This document is a draft format of the protocols that will be used for the 2008 reporting required by the recently adopted Part 48 of 20.11 NMAC *Greenhouse Gas Reporting.*

Part 48 directs the Department to develop Emissions Reporting Procedures that are consistent with comparable programs nationwide. For that reason, the draft emissions quantification procedures use relevant procedures contained in California's proposed mandatory reporting rule. The California rule is broader in scope (gases, sources) than the adopted regulations reporting requirements for year 2008 as established in Part 48. Therefore, portions of California's proposed mandatory reporting rule were removed. If you would like to review California's original document please go to:

http://www.arb.ca.gov/cc/ccei/reporting/GHGReportingReg8_10_07.pdf

Public Comment on this document is requested. Formatting of this document and the methods described may change – this is a DRAFT document. Please direct any and all comments on the reporting procedures to Stephanie Summers at ssummers@cabq.gov. If you would like to mail in comments, please send to:

City of Albuquerque
Air Quality Division
Attn: Stephanie Summers
11850 Sunset Gardens SW
Albuquerque, NM 87121

The City of Albuquerque Air Quality Division will consider any comments received prior to January 1, 2008.

The reporting tool that is being prepared for use to report the 2008 emissions and related information is the AEI2004 software that is currently used for reporting of criteria and hazardous air pollutants for the National Emissions Inventory. All sources required to report these emissions were distributed this software last year and have used it for 2005 and 2006 reporting. The software will be modified to accept CO2 emissions. Otherwise, there should be no changes in the software. Please call Stephanie Summers at 505-768-1908 if you have any questions about the reporting tool or these procedures.

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) *Error! No table of contents entries found..* 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)

(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. CaO Content of clinker (percent)
      c. 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)

(b) ***Calculation of CO_2.*** 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) ***Cogeneration.*** Operators of cement plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(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 CO2 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)(1)(A)
CKD	=	Quantity CKD discarded
EF_{CKD}	=	CKD emission factor, computed as specified in section 95110(b)(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)(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)(1)(B). The CKD emission factor shall be calculated using the Plant-specific CKD Calcination Rate equation below.

CKD Emission Factor

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

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 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).

(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 shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(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 (h)(3).

(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.

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 shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements in sections 95111 (c) through 95111(i) in preparing the greenhouse gas emissions calculations for inclusion in the report.

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

(A) State facility identifier, 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 emissions from fuel 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 CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;

(2) For each generating unit operators shall include:

(A) Unit ID, 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 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.

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

(1) ***Natural Gas.*** Operators of generating facilities 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 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 facilities 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 facility 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 facility 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 facility 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.*** If a facility combusts biomass or municipal solid waste, the operator shall calculate and include CO_2 emissions for the report year based on methodologies provided in section 95125(g) based on continuous emission monitoring systems, CO_2 concentrations, and flue gas flow rates. If the facility does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, then the operator of the facility shall use methods specified in section 95125(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.

(c) ***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).

(d) ***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 calculate CO_2 emissions using a source specific emission factor derived from source tests conducted under the supervision of local air pollution control districts. Once the source test plan has been approved, the source test procedures shall be repeated in future years to update the source specific emission factors annually. In the absence of approved source specific emission factors, the operator shall use the method specified above in 95111(i)(1).

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 shall include the following information in the greenhouse gas emissions data report for each report year.

(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.

(3) Electricity Generation:
(A) Electricity sold wholesale (MWh)
(B) Electricity sold or provided to off-site end-users (MWh)
1. User'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 (MMBtu)
1. User'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)

(b) ***Calculation of CO_2 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) **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. 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 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

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

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:*

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

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.

95113. Data Requirements and Calculation Methods for Petroleum Refineries.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a petroleum refinery 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(e), (metric tonnes).

(B) Natural 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).

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

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

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

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

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

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

(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 regeneration of catalyst material using the methods specified below in 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. 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)
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)
Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/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)
$\%O_{xy}$ = 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)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min)
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/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.

(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 Catalyst Regeneration

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

$$CO_2 = \sum_{1}^{n} CR_{ave} * CF * H * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
CR_{ave} = mass of catalyst regenerated (mass/regeneration cycle)
CF = weight fraction of carbon on the catalyst (default = 1)
n = number of regeneration cycles (#/yr)
0.001 = conversion factor – kg to metric tonnes

(3) Process Vents

(A) Operators shall calculate and report process emissions of CO_2 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)
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 scf/kg-mole)
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 emissions resulting from asphalt bowing activities using the method specified below:

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

Where:
CO_2 = CO_2 emissions (metric tonnes/yr)
M_A = mass of asphalt blown (10^6 bbl/yr)
EF = default emission factor (2,555 scf $CH_4/10^6$ bbl)
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg mole)
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 to SRU (scf/year)
MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole)
MF = molecular fraction of CO_2 in sour gas (default = 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 source specific emission factors derived from source tests conducted at least per calendar year under the supervision of the local air pollution control district.

(c) ***Calculation of Flaring Emissions.***

(1) Operators shall calculate CO_2 emissions resulting from the combustion of flare pilot and purge gas using the method shown below:

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

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)
0.001 = 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 not reporting flare emissions to their local AQMD/APCD shall use a default emission factor to calculate CO_2 emissions as shown below:

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

Where:

CO_2 = CO_2 emissions (metric tonnes/year)
EF_{CO2} = default CO_2 emission factor (tonnes $CO_2/10^6$ barrels crude)
RT = refinery throughput (10^6 barrels crude /year)

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 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)

(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)

(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)-(f).

(A) For natural 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 specified in section 95125(e);

(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 as specified in sections 95125(a);

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

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

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:

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

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, MMBtu per unit of mass or volume

EF_{CO2} = Default carbon dioxide emission factor, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(b) **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, 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, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

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

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

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

1. For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (2006).

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

(c) ***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.

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

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

(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, 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)
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. 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.

(d) ***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 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.

$EF_{CO2\text{-}A} = CC_A/HHV_A * MW_{CO2}/MVC * 0.001$

Where:

$EF_{CO2\text{-}A}$ = 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)
MW_{CO2} = molecular weight of CO_2
MVC = molar volume conversion (849.5 scf/ kg-mole)
0.001 = factor to convert kg to metric tonnes

(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).

(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 fuel emission factor calculated using the equation in section 95125(e)(3) to calculate daily CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

$$CO_{2\text{-}A} = \sum_{1}^{365} HHV_A * FR_A * EF_{CO2\text{-}A}$$

Where:

$CO_{2\text{-}A}$ = CO_2 emissions resulting from the combustion of fuel gas from system A (metric tonnes/yr)
HHV_A = daily average high heating value for system A (Btu/scf)
FR_A = daily fuel consumption for fuel gas system A (scf/d)
$EF_{CO2\text{-}A}$ = daily CO_2 emission factor for fuel gas system A (tonnes $CO_2/10^6$ Btu)

(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)

(e) ***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.

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

(1) Operators that combust fossil fuels other than refinery fuel gas, and operate continuous emissions monitoring systems (CEMS) in response to federal, 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.

(2) Operators that combust biomass or municipal solid waste and operate a CEMS in response to federal, state, or local regulations including 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 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 report CO_2 emissions using CEMS data and 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 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 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 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.

(g) ***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 approved source specific emission factors derived from source tests conducted at least annually under the supervision of local air pollution control district.

APPENDIX A

to the Regulation for the Mandatory Reporting
of Greenhouse Gase Emissions

COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

<u>**CONTENTS**</u>

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 City of Albuquerque Air Quality Division, as specified in the 20.11.48 NMAC *Greenhouse Gas Emissions Reporting*.

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. 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	Varies	Varies	52.03

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) 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

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)

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)(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	0.0186
K_2	2.0830	0.1303
K_3	0.0994	0.0062

Source: US EPA Title 40 CFR 63.1564

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