ***

(~~356~~360) “Process” ***

(~~357~~361) “Primary fuel” ***

(~~358~~362)“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, ~~and~~ nitric acid production, and lead production.

(~~359~~363) “Process gas” ***

(~~360~~364) “Process Heater” ***

(~~361~~365) “Process unit” ***

(~~362~~366) “Process vent” ***

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

(~~363~~368) “Producer” ***

(~~364~~369) “Product data” ***

(~~365~~370) “Product data verification statement” ***

(~~366~~371) “Professional judgment” ***

(~~367~~372) “Project baseline” ***

(~~368~~373) “Propane” ***

(~~369~~374) “Propylene” ***

(~~370~~375) “Public utility gas corporation” ***

(~~371~~376) “Publicly-owned natural gas utility” ***

(~~372~~377) “Pump” ***

(~~373~~378) “Pump seal emissions” ***

(~~374~~379) “Pump seals” ***

(~~375~~380) “Purchasing-selling entity” ***

(~~376~~381) “Pure” ***

(~~377~~382) “PURPA Qualifying Facility” ***

(~~378~~383) “QA/QC” ***

(~~379~~384) “Qualified exports” ***

(~~380~~385) “Qualified positive emissions data verification statement” ***

(~~381~~386) “Qualified positive product data verification statement” ***

(~~382~~387) “Qualified positive verification statement” ***

(388) “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.

(~~383~~389) "Quality-assured data" or quality-assured value" ***

(~~384~~390) "Rack" ***

(~~385~~391) "RBOB-summer" or "reformulated blendstock for oxygenate blending-summer" ***

(~~386~~392) "RBOB-winter" or "reformulated blendstock for oxygenate blending-winter" ***

(~~387~~393) "Reasonable assurance" ***

(~~388~~394) "Reciprocating compressor" ***

(~~389~~395) "Reciprocating compressor rod packing" ***

(~~390~~396) "Reciprocating internal combustion engine" ***

(~~391~~397) "Re-condenser" ***

~~(392) "Recycled" refers to a material that is reused or reclaimed.~~

~~(393) "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.~~

~~(394) "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.~~

~~(395) "Recycled medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.~~

(~~396~~398) "Refiner" ***

(~~397~~399) "Refinery fuel gas" or "still gas" ***

(~~398~~400) "Reformulated Gasoline Blendstock for Oxygenate Blending" or RBOB" ***

(~~399~~401) "Reformulated-summer" ***

(~~400~~402) "Reformulated-winter" ***

(~~401~~403) "Regular grade gasoline" ***

(~~402~~404) “Relative Accuracy Test Audit” ***

(~~403~~405) “Rendered animal fat” or “tallow” ***

(~~404~~046) “Renewable diesel” ***

(~~405~~407) “Renewable energy” ***

(~~406~~408) “Renewable Energy Credit” or “REC” has the same meaning ~~as ascribed to the cap-and-trade regulation section 95802(a).~~ defined in the California Energy Commission’s “Renewable Portfolio Standard Eligibility,” 7th edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF.

(~~407~~409) “Renewable liquid fuels” ***

(~~408~~410) “Reporting entity” ***

(~~409~~411) “Reporting period” ***

(~~410~~412) “Reporting year” or “report year” ***

(~~411~~413) “Reservoir” means a porous and permeable underground natural formation containing ~~significant quantities of hydrocarbon liquids and/or gases~~crude oil or gas. A reservoir is characterized by a single natural pressure.

(~~412~~414) “Residual fuel oil” ***

(~~413~~415) “Residue gas and residue gas compression” ***

(~~414~~416) “Retail end-use customer” or “retail end user” ***

(~~415~~417) “Retail provider” ***

(~~416~~418) “Retail sales” ***

(~~417~~419) “Sales oil” ***

(420) “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.

(~~418~~421) “Sector” ***

(~~419~~422) “Sector specific verifier” ***

(~~420~~423)"Separator" means a sump or vessel used to~~in which streams of multiple phases are gravity~~ separate~~d~~ crude oil, condensate, natural gas, produced water, emulsion or solids~~into individual streams of single phase~~.

(~~421~~424) "Short ton" ***

(~~422~~425) "Shutdown" ***

(~~423~~426) "Simplified block diagram" ***

(~~424~~427) "Sink" or "sink to load" or "load sink" ***

~~(425) "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.~~

(~~426~~428) "Solomon Energy Intensity Index®" or "Solomon EII" or "EII" ***

(~~427~~429) "Solomon Energy Review" ***

(430) "Sorbent" means a material used to absorb or adsorb liquids or gases.

(~~428~~431) "Sour natural gas" ***

(~~429~~432) "Source" ***

(~~430~~433) "Source category" ***

(~~431~~434) "Source of generation" ***

(~~432~~435) "Specified source of electricity" ***

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

(~~433~~437) "Stand-alone electricity generating facility" ***

(~~434~~438) "Standard conditions" ***

(~~435~~439) "Standard cubic foot" ***

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

(~~436~~440) "Steam generator" ***

(~~438~~441)"Stationary" means neither portable nor self-propelled, and operated at a single facility.

~~(439) "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.~~

(~~440~~442) “Storage tank” ***

~~(441) “Stucco” means hemihydrate plaster ($CaSO_4 \bullet \frac{1}{2} H_2O$) produced by heating (“calcining”) raw gypsum, thereby removing three-quarters of its chemically combined water.~~

(~~442~~443) “Substitute power” ***

(~~443~~444) “Sulfur hexafluoride”” ***

(445) “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.

(~~444~~446) “Supplemental firing” ***

(~~445~~447)“Supplier” means a producer, importer, exporter, position holder, interstate pipeline operator, or local distribution company of a fossil fuel or an industrial greenhouse gas.

(~~446~~448) “Sweet gas” ***

(~~447~~449) “Tactical support equipment” ***

(450) “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.

(451) “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.

(452) “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.

(~~448~~453) “Thermal host” ***

(~~449~~454) “Terminal” ***

(~~450~~455) “Terminal operator” ***

~~(451) “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) “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.

(457) “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.

(458) “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 between those liquids and the produced water.

(~~452~~459) “Tier”” ***

(~~453~~460) “Tier 1” ***

(~~454~~461) “Tier 2” ***

(~~455~~462) “Tier 3” ***

(~~456~~463) “Tier 4” ***

~~(457) "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 chromium, metallic and oxide. Tin plate is used primarily in canmaking.~~

~~(458) “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.~~

(~~459~~464) “Tolling agreement” ***

(~~460~~465) “Topping cycle” ***

(~~461~~466) “Total thermal output” ***

(~~462~~467) “Transactions specialist” ***

(~~463~~468) "Transmission-distribution (T-D) transfer station" means a ~~Federal Energy Regulatory Commission rate-regulated Interstate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994).~~ 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.

(~~464~~469) "Transmission pipeline" ***

(~~465~~470) "Traceable" ***

(~~466~~471) "Turbine" ***

(~~467~~472) "Turbine meter" ***

(~~468~~473) "Uncertainty" ***

(~~469~~474) "Uncontrolled blowdown system" ***

(~~470~~475) "Unconventional wells" means crude oil or gas wells in producing fields that employ hydraulic fracturing to enhance crude oil or gas production volumes.

(~~471~~476) "United States parent company(s)" ***

(~~472~~477) "Unspecified source of electricity" ***

(~~473~~478) "Upstream entity" ***

(~~474~~479) "Urban waste" ***

(~~475~~480) "U.S. EPA" ***

(~~476~~481) "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.).

(~~477~~482) "Vapor recovery system" ***

(~~478~~483) "Vegetable oil" ***

(~~479~~484) "Vented emissions" ***

(~~480~~485) "Verification" ***

(~~481~~486) “Verification body” ***

(~~482~~487) “Verification services” ***

(~~483~~488) “Verification statement” ***

(~~484~~489) “Verification team” ***

(~~485~~490) “Verified emissions data report” ***

(~~486~~491) “Verifier” ***

(~~487~~492) “Verifier review” ***

(~~488~~493) “Vertical well” ***

(494) “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.

(~~489~~495) “Volatile organic compound” or “VOC” ***

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

(497) “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.

(~~490~~498) “Weighted monthly average” ***

(~~491~~499) “Well completions” ***

(~~492~~500) “Well testing venting and flaring” ***

(~~493~~501) “Well workover” ***

(~~494~~502) “Wellhead” ***

(~~495~~503) “Wet natural gas” ***

(~~496~~504) “Wholesale sales” ***

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

(1) "Activin" means the extract from grape seeds containing concentrations of proanthocyanidin ($C_{31}H_{28}O_{12}$).

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

(3) "Almond" means the edible seeds of the almond (*Prunus amygdalus*).

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

(5) "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.

(6) "Aseptic" is the process by which a sterile (aseptic) product (typically food or pharmaceutical) is packaged in a sterile container in a way that maintains sterility.

(7) "Aseptic tomato paste" means tomato paste packaged using aseptic preparation. Aseptic paste is normalized to 31 percent tomato soluble solids (TSS). Aseptic Paste Normalized to 31% TSS = (%TSS - 5.28)/(31 - 5.28)

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

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

(10) "Butter" means the product made by gathering the fat or fresh or ripened milk or cream into a mass, which also contains a small portion of other milk constituents.

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

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

(13) "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.

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

(15) "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.

(16) "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.

(17) “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.

(18) “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.

(19) “Corn chip” is 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.

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

(21) “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 (HFCS), animal feed and by-products such as gluten meal and germ.

(22) “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.

(23) 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.

(24) "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.

(25) “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.

(26) “Distillate products” means a spirit made from the separation of alcohol and a fermented product.

(27) “Dolime" is calcined dolomite.

(28) “Dehydrated chili peppers” means chili peppers that have been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated chili peppers are processed to remove moisture to no more than 12% water by weight. Chili peppers are the fruit of plants from the genus *Capsicum*, members of the nightshade family, Solanaceae.

(29) “Dehydrated garlic” means garlic that has been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated garlic is processed to remove moisture to no more than 6.8% water by weight.

Garlic is an onion like plant *(Allium sativum)* having a bulb that breaks up into separable cloves with a strong distinctive odor and flavor.

(30) “Dehydrated onions” mean onions that have been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated onions are processed to remove moisture to no more than 5.5% water by weight. 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. In the autumn the foliage dies down and the outer layers of the bulb become dry and brittle.

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

(32) “Dehydrated spinach” means spinach that has been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated spinach is processed to remove moisture to no more than 7% water by weight. Spinach (*Spinacia oleracea*) is an edible flowering plant in the family of Amaranthaceae.

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

(34) "Dry whey protein concentrate" means the substance obtained by the removal of sufficient non-protein constituents from pasteurized whey so that the finished dry product contains not less than 25 percent or more than 89.9 percent protein, and not more than 5.0 percent moisture. DWPC is produced by physical separation techniques such as precipitation or ultrafiltration. High protein concentration typically requires diafiltration in addition to filtration. The acidity of WPC may be adjusted by the addition of safe and suitable pH adjusting ingredients.

(35) “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.

(36) "Evaporated milk" means the liquid food obtained by partial removal of water only from milk.

(37) "Fiberglass glass 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.

(38) "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.

(39) “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.

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

(41) "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.

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

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

(44) “Gypsum” means a very soft sulfate mineral composed of calcium sulfate dihydrate, with the chemical formula $CaSO_4 \cdot 2H_2O$.

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

(46) "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.

(47) “Intermediate dairy ingredients” means intermediate dairy product feedstock entering rehydrating process using water and heat to manufacture powdered products.

(48) “Lactose (milk sugar)” 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.

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

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

(51) “Limestone” means a sedimentary rock composed largely of the minerals calcite and aragonite, which are different crystal forms of calcium carbonate (CaCO3).

(52) “Liquid Color Concentrate” means a fluid extract from fruits and vegetables reduced by driving off water whose uses are for altering the color of materials and/or food.

(53) “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.

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

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

(56) “Non-Aseptic tomato paste” means tomato paste packaged using methods other than aseptic preparation. Non-Aseptic paste is normalized to 24 percent tomato soluble solids (TSS). Non-Aseptic Paste Normalized to 24% TSS = (%TSS - 5.28)/(24 - 5.28).

(57) “Non-Aseptic tomato sauce” means tomato sauce packaged using methods other than aseptic preparation. Non-Aseptic tomato sauce is normalized to 24 percent tomato soluble solids (TSS) using
TSS = (%TSS - 5.28)/(24 - 5.28).

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

(59) “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 CO2 injection, to increase the recovery of crude oil from a reservoir.

(60) “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.

(61) “Pistachio” means the nuts of the pistachio tree of the genus *Pistacia vera* grown in the production area whether inshell or shelled.

(62) "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.

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

(64) “Poultry deli product” means the Products that contain a significant portion of pre-processed poultry and are prepared for human consumption (with or without additional cooking required), including sausages and corn dogs.

(65) “Powdered milk” means the manufactured dairy product made by evaporating milk to dryness. Powdered milk includes non fat dry milk powder, skimmed milk powder, whole milk powder and buttermilk powder.

(66) “Pretzel” is a type of baked bread product made from dough made into a desired shape. The dough is then passed through a caustic hot water bath and then baked in an oven.

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

(68) “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.

(69) “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.

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

(71) "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.

(72) "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.

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

(74) “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).”

(75) “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.

(76) "Skim milk" means non-fat or fat-free milk that results from the complete or partial removal of milk fat from milk.

(77) "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.

(78) "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.

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

(80) “Sweetened 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 milk fat, 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.

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

(82) "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 chromium, metallic and oxide. Tin plate is used primarily in can making.

(83) “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.

(84) “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.

(85) “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.

(86) “Tomato puree” or "tomato sauce" 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.

(87) “Tomato soluble solids” 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.”

(88) “Ultrafiltered milk products” means milk products produced by passing milk under pressure through a thin, porous membrane to separate the components of milk according to their size. Ultrafiltered milk products include ultrafiltered milk, ultrafiltered skim milk and ultrafiltered permeate.

(89) “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.

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

(91) "Whey permeate" means a source of dairy solids obtained by the removal of protein and some minerals and lactose from whey. The separation is accomplished by ultrafiltration and diafiltration. The product is labeled to reflect protein, ash and lactose content. The acidity of permeates may be adjusted by the addition of safe and suitable pH ingredients.

(92) “Whole chicken and chicken parts” means the whole chicken or chicken parts (including breasts, thighs, wings) that are bone-in or deboned and packaged for wholesale or retail.

(93) “Whole Peeled 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.

(46) “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.

(47) “Other FCC” means early catalytic cracking processes on fixed catalyst beds, including Houdry catalytic cracking and Thermofor catalytic cracking.

(48) “Oxygenates” means ethers that are produced by reacting an alcohol with olefins.

(49) “Paraxylene production” means the physical separation of paraxylene from mixed xylenes.

(50) “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.

(51) “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.

(52) “POX syngas for fuel” means the production of synthesis gas by gasification (partial oxidation) of heavy residues. This includes syngas clean-up.

(53) “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.

(54) “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.

(55) “Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of greater than or equal to 3.5% by weight.

(56) “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.

(57) "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.

(58) "S-Zorb™ process for kerosene and gasoil" means desulfurization of gasoil using an absorption process. This process does not utilize hydrogen.

(59) "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.

(60) "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) "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.

(62) "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.

(63) "Standard FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of less than 2.25% by weight.

(64) "Sulfur Recovery" means a process where hydrogen sulfide is converted to elemental sulfur."

(65) "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, SO_3 recycle, gas cleaning including electrostatic precipitator and amine regenerator.

(66) "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.

(67) “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.

(68) “Toluene disproportionation/transalkylation means a fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen.

(69) “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.

(70) “Vacuum Distillation” means distillation of atmospheric residues under vacuum. Some units may have more than one main distillation column.

(71) “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.

(72) “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.

(73) “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.

(74) “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.

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(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the cap-and-trade regulation during any year of the current compliance period; the operator is not subject to the reporting requirements of 40 CFR Part 98 specified in this article; and the facility total stationary combustion, process, fugitives and venting emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the information in paragraphs (1)-(7) below, and comply with the requirements specified in paragraphs (8)-(11) below:

(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) ~~Total f~~Facility GHG stationary combustion emissions ~~aggregated~~ for all stationary fuel combustion units and calculated according to any method in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O. If the facility includes multiple stationary fuel combustion units that belong to more than one unit type category listed in section 95115(h), the operator may report the multiple units in aggregate but must indicate the percentage of the aggregated fuel consumption attributed to each unit type category. In addition, if the facility includes an electricity generating unit, the facility operator must report the electricity generating unit separate from other stationary fuel combustion sources by following the unit aggregation provisions in sections 95112(b) and 95103(a)(6). The operator has the option of using engineering estimation or any combination of existing meters to meet the requirements of this paragraph.

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(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).

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(8) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year.

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

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

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(e) *Reporting Deadlines.* Except as provided in section 95103(a)(7)-(8), each facility operator or supplier must submit an emissions data report ~~for the previous calendar year~~ no later than April 10 of each calendar year. Each electric power entity must submit an emissions data report ~~for the previous calendar year~~ no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* The requirements of this paragraph apply to each reporting entity submitting an emissions data report ~~for the previous calendar year~~ that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, or each reporting entity that has or has had a compliance obligation under the cap-and-trade regulation in any year of the current compliance period. The requirements of this paragraph also apply to electric power entities that are electricity importers or exporters that have not met the requirements for cessation in section 95101(~~h~~i)(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).

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(h) *Reporting in 2014.* For 2013 data reported in 2014, the following applies:

(1) Reporting entities may use best available methods for reporting and calculating the general requirements in sections 95101(a)(1)(B)(8) and 95101(b)(1)-(2), the information regarding *de minimis* reporting for suppliers in section 95103(i), section 95103(j)(3), section 95104(f), the information regarding mixed fuels in section 95115(c)(1), the information regarding mixed fuels in section 95115(e), the information regarding the percentage of

aggregated fuel consumption in section 95115(h), section 95115(k)-(l), and the information regarding fuel characteristic data elements and Table 1 in section 95129(c)(3). Reporting entities must adhere to the general provisions found in section 95101(a)(3), section 95101(h)-(i), section 95103(k)(7)(C), section 95103(l), section 95103(m), section 95103(n), section 95104(d)(4), and section 95105(c);

(2) Abbreviated reporters may use best available methods for reporting and calculating the requirements in sections 95103(a)(1)-(2). Abbreviated reporters must adhere to the general provisions found in sections 95103(a)(8)-(9);

(3) Operators of electricity generating facilities may use best available methods for reporting and calculating the requirements for the information regarding legacy contract transition assistance in section 95112(a), section 95112(a)(4)(C), section 95112(a)(5)(C), section 95112(b)(2), the information regarding total thermal output in section 95112(b)(3), section 95112(c) and section 95112(c)(3);

(4) Facility operators may use best available methods for reporting and calculating covered product data listed in section 95113(l)(3), the information regarding liquid hydrogen sold, on-purpose and by-product hydrogen gas in section 95114(j), section 95115(n)(5)-(18), the information regarding the tissue produced with water absorption capacity in 95119(d), the information regarding lead and lead alloys in section 95124(d), the information regarding emulsion in sections 95156(a)(7)-(10), the information regarding a gas plant that produces less than 25 MMscf per day in section 95156(c), and section 95156(d);

(5) Operators of hydrogen plants who report under sections 95114(e)(1), (g), (i), (k), and (l) may use best available methods for calculating those reporting requirements. Operators of hydrogen plants who report under section 95114(e)(2) must report using the full requirements of that provision;

(6) Operators of a lead production facility who report under section 95124 must use best available methods for calculating their emissions. Operators of a lime manufacturing facility may use best available methods to calculate emissions under sections 95117(c)(3) and 95117(e);

(7) Suppliers of natural gas must adhere to the general provisions found in sections 95122(a)(2) and 95122(d)(2)-(6);

(8) Electric power entities must report 2013 electricity transactions (MWh) and emissions (metric tons of CO_2e) under the specifications of this article, including the requirement listed in section 95111(a)(5)(E). The requirement that a seller warrant the sale or resale of specified source power in section 95111(a)(4) and the requirement for reporting of asset controlling supplier power in section 95111(a)(5)(B) are effective starting with the reporting of 2014 data in 2015 and later years;

(9) All reporting entities and verification bodies must follow the requirements in sections 95130 to 95133, including those amendments outlined in sections 95130(a)(1)(D), 95130(a)(2), 95131(a)(2)(C), 95131(b)(8)(D), 95131(b)(8)(F), 95131(b)(9), 95131(b)(12)(B)-(C), 95131(b)(13), 95131(b)(14), 95131(c)(1),

95131(c)(3), 95131(c)(4), 95131(e), 95132(b)(1)(A),(C), 95132(d), 95133(a)-(c);

(10) Operators for the petroleum and natural gas systems sector subject to sections 95150(a)(2), including the definitional change to an onshore petroleum and natural gas systems facility in section 95102(a), 95152(i)(9), 95153(y)(2)(C)-(D), 95157(c)(6), 95157(c)(18)(B), 95157(c)(19)(H) must use best available methods for these reporting requirements;

(11) If a regulatory amendment is not specifically listed above, reporting entities must comply with the amendment for 2014 data reported in 2015.

~~(h) *Reporting in 2012*. For emissions data reports due in 2012, facility operators may report 2011 emissions using applicable monitoring and calculation methods from 40 CFR Part 98. For entities not required to report 2011 emissions under 40 CFR Part 98, best available data and methods may be used for the 2011 data year. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012. For 2012 reports of 2011 emissions by facilities and suppliers, the missing data substitution requirements specified in this article that are different from the requirements of 40 CFR Part 98 do not apply; missing data for the 2012 report of 2011 emissions must be substituted according to the requirements of 40 CFR Part 98.~~

(i) *Calculation and Reporting of De Minimis Emissions.* A facility operator or supplier may designate as *de minimis* a portion of GHG emissions representing no more than 3 percent of a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstocks), not to exceed 20,000 metric tons of CO_2e. The operator or supplier may estimate *de minimis* emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the *de minimis* limits. The operator or supplier must separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator must determine CO_2 equivalence according to the global warming potentials provided in Table A-1 of 40 CFR Part 98.

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify and report all biomass-derived fuels as described in section 95852.2(a) of the cap-and-trade regulation. Except for operators that use the methods of 40 CFR §98.33(a)(2)(iii) or §98.33(a)(4), the operator or supplier must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95112 and 95115 for facilities, and sections 95121 and 95122 for suppliers. A biomass-derived fuel not listed in section 95852.2(a) of the cap-and-trade regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the cap-and-trade regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements of section 95852.1.1 of the cap-and-trade regulation, or the fuel must be identified as non-exempt biomass-derived fuel. Carbon dioxide combustion emissions from non-exempt biomass-derived fuel will be identified as non-exempt biomass-derived CO_2. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the cap-and-trade regulation.

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(3) When reporting biomethane, <u>the operator or supplier who is reporting biomass emissions from biomethane fuel must also report the following information for each contracted delivery:</u>

<u>(A) Name and address of the biomethane vendor from which biomethane is purchased;</u>
<u>(B) Annual MMBtu delivered by each biomethane vendor.</u>

<u>The operator must also report the name, address, and facility type of the facility from which the biomethane is produced. In addition, relevant</u> documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or ARB review to demonstrate the receipt of eligible biomethane.

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(k) *Measurement Accuracy Requirement*. The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements<u> for data used for calculating non-covered emissions and non-covered product data</u>, 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.

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(7) The requirements of section 95103(k) do not apply under the following circumstances:

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(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).

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(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date~~ except in 2012, where the postponement request must be received by the reporting deadline in section 95103(e)~~. The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to ARB within ten (10) working days of a request by ARB.

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(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95124~~3~~ 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 may elect to exclude inaccurate covered product data. Reporting entities that elect to exclude inaccurate 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, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

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

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(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(f);

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

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

§ 95104. Emissions Data Report Contents and Mechanism.

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(d) *Facility Level Energy Input and Output.* The operator must include in the emissions data report information about the facility's energy acquisitions and energy provided or sold as specified below. For the purpose of reporting under this paragraph, the operator may exclude any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility. The operator may also exclude electricity consumed by operations or activities that do not generate any emissions, energy outputs, or products that are covered by this article, and that are neither a part of nor in support of electricity generation or any industrial activities covered by this article. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

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(4) Thermal energy provided or sold to entities outside of the facility boundary: the operator must report the amount of thermal energy provided or

sold (MMBtu), the names and ARB identification number of each end-user as applicable, and the type of unit that generates the thermal energy. If section 95112 applies to the operator, the operator must follow the requirements of section 95112(a)(5) in reporting the thermal energy generated by cogeneration or bigeneration units, and if applicable, also separately report the information required in paragraph 95104(d)(4) for the thermal energy provided or sold that is not generated by cogeneration or bigeneration units.

If the facility boundary includes more than one cogeneration system, boiler, or steam generator, and each unit/system or each group of units produces thermal energy for different particular end-users or on-site industrial processes and operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions, and by the type of thermal energy product provided.

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(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.

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(c) *GHG Monitoring Plan for Facilities and Suppliers*. Each facility operator or supplier that reports under 40 CFR Part 98, each facility operator or supplier with ~~covered~~ emissions equal to or exceeding 25,000 $MTCO_2e$ (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:

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(7) Records of the most recent orifice plate inspection performed according to the requirements of ISO 5167-2 (2003), section 5, or AGA Report No 3 (2003) Part 2, which ~~is~~ are hereby incorporated by reference.

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

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

§ 95110. Cement Production.

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

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

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

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.*

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(4) *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The reporting entity must also report total GHG emissions and MWh from specified sources and the sum of emissions from specified sources explicitly listed as not covered pursuant to section 95852.2 of the cap-and-trade regulation. <u>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.</u>

(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 ~~known~~ provided, report the amount of imported electricity as measured at the first point of delivery in California, including estimated transmission losses as required in section 95111(b), and the reason why measurement at the busbar is not known.

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

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(B) ~~Report delivered electricity as specified and not as unspecified;~~Report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

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(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.

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(b) *Calculating GHG Emissions*.

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

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

Where:

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~~-specific~~ system emission factor published on the ARB Mandatory Reporting website (MT CO_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 ~~a~~ 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) (MT CO_2e/MWh).

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

***

(c) *Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b) and (g).

(1) Retail providers must report California retail sales. A retail ~~providers~~ provider who is required only to report retail sales may choose not to apply the verification requirements specified in section 95103, if the retail provider deems the emissions data report non-confidential.

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

§ 95112. Electricity Generation and Cogeneration Units.

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(a) *Information About the Electricity Generating Facility*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. However, facility operators that are applying for the legacy contract transition assistance under the cap-and-trade regulation must always report the information in section

95112(a)(4)-(6), even if they do not provide or sell any generated energy outside of the facility boundary.

***

(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 ~~T~~the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit (“generated thermal energy”)~~, if applicable~~, reported at the facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Thermal Energy For Other Users.* Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user’s facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user.

(B) *Parasitic Steam Use.* Thermal energy used for supporting power production that has been included in the quantity reported under paragraph 95112(b)(3) but that is not accounted for in the quantities reported under paragraphs 95112(a)(5)(A) and (C). This thermal energy quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include steam used for power augmentation, NO_x control, sent to a de-aerator, or sent to a cooling tower.

(C) *Generated Thermal Energy For On-Site Industrial Applications Not Related to Electricity Generation.* If the facility includes other industrial processes or operations that are neither in support of or a part of the electricity generation or cogeneration system, report the amount of generated thermal energy that is used by those on-site industrial processes or operations and heating or cooling applications. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations. This quantity does not include the amount of thermal energy generated by equipment that is not an integral part of the cogeneration unit.

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

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

If the facility includes equipment that utilizes generated thermal energy to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, follow 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~~ in 2012 or later~~, operators of cogeneration or bigeneration units must submit a simplified block diagram depicting the following, as applicable: individual equipment included in the generation system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (a)(4)-(5), (b)(2)-(4) and (b)(7)-(8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements. If the cogeneration or bigeneration system is modified after the initial submission of the diagram~~ in 2012~~, the operator must resubmit an updated diagram to ARB.

(b) *Information About Electricity Generating Units.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must meet the applicable criteria in 40 CFR §98.36(c)(1)-(4), unless otherwise specified in sections 95115(h) and 95112(b). For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to ARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR §98.36(d)(1)(i). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h). Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).

***

(2) Net and gross power generated, in megawatt hours (MWh). 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).

***

(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.

***

(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.

***

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

***

(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) x EF (kg CO_2/MMBtu) x 0.001 (MT/kg)

Where
CO_2 = Annual CO_2 emissions from fuel and feedstock consumption (metric tons/year)
H = Total fuel heat input for the year (MMBtu/year)
EF = Default CO_2 emission factor. Use 53.02 kg CO_2/ MMBtu for natural gas. Use 52.07 kg CO_2/MMBtu for biogas.
0.001 = Conversion factor from kg to metric tons.

(C) For biogas fuels, the facility operator may elect to use the best available estimation and engineering estimation approach to calculate emissions.

***

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of ~~40 CFR §98.35 when reporting in 2012, and~~ section 95129 of this article ~~when reporting in 2013 and later years~~. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

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.

***

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

***

(l) *Additional Product and Process Data*.

(1) *Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR 98, each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, barrels for liquid products, short tons for solid products), and calcined coke (short tons). For calcined coke, specify whether the calciner is integrated with the petroleum refinery operation. Among the products reported, only calcined coke and primary refinery products will be subject to review for material misstatement under the requirements of section 95131(b)(12). <u>Primary refinery 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.</u>

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

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

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

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

~~(B) *Total facility CWT.* The total facility CWT production value must be~~

~~calculated according to the following formula.~~

$$\cancel{CWT = \sum CWT_{Factor} * Throughput}$$

~~Where:~~

~~"CWT" = The total amount of CO_2 Weighted Tonnes from a petroleum refinery.~~

~~"CWT_{Factor}" = The CWT factor for each process found in Table 1 of this section.~~

~~"Throughput" = The reported value for each CWT function identified in Table 1 of this section reported pursuant to section 95113(~~m~~l)(3)(A).~~

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

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

(3) *Complexity Weighted Barrel (CWB) Calculation.*

(A) *Reporting of CWB Throughput Functions.* The operator must report annual volume in barrels for each applicable throughput in Table 1 of this section, unless other units are listed in column 3 of Table 1 of this section. The percent of coke on the catalyst 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.

$$CWB = \sum (CWB_{Factor} * Throughput) + CWB_{Off-Sites\ and\ Non-Energy\ Utilities}$$

Where:

"CWB" = The total amount of complexity weighted barrels from a petroleum refinery.

"CWB_{Factor}" = The CWB factor for each process found in Table 1 of this section.

"Throughput" = The reported value for each CWB function identified in Table 1 of this section reported pursuant to section 95113(l)(3)(A).

"$CWB_{Off\text{-}Sites\ and\ Non\text{-}Energy\ Utilities}$" = 0.327 * Total Refinery Input + [0.0085 * $CWB_{process}$

"$CWB_{process}$" = $\sum(CWB_{Factor} * Throughput)$],excluding contributions from total refinery input and non-crude input.

(C) *Catalytic Cracking Correction.* For fluid catalytic cracking, mild residual catalytic cracking, and residual catalytic cracking that result in coke on the catalyst, the following equation must be used in substitution for CWB_{Factor} * Throughput:

$$CWB_{CC} = (A + (B * COC)) * Throughput_{CC}$$

Where:

"CWB_{CC}" = The complexity weighted barrel amount from catalytic cracking.

"A" = The first CWB factor listed in column 4 of Table 1 of this section.

"B" = The second CWB factor listed in column 4 of Table 1 of this section.

"COC" = The percent of coke on the catalyst in the catalytic cracking unit.

(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).

Table 1. CWB~~T~~ 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 CWB: 1.041	407	Fluid Catalytic Cracking (Feed ConCarbon <2.25 wt%)
Mild Residual FCC	Feed	thousands of barrels/year	0.6593, Coke-on-Catalyst CWB: 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 C5+ Product	thousands of barrels/year	5	415	Alkylation with Hydrofluoric Acid Alkylation with Sulfuric Acid 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

<table>
<tr><td>POX Syngas for Fuel</td><td rowspan="2">Product</td><td rowspan="2">millions of standard cubic feet/year[1]</td><td rowspan="2">2.75</td><td rowspan="2"></td><td>POX Syngas for Fuel</td></tr>
<tr><td>POX Syngas for Fuel</td><td>Air Separation Unit</td></tr>
<tr><td rowspan="3">Sulfur Recovery</td><td rowspan="2">Product Sulfur</td><td rowspan="3">thousands of long tons/year</td><td rowspan="3">140</td><td rowspan="3">435</td><td>sulfur Recovery Unit</td></tr>
<tr><td>Tail Gas Recovery Unit</td></tr>
<tr><td>Sulfur Sprung</td><td>H2S Springer Unit</td></tr>
<tr><td rowspan="7">Aromatics Production (All)</td><td rowspan="7">Feed</td><td rowspan="7">thousands of barrels/year</td><td rowspan="7">3.3</td><td rowspan="7">437</td><td>Aromatics Solvent Extraction: Extraction Distillation</td></tr>
<tr><td>Aromatics Solvent Extraction: Liquid/Liquid Extraction</td></tr>
<tr><td>Aromatics Solvent Extraction: Liq/Liq w/ Extr. Distillation</td></tr>
<tr><td>Benzene Column</td></tr>
<tr><td>Toluene Column</td></tr>
<tr><td>Xylene Rerun Column</td></tr>
<tr><td>Heavy Aromatics Column</td></tr>
<tr><td>Hydrodealkylation</td><td>Feed</td><td>thousands of barrels/year</td><td>2.5</td><td></td><td>Hydrodealkylation</td></tr>
<tr><td>Toluene Disproportionation/ Transalkylation</td><td>Feed</td><td>thousands of barrels/year</td><td>1.9</td><td></td><td>Toluene Disproportionation / Transalkylation</td></tr>
<tr><td>Cyclohexane production</td><td>Cyclohexane Product</td><td>thousands of barrels/year</td><td>2.8</td><td></td><td>Cyclohexane</td></tr>
<tr><td>Xylene Isomerization</td><td>Feed</td><td>thousands of barrels/year</td><td>1.9</td><td></td><td>Xylene Isomerization</td></tr>
<tr><td rowspan="4">Paraxylene Production</td><td rowspan="2">Paraxylene Product</td><td>thousands of barrels/year</td><td rowspan="4">6.5</td><td rowspan="4"></td><td>Paraxylene Adsorption</td></tr>
<tr><td>thousands of barrels/year</td><td>Paraxylene Crystallization</td></tr>
<tr><td rowspan="2">Feed</td><td>thousands of barrels/year</td><td>Xylene Splitter</td></tr>
<tr><td>thousands of barrels/year</td><td>Orthoxylene Rerun Column</td></tr>
<tr><td rowspan="2">Ethylbenzene production</td><td>Ethylbenzene Product</td><td>thousands of barrels/year</td><td rowspan="2">1.6</td><td rowspan="2"></td><td>Ethylbenzene Manufacture</td></tr>
<tr><td>Feed</td><td>thousands of barrels/year</td><td>Ethylbenzene Distillation</td></tr>
<tr><td>Cumene production</td><td>Cumene Product</td><td>thousands of barrels/year</td><td>5</td><td></td><td>Cumene</td></tr>
<tr><td>Lubricant solvent extraction</td><td>Feed</td><td>thousands of barrels/year</td><td>2.2</td><td rowspan="6">815/854</td><td>Extraction: Solvent is Duo-Sol, Furfural, NMP, Phenol, or SO2</td></tr>
<tr><td>Lubricant solvent dewaxing</td><td>Feed</td><td>thousands of barrels/year</td><td>4.55</td><td>Dewaxing: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane</td></tr>
<tr><td>Lubricant Catalytic Dewaxing</td><td>Feed</td><td>thousands of barrels/year</td><td>1.6</td><td>Catalytic Wax Isomerization and Dewaxing, Selective Wax Cracking</td></tr>
<tr><td>Lubricant Hydrocracking</td><td>Feed</td><td>thousands of barrels/year</td><td>2.5</td><td>Lube Hydrocracker with Multi-fraction Distillation, Lube Hydrocracker with Vacuum Stripper</td></tr>
<tr><td>Lubricant Wax Deoiling</td><td>Product</td><td>thousands of barrels/year</td><td>11.8</td><td>Deoiling: Solvent is Chlorocarbon, MEK/Toluene, MEK/MIBK, or Propane</td></tr>
<tr><td>Lubricant and Wax Hydrofining</td><td>Feed</td><td>thousands of barrels/year</td><td>1.15</td><td>Lube Hydrofinishing with Vacuum Stripper</td></tr>
</table>

					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
Total Refinery Input	Feed	thousands of barrels/year	0.327		-
Non-Crude Input	Feed	thousands of barrels/year	0.44		-

[1] Standard cubic feet are dry @ 60° F and 14.696 psia or 15 °C and 1 atmosphere.

~~***CWT function***~~	~~***Description***~~	~~***Basis (Thousands of Metric Tons/Year)***~~	~~***CWT factor***~~
~~Atmospheric Crude Distillation~~	~~Mild Crude Unit, Standard Crude Unit~~	~~F~~	~~1.00~~

~~Vacuum Distillation~~	~~Mild Vacuum Fractionation, Standard Vacuum Column, Vacuum Fractionating Column~~ ~~Vacuum distillation factor also includes average energy and emissions for Heavy Feed Vacuum (HFV) unit. Since this is always in series with the MVU, HFV capacity is not counted separately~~	~~F~~	~~0.85~~
~~Solvent Deasphalting~~	~~Conventional Solvent, Supercritical Solvent~~	~~F~~	~~2.45~~
~~Visbreaking~~	~~Atmospheric Residuum (w/o a Soaker Drum), Atmospheric Residuum (with a Soaker Drum), Vacuum Bottoms Feed (w/o a Soaker Drum), Vacuum Bottoms Feed (with a Soaker Drum)~~ ~~Visbreaking factor also includes average energy and emissions for Vacuum Flasher Column (VAC VFL) but capacity is not counted separately~~	~~F~~	~~1.40~~
~~Thermal Cracking~~	~~Thermal cracking factor also includes average energy and emissions for Vacuum Flasher Column (VAC VFL) but capacity is not counted separately~~	~~F~~	~~2.70~~
~~Delayed Coking~~	~~Delayed Coking~~	~~F~~	~~2.20~~
~~Fluid Coking~~	~~Fluid Coking~~	~~F~~	~~7.60~~
~~Flexicoking~~	~~Flexicoking~~	~~F~~	~~16.60~~
~~Coke Calcining~~	~~Vertical-Axis Hearth, Horizontal-Axis Rotary Kiln~~	~~P~~	~~12.75~~
~~Fluid Catalytic Cracking~~	~~Fluid Catalytic Cracking, Mild Residuum Catalytic Cracking, Residual Catalytic Cracking~~	~~F~~	~~5.50~~
~~Other Catalytic Cracking~~	~~Houdry Catalytic Cracking, Thermofor Catalytic Cracking~~	~~F~~	~~4.10~~
~~Distillate/Gasoil Hydrocracking~~	~~Mild Hydrocracking, Severe Hydrocracking, Naphtha Hydrocracking~~	~~F~~	~~2.85~~
~~Residual Hydrocracking~~	~~H-Oil, LC-Fining™ and Hycon~~	~~F~~	~~3.75~~
~~Naphtha/Gasoline Hydrotreating~~	~~Benzene Saturation, Desulphurisation of C4–C6 Feeds, Conventional Naphtha H/T, Diolefin to Olefin Saturation, Diolefin to Olefin Saturation of Alkylation Feed, FCC Gasoline hydrotreating with minimum octane loss, Olefinic Alkylation of Thio S, S-Zorb™ Process, Selective H/T of Pygas/Naphtha, Pygas/Naphtha Desulphurisation, Selective H/T of Pygas/Naphtha~~ ~~Naphtha hydrotreating factor includes energy and emissions for Reactor for Selective H/T (NHYT/RXST) but capacity is not counted separately~~	~~F~~	~~1.10~~

~~Kerosene/Diesel Hydrotreating~~	~~Aromatic Saturation, Conventional H/T, Solvent aromatics hydrogenation, Conventional Distillate H/T, High Severity Distillate H/T, Ultra-High Severity H/T, Middle Distillate Dewaxing, S-Zorb™ Process, Selective Hydrotreating of Distillates~~	~~F~~	~~0.90~~
~~Residual Hydrotreating~~	~~Desulphurisation of Atmospheric Residuum, Desulphurisation of Vacuum Residuum~~	~~F~~	~~1.55~~
~~VGO Hydrotreating~~	~~Hydrodesulphurisation/denitrification, Hydrodesulphurisation~~	~~F~~	~~0.90~~
~~Hydrogen Production~~	~~Steam Methane Reforming, Steam Naphtha Reforming, Partial Oxidation Units of Light Feeds~~ ~~Factor for hydrogen production includes energy and emissions for purification (H_2PURE), but capacity is not counted separately~~	~~P~~	~~300.00~~
~~Catalytic Reforming~~	~~Continuous Regeneration, Cyclic, Semi-Regenerative, AROMAX~~	~~F~~	~~4.95~~
~~Alkylation~~	~~Alkylation with HF Acid, Alkylation with Sulfuric Acid, Polymerisation C3 Olefin Feed, Polymerisation C3/C4 Feed, Dimersol~~ ~~Factor for alkylation/polymerisation includes energy and emissions for acid regeneration (ACID), but capacity is not counted separately~~	~~P~~	~~7.25~~
~~C4 Isomerisation~~	~~C4 Isomerisation~~ ~~Factor also includes energy and emissions related to average EU-27 special fractionation (DIB) correlated with C4 isomerisation~~	~~R~~	~~3.25~~
~~C5/C6 Isomerisation~~	~~C5/C6 Isomerisation~~ ~~Factor also includes energy and emissions related to average EU-27 special fractionation (DIH) correlated with C5 isomerisation~~	~~R~~	~~2.85~~
~~Oxygenate Production~~	~~MTBE Distillation Units, MTBE Extractive Units, ETBE, TAME, Isooctene Production~~	~~P~~	~~5.60~~
~~Propylene Production~~	~~Chemical Grade, Polymer grade~~	~~F~~	~~3.45~~
~~Asphalt Manufacture~~	~~Asphalt and Bitumen Manufacture Production figure should include Polymer-Modified Asphalt. CWT factor includes blowing~~	~~P~~	~~2.10~~
~~Polymer-Modified Asphalt Blending~~	~~Polymer-Modified Asphalt Blending~~	~~P~~	~~0.55~~

~~Sulfur Recovery~~	~~Sulfur Recovery~~ ~~Factor for sulfur recovery includes energy and emissions for tail gas recovery (TRU) and H_2S Springer Unit (U32), but capacity is not counted separately~~	~~P~~	~~18.60~~
~~Aromatic Solvent Extraction~~	~~ASE: Extraction Distillation, ASE: Liquid/Liquid Extraction, ASE: Liq/Liq w/Extr. Distillation~~ ~~CWT factor cover all feeds including Pygas after hydrotreatment. Pygas hydrotreating should be accounted under naphtha hydrotreatment~~	~~F~~	~~5.25~~
~~Hydrodealkylation~~	~~Hydrodealkylation~~	~~F~~	~~2.45~~
~~TDP/TDA~~	~~Toluene Disproportionation/Dealkylation~~	~~F~~	~~1.85~~
~~Cyclohexane production~~	~~Cyclohexane production~~	~~P~~	~~3.00~~
~~Xylene Isomerisation~~	~~Xylene Isomerisation~~	~~F~~	~~1.85~~
~~Paraxylene production~~	~~Paraxylene Adsorption, Paraxylene Crystallisation~~ ~~Factor also includes energy and emissions for Xylene Splitter and Orthoxylene Rerun Column~~	~~P~~	~~6.40~~
~~Metaxylene production~~	~~Metaxylene production~~	~~P~~	~~11.10~~
~~Phthalic anhydride production~~	~~Phthalic anhydride production~~	~~P~~	~~14.40~~
~~Maleic anhydride production~~	~~Maleic anhydride production~~	~~P~~	~~20.80~~
~~Ethylbenzene production~~	~~Ethylbenzene production~~ ~~Factor also includes energy and emissions for Ethylbenzene distillation~~	~~P~~	~~1.55~~
~~Cumene production~~	~~Cumene production~~	~~P~~	~~5.00~~
~~Phenol production~~	~~Phenol production~~	~~P~~	~~1.15~~
~~Lube solvent extraction~~	~~Lube solvent extraction: Solvent is Furfural, Solvent is NMP, Solvent is Phenol, Solvent is~~ ~~SO_2~~	~~F~~	~~2.10~~
~~Lube solvent dewaxing~~	~~Lube solvent dewaxing: Solvent is Chlorocarbon, Solvent is MEK/Toluene, Solvent is MEK/MIBK, Solvent is propane~~	~~F~~	~~4.55~~
~~Catalytic Wax Isomerisation~~	~~Catalytic Wax Isomerisation and Dewaxing, Selective Wax Cracking~~	~~F~~	~~1.60~~
~~Lube Hydrocracker~~	~~Lube Hydrocracker w/Multi-Fraction Distillation, Lube Hydrocracker w/Vacuum Stripper~~	~~F~~	~~2.50~~
~~Wax Deoiling~~	~~Wax Deoiling: Solvent is Chlorocarbon, Solvent is MEK/Toluene, Solvent is MEK/MIBK, Solvent is Propane~~	~~P~~	~~12.00~~

~~Lube/Wax Hydrotreating~~	~~Lube H/F w/Vacuum Stripper, Lube H/T w/Multi-Fraction Distillation, Lube H/T w/Vacuum Stripper, Wax H/F w/Vacuum Stripper, Wax H/T w/Multi-Fraction Distillation, Wax H/T w/Vacuum Stripper~~	~~F~~	~~1.15~~
~~Solvent Hydrotreating~~	~~Solvent Hydrotreating~~	~~F~~	~~1.25~~
~~Solvent Fractionation~~	~~Solvent Fractionation~~	~~F~~	~~0.90~~
~~Mol sieve for C10 + paraffins~~	~~Mol sieve for C10 + paraffins~~	~~P~~	~~1.85~~
~~Partial Oxidation of Residual Feeds (POX) for Fuel~~	~~POX Syngas for Fuel~~	~~SG~~	~~8.20~~
~~Partial Oxidation of Residual Feeds (POX) for Hydrogen or Methanol~~	~~POX Syngas for Hydrogen or Methanol, POX Syngas for Methanol~~ ~~Factor includes energy and emissions for CO Shift and H_2 Purification (U71) but capacity is not counted separately~~	~~SG~~	~~44.00~~
~~Methanol from syngas~~	~~Methanol~~	~~P~~	~~– 36.20~~
~~Air Separation~~	~~Air Separation~~	~~P (MNm^{3}O$_2$)~~	~~8.80~~
~~Fractionation of purchased NGL~~	~~Fractionation of purchased NGL~~	~~F~~	~~1.00~~
~~Flue gas treatment~~	~~DeSOx and DeNOx~~	~~F (MNm^3)~~	~~0.10~~
~~Treatment and Compression of Fuel Gas for Sales~~	~~Treatment and Compression of Fuel Gas for Sales~~	~~Elec. Consumption (kW)~~	~~0.15~~
~~Seawater Desalination~~	~~Seawater Desalination~~	~~P~~	~~1.15~~
~~*Basis for CWT factors: Net fresh feed (F), Reactor feed (R, includes recycle), Product feed (P), Synthesis gas production for POX units (SG).*~~			

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.

***

(a) *Definition of Source Category*. This source category is defined consistent with 40 CFR §98.160(b) and(c). This category is further defined as a hydrogen production source that produces hydrogen whether sold to other entities or consumed on-site.

***

(e) *Sampling Frequencies.* When monitoring GHG emissions ~~without a CEMS~~ as specified at 40 CFR §98.16~~4~~3~~(b)(2)~~, and reporting data as specified at §98.166, the operator must report the following:~~determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.~~

(1) Carbon and hydrogen content for each feedstock using engineering estimates based on measured data as specified below:

(~~1~~A) ~~When reporting CO_2 emissions f~~For gaseous ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(1),~~ the operator must use ~~a~~ weighted average carbon content and 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 ~~daily~~ monthly analysis for other gaseous fuels and feedstocks such as refinery fuel gas;

(~~2~~B) ~~When reporting CO_2 emissions f~~For liquid ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(2),~~ the operator must use weighted average carbon content and 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 ~~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~~;

(~~3~~C) ~~When reporting CO_2 emissions f~~For solid ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(3),~~ the operator must use weighted average carbon content and hydrogen content from the results of ~~daily~~monthly sampling ~~for month n~~. ~~Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.~~

(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.

***

(g) *Data Reporting Requirements.* When reporting data as specified ~~at~~in 40 CFR §98.166, the operator ~~may~~must also report the ~~amount~~mass of carbon and methane ~~in unconverted feedstock and CO_2~~ for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation (e.g., carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods specified in this regulation). To avoid double-counting, these emissions must ~~such carbon may~~ be subtracted from the total facility emissions.~~carbon in the feedstock. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation, may be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.~~

***

(i) *Transferred CO_2.* The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Refineries and ~~H~~hydrogen production facilities ~~should adjust~~ must subtract this reported ~~emissions~~mass ~~for~~of CO_2 that is captured and sold or transferred off-site from their facility emissions report to avoid double counting.

(j) *Additional Product Data.* Operators must report the annual mass of hydrogen gas produced (metric tons) and liquid hydrogen sold~~produced~~ (metric tons)~~ and~~. For hydrogen gas sold, annual masses of on-purpose hydrogen and by-product hydrogen produced must be reported (metric tons). Operators must also specify if the hydrogen plant is an integrated refinery operation.

(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.

***

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 1 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels listed in Table C-1 of 40 CFR Part 98 when ~~their~~these emissions are not subject to a compliance obligation under the cap-and-trade, except as limited by section 95115(e) ~~regulation and which are not mixed prior to combustion with fuel that has emissions with a compliance obligation~~.

***

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume is~~it~~ measured by lot, the term "n" in Equation C-2b is substituted as the number of lots received in the year.

***

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

***

(h) *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs

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

***

(k) *Natural Gas ~~Provider~~ Supplier Information.* The operator who is reporting emissions from the combustion of natural gas must report the ~~provider(s)~~ 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 ~~each provider's~~ billing statements (10 therms = 1 MMBtu). 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~~l~~) *Procedures for Missing Data*. To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129~~ beginning with the 2013 emissions data report. For reporting of 2011 emissions in 2012, the operator must use the applicable missing data substitution requirements of 40 CFR Part 98~~.

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

***

(5) The operator of a poultry processing facility must report the quantity of whole

chicken and chicken parts, poultry deli products, and protein meal produced in the data year (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, aseptic whole/diced tomato, non-aseptic tomato paste, non-aseptic whole/diced tomato, and non-aseptic tomato juice, and non-aseptic tomato sauce produced in the data year (short tons).

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

(12) The operator of a facility producing aluminum billets must report the production of aluminum billets 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 diatomaceous earth 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 rings 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, sweetened condensed milk, evaporated milk, intermediate dairy ingredients, dairy product solids for animal feed, lactose, whey permeate, dry whey protein concentrate (DPWC), and deproteinized whey during the data year (short tons). The operator must also report the production of cheese by cheese type, the production of powdered milk by the type of heat treatment (low heat, medium or high heat), and the production of ultrafiltered milk products by product type during the data year (short tons). The operator must report the production of total DPWC and DPWC with high protein concentration using dialifration process during the data year (short tons).

(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).

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

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.

[1] Commercially sold as "propane" including grades such as HD5.

§ 95116. Glass Production.

***

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

***

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

§ 95117. Lime Manufacturing.

***

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

***

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data for the reporting year.

***

(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~~, when calculating emissions,~~ apply a substitute value according to the procedures in paragraphs (A)-(B) below.

***

(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.

***

(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~~2~~) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

***

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

***

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

***

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

§ 95119. Pulp and Paper Manufacturing.

***

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

***

(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, recycled medium, and tissue. The operator producing tissue products must also report the annual production (air dried short tons) of tissue produced adjusted by water absorbency capacity. ~~For tissue, t~~The operator producing tissue products must also report:

(1) A~~a~~ description of the process used to produce tissue, such as through use of an air dryer.

(2) Weighted average water absorption capacity of tissue manufactured using the following equation:

Weighted average water capacity for tissue type =

$$\sum_{i=1}^{n} Oi\, WACi$$

Where:

O_i = annual product output in air dried ton for each tissue product type

WAC_i = water absorption capacity measured at least annually for each product type using the methodology specified by ISO 12625-8:2010, except the humidity and temperature conditions shall be 50% relative humidity ±2%, and 23C ±1 C.

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

§ 95120. Iron and Steel Production.

***

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

***

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

§ 95121. Suppliers of Transportation Fuels.

***

(a) *GHGs to Report.*

***

(2) Refiners, position holders of fossil fuels and biomass-derived fuels that supply fuel at California terminal racks, and enterers outside the bulk transfer/terminal system of fossil fuels must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section. However, reporting is not required for fuel in which a final destination outside California 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.

***

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

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

***

(a) *GHGs to Report.*

***

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies ~~and~~ 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 ~~provided~~ delivered to all entities on their distribution systems in California.

(3) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas, compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside California can be demonstrated.

(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.*

***

(2) For the calculation of CO_{2i} in section 95122(b)(6), ~~L~~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), ~~P~~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), ~~E~~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:

***

(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).

***

(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. ~~received.~~

(10) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(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).

(~~11~~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.

***

(d) *Data Reporting Requirements.*

***

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

***

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

(E) ~~For each customer,~~In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies including intrastate pipelines ~~that report under 40 CFR §98.406 (b)(7)~~ must report the annual volumes in Mscf, annual energy in MMBtu, ~~and~~ customer information required in 40 CFR §98.406(b)(12), and ARB ID number if available for all end-users registering supply equal to or greater than 188,500 MMBtu during the calendar year.

***

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline that delivers natural gas directly to end users~~, local distribution companies, interstate pipelines or other intrastate pipelines~~ must follow the reporting requirements described under Subpart NN of 40 CFR Part 98 and this section for local distribution companies. In lieu of the city gate information specified by section 95122(b)(2), the intrastate pipeline operator must report the summed volumes (Mscf) and energy (MMBtu) of natural gas delivered to each entity receiving gas from the intrastate pipeline for purposes of estimating the CO_{2i} parameter as specified in section 95122(b)(6).

Additionally, intrastate pipeline operators are ~~not~~ required to estimate a value~~s~~ for CO_{2j} ~~and CO_{2l}~~ as specified in section 95122(b)(3) for natural gas delivered to local distribution companies, interstate pipelines, and other intrastate pipelines. The CO_{2l} parameter as specified in section 95122(b)(4) ~~and (b)(4) and~~ must ~~use~~ have a value of 0 for ~~both when~~ calculating emissions as required by 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 ~~or natural gas liquids~~ and liquefied natural gas production facilities as described in section 95122(a)(4) must record the annual quantities imported, ~~in standard cubic feet or barrels, respectively,~~ 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 ~~liquids~~ 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 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).

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

§ 95123. Suppliers of Carbon Dioxide.

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

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

§ 95124. Lead Production.

The operator of a facility who is required to report under section 95101(a)(1)(B)(8.) of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart R of 40 CFR Part 98 (§§98.180 to 98.188) in reporting stationary combustion and process emissions and related data from lead production to 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 §98.225 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If the annual mass or carbon content of carbon-containing inputs are missing when using the process emissions calculation procedure in 40 CFR §98.183(b)(2), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

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

(B) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum capacity of the system and the number of days per month.

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

(d) *Additional Product Data.* The operator of a lead production, 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.

***

(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

***

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

(A) If historical fuel characteristics data are available and kept according to the requirements of section 95105, substitute with the greater of the following:

~~(A)~~ 1. The highest valid value recorded for that type of fuel for all records kept under the requirements of section 95105, or

~~(B)~~ 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%*
~~*Other Gaseous Fuels*~~	~~*90%*~~

***

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

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

§ 95130. Requirements for Verification of Emissions Data Reports.

***

(a) *Annual Verification.*

(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:

***

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

***

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifier(s) for a period of more than six consecutive years, which includes any verifications conducted under this article and for the California Climate Action Registry;~~,~~ The Climate Registry;~~, or~~ Climate Action Reserve; or other verifications conducted in accordance with, or equivalent to, section 95133, including 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 verifications 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 verification body first provides ARB or other verification services to the reporting entity and ends on the date the final verification statement is submitted. The six year period does not reset upon a change in reporting entity ownership or operational control.

***

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.~~*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:

***

(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:

***

(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, ~~or~~ nitric acid production, or lead production, at least one verification team member must be accredited by ARB as a process emissions specialist.

***

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

***

(8) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions, product data and fuel and electricity transactions, and shall include the following:

(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 9515~~7~~8;

(B) The verification team shall use data checks to ensure the accuracy of product data reported under sections 95110 to 95123, and 95150 to 9515~~7~~8 of this article;

***

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

***

(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) and annual MMBtu of natural gas delivered, 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.

(~~F~~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 ~~make any possible improvements or corrections to~~ 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.

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

***

(12) *Material Misstatement Assessment.* Assessments of material misstatement are conducted independently on total reported covered emissions and total reported covered product data (units from the applicable sections of this article).

***

(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:

***

~~(B) The difference between the reporting entity's calculated emissions and verifier's calculated emissions for that source will be zero when assessing for material misstatement under section 95131(b)(12)(A), when the~~

~~applicable missing data substitution procedures or interim data collection procedure has been correctly applied by the reporting entity; or, any relative accuracy assigned to the emissions estimate under section 95129(h)(4) has been correctly applied.~~

(B~~C)~~) 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 9515~~7~~8 these emissions will be considered accurate and as meeting the reporting requirements for that source.

(C~~D~~) 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 9515~~7~~8, the verifier ~~will~~ must include a finding of ~~note, at a minimum, a~~ non-conformance with the required emissions calculation methodology as part of the verification statement.

(D~~E~~) 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 must confirm that data substitutions were not used for 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, and 2014 data reported in 2015. Beginning with 2015 primary refinery product data reported in 2016, verifiers will evaluate for conformance, and will not assess material misstatement.
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 ~~a~~ product data verification statement(s), and provide those statements to the reporting entity and ARB by the applicable verification deadline specified in section 95103(f). Before the emissions data verification statement and product data verification statement(s) are completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

***

(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:

***

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.

***

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

***

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, <u>an error is identified,</u> 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. <u>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.</u>

***

(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:

***

(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<u>.1</u> and 95852.2 of the cap-and-trade regulation.

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

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

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(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

***

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

***

(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. <u>Neither general nor umbrella liability policies can be used for the professional liability insurance minimum for the purposes of this provision.</u>

***

(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 ~~an~~ additional time to hire additional staff to meet the requirements of this section.

***

(5) Sector Specific and Offset Project Specific Verifiers.

***

(B) *Offset Project Specific Verifier*. The applicant seeking to be accredited as an offset project specific verifier as specified in ~~section 95977.1(b) of~~ 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:

***

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier<u>, and Voluntary Withdrawal from the Accreditation Program</u>.* 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.

***

(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.

***

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.

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

***

(2) ~~Within the previous five years, a~~Any ~~staff member~~ 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:

***

(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~~certification~~ or energy management systems such as those conforming to ISO 50001, unless those systems will not be part of the verification process;

***

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

***

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

***

(2) Any ~~non-verification~~ services provided by any member of the verification body or verification team to the reporting entity, within the last five years, are valued at less than 20 percent of the fee for the proposed verification services. Any ~~independent greenhouse gas emissions~~ verification conducted in accordance with, or equivalent to, section 95133 provided by the verification body or verification team outside the jurisdiction of ARB is excluded from this financial assessment but must be disclosed to ARB in accordance with section 95133(e).

(3) Non-ARB verification services are deemed to be low risk if those services are conducted in accordance with, or equivalent to, section 95133, including, but not limited to, third-party certification of environmental management system under ISO 14001 or energy management system under 50001 standards.

***

(g) *Monitoring Conflict of Interest Situations.*

***

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

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

Subarticle 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:

***

(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. <u>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.</u>

***

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

§95151. Reporting Threshold.

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

***

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

§95152. Greenhouse Gases to Report.

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

***

(8) ~~Onshore production and storage tanks~~Dump valves;

***

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

~~(16) Produced water CO_2 and CH_4;~~

(1~~7~~6) 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

(1~~8~~7) 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.

***

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

***

(9) Pipeline main equipment leaks.

***

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.

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

***

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

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

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

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

***

(f) *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 injected and the volume of gas recovered into a sales lines as follows:

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

Where:

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

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

$V_{CO2\cancel{/}\underline{or}\ N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).
V_{SG} = Volume of natural gas recovered into a sales pipeline (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).

***

(j) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

***

(3) Estimate venting emissions using Equation 15 or Equation 16 of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. 15)}$$
$$E_{a,n} = PR * D \qquad \text{(Eq. 16)}$$

Where:
$E_{a,n}$ = 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 = 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.

***

(k) *Associated gas venting and flaring.*

***

(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

***

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

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

***

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

***

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

***

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

***

(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~~7~~), (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).

***

(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)(~~5~~7), (g)(3), (h)(3), (i)(2), (i)(3), (i)(4), ~~(i)(5), and~~ (i)(6) and (i)(9) 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.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. 27)}$$

***

(6) Natural gas distribution facilities must use the appropriate emission factors as described in paragraph (p)(6) of this section.

***

(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).

$$EF = E_{s,i}/(8760 * Count) \qquad \text{(Eq. 28)}$$

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 2~~7~~6.
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 (~~p~~o)(8)(~~i~~A) of this section.
8760 = Conversion to hourly emissions.

***

(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~~ 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. 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 ~~a~~ARB's sampling methodology and ~~a~~ flash liberation test ~~such as~~ procedure entitled "Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems," which is included as Appendix B of this article. ~~adopted Gas Processor Association, American Society for Testing and Materials, or U.S. EPA standards.~~ The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of crude oil, condensate, or produced water. The test results from the flash liberation test must be submitted to ARB as part of the emissions data report.

2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from crude oil, condensate, or produced water as follows:

***

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.

***

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

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C of 40 CFR Part 98, or is a blend ~~containing~~ 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 ~~containing~~ 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 ~~follows~~:

(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~~ as specified in paragraph (s)(2) of this section~~.

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

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

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

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the ~~year~~month.
Y_{CO2} = Monthly ~~C~~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 ~~C~~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 ~~C~~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 1.235×10^{-3} ~~mm~~MMBtu/scf for HHV.
EF = Use 1.0×10^{-4} kg N_2O/~~mm~~MMBtu.
1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 ~~mm~~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 ~~mm~~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.

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.

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

(1) *Optical gas imaging instrument*. Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR Part 60, subarticle A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subarticle A, Table 1: *Detection Sensitivity Levels*; §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records (July 1, 2011, which is hereby incorporated by reference). Any emissions detected by the optical gas ~~imagining~~ imaging instrument is a leak unless screened with Method 21 (40 CFR Part 60, appendix A-7 (July 1, 2011), which is hereby incorporated by reference) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, facility operators must operate the optical gas ~~imagining~~ imaging instrument to image the source types required by this subarticle in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas ~~imagining~~ imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than two meters above a support surface.

***

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

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

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

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

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

~~(3) Operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subarticle, specifically for events that generate data that can be collected in 2012 and cannot be duplicated after December 31, 2012. These sources are:~~

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

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

~~(A) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152 (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4).~~
~~(B) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152(d)(5), (e)(6), (f)(5), (g)(3), and (h)(3).~~

~~(C) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in sections 95152(c)(3) and (d)(4).~~

~~(D) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in sections 95152(c)(17) (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1).~~

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:~~for 2013 and later emissions data reports.~~

***

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

§ 95156. Additional Data Reporting Requirements.

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

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

***

(7) Barrels of crude oil produced using thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);

(8) Barrels of crude oil produced using methods ~~other than~~ of non-thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);

(9) 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);

(10) MMBtu of associated gas produced using methods ~~other than~~ of non-thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a).

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

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

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

(c~~d~~) The operator of a natural gas liquid fractionating facility, ~~or~~ a natural gas processing facility, or an onshore petroleum and natural gas production facility with a natural gas processing plant that processes less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

***

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

(d) Onshore natural gas processing facilities that have an annual average throughput of 25 MMscf per day or greater must also report the volume of associated gas, waste gas, and natural gas processed (MMBtu).

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.

***

(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.

***

(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;

***

(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).

***

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

***

(18) For ~~EOR hydrocarbon liquids~~ 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) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.~~
(~~C~~B) Report annual CO_2 and CH_4 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

***

(H) Annual volume of associated gas produced (MMBtu) using thermal enhanced oil recovery and non-thermal enhanced oil recovery.

***

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 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.

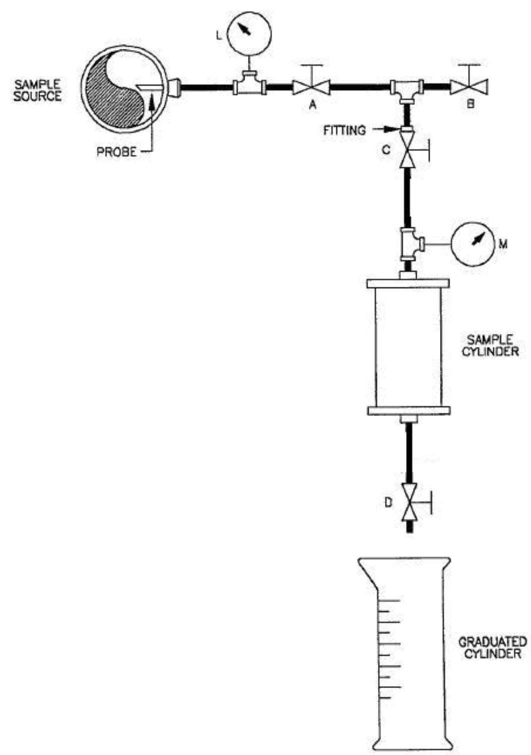
When a liquid sample is gathered, the technician measures the pressure and temperature of the liquid using the calibrated gauges specified and records the vessel and liquid characteristics as reported by the facility operator. The cylinder is then identified with a Cylinder Identification Tag (See Section 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

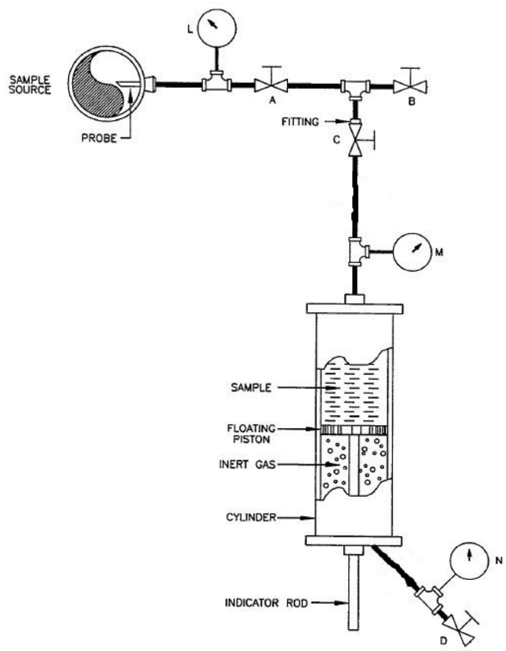
The Produced Water Sampling Method is conducted using a Floating-Piston Cylinder. This allows the sample liquid to be extracted from the cylinder without using laboratory water. The cylinder is provided by a laboratory with the piston pressurized with inert gas to approximately 1,000 psig or greater. 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:

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

Where:

Barrels/Day = barrels per day crude oil or condensate

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

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

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

Where:

Barrels/Day = barrels per day produced water

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

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

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

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

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

Where:

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

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

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

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

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

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

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

Where:

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

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

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

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

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

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

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

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

Where:

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

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

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

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

(b) Convert the total gas volume to pounds:

Equation 8

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

Where:

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

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

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

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

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

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

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

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^oF): 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% CO2, CH4
WT% C2-C9, C10+
WT% BTEX
WT% O2
WT% N2
WT% H2S
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: ____________________