Attachment B to Resolution 07-54

Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Note: This document contains staff's suggested modifications to the originally proposed regulatory language set forth in Appendix A to the Staff Report: Initial Statement of Reasons, which was released to the public on October 19, 2007. The originally proposed regulatory language is indicated by plain type. The suggested modifications are shown in underline to indicate proposed additions to the original proposal and ~~strikethrough~~ to indicate proposed deletions. The text of all proposed modifications will be made available to the public for a comment period of at least 15 days, before the ARB takes final action to adopt the proposed regulation.

Adopt new Subchapter 10, Article 1, sections 95100 to 95133, title 17, California Code of Regulations, to read as follows:

Subchapter 10: Climate Change

This subchapter contains regulations to implement the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)

Article 1: Mandatory Greenhouse Gas Emissions Reporting

95100. Purpose.

The purpose of this article is to require the reporting and verification of greenhouse gas emissions from specified greenhouse gas emissions sources~~ in California~~. This article is designed to meet the requirements of section 38530 of the Health and Safety Code.

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

95101. Applicability.

(a) ***Organization of this article.*** Subarticle 1 specifies general requirements for the reporting of greenhouse gas emissions that apply to all facilities listed below in section (b). Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities. Subarticle 3 specifies calculation methods that are applicable to multiple types of facilities. Subarticle 4 specifies greenhouse gas emissions data report verification requirements and the requirements for those who perform greenhouse gas emission verifications.

(b) Except as provided in ~~section~~sections 95101(c) and 95103(e) , this article applies to the following entities conducting business in California:

(1) Operators of cement plants;
(2) Operators of petroleum refineries that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion and process sources;
(3) Operators of hydrogen plants that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion sources and hydrogen production processes ~~in the report year~~;
(4) Operators of electric generating facilities (except as provided in section 95101(c)) ~~with~~that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW) that emit ~~at least~~greater than or equal to 2,500 metric tonnes ~~or more~~ of CO_2 in ~~the report~~any calendar year after 2007 from electricity generating activities, including hybrid generating facilities and electrical generation facilities under the operational control of other operators subject to the requirements of this article;
(5) Retail providers as defined in section 95102(a);
(6) Marketers as defined in section 95102(a);
(7) Operators of cogeneration facilities ~~with~~that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW) that emit ~~at least~~greater than or equal to 2,500 metric tonnes ~~or more~~ of CO_2 in ~~the report~~any calendar year after 2007 from electricity generating activities, including such cogeneration facilities that are within the operational control of other operators subject to the requirements of this article;
(8) Operators of other facilities that emit greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources in ~~a report~~any calendar year after 2007.

(c) This article does not apply to:

(1) Electric generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy;
(2) Portable equipment or ~~electricity generators~~generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;
(3) Hospitals with a North American Industry Classification System (NAICS) code starting with 62;
(4) Primary and secondary schools with a NAICS code of 611110.

(d) The Executive Officer may request a demonstration from any ~~operator~~entity operating a facility to establish that a specified facility does not meet one or more of the applicability criteria specified in section 95101(b). Such demonstration shall be provided to the Executive Officer within 20 days of a written request received from the Executive Officer.

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

Subarticle 1. General Requirements for the Mandatory Reporting of Greenhouse Gas Emissions

95102. Definitions.

(a) For the purposes of this article, the following definitions shall apply:

~~(1) "Accredited verifier" means an individual approved by the ARB to provide verification services for those subject to reporting.~~

(1) ~~(2)~~ "Adverse verification opinion" means ~~the final~~a verification opinion rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement and~~/or does~~ a qualifying statement as to whether or not ~~conform~~it conforms with the requirements of ~~the regulation, and that all verification services have been completed by the verification team~~this article.

(2) ~~(3)~~ "Annual" means ~~a period of time covering a calendar year from January 1 through December 31.~~with a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

(3) ~~(4)~~ "API" means the American Petroleum Institute.

(4) ~~(5)~~ "AQMD/APCD" means air quality management district or air pollution control district~~, as applicable to the facility location~~.

(5) ~~(6)~~ "ARB" means the California Air Resources Board.

(6) ~~(7)~~ "Asphalt" means a dark brown or black cementitious material (solid or liquid) of which the main constituents are bitumins ~~which~~that occur naturally or as a residue of petroleum refining.

(7) ~~(8)~~ "Asphalt blowing" means the process by which air is blown through asphalt flux to change the softening point and penetration rate.

(8) ~~(9)~~ "Asset controlling supplier" means any entity that operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them.

(9) ~~(10)~~ "Asset owning supplier" means any entity owning electricity generating facilities that delivers electricity to a transmission or distribution line~~.~~

(10) ~~(11)~~ "Associated gas" or "produced gas" means a natural gas ~~which is found~~that is produced from gas wells or gas produced in association with ~~crude oil either dissolved in the oil or as a cap of free gas above the~~the production of crude oil.

(11) ~~(12)~~ "Barrel" means a volume equal to 42 U.S. gallons.

(12) ~~(13)~~ "Best available data and methods" means ARB methods for emissions calculations ~~defined~~set forth in this article where reasonably feasible; or facility fuel use and other facility process data used in conjunction with ARB -provided emission factors and other data; or other generally accepted methods for calculating greenhouse gas emissions.

(13) ~~(14)~~ "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

(14) ~~(15)~~ "Biomass-derived fuels" or "biomass fuels" means fuels derived from biomass.

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

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

(17) ~~(18)~~ "British Thermal Unit " or "~~(~~Btu~~)~~" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

(18) ~~(19)~~ "Busbar" means the power conduit of an electric generating facility that serves as the starting point for the electric transmission system.

(19) ~~(20)~~ "Butane" ~~(C_4H_{10})~~ means a normally gaseous straight-chain or branch chain hydrocarbon extracted from natural gas or refinery fuel gas streams~~.~~ ~~It~~ and is represented by the chemical formula C_4H_{10}. Butane includes normal butane and refinery-grade butane.

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

(21) "CAISO" means the California Independent System Operator.

(22) "CAISO integrated forward market" is the electric power market conducted by the ~~California Independent System Operator~~CAISO that determines the best use of resources available while finding the least cost method of procuring required components.

(23) "CAISO markets" mean the ~~California Independent System Operator~~CAISO's real-time market and the day-ahead integrated forward market.

(24) "CAISO real-time market" means the electric power market conducted by the ~~California Independent System Operator~~CAISO where supplemental electric power is quickly bought or sold every ten minutes to accommodate power use just moments before it occurs.

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

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

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

(28) "California Climate Action Registry" means the entity established pursuant to Health and Safety Code Section 42900 et seq.

(29) "California Energy Commission" means the California Energy Resources Conservation and Development Commission.

(30) ~~(29)~~ "California eligible renewable resource" means an electric generating facility that the California Energy Commission has certified as an eligible renewable energy resource that may be used by a retail seller of electricity to satisfy its California Renewables Portfolio Standard Program procurement requirements, consistent with Public Utilities Code Sections 399.11 through 399.16 and Public Resources Code Sections 25740 through 25751.

(31) ~~(30)~~ "Capacity factor" means the amount of energy that an electric generating facility actually generates compared to its maximum rated output over a given period of time, usually one year.

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

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

(34) ~~(33)~~ "Catalyst coke" means carbon that is deposited on a catalyst, thus deactivating the catalyst.

(35) ~~(34)~~ "Catalytic cracking" means a refinery process of breaking down larger, heavier, and more complex hydrocarbon molecules ~~onto~~into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a ~~catalytic agent~~catalyst.

(36) ~~(35)~~ "Catalytic reforming" means a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

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

(38) ~~(37)~~ "Cementitious product" means cement, cement kiln dust, cement clinker, clinker dust, fly ash, slag, and other pozzolans.

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

(40) ~~(39)~~ "Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

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

(42) ~~(40)~~ "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–92 "Standard Classification of Coals by Rank" (as incorporated by reference in §72.13).

(43) ~~(41)~~ "Coal-derived fuel" means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquefied or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coal-derived coke).

(44) ~~(42)~~ "Cogeneration facility~~,~~" means an industrial structure, installation, plant, building, or self-generating facility, which may include one or more cogeneration systems that has sequential generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system.

(45) ~~(43)~~ "Cogeneration system~~,~~" means ~~the~~ individual cogeneration components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole.

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

(47) ~~(45)~~ "Coke burn-off" means ~~the~~ coke ~~removed~~removal from the surface of a catalyst by combustion ~~in the~~during catalyst ~~regenerator~~regeneration.

(48) ~~(46)~~ "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(49) ~~(47)~~ "Combustion source" means a ~~stationary fuel fired boiler, turbine, or internal~~source of emissions resulting from combustion~~ engine~~.

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

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

(52) ~~(50)~~ "Conveying system" means a device for transporting materials from one piece of equipment or location to another location within a facility.

Conveying systems include but are not limited to the following: feeders, belt conveyors, bucket elevators and pneumatic systems.

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

(54) ~~(52)~~ "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase which is found in natural underground reservoirs.

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

(56) ~~(54)~~ "De minimis" means those emissions reported for a source or sources that are calculated using alternatives methods selected by the operator, subject to the limits specified in section 95103(a)(6).

(57) ~~(55)~~ "Diesel fuel" means a fuel composed of distillates obtained in petroleum refining operation ~~or blends of such distillates with residual oil~~.

(58) ~~(56)~~ "Direct emissions" means greenhouse gas emissions from ~~applicable greenhouse gas emitting~~ sources that are under the operational control of the operator.

(59) ~~(57)~~ "Distillate fuel oil" means a general classification for a petroleum fraction produced in conventional distillation operations. It includes diesel fuels and fuel oils.

(60) ~~(58)~~ "Distributed emissions" means CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and~~, where applicable,~~ potentially other product outputs.

(61) ~~(59)~~ "District heating and cooling" means the distribution of heat or cooling from one or more sources to multiple buildings.

(62) ~~(60)~~ "Electric generating facility" means generating facility.

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

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

(65) ~~(63)~~ "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility.

(66) ~~(64)~~ "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator each year and submitted by electronic means to ARB that provides the information required by this article.

(67) ~~(65)~~ "Entity" means a ~~company~~person, firm, association, organization, partnership, business, trust, corporation, ~~nonprofit organization,~~LLC, company, or government agency~~ or other legally constituted body that has operational control over one or more facilities~~.

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

(69) ~~(67)~~ "Ethane" ~~(C_2H_6)~~ means a normally gaseous straight-chained hydrocarbon that boils at a temperature of -127.48 degrees Fahrenheit~~.~~ with a chemical formula of C_2H_6.

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

(71) ~~(69)~~ "Executive Officer" means the Executive Officer of the ARB or his or her delegate.

(72) ~~(70)~~ "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of way, and under common operational control, that emits or may emit any greenhouse gas~~ and is considered a single major industrial grouping as identified by first two digits of the North American Industry Classification System (NAICS). Under this definition, those in operational control~~. Operators of military installations may classify ~~military~~such installations as more than a single facility based on

distinct and independent functional groupings within contiguous military properties.

(73) ~~(71)~~ "Feed" means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust, and fly ash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

(74) ~~(72)~~ "Feedstock" means the raw material supplied to a process.

(75) ~~(73)~~ "Flare" means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means the combustion of vent gas in a flare.

(76) ~~(74)~~ "Flexicoking" means a thermal cracking process which converts heavy hydrocarbons such as crude oil, tar sands bitumen, and distillation residues into light hydrocarbons.

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

(78) ~~(76)~~ "Fluid catalytic cracking unit regenerator" means the portion of the fluid catalytic cracking unit in which coke burn-off and catalyst regeneration occurs, and includes the regenerator combustion air blower(s).

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

(80) ~~(78)~~ "Fly ash" means particles of ash, such as particulate matter which may also have metals attached to them~~that~~, which are carried up the stack of a combustion unit with gases during combustion.

(81) ~~(79)~~ "Fossil fuel" means a fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

(82) ~~(80)~~ “Fuel” means solid, liquid or gaseous combustible material.

(83) ~~(81)~~ “Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

(84) ~~(82)~~ “Fugitive emissions” means the unintended or incidental emissions of greenhouse gases from the transmission, processing, or transportation of fossil fuels or other materials, ~~such as~~including but not limited to HFCs from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and ~~also includes~~ CO_2 emitted ~~incidentally with~~from geyser steam and/or fluid used in geothermal generating facilities.

(85) “Fugitive source” means a source of fugitive emissions.

(86) ~~(83)~~ "Full verification" means all verification services as provided in section 95131.

(87) ~~(84)~~ “General stationary combustion facility” means a facility not otherwise subject to sector-specific reporting requirements that emits ≥25,000 metric tonnes of CO_2 in 2008 or any subsequent year from stationary combustion sources.

(88) ~~(85)~~ “Generating facility” means a facility that generates electricity and includes one or more generating units at the same location.

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

(90) ~~(87)~~ “Greenhouse gas” or “GHG” ~~(GHG)~~ means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs), as defined in section 39505(g) of the Health and Safety Code.

(91) ~~(88)~~ “Greenhouse gas source” means any physical unit or process that releases a greenhouse gas into the atmosphere.

(92) ~~(89)~~ “Gross generation” means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

(93) ~~(90)~~ “Global warming potential~~(~~” or “GWP~~)~~“ factor” means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

(94) ~~(91)~~ "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen~~, including fossil fuels and a variety of major air pollutants~~.

(95) ~~(92)~~ "Hydrofluorocarbons ~~(~~" or "HFCs~~)~~" means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

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

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

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

(99) ~~(96)~~ "Indirect energy" means electricity, thermal, or other energy sources provided by a retail provider or facility not owned or operated by the user of the energy.

(100) ~~(97)~~ "Kerosene" means a light distillate fuel having a maximum distillation temperature of 400 degrees Fahrenheit at the 10~~%~~ percent recovery point, a final boiling point of 572 degrees Fahrenheit and a minimum flash point of 100 degrees Fahrenheit. "Kerosene" includes No. 1-K and No. 2-K as well as other grades of kerosene called range or stove oil which have properties similar to those of No. 1 fuel oil.

(101) ~~(98)~~ "Kiln" means a device, including any associated preheater or precalciner devices. that produce clinker by heating limestone and other materials for subsequent production of Portland cement.

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

(103) ~~(100)~~ "Less intensive verification" means the verification services provided in interim years between full verifications ~~that~~; less intensive verification only ~~require~~requires data checks on a operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services.

(104) ~~(101)~~ “Liquefied petroleum gas~~ (~~” or “LPG~~)~~” means a petroleum hydrocarbon mixture containing propane, propene, butane, butene, and isobutane as its main components and is normally a gas but ~~which~~ can be compressed and condensed to a liquid.

(105) “Long-term power contract” means a power contract with a term of five years or more.

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

(107) ~~(102)~~ “Marketer” means a purchasing/selling entity that is not a retail provider, and that is ~~listed as~~ a purchasing/selling entity at the first point of delivery in California for electric power imported into California, or the last point of receipt for power exported from California. ~~A marketer is an operator delivering power to the first point of delivery inside California for imports or delivering power to the first point of delivery outside California for exports.~~

(108) ~~(103)~~ “Material misstatement” means ~~an error~~one or ~~errors~~more inaccuracies discovered in the course of verification that result in the total reported emissions, or reported purchases, sales, imports or exports of electricity, being outside the 95 percent accuracy required to receive a positive verification opinion.

(109) ~~(104)~~ “Methane~~ (~~” or “CH_4~~)~~” means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(110) ~~(105)~~ “Metric tonne” ~~(~~or “MT~~)~~“ or “tonne” means a common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.

(111) ~~(106)~~ “MMBtu” means million British thermal units.

(112) ~~(107)~~ “Mobile combustion emissions” means emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources~~ (e.g., cars, trucks, buses, trains, airplanes, ships, etc.).~~.

(113) “Mobile combustion source” means a source of greenhouse gas emissions resulting from combustion by a mobile source including, but not limited to, passenger cars, large/heavy duty truck cabs and chassis, light and medium duty trucks and vans, motorcycles, public transit buses, or military tanks or other tracked military vehicles, mobile cranes, bulldozers,

concrete mixers, street cleaners, golf carts, all terrain vehicles, trains, airplanes, boats, ships, implements of husbandry, hauling equipment used inside and around airports, docks, depots, industrial and commercial plants.

(114) ~~(108)~~ "Motor gasoline" means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158 degrees Fahrenheit at the 10-percent recovery point to 365 to 374 degrees Fahrenheit at the 90-percent recovery point.

(115) ~~(109)~~ "Multi-jurisdictional ~~utility~~retail provider" means a ~~distribution utility~~retail provider that provides electricity to end users in California and in one or more other states.

(116) ~~(110)~~ "NAICS" means North American Industry Classification System.

(117) ~~(111)~~ "Nameplate generating capacity" means the rated continuous load-carrying ability expressed in megawatts (MW)~~. Also,~~ or the maximum rated output of a generator under specific conditions designated by the manufacturer, whichever is greater.

(118) ~~(112)~~ "Naphtha" means a generic term applied to a petroleum fraction with an approximate boiling range between 122 degrees Fahrenheit and 400 degrees Fahrenheit.

(119) ~~(113)~~ "Natural gas" means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions.

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

(121) ~~(115)~~ "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow ~~within,~~ between~~,~~ or across ~~electric utility company territories~~control areas.

(122) ~~(116)~~ “No. 1 diesel fuel” means a light distillate that has a distillation temperature of 55 degrees Fahrenheit at the 10~~-~~ percent recovery point and 550 degrees Fahrenheit at the 90-percent recovery point.

(123) ~~(117)~~ “No. 1 distillate” means a petroleum distillate that can be used as either a diesel fuel or a fuel oil.

(124) ~~(118)~~ “No.1 fuel oil” means a light petroleum distillate fuel having a maximum distillation temperature of 190 degrees Celsius at the 10~~%~~ percent recovery point and 275 degrees Celsius at the 90~~%~~ percent recovery point.

(125) ~~(119)~~ “No. 2 diesel fuel” means a distillate fuel that has a distillation temperature of 640 degrees Fahrenheit at the 90~~-~~ percent recovery point.

(126) ~~(120)~~ “No. 2 distillate” means a petroleum distillate that can be used as either a diesel fuel or a fuel.

(127) ~~(121)~~ “No.2 fuel oil ~~(~~” or “heating oil~~)~~” means a distillate fuel oil that has distillation temperatures of 640 degrees Fahrenheit at the 90~~%~~ percent recovery point.

(128) ~~(122)~~ “No. 4 fuel” means a distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks.

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

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

(131) ~~(125)~~ “North American Industry Classification System” means a standard for use by Federal statistical agencies in classifying business establishments for the collection, analysis, and publication of statistical data related to the business economy of the United States.

(132) ~~(126)~~ “Null power” means any electricity produced by a renewable energy electric generating facility from which a Western Renewable Energy Generation Information System (WREGIS) certificate has been unbundled and sold separately.

(133) ~~(127)~~ "Operator" means the ~~company or organization~~entity having operational control of a facility or entity ~~for~~from which an emissions data report is otherwise required under this article. For purposes of reporting

electricity transactions as required in section 95111, “operator” means ~~the company or organization that is the~~a retail provider or marketer.

(134) ~~(128)~~ “Operational control” for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple parties, the party holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of ~~submitting the emissions data report~~this article.

(135) ~~(129)~~ “Pacific Northwest” means Washington, Oregon, Idaho, Montana, and British Columbia.

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

(137) ~~(131)~~ “Petroleum” means oil removed from the earth and the oil derived from tar sands, shale and coal.

~~(132) “Petroleum coke” means a residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking.~~

(138) ~~(133)~~ “Petroleum refinery” or “refinery” means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(139) ~~(134)~~ “Point of delivery” means a point on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider’s transmission and distribution systems are connected to another system.

(140) ~~(135)~~ “Point of receipt” means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

(141) ~~(136)~~ “Point source” means any separately identifiable stationary point from which greenhouse gases are emitted.

(142) ~~(137)~~ “Portable” is as defined in title 17, California Code of Regulations, Section 93116.2(bb).

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

(144) ~~(139)~~ "Positive verification opinion" means the final opinion rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement ~~and~~with a qualifying statement as to whether or not the emissions data report conforms ~~with~~to the requirements of this article~~, and that all verification services have been completed by the verification team.~~.

(145) "Power" means electricity, except where the context make clear that another meaning is intended.

(146) ~~(140)~~ "Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(147) ~~(141)~~ "Pressure swing adsorption ~~(~~" or "PSA~~)~~" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

(148) ~~(142)~~ "PSA off-gas" or "tail-gas" means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

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

(150) ~~(144) "Process emissions" means greenhouse gas emissions other than combustion emissions occurring as a result of~~"Process" means the intentional ~~and~~or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(151) "Process emissions" means greenhouse gas emissions other than combustion emissions occurring as a result of a process.

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

(153) ~~(146)~~ "Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation~~. Process vents include openings where gas streams are discharged to the atmosphere directly or are discharged to the atmosphere after being routed to a control device or a product recovery device~~.

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

(155) ~~(148)~~ "Propane" ~~(C_3H_8)~~ means a normally straight chain hydrocarbon that boils at -43.67 degrees Fahrenheit~~.~~ and is represented by the chemical formula C_3H_8.

(156) ~~(149)~~ "Purchasing/selling entity" means an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

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

(158) ~~(151)~~ "Purge gas" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header~~;~~.

(159) ~~(152)~~ "Qualifying facility" means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

(160) ~~(153)~~ "Reasonable assurance" means a high degree of confidence that submitted data and statements ~~should be treated as~~are valid.

(161) ~~(154)~~ "Recycled" refers to a material that is ~~used or~~ reused~~,~~ or reclaimed.

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

(163) ~~(156)~~ "Renewable energy" means ~~resources~~energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy

derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(164) ~~(157)~~ "Report year" means the calendar year for which emissions are being reported in the emissions data report.

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

(166) ~~(159)~~ "Retail provider" means an ~~operator~~entity that is ~~any~~an electric corporation as defined in Public Utilities Code ~~Section~~section 218, electric service provider as defined in Public Utilities Code Section 218.3, public owned electric utility as defined in Public Resources Code ~~Section~~section 9604, community choice aggregator as defined in Public Utilities Code ~~Section~~section 331.1, or the Western Area Power Administration~~, or the California Department of Water Resources~~.

(167) ~~(160)~~ "Screening value" ~~(~~or "SV~~)~~" means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in U.S. E.P.A. Method 21 – Determination of Volatile Organic Compound Leaks.

(168) ~~(161)~~ "Sector" means a broad industrial categorization such as specified in section 95101(b).

(169) ~~(162)~~ "Self-generation facility" means a facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

~~(163) "Source" means a stationary point source or a collection of stationary point sources of the same type on the same facility.~~

(170) "Small refiner" means any refiner who conforms to the definition of small refiner in California Code of Regulations, Title 13, Division 3, Chapter 5, Article 1, Subarticle 2, as incorporated herein by reference.

(171) ~~(164)~~ "Source~~ stream~~" means ~~a specific fuel type, raw material or product giving rise to emissions of relevant greenhouse gases at one or more emission sources as a result of its consumption or production.~~any source, or category of sources, of greenhouse gas emissions.

(172) ~~(165)~~ "Southwest" means Arizona, Nevada, Utah, Colorado, and western New Mexico.

(173) ~~(166)~~ "Specified source of power" or "specified source" means a particular generating unit or facility ~~whose~~for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract~~.~~

~~(167) "Specified wholesale sales" means wholesale electric power sales made by retail providers that can be matched to a specified source of power~~, including any California eligible renewable resource.

(174) ~~(168)~~ "Standard conditions" means a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and an absolute pressure of 760 mm (30 inches) of mercury.

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

(176) ~~(169)~~ "Stationary" means neither portable nor self propelled and is operated at a single facility.

(177) ~~(170)~~ "Stationary combustion source" means a stationary source of emissions from ~~the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.~~

~~(171) "Still gas (refinery gas)" means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes~~combustion activities.

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

~~(173) "Substitute energy" means electric power delivered under a facility-specific contract that was not produced by the facility specified in the contract.~~

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

(180) ~~(175)~~ "Sulfur recovery unit" means a ~~refinery unit that removes sulfur from distillate fuel.~~process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(181) ~~(176)~~ "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle plant, or in the

electric generating or manufacturing process of a bottoming-cycle cogeneration facility.

(182) ~~(177)~~ "Tactical support equipment" is as defined in Title 17, California Code of Regulations, section 93116.2(~~ii~~a)(36).

(183) ~~(178)~~ "Ton" means a short ton equal to 2000 pounds.

(184) ~~(179)~~ "Topping cycle plant" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal ~~energy~~output.

(185) ~~(180)~~ "Total organic carbon or TOC" means a measure of the total organic carbon molecules present in a sample.

(186) ~~(181)~~ "Transferred CO_2" means carbon dioxide that is not emitted directly at the facility but is sold and transferred out of the installation as a pure substance.

~~(182) "Uncertainty" means a parameter, associated with the results of the determination of a quantity, that characterizes the dispersion of the values that could reasonably be attributed to the particular quantity, including the effects of systematic as well as random factors and expressed in percent and describes a confidence interval around the mean value comprising 95% of inferred values taking into account any asymmetry of the distribution of values.~~

(187) "Uncertainty" means a measure of the amount of doubt or distrust with which the data should be used.

(188) ~~(183)~~ "Unspecified source of power" or "unspecified source" refers to electricity generation that cannot be matched to a particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

(189) "Useful power output" means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

(190) ~~(184)~~ "Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(191) ~~(185)~~ "Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with ARB's procedures and methods for calculating and reporting GHG emissions.

(192) ~~(186)~~ "Verification body" means an ARB -accredited firm or an AQMD/APCD that is able to render a verification opinion and provide verification services for operators subject to reporting under this article.

(193) ~~(187)~~ "Verification cycle" means one year of full verification and the proceeding two years of verification requirements for operators subject to annual verification. For operators subject to triennial verification, a "verification cycle" means one year of full verification, and if elected, the proceeding two years of less intensive verification. A verification cycle ~~can not~~cannot exceed 3 calendar years.

(194) ~~(188)~~ "Verification opinion" means the final opinion rendered by a verification ~~firm~~body attesting whether or not an operator's emissions data report is free of material misstatement and that all verification ~~process checklist items~~services as provided in section 95131 have been completed by the verification ~~firm~~body.

(195) ~~(189)~~ "Verification services" means services provided during verification as specified in section 95131, including but not limited to reviewing an operator's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator's compliance with this article, and submitting a verification opinion to the ARB.

(196) ~~(190)~~ "Verification team" means ~~more than one verifier~~all of those working for a verification body, including all subcontractors, ~~acting for a verification body~~ to provide verification services for ~~a client~~an operator. The lead verifier for the verification team shall be a lead verifier in the verification body.

(197) ~~(191)~~ "Verified emissions data report" means an emissions data report that has been reviewed ~~and approved~~ by a third-party verifier and has a verification opinion accepted by the ARB.

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

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

(200) ~~(193)~~ "Wastewater" means any process water which contains oil, emulsified oil, or other organic compounds ~~which~~that are not recycled or otherwise used in a facility.

(201) ~~(194)~~ "Wastewater separator" means equipment used to separate oils and water from locations downstream of process drains.

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

95103. General Greenhouse Gas Reporting Requirements.

(a) ***General Reporting Requirement.*** The operators listed in section 95101(b), except as provided in section 95103(e), shall submit greenhouse gas emissions data reports on the schedule specified in section 95103(b).

(1) The operator shall submit a report for the 2008 report year that applies best available data and methods to develop emissions estimates. The operator shall submit a report for the 2009 and subsequent report years that meets all specifications of this article.

(2) ***Stationary sources.*** The operator shall identify, calculate, and report all ~~direct~~ CO_2, N_2O, and CH_4 emissions from stationary combustion, process, and fugitive sources at the facility as specified in sections 95110 through 95115. The operator shall calculate and report each GHG separately for each fuel type used, and for each process unit as applicable, as specified in sections 95110 through 95115 except where specific unit-level fuel use is not separately metered.

(3) The operator shall separately identify, calculate and report all direct emissions of CO_2 resulting from combustion of biomass-derived fuels as specified in sections 95110 through 95115;

(4) ***Mobile sources.*** The operator may elect to identify, calculate, and separately report facility CO_2, N_2O, and CH_4 emissions from mobile combustion using the methods specified in section 95125(i).

(5) The operator shall separately calculate and report consumption of purchased or acquired electricity, heat, cooling or steam when specified in sections 95110 through 95115.

(6) ***Emissions calculation and reporting procedures for de minimis sources.*** The operator may elect to designate ~~up to~~one or more sources as *de minimis* that collectively produce no more than 3 percent of the facility's total CO_2 equivalent emissions~~ fro discrete sources, not to exceed a total of 10,000 metric tonnes, as *de minimis* for purposes of applying the calculation methods specified in this article~~, but in no case designating in excess of 20,000 metric tonnes CO_2 equivalent emissions. The operator may estimate emissions for these ~~emissions~~*de minimis* sources using alternative methods of the operator's choosing, subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated and estimated do not exceed the applicable *de minimis* limit. The operator shall separately identify and include in the emissions data report the emissions designated as *de minimis*. The operator

shall determine CO_2 equivalence according to the 100-year global warming potentials provided in Appendix A.

(7) The operator shall report information in the units of measurement specified in sections 95110 through 95115, to the nearest whole unit.

(8) ***Fuel analytical data capture.*** When the applicable emissions estimation methodologies in sections 95110 through 95125 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(A) If the operator is unable to obtain ~~a~~ fuel analytical data ~~capture rate~~ such that more than 20 percent of emissions ~~for~~from a source cannot be directly accounted for, and the source~~(s)~~ for which data are missing ~~are~~is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the emissions from that source shall be considered unverifiable for the report year.

(B) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source ~~as applicable~~identified in sections 95110 through 95125, and that source is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(9) ***Fuel activity measurement uncertainty.*** The operator shall employ procedures for the measurement of fuel activity data (mass or volume flow) that quantifies fuel use with an uncertainty of ~~no~~not more than ~~±~~ ~~2.5~~5 percent. All fuel activity measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of measurement uncertainty. The operator shall make available to the verification team documentation of measurement uncertainty within this range. For solid fuels, the operator shall validate fuel consumption estimates with quarterly belt or conveyor scale calibrations, and retain record of such calibrations.

(10) In cases where this article specifies a choice between use of a fuel-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions from combustion, the operator shall make this choice and continue to use the method chosen for all future emissions data reports.~~, except as specified in section 95103(a)(10)(A). (A)~~ When an operator elects to install a new CEMS ~~or CEMS CO2 monitor~~ prior to January 1, ~~2010,~~2011, the operator may report combustion emissions on the basis of the fuel-based calculation specified in this article for the

~~2008~~2008, 2009, and ~~2009~~2010 report years. The new CEMS ~~or CEMS CO2 monitor~~ shall be installed and operated according to requirements in section 95125(g), and become operational for purposes of emissions reporting by January 1, ~~2010.~~ 2011.

(b) ***Reporting Schedule – Existing Facilities.*** Operators of the facilities and entities listed in section 95101(b) ~~that~~, except as provided in section 95103(e), which are operational as of January 1, ~~2008~~2008, must submit ~~greenhouse gas~~ emissions data reports to ARB for emissions in 2008 and each ~~future~~subsequent calendar year. Operators shall submit these reports in the calendar year following each report year as specified in the following schedule:

(1) The following operators subject to the requirements of this article shall submit a complete emissions data report to the ARB no later than April 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:

(A) Operators of general stationary combustion facilities, excluding oil and gas facilities with a NAICS code of 211111;

(B) ~~(1) Operators of general stationary combustion facilities outside the oil and gas sector (NAICS 211111) and~~Operators of electric generating facilities and cogeneration facilities not under the operational control of a retail provider, cement plant operator, refinery operator, ~~or hydrogen plant operator subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than April 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year.~~hydrogen plant operator, or oil and gas facility with a NAICS code of 211111;

(2) ~~Retail providers, marketers, operators of general stationary combustion facilities within the oil and gas sector (NAICS 211111), operators of cement plants, petroleum refineries, and hydrogen plants~~The following operators subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than June 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:~~.~~ ~~When the operator has operational control of an electric generating facility or cogeneration facility subject to the requirements of this article, the operator shall submit by the same date an emissions data report for this facility that meets the requirements of sections 95111 and 95112 as applicable.~~

(A) Retail providers;

(B) Marketers;

(C) Operators of general stationary combustion facilities within the oil and gas sector with a NAICS code of 211111;

(D) Operators of cement plants;

(E) Operators of petroleum refineries;

(F) Operators of hydrogen plants.

(c) ***Verification – Existing Facilities.*** Operators of all facilities subject to the reporting requirements of this article shall obtain verification services for emissions data reports submitted in 2010 and subsequent years from a verification body that meets the requirements of sections 95131 through 95133. Verification shall be obtained as provided in the following schedule.

(1) ***Annual schedule.*** ~~Retail providers, marketers, and operators of petroleum refineries, hydrogen plants, general stationary combustion facilities in the oil and gas sector (NAICS 211111), and electric~~The following operators shall obtain verification of each annual emissions data report:

(A) Retail providers, marketers, and operators of petroleum refineries and hydrogen plants;

(B) General stationary combustion facilities in the oil and gas sector identified by NAICS code of 211111;

(C) Electric generating and cogeneration facilities that combust fossil fuels and have a total nameplate generating capacity $\geq$10 MW~~ shall obtain verification of each annual emissions data report~~.

(2) ***Triennial schedule commencing in 2010.*** The following shall obtain verification of the emissions data report submitted in 2010, and shall obtain verification of the emissions data reports submitted every third year thereafter~~. .~~ ~~Operators of cement plants and electric generating and cogeneration facilities that combust pure biomass fuels or have a total nameplate generating capacity <10 MW shall obtain verification of the emissions data report submitted in 2010, and Operators of general stationary combustion facilities outside the oil and gas sector (NAICS 211111) shall obtain verification of the emissions data report submitted in 2011, and of the emissions data reports submitted every third year thereafter. If~~:

(A) Operators of cement plants; however, if any change in materials or operations occurs at a cement plant ~~that~~ requires a change in a permit filed with an air pollution control district or air quality management district, the operator of the cement ~~plan~~plant shall obtain verification of the ~~submitted~~ emissions data report ~~for~~that covers the first full calendar year following the permit change~~.~~, in addition to the regular triennial schedule;

(B) Operators of electric generating or cogeneration facilities that combust pure biomass fuels;

(C) Operators of electric generating or cogeneration facilities that have a total nameplate generating capacity <10 MW.

(3) ***Triennial schedule commencing in 2011.*** The following shall obtain verification of the emissions data report submitted in 2011, and shall obtain verification of the emissions data reports submitted every third year thereafter:

(A) Operators of general stationary combustion facilities, excluding facilities in the oil and gas sector identified by NAICS code 211111.

(4) ~~(3)~~ ***Verification opinion due dates.*** In the calendar years when verification is required, the ~~operator~~verification body shall submit to the ARB the verification opinion specified in section 95131(c)(1) no later than six months after the deadlines specified in section 95103(b) for submitting emission reports.

(A) For operators ~~with~~having an emissions data report due April 1, as specified in section 95103(b)(1), the verification opinion must be submitted no later than October 1 of the same calendar year;

(B) For operators ~~with~~having an emissions data report due June 1, as specified in section 95103(b)(2), the verification opinion must be submitted no later than December 1 of the same calendar year.

(d) ***Reporting Schedule – New Facilities.*** ~~All operators~~Any operator described in section 95101(b), except as provided in section 95103(e), that ~~commence operation~~commences operations after January 1, 2008 ~~must report greenhouse gas emissions. The~~must submit its initial ~~facility GHG~~ emissions data report ~~data shall be submitted~~ based on emissions produced during the first full calendar year of operation and any subsequent years. The emissions data report and a verification opinion shall be submitted during the year following the first full calendar year of operation~~, by the month and day of the year as specified for the relevant industrial sector~~ according to the schedule in sections 95103(b) and (c).

(e) ***Cessation of Reporting After Reduced Emissions.***

(1) When the operation of a general stationary combustion facility, refinery, or hydrogen plant subject to the requirements of this article is changed such that the operator has reported less than 20,000 metric tons of CO_2 from combustion for three consecutive report years, the operator shall be exempted from further reporting until CO_2 emissions from combustion again ~~exceed~~exceeds 25,000 metric tonnes in any ~~future~~ calendar year.

(2) When the operation of ~~a power generation~~an electric generating or cogeneration facility subject to this article is changed such that the operator has reported less than 2,000 metric tons of CO_2 for three consecutive report years, the operator shall be exempted from further reporting until CO_2 emissions again exceeds 2,500 metric tonnes in any ~~future~~ calendar year.

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

95104. Greenhouse Gas Emissions Data Report.

(a) ***Emissions Data Report.*** Operators subject to this article shall submit emissions data reports according to the schedule specified in section 95103(b), except as provided in section 95103(e). Emissions data reports shall include the information below and the additional data specified in sections 95110 through 95115, as applicable.

(1) Facility name, identification number, physical address, mailing address, location, NAICS code;

(2) A description of facility or entity boundaries for the report, including geographic location;

(3) Name of the person responsible for ~~reporting and his or her~~preparing and submitting the emissions report, and contact information, including e-mail address, and telephone number;

(4) The report year;

(5) The direct GHG emissions, electricity transactions information, and other data specified in sections 95110 through 95115 as applicable to the operator, including emissions occurring during routine maintenance, start-ups, shutdowns, upsets and downtime ~~subject to the limitations of section 95103(a)(8)~~;

(6) Indirect electric and thermal energy consumed for electricity, heat, steam, and cooling when required for the facility as specified in sections 95110 through 95115;

(7) Efficiency metrics when required for the facility as specified in sections 95110 through 95115;

(8) The parent company or companies with ownership of the facility that is the subject of the report;

(A) ~~(8) The parent company or companies with ownership of the facility that is the subject of the report, and a~~A list of all facilities and offices in California owned or operated by that parent company, including subsidiary facilities and offices not subject to the requirements of this article~~. The operator may elect to have this information submitted separately by the parent company for all facilities under its ownership and operational control, with indication of the parent company's ownership share and operational control for each~~ that emit direct GHG emissions from combustion that is not for the purpose of facility space heating;

(B) ~~(9)~~ Contact information for the companies and facilities provided in section 95104(a)(8)(A), including physical addresses, e-mail addresses if available, and telephone numbers~~;~~

(C) The operator may elect to have information required by sections 95105(a)(8)(A)-(B) submitted separately by the parent company for all facilities under its ownership and operational control;

(D) The operator may also elect to provide a single contact person, e-mail, and phone contact for all facilities listed under the requirements of section 95105(a)(8)(A)-(B);

(E) Information provided under 95104(a)(8) is not subject to the verification requirements of this article.

(9) ~~(10)~~ A signed and dated statement provided by the operator that the ~~GHG~~ report has been prepared in accordance with this article, and that the statements and information contained in the emissions data report are true and accurate to the best knowledge and belief of the certifying official.

(b) ***Maintaining the GHG Inventory Program.*** To facilitate annual compilation of the emissions data report, the operator shall maintain a greenhouse gas inventory program that ensures that emissions calculations and electricity transactions information are transparent, accurate, and independently verifiable. The operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of greenhouse gas emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this article.

(c) ***Data Completeness.*** To facilitate replication of the emissions and electricity transactions information reported as specified by this article by the verification team or another party including ARB, the operator shall establish, document, implement and maintain a system that provides clarity, transparency, and completeness of data. The operator shall make every reasonable effort to complete emissions data reports that contain no material misstatements and are in conformance with the emission calculation methodologies and factors specified by this article. The operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.

(d) ***Revisions.*** The operator may revise a submitted emissions data report in the following circumstances. The operator shall maintain documentation to support any revisions made to a previously submitted emissions data report. Documentation for all emissions data report ~~submittals~~revisions shall be retained by the operator for five years, as specified in section 95105.

(1) If during the course of receiving verification services and prior to completion of a verification opinion an operator chooses to make a correction or improvement to the report.

(2) If an operator wishes to correct or improve an emissions data report not subject to verification, provided those changes are documented and approved by ARB;

(3) If an operator wishes to correct or improve a verified emissions data report within five years of submittal, in which case the revision must also be made subject to verification.

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

95105. Document Retention and Record Keeping Requirements.

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain documents regarding the design, development and maintenance of the GHG inventory, in paper, electronic or other format, for a period of not less than five years following submission of each emissions data report. The documented and archived GHG emissions estimation data shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by ARB, the operator shall provide to ARB within 20 days ~~any~~all data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least five years after the submission of the report:

(1) The list of all ~~source streams~~sources included in the emission estimates;
(2) The activity data used to calculate emissions for each source ~~stream~~, categorized by process and fuel or material type;
(3) Documentation of the process for collecting activity data for the facility and its ~~source streams~~sources;
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided by ARB;
(6) Any facility or other input data used for emission estimates;
(7) Documentation of biomass fractions for specific fuels;
(8) Record of electric power purchase and sale transactions, including imports and exports of power from California;
(9) The activity data, emissions, or other data submitted to the ARB under this article;
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) The emissions data report; and
(12) Any other information that is required for the verification of the emissions data report.

(13) Beginning January 1, 2009, reporters shall maintain a log for each reporting period documenting all procedural changes made in GHG accounting methods and changes to instrumentation critical to GHG emissions determination.

(d) For measurement based methodologies, each operator shall retain the following information for at least five years after the submission of the emissions data report:

(1) The list of all emission sources monitored;
(2) Collected monitoring data;
(3) The data used for the uncertainty analysis of emissions from each emissions source, categorized by process;
(4) Quality assurance and quality control information including information regarding any measurement gaps ~~as applicable~~;
(5) The data used for the corroborating calculations;
(6) A detailed technical description of the continuous measurement system including the documentation of the approval from the competent authority;
(7) Raw and aggregated data from the continuous measurement system; including documentation of changes over time and the log book on tests, down-times, calibrations, servicing and maintenance;
(8) Documentation of any changes in continuous measurement systems.

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

95106. Confidentiality.

(a) ~~The following information~~Emissions data submitted to the ARB under this article is public information and shall not be designated as confidential~~: estimates of direct facility emissions of any greenhouse gases by major source category (combustion, process, fugitive)~~.

(b) ~~Except as provided in section 95106(a), any~~Any person submitting information to the ARB pursuant to this article may designate ~~such~~ information that is not emissions data as confidential because it is a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 39600, 41511, and 38530, Health and Safety Code.

95107. Enforcement.

~~(a) Failure to submit any report or information required by this article shall constitute a single, separate violation of this article for each day until the information is submitted.~~

(a) ~~(b)~~ Knowing submission of false information, with intent to deceive, to the Executive officer or a verifier, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer.

(b) ~~(c) Late~~Failure to submit any report or to include in a report all information required by this article, or late submittal of ~~an emissions data~~any report ~~or verification opinion~~, shall constitute a single, separate violation of ~~the requirements of~~ this article for each day that the ~~information~~report has not been submitted beyond the specified reporting ~~dates~~date. For the purposes of this section, "report" means any emissions data report, verification opinion, or other document required to be submitted by this article.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 39600, 41511, and 38530, Health and Safety Code.

95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

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

95109. Incorporation by Reference.

The following documents are incorporated by reference in this article. These materials are incorporated as they exist on the date ~~of the approval~~this article is adopted.

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (2006), ASTM D240-02 (2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04 (Reapproved 2002), ASTM D2503-92 (Reapproved 2002), ASTM D1945-03 (Reapproved 2006), ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a (2006), ASTM D388–92 (1992), ASTM Specification D1835-05 (2005), ASTM Specification D3699 (2006), ASTM Specification D4814-07a (2007).

(b) *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities*, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) *Control of Emissions from Refinery Flares*, South Coast Air Quality Management District, Amended November 4, 2005.

(d) *U.S. EPA TANKS Version 4.09D*, US Environmental Protection Agency, October 2005.

(e) *California Code of Regulations*, Title 13. Motor Vehicles, Division 3. Air Resources Board, Chapter 5. Standards for Motor Vehicle Fuels, Article 1. Standards for Gasoline, Subarticle 2. Standards for Gasoline Sold Beginning March 1, 1996.

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

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

95110. Data Requirements and Calculation Methods for Cement Plants.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a cement plant shall include the following information in the ~~greenhouse gas~~ emissions data report for each report year.

(1) Total Emissions:
- (A) Total CO_2 emissions (metric tonnes)
- (B) Total CH4 emissions (metric tonnes)
- (C) Total N20 emissions (metric tonnes)

(2) Process CO2 Emissions from Cement Manufacturing:
- (A) Clinker Based Methodology for CO_2 Estimates
  1. Clinker emission factor (kg CO_2/metric tonnes clinker)
     a. Quantity of clinker produced (metric tonnes)
     b. Lime (CaO) Content of clinker (percent)
     c. Magnesium Oxide (MgO) Content of clinker (percent)
     d. Non-carbonate CaO (percent)
     e. Non-carbonate MgO (percent)
  2. Cement kiln dust (CKD) emission factor (kg CO_2/metric tonnes clinker)
     a. Plant specific CKD calcination rate (unitless)
     b. Quantity of CKD discarded (metric tonnes)
  3. CO_2 emissions from clinker production (metric tonnes)
- (B) Total Organic Carbon (TOC) Content in Raw Materials:
  1. Amount of raw material consumed in the report year (metric tonnes)
  2. Organic carbon content of raw material (percent)
  3. CO_2 emissions from TOC in Raw Materials (metric tonnes)

(3) Stationary Combustion:
- (A) Fuel consumption by fuel type (scf, gallons, or tons)
- (B) Average carbon content by fuel type if measured or provided by fuel supplier (kg Carbon/MMBtu)
- (C) Average high heat value by fuel type if measured or provided by fuel supplier (HHV)
- (D) CO_2 emissions by fuel type (metric tonnes)
  1. CO_2 emissions from biomass-derived fuels (metric tonnes)
- (E) CH_4 emissions by fuel type (metric tonnes)
- (F) N_2O emissions by fuel type (metric tonnes)

(4) Fugitive Emissions:
   (A) Coal consumption by coal type (~~metric tonnes~~tons)
   (B) Emission factor (standard cubic feet (scf) CH_4/metric tonne)
   (C) CH_4 Emissions from coal storage (metric tonnes)

(5) Indirect Energy Usage
   (A) Electricity purchases from each electricity provider (kWh)
   (B) Steam, heat, and cooling purchases from each energy provider (Btu)

(6) Efficiency Metrics
   (A) CO_2 emissions per metric tonne of cementitious product
      1. Amount of own clinker consumed (metric tonnes)
      2. Amount of clinker added to stock (metric tonnes)
      3. Amount of clinker sold directly (metric tonnes)
      4. Amount and type of clinker substitutes consumed for blending (metric tonnes)
      5. Amount and type of cement substitutes consumed for blending (metric tonnes)
   (B) CO_2 emissions per metric tonne of clinker
      1. Amount of own clinker consumed (metric tonnes)
      2. Amount of clinker added to stock (metric tonnes)
      3. Amount of clinker sold directly (metric tonnes)

(b) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cement plants shall calculate emissions and indirect energy usage for each source as specified in this section.

(1) ***Total CO_2 Emissions.*** Operators of cement plants shall calculate total CO_2 emissions from either (A) or (B) below.

(A) Continuous emissions monitoring systems (CEMS) as specified in section 95125(g). Operators of cement plants that measure CO_2 emissions using CEMS shall also report fuel usage by fuel type~~.~~, or

(B) Process CO_2 emissions from cement manufacturing as specified in section 95110(c) and stationary combustion CO_2 emissions as specified in section 95110(d).

(2) ***Direct N_2O and CH_4 Emissions.*** Operators of cement plants shall calculate N_2O and CH_4 emissions from fuel combustion as specified in section 95125(b).

(3) ***Direct Fugitive Emissions .*** Operators of cement plants shall calculate fugitive CH_4 emissions from coal fuel storage as specified in section 95125(j).

(4) ***Indirect Energy Usage.*** Operators of cement plants shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

(5) ***Electric Generating Units***. Operators of cement plants with electric generating units subject to the requirements of this article shall meet the requirements of section 95111.

(6) ~~(5)~~ ***Cogeneration.*** Operators of cement plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(7) ~~(6)~~ ***Efficiency Metrics.*** Operators of cement plants shall calculate CO_2 emissions per metric tonne of cementitious product as specified in section 95110(e).

(c) ***Process CO_2 Emissions from Cement Manufacturing.*** Operators of cement plants shall calculate CO_2 emissions from clinker production using the Clinker-Based Methodology as specified in section 95110(c)(1). Operators shall calculate CO_2 process emissions from the total organic carbon (TOC) content in raw materials as specified in section 95110(c)(2).

(1) **Clinker-Based Methodology*.*** Operators of cement plants shall calculate CO_2 emissions from clinker production using a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section~~, 95110(b)(1)~~.

Clinker-Based Methodology

$$CO_2 \text{ Emissions (metric tonnes)} = [(Cli) \times (EF_{Cli})] + [(CKD) \times (EF_{CKD})]$$

Where:

Cli	=	Quantity of clinker produced, metric tonnes
EF_{Cli}	=	Clinker emission factor, metric tonnes CO_2/metric tonnes clinker computed as specified in section 95110(~~b~~c)(1)(A)
CKD	=	Quantity CKD discarded, metric tonnes
EF_{CKD}	=	CKD emission factor, computed as specified in section 95110(~~b~~c)(1)(B)

(A) ***Clinker Emission Factor (EF_{Cli}).*** Cement plant operators shall calculate a plant-specific clinker emission factor for each report year based on the percent of measured CaO and MgO content in the clinker and adjusted to account for non-carbonate CaO and MgO using the Clinker Emission Factor equation specified in this section, 95110(~~b~~c)(1)(A). Each fraction of non-carbonate sources (e.g., steel slag, calcium silicates or fly ash) of CaO and MgO shall be subtracted from the total amount of CaO and MgO content of the clinker.

Clinker Emission Factor:

EF_{Cli} = [(CaO content – non-carbonate CaO) x Molecular ratio of CO_2/CaO] + [(MgO Content – non-carbonate MgO) x Molecular Ratio of CO_2/MgO]

Where:

CaO Content (by weight)	=	CaO content of Clinker (%)
Molecular Ratio of CO_2/CaO	=	44g/56g = 0.785
MgO Content(by weight)	=	MgO content of Clinker (%)
Molecular Ratio of CO_2/MgO	=	44g/40g = 1.092
Non-carbonate CaO (by weight)	=	Non-carbonate CaO of Clinker (%)
Non-carbonate MgO(by weight)	=	Non-carbonate MgO of Clinker (%)

(B) ***CKD Emission Factor.*** Operators of cement plants that generate CKD and do not recycle the CKD back to the kiln shall calculate a plant-specific CKD emission factor. The CKD emission factor shall be calculated using the CKD Emission Factor equation specified in this section, 95110(~~b~~c)(1)(B). The CKD emission factor (EF_{CKD}) shall be calculated using the Plant-specific CKD Calcination Rate (d) equation below.

CKD Emission Factor

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \frac{EF_{Cli}}{1 + EF_{Cli}} \times d}$$

Where:

EF_{CKD}	=	CKD Emission Factor
EF_{Cli}	=	Clinker Emission Factor
d	=	CKD Calcination Rate

Plant-specific CKD Calcination Rate

$$d = 1 - \frac{fCO_{2\,CKD} \times (1 - fCO_{2\,RM})}{(1 - fCO_{2\,CKD}) \times fCO_{2\,RM}}$$

Where:

$fCO_{2\,CKD}$ = weight fraction of carbonate CO_2 in the CKD

$fCO_{2\,RM}$ = weight fraction of carbonate CO_2 in the raw material

(2) ***TOC Content in Raw Materials.*** Operators of cement plants shall calculate CO_2 emissions from the TOC content in raw materials by applying an assumed 0.2 percent ~~assumed~~ organic carbon factor to the amount of raw material consumed then converting from carbon to CO_2 using the equation below.

TOC Content in Raw Materials

$$CO_2 \text{ emissions} = (TOC_{R.M.}) \times (R.M.) \times (3.664)$$

Where:

$TOC_{R.M}$	=	0.2% = Organic carbon content of raw material (%)
R.M.	=	The amount of raw material consumed (metric tonnes/yr)
3.664	=	The CO_2 to carbon molar ratio

(d) ***Stationary Combustion CO_2 Emissions.*** Operators of cement plants shall calculate stationary combustion CO_2 emissions at cement kiln and non-kiln units separately based on the quantity and type of fuel combusted during each report year as specified in this section.

(1) Natural Gas: Operators of cement plants that combust natural gas shall calculate CO_2 emissions resulting from the combustion of natural gas using the method provided in section 95125(c) or section 95125(d).

(2) Coal or Petroleum Coke: Operators of cement plants that combust coal or petroleum coke shall calculate CO_2 emissions using the method provided in section 95125(d). Operators of cement plants shall measure and record coal consumption and carbon content weekly.

(3) Other Fossil Fuels: Operators of cement plants that combust ~~No. 1, No. 2 fuels, gasoline, diesel fuel,~~ middle distillates (such as diesel, fuel oil, or kerosene), residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(4) Refinery Fuel Gas: Operators of cement plants that combust refinery gas, still gas, process gas, or associated gas shall calculate CO_2 emissions using the method provided in section 95125(e).

(5) Landfill Gas or Biogas: Operators of cement plants that combust landfill gas or biogas from waste water treatment shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(6) Biomass~~ or~~: Operators of cement plants that combust biomass shall calculate CO_2 emissions using the method provided in section 95125(a), section 95125(c), section 95125(d) or section 95125(h)(3).

(7) Municipal Solid Waste: Operators of cement plants that combust~~ biomass or~~ municipal solid waste shall calculate CO_2 emissions using the method provided in section 95125(a) or section 95125 (h~~)(3~~).

(8) ~~(7)~~ Alternative Fuels: Operators of cement plants that combust impregnated saw dust, solvents, plastics, waste oil, fossil-based wastes, tire-derived fuel, diaper waste, charcoal, and any other alternative fuel as specified in Appendix A shall calculate CO_2 emissions using the method provided in section 95125(c), or section 95125(d), or section 95125(h)(3).

(9) ~~(8)~~ Co-Firing of Fuels

(A) Operators of cement plants that co-fire more than one fossil or alternative fuel shall calculate CO_2 emissions separately for each fuel type using methods specified in this section 95110(d).

(B) Operators of cement plants that co-fire biomass-derived fuels with fossil fuels shall calculate CO_2 emissions associated with each fuel using the method provided in section 95125(a) or section 95125(h)(3).

(10) ~~(9)~~ Start-Up Fuels: Operators of cement plants that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall report CO_2 emissions from the fossil fuels using methodologies in section 95125(a) or methods specified in this section by fuel type.

(e) ***Efficiency Metrics.*** Cement plant operators shall calculate for the report year the CO_2 emissions generated per metric tonne of cementitious product and CO_2 emissions generated per metric tonne of clinker using the efficiency metric equations specified in this section, 95110(e).

(1) CO_2 Emissions per metric tonne of Cementitious Product

$$\text{CO}_2\text{ emissions} = \frac{\text{Direct CO}_2\text{ emissions from cement manufacturing}}{\begin{pmatrix}\text{Own clinker}\\ \text{consumed or}\\ \text{added to stock}\end{pmatrix} + \begin{pmatrix}\text{Own clinker}\\ \text{sold directly}\end{pmatrix} + \begin{pmatrix}\text{gypsum, limestone,}\\ \text{CKD \& clinker}\\ \text{substitutes consumed}\\ \text{for blending}\end{pmatrix} + \begin{pmatrix}\text{cement}\\ \text{substitutes}\end{pmatrix}}$$

(2) CO_2 Emissions per metric tonne of Clinker

$$\text{CO}_2\text{ emissions} = \frac{\text{Direct CO}_2\text{ emissions from cement manufacturing}}{(\text{Own clinker consumed or added to stock}) + (\text{own clinker sold directly})}$$

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

95111. Data Requirements and Calculation Methods for Electric Generating Facilities, Retail Providers and Marketers.

(a) ***Electric Generating Facilities.*** The operator of an electric generating facility subject to the requirements of this article, except as provided in section 95103(e)(2), shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements specified in sections 95111 ~~(c) through 95111(i) in preparing the greenhouse gas emissions calculations~~(c)-(i) as applicable to the facility when calculating emissions for inclusion in the report.

(1) At the facility level, operators shall include:

(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);

(B) Fuel consumption by fuel type (scf, gallons, tons, or bone dry tons);

(C) Average high heat value (MMBtu per unit of mass or volume) by fuel type based on values measured by the operator or the fuel supplier as specified in section 95125(c)(1)(B) if the operator elects to calculate CO_2 emissions using methods specified in section 95125(c) or (e) pursuant to the operator's options as specified in section 95111(c). If high heat value is not measured by the operator or the fuel supplier using methods specified in section 95125 (c)(1)(B), then the operator shall report steam produced in pounds. Boiler efficiency may also be reported;

(D) Average carbon content by fuel type as a percent based on values measured by the operator or the fuel supplier as specified in section 95125(d) if the operator elects to calculate CO_2 emissions using methods defined in section 95125(d) or (e) pursuant to the operator's options as specified in section 95111(c);

(E) CO_2, N_2O, and CH_4 emissions from ~~fuel~~stationary combustion in metric tonnes;

(F) Process CO_2 emissions from acid gas scrubbers or acid gas reagent used in the combustion source, if applicable, in metric tonnes;

(G) Fugitive CH_4 emissions from coal storage from coal-fired facilities, if applicable, in metric tonnes;

(H) Fugitive emissions of HFC related to the operation of cooling units that support power generation, if applicable, in kilograms;

(I) Fugitive CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;

(J) Fugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order~~, if applicable, in kilograms~~. Operators of multiple facilities or operators subject to the requirements in section 95111(b)(2)(A) may aggregate SF_6 emissions for all sources or any subset of sources;

(K) Wholesale sales (MWh) exported directly out-of-state, if known, that are additional to electricity transactions reported as specified in section 95111(b)(2)(D). Sales shall be aggregated by counterparty and measured at the busbar. The operator shall report the region of destination as Pacific Northwest (PNW) or Southwest (SW).

(2) For each generating unit operators shall include:

(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);

(B) Fuel consumption by fuel type (scf, gallons, tons or bone dry tons);

(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes;

(D) Wholesale sales (MWh) exported directly out-of-state by generating unit if applicable and as specified in section 95111(a)(1)(K).

(3) ***Aggregation of Multiple Units*****.** If a facility lacks the necessary metering or monitoring equipment to measure data individually for each generating unit, the operator may report data on an aggregated basis for multiple units that combust the same fuel type.

(4) ***Cogeneration Facilities*****.** Operators of generating facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(5) ***Out-of-State Operators*****.** Operators of out-of-state generating facilities may voluntarily submit a greenhouse gas emissions data report that meets applicable requirements defined in this article for generating facilities.

(6) ***Asset Owning/Asset Controlling Suppliers***. Asset owning or asset controlling suppliers that do not purchase power or use substitute power accounting for more than 10% of the power they sell, may voluntarily request that ARB assign a supplier-specific ID to the supplier's fleet of

generating facilities. Asset owning or asset controlling suppliers that choose this option shall:

(A) Meet the requirements in this article as applicable for each generating facility in the supplier's fleet;

(B) Include in their greenhouse gas emissions data report the list of the generating facilities in their fleet along with the ARB designated facility ID;

(C) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operation control or that the supplier serves as the fleet's exclusive marketer;

(D) Provide the supplier-specific ID to retail providers who purchase unspecified power from the supplier's fleet.

(b) ***Retail Providers and Marketers*.**

(1) ***General Requirements for Retail Providers and Marketers*.** Retail providers and marketers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. Retail providers and marketers shall include electricity transactions associated with both renewable and nonrenewable energy sources of power.

(A) When reporting electricity transactions, retail providers and marketers shall:

1. Specify the amount of electricity in MWh;
2. ~~From~~For electricity from specified sources, specify the amount of electricity as measured at the busbar;
3. ~~From~~For electricity from unspecified sources, specify the amount of electricity as measured at the first point of receipt for which the reporting entity has information;
4. ~~From~~For electricity from specified sources, specify the facility name, the ARB designated facility ID, and the generating unit ID for the unit generating the power, if applicable;
5. Specify region of origin and region of destination;
6. Retail providers shall aggregate and specify electricity transactions by counterparty;
7. Marketers shall aggregate and specify electricity transactions by power supplier;
8. Specify the amount of electricity (MWh) that is null power when applicable;

9. Specify electricity received under exchange agreements as purchases and electricity delivered under exchange agreements as wholesale sales;

~~10. Specify purchases of substitute energy and provide the same information required for other types of power purchases in this article as applicable.~~

(B) If the region of origin~~ or region of destination~~ for an electricity transaction cannot be documented, the retail provider or marketer shall designate the region as unknown.

(C) ***Power Wheeled through California.*** When reporting power transactions imported into California or exported out of California, exclude the amount of power imported into California that terminates in a location outside of California, as measured at the first California point of delivery.

(D) ***California Department of Water Resources (DWR).*** The California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of power used by DWR~~,~~ itself.

(E) ***Multi-jurisdictional ~~Utilities~~Retail Providers.*** Multi-jurisdictional ~~utilities~~retail providers shall include information required for retail providers in this article~~ as applicable~~ for the service territory that includes California end-use customers.

(F) ***Western Area Power Administration (WAPA).*** The Western Area Power Administration shall include information required of retail providers in this article ~~as applicable~~relating to serving end use California customers and reporting fugitive SF_6 emissions. In particular, WAPA shall include electricity transactions related to sources of electricity located in California that are used to serve WAPA's end-use California customers, power imported to California to serve WAPA's end-use customers including transactions from facilities owned by the Bureau of Reclamation on the Lower Colorado River, and power exported from California.

(2) ***Greenhouse Gas Emissions Data Report: Retail Providers and Marketers.*** Retail providers and marketers shall include the following information in the greenhouse gas emissions data report for each report year.

(A) Fugitive emissions of SF_6 (kg) related to transmission and distribution systems, substations, and circuit breakers located inside California that the retail provider or marketer is responsible to maintain in proper working order. SF_6 emissions shall be calculated using the methodology specified in section 95111(f).

(B) Power imported (MWh) from specified sources with final point of delivery in California~~ and designate~~, designating the region of origin as PNW or SW.

(C) Power imported (MWh) from unspecified sources with final point of delivery in California. The retail provider or marketer shall designate the region of origin as PNW, SW, or unknown and shall retain for verification purposes NERC E-tags, settlements data, or other information as confirmation of the region of origin.

(D) Power exported (MWh) from specified sources located inside California, and ~~designate~~designating the region of destination (PNW, SW, or unknown).

(E) Power exported (MWh) from unspecified sources located inside California, and ~~designate~~designating the region of destination (PNW, SW, or unknown).

(F) ***Electricity transactions wheeled through California***. Power imported (MWh) into California that terminates in a location outside of California, as measured at the first California point of delivery. The retail provider or marketer shall specify these transactions separately by the counterparty supplying power and specify the region of origin (PNW or SW). The retail provider or marketer shall retain for purposes of verification~~,~~ NERC E-tags, settlements data, or other information to confirm the transactions.

(G) Retail providers shall include in their greenhouse gas emissions data report for each report year the additional information listed in section 95111(b)(3).

(3) ***Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only.*** Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in sections 95111(b)(1)-(2).

(A) The information listed in section 95111(a) for each generating facility over which the retail provider has operational control.

(B) ~~Retail providers shall include the~~The facility name, ARB designated facility ID, nameplate generating capacity (MW) and net power generated in the report year (MWh) for generating facilities ~~for~~over which they have operational control that are solely powered by nuclear, hydroelectric, wind, or solar energy.

(C) Total retail sales in megawatt hours (MWh). Multi-jurisdictional ~~utilities~~retail providers shall include total retail sales for their service territories that include California customers, the portion of total annual retail sales to California customers only, and the ratio of retail sales to California customers only divided by the retail sales for the service area that includes California customers.

(D) Retail sales (MWh) from specified sources that use renewable energy may be reported as a subset of total retail sales in order to reflect special retail programs to reduce greenhouse gases. Retail providers ~~who~~that choose to report retail sales for these programs shall aggregate sales by specified facility and include the facility name, the ARB designated ID, and a description of the program.

(E) Power purchased or taken (MWh) from in-state specified sources. For these purchases, the retail provider shall designate the region of origin as California.

(F) Power purchased or taken (MWh) from hydroelectric generating facilities with nameplate capacity of > 30 MW or from nuclear facilities (that are not California eligible renewable resources) shall be listed as one of the following:

1. Power purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renewed without interruption;
2. Power purchased not meeting the stipulation specified in section 95111(b)(3)(F)(1)~~.~~ and that is not associated with an increase in the facility’s generating capacity;
3. Power purchased not meeting the stipulation specified in section 95111(b)(3)(F)(1) that is associated with an increase in the facility’s generating capacity due to increased efficiencies or other capacity increasing actions;
4. Power purchased from hydroelectric generating facilities during a “spill or sell” situation where power not purchased is lost.

(G) Power purchased (MWh) from unspecified sources within California. For these purchases the retail provider shall designate the region of origin as one of the following:

1. From the CAISO pooled real-time market;
2. From the CAISO pooled integrated forward market;
3. From California but other than from the pooled CAISO markets;

4. From a region of origin that is unknown. Unspecified power purchased from an unknown region shall be reported as an import in section 95111(b)(2)(C).

(H) ***Native Load*.** The retail provider may elect to designate the power taken from a generating facility operated by the retail provider and power purchased or taken from other specified sources as serving native load if the facility meets one of the following criteria and shall state which of the criteria were met:

1. The generating facility is a California eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS certificates associated with the power received from the facility during the report year.
2. The generating facility is a hydroelectric generation facility whose output the reporting entity takes whenever it is available.
3. The generating facility is ~~a base-load facility running at an average annual capacity factor of 60 percent or greater~~owned or in a long term power contract. If a facility is designated as serving native load on this basis, all generating facilities from which the retail provider purchases or takes specified power that run at the same or greater average annual capacity factor shall also be designated as serving native load.
4. The generating facility is a Qualifying Facility whose generation the reporting entity purchases under a power contract.

(I) Retail providers shall designate wholesale sales as inside California ~~only if those sales go to other retail providers or to marketers who~~if the point of delivery of the sales is within California. If the retail provider cannot provide documentation that the ~~sale went to the California region. The retail provider shall retain the documentation for purposes of verification. If the retail provider cannot document the region of destination for any wholesale sale, the region of destination shall be designated as unknown. Wholesale sales designated with unknown destinations~~point of delivery of the sales is within California, the wholesale sales shall be reported as an export under section 95111(b)(2)(D)-(E).

(J) Wholesale sales (MWh) of power purchased or taken from specified facilities operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(K) Wholesale sales (MWh) of power purchased or taken from specified sources not operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(L) Wholesale sales (MWh) ~~from~~of power purchased or taken from unspecified sources to counterparties inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(M) If the retail provider holds a contract that entitles the retail provider to a specified percentage of a facility's generation in the report year, the retail provider shall include power purchased or sold from that facility as being from a partially owned facility.

(N) ***Ownership Share Differential.*** Retail providers shall report the following information for facilities that are fully or partially owned by the retail provider and that have CO_2 emissions greater than 1,100 lbs of CO_2 per MWh based on the most recent verified greenhouse gas emissions data report or on CO_2 emissions reported to U.S.EPA under 40 CFR Part 75.

1. Facility name, ARB designated facility ID, and generating unit ID as applicable;
2. Percent ownership share at the facility level and ownership share at the unit level as applicable;
3. By facility or generating unit as applicable the amount of power to be called the "ownership share differential" that is calculated as follows:

$$OSD_{MWh,i} = 0.9(OS_i)(NG_{MWh,i}) - GF_{MWh,i}$$

Where:
$OSD_{MWh,\,i}$ = power ownership share differential for facility i, MWh per year
OS_i = ownership share of facility i, percentage expressed as a value from 0-1 (e.g., 50% = 0.5)
$NG_{MWh,\,i}$ = total net generation of facility i, MWh per year
$GF_{MWh,\,i}$ = net generation taken from facility i, MWh per year

(O) For retail providers that report a positive ownership share differential from a facility in section 95111(b)(3)(N), the retail provider shall specify the amount of wholesale sales (MWh) made by the retail provider or on behalf of the retail provider from the facility to counterparties located outside California that meets either one of the following criteria and shall retain documentation for verification purposes.

1. The power could not be delivered to the reporting entity during the hours in which it was sold due to congestion in the transmission and distribution system or similar issues;
2. The retail provider did not need the power during the hours in which it was sold for reasons not related to reducing the retail provider's greenhouse gas emissions responsibility. Reasons may include, but are not limited to, that the retail provider's own load was met by resources that were less expensive than the specified facility (excluding any value associated with greenhouse gas mitigation).

(P) ***Adjusted Ownership Share Differential.*** Retail providers that report a positive ownership share differential in section 95111(b)(3)(N) shall report the difference in ~~this amount of power~~the ownership share differential and the amount of wholesale sales that meet either of the two criteria in section 95111(b)(3)(O). The difference shall be called the "adjusted ownership share differential". The adjusted ownership share differential may be reduced further as specified in section 95111(b)(3)(Q).

(Q) Retail providers that report a positive adjusted ownership share differential in section 95111(b)(3)(P) for a specified facility may retain for purposes of verification, documentation that the facility reduced operations as a result of a reduced demand for power by the retail provider. The retail provider may reduce the adjusted ownership share differential by the amount of power generation that was reduced if such documentation is retained and the reduction is verified.

(R) For facilities fully or partially owned by the retail provider not reported in section 95111(b)(3)(N), include facility name, ARB designated facility ID, generating unit ID as applicable, percent ownership share at the facility level, and ownership share at the generating unit level as applicable.

(S) The retail provider may elect to separately report retail sales related to the electrification of shipping ports, truck stops, and ~~other~~ motor vehicles if metering is available to separately track these sales from other retail sales.

(T) Multi-jurisdictional retail providers shall include wholesale power transactions from specified or unspecified sources that were imported to or exported from their service territories and not already reported in Section 95111(b)(2).

(c) ***Calculation of CO_2 Emissions from ~~Fuel~~Stationary Combustion***. Operators of generating facilities, retail providers, and marketers shall meet the following requirements in preparing CO2 emission calculations from ~~fuel~~stationary combustion for inclusion in the greenhouse gas emissions data report.

(1) ***Natural Gas.*** Operators of generating facilities or units that combust natural gas and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year. Operators may elect to use revenue fuel meters to conduct quality checks on generating unit level information. For facilities or units that combust natural gas but are not required to report CO_2 emissions under 40 CFR Part 75, the operator shall calculate and include CO_2 emissions using methodologies provided in:

(A) Sections 95125(c)-(d) or (g) if the high heat value is $\geq$ 975 and $\leq$ 1100 Btu per scf or;

(B) Section 95125(d) or (g) if the high heat value is < 975 or > 1100 Btu per scf.

(2) ***Coal or Petroleum Coke.***

(A) Operators of generating facilities or units that combust coal or petroleum coke and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year, or CO_2 emissions based on alternative equations and specifications by fuel type provided in 40 CFR Part 75, Appendix G;

(B) If the generating facility or unit is not subject to the requirements in 40 CFR Part 75, the operator of the generating facility shall calculate and include CO_2 emissions using methods specified in section 95125(d) or section 95125(g).

(3) ***Middle distillates, gasoline, residual oil, or liquid petroleum gases (LPG).***

(A) If a generating facility or unit combusts middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) and is subject to the requirements of 40 CFR Part 75, the operator of the facility shall include Part 75 CO_2 emissions data for the report year;

(B) If the generating facility or unit is not subject to the requirements of 40 CFR Part 75, the operator shall calculate and include annual CO_2 emissions using the methods specified in sections 95125(c)-(d) or (g).

(4) ***Refinery Gas, Still Gas, Process Gas, or Associated Gas.*** If a generating facility combusts refinery gas, still gas, process gas, or

associated gas, the operator shall calculate and include CO_2 emissions for the report year using the methods specified in section 95125(e) or 95125(g).

(5) ***Landfill Gas or Biogas.*** If a facility combusts landfill gas or biogas from derived from biomass, the operator shall calculate and include CO_2 emissions for the report year using the method specified in section 95125(c), 95125(d), or 95125(g).

(6) ***Biomass or Municipal Solid Waste.***

(A) ~~(6) ***Biomass or Municipal Solid Waste.***~~ If a facility combusts biomass or municipal solid waste, the operator shall calculate and include CO_2 emissions for the report year ~~based on~~ using methodologies provided in section 95125(g) based on continuous emission monitoring systems, CO_2 concentrations, and flue gas flow rates~~. If the facility~~;

(B) If the facility combusts municipal solid waste and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, ~~then the operator of the facility~~the operator shall use methods specified in section 95125(h)~~.~~;

(C) If the facility combusts biomass and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use methods specified in section 95125(c)-(d) or section 95125(g)-(h).

(7) ***CO_2 Emissions for Fuels Co-Fired.*** Operators shall use the following methodologies to determine separately and include CO_2 emissions from fuels (excluding refinery gases) that are co-fired at a facility.

(A) If more than one fossil fuel is co-fired in a facility that does not report using data from a continuous emissions monitoring system, then CO_2 emissions shall be calculated separately for each fuel type using methods specified in section 95111(c) by fuel type. Operators who have the option in this article to calculate emissions based on data from a continuous emissions monitoring system, and who co-fire more than one fossil fuel, need not report emissions separately for each fossil fuel.

(B) If a biomass-derived fuel is co-fired with a fossil fuel in a facility and the operator does not report CO_2 emissions using data from a continuous emissions monitoring system, then CO_2 emissions shall be calculated separately for each fuel type using methods specified in section 95111(c) by fuel type. If the facility does have a continuous emissions monitoring system, then the operator shall calculate emissions associated with each fuel using the methods specified in section 95125(g)(4).

(8) ***Start-Up Fuels***. The operators of generating facilities that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall calculate and include CO_2 emissions from fossil fuel combustion using methodologies in section 95125(a) or methods specified in section 95111(c) by fuel type.

(d) ***Calculation of N_2O and CH_4 from ~~Fuel~~Stationary Combustion.*** Operators of generating facilities, retail providers, and marketers shall use the methodologies provided in section 95125(b) to calculate and include N_2O and CH_4 emissions from ~~fuel~~stationary combustion.

(e) ***Calculation of CO_2 Process Emissions from Acid Gas Scrubbing.*** Operators that use acid gas scrubbers or add an acid gas reagent to the combustion source shall include CO_2 emissions from these processes if these emissions are not already captured in CO_2 emissions calculations based on a continuous emissions monitoring system. The operator shall calculate CO_2 emissions from the acid gas processes using the following equation:

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{MW})$$

Where:
CO_2 = CO_2 emitted from sorbent for the report year, metric tonnes;
S = Limestone or other sorbent used in the report year, metric tonnes;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

(f) ***Determining Fugitive SF_6 Emissions.*** Operators of generating facilities, retail providers, and marketers shall use the methodology provided by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems to determine fugitive SF_6 emissions as specified in Appendix A. The operator shall convert pounds of SF_6 into kilograms.

(g) ***Determining Fugitive HFC Emissions.*** Operators of generating facilities shall calculate fugitive HFC emissions from cooling units used in support to power generation or used in heat transfers used to cool stack gases using the methodology provided by U.S. EPA SF_6 Emission Reduction Partnership but substituting HFCs for SF_6 in the methodology. The operator shall convert pounds of HFCs into kilograms. This section does not apply to air or water cooling systems or condensers that do not contain HFCs.

(1) Operators who are reporting by individual cooling unit may elect to use service logs to record measurements of HFCs added to the unit. Service

logs shall include measurements for all applications during the report year, including a record at the beginning and ending of each year.

(h) ***Calculation of Fugitive CH_4 Emissions.*** Operators for generating facilities that combust coal shall calculate and include fugitive CH_4 emissions from coal storage using the methodology provided in section 95125(j).

(i) ***Calculation of Fugitive CO_2 Emissions from Geothermal Generating Facilities.*** Operators of geothermal electric generating facilities shall calculate and include fugitive CO_2 emissions using one of the following methods:

(1) $CO_2 = EF * Heat * (0.001)$

Where
CO_2 = CO_2 emissions, metric tonnes per year;
EF = Default fugitive CO_2 emission factor for geothermal facilities as specified in Appendix A, kg per MMBtu;
Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.

(2) Operators of geothermal generating facilities may elect to calculate CO_2 emissions using ~~a~~ARB approved source specific emission ~~factor~~factors derived from ~~source~~ tests conducted at least annually under the supervision of ARB or the local air pollution control ~~districts/~~district or air quality management ~~districts and approved by ARB. Once the source~~district. Upon approval of a test plan ~~has been approved~~ by ARB, the ~~source~~ test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the method specified above in section 95111(i)(1).

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

95112. Data Requirements and Calculation Methods for Cogeneration Facilities.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a cogeneration facility subject to the requirements of this article, except as provided in section 95103(e)(2), shall include the following information in the greenhouse gas emissions data report for each report year. The operator of a cogeneration facility with nameplate generating capacity less than 10 megawatts (MW) who is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)-(6) and (8), may elect to submit an abbreviated emissions data report as specified in Section 95112(c).

(1) Facility level and generating unit information as specified in sections 95111(a)(1)-(3) as applicable.

(2) Cogeneration System:
  (A) Prime mover of each cogeneration system.
  (B) Identification of the cogeneration facility as a topping cycle or bottoming cycle plant
  (C) Description of waste heat technology, including nameplate data for waste heat boiler, waste heat jacket heat exchanger, absorption chiller, and hot water heat exchanger

(3) Electricity Generation:
  (A) Electricity sold wholesale (MWh)
    1. Name of retail provider
  (B) Electricity sold or provided directly to ~~off-site~~ end-users (MWh)
    1. ~~User~~Customer's NAICS code
  (C) Electricity consumed on-site for each report year (MWh)

(4) Thermal Energy Production:
  (A) Useful thermal output (MMBtu)
  (B) Amount of thermal energy sold or provided to ~~off-site end-users~~cogeneration thermal host (MMBtu)
    1. ~~User~~Customer's NAICS code
  (C) Amount of thermal energy consumed on-site for processes other than the cogeneration system for each report year (MMBtu)
  (D) Output of heat recovery steam generator (HRSG) (MMBtu)
  (E) Fuel fired for supplemental firing in the duct burner of the HRSG (MMBtu)
  (F) Efficiency of HRSG (percent)

(5) Distributed Emissions:
  (A) Distributed emissions to thermal energy production (metric tonnes CO_2)
  (B) Distributed emissions to electricity generation (metric tonnes CO_2)

1. Efficiency of electricity generation (percent)
2. Total fuel input (MMBtu)

(C) Distributed emissions to manufactured product outputs, as applicable (metric tonnes CO_2)

(6) Indirect electricity usage as specified in section 95125(k).

(A) Electricity purchased and consumed (kWh)

(B) Electricity provider (Name)

(b) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cogeneration facilities shall calculate emissions for each source specified in this section.

(1) CO_2 emissions from stationary combustion using methodologies listed by fuel type for electric generating facilities as specified in section 95111(c).

(2) GHG emissions from processes and from fugitive sources as specified for electric generating facilities in sections 95111(e)-(h), if applicable, using the methodologies designated in the respective sections.

(3) N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).

(4) **Distributed Emissions.** Topping cycle plant operators shall calculate distributed emissions for electricity generation and thermal energy production separately using the Efficiency Method provided in section 95112(b)(4)(A). Bottoming cycle plant operators shall calculate and report distributed emissions for electricity generation, thermal energy production, and manufactured product outputs using the Detailed Efficiency Method provided in section 95112(b)(4)(B).

(A) Distributed Emissions for Topping Cycle Plants: Operators shall calculate distributed emissions using the Efficiency Method equations specified in this section, 95112(b)(4)(A). Topping cycle plant operators shall calculate emissions distributed to thermal energy production using a facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(A)~~1.~~1 or an assumed 0.35 average value for electricity efficiency. Operators shall calculate distributed emissions using an assumed 0.80 average value or use the Heat Recovery Steam Generator (HRSG) or boiler manufacturers rating for the thermal energy production efficiency (e_H) value. Operators shall select one approach to determine electricity and thermal energy efficiency values to calculate distributed emissions and must use the same approach each report year. Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production from CO_2 emissions from stationary combustion for the report year.

Efficiency Method

Thermal Energy Production

$$E_H = \frac{H / e_H}{H / e_H + P / e_P} \times E_T$$

Electricity Generation

$$E_P = E_T - E_H$$

Where:

E_H = Distributed emissions to thermal energy production, metric tonnes CO_2

H = Useful thermal output for the report year, MMBtu

e_H = Efficiency of thermal energy production

P = Annual net power generated, MMBtu (MWh x 3.413) = MMBtu

e_P = Efficiency of electricity generation

E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes CO_2

E_P = Distributed emissions to electricity generation, metric tonnes CO_2

1. Facility-Specific Electricity Generation Efficiency Value:

$$e_P = \frac{P}{F}$$

Where:

e_P = Efficiency of electricity generation

P = Net power generated in the report year, MMBtu

F = Total Fuel Input, MMBtu

(B) Distributed Emissions for Bottoming Cycle Plants: Operators shall calculate distributed emissions using the Detailed Efficiency Method equations specified in this section, 95112(b)(4)(B). Bottoming cycle plant operators shall calculate emissions from stationary combustion for the manufacturing process as specified in section 95112(b)(4)(B)2. Operators shall use assumed values of 0.80 for thermal energy and 0.35 for electricity efficiency. Operators may also report emissions using a calculated facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(B)1 or use the Heat Recovery Steam Generator (HRSG) or boiler manufacturers rating for the thermal energy production efficiency (e_H) value. Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production and manufactured product from CO_2 emissions from fuel combustion for the report year.

Detailed Efficiency Method

Thermal Energy Production

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} \times (E_T - E_M)$$

Electricity Generation

$$E_P = E_T - E_H - E_M$$

Where:

E_H	=	Distributed emissions to thermal energy production, metric tonnes CO_2
H	=	Useful thermal output for the report year, MMBtu
e_H	=	0.80 = Efficiency of thermal energy production
P	=	Net power generated for the report year, MMBtu (MWh x 3.413) = MMBtu
e_P	=	Efficiency of electricity generation
E_T	=	CO_2 emissions from stationary combustion in the report year, metric tonnes
E_M	=	Distributed emissions to manufacturing product, metric tonnes CO_2, computed as specified in section 95112(b)(4)(B)2.
E_P	=	Distributed emissions to electricity generation, metric tonnes CO_2

1. *Facility-Specific Electricity Generation Efficiency Value:*

$$e_P = \frac{P}{(F + H_e)}$$

Where:

e_P	=	Efficiency of electricity generation
P	=	Net power generated in the report year, MMBtu
F	=	Total Fuel input, MMBtu
He	=	Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.

2. *Emissions Assigned to Manufacturing Process:*

$$E_M = E_T\left[1 - \frac{P + H + F_S \times (1 - HRSG_{EF})}{F + H_e}\right]$$

Where:

E_M	=	Distributed emissions to manufacturing product, metric tonnes CO_2
E_T	=	Emissions from stationary combustion in the report year, metric tonnes CO_2
P	=	Annual net power generated, MMBtu (MWh × 3.413) = MMBtu

H	=	Useful thermal output in the report year, MMBtu
F	=	Total Fuel Input, MMBtu
F_S	=	Supplemental Firing of Fuel Fired in Duct Burner of HRSG, MMBtu
H_e	=	Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.
$HRSG_{EF}$	=	Efficiency of HRSG, use 0.8 as a default if actual efficiency is unknown

H_e shall only be included if an exothermic manufacturing process is used.

3. *Exothermic Heat from Manufacturing Process*

$$He = \frac{HRSG}{HRSG_{EF}} - F$$

Where:

H_e	=	Exothermic heat from manufacturing process, MMBtu
HRSG	=	Output of heat recovery steam generator in the report year, MMBtu
$HRSG_{EF}$	=	Efficiency of HRSG, use 0.8 as a default if actual efficiency is unknown
F	=	Total Fuel Input, MMBtu

If H_e value calculated above is negative, then the exothermic heat of the process is not sufficient to overcome the process use and/or loss of the input fuel heat and the H_e value is then set to 0.

(c) Abbreviated Greenhouse Gas Emissions Data Report. The operator of a cogeneration facility with nameplate generating capacity less than 10 MW who is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)–(6) and (8) and elects to submit an abbreviated emissions data report shall include the following information for each report year.

(1) At the facility level, operators shall include:

(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);
(B) Total fuel consumption by fuel type for each cogeneration system (scf, therms, MMBtu, gallons, tons or bone dry tons);

(C) Cogeneration system information as specified in section 95112(a)(2);
(D) Electricity generation information as specified in section 95112(a)(3);
(E) CO_2, N_2O, and CH_4 emissions from stationary combustion associated with the facility's cogeneration system in metric tonnes, calculated as specified in section 95112(d);

1. CO_2 emissions from biomass-derived fuels (metric tonnes)

(2) For each generating unit operators shall include:

(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);
(B) Fuel consumption by fuel type, where generating units of the same fuel type are separately metered;
(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95112(d), where generating units of the same fuel type are separately metered.

(3) Operators may elect to submit any of the additional information required in section 95112(a).

(d) Calculation of CO_2, N_2O, and CH_4 Emissions. The operator of a cogeneration facility with nameplate generating capacity less than 10 MW who elects to submit an abbreviated emissions data report as specified in section 95112(c) shall calculate emissions as specified below:

(1) CO_2 Emissions from stationary combustion using the methodologies provided in either (A), (B), or (C) below.

(A) Use of continuous emissions monitoring systems (CEMS) as specified in section 95125(g);
(B) Use of default emission factors as specified in section 95125(a);
(C) Use of fuel heat content, carbon content or other fuel-specific parameters as specified in section 95125(c), (d), or (h).

(2) N_2O, and CH_4 Emissions from stationary combustion using the methodologies provided in section 95125(b).

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

95113. Data Requirements and Calculation Methods for Petroleum Refineries.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a petroleum refinery that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from the combination of stationary combustion and process sources, except as provided in section 95103(e), shall include the following information in the greenhouse gas emissions data report for each report year from facility emission sources as specified:

(1) ***Stationary Combustion – CO_2 Emissions by Fuel Type.***

(A) Refinery Fuel Gas: CO_2 emissions resulting from the combustion of refinery fuel gas as specified in section 95125(d) or 95125(e), (metric tonnes).

(B) Natural Gas and Associated Gas: CO_2 emissions resulting from the combustion of natural gas as specified in section 95125(c) or (d), (metric tonnes).

(C) Fuel Mixtures: CO_2 emissions resulting from the combustion of each fuel contained in the fuel mixture or for each fuel mixture as specified in section 95125(f), (metric tonnes).

(D) Other Fuels: CO_2 emissions resulting from the combustion of No. 1, No. 2, No 4, No. 5, and No. 6 fuels, kerosene, residual oil, distillate oil, gasoline, diesel fuel, and LPG using the methods specified in section 95125(a), (metric tonnes).

(E) Low Btu gases: CO_2 emissions resulting from the combustion and/or destruction of low Btu gases as specified in section 95113(e)(3).

(2) ***Stationary Combustion – CH_4 and N_2O.*** Emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

(3) ***Fuel Consumption.*** Fuel consumption by fuel type in the report year (including petroleum coke) (scf, gallons, or ton)

(4) ***Hydrogen Production Plant Emissions.*** The operator shall calculate emissions using the methodologies specified in section 95114, (metric tonnes).

(5) ***Process Emissions.*** The operator shall calculate process emissions using the methodologies in section 95113(b), (metric tonnes).

(6) ***Fugitive Emissions.*** The operator shall calculate ~~process~~fugitive emissions using the methods specified in section 95113(c), (metric tonnes).

(7) ***Flaring Emissions***. The operator shall calculate flaring emissions using the methods specified in section 95113(d), (metric tonnes)

(8) ***Electric Generating Units***. Operators of refineries with electric generating units subject to the requirements of this article shall meet the requirements of section 95111.

(9) ~~(8)~~ ***Cogeneration Emissions***. Operators of refineries with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(10) ~~(9)~~ ***Indirect Energy Purchases.*** The operator shall calculate indirect energy purchased and consumed using methods specified in section 95125(k)-(l).

(b) Operators may elect to determine CO_2 combustion emissions using Continuous Emissions Monitoring Systems as specified in section 95125(g)(7).

(c) ~~(b)~~ ***Calculation of Process Emissions.*** The operator shall calculate process emissions as specified in this section.

(1) Catalytic Cracking

(A) Operators shall calculate and report CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using the methods specified ~~below~~ in ~~section~~section 95113(~~b)(1)(A), (B), (C) and (D). These methods shall be applied to fluid catalytic cracking units, fluid cokers, catalytic reforming units including but not limited to those engaged in semi-regenerative, cyclic or continuous catalyst regeneration~~c)(1)(A)-(C). Hourly coke burn rate shall be calculated as shown below:

$$CR = K_1Q_r(\%CO_2 + \%CO) + K_2Q_a - K_3Q_r[\%CO/2 + \%CO_2 + \%O_2] + K_3Q_{oxy}(\%O_{xy})$$

Where:

CR = coke burn rate (kg/hr or lb/hr)

K_1, K_2, K_3 = material balance and conversion factors (K_1, K_2, and K_3 - see Appendix A)

Q_r = volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)

Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)

$\%CO_2$ = percent CO_2 concentration in regenerator exhaust, percent by volume – dry basis

%CO = percent CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$ = percent oxygen concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

Q_r shall be determined in the following manner:

$$Q_r = (79 * Q_a + (100 - \%Q_{oxy}) \times Q_{oxy})/(100 - \%CO_2 - \%CO - \%O_2)$$

Where:

Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)
$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO = carbon monoxide concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(B) Operators shall calculate a daily average coke burn rate (CR_d) for each day of operation as the sum of hourly coke burn rate determinations for each hour of operation divided by the number of operational hours per day. CR_d (lb/day) shall be converted to (kg/day).

(C) Operators shall calculate and report CO_2 emissions as shown below:

$$CO_2 = \sum_{0}^{n} CR_d * CF * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
n = number of days of operation in the report year
CR_d = daily average coke burn rate (kg/day)
CF = carbon fraction in coke burned (default = 1)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(2) ~~Periodic~~Other Catalyst Regeneration

(A) Operators shall calculate and report process CO_2 emissions resulting from periodic catalyst regeneration as shown below.

$$CO_2 = \sum_{\cancel{1}\,0}^{n} \cancel{CR_{ave} * CF * H}\,CRR * (CF_{spent} - CF_{regen}) * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

~~CR_{ave}~~CRR = mass of catalyst regenerated (mass/regeneration cycle)

~~CF~~CF_{spent} = weight fraction ~~of~~ carbon on ~~the~~spent catalyst

CF_{regen} = weight fraction carbon on regenerated catalyst (default = ~~1~~0)

n = number of regeneration cycles ~~(#/yr)~~

0.001 = conversion factor – kg to metric tonnes

(B) Operators shall calculate and report process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCU and fluid cokers (e.g. Catalytic reforming) as shown below.

$$CO_2 = CC_{irc} * (CF_{spent} - CF_{regen}) * H \times 3.664$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

CC_{irc} = average catalyst regeneration rate (tonnes/hr)

CF_{spent} = carbon fraction on spent catalyst

CF_{regen} = carbon fraction on regenerated catalyst (default = 0)

H = hours regenerator was operational (hr/yr)

3.664 = conversion factor – carbon to carbon dioxide

(3) Process Vents

(A) Operators shall calculate and report process emissions of CO_2, CH_4, and N_2O using the method shown below. Process emissions calculated and reported using other methods specified in this regulation shall not be calculated and reported here.

$$E_x = \sum_{1}^{n} VR * F_x * MW_x/MVC * VT * 0.001$$

Where:

E_x = emissions of x (metric tonnes/yr)
(x = CO_2, N_2O, CH_4)
VR = vent rate (scf/unit time)
F_x = molar fraction of x in vent gas stream
MW_x = molecular weight of X (kg/kg-mole)
MVC = molar volume conversion (~~849.5~~849 scf/kg-mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, for STP of 60℉, and 1 atmosphere)
VT = time duration of venting
n = number of venting events
0.001 = conversion factor – kg to metric tonnes

(4) Asphalt Production

(A) Operators shall calculate and report CO_2 and CH_4 emissions resulting from asphalt bowing activities (where these emissions are not reported to the local AQMD/APCD and subsequently reported as directed in section 95113(f)) using the method specified below:

$$CH_4 = (\cancel{Ma}M_A * EF * MW_{CH4}/MCV)(1 – DE) * 2.743 * 0.001$$

Where:

CH_4 = CH_4 emissions (metric tonnes/yr)
M_A = mass of asphalt blown ($\cancel{10^6}10^3$ bbl/yr)
EF = default emission factor (2,555 scf CH_4/$\cancel{10^6}10^3$ bbl)
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg-mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, for STP of 60℉, and 1 atmosphere)
DE = control measure destruction efficiency (default = 98% expressed as 0.98)
2.743 = conversion factor CH_4 to CO_2
0.001 = conversion factor – kg to metric tonnes

$$CO_2 = (\cancel{Ma}M_A * EF * MW_{CH4}/MCV) * DE * 2.743 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
M_A = mass of asphalt blown ($\cancel{10^6}10^3$ bbl/yr)
EF = default emission factor (2,555 scf CH_4/$\cancel{10^6}10^3$ bbl)
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, for STP of 60℉, and 1 atmosphere)

DE = control measure destruction efficiency (default = 98% expressed as 0.98)
2.743 = CH_4 to CO_2 conversion factor
0.001 = conversion factor – kg to metric tonnes

(5) Sulfur Recovery

(A) Operators shall calculate CO_2 process emissions from sulfur recovery units (SRU) using the methods specified below:

$$CO_2 = FR * MW_{CO2}/MVC * MF * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
FR = volumetric flow rate of acid gas to SRU (scf/year)
MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, fo r STP of 60℉, and 1 atmosphere)
MF = molecular fraction of CO_2 in sour gas (~~default~~MF = 0.20)
0.001 = conversion factor – kg to metric tonnes

(B) As an alternative to using the default emission factor, the operator may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from source tests conducted at least once per calendar year under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission ~~factors~~factor provided by ARB.

(d) ~~(c)~~ ***Calculation of Fugitive Emissions.*** The operator shall calculate fugitive emissions as specified ~~in section 95113(c)~~below.

(1) Wastewater Treatment – CH_4 and N_2O

(A) Operators shall calculate methane emissions from wastewater treatment as shown below:

$$CH_4 = [(Q * COD) – S] * B * MCF * 0.001$$

Where:

CH_4 = emission of methane (tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S = organic component removed as sludge (kg COD/yr)
B = methane generation capacity (~~default~~B = 0.25 kg CH_4/kg COD)
MCF = methane conversion factor for the anaerobic decay (0-1.0) consult Table provided in Appendix A
0.001 = conversion factor – kg to metric tonnes

(B) Operators shall calculate and report nitrous oxide emissions from wastewater treatment as shown below:

$$N_2O = Q * N_{qave} * EF_{N2O} * 3.142 * 0.001$$

Where:

N_2O = emissions of N_2O (metric tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3~~) nitrogen content of effluent (kg N/yr~~)
EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N~~) (default = 0.005~~)
3.142 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tonnes

(2) Oil-Water Separators – Operators shall calculate emissions from oil-water separators as shown below.

$$CH_4 = F_{sep} * V_{water} * CF_{NMHC} * 0.001$$

Where:

CH_4 = emission of methane (tonnes/yr)
F_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) see Table in Appendix A.
V_{water} = volume of waste water treated by the separator (m^3/yr)
CF_{NMHC} = NMHC to CH_4 conversion factor (~~default~~CF_{NMHC} = 0.6)
0.001 = conversion factor – kg to metric tonnes

(3) Storage Tanks

(A) Operators shall calculate CH_4 emissions from crude oil, naphtha, distillate oil, asphalt, and gas oil storage tanks using the U.S. EPA TANKS Model (Version 4.09D).

(4) Equipment Fugitive Emissions

(A) Operators shall calculate CH_4 fugitive emissions for all gas service components as specified in CAPCOA (1999) Method 3: Correlation Equation Method in the following manner:

1. Screening values (SV) for all components comprising all natural gas, refinery fuel gas, process gas, and PSA off-gas systems shall be recorded and identified as one of the following component leak categories 1) default zero components, 2) components where the SV is above background but below 10,000 ppm, 3) pegged source components (SV greater than 10,000 ppm but less than 100,000 ppm or 4) pegged source components where the SV is greater than 100,000 ppm. Components will be characterized as one of the following 1) valves, 2) pump seals, 3) connectors, 4) flanges, 5) open-ended lines or 6) others (component types other than 1-5). Operators shall use the Component Identification and Counting Methodology found in CAPCOA (1999), which is incorporated by reference herein.

2. VOC emissions for each of the four leak categories shall be calculated in the following manner:

For Zero components use the following equation:

$$E_{VOC-0} = \sum_{1}^{n} CC_i * RF_{i0}$$

Where:

E_{VOC-0} = VOC emission rate for all zero components (kg/hr)
n = total number of zero components
CC_i = component count (i= values, pump seals, connectors, flanges, open-ended lines, others)
RF_{i0} = default VOC emission factor for zero component i (kg/hr) (see Table in Appendix A.)

For SV > Bkgd and SV <10,000 ppmv components use the following equation:

$$E_{VOC-L} = \sum_{1}^{n} C_{ief} * SV^{\beta}$$

Where:

E_{VOC-L} = VOC emission rate – leaking components (kg/hr)
C_{ief} = component i correlation equation constant

n = total number of components in this class
SV = screening value (ppmv)
β = correlation equation exponent (see Table in Appendix A)

For 10K Pegged components (SV > 10,000 ppmv, SV <100,000 ppmv) components use the following equation:

$$E_{VOCP-10} = \sum_{1}^{n} CC_i * RF_{iP10}$$

Where:

$E_{VOCP-10}$ = VOC emission rate – 10K pegged components (kg/hr)
CC_i = component count (i= values, pump seals, connectors, flanges, open-ended lines, others)
n = total number of components in this class
RF_{iP10} = default VOC emission factor for component i pegged above 10,000 ppmv but below 100,000 ppm (see Table in Appendix A)

For 100K Pegged components (SV > 100,000 ppmv) components use the following equation:

$$E_{VOCP-100} = \sum_{1}^{n} C_{ief} * RF_{iP-100}$$

Where:

$E_{VOCP-100}$ = VOC emission rate – 100 K pegged components (kg/hr)
C_{ief} = component i correlation equation constant
n = total number of components in this class
RF_{iP-100} = default VOC emission factor for component i pegged above 100,000 ppmv. (see Table in Appendix A)

3. Methane emissions shall be calculated in the following manner:

$$CH_4 = (E_{VOC-0} + E_{VOC-L} + E_{VOCP-10} + E_{VOCP-100}) * t * CF_{VOC} * 0.001$$

Where:

CH_4 = methane emissions (metric tonnes /yr)
t = hours/yr components were pressurized (default = 8,760 hrs)
CF_{VOC} = default VOC to CH_4 conversion factor = 0.6
0.001 = conversion factor – kg to metric tonnes

(e) ~~(d)~~ ***Calculation of ~~Flaring~~ Emissions from Flares and Other Control Devices.***

(1) Operators shall calculate CO_2 emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in section 95113(a)(1). ~~shown below:~~

$$\cancel{CO_2 = \sum_{1}^{n} CC * FR * FE * MW_{CO2}/MVC * 0.001}$$

~~Where:~~

~~CO_2 = emissions of CO_2 (metric tonnes/yr)~~
~~CC = carbon content of the fuel (mole percent)~~
~~FR = fuel flow rate (scf/yr)~~
~~FE = flare destruction efficiency (%)~~
~~MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)~~
~~MVC = molar volume conversion (849.5 scf/ kg-mole)~~
~~0.01 = conversion factor – kg to metric tonnes~~

~~The carbon content of natural gas combusted as flare pilot and purge gas will be measured monthly by the refiner.~~

(2) Operators shall calculate and report CO_2 (and CH_4 where applicable) emissions resulting from the combustion of hydrocarbons routed to flares for destruction using one of the methods specified below:

(A) Operators reporting CH_4 and NMHC emissions to their local Air Quality Management District shall calculate CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} [CF_{NMHC} * NMHC * \cancel{1}FE/(\cancel{1}100\text{-}FE) * 3.664 + \cancel{(}CH_4 * \cancel{1}FE/(\cancel{1}100\text{-}FE\cancel{)}) * 2.746] * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
CF_{NMHC} = carbon fraction in NMHC (CF_{NMHC} = 0.6 ~~default value~~)
NMHC = flare non-methane hydrocarbon emissions (kg/day)
CH_4 = flare methane emissions (kg/day)
FE = flare destruction efficiency (%)
2.746 = conversion factor – methane to carbon dioxide
0.001 = conversion factor – carbon to carbon dioxide

Operators shall use the following flare destruction efficiencies (FE):

Gas combusted HHV > 200 Btu/scf FE = 98%
Gas combusted HHV < 200 Btu/scf FE = 93%

Operators shall ~~calculate and~~also report the sum of all flare CH_4 emissions reported to the local AQMD/APCD for the report year (metric tonnes/yr)

(B) Operators subject to Rule 1118 – Control of Emissions from Refinery Flares (South Coast Air Quality Management District) shall calculate ROG as specified in Attachment B of Rule 1118, which is incorporated by reference herein, and report flare CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} (CF_{ROG} * [ROG * \cancel{1}FE/(\cancel{1}100\text{-}FE)] * 3.664) * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
CF_{ROG} = carbon fraction in ROG (CF_{ROG} = 0.6~~ default value~~)
ROG = reactive organic gas flare emissions (kg/day)
FE = flare destruction efficiency (%)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

Operators shall use the following flare destruction efficiencies (FE):

Gas combusted HHV > 200 Btu/scf FE = 98%
Gas combusted HHV < 200 Btu/scf FE = 93%

(C) Operators not reporting flare emissions to their local AQMD/APCD shall ~~use a default emission factor to~~ calculate CO_2 emissions as shown below:

$$\cancel{CO_2 = EF_{CO2} * RT}$$

$$CO_2 = RFT * EF_{NMHC} * CF_{NMHC} * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/year)
~~EF_{CO2}~~RFT = ~~default CO_2 emission factor (tonnes CO_2/10^6 barrels crude~~refinery feed throughput (m^3/yr)
~~RT = refinery throughput (10^6 barrels crude /year)~~
EF_{NMHC} = non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3)
CF_{NMHC} = conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – carbon to carbon dioxide

(3) Operators utilizing other methods for the destruction of low Btu gases (e.g. gases from vapor recovery systems, casing vents and product storage tanks) such as incineration or combustion as a supplemental fuel in heaters, boilers etc., shall calculate CO_2 emissions as specified below:

$$CO_2 = GV_A * CC_A * MW_A * 1/MVC * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/year)
GV_A = volume of gas A destroyed annually (scf/year)
CC_A = carbon content of gas A (kg C/kg fuel)
MW_A = molecular weight of gas A
MVC = molar volume conversion factor (849.5 scf/kg- mole for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, fo r STP of 60℉, and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

Operators shall determine CC_A and MW_A quarterly (four times per year) using methods specified in section 95125(d)(3)(A) and compute an annual average value. GV_A shall be determined with an uncertainty of no more than ± 7.5%.

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

95114. Data Requirements and Calculation Methods for Hydrogen Plants.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a hydrogen production facility that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from the combination of stationary combustion sources and hydrogen production processes, except as provided in section 95103(e), shall report emissions of CO_2, CH_4 and N_2O from the facility. The operator shall include in the emissions data report for each report year the information required by this section, using the methods specified.

(1) ***Fuel and Feedstock Consumption.*** Fuel and feedstock consumption in the report year by fuel/feedstock type (including petroleum coke) (scf, gallons, or ton).

(2) ***Production.*** Operators shall report the total hydrogen produced at the facility in the report year (scf) and the amount of hydrogen sold for use as transportation fuel (scf).

(3) ***Stationary Combustion – CH_4 and N_2O.*** The operator shall calculate CH_4 and N_2O emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

(4) ***Fugitive Emissions.*** The operator shall calculate fugitive emissions using the methods specified in section 95113(c), (metric tonnes).

(5) ***Flaring Emissions.*** The operator shall calculate emissions resulting from flaring (if these emissions are not ~~calculate~~calculated using other methods specified ~~ion~~in this regulation) using the methods specified in section 95113(d), (metric tonnes).

(6) ***Transferred CO_2 and CO.*** The operator shall calculate the amount of CO_2 and CO sold as transferred carbon dioxide and carbon monoxide respectively, (metric tonnes). Transferred carbon dioxide and carbon monoxide shall not be subtracted from total CO_2 emissions reported.

(7) ***Process Vent Emissions*.** The operator shall report process vent emissions not reported using other methods specified in this regulation as specified in section 95113(b)(3), (metric tonnes)

(8) ***Sulfur Recovery Process Emissions.*** The operator shall report CO_2 process emissions from sulfur recovery units as specified in section 95113(b)(5), (metric tonnes).

(9) ***Electric Generating Units.*** Operators of hydrogen plants with electric generating units subject to the requirements of this article shall meet the requirements of section 95111.

(10) ~~(9)~~ ***Cogeneration Emissions.*** Operators of hydrogen plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(11) ~~(10)~~ ***Indirect Energy Purchases.*** Operators shall report all indirect energy purchased and consumed as specified in sections 95125(k)-(l).

(12) ~~(11)~~ ***Stationary Combustion and Process CO_2 Emissions.*** Operators shall calculate stationary combustion and process CO_2 emissions as specified in section 95114(b), (metric tonnes).

(b) ***Calculation of CO_2 Stationary Combustion and Process Emissions.*** The operator shall calculate CO_2 stationary combustion and process emissions using one of the methods specified in this section.

(1) ***Continuous Monitoring Systems.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g)(~~6~~7).

(2) ***Fuel and Feedstock Mass Balance.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion emissions using the method specified below.

$$CO_2 = \cancel{[}\ \sum_{1}^{n} \cancel{\sum_{\cancel{1}}^{\cancel{x}} F_i} [(F * \cancel{CF_{Fi}} CF_F) + (FS * CF_{FS}) - S] * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide process and stationary combustion emissions – metric tonnes/year
~~x~~n = days of operation per reporting period
~~n = total number of fuels combusted~~
~~F_i~~F = fuel ~~i~~ consumption rate (~~kg~~scf/day)
~~CF_{Fi}~~
CF_F = carbon ~~fraction~~content of fuel ~~I~~ (kg C/~~kg fuel)~~
~~S = carbon fraction accounted for elsewhere (kg C/day~~scf fuel)
FS = feedstock ~~supply~~consumption rate (~~kg~~scf/day)
CF_{FS} = carbon ~~fraction~~content of feedstock (kg C/~~kg fuel~~scf feedstock)
S = carbon accounted for elsewhere (kg C/day)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 emissions are accounted for using other methods specified in these regulations (for example: an off-gas stream, such as PSA off-gas, diverted to a refinery fuel gas system or flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon ~~fraction~~content of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another fuel or feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(3) ***Fuel Stationary Combustion and Feedstock Process Emissions.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion emissions using the methods specified below.

(A) Operators shall calculate CO_2 stationary combustion emissions using methods specified in section 95113(a)(1)

(B) Operators shall calculate CO_2 process emissions using the method specified in this section.

$$CO_2 = \sum_{1}^{n} [(FSR * CF) - S] * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions (metric tonnes/yr)
N = number of operational days
FSR = feedstock supply rate (~~kg~~scf/day)
CF = carbon ~~fraction in~~content of feedstock (kg C/~~kg~~scf fuel)
S = carbon ~~fraction~~ accounted for elsewhere (kg C/day)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 emissions are accounted for using other methods specified in these regulations (for example: an off-gas stream, such as PSA off-gas, diverted to a refinery fuel gas system or flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon fraction of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(4) ***Process Vent Emission.*** Hydrogen plant operators shall report process emissions of CO_2, CH_4 and N_2O using the method specified in section

95113(b)(3). Process vent emissions calculated using other methods specified in this regulation shall not be calculated here.

(5) ***Sulfur Recovery process Emissions.*** Hydrogen plant operators shall report CO_2 process emissions from sulfur recovery units (SRU) using the method specified in section 95113(b)(5).

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

95115. Data Requirements and Calculation Methods for General Stationary Combustion Facilities.

(a) ***Emissions data report.*** The operator of any facility within California that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources, except as provided in section 95103(e), shall submit an emissions data report in cases where these sources are not included in a report submitted to satisfy the requirements of sections 95110, 95111, 95112, 95113 or 95114. The operator shall include the following information in the emissions data report for each report year:

(1) Stationary Combustion emissions:
(A) Total CO_2 emissions (metric tonnes)
1. CO_2 emissions from biomass-derived fuels (metric tonnes)
(B) Total CH_4 emissions (metric tonnes)
(C) Total N_2O emissions (metric tonnes)

(2) Fuels information:
(A) Fuel consumption by fuel type (scf, gallons, or metric tonnes)
1. The operator shall determine and provide consumption of each fuel by direct measurement for the report year. If there are no installed devices for direct measurement of fuel consumption, facilities shall report consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, standard cubic feet or metric tonnes) using the following equation:

Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

(B) Average annual carbon content by fuel type, if measured or provided by fuel supplier. (kg Carbon/MMBtu)
(C) Average annual high heat value by fuel type if measured or provided by fuel supplier. (HHV)

(3) Indirect energy usage:
(A) Electricity purchases from each electricity provider (kWh)
(B) Steam, heat, and cooling purchases from each energy provider (Btu)

(b) ***Calculation of CO_2 Emissions.*** The operator shall calculate emissions of CO_2 as specified below.

(1) The operator of a crude petroleum or natural gas production facility identified with the NAICS code 211111 shall report CO_2 emissions from

stationary combustion according to the methods specified in sections 95125(c), (d), and(f).

(A) For natural gas and associated gas, the operator shall use the method specified in section 95125(c) or 95125(d)~~;~~.

(B) ~~For associated gas, still gas, and process gas, the operator shall use the method~~Low Btu gases: CO_2 emissions resulting from the combustion and/or destruction of low Btu gases as specified in section ~~95125(e);~~95113(d)(3).

(C) For fuel mixtures, the operator shall apply the method specified in section 95125(f).

(2) For all other facilities, the operator shall measure and report direct CO_2 emissions from stationary combustion using one of the following methods:

(A) Use of a continuous emissions monitoring systems (CEMS) as specified in section 95125(g);

(B) Use of default emission factors and high heat values as specified in ~~sections 95125(a)~~section 95125(a). Where a default high heat value is not supplied for a specific fuel type in Appendix A, the operator shall use the method provided in section 95125(c) to calculate CO_2 emissions. ;

(C) Use of fuel heat content, carbon content and other fuel-specific parameters as specified in section 95125(c), (d), and (h).

(c) ***Calculation of N_2O and CH_4 Emissions.*** The operator shall calculate emissions of N_2O and CH_4 emissions from ~~fuel~~stationary combustion using the methodologies provided in section 95125(b).

(d) ***Electric Generating Units*.** Operators of general stationary combustion facilities ~~that operate an~~with electric generating ~~unit or units with nameplate generating capacities greater than or equal to 1 MW that emit 2,500 metric tonnes of CO_2 in the report year shall calculate and report those emissions as specified in section 95111. Electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district are not subject to this reporting requirement.~~units subject to the requirements of this article shall meet the requirements of section 95111.

(e) ***Cogeneration.*** Operators of general stationary combustion facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(f) ***Indirect Energy Usage.*** Operators of general stationary combustion facilities shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

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

Subarticle 3. Calculation Methods Applicable to Multiple Types of Facilities

95125. ***Additional Calculation Methods.*** Operators shall use one or more of the following methods to calculate emissions as required in sections 95110 through 95115.

(a) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content.**

(1) The operator shall use the method in section 95125(a)(2) to calculate CO_2 emissions, applying the default emission factors and default heat content values provided in the Appendix A, for each type of fuel combusted at the facility.

(2) The operator shall calculate each fuel's CO_2 emissions and report them in metric tonnes using the following equation:

$$CO_2 = \text{Fuel} * HHV_D * EF_{CO2} * 0.001$$

Where:

CO_2 = CO_2 emissions from a specific fuel type, metric tonnes CO_2 per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume

EF_{CO2} = Default carbon dioxide emission factor ~~supplied by ARB~~provided in Appendix A, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(b) **Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors.**

(1) The operator shall use the methods in this section to calculate CH_4 and N_2O emissions, applying the default emission factors provided in the Appendix A for each type of fuel, except as provided in section 95125(b)(4). If the operator is required to measure heat content in sections 95110 through 95115, the measured heat content shall be used in the equation in section 95125(b)(2). If the heat content is not measured, the operator shall employ the default heat content values specified in Appendix A by fuel type and the equation specified in section 95125(3).

(2) If the heat content of the fuel is measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tonnes CH_4 or N_2O per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default carbon dioxide emission factor ~~supplied by ARB~~provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(3) If the heat content of the fuel is not measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = Fuel * HHV_D * EF * 0.001$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tonnes CH_4 or N_2O per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume

EF = Default emission factor ~~supplied by ARB~~provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(4) The operator may elect to calculate CH_4 and N_2O emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided in Appendix A.

(c) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat Content.**

(1) The operator shall use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:

$$CO_2 = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CO_2 = combustion emissions from specific fuel type, metric tonnes CO_2 per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default carbon dioxide emission factor ~~supplied by ARB~~provided in the Appendix A, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(A) The operator shall measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. The operator may elect to utilize and record high heat values provided by the fuel supplier. The frequencies for measurements and recordings are as follows:

1. At receipt of each new fuel shipment or delivery or monthly for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid alternative fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

2. Monthly for natural gas and associated gas with high heat value $\geq$975 and $\leq$1100 Btu per scf. Natural gas and associated gas with high heat value <975 or >1100 Btu per scf shall use the methodology provided in section 95125 (d);

3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

4. The heat content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a

location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion. Each weekly sub-sample shall be collected at the same time (day and hour) of the week and/or at a time when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(B) When measured by the operator or fuel supplier, high heat values shall be determined using one of the following methods:

1. For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (2006)~~.~~, GPA Standard 2261-90 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography”, GPA Standard 2261-99.

2. For middle distillates and oil, or liquid alternative fuels, use ASTM D240-02 (2007) ~~or~~, ASTM D240-87, ASTM D4809-00 (Reapproved 2005).

3. For solid biomass-derived fuels and solid dry alternative fuels including but not limited to tire-derived fuel and dried biosolids, use ASTM D 5865-07

4. For solid alternative fuels including but not limited to wet and dried biosolids, use ASTM D5468-02.

(C) When measured using on-line instrumentation, high heating value shall be determined with an uncertainty of no more than ± 2.5%.

(d) ***Method for Calculating CO_2 emissions from Fuel Combustion Using Measured Carbon Content -*** For each type of fuel combusted at the facility, the operator shall calculate CO_2 emissions using the appropriate method below:

(1) ***Solid fuels.***

(A) Operators combusting solid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = mass of fuel combusted in month "n", metric tonnes per year
CC_n = carbon content from fuel analysis for month "n", percent (e.g. 95% expressed as 0.95)
3.664 = conversion factor for carbon to carbon dioxide

(B) The carbon content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations (e.g. coal milling) and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion. Each weekly sub-sample shall be collected at the same time (day and hour) of the week and/or at a time when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(C) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method:

1. For coal and coke: ASTM 5373-02 (Re-approved 2007) which is incorporated by reference herein.

2. For solid biomass-derived fuels including but not limited to wood pellets, use ASTM D5373-02 (Reapproved 2007).

3. For solid dry alternative fuels including but not limited to tire-derived fuel and dried biosolids, use ASTM D5373-02 (Reapproved 2007).

(2) ***Liquid fuels.***

(A) Operators combusting liquid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = volume of fuel combusted in month "n", gallons per year
CC_n = carbon content from fuel analysis for month "n", kg C per gallon fuel
3.664 = conversion factor for carbon to carbon dioxide
0.001 = factor to convert kg to metric tonnes

(B) The carbon content shall be measured and recorded monthly. When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: For petroleum-based liquid fuels and liquid alternative fuels, use ASTM D5291-02 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Re-approved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Re-approved 2002), all incorporated by reference herein.

(3) ***Gaseous Fuels.*** Operators combusting gaseous fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 1/MVC * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = volume of gaseous fuel combusted in month "n", scf
CC_n = carbon content from fuel analysis for month "n", kg C per kg-mole fuel
MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, for STP of 60℉, and 1 atmosphere)
3.664 = conversion factor for carbon to carbon dioxide
0.001 = Factor to convert kg to metric tonnes

(A) The carbon content shall be measured and recorded monthly except in the case of refinery fuel gas as required in section 95125(d)(3)(A)(1).

When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method. ASTM D1945-03 or ASTM D1946-90 (Re-approved 2006) which is incorporated by reference herein.

1. Petroleum refiners electing to use this method to calculate CO_2 emissions resulting from the combustion of refinery fuel gas shall determine refinery fuel gas carbon content (CC) a minimum of 4 times per day (every eight hours) using on-line instrumentation. Operators shall calculate CO_2 emissions for a refinery fuel gas system in the following manner:

$$CO_2 = \sum_{1}^{365} Fuel_n * CC_{An\text{-}ave} * MW_{RFG\text{-}A}/MVC * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes/year
$Fuel_A$ = refinery fuel from system A combusted in day n (scf)
$CC_{An\text{-}ave}$ = system A refinery fuel gas average daily carbon content for day n (kg C/kg fuel)
$MW_{RFG\text{-}A}$ = average daily molecular weight of refinery fuel gas system A for day n
MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20℃ and 1 atmosphere, or 836 scf/kg-mole fo r STP of 60℉ and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(e) ***Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat and Carbon Content.***

(1) The operator shall use the following method to calculate CO_2 emissions from ~~fuel gas systems in the oil and gas sector, including combusted~~combustion of refinery fuel ~~gas, still gas, process gas, associated gas or pressure swing adsorption off-~~gas using both high heat value (HHV) and fuel carbon content.

(2) Each fuel gas system that provides fuel to one or more combustion devices shall be subject to the measurement and reporting methods described herein. The operator shall obtain fuel samples and choose measurement locations in a manner that minimizes bias and is representative of each fuel gas system.

(3) For each separate fuel gas system, the operator shall calculate a daily fuel specific emission factor using the equation shown below. Operators

meeting the definition of “small refiner” shall calculate a weekly emission factor for each refinery fuel gas system.

$$EF_{CO2-A} = CC_A/HHV_A * \cancel{MW_{CO2}}MW_A/MVC * \cancel{0.001}3.664 * 1000$$

Where:

EF_{CO2-A} = daily CO_2 emission factor for fuel gas system A (tonnes CO_2/MMBtu)
CC_A = fuel gas carbon content for fuel gas system A (kg carbon/kg fuel)
HHV_A = high heating value for fuel gas system A (MMBtu/scf)
$\cancel{MW_{CO2}}MW_A$ = refinery fuel A molecular weight ~~of CO_2~~(kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere)
~~0.001~~1000 = conversion factor ~~to convert~~- kg/Btu to metric tonnes/MMBtu

(A) The operator shall determine carbon content once per day for each fuel gas system, by on-line instrumentation or by laboratory analysis of a representative gas sample drawn from the system, using the method specified in section 95125(d)(3)~~(C)~~. Small refiners shall determine carbon content weekly.

(B) The operator shall determine high heating value from the fuel sample obtained to conduct carbon analysis, or from a continuous in-line monitor. When HHV is derived from an in-line monitor, operators shall use either an hourly average HHV value coinciding with the hour in which the carbon content determination was made (in the case where an on-line analyzer was used), or the hour in which the sample was collected for analysis. The operator shall use the method specified in section 95125(c)(1)(B).

(4) For each refinery fuel gas system the operator shall use the system specific daily (weekly for small refiners) fuel emission factor calculated using the equation in section 95125(e)(3) to calculate daily (weekly for small refiners) CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

.
$$CO_{2-A} = \sum_{1}^{365} \cancel{HHV_A}HHV_{DA} * FR_A * EF_{CO2-A}$$

Where:

CO_{2-A} = CO_2 emissions resulting from the combustion of fuel gas from system A (metric tonnes/yr)

~~HHV_A~~$\underline{HHV_{DA}}$ = daily average high heating value for system A (Btu/scf)
FR_A = daily fuel consumption for fuel gas system A (scf/d)
EF_{CO2-A} = daily CO_2 emission factor for fuel gas system A (tonnes CO_2/~~10^6~~MM Btu)

Small refiners may use the HHV value determined as part of the weekly fuel carbon content analysis to calculate weekly CO_2 emissions.

(5) The operator shall calculate and report total CO_2 emissions resulting from the combustion of fuel gas as the sum of CO_2 combustion emissions from each fuel gas system in the following manner:

$$CO_2 = CO_{2\text{-}A} + CO_{2\text{-}B} + CO_{2\text{-}C} + \ldots\ldots CO_{2\text{-}X}$$

Where:

CO_2 = total CO_2 emissions from the combustion of fuel gas (metric tonnes/yr)
$CO_{2A,B,C}$ = CO_2 emissions from the combustion sources in fuel gas system A,B,C, etc. (metric tonnes/yr)
$CO_{2\text{-}X}$ = CO_2 emissions from the combustion of fuel gas system X, where X is the total number of fuel gas systems (metric tonnes/yr)

(f) ***Method for Calculating CO_2 Emissions from Fuel Combustion for Fuel Mixtures.***

(1) Where individual fuels are mixed prior to combustion, the operator shall choose one of the two methods below to calculate and report CO_2 emissions.

(A) Measure the flow rate of each fuel stream prior to mixing, apply the fuel specific sampling scheme specified for each fuel, calculate CO_2 emissions for each fuel in the mixture and sum to calculate total combustion emissions.

(B) Measure the flow rate of the fuel mixture and apply the methodology specified in section 95125(e)~~.~~

~~(2) This provision does not apply in situations where equipment such as a hot oil heater or flare functions as an abatement device. This provision does not apply where a primary fuel supply is augmented with low Btu gas recovered from a controlled source such as a product or crude oil storage tank.~~ for refinery fuel mixtures and section 95125(c) or 95125(d) for associated gas.

(g) ***Method for Calculating CO_2 Emissions ~~from Fuel Combustion~~ Using Continuous Emissions Monitoring Systems.***

(1) Operators of facilities that combust fossil fuels ~~other than refinery fuel gas,~~or biomass and operate continuous emissions monitoring systems (CEMS) in response to federal, state, or air pollution control district/air quality management district (AQMD/APCD) regulations, including air district operating permit programs that meet the requirements of 40 CFR Part 60, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(A) If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations are within 5% of measured CO_2 concentrations.

(2) Operators of facilities that combust ~~biomass or~~ municipal solid waste and operate a CEMS in response to federal, state, or AQMD/APCD regulations including air district operating permit programs that meet the requirements of 40 CFR Part 60, may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year and converted to metric tonnes. Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts municipal solid waste who chooses to calculate CO_2 emissions using the methodology provided in section 95125(g)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in section 95125(h)(2).

(4) The operator who chooses to use CEMS data to report CO_2 emissions ~~using CEMS data and~~from a facility that co-fires a fossil fuel with a biomass-derived fuel shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in section 95125(h)(2). The operator may elect to calculate CO_2 emissions for the fossil fuel using methods as designated in section 95111(c) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) The operator who chooses to ~~reports~~report CO_2 emissions using CEMS data is relieved of requirements to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance operators shall still report fuel use by fuel type as otherwise required in this article.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring ~~systems~~system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 ~~as applicable~~that apply to the facility.

(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CRF Part 75. The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(h) ***Method for Calculating CO_2 Emissions from Combustion of Biomass or Municipal Solid Waste.***

(1) The operator shall use the following method to calculate CO_2 emissions in the report year from combustion of biomass or municipal solid waste.

(A) CO_2 emissions from combusting biomass or municipal solid waste shall be calculated using the following equation:

$$CO_2 = Heat * CC_{EF} * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions from fuel combustion, metric tonnes per year
Heat = Heat calculated in section 95125(h)(1)(B), MMBtu per year
CC_{EF} = Default carbon content emission factor provided in Appendix A, kg carbon per MMBtu
3.664 = CO_2 to carbon molar ratio
0.001 = Conversion factor to convert kilograms to metric tonnes

(B) Heat content shall be calculated using the following equation:

$$Heat = Steam * B$$

Where
Heat = Heat, MMBtu per year
Steam = Actual Steam generated, pounds per year
B = Boiler Design Heat Input/Boiler Design Steam Output, as Design MMBtu per pound Steam

(2) The operator shall determine the biomass-derived portion of CO_2 emissions from combusting municipal solid waste using ASTM D6866-06a. The operator shall conduct ASTM D6866-06a analysis at least every three months, and each gas sample analyzed shall be taken during normal operating conditions over at least 24 consecutive hours or for as long as necessary to gather a sample large enough to meet the specifications of ASTM D6866-06a. The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

(3) Operators of facilities that combust biomass-derived fuels or municipal solid waste may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in ~~future~~subsequent years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided ~~by ARB~~in Appendix A.

(i) ***Method for Calculating Mobile Combustion Emissions.***

(1) ~~The~~For operators choosing to report mobile source combustion emissions the operator shall use the following equation to compute mobile combustion CO_2 emissions for the report year by fuel type:

$$CO_2 = Fuel * EF_{CO2} * 0.001$$

Where:
CO_2 = emissions from mobile combustion by fuel type, metric tonnes
Fuel = volume of fuel consumed, gallons
EF_{CO2} = default emission factor by fuel type ~~supplied by ARB, kg CO~~provided in Appendix A, kgCO_2/gallon
0.001 = conversion factor to convert kg to metric tonnes

(2) The operator shall obtain data on the volume of fuel consumed during the report year from fuel records data (including bulk fuel purchase records, collected fuel receipts, official logs of vehicle fuel gauges or storage tanks) as shown in section 95125(i)(1)(A)~~. The~~, unless the operator ~~may~~ ~~elect~~elects to calculate fuel use from miles traveled per vehicle using the fuel economy method shown in section 95125(i)(~~1~~2)(B).

(A) The operator shall use the following equation to calculate mobile source fuel consumption from fuel records data:

$$Fuel = FP + FS_{beg} - FS_{end}$$

Where:
Fuel = volume of fuel consumed, gallons
FP = total fuel purchases, gallons
FS_{beg} = amount of fuel stored at the beginning of the year, gallons
FS_{end} = amount of fuel stored at the end of the year, gallons

(B) The operator shall use the following equation to calculate mobile source fuel consumption using U.S. EPA fuel economy values for specific vehicle models and miles traveled per vehicle:

$$Fuel = \sum_{i}^{n} Mileage_i / (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:
Fuel = volume of fuel consumed, gallons
$Mileage_i$ = total miles traveled by vehicle i, miles
$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon
$DP_{city,i}$ = proportion of miles traveled spent in city driving conditions for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may be substituted if known)
$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon
$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)
n = total number of vehicles

(3) The operator shall use the following equation to compute mobile combustion CH_4 and N_2O emissions by vehicle type:

$$TE = EF * Mileage * 0.000001$$

Where:

TE = total emissions of CH_4 or N_2O from mobile combustion by vehicle type, metric tonnes per year

EF = emission factor by vehicle type and fuel type provided by ARB, g of CH_4 or N_2O/mile

Mileage = total miles traveled by vehicle type, miles per year

0.000001 = conversion factor to convert grams to metric tonnes

(A) If mile traveled data are not available, the operator may elect to back calculate total miles traveled by vehicle type from fuel usage data using U.S. EPA fuel economy values for specific vehicle models and the following equation:

$$Mileage = \sum_{i}^{n} Fuel_i * (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:

Mileage = total miles traveled by vehicle type, miles

$Fuel_i$ = volume of fuel consumed by vehicle model i, gallons

$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon

$DP_{city,i}$ = proportion of miles traveled spent in city driving for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may substituted if known)

$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon

$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)

n = number of vehicles

(j) ***Method for Calculating Fugitive CH_4 Emissions from Coal Storage.***

The operator shall calculate fugitive CH_4 emissions from coal storage using the following equation:

$$CH_4 = PC * EF * CF_1 / CF_2$$

Where

CH_4 = CH_4 emissions in the report year, metric tonnes

PC = Purchased coal in the report year, tons

EF = Default emission factor for CH_4 based on coal origin and mine type provided in Appendix A, scf CH_4/ton

CF_1 = Conversion factor equals 0.04228, lbs CH_4/scf

CF_2 = Conversion factor equals 2,204.6, lbs/metric ton

(k) ***Method for Calculating Indirect Electricity Usage.***

The operator ~~who~~a facility that consumes electricity that is purchased or acquired from a retail provider or a facility they do not own or operate shall report electricity use and identify the provider(s) for all electricity consumed at the facility.

(1) For each electricity provider, the operator shall sum electricity use (kWh) from billing records for the report year. If the records do not begin ~~or end exactly~~ on January 1 and end on December ~~31,~~31 of the report year, but span two calendar years, the facility shall pro-rate its power usage according to the fraction of days billed for each month in each year using the equation shown.

Calculating electricity use for partial months:

Partial Month Electricity use (kWh) =
*(electricity use (kWh) in period billed / total number days in period billed) * (number of report year days in the period billed ~~in partial month~~)*

(2) The operator shall report by electricity provider the electricity consumed at the facility in kilowatt-hours (kWh).~~.~~

(l) ***Method for Calculating Indirect Thermal Energy Usage.***

The operator ~~who~~of a facility that consumes steam, heat, and/or cooling that is purchased or acquired from a facility that they do not own or operate shall report thermal energy use and identify the provider(s) for all thermal energy consumed at the facility.~~.~~

(1) For each thermal energy provider, the operator shall obtain data from the facility's thermal use records, and sum this usage for the report year. If the records do not begin ~~or end exactly~~ on January 1 and end on December ~~31,~~31 of the report year, but span two calendar years, the facility shall pro-rate its indirect thermal energy usage according to the fraction of days billed for each month in each year using the equation shown.

Calculating thermal use for partial months:

Partial Month Thermal use (Btu) =
(thermal use (Btu) in period billed / total number days in period billed)
** (number of report year days in the period billed ~~in partial month~~)*

(2) The operator shall report by thermal energy provider the thermal energy consumed at the facility in British thermal units (Btu).

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

<u>Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers</u>

95130. Requirements for Verification of Emissions Data Reports. Operators shall obtain the services of an accredited verification body for purposes of verifying emissions data reports submitted under this article, as specified in section 95103(c).

(a) ***Annual Verification.***

(1) Operators required to obtain annual verification under section 95103(c) shall be subject to full verification requirements beginning in the calendar year following their first report year. Upon completion of a positive verification opinion under full verification requirements, the operator may choose to obtain two years of less intensive verification services. This cycle may be repeated in subsequent three-year cycles, but full verification requirements shall not apply less frequently than every three years.

(2) Operators subject to annual verification shall not use the same verification body for a period of more than six consecutive years. The operator may resume verification services with a verification body that has provided verification services for six consecutive years after at least three years of not contracting for such services with the same verification body.

(b) ***Triennial Verification.***

(1) Operators required to obtain triennial verification under section 95103(c) shall be subject to full verification requirements every year that verification is required. However, such operators may choose to obtain less intensive verification services for the two years following completion of full verification services and prior to the next three-year cycle.

(2) Operators subject to triennial verification requirements shall not use the same verification body for more than two consecutive verification cycles. The operator may resume verification services with that verification body after one verification cycle of not obtaining verification services from the same verification body.

(c) Operators who are members of the California Climate Action Registry may use the same verification body for ARB and Registry emissions data reports, when that body has met both ARB and Registry accreditation requirements. When an operator is required to rotate verification bodies by the California Climate Action Registry, the operator shall also rotate the verification body used to meet the verification requirements of this article if the operator chooses to use the same verification body.

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

95131. Requirements for Verification Services. Verification services shall be subject to the following requirements.

(a) ***Notice of Verification Services.*** After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the operator ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification;

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited to provide sector specific verification services when required below:

(A) For providing verification services to a retail provider or marketer, at least one verification team member must be accredited by ARB as an electricity transactions specialist.
(B) For providing verification services to the operator of a petroleum refinery or hydrogen plant, at least one verification team member must be accredited by ARB as a refinery specialist.
(C) For providing verification services to the operator of a cement plant, at least one verification team member must be accredited by ARB as a cement plant specialist.

(3) General information on the lead verifier and the operator, including:

(A) The name, office address, telephone number, and e-mail address of the lead verifier;
(B) The name of the operator and the facilities and other locations that will be subject to verification services; operator contact, address, telephone number, and e-mail address;
(C) The industry sector, and the Standard Industrial Classification and North American Industry Classification System (NAICS) codes of the reporting facility;

(D) The expected date(s) of on-site visits, with facility address and contact information;

(E) A brief description of expected verification services to be performed, including expected completion date.

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

(1) ***Verification Plan.*** The verification team shall obtain information from the operator necessary to develop a verification plan. Such information shall include but is not limited to:

(B) ~~(A)~~ Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity transactions as applicable;

(C) ~~(B)~~ Information regarding the training or qualifications of personnel involved in developing the emissions data report;

(D) ~~(C)~~ Description of the specific methodologies used to quantify and report greenhouse gas emissions, electricity transactions, and other required data as applicable;

(E) ~~(D)~~ Information about the data management system used to track greenhouse gas emissions, electricity transactions, and other required data as applicable.

(2) The verification team shall develop a verification plan that includes, at a minimum:

(A) Dates of proposed meetings and interviews with reporting facility personnel;

(B) Dates of proposed site visits;

(C) Types of proposed document and data reviews;

(D) Expected date for completing verification services.

(3) The verification team shall discuss with the operator the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan a review of original documents and supporting data for the emissions data report.

(4) ***Site visits.*** The verification team shall at a minimum make one site visit, in the first year of each three-year reporting cycle, to each facility for which an emissions data report is submitted. The verification team shall visit the headquarters or other location of central data management when the operator is also a retail provider or marketer, The objectives of the verification team during the site visit shall include the following:

(A) The verification team shall ~~ensure~~check that all sources specified in sections 95110 to 95115 as applicable to the operator are ~~accounted for~~identified appropriately;

(B) The verification team shall review and understand the data management systems used by the operator to track, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions. The verification team shall evaluate the uncertainty and effectiveness of these systems.

(C) The verification team shall collect and review other information that, in the professional judgment of the team, is needed in the verification process.

(5) The verification team shall review facility operations to identify applicable greenhouse gas emissions sources. This shall include a review of the emissions inventory and each type of emission source to assure that all sources applicable under 95110 to 95115 of this article are properly included in the inventory.

(6) Operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this article, as applicable.

(7) As applicable for retail providers and marketers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags.

(8) ***Sampling Plan.*** As part of confirming emissions data or electricity transactions the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for an operator. The analysis shall review ~~all~~the inputs for the development of the submitted emissions data report, the rigor and appropriateness of the greenhouse gas or electricity transaction data management system, and the coordination within a facility or retail provider's or marketer's organization to manage the operation and maintenance of equipment or systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the operator, and a ranking of emissions sources with largest ~~estimation~~calculation uncertainty. As applicable and deemed appropriate by the verifier, electricity transactions shall also be ranked or evaluated for relative amount of power exchanged and any uncertainties that may apply to data summaries provided by the retail provider or marketer.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95115:

1. data acquisition equipment;
2. data sampling and frequency;
3. data processing and tracking;
4. emissions calculations;
5. data reporting;
6. management policies or practices in developing emissions data reports.

(D) The verification team may change the sampling plan as relevant information becomes available and potential issues of misstatement or nonconformance with regulation requirements emerge.

(9) ***Data checks.*** To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus first on the largest and most uncertain estimates of emissions 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 and electricity transactions required under sections 95110 to 95115;

(B) The verification team shall choose emissions sources and, as applicable, electricity transactions, for data checks based on their relative sizes and risks of ~~uncertainty~~material misstatement as indicated in the sampling plan;

(C) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance that the reported emissions and transactions are free or not free of material misstatement and nonconformance.

(10) ***Emissions data report modifications.*** If as a result of review by the verification team and prior to completion of a verification opinion the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report may be submitted to ARB as specified by section 95104(d). The operator 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 operator for five years.

(11) ***Findings.*** To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of total emissions for checked sources and shall determine whether there is reasonable assurance that the reported emissions are within 95% of the CO_2e total actual emissions. To assess conformance the team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this article.

(A) The verification team shall keep a log of any issues identified that may impact material misstatement and nonconformance determinations and how those issues were resolved.

(c) Completion of verification services shall include:

(1) ***Verification opinion.*** ~~At~~Upon the completion of verification services the verification body shall complete a verification opinion, and provide that opinion to the operator and the ARB according to the schedule specified in section 95103(c)(4). Before that opinion is ~~made available to the operator~~completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by a lead verifier not involved in services for that operator during that year.

(2) When the verification team completes its findings:

(A) The verification body shall provide to the operator a detailed verification report. The verification report shall at minimum include the verification plan, sampling plan, the detailed comparison of the data checks with the submitted emissions data report, ~~the~~a issues log, and any qualifying comments on findings during verification services. The detailed verification report shall be made available to ARB upon request.

(B) The ~~lead verifier~~verification body shall provide ~~a~~the verification opinion to the operator and the ARB, attesting that the verification body has found the submitted emissions data report free of material misstatement and nonconformance or, alternatively, the emissions data report does not meet the material misstatement or conformance requirements as specified in this article. In the verification opinion, the lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier that has conducted the independent review of verification services and findings specified in section 95131(c)(1) shall attest to his or her independent review on behalf of the verification body.

(3) ~~If~~Prior to the verification body ~~provides~~providing an adverse verification opinion to the ARB on the emissions data report, the operator may modify the report to remove any material misstatement or nonconformance found by the verification team in order to receive a subsequent positive verification opinion. The modified report must be submitted to ARB before the applicable verification deadline, unless the operator makes a request to the Executive Officer as provided below in section 95131(c)(3)(A).

(A) If the operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification opinion, the operator may petition the ARB Executive Officer to make a final decision as to the verifiability of the submitted emissions data report.

(B) If the Executive Officer determines that the emissions data report does not meet the standards and requirements specified in this article, the operator shall submit for re-verification within thirty days of the date of this decision a revised emissions data report that reflects the Executive Officer's determination. In re-verifying any revised emissions data reports, the verification team shall be subject to the requirements in section 95131(c)(1)-(2).~~.~~

(d) Once the verification opinion has been provided to ARB by the applicable verification deadline, the emissions data report shall be considered final and no changes shall be made except as provided in section 95104(d)(3) and all verification requirements of this article shall be considered complete.

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and an operator, or the verified emissions data report fails an ARB audit, then the Executive Officer may set aside a positive verification opinion submitted by the verification body.

(f) ~~(d)~~ Upon request by the Executive Officer the operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. ARB may also review the full verification report given by the verification body to the operator. The full verification report shall be provided to the Executive Officer upon request.

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

95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article.

(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, except as provided in section 95132(b)(1)(F).

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

1. A verification body shall have at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
2. A verification body shall have at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation to demonstrate that the proposed verification body has a minimum of one million U.S. dollars of professional liability insurance.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries and customers that the body serves, and the locations where those services are provided;
2. An organization chart that includes the verification body and any related entities, a brief description of services provided by related entities, the industries~~ and customers~~ served, and locations where those services are provided.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification.

(F) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(~~a~~A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) ***Lead Verifier Accreditation Application.*** To apply for accreditation as a lead verifier, the applicant shall submit the following documentation to the Executive Officer.

(A) Evidence that the applicant has completed ARB approved verification training and received a passing score on an exit examination. ; And,

(B) ~~(A)~~ Evidence that the applicant has acted as project manager or in a lead capacity in one or more of the following greenhouse gas reporting programs:

1. As ~~a registered~~an approved lead verifier in good standing for the California Climate Action Registry prior to December 1, 2007, having performed at least three verifications by December 31, ~~2007;~~ 2007.This shall include acting lead verifiers in the California Climate Action Registry that have taken CCAR or other GHG lead verification training and have performed at least three verifications by December 31, 2007.;or,
2. ~~As a registered~~Serving as a recognized lead verifier in good standing for the United Kingdom Accreditation System, having performed at least three verifications by December 31, 2007; or,
3. Is accredited by a recognized agency in ISO ~~14065,~~ 14064 or ISO 19011, having performed at least three verifications by December 31, ~~2007.~~2007; or,

(C) ~~(B)~~ Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment for services performed; or,

(D) ~~(C)~~ Evidence that the applicant has worked as a project manager or leadperson for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories: or,
2. As a lead environmental data auditor in the private sector.

~~(D) Evidence that the applicant has completed ARB approved general verification training and received a passing score on an exit examination.~~

(E) For each applicant for accreditation as a lead verifier who has not submitted evidence of qualification under sections 95132(b)(2)(A), 95132(b)(2)(B), or 95132(b)(2)(C)2, evidence that the applicant has completed ARB approved auditor training and received a passing score on an exit examination.

(3) ***Verifier Accreditation Application*.** To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) The applicant must submit evidence demonstrating the minimum educational background required to act as a verifier for ARB. "Minimum education background" means that the applicant has either:

1. A bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or
2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) The applicant must also submit evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of fulltime work experience in a professional role involved in emissions data management, emissions technology, emissions field enforcement, or other technical skills necessary to conduct verification.

(4) All verifier applicants shall take an ARB approved general verification training course and receive a passing score on an exit examination.

(5) ***Sector Specific Verifiers.*** All applicants seeking to be approved as sector specific verifiers as specified in section 95131(a)(2) must, in addition to meeting the requirements for verifier qualification, take ARB sector specific verification training and receive a passing score on an exit examination.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier; or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) ***ARB Accreditation.***

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, or verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is necessary required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verifier or lead verifier is complete, the prescreening requirement is met and the applicant may attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to grant or withhold accreditation for the verification body, lead verifier, or verifier.

(4) The Executive Officer shall issue an Executive Order to grant accreditation to the applicant if the evidence of qualification submitted by the applicant has been found complete and sufficient and the applicant has successfully completed the required training and examination(s).

(5) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, or verification body. All ARB approved general or sector specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer.

(6) The Executive Officer shall issue an Executive Order to grant accreditation to a verification body if evidence of qualification submitted by the applicant has been found to meet the requirements of section 95132(b)(1).

(7) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in this subsection (c), and the applicant may submit additional supporting documentation before a decision has been made by the Executive Officer.

(d) ***Modification or Revocation of an Executive Order Approving a Third Party Verifier*.** The Executive Officer may review and, for good cause, modify or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not modify or 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.

(e) ***Subcontracting.*** The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.
(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers or verification bodies.
(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements specified section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.
(4) A verification body or verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for an operator.
(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the operator for which it will provide verification services.

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

95133. Conflict of Interest Requirements for Verifiers.

(a) The conflict of interest provisions of this section shall apply to verification bodies and verifiers accredited by ARB to perform verification services.

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

(1) The verification body and operator share any management or board of directors membership, or any of the management staff of the operator have been previously employed by the verification body, or vice versa, within the previous three years, or

(2) Within the previous three years, any staff member of the verification body or any related entity has provided to the operator any of the following non-verification services:
(A) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;
(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
(D) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
(E) Appraisal services of carbon or greenhouse gas liabilities or assets;

(F) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
(G) Managing any health, environment or safety functions;
(H) Bookkeeping or other services related to the accounting records or financial statements;
(I) Any service related to information systems, unless those systems will not be part of the verification process;
(J) Appraisal and valuation services, both tangible and intangible,
(K) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;
(L) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
(M) Any internal audit service that has been outsourced by the operator that relates to the operator's internal accounting controls, financial systems or financial statements, unless the result of those services shall not be part of the verification process;
(N) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the operator;
(O) Any legal services;
(P) Expert services to the operator or their legal representative for the purpose of advocating the operator's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

(3) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the operator within the last three years, except within the time periods in which the operator is allowed to use the same verification body as provided by sections 95130(a) and 95130(b).

(c) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section 95133(b) and any non-verification services provided by any member of the verification body to the operator within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95132(b) and 95132(c).

(1) If a verification body identifies a medium potential for conflict of interest and wishes to provide verification services for the operator, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of

interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any conflicted individuals have been removed and insulated from the project.
(B) An explanation of any changes to the organizational structure or verification body to remove the conflict of interest. A demonstration that any conflicted unit has been divested or moved into an independent entity or any conflicted subcontractor has been removed.
(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) The Executive Officer shall evaluate the conflict of interest mitigation plan as provided in section 95133(f) and determine whether verification services may proceed.

(e) ***Conflict of Interest Submittal Requirements for Accredited Verifiers*.**

(1) Before the start of any work related to providing verification services to an operator, a verification body must first be authorized by the Executive Officer in writing to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the body, its partners, or any subcontractors performing verification services may have with the operator for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);
(B) An organizational chart of the verification body and brief description of the verification body and any related entities;
(C) Identification of whether any member of the verification team has previously provided verification services for the reporting facility and, if so, the years in which such verification services were provided;
(D) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the reporting facility either within or outside California during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with

implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions.

2. The nature of past, present or future relationships with the reporting facility, retail provider, or marketer including:
   a. Instances when any member of the verification team has performed or intends to perform work for the operator;
   b. Identification of whether work is currently being performed for the operator, and if so, the nature of the work;
   c. How much work was performed for the operator in the last three years, in dollars or percentage of verifier's revenues or gross income;
   d. Whether any member of the verification team has any contracts or other arrangements to perform work for the operator or a related entity;
   e. How much work related to greenhouse gases or electricity transactions the verification team has performed for the reporting facility or related entities in the last three years, in dollars or percentage of the body's and its subcontractors' revenues or gross income.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(E) A list of names of the staff that would perform verification services for the operator, and a description of any instances of personal or family relationships with management or employees of the operator that potentially represent a conflict of interest; and,

(2) Identification of any other circumstances known to the verification body or operator that could result in a conflict of interest.

(f) ***Conflict of Interest Determinations*.** The Executive Officer shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the operator.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within forty-five days of deeming the evaluation information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and shall so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the

Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to sections 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the operator, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate a low conflict of interest, then verification services may proceed.

(g) ***Monitoring Conflict of Interest Situations.***

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body shall 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 entering into any contract with the operator for which the body has provided verification services, the verifier shall notify the Executive Officer of the contract and the nature of the work to be performed.

(3) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(4) The Executive Officer may invalidate a verification finding if a conflict of interest has arisen for any member of the verification team. In such a case, the operator shall be provided 180 days to complete re-verification.

(5) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may

rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section 95132(d).

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

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APPENDIX A

to the Regulation for the Mandatory Reporting
of Greenhouse Gase Emissions

ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

October 19, 2007

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ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

October 2007

CONTENTS

1. Introduction

The contents of this compendium specify acceptable methods and emission factors that operators must use when preparing greenhouse gas emissions data reports for submission to the California Air Resources Board (ARB), as specified in the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

2. Unit Conversions

Table 1. Conversion Table		
To Convert From	**To**	**Multiply By**
Grams (g)	Tonnes (metric)	1×10^{-6}
Kilograms (kg)	Tonnes (metric)	1×10^{-3}
Megagrams	Tonnes (metric)	1
Gigagrams	Tonnes (metric)	1×10^{3}
Pounds (lbs)	Tonnes (metric)	4.5359×10^{-4}
Tons (long)	Tonnes (metric)	1.016
Tons (short)	Tonnes (metric)	0.9072
Barrels	Cubic metres (m^3)	0.15898
Cubic feet (ft^3)	Cubic metres (m^3)	0.028317
Litres	Cubic meters (m^3)	1×10^{-3}
Cubic yards	Cubic meters (m^3)	0.76455
Gallons (liquid, US)	Cubic meters (m^3)	3.7854×10^{-3}
Imperial gallon	Cubic meters (m^3)	4.54626×10^{-3}
Joule	Gigajoules (GJ)	1×10^{-9}
Kilojoule	Gigajoules (GJ)	1×10^{-6}
Megajoule	Gigajoules (GJ)	1×10^{-3}
Terajoule (TJ)	Gigajoules (GJ)	1×10^{3}
Btu	Gigajoules (GJ)	1.05506×10^{-6}
Kilocalorie	Gigajoules (GJ)	4.187×10^{-6}
Tonne oil eq. (toe)	Gigajoules (GJ)	41.86
kWh	Gigajoules (GJ)	3.6×10^{-3}
Btu / ft^3	GJ / m^3	3.72589×10^{-5}
Btu / lb	GJ / Tonnes (metric)	2.326×10^{-3}
Lb / ft^3	Tonnes (metric) / m^3	1.60185×10^{-2}
Psi	Bar	0.0689476
Kgf / cm^3 (tech atm)	Bar	0.980665
Atm	Bar	1.01325
Mile	Kilometer	1.6093
Hectares	Acres	2.471
Barrels	Gallons (liquid, US)	42

3. Global Warming Potentials

According to the Intergovernmental Panel on Climate Change (IPCC), the global warming potential (GWP) of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas. The reference gas used is CO_2. The values given below are those reported in the IPCC Second Assessment Report (IPCC 1996). These values are used to be consistent with other statewide and national Greenhouse Gas (GHG) inventories. Operators must use these values when converting emissions of greenhouse gases to carbon dioxide equivalent values (CO_2e) for purposes of estimating *de minimis* emissions as specified in section 95103(a)(6).

Table 2. Global Warming Potentials (100-Year Time Horizon)

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Source: IPCC Climate Change 1995: The Science of Climate Change. (1996) Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds. Cambridge University Press. Cambridge, U.K.

4. Method for Fuel Use to Carbon Dioxide Emissions Estimations

The following table shows the approximate amount of fuel that, when fully combusted, would result in 25,000 and 2,500 metric tonnes of CO_2 for selected common fuel types.

The 25,000 metric tonne threshold is the level at or above which general stationary sources of combustion are required to report under the regulation. Similarly, the 2,500 metric tonne threshold is the level at or above which electrical generating facilities $\geq$1MW are required to report. This information is provided to give operators a rough estimate of whether or not a given facility falls within the scope of ARB's mandatory reporting program. However, this table alone may not be used to demonstrate that that a facility has no reporting obligation.

These tables are based on the ARB accepted emission factors which are set forth in this document. If an operator is combusting multiple fuels types, or is using a fuel type not listed in this table, then the operator must multiply the amount of fuel consumed annually for each fuel type by the ARB provided emission factor and sum the emissions to determine annual CO_2 emissions from stationary combustion.

Table 3. Fuel Amounts Resulting in 25,000 or 2,500 MT of CO_2 by Fuel Type

Fuel Type	Fuel Units	Kg CO_2/Unit	Amount of fuel to produce 25,000 MT CO_2	Amount of fuel to produce 2,500 MT CO_2
Natural Gas (unspecified)	scf	0.05	459,140,464	45,914,046
LPG (energy use)	Gal	5.79	4,317,757	431,776
Distillate Fuel (#1,2 &4)	Gal	10.14	2,466,011	246,601
Motor Gasoline	Gal	8.80	2,841,174	284,117
Landfill Gas	MMBtu	52.03	480,503	48,050
Coal (Unspecified Other Industrial)	Short Ton	2,082.89	12,003	1,200
Jet Fuel	Gal	9.56	2,614,682	261,468
Kerosene	Gal	9.75	2,562,972	256,297
Petroleum Coke	MMBtu	102.04	244,996	24,500
Crude Oil	Gal	10.29	2,430,348	243,035

5. Emission Factors

When working with the following emission factor tables the molar mass ratio of carbon dioxide to carbon (CO_2/C) is assumed to be 3.664. Complete oxidation is assumed for all fuels (oxidation factor = 1).

(a) Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors for Stationary Combustion

The default heat contents specified in Table 4 are provided for use with sections 95125(a) and (b) of the regulation.

The default carbon dioxide emission factors from stationary combustion on a heat content basis (kg CO_2 / MMBtu) specified in Table 4 and Table 5 are provided for use with sections 95125(a), (c) and (h) of the regulation.

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	**Default Carbon Content**	**Default Heat Content**	**Default CO_2 Emission Factor**	**Default CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cub. ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)				
Petroleum Products	**kg C / MMBtu**	**MMBtu / Barrel**	**kg CO_2 / gallon**	**kg CO_2 / MMBtu**
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Biomass-derived Fuels (Solid)	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cub. ft.**	**kg CO_2 / MMBtu**
Biogas	~~14.2~~28.4	Varies	Varies	~~52.03~~104.06
Note: Heat content factors are based on higher heating values (HHV).				
Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except: Heat Content factors for Unspecified Coal (by sector), Coke, Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2005* (2006), Tables A-1, A-4, and A-5); Heat Content factors for Coal (by type) and LPG and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2).				

Table 5. Default Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type for Alternative Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	74
Tires	85
Plastics	75
Solvents	74
Impregnated Saw Dust	75
Other Fossil Based Wastes	80
Dried Sewage Sludge	110
Mixed Industrial Waste	83
Municipal Solid Waste	90.652
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	
Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* Calculation Tool (2004), except: Municipal Solid Waste, (from EIA *Voluntary Reporting of Greenhouse Gases Website* http://www.eia.doe.gov/oiaf/1605/coefficients.html (Accessed October 5, 2007))	

(b) Methane and Nitrous Oxide Emission Factors for Stationary Combustion

The default methane and nitrous oxide emission factors for stationary combustion in Table 6 are provided for use with section 95125(b) of the regulation.

Table 6. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	Default CH_4 Emission Factor (g CH_4/ MMBtu)	Default N_2O Emission Factor (g N_2O / MMBtu)
Asphalt	3.0	0.6
Aviation Gasoline	3.0	0.6
Coal	10.0	1.5
Crude Oil	3.0	0.6
Digester Gas	0.9	0.1
Distillate	3.0	0.6
Gasoline	3.0	0.6
Jet Fuel	3.0	0.6
Kerosene	3.0	0.6
Landfill Gas	0.9	0.1
LPG	1.0	0.1
Lubricants	3.0	0.6
MSW	30.0	4.0
Naphtha	3.0	0.6
Natural Gas	0.9	0.1
Natural Gas Liquids	3.0	0.6
Other Biomass	30.0	4.0
Petroleum Coke	3.0	0.6
Propane	1.0	0.1
Refinery Gas	0.9	0.1
Residual Fuel Oil	3.0	0.6
Tires	3.0	0.6
Waste Oil	30.0	4.0
Waxes	3.0	0.6
Wood (Dry)	30.0	4.0

Notes: Heat content factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 2, Tables 2.2 and 2.3.

(c) Carbon Dioxide Emission Factors for Transportation Fuels

The default carbon dioxide emission factors in Table 7 are provided for use with section 95125(i) of the regulation. These factors may only be used for vehicular emissions and should not be applied to stationary combustion sources.

Table 7. Carbon Dioxide Emission Factors for Transportation Fuels

Fuel	kg CO_2/gallon
Aviation gasoline	8.24
Biodiesel	9.52
CA Low Sulfur Diesel	9.96
CA Reformulated gasoline, 5.7% ethanol	8.55
Crude Oil	10.14
Non-CA Diesel/Diesel No.2	10.05
Ethanol (E85)	6.10
Fischer Tropsch Diesel	9.13
Jet Fuel, Kerosene (Jet A or A-1)	9.47
Jet Fuel, Naphtha (Jet B)	9.24
Kerosene	9.67
Liquefied Natural Gas (LNG)	4.37
Liquefied Petroleum Gas (LPG)	5.92
Methanol	4.10
Motor Gasoline (Non CA and off-road)	8.78
Propane	5.67
Residual Oil	11.67
Fuels With Other Units Of Measure	
Natural Gas (CNG) per therm	5.28
Natural Gas (CNG) per gasoline gallon equivalent	6.86
Hydrogen per kg	0.00

Note: Emission factors are based on complete combustion and high heating value (HHV).

Source: California Energy Commission*, Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002); Energy Information Administration*, Emissions of Greenhouse Gases in the United States 2000*, (2001), Table B1, page 140, see http://www.eia.doe.gov/oiaf/1605/ggrpt; propane and butane emission factors and fractions oxidized from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, AP- 42*, Fifth Edition, see http://www.epa.gov/ttn/chief/ap42/index.html. Methanol emission factor is calculated from the properties of the pure compounds; the fraction oxidized is assumed to be the same as for other liquid fuel.

(d) Methane and Nitrous Oxide Emission Factors for On-Road Mobile Sources

The default methane and nitrous oxide emission factors in Table 8 are provided for use with section 95125(i) of the regulation.

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type

Vehicle Types/Model Years	CH_4 (g/mile)	N_2O (g/mile)
Passenger Cars - Gasoline		
Model Year 1966-1972	0.22	0.02
Model Year 1973-1974	0.19	0.02
Model Year 1975-1979	0.11	0.05
Model Year 1980-1983	0.07	0.08
Model Year 1984-1991	0.06	0.08
Model Year 1992	0.06	0.07
Model Year 1993	0.05	0.05
Model Year 1994-1999	0.05	0.04
Model Year 2000– present	0.04	0.04
Passenger Cars - Alternative Fuels and Diesel		
CNG Model Year 2000– present	0.04	0.04
LPG Model Year 2000– present	0.04	0.04
E85 Model Year 2000– present	0.04	0.04
Diesel all model years	0.01	0.02
Light Duty Truck (<5750 GVWR*) - Gasoline		
Model Year 1966-1972	0.22	0.02
Model Year 1973-1974	0.23	0.02
Model Year 1975-1979	0.14	0.07
Model Year 1980-1983	0.12	0.13
Model Year 1984-1991	0.11	0.14
Model Year 1992	0.09	0.11
Model Year 1993	0.07	0.08
Model Year 1994-1999	0.06	0.06
Model Year 2000– present	0.05	0.06
Light Duty Truck - Alternative Fuels and Diesel		
CNG Model Year 2000– present	0.05	0.06
LPG Model Year 2000– present	0.05	0.06
E85 Model Year 2000– present	0.05	0.06
Diesel all model years	0.01	0.03

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type (continued)		
Heavy-Duty Vehicle (>5751 GVWR) - Gasoline	**CH_4 (g/mile)**	**N_2O (g/mile)**
Model Year 1981 and older	0.43	0.04
Model Year 1982-1984	0.42	0.05
Model Year 1985-1986	0.20	0.05
Model Year 1987	0.18	0.09
Model Year 1988-1989	0.17	0.09
Model Year 1990-present	0.12	0.20
Heavy Duty Trucks - Diesel and Alternative Fuels		
Model Year 1966-1982	0.10	0.05
Model Year 1983-1995	0.08	0.05
Model Year 1996 to present	0.06	0.05
CNG, LNG	3.48	0.05
FTD, Biodiesel	0.06	0.05
Motorcycles		
Model Year 1966-1995	0.42	0.01
Model Year 1996-present	0.09	0.01

*GVWR = Gross Vehicle Weight Rating
Note: Emission factors are based on complete combustion and high heating value (HHV).

Source: Derived from California Energy Commissions, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002).

(e) Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

The default carbon dioxide emission factor for geothermal power plants given in Table 9 is provided for use with section 95111(i) of the regulation.

Table 9. Default Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants	
Fuel Type	**kg CO_2 / MMBtu**
Geothermal	~~16.6~~7.53
Source: Energy Information Administration, *Electric Power Annual with data for 2005*, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07)	

(f) Fugitive Emission Factors for Coal Storage

The emission factors for fugitive methane emissions from coal storage in Table 10 are derived from the U.S. EPA Coal Bed Methane Emissions Estimates Database. These factors must be applied as indicated in section 95125(j) of the regulation.

Table 10. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling

Coal Origin			**Coal Mine Type**	
Coal-Producing Region	**Basin or Coalbed Name**	**State**	**Surface Mines (scf CH_4/ton)**	**Underground Mines (scf CH_4/ton)**
Appalachian	Northern Appalachian	MD, OH, PA, northern WV	16.0	55.8
	Central Appalachian	Eastern KY, TN, VA, southern WV	16.0	107.5
	Warrior	AL	16.0	103.4
Interior	Illinois	IL, IN, western KY	11.1	20.9
Western	Rockies and Southwest Basins	Colorado, New Mexico, Utah	5.0	73.4
All Other States			1.0	13.5

Source: EPA/STAPPA/ALAPCO *Method for Estimating Methane Emissions from Coal Mining*, Volume VIII: Chapter 4, (1999); Exhibit 4.4-2; http://www.p2pays.org/ref/17/ttn/volume08/viii04.pdf, (accessed October 11, 2007).

(g) Coke Burn Rate Material Balance and Conversion Factors

The coke burn rate material balance and conversion factors given in Table 11 are provided for use with section 95113(~~d~~b)(1)(A) of the regulation.

Table 11. Coke burn rate material balance and conversion factors		
	(kg min)/(hr dscm %)	**(lb min)/(hr dscf %)**
K_1	~~0.2932~~0.2982	0.0186
K_2	~~2.0830~~2.0880	0.1303
K_3	0.0994	~~0.0062~~0.00624
Source: US EPA Title 40 CFR 63.1564		

(h) Nitrous Oxide Emission Factor for Wastewater Treatment

The method to derive an emission factor for fugitive methane and nitrous oxide emissions from wastewater treatment specified below is based on 2006 IPCC guidelines. This method is provided for use with section 95113(~~e~~c)(1)(A)-(B) of the regulation.

Table 12. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
	Untreated		
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
	Treated		
Aerobic treatment plant	Well maintained, some CH4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 5, Waste, Chapter 6: Wastewater Treatment and Discharge. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).			

MCF = methane correction factor – the fraction of waste treated anaerobically

B_0 = maximum CH_4 producing capacity (kg CH_4/kg COD)
Default factor = 0.25 kg CH_4/kg COD

COD = chemical oxygen demand (kg COD/m^3)
Default factor = 1.0 kg COD/m^3

EF_{N2O} = 0.005 kg N_2O-N/kg-N (Range 0.0005 – 0.25)

(i) Emission Factors for Oil/Water Separators

Use Table 13 to derive emission factors for oil/water separators

Table 13. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF_{sep})[1] kg NMVOC/m^3 wastewater treated
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e03
Gravity type – covered and connected to destruction device	0
DAF[2] of IAF[3] - uncovered	4.00e-03[4]
DAF or IAF - covered	1.20e-04[4]
DAF or Iaf – covered and connected to a destruction device	0

1. EFs do not include ethane
2. DAF = dissolved air flotation type
3. IAF = induced air flotation device
4. EFs for these types of separators apply where they are installed as secondary treatment systems

(j) ~~(i)~~

Gas Service Components Fugitive Emission Factors

The information presented in Table ~~13~~14 is provided for use with section 95113(~~e~~c)(4) as part of the method to determine fugitive methane emissions from fuel gas systems.

Table ~~13.~~14. Gas Service Components Fugitive Emissions

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)	
			10,000 ppmv	100,000 ppmv
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064	0.138
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089	0.610
Others	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082	0.138
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030	0.034
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033	0.082

Source: California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board

6. Method for Calculating Emissions of High Global Warming Potential Compounds

Provided below is the fugitive SF_6 emissions calculation methodology created by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. Operators shall use this approach or a service log for estimating fugitive emissions of high global warming potential compounds, including SF_6, HFCs, and PFCs, as specified in sections 95111(f)-(g) of the regulation. The reporting form that follows the method below is for illustrative purposes. Pounds will be converted to kilograms for purposes of reporting.

SF_6 EMISSIONS INVENTORY REPORTING METHOD AND FORM

This worksheet is based on the **mass-balance method**. The mass-balance method works by tracking and systematically accounting for all operator uses of SF_6 during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory**. This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF_6.** This is the sum of all the SF6 acquired from other entities during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF_6**. This is the sum of all the SF6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment**. This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF_6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF_6 and in metric tonnes of CO_2-equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF_6 emitted. Because SF_6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF_6 is equivalent to nearly 11 metric tonnes of carbon dioxide.

F. **Emission Rate (optional)**. By providing the total nameplate capacity of all the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year).
The emission rate is equal to the total annual emissions divided by the total nameplate capacity.

SF_6 Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Change in Inventory (SF_6 contained in cylinders, not electrical equipment)

Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Change in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Change in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of new equipment		
11. Total nameplate capacity (proper full charge) of retired or sold equipment		
D. Change in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	Tonnes CO_2 equiv. (lbs.SF_6x23,900/2205)
E. Total Emissions (A+B-C-D)	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	