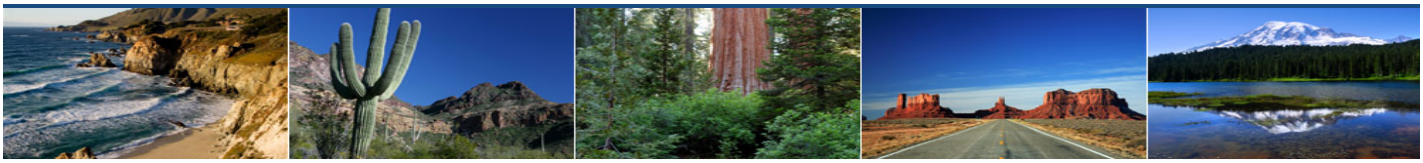
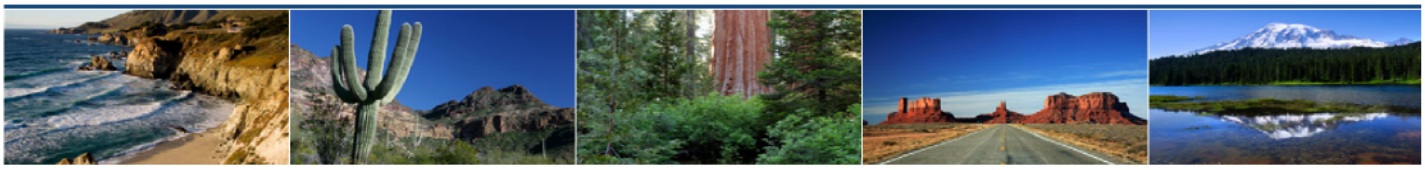
Western Climate Initiative



Final Essential Requirements of Mandatory Reporting

July 15, 2009

Western Climate Initiative



[These Essential Requirements for Reporting include placeholder references to requirements for reporting GHG emissions from the combustion of residential, commercial and industrial fuels and electricity imports that have not yet been completed by the WCI and will not go into effect for the 2010 reporting year. WCI Partner Jurisdictions may omit these references until they amend their rules to include reporting requirements for these sectors.]

§ WCI.0 PURPOSE

This rule requires mandatory reporting and verification of greenhouse gas (GHG) emissions data by certain facilities that directly emit GHG, by importers of electricity, and by suppliers of fossil fuels. The GHGs that must be reported under this rule are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), and sulfur hexafluoride (SF_6).

§ WCI.1 APPLICABILITY

(a) The GHG emissions reporting requirements, and related monitoring, recordkeeping, and verification requirements of this rule apply to the owners and operators *[Each jurisdiction will select the specific terminology for the regulated persons in accordance with its customary rule-writing practices]* of any facility that meets the requirements of paragraph (a)(1) of this section; and any fuel suppliers and electricity importers that meet the requirements of paragraph (a)(2), (a)(3), or (a)(4) of this section:

(1) Any facility that emits 10,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in this paragraph in any calendar year starting in 2010.

[Please note that the quantification and monitoring methods for many of these source categories are currently being assessed. Only source categories for which adequate quantification methods exist will be included in the final WCI Essential Requirements for mandatory reporting.]

Adipic acid manufacturing
Aluminum manufacturing
Ammonia manufacturing [*still being assessed*]
Carbon dioxide transfer recipients [*still being assessed*]
Cement manufacturing
Coal mine fugitive emissions (active and abandoned)
Coal storage
Cogeneration
Electricity generation
Electronics Manufacturing [*still being assessed*]
Ferroalloy production [*still being assessed*]
General stationary fuel combustion
Glass Production and other uses of carbonates [*still being assessed*]
HCFC-22 production [*still being assessed*]
Hydrogen production
Industrial wastewater [still being assessed for some industries]
Iron and steel manufacturing
Lead production

Lime manufacturing
Magnesium production [still being assessed]
Natural gas transmission and distribution systems *[still being assessed]*
Nitric acid manufacturing *[still being assessed]*
Nonroad equipment at facilities *[still being assessed]*
Oil and gas production & gas processing *[still being assessed]*
Petrochemical production
Petroleum refineries
Phosphoric acid production *[still being assessed]*
Pulp and paper manufacturing
Refinery fuel gas
SF_6 from electrical equipment *[still being assessed]*
Soda ash manufacturing
Zinc production

(2) All importers of electricity. Importers of electricity include both retail providers and marketers that import electricity into the WCI region. *[This is preliminary language, pending definition of electricity importers by another WCI Committee.]*

(3) Any supplier that within the WCI region distributes transportation fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of point of regulation for transportation fuels.]*

(4) Any supplier that distributes within the WCI region residential, commercial, and industrial fuels in quantities that when combusted would emit 10,000 metric tons CO_2e per year or more in any calendar year starting in 2010. *[This is preliminary language, pending future determination of points of regulation for these fuels.]*

(b) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Estimate the annual emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 in metric tons for each unit, process, activity, or operation for which emission calculation methodologies are provided in sections WCI.20 through WCI.XX. The GHG emissions shall be calculated using methodologies specified in each applicable section.

(2) For stationary combustion units, carbon dioxide emissions from the combustion of biomass fuels shall be included in the calculations, with the following exceptions:

(A) Until such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold in paragraph (a)(1) of this section, provided that total GHG emissions including emissions from solid biomass fuel are less than 25,000 metric tons CO_2e.

(B) After such time as [jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion

of those fuels may be excluded from calculation of GHG emissions for determining whether the 10,000 metric tons CO_2e per year emission threshold in paragraph (a)(1) of this section has been met.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of stationary combustion units that are required to report and may require that those emissions be reported separately from emissions from fossil fuels.]

(3) Sum the total facility emissions for each GHG and calculate the metric tons of CO_2e using equation 1-1 below.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \textbf{Equation 1-1}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of each greenhouse gas emitted, metric tons/year.

GWP_i = Global warming potential for each greenhouse gas from Table WCI.10-1 of this regulation.

n = The number of greenhouse gases emitted.

(4) For purpose of determining if an emission threshold has been exceeded, any CO_2 that is captured for on-site use, on-site storage, or transfer off-site must be included in the emissions total.

(c) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of transportation fuels in paragraphs (a)(3) of this section, the owner or operator shall follow the procedures of paragraphs (c)(1) through (c)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all transportation fuels that are distributed within the WCI region. The mass of each GHG shall be calculated using any of the applicable methodologies specified in section WCI.XX [Transportation Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(d) To calculate GHG emissions for comparison to the 10,000 metric ton CO_2e per year emission threshold for suppliers of residential, commercial, and industrial fuels in paragraph (a)(4) of this section, the owner or operator shall follow the procedures of paragraphs (d)(1) and (d)(2) below:

(1) Calculate the total mass in metric tons per year of CO_2, CH_4, and N_2O that would result from the complete combustion or oxidation of all residential, commercial, and industrial fuels that are distributed within the WCI region. The calculation shall exclude any fuels that are supplied to facilities that are required to report GHG emissions under section WCI.1(a)(1). *[These accounting issues will be dealt with later in 2009 or in 2010.]* The mass of each GHG shall be calculated using any of the applicable methodologies

specified in section WCI.XX [Residential, Commercial and Industrial Fuels Combustion] of this rule.

(2) Sum the emissions of each GHG and calculate total metric tons of CO_2e using Equation 1-1 of this rule.

(e) If the operations of a facility or fuel supplier that is subject to this rule change such that emissions fall below 10,000 metric tons CO_2e per year, then the following reporting requirements shall apply:

(1) If, prior to such emission reduction, the emissions report was subject to the verification requirements of this rule; then the owner or operator shall continue to submit emission reports until reported emissions are below 10,000 metric tons CO_2e per year for a minimum of 3 consecutive years. If reported emission are less than 10,000 metric tons CO_2 per year during 3 consecutive years, then the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(2) If, prior to such emission reduction, the emissions report was not subject to the verification requirements of this rule; then the owner or operator shall submit to the *[jurisdiction]* a signed statement certifying that emissions are less than 10,000 metric tons CO_2e during the prior year. After certifying that emissions are below 10,000 metric tons CO_2e per year for 3 consecutive years, the owner or operator shall be exempted from further reporting until CO_2e emissions again exceed 10,000 metric tons in any future calendar year.

(3) Notwithstanding the requirements of paragraphs (e)(1) and (2) of this section, a facility or fuel supplier that is a covered entity under the WCI cap-and-trade program must continue to submit annual emissions reports.

(f) Upon request by the [*jurisdiction*], owner or operator of any facility or fuel supply operation must submit a demonstration that emissions have not exceeded one or more of the applicability criteria specified in this section in any year since 2010. Such demonstration shall be provided to the [*jurisdiction*] within 20 working days of receipt of a written request.

§ WCI.2 GENERAL GREENHOUSE GAS REPORTING REQUIREMENTS AND SCHEDULE

[Specific requirements of this section may change based on the future final design of the market trading program.]

(a) General. Owners or operators that are subject to this rule must submit an annual GHG emissions report. Owners and operators must collect data; calculate GHG emissions; and follow the procedures for quality assurance, missing data, recordkeeping, and reporting as specified in these General Provisions and in each relevant section WCI.20 through WCI.XX of this rule.

[WCI jurisdictions have the flexibility during the first year of reporting, 2010, to allow the application of Best available data and methods (as defined in WCI.9) in circumstances in which owners and operators demonstrate that they require additional time, for example, to install equipment and institute procedures that are required for reporting.]

(1) A facility, fuel supplier, or electricity importer that commenced operation before January 1, 2010, must report emissions beginning in 2011 for GHGs emitted in calendar year 2010.

(2) A new facility, fuel supplier, or electricity importer that commences operation on or after January 1, 2010, must report emissions for the first calendar year in which the facility operates, beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(b) Reporting and Verification Schedule.

(1) Annual GHG emissions reports must be submitted to [*the jurisdiction*] by April 1 of each year for emissions in the previous calendar year.

(2) Reporters subject to the verification requirements of WCI.8, must complete their verification process, including submittal of a verification statement to [*the jurisdiction*], according to the following schedule:

(A) For reporting years 2010 through 2011, September 1 of the year following the reporting year.

(B) For reporting years 2012 and later, *[date to be determined]*.

(c) Submission of GHG Emissions Report. The annual GHG emissions report must be submitted to [*the jurisdiction*] in a format [*to be specified by each jurisdiction*].

(d) Simplified Emission Calculation Methods for De Minimis Sources. The owner or operator may elect to designate as de minimis one or more sources or pollutants that collectively emit no more than 3 percent of the facility's total CO_2e emissions, but not to exceed 20,000 metric tons CO_2e. The owner or operator may estimate emissions for these de minimis sources using alternative methods to those required to be used by this rule. If verification of the emissions report is required by this rule, then the selection of any alternative GHG calculation method is subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated do not exceed the applicable de minimis limits. The operator shall separately identify and include in the emissions data report the emissions from designated de minimis sources.

(e) To ensure accuracy of reported data and the ability to conduct audits and/or verifications of each emissions data report, the owner or operator shall establish and maintain data acquisition and handling activities that provide for the transparency and verifiability of emissions calculations and supporting information consistent with section WCI.4.

[As a means of assuring a smooth verification process and a positive verification opinion WCI jurisdictions may also require or advise in guidance materials that facilities have a full GHG inventory management plan.]

(f) GHG Emissions Report Revisions.

(1) The owner or operator shall maintain documentation to support any revisions made to a previously submitted annual GHG emissions report. Documentation for all revisions shall be retained by the operator for 7 years.

(2) If, after the verification deadline, a report subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 60 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(3) If, after the report submittal deadline, a report not subject to verification is found to contain an error, or accumulation of errors, greater than 5 percent of the total CO_2e emissions reported, the owner or operator shall revise and resubmit an annual GHG emissions report within 30 days of the finding. To the extent possible, the revised report must correct all identified errors. A revised report will be accepted only if approved by [*the jurisdiction*]. [The jurisdiction] will send notification of approval or disapproval and an explanation of the reasons for any disapproval within 60 days of receipt of the revised report.

(4) An owner or operator that voluntarily chooses to correct errors of 5 percent or less in total CO_2e emissions reported may do so according to the following requirements:

(A) For reports subject to verification, a revised report will be accepted only if verified according to WCI.8 and approved by [*the jurisdiction*].

(B) For reports not subject to verification, a revised report will be accepted if approved by [*the jurisdiction*].

(g) Where this rule specifies a choice between use of a fuel-based or mass balance-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, unless the use of the alternative calculation method is approved in advance by *[the jurisdiction]*.

§ WCI.3 CONTENTS OF THE GREENHOUSE GAS EMISSIONS REPORT

Each annual GHG emissions report shall contain the following information:

(a) Facility name, identification number, physical address, mailing address, and NAICS code.

(b) Reporting year.

(c) Date of report submittal.

(d) Total facility emissions aggregated from all applicable source categories in subparts WCI.20 through WCI.XX expressed in metric tons of CO_2e calculated using Equation 1-1 of section WCI.1, excluding emissions from CO_2 that is captured and CO_2 emissions from the combustion of biomass and biomass-derived fuels, which are reported separately.

(e) Total facility emissions of CO_2 from the combustion of biomass and biomass-derived fuels.

(f) Total annual mass of CO_2 captured for on-site use, on-site storage, or transfer off site, in metric tons.

(g) For applicable fuel supplier categories in subparts WCI.XX [Transportation Fuels Combustion] and WCI.XX [Residential, Commercial and Industrial Fuels Combustion], total CO_2e emissions aggregated from all specified fuels.

(h) Emissions from each applicable source category or fuel supplier category in subparts WCI.20 through WCI.XX, expressed in metric tons per year of CO_2, CH_4, N_2O, HFC, PFC, and SF_6. CO_2 emissions from the combustion of biomass and biomass-derived fuels shall be reported separately.

(i) For electricity importers, the information required by WCI.XX [Electricity Imports].

(j) Emissions and other data for individual units, processes, activities, and operations as specified for each source category in sections WCI.20 through WCI.XX of this rule.

(k) Emission factors developed or measured by the operator using approved source testing as provided under sections WCI.20 through WCI.XX. Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in the units specified in this regulation.

(l) Mass emissions from each designated de minimis source or pollutant, reported in metric tons per year of each GHG for which an alternative emission calculation method is used.

(m) Name and contact information including e-mail address and telephone number of the person primarily responsible for preparing and submitting the emissions report.

(n) [only applicable in United States jurisdictions] A signed and dated statement provided by the owner or operator, or their designated representative, certifying that the report has been prepared in accordance with this rule and that, subject to verification, the statements and information contained in the emissions data report are true, accurate, and complete to the best of their knowledge.

(o) [only applicable in Canadian jurisdictions] A statement signed and dated by the operator's representative, certifying that:

(1) The operator's representative has examined the emissions report and ensured that it is complete and accurate; and

(2) The emissions report has been prepared in accordance with this rule and that the statements and information contained in the emissions report are true and fair to the best of the knowledge of the operator's representative.

§ WCI.4 DOCUMENT RETENTION AND RECORD KEEPING REQUIREMENTS

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain all documents regarding the design, development and maintenance of the GHG inventory in paper, electronic or other usable format for a period of not less than 7 years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by *[jurisdiction]*, the operator shall provide within 10 working days all documents and 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, if applicable, for at least 7 years after the submission of the report:

(1) A list of all GHG sources (i.e., units, operations, processes, and activities) included in the emission estimates.

(2) All records and documents used to calculate emissions for each source, categorized by process and fuel or material type.

(3) Documentation of the process for collecting emissions data.

(4) Any GHG emissions calculations and methods used;

(5) All emission factors used for emission estimates, including documentation for any factors not provided in the rule.

(6) All input data used for emission estimates.

(7) Documentation of biomass fractions for specific fuels.

(8) All other data submitted to the [*jurisdiction*] under this rule, including the GHG emissions report.

(9) All computations made to gap-fill missing data.

(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;

(11) Any other information that is required for the verification of the GHG emissions report.

(12) A log to be prepared for each reporting year, beginning January 1, documenting all procedural changes made in GHG accounting methods and changes to instrumentation for GHG emissions estimation.

(13) Documentation of the data acquisition and handling activities required by WCI.2(e).

(d) For measurement based methodologies, the following information, if applicable, also must be retained for at least 7 years after the submission of the emissions data report:

(1) List of all emission points monitored.

(2) Collected monitoring data.

(3) Any quality assurance and quality control information collected in accordance with the data acquisition and handling activities required by WCI.2(e).

(4) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies.

(5) Raw and aggregated data from the continuous measurement system.

(6) A log book of all system down-times, calibrations, servicing, and maintenance of the continuous measurement system.

(7) Documentation of any changes in the continuous measurement system over time.

§ WCI.5 COMPLIANCE AND ENFORCEMENT

(a) Submission of false or misleading information to the *[jurisdiction]* or a verification body 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 or verification body. *[Partners must be able to enforce this provision in the absence of evidence of intent, e.g., strict or absolute liability, depending on the jurisdiction.]*

(b) Each violation of this rule shall constitute a single, separate violation for each day the violation continues.

§ WCI.6 INCORPORATION BY REFERENCE

The following documents are incorporated by reference into this rule. These materials are incorporated as they exist on the date this article is adopted.

(a) The following materials are available for purchase from the following addresses: American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959; and the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106:

(1) ASTM D240-02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter.

(2) ASTM D388-05, Standard Classification of Coals by Rank.

(3) ASTM D396-08, Standard Specification for Fuel Oils.

(4) ASTM D975-08, Standard Specification for Diesel Fuel Oils.

(5) ASTM D1250-07, Standard Guide for Use of the Petroleum Measurement Tables.

(6) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter.

(7) ASTM Specification D1835-05 (2005).

(8) ASTM D1945-03 (Reapproved 2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography.

(9) ASTM D1946-90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography.

(10) ASTM D2013-07, Standard Practice of Preparing Coal Samples for Analysis.

(11) ASTM D2234/D2234M-07, Standard Practice for Collection of a Gross Sample of Coal.

(12) ASTM D2502-04 (Reapproved 2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.

(13) ASTM D2503-92 (Reapproved 2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.

(14) ASTM D2880-03, Standard Specification for Gas Turbine Fuel Oils.

(15) ASTM D3176-89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.

(16) ASTM D3238-95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method.

(17) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels.

(18) ASTM Specification D3699-07, Standard Specification for Kerosene.

(19) ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

(20) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).

(21) ASTM Specification D4814-08a, Standard Specification for Automotive Spark-Ignition Engine Fuel.

(22) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion.

(23) ASTM D5291-02 (Reapproved 2007), Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

(24) ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke.

(25) ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke.

(26) ASTM D6316-04, Standard Test Method for the Determination of Total, Combustible and Carbonate Carbon in Solid Residues from Coal and Coke.

(27) ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis.

(28) ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys.

(29) ASTM E1915-07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry.

(30) ASTM D7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.

(31) ASTM D6060-96(2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph.

(32) ASTM D 2502-88(2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography.

(33) ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime.

(34) C1271-99(2006) Standard Test Method for X-ray Spectrometric Analysis of Lime and Limestone.

(35) C1301-95(2001) Standard Test Method for Major and Trace Elements in Limestone and Lime by Inductively Coupled Plasma-Atomic Emission Spectroscopy (ICP) and Atomic Absorption (AA).

(36) UOP539-97 Refinery Gas Analysis by Gas Chromatography.

(37) ASTM D5468-02 (Reapproved 2007).

(b) The following materials are available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O.Box 2900, Fairfield, NJ 07007-2900:

(1) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi.

(2) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters.

(3) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters.

(4) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters.

(5) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles.

(6) ASME MFC-9M-1988 (Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method.

(c) The following materials are available for purchase from the American National Standards Institute (ANSI), 25 West 43rd Street, Fourth Floor, New York, New York 10036:

(1) ISO 8316: 1987 Measurement of Liquid Flow in Closed Conduits- Method by Collection of the Liquid in a Volumetric Tank.

(2) ISO/TR 15349-1:1998, Unalloyed steel-Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation).

(3) ISO/TR 15349-3: 1998, Unalloyed steel-Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating).

(d) The following materials are available for purchase from the following address: Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143:

(1) GPA Standard 2172-09, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis.

(2) GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(e) The following American Gas Association materials are available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering of Natural Gas, Part 1: General Equations and Uncertainty Guidelines (1990), Part 2: Specification and Installation Requirements (1990).

(2) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (2006).

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street, NW., Washington, DC 20005-4070:

(1) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 3- Tank Gauging:

(A) Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005.

(B) Section 1B-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition June 2001 (Reaffirmed, October 2006).

(C) Section 3-Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, First Edition June 1996 (Reaffirmed, October 2006).

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992).

(3) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 4- Proving Systems:

(A) Section 2-Displacement Provers, Third Edition, September 2003.

(B) Section 5-Master-Meter Provers, Second Edition, May 2000 (Reaffirmed, August 2005).

(4) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22- Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005.

(g) The following material is available for purchase from the following address: American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc., 1791 Tullie Circle, NE., Atlanta, Georgia 30329: ASHRAE 41.8-1989: Standard Methods of Measurement of Flow of Liquids in Pipes Using Orifice Flowmeters.

(h) 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.

(i) Control of Emissions from Refinery Flares, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

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

(k) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

§ WCI.7 DESIGNATED REPRESENTATIVE (ONLY APPLICABLE TO WCI JURISDICTIONS IN THE UNITED STATES)

(a) General. Each fuel supplier, electricity importer, and owner or operator of a facility that is subject to this rule, shall select a designated representative that is responsible for certifying and submitting GHG emissions reports under this reporting rule.

(b) Authorization of a Designated Representative. The designated representative of the facility shall be selected by a certificate of representation agreement that is signed by the designated representative and owners or operators of the facility. The designated representative must be an individual having responsibility for the overall operation of the facility or activity such as the position of the plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the company.

(c) Responsibility of the Designated Representative.

(1) The designated representative of the facility shall represent and by any representations, actions, inactions, or submissions, legally bind each owner and operator in all matters pertaining to this rule.

(2) Each GHG emission report submitted under this rule must be signed by the designated representative and must contain the following certification statement: "I have been authorized to make this submission on behalf of the owners and operators of the facility (or supply operation, as appropriate). I certify under penalty of law that I have personally examined the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(d) Changing a Designated Representative. The designated representative may be changed at any time upon submission of a superseding certificate of representation. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before time of the superseding certificate of representation shall be binding on the new designated representative and the owners and operators.

(e) Changes in Owners and Operators. In the event of any change in ownership of the facility, any new owner or operator shall be deemed to be bound by the representations, actions, inactions, and submissions of the designated representative of the facility until such time as the designated representative is changed.

(f) Certificate of Representation. A certificate of representation must be submitted to *[the jurisdiction]* and kept on location by the facility, fuel supplier, or electricity importer. The certificate shall include the following information:

(1) Identification of the facility, fuel supplier, or electricity importer for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative.

(3) A list of the owners and operators.

(4) Certification statements that the actions of the designated representative with respect to this rule are binding on the owners and operators, and that the designated representative has the necessary authority to carry out duties and responsibilities on behalf of the owners and operators.

(5) The signature of the designated representative and owner(s) and operator(s), and the dates signed.

§ WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

[See separate document.]

§ WCI.9 DEFINITIONS

[See separate document.]

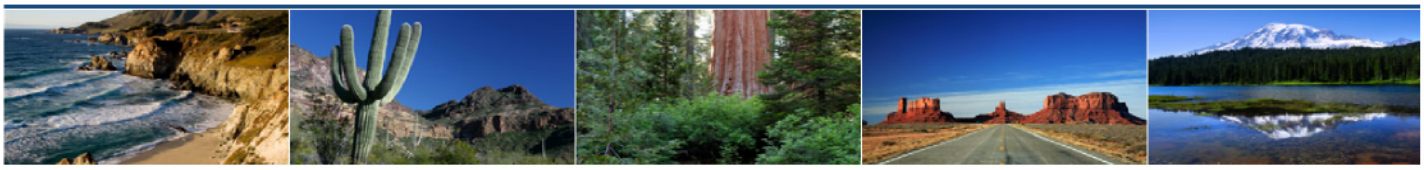
§ WCI.10 GLOBAL WARMING POTENTIALS

Owners and operators must use the global warming potential (GWP) values given in Table WCI.10-1 when converting emissions of greenhouse gases to metric tons of carbon dioxide equivalent (CO_2e), using Equation 1-1.

Table WCI.10-1. Global Warming Potential Factors for Greenhouse Gases

Common Name	Formula	Chemical Name	GWP
Carbon dioxide	CO_2		1
Methane	CH_4		21
Nitrous oxide	N_2O		310
Sulfur hexafluoride	SF_6		23,900
Hydrofluorocarbons (HFCs)			
HFC-23	CHF_3	trifluoromethane	11,700
HFC-32	CH_2F_2	difluoromethane	650
HFC-41	CH_3F	fluoromethane	150
HFC-43-10mee	$C_5H_2F_{10}$	1,1,1,2,3,4,4,5,5,5- decafluoropentane	1,300
HFC-125	C_2HF_5	pentafluoroethane	2,800
HFC-134	$C_2H_2F_4$	1,1,2,2-tetrafluoroethane	1,000
HFC-134a	$C_2H_2F_4$	1,1,1,2-tetrafluoroethane	1,300
HFC-143	$C_2H_3F_3$	1,1,2-trifluoroethane	300
HFC-143a	$C_2H_3F_3$	1,1,1-trifluoroethane	3,800
HFC-152	$C_2H_4F_2$	1,2-difluoroethane	43
HFC-152a	$C_2H_4F_2$	1,1-difluoroethane	140
HFC-161	C_2H_5F	fluoroethane	12
HFC-227ea	C_3HF_7	1,1,1,2,3,3,3- heptafluoropropane	2,900
HFC-236cb	$C_3H_2F_6$	1,1,1,2,2,3-hexafluoropropane	1,300
HFC-236ea	$C_3H_2F_6$	1,1,1,2,3,3-hexafluoropropane	1,200
HFC-236fa	$C_3H_2F_6$	1,1,1,3,3,3-hexafluoropropane	6,300
HFC-245ca	$C_3H_3F_5$	1,1,2,2,3-pentafluoropropane	560

HFC-245fa	$C_3H_3F_5$	1,1,1,3,3-pentafluoropropane	950
HFC-365mfc	$C_4H_5F_5$	1,1,1,3,3-pentafluorobutane	890
Perfluorocarbons (PFCs)			
Perfluoromethane	CF_4	tetrafluoromethane	6,500
Perfluoroethane	C_2F_6	hexafluoroethane	9,200
Perfluoropropane	C_3F_8	octafluoropropane	7,000
Perfluorobutane	C_4F_{10}	decafluorobutane	7,000
Perfluorocyclobutane	c-C_4F_8	octafluorocyclobutane	8,700
Perfluoropentane	C_5F_{12}	dodecafluoropentane	7,500
Perfluorohexane	C_6F_{14}	tetradecafluorohexane	7,400



§WCI.8 REQUIREMENTS FOR VERIFICATION OF GREENHOUSE GAS EMISSIONS DATA REPORTS AND REQUIREMENTS APPLICABLE TO EMISSIONS DATA VERIFIERS

Note: The verification requirements laid out in this section strive for consistency with ISO 14064-3[1] requirements and set forth a high standard for verification that will ultimately support a WCI cap and trade program. Due to differences in rulemaking procedures between jurisdictions, Supplement 1 provides supplemental text that jurisdictions must incorporate into either the jurisdiction's prescriptive rule language, replacing more general procedural language in Section WCI.8, or into enforceable guidance documents. There are notes in WCI.8 that direct readers to appropriate text in Verification Supplement 1 when applicable.

It would be ideal for all jurisdictions to enforce the same requirements and have the same implementation processes for accreditation and verification to ensure that consistent accurate data exists throughout the WCI regional program. Reporters and verifiers with operations throughout the WCI region will benefit from a consistent approach and such an approach would facilitate administration of the verification requirements by a central body or designee.

(a) Applicability and Scope.

(1) Except as provided in WCI.8(a)(2) through (4) owners or operators [Each jurisdiction will select the specific terminology for the regulated persons in accordance with their customary rule-writing practices] are required to obtain annual verification for a facility that emits 25,000 metric tons CO_2e or more per year in combined emissions from one or more of the source categories listed in WCI.1 in any calendar year starting on or after 2010.

(2) When the operation of a facility, fuel supplier, or electricity importer subject to the requirements of this section is changed such that the operator has reported less than 25,000 metric tons of CO_2e emissions for a calendar year, the operator shall obtain verification of annual emissions reports for the lesser of three subsequent calendar years or for those years remaining in the current compliance period. If CO_2e emissions of a facility, fuel supplier, or electricity importer subject to the requirements of this section again exceed 25,000 metric tons in any calendar year the provisions of WCI.8(a)(1) apply.

[1] ISO (2006) ISO 14064-3: Greenhouse Gases-Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, March, 2006, International Organization for Standardization, Switzerland.

(3) Carbon dioxide emissions from the combustion of biomass fuels shall be included in the determination regarding verification applicability, with the following exceptions:

(A) Until such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, a maximum of 15,000 metric tons of carbon dioxide emissions from the combustion of pure solid biomass fuel may be excluded from calculation of GHG emissions for comparison to the 25,000 metric ton CO_2e per year verification threshold in paragraph (a) of this section.

(B) After such time as [the jurisdiction] has made a determination regarding the carbon neutrality of any biomass fuels, the carbon dioxide emissions from the combustion of those fuels may be excluded from calculation of GHG emissions for determining whether the 25,000 metric tons CO_2e per year verification threshold in paragraph (a)(1) of this section has been met.

[Under Design Recommendation 1.3, carbon neutral biomass will be excluded from the cap-and-trade program. A WCI Partner jurisdiction, however, may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the determination of the verification threshold in order to obtain a complete inventory of the fuels being combusted in the jurisdiction.]

(4) Owners or operators may exclude carbon dioxide emissions from the combustion of biomass fuels that [jurisdiction] has deemed carbon neutral from the scope of verification.

[A WCI Partner jurisdiction may, in its discretion, choose to require carbon dioxide emissions from the combustion of biomass fuel to be included in the scope of verification.]

(5) Notwithstanding WCI.8(a)(2) and (3), any facility, fuel supplier or electricity importer subject to a cap-and-trade program for CO_2e emissions established by [the jurisdiction] shall obtain verification of reported annual emissions.

(b) Requirements for Annual Verification of Emissions Data Reports.

(1) Verification bodies shall conduct verification processes and design verification procedures to determine whether there is a reasonable level of assurance for each separate emissions data report every year of the verification cycle. The verification team shall find that there is a reasonable level of assurance for an emissions data report if the report

(A) contains no material misstatement; and

(B) conforms to the requirements of this article.

(2) The verification body must provide verification services in compliance with WCI.8.

(3) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification shall be subject to full verification requirements in the first year that verification is required for an emissions data report. Upon completion of a positive verification statement under full verification requirements, the facility owner or operator, fuel supplier, or electricity importer may be eligible for two years of less intensive verification services as described in section WCI.9. This cycle may be

repeated in subsequent three-year cycles; however, full verification requirements shall apply at least once every three years.

(4) Facility owners or operators, fuel suppliers, and electricity importers required to obtain annual verification will be required to obtain full verification services if any of the following apply:

(A) There has been a change in the verification body from the previous year; or

(B) A verification body issued an adverse verification statement for that facility's previous year's emissions data report.

(c) Accreditation Requirements for Verification Bodies.

(1) The accreditation requirements specified in this subsection shall apply to all verification bodies that wish to provide verification services under this rule.

(2) A verification body is qualified to conduct verification services for the WCI if

(A) it has demonstrated knowledge of the WCI reporting requirements; and

(B) it is accredited to ISO 14065 through a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.

[Note the details of the WCI's specific accreditation process for verification bodies (which has yet to be developed) will be consistent with ISO 14065 through an accreditation program that will developed under ISO 17011 and will include demonstrated knowledge of the WCI reporting requirements. The WCI will explore additional accreditation requirements and/or other criteria for individual lead verifiers, general verifiers, and/or sector specialists.]

(3) Prior to January 1, 2013, accreditation by the California Air Resources Board under Title 17, California Code of Regulation, section 95132, may be substituted for the accreditation required under WCI.8(c)(2)(B).

(d) Requirements for Verification Services. The following verification services must be provided for each emissions data report.

(1) As part of the verification services, the verification team shall review documents submitted, assess risks of a material misstatement, develop a verification plan (that includes a sampling plan), evaluate the emissions data report against the verification requirements, and assess the materiality of errors, omissions and misstatements identified.

(2) The verification team shall request any information and documents needed for verification services. Such information shall include, but is not limited to original records and supporting data for the emissions data report.

(e) A verification team must include the following:

(1) a Lead Verifier;

(2) an Independent Peer Reviewer;

(3) any subcontractor elected to provide verification services under WCI.8(f).

(f) Subcontracting. The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) The primary verification body must assume full legal responsibility for verification services performed by subcontracted verifiers or verification bodies.

(2) A verification body or verifier acting as a subcontractor to the primary verification body will not further subcontract that same work to another firm or individual.

(3) A verification body or verifier acting as a subcontractor is subject to all Conflict of Interest requirements in Section WCI.8(g).

(4) A verification body or verifier acting as a subcontractor must be identified by the primary verification body as part of the verification team.

(g) Conflict of Interest Requirements for Verification Bodies. The conflict of interest provisions of this section shall apply to the verification body, entities related to the verification body, and the verification team accredited according to the requirements of the WCI to perform verification services for the WCI program. Member for purposes of this section means any employee or subcontractor of the verification body or entities related to the verification body. Member also includes any individual with a majority equity share in the verification body or entities related to the verification body.

(1) Prior to a jurisdiction accepting a verification statement, and prior to a jurisdiction accepting the associated emissions report for consideration for approval, the AVA must determine that the verification body has a low potential for conflict of interest as described under WCI.8(g)(6). To inform this determination by the AVA, a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team, including subcontractors, may have with the owner or operator or their related entities for which verification services will be or have been provided shall be submitted to the AVA. This self-evaluation must include an evaluation of any threats to the verification body's independence including: [*note: a standardized Conflict of Interest Assessment form will be developed for the WCI*]

[To facilitate timely determinations of conflict-of-interest potential, and to reduce the risk of finding medium or high conflict-of-interest potential after verification services have been initiated, it is recommended that jurisdictions require that the self evaluations be submitted and evaluated by the AVA prior to the initiation of verification services. A jurisdiction may elect to allow verification services to commence prior to the determination of the conflict-of-interest potential by the AVA.]

(A) Threats created by the reporting operation offering inducements to the verification body, subcontractors or verification team members for a positive opinion;

(B) Threats created by members of the verification body, verification team members, subcontractors, or family of subcontractors or team members having a financial interest in the reporting operation or its operator;

(C) Threats created by members of the verification body reviewing work of the verification body, subcontractors, members of the verification team, or related companies, including but not limited to any situation where the body,

subcontractors, team members or companies have provided services related to greenhouse gases;

(D) Threats created by members of the verification body, verification team members, or subcontractors having a close relationship with the reporting operation, such that they might become too sympathetic to the interests of the reporting operation; and

(E) Threats created by members of the verification body, verification team members, or subcontractors being deterred from acting objectively or exercising professional skepticism by threats, actual or perceived, from the reporting operation.

(2) The verification body shall deem the potential for conflict of interest to be low if

(A) No threats as listed in WCI.8(g)(1) exist, and

(B) Any non-verification services provided by the verification body to the owner or operator within the last three years are valued at less than five percent of the verification body's annual revenue in each of those years.

(3) The verification body shall deem the potential for conflict of interest to be high if threats as listed in WCI.8(g)(1)(A) or (E) exist.

[A jurisdiction may expand the list of high threats (i.e. un-mitigatable conflicts) with the items included in paragraph 2 of the Conflict of Interest section of Supplement 1 below.]

(4) The verification body shall deem the potential for a conflict of interest to be medium if the potential for a conflict of interest is not deemed to be either low or high as specified in sections WCI.8(g)(2)-(3).

(5) If a verification body deems the potential for conflict of interest to be medium and wishes to provide verification services for the owner or operator, then the verification body shall submit, in addition to the self-evaluation, a plan to avoid, neutralize, or mitigate the potential conflict of interest situation.

(6) Conflict of Interest Determinations. The AVA shall review the self-evaluation submitted by the verification body and determine the verification body's potential conflict of interest in performing verification services for the owner or operator.

[In addition to the AVA determination, a jurisdiction may elect to conduct audits of conflict of interest submissions for compliance verification and enforcement purposes.]

(A) The AVA shall notify the verification body in writing when the conflict of interest evaluation information submitted under section WCI.8(g)(1) is deemed complete. Within 45 days after deeming the evaluation information complete, the AVA shall determine the conflict-of-interest potential and shall notify the verification body or owner or operator if the potential conflict of interest is determined to be medium or high.

(B) If the AVA determines the verification body or any member of the verification team has any threats specified in section WCI.8(g)(1), the AVA shall find a high potential conflict of interest and verification services may not proceed.

(C) If the AVA determines that there is a low potential conflict of interest prior to the verification services being provided, verification services may proceed.

(D) If the AVA determines that the verification body and verification team have a medium potential for a conflict of interest, the AVA shall evaluate the conflict of interest mitigation plan and may request additional information from the applicant to complete the determination. In determining potential conflict of interest, the AVA 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 owner or operator, and the cost of the verification services to be performed. The AVA will determine whether these factors when considered in combination with the mitigation plan demonstrate a low level of potential conflict of interest or a high level. If the AVA determines that there is a low potential conflict of interest prior to the verification services being initiated, verification services may proceed. If a high potential is determined prior to verification services being initiated, verification services may not proceed. If a high potential is determined after verification services have been initiated, the verification statement shall not be accepted..

(7) Monitoring Conflict of Interest Situations.

(A) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the AVA 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.

(B) 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 calendar days of any change in arrangements or relationships with the owner or operator for which the verification body has provided verification services that may create a medium or high threat of conflict of interest, the verification body shall notify the AVA of the change and provide a description of the nature of the change. The AVA will make a conflict of interest determination under WCI.8(g)(6).

(C) The verification body shall report to the AVA any changes in its organizational structure, including mergers, acquisitions, or divestitures that may have created a medium or high threat of conflict of interest for one year after completion of verification services within 30 days and submit an evaluation of how the change(s) impacts the potential for conflict of interest.

(D) The AVA may invalidate a verification finding if a medium or high threat of a conflict of interest has arisen for the verification body or any member of the verification team and, in the case of a medium threat, the threat has not been adequately mitigated. In such a case, the owner or operator shall be provided 180 calendar days to have their emissions report verified by a different verification body.

(E) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this section, the AVA may rescind its accreditation for any appropriate period of time . Additionally, the AVA may separately revoke its recognition of an accredited Verification Body under WCI.8(w). *[The WCI intends to develop more detailed accreditation requirements in the future.]*

(h) Notice of Verification Services. Prior to commencing verification services for a facility owner or operator, fuel supplier, and electricity importer, the verification body shall submit a notice of verification services to the AVA. Verification activities shall not proceed for 15 business days or until the verification body receives written approval to proceed from the AVA, whichever is earlier. If the AVA does not respond to the verification body within 15 business days, the verification body may begin to conduct verification activities.

[The NOVS form will be standardized across WCI and developed later.]

(i) Verification Plan.

(1) Accounting for requirements set by WCI.8, the verification plan shall document:

(A) the scope of the verification;

(B) the level of assurance;

(C) the verification standard;

(D) the verification criteria;

(E) the objectives of the verification;

(F) the timing of the verification, including site visits;

(G) the nature of the communications required;

(H) the resources required to conduct the verification, including the role of verification team members; and

(I) the nature, timing and extent of the verification procedures, including the sampling plan.

(2) The verification body shall retain the verification plan in paper, electronic, or other format for a period of not less than seven years following the submission of each verification statement.

(j) Site visits. In years for which full verification services are required under WCI.8(b)(3), at least one member of the verification team shall at a minimum make one onsite site visit to each facility or fuel supply location *[Note that exact location of fuel supplier site visits remains TBD]* for which an emissions data report is submitted. The verification team member(s) shall also conduct an onsite visit of the headquarters or other location of central data management, if different from the facility or fuel supply location, when the owner or operator is an electricity importer.

(k) Owners or 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 rule, as applicable.

(l) As applicable for electricity importers, 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, settlements data, or other information as confirmation of the region of origin. [*Note that this procedure is subject to change pending WCI Electricity Committee review.*]

(m) Data Checks. To determine the reliability of the submitted emissions data report, the verification team shall use data checks as defined in WCI.9. Verifiers will use their professional judgment in determining how many data checks are needed to provide a reasonable level of assurance.

(n) Emissions Data Report Modifications. If as a result of review by the verification team and prior to completion of a verification statement the owner or operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report must be submitted to [the jurisdiction] as specified by section WCI.8(q). The owner or 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 seven years pursuant to section WCI.4.

(o) Materiality and Conformance Assessment Criteria. The verifier shall determine if the annual emissions report is prepared in such a way that it satisfies WCI.8(b)(1).

(1) A verification team shall determine that an emission data report contains a material misstatement, if either of the following is true:

(A) Based on the verification team's own determination of the level of emissions subject to verification based on the sampling plan, the verification team concludes that total reported emissions are less than 95 percent accurate using the following equation:

$$PA = 100 - (SOU/TRE * 100)$$

Where:

PA	=	Percent accuracy
SOU	=	The net result of summing overstatements and understatements resulting from errors, omissions and misreporting
TRE	=	Total reported emissions

(B) The individual or aggregate effect of one or more errors, omissions or misstatements identified in the course of verification make it probable that the judgment of a reasonable person regarding the total reported emissions would have been changed or influenced by the error, omission or misrepresentation.

(2) To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this rule.

(3) The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall complete a verification statement for each emissions data report, and provide that statement to the owner or operator and [the jurisdiction or other body] according to the schedule specified in section WCI.2(b). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed and approved by an Independent Peer Reviewer.

(2) The verification body shall provide either a positive or adverse verification statement to the reporter and to the AVA *[alternatively, this could be the reporter's responsibility to submit the statement to the AVA]* based on its findings during the verification process.

(3) The lead verifier in the verification team shall attest on the verification statement that the verification team has carried out all verification services as required by this rule, and the Independent Peer Reviewer shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings. If the Independent Peer Reviewer does not determine that the verification team has carried out all verification services as required by the rule or if the Independent Peer Reviewer rejects the verification team's findings, then the verification body cannot issue a positive verification statement.

(4) The verification body shall provide to the owner or operator a detailed verification report. The verification report shall at minimum include the detailed comparison of the data checks with the submitted emissions data report, errors, omissions and misstatements identified during the course of the verification, any corrections made to the original annual emissions report as a result of the verification, and observations about the data management systems that are connected to the errors, omissions and misstatements identified, as well as any qualifying comments on findings during verification services. The detailed verification report shall be made available to [the jurisdiction] upon request.

(q) Prior to the verification body providing an adverse verification statement pursuant to WCI.8(p)(2), the owner or operator shall be provided at least 14 working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to [the jurisdiction] before the applicable verification deadline, unless the operator makes a request to [the jurisidiction*]* as follows:

(1) If the owner or operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement, the operator may petition the AVA to make a final decision as to the verifiability of the submitted emissions data report.

(2) If the AVA determines that the emissions data report does not meet the standards and requirements specified in this article, the owner or operator shall have the opportunity to submit within 60 calendar days of the date of this decision *[Note that this time frame may need to be changed pending details of cap-and-trade system design and needs.]* any emissions data report revisions that address the AVA's determination, for re-

verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section WCI.8(q)-(s).

(3) Upon provision of the verification statement to [the jurisdiction], the emissions data report shall be considered final and no changes shall be made except as provided in section WCI.8(n) or (q). All verification requirements of this rule shall be considered complete upon provision of the verification statement.

(r) In addition to initiating WCI's dispute resolution process, the operator and verification body must inform the applicable accreditation body of the dispute.

(s) The AVA may make void the positive verification statement submitted by the verification body if:

(1) The AVA finds a high level of conflict of interest existed between a verification body and an owner or operator; or,

(2) An emissions data report that received a positive verification statement fails an audit by the AVA.

(t) Upon request by the AVA, the owner or operator shall provide the data used to generate an emissions data report, including all data available to a verification body. The AVA may also review the full verification report given by the verification body to the owner or operator. The full verification report shall be provided to the AVA upon request.

(u) Upon written notification by the AVA, the verification body shall make itself available for a verification services audit.

(v) Duration of verification services by one verification body. Facility owners or operators, fuel suppliers, or electricity importers subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If a facility owner or operator, fuel supplier, or electricity importer is required or elects to contract with another verification body, they may contract verification services from the previous verification body only after not using the previous verification body for at least three years. If a verification body or verification team member has been providing verification services for an owner or operator in a greenhouse gas reporting or reductions program other than [the jurisdiction's] within the previous three years, those years of services will count towards the six consecutive year limit in this section.

(w) Revocation of Recognition. A jurisdiction may review, and for good cause, work to revoke or modify the accreditation status of a recognized verification body. If a recognized verification body is suspended in any other mandatory or voluntary GHG reporting or trading program, that verification body will not be allowed to provide any verification services until that suspension ends. If a recognized verification body has its accreditation revoked under any other mandatory or voluntary GHG reporting or trading program, that verification body will no longer be allowed to provide verification services under WCI.8 until it is reaccredited.

Verification Supplement 1

Note: the additional content in this Supplement must either be included in regulatory text in the appropriate subsections of WCI.8 or enforceable guidance documents by jurisdictions. The language in this section provides further explanation of items required in WCI.8 or alternative, more prescriptive language of those requirements.

Preliminary Activities and Verification Plan

The verification team shall discuss with the owner or operator the scope and objective of the verification services and obtain information from the owner or operator necessary to develop a verification plan. Such information shall include but is not limited to:

- Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, electricity transactions, as applicable;
- Information about the data management system used to track GHG emissions, electricity transactions, and other required measurement data as applicable;
- Information regarding the training or qualifications of personnel involved in developing the GHG emissions data report;
- Description of the specific methodologies used to quantify and report GHG emissions, electricity transactions, and other required data as applicable;
- Records of measured data related to emissions and operations for the prior and current period;
- Inventory of sources and their associated emissions for the reporting period, and
- Any prior verification reports, if applicable.

In developing the verification plan, the verifier shall:

- Gain an understanding of the organization and the process that emit greenhouse gases;
- Conduct a risk assessment to evaluate inherent, control and detection risk;
- Conduct preliminary analytical testing to identify anomalies in the data;
- Conduct a sensitivity analysis to assess the relative contribution of each source in the inventory to the reported annual emissions, and
- Consider any other relevant developments at the facility, in the regulations, or legal environment.

Sampling Plan

As part of the verification procedures, the verification team shall develop a sampling plan that, when combined with the other verification procedures, provides sufficient and appropriate evidence to allow the verifier to arrive at a conclusion. The sampling plan shall be designed to achieve the specified verification objective. The sample plan shall consider:

- Statistical versus non-statistical approaches
- Design of the sample, including the population characteristics
- Stratification (categorization of population into subgroups)
- Emission weighted selection
- Sample size

- Sample selection

As relevant information becomes available during the course of verification activities, the verification team must modify the sampling plan as necessary to address potential issues emerge of material misstatement or nonconformance with the requirements of this rule.

Data Checks

The verification team conducts data checks throughout the verification process and shall focus first on the largest and most uncertain estimates of emissions and electricity transactions.

- In establishing the verification plan, the verification team shall use professional judgment to determine the number of data checks required for the team to conclude with reasonable assurance whether the reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this rule.
- The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement as indicated in the verification plan;
- The verification team, through the conformance assessment, shall ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions for sampled data covered under sections WCI.20 through WCI.XX;

Site Visits

During the site visit, the verification team member(s) shall conduct the following:

- Observe whether all sources at the site are represented in the emissions report as specified in sections WCI.20 to WCI.XX as applicable to the owner or operator.
- Assess whether the source inventory is identified, categorized, and reported appropriately. Collect evidence as to explanations for data anomalies identified in the verification plan.
- Understand the data trail used by the owner or operator to measure, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions.
- Understand and evaluate the associated data controls used by the owner to ensure the completeness and accuracy of the data

Materiality Assessment

In assessing whether misstatements are material, the verification team shall determine whether the total reported emissions are at least 95 percent accurate using the following equation:

Percent accuracy = 100 – (sum of (errors, omissions, misreporting) * 100 / (total reported emissions))

To assess conformance with this rule the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this rule. The verification team shall keep a record of any errors, omissions or misstatements identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

Conflict of Interest (*could replace more general procedural language in Section WCI.8*)

(1) Conflict of Interest Submittal Requirements for Accredited Verification Bodies.

(A) Before the start of any work related to providing verification services to an owner or operator, a verification body must first be authorized in writing by *the AVA* to provide verification services. To obtain authorization the verification body shall submit to *the AVA* a self-evaluation of the potential for any conflict of interest that the verification body, entities related to the verification body, and members of the verification team including, subcontractors may have with the owner or operator or their related entities for which it will perform verification services. For the purposes of this section, the term member refers to staff on the verification team, in the verification body and any subcontractors. The submittal shall include the following:

(i) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in this section;

(ii) An organizational chart of the business structure of the verification body, including its related entities and brief description of the primary work done by the verification body and related entities;

(iii) iii. Identification of whether any member of the verification body, entities related to the verification body, or the verification team including subcontractors has previously provided verification services for the owner or operator or its related entities and, if so, the years in which such verification services were provided;

(iv) Identification of whether any member of the verification body, entities related to the verification body, or the verification team or including subcontractors has engaged in any non-verification services of any nature with the owner or operator or related entities either within or outside the WCI region during the previous three years. The verification body must also disclose any services listed under section (high COI list) it has provided to the owner or operator, regardless of when these services occurred. If non-verification services have previously been provided, the following information shall also be submitted:

(v) Identification of the nature and location of the work performed for the owner or 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;

(vi) The nature of past, present or future relationships the verification body, entities related to the verification body, and members of the verification team including subcontractors have with the owner or operator or related entity including:

- Instances when any member has performed or intends to perform work for the owner or operator;
- Identification of whether work is currently being performed for the owner or operator and, if so, the nature of the work;

- Whether any member has any contracts or other arrangements to perform work for the owner or operator or a related entity;
- Identify how much work was performed in each of the last three years, as a percentage of the verification body's total gross income for each of the last three years;
- Identify how much work related to greenhouse gases or electricity transactions was has performed for the owner or operator or related entities in each of the last three years, as a percentage of the verification body's income for each of the last three years;
- Identify how much work was performed by each subcontractor for the operator in each of the last three years, as a percentage of each subcontractor's total gross income for each of the last three years.

(vii) 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.

(viii) A list of names of the verification team members that will perform verification services for the owner or operator and a description of any instances of personal or family relationships with management or employees of the owner or operator that potentially represent a conflict of interest; and,

(ix) Identification of any other circumstances or relevant information known to the verification body or owner or operator that could result in a conflict of interest, or any situation where the appearance of impartiality could undermine confidence in the verification body's ability to assess the reported emissions.

(2) The potential for a conflict of interest shall be deemed to be high where:

(A) The verification body and owner or operator share any management staff or board of directors membership, or any of the management staff of the owner or operator have been employed by the verification body, or vice versa, within the previous three years; or

(B) Within the previous three years, any member of the verification body, any entity related to the verification body, and the verification team has provided to the owner or operator any of the following non-verification services:

(i) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;

(ii) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;

(iii) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(iv) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;

(v) Appraisal services of carbon or greenhouse gas liabilities or assets;

(vi) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(vii) Managing any health, environment or safety functions which explicitly identify greenhouse gas reductions as a benefit;

(viii) Bookkeeping or other services related to the accounting records or financial statements, unless those services limited to financial auditing;

(ix) Any service related to information systems, unless those systems will not be part of the verification process and excluding third-party auditor or registration services;

(x) Appraisal and valuation services, both tangible and intangible related to GHG emissions or reductions inventories;

(xi) 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;

(xii) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(xiii) Any internal audit service as provided under section (GHG plan) that has been outsourced by the operator that relates to the owner's or operator's internal accounting controls, financial systems or financial statements, unless no consulting or advice was provided as part of the audit;

(xiv) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the owner or operator;

(xv) Any legal services related to GHG emissions;

(xvi) Expert services to the owner or operator or his or her legal representative for the purpose of advocating his or her's interests in litigation or in a regulatory or administrative proceeding or investigation involving GHG emissions, unless providing factual testimony.

(C) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body, entity related to the verification body, or the verification team has provided verification services for the owner or operator for six consecutive years or within three years of the termination of a previous GHG verification contract with the owner or operator. If a verification body or verification team member has been providing verification services for a [operator/owner] in a greenhouse gas reporting or reductions program other than WCI within the past three years, those years of services will count towards the six consecutive year limit in the WCI.

(D) The potential for a conflict of interest shall be deemed high where the Independent Peer Reviewer for the verification team has provided verification or non-verification services for the operator during the current reporting year.

(3) 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 WCI.8(g) *[may need to be updated, depending upon final version of WCI.8)* and any non-verification services provided by all members of the verification body and the verification team to the owner or operator within the last three years are valued at less than five percent of the verification body's revenue.

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WCI.8 OPTIONAL GUIDANCE

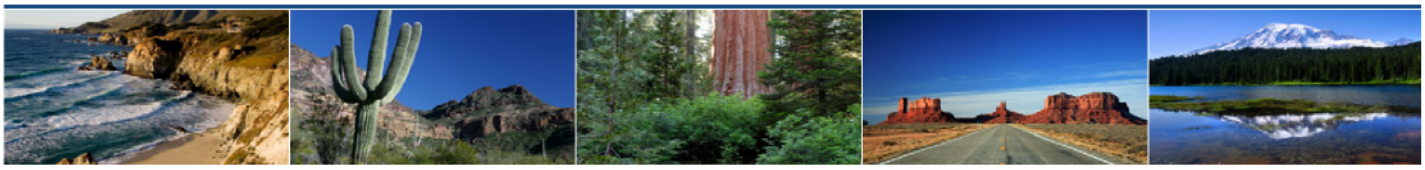
Note: This text is supporting material and not intended as part of the essential requirements.

Collection of Evidence

The verification body shall obtain sufficient and appropriate evidence to be able to draw reasonable conclusions on which to base the verification statement. The verification body obtains evidence by performing verification procedures. Verification procedures are classified as:

- **Computation (or Recalculation)** is the checking of mathematical accuracy of documents or records
- **Observation** of a process or procedure
- **Confirmation** is obtaining representations from a third party
- **Enquiry** is seeking information from a knowledgeable person
- **Inspection** of Records or Documents/Assets
- **Re-performance** is the verifiers independent execution of procedures or controls
- **Analysis** is the evaluation of information made by studying the plausible relationships among different types of data

Some or all of these techniques can be used to obtain sufficient and appropriate evidence. Site visits are used to obtain evidence that is readily available at that location.



§ WCI.9 DEFINITIONS

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

"Acid gas" means a gas mixture that has been separated from natural gas and consists mostly ofhydrogen sulphide or carbon dioxide and that may contain trace amounts of hydrocarbons, water, or other contaminants.

"Accreditation and Verification Authority" or "AVA" means [the jurisdiction] or any entity or entities to which [the jurisdiction] assigns any of the responsibilities for oversight and execution of the accreditation and verification program established in WCI.8.

"Adverse verification statement" means a verification statement rendered by a verification body stating that the verification body cannot conclude that there is a reasonable level of assurance for an emissions data report.

["Article" is a placeholder for a jurisdiction-specific cross reference to whatever subdivision of its administrative code contains the WCI's Essential Requirements for Mandatory Reporting in their entirety.]

"Asphalt" means a highly viscous liquid or semi-solid consisting mostly of bitumen and which is a residue by-product of petroleum refining

"Asphalt blowing" means the process by which air is blown through liquid asphalt to remove contaminants such as volatile compounds and to increase viscosity.

"Associated gas" means a natural gas which is found in association with crude oil, either dissolved in crude oil or as a cap of free gas above the crude oil.

"Barrel" or "bbl" means a volume equal to 42 U.S. gallons.

"Best available data and methods" means [the jurisdiction's] methods for emissions calculations set forth in this article; or [the jurisdiction's] approved next best alternative from the WCI source category quantification methodologies or other generally accepted methods for calculating greenhouse gas emissions organized by the same source categories and GHG species, using [jurisdiction] provided emission factors and other data.

“Compliance period” means, until such time as [the jurisdiction] adopts a cap-and-trade program covering sources subject to this article, a period of three calendar years.

“Biomass” means non-fossilized plants or parts of plants, animal waste, micro-organisms or any product made of either of these, and includes wood and wood products, agricultural residues and wastes, biologically derived organic matter found in municipal and industrial wastes, landfill gas, bio-alcohols, spent pulping liquor (black liquor), pulp fibers, sludge gas, and animal- or plant-derived oils.

“Biomass fuels” or “biomass-derived fuels” means fuels whose entire heat generating capacity is derived entirely from biomass.

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

“Calcination” means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide

“Calcine” means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.

“Calcined byproduct/waste type” refers to lime kiln dust and other partially calcined materials and co-products generated during the production of one of the three types of quicklime.

“Calcined byproduct type sold” refers to lime kiln dust and other calcined materials and coproducts, such as off-spec lime, that enters commerce.

“Calcined co-product/waste not sold” refers to any partially calcined co-product or partially calcined material produced during the calcination of limestone or other highly calcareous material that does not enter commerce as its own product or as part of another lime product. Types of calcined co-products/partially calcined material not sold include, but are not limited to, lime kiln dust, scrubber sludge, waste cores, and off-spec lime.

“Carbon dioxide equivalent” or “CO_2 equivalent” or “CO_2e” means a measure for comparing the global warming potentials of different greenhouse gases. By definition, carbon dioxide has a carbon dioxide equivalent of one, with the global warming potentials of other greenhouse gases stated relative to carbon dioxide.

“Catalytic cracking” means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

“Catalytic reforming” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

“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 to produce a finished powder.

“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 of partly calcined kiln feed material, dust from cement kilns and bypass systems, including bottom ash and bypass dust.

“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.

“Chemical oxygen demand” or “COD” means the measure of the amount of organic compounds in water, in units of mass per unit volume of water, used to determine water quality.

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

“Coal” means a combustible sedimentary rock composed primarily of carbon and classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 “Standard Classification of Coals by Rank”.

“Cogeneration unit” means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the operator of the facility where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

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

“Coke ” means a solid residue consisting mainly of carbon which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulfur bituminous coal (coal coke).

“Coke burn-off” means the removal of coke from the surface of a catalyst through combustion during catalyst regeneration.

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

“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.

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

"Crude oil" means a combustible, liquid mixture found in natural underground reservoirs consisting of hydrocarbons and other organic compounds, or derived from tar sands, shale and coal.

"Data check" means an independent calculation or checking of data conducted by a verifier to recreate the emissions for a discreet source included in an emissions data report.

"Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electricity.

"Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility.

"Equipment leak" means releases of fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

"Exporter" means *[To be defined later for transportation and RCI fuels accounting.]*

"Facility" means all buildings, plants, structures, installations, and equipment that:
(a) Emit or may emit GHG(s);
(b) Are located on one or more contiguous or adjacent properties;
(c) Are under common control of the same owner(s) or operator(s); and
(d) Form a producing unit, function as a single integrated site, or have the same first two digits of the Standard Industrial Classification or same first three digits of the North American Industry Classification System.

[For this version of the Essential Requirements, the words "nonroad engine" have been deleted from the definition of "facility." WCI, however, is considering the inclusion of a protocol for calculating nonroad engine emissions from certain facilities in a future version of the Essential Requirements. If and when that occurs, it may be appropriate to amend this definition to include nonroad engines in the list of covered activities at a stationary source.]

"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, green coke and fly ash, that are fed into a kiln, furnace, or other equipment type but which exclude fuels that are combusted.

“Feedstock” means any raw material that is used in or upgraded by an industrial process but not combusted.

“Flexigas” means a low BTU gaseous fuel produced through the gasification of coke.

“Fluid catalytic cracking unit” or “FCCU” means a process unit in a refinery in which crude oil or a crude oil-derived 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.

“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.

“Fossil fuel” means a fuel consisting of the decomposed remains of ancient plants and animals.

“Fuel” means solid, liquid or gaseous combustible material consisting of hydrocarbons and other compounds that is combusted or oxidized for the purpose of producing energy.

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

“Fuel gas system” means a system of compressors, piping, knock-out pots, mix drums, sulfur removal units (if necessary) and flaring units (if necessary) that collects fuel gas from one or more sources for treatment(if necessary), and transports it to a stationary combustion unit.

“Fugitive emissions” means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use, or transportation of fossil fuels, greenhouse gases or other substances, including but not limited to HFC emissions from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and CO_2 emitted from geyser steam and/or fluid used in geothermal generating facilities.

“Full verification” means all verification services as provided in section WCI.8(b).

“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 electricity.

“Global warming potential” or “GWP factor” means the radiative forcing of a greenhouse gas, calculated over a time interval of 100 years

“Greenhouse gas”, or “GHG” means any of the following: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

“High heat value” or “HHV” means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel

“Hydrocarbons” means chemical compounds consisting entirely of carbon and hydrogen.

“Hydrofluorocarbons” or “HFCs” means a class of GHGs consisting of hydrogen, fluorine, and carbon and primarily used as refrigerants, specifically those listed in Table WCI.10-1.

“Hydrogen plant” means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

“Importer” means *[To be defined later with input from the Electricity Subcommittee.]*

“Impregnated saw dust” means saw dust containing resins, preservatives or other substances derived from fossil fuels.

“Independent Peer Reviewer” means a Lead Verifier within a Verification Body who has not participated in conducting verification services for the current reporting year who provides an independent review of verification services rendered as required in section WCI.8(f).

“Kiln” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes any associated preheater or precalciner devices.

“Less Intensive Verification” means the verification services provided in interim years between full verifications; less intensive verification only requires risk assessment and data checks on an owner or operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

“Lime kiln dust” or “LKD” means lime dust produced in the course of production of quick lime.

“Lime type” refers to three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:

(a) High calcium quicklime, which is derived from limestone containing 0 to 5 percent magnesium carbonate.
(b) Magnesian quicklime, which is derived from limestone containing 5 to 35 percent magnesium carbonate
(c) Dolomitic quicklime, which is derived from limestone containing 35 to 46 percent magnesium carbonate.

“Liquefied petroleum gas” or “LPG” means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

“Low BTU gas” means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

“Low Heat Value” or “LHV” means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

“Material misstatement” means an error or omission, or a collection of errors or omissions, that results in a determination that a verification statement contains a material misstatement under WCI.8(o)(1)(A) or (B).

“Measurement-based” means any of the various emission quantification methodologies that involve the determination of emissions by means of direct measurement of the flue gas flow, as well as the concentration of the relevant GHG(s) in the flue gas.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

“Municipal solid waste” or “MSW” means waste products collected from households, commercial/retail units, or institutions.

“NAICS” means the North American Industry Classification System.

“Nameplate generating capacity” means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

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

“Nonroad equipment” means [WCI is addressing the definition for nonroad equipment as part of its development of a nonroad equipment rule].

[“Owner or operator,” as noted in WCI.1(a), is a placeholder. Each jurisdiction will select the specific terminology for the regulated persons in accordance with its customary rule-writing practices.]

“Operator's representative” means:

(a) If the operator of the facility is an individual, the operator.

(b) If the operator of the facility is a corporation, either

  (1) Any officer of the corporation, whether or not the officer is also a director of the corporation, who performs a policy making function in respect of the corporation and who has the capacity to influence the direction of the corporation; or

(2) The individual with primary responsibility for the operations and management of the facility.

(c) If the operator of the facility is not an individual or a corporation, the individual with primary responsibility for the operations and management of the facility.

"Perfluorocarbons" or "PFCs" means synthetic compounds derived from hydrocarbons through the replacement of hydrogen with fluorine atoms.

"Petroleum" means crude oil.

"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.

"Positive verification statement" means a verification statement 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 that the emissions data report conforms to the requirements of this article.

"Power" means electricity, except where the context makes clear that another meaning is intended.

"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.

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

"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.

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

"Process emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

“Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

“Pure” means consisting of at least 97 percent by mass of a specified substance.

“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.

“Quick lime” means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone.

“Reasonable level of assurance” for an emissions data report means the report satisfies WCI.8(b)(1).

“Recycled” means a material that is reused or reclaimed.

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

“Reporting year” means the calendar year for which emissions are being reported in the emissions data report.

“Retail provider” means an entity that provides electricity to retail end users.

“Senior officer” means:

(a) The chair of the board of directors, a vice-chair of the board of directors, the president, a vice-president, the secretary, the treasurer or the general manager of a corporation or any other individual who performs functions for a corporation similar to those normally performed by an individual occupying any such office, and

(b) Each of the five highest paid employees of a corporation, including any individual referred to in clause (a).

“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 United States Environmental Protection Agency (U.S. EPA) Method 21 – Determination of Volatile Organic Compound Leaks.

“Sinter production” means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

“SI units” means the Système international d’unités (International System of Units).

“Small refiner” means any petroleum refiner who owns or operates a refinery that has a crude oil throughput capacity equal to or less than 55,000 barrels per day.

“Solid biomass fuel” means plants or parts of plants, in their natural state that have been mechanically or chemically separated, but not chemically altered from the natural state.

“Standard conditions” or “Standard Temperature and Pressure” or “STP” means either a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and a pressure of 101.325 kPa (14.696 PSI) according to IUPAC standards, or a temperature of 0 degrees Celsius (32 degrees Fahrenheit) and an absolute pressure of 100 kPa, according to NIST standards.

“Standard cubic foot” or “scf” means the amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.

“Stationary combustion unit” means any boiler, heater, furnace, kiln, turbine, internal combustion engine, incinerator or other non-mobile source device that combusts any solid, liquid, or gaseous fuel for purposes of producing useful heat or energy for industrial, commercial, or institutional use; or for purposes of reducing the volume of waste by removing combustible material.

“Stationary fuel combustion emissions” means greenhouse gas emissions from stationary combustion units, including cogeneration units.

“Steam reforming” means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

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

“Sulfur hexafluoride” or “SF_6” means a greenhouse gas composed of a single sulfur atom and six fluorine atoms, commonly used as a dielectric medium.

“Sulfur recovery unit” or “SRU” means a 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.

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

“Supplier” means . . . [To be defined later for transportation and RCI fuels accounting.].

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

“Total organic carbon” or “TOC” means a measure of the amount of carbon in an organic compound and is used as a measure of water quality.

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

“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.

“Verification” means a systematic, independent and documented process for the evaluation of an operator’s emissions data report against the WCI’s reporting procedures and methods for calculating and reporting GHG emissions.

“Verification body” means a firm accredited by the [Accreditation Body TBD] and recognized by the jurisdiction or its designee, that is able to render a verification statement and provide verification services for operators subject to reporting under this article.

“Verification cycle” means three years of verification activities. Each verification cycle must include at least one year of full verification, and may include two years of less intensive verification, if eligible.

“Verification statement” means the final written declaration rendered by a verification body attesting whether an operator’s emissions data report is free of material misstatement and whether the emissions data report conforms to the requirements of this article.

“Verification services” means services provided during verification as specified in WCI.8, 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 rule, and submitting a verification opinion to the *[jurisdiction or its agent]*.

“Verification team” means all of those working for a verification body, including all subcontractors, to provide verification services for an operator.

“Verifier” means an individual employed or contracted by an accredited verification body who has been deemed competent by the verification body to carry out verification services as specified in section WCI.8.

“Volatile Organic Compound” or “VOC” means an organic compound containing at least one carbon atom and which evaporates or vaporizes readily under normal conditions, participates in

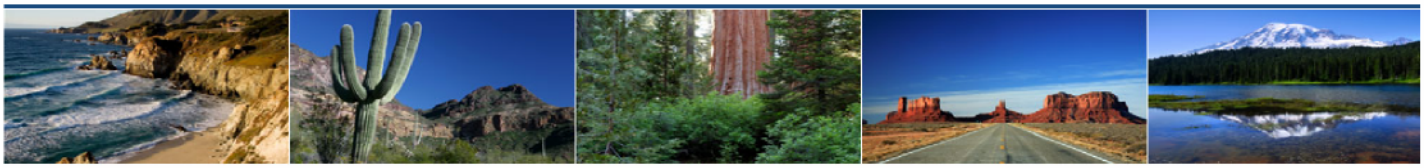
atmospheric photochemical reactions, and excludes carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

“Waste-derived fuel” means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include substances derived from fossil fuels such as waste oil, plastics, or solvents. Waste-derived fuels can also include fuels containing fractions of both fossil fuels and biomass, such as municipal solid waste, tires, dried sewage or impregnated saw dust. Waste-derived fuel does not include fuels which are pure biomass.

“Wastewater” means any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.

“Wastewater emissions” means releases of greenhouse gas emissions from wastewater and on-site wastewater treatment.

“Wastewater separator” means equipment used to separate oils and water from locations downstream of process drains.



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO2 emissions for fossil and biomass fuels, reported by fuel type.

(2) Total CH4 emissions, reported by fuel type.

(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic feet.

(2) For liquids, report in units of gallons.

(3) For non-biomass solids, report in units of short tons.

(4) For biomass solid fuels, report in units of bone dry short tons or bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in pounds or kilograms, for units that burn biomass fuels or municipal solid waste.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times CF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV	=	Default high heat value of the fuel, from column 3 of Table 20-1 (mmBtu per mass or mmBtu per volume, as applicable).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 (kg CO_2/mmBtu).
CF	=	Conversion factor of 0.024 (gallons to barrels) for petroleum products, only; 1.0 for all other fuels.
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-1 or 20-2, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25(a).
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (mmBtu per mass or volume).
EF	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664 \times 0.907$$

Equation 20-4

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year as specified in WCI.25(a).
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (short tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.907	=	Conversion factor from short tons to metric tons.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from column 5 of Table 20-1, (kg CO_2/mmBtu), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times 0.001$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25(a).
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (gallons).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (kg C per gallon of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25(a).
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scf).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf per kg-mole for STP of 20°C and 1 atmosphere or 836 scf per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, 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 or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and listed in Table 20-2, including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations 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 or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(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 CEMS 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 that apply to the facility. If

the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS 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 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) 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 or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 975 and 1,100 Btu per cubic foot. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor and a default high heat value for the fuel is specified in Table 20-1.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 975 and 1,100 Btu per cubic foot. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO_2 emission factor for the fuel is specified in Table 20-1 or 20-2.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO_2 emissions using ASTM

D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(B) The operator shall divide total CO_2 emissions between biomass emissions and non-biomass emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(C) 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.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.001 \qquad \textbf{Equation 20-8}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-1, MMBtu per unit of mass or volume.
EF	=	Default CH_4 or N_2O emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(b) If the heat content of the fuel is measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-9:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
$Fuel_p$	=	Mass or volume of fuel combusted for the measurement period, p, specified by fuel type, unit of mass (short tons) or volume (scf, barrel) per year.

HHV_p	=	High heat value measured for the measurement period, p, specified by fuel type, MMBtu per unit mass or volume.
EF	=	Default emission factor provided in Table 20-3, kg CH_4 or N_2O per MMBtu.
0.001	=	Factor to convert kg to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.001 \qquad \textbf{Equation 20-10}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (lb steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Table WCI.20-3 of this subpart (kg CH_4 or N_2O per mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor and a default higher heat value for the fuel is specified in Table 20-3.

(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.

(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.

(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).

(2) Monthly for natural gas, associated gas, and mixtures of low Btu gas.

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

(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.

(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.

(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.

(D) 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.

(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.

(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.

(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO2/MMBtu not less frequently than every third year, through a stack test measurement of CO2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short, tons) 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

(2) Fuel consumption measured in Btu values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.

(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(4) For fuel oil, tank drop measurements may also be used.

(5) Equipment used to measure solid fuel consumption at a facility shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using a test method listed in section WCI.6 or the calibration procedures specified by the equipment manufacturer. Equipment shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture high heat value (Btu/scf).
LHV = fuel or fuel mixture low heat value (Btu/scf).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,

(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).

(3) For solid biomass-derived fuels, use ASTM D5865-07a.

(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "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 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX 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.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.

(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, 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.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;

(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and

(E) A demonstration that the proposed interim procedure meets the criteria specified in sectionWCI.25(f)(1).

(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.25(f)(1) are met.

(4) When approving an interim data collection procedure, [jurisdiction] shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
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	22.07	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.27	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.05	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.93	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**MMBtu / 1,000 Standard cubic foot**	**kg CO_2 / 1,000 Standard cubic foot**	**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	54.4	53.02

Table 20-1. 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
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass fuels (EPA)	25.60	15.38	1,442.62	93.80
Biomass Derived Fuels (Solid). Wood and Wood Waste (50% moisture content) (Environment Canada	29.97	15.47	861.83	55.68
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Peat	29.07	8.83	940.66	106.53
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic foot**	**kg CO_2 / MMBtu**
Biogas (includes landfill gas and manure biogas)*	28.4	Varies	Varies	104.06

Note: Heat content factors are based on high heat values (HHV).
The emission factors for biogas include both CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.
Sources:
U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2007 (2009)*, 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, Naptha (<401 F°), and Other Oil (>401 F°), from U.S. Energy Information Administration, *Annual Energy Review 2007 (Released June 23, 2008)*, 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 U.S. EPA Climate Leaders, *Stationary Combustion Guidance (May, 2008)*, Tables B-1 and B-2; and
- Municipal Solid Waste (MSW) factors, from Energy Information Administration, http://www.eia.doe.gov/oiaf/1605/coefficients.html.
- Peat Emission Factors are based on high heat values (HHV). Values were converted from LHV to HHV assuming that LHV is 5 percent lower than HHV for solid and liquid fuels.
- HHV calculated from net calorific values in Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 1, Tables 1.2.

Table 20-2. Default Carbon Dioxide Emission Factors from Stationary Combustion for Waste Derived Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	See Table 20-1

Note: Emission factors are based on high heat 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).*

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

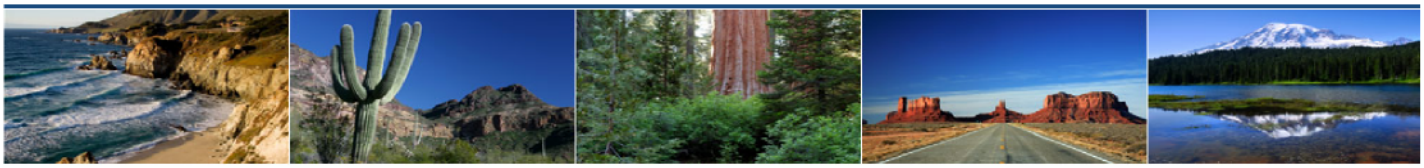
Fuel Type	CH_4 Emission Factor (kg CH_4/ MMBtu)	N_2O Emission Factor (kg N_2O / MMBtu)
Asphalt	0.003	0.0006
Aviation Gasoline	0.003	0.0006
Coal	0.01	0.0015
Crude Oil	0.003	0.0006
Digester Gas	0.0009	0.0001
Distillate	0.003	0.0006
Gasoline	0.003	0.0006
Jet Fuel	0.003	0.0006
Kerosene	0.003	0.0006
Kraft Black Liquor (ICFPA)	0.0026	0.0021
Kraft Black Liquor (Environment Canada)	0.0038	0.0015
Kraft Black Liquor (EPA)	0.03	0.005
Landfill Gas	0.0009	0.0001
LPG	0.001	0.0001
Lubricants	0.003	0.0006
Municipal Solid Waste	0.03	0.004
Naphtha	0.003	0.0006
Natural Gas	0.0009	0.0001
Natural Gas Liquids	0.003	0.0006
Other Biomass Fuels	0.03	0.004
Petroleum Coke	0.003	0.0006
Propane	0.001	0.0001
Refinery Gas	0.0009	0.0001
Residual Fuel Oil	0.003	0.0006
Tires	0.003	0.0006
Waste Oil	0.03	0.004
Waxes	0.003	0.0006
Wood (Dry)	0.03	0.004

Table 20-3. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**CH_4 Emission Factor (kg CH_4/ MMBtu)**	**N_2O Emission Factor (kg N_2O / MMBtu)**
Wood Waste (Environment Canada)	0.0029	0.001

Note: Heat content factors are based on high heat values (HHV).
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006)*, Volume 2, Tables 2.2, 2.3, and 2.4, except:

- Kraft Black Liquor emission factors, from International Council of Forest and Paper Associations, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (2005)*, Appendix F, Table 8.

The RC notes the significant difference in both the kraft black liquor and solid biomass (wood waste) emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.



§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

General stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, combustion turbines, engines, incinerators, and process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this rule.

Note: The source category definition may need to be revised after the remaining ER sections are completed.

§ WCI.22 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil and biomass fuels, reported by fuel type.
(2) Total CH_4 emissions, reported by fuel type.
(3) Total N_2O emissions, reported by fuel type.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.
(2) For liquids, report in units of kiloliters.
(3) For non-biomass solids, report in units of metric tons.
(4) For biomass solid fuels, report in units of bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

(e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste.

§ WCI.23 Calculation of CO_2 Emissions

For each fuel, calculate CO_2 mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §WCI.23(e).

(a) Calculation Methodology 1. Calculate the annual CO_2 mass emissions by substituting a fuel-specific default CO_2 emission factor, a default high heat value, and the annual fuel consumption into the Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001$$ **Equation 20-1**

Where:

CO_2	=	Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel	=	Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 20-1 (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(b) Calculation Methodology 2. Calculate the annual CO_2 mass emissions using a default fuel-specific CO_2 emission factor, a high heat value provided by the supplier or measured by the operator, using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the operator may instead elect to use the method shown in Equation 20-3.

(1) For any type of fuel for which an emission factor is provided in Tables 20-2, 20-3, 20-5, or 20-7, as applicable, except biomass fuels and municipal solid waste when the operator elects to use the method in WCI.23(b)(2), use Equation 20-2:

$$CO_2 = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.001$$ **Equation 20-2**

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
n	=	Number of required heat content measurements for the year as specified in WCI.25.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV_p	=	High heat value of the fuel for the measurement period (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Fuel-specific default CO_2 emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 above or Equation 20-3:

$$CO_2 = Steam \times B \times EF \times 0.001$$ **Equation 20-3**

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).

Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO_2/GJ).
0.001	=	Conversion factor from kilograms to metric tons.

(c) Calculation Methodology 3. Calculate the annual CO_2 mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the operator or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4. For emissions from the combustion of biomass fuels and municipal solid waste, the operator may instead elect to use the method shown in Equation 20-5.

(1) For a solid fuel, use Equation 20-4 of this section:

Equation 20-4

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times 3.664$$

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).
n	=	Number of carbon content determinations for the year.
$Fuel_i$	=	Mass of the solid fuel combusted in measurement period "i" (metric tons).
CC_i	=	Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(2) For biomass fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$CO_2 = Steam \times B \times EF \times 0.001$$

Equation 20-5

Where:

CO_2	=	Annual CO_2 mass emissions from biomass solid fuel or municipal solid waste combustion (metric tons).
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/metric ton steam).
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO_2/GJ), adjusted no less often than every third year as provided in WCI.25(a)(5)(B).
0.001	=	Conversion factor from kilograms to metric tons.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i$$ **Equation 20-6**

Where:

CO_2	=	Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).
n	=	Number of required carbon content determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the liquid fuel combusted in measurement period "i" (kiloliters).
CC_i	=	Carbon content of the liquid fuel, from the fuel analysis results for measurement period "i" (metric ton C per kiloliter of fuel).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$CO_2 = \sum_{i=1}^{n} 3.664 \times Fuel_i \times CC_i \times \frac{MW}{MVC} \times 0.001$$ **Equation 20-7**

Where:

CO_2	=	Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
n	=	Number of required carbon content and molecular weight determinations for the year, as specified in WCI.25.
$Fuel_i$	=	Volume of the gaseous fuel combusted in period "i" (a day or month, as applicable) (scm).
CC_i	=	Average carbon content of the gaseous fuel, from the fuel analysis results for the period "i" (day or month, as applicable) (kg C per kg of fuel).
MW	=	Molecular weight of the gaseous fuel, from fuel analysis (kg/kg-mole).
MVC	=	Molar volume conversion factor (24.1 scm per kg-mole for STP of 20°C and 1 atmosphere or 23.7 scm per kg-mole for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to metric tons.

(d) Calculation Methodology 4. Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For a facility that combusts fossil fuels or biomass fuels and operates CEMS in response to federal, state, provincial, or local regulation, 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 or equivalent requirements as applicable in Canada.

(A) The operator shall report CO_2 emissions for the reporting year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(B) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated

CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2) For a facility that combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), and operates a CEMS in response to federal, state, provincial, or local regulations 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 or equivalent requirements as applicable in Canada.

(A) Annual CO_2 emissions shall be reported in metric tons based on the sum of hourly CO_2 mass emissions over the year.

(B) Emissions calculations shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts waste-derived fuels and calculates CO_2 emissions using the methodology provided in WCI.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in WCI.23(f).

(4) An operator who uses CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass using the method provided in WCI.23(f), if applicable. The operator who co-fires pure biomass fuels with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in WCI.23(a) or WCI.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) For any units for which CO2 emissions are reported using CEMS data, the operator is relieved of the requirement to separately report process emissions from combustion emissions for that unit or to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, operators shall still report fuel use by fuel type as otherwise required.

(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 CEMS for the purpose of measuring CO2 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 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7) If a facility does not have a CEMS 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 CFR Part 75 or equivalent requirements as applicable in Canada.

(A) 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 or equivalent requirements as applicable in Canada.

(B) The operator shall report CO_2 emissions for the report year in metric tons based on the sum of hourly CO_2 mass emissions over the year, converted to metric tons.

(C) Operators who add CEMS under this article are subject to specifications in WCI.23(d)(1)-(5), if applicable.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CO_2 emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 1 may be used for any type of fuel for which a default CO2 emission factor (Tables 20-2, 20-3, 20-5, or 20-7, as applicable) and a default high heat value for the fuel (Table 20-1) is specified.

(2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter. Otherwise, Calculation Methodology 2 may be used for any type of fuel combusted for which a default CO2 emission factor for the fuel is specified in Tables 20-2, 20-3, 20-5, or 20-7, as applicable.

(3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.

(4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for: a combustion unit with a CEMS that is required by any federal, state, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(f) Mixtures of biomass or biomass fuel and fossil fuel.

(1) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in WCI.23(a) through (c) to determine the fossil fuel fraction and shall determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.

(2) The owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO_2 emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 percent biomass by weight or for waste-derived fuels that are less than 30 percent by weight of total fuels combusted in the year for which emissions are being reported, except where the operator wishes to report a biomass fuel fraction of CO_2 emissions.

(A) The operator shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.

(B) The operator shall divide total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.

(C) 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.

§ WCI.24 Calculation of CH_4 and N_2O Emissions

Calculate the annual CH_4 and N_2O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate.

(a) If the heat content of the fuel is not measured for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-8 for all fuels except coal. For coal, use Equation 20-9:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \qquad \textbf{Equation 20-8}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.000001 \qquad \textbf{Equation 20-9}$$

Where:

CH_4 or N_2O	=	Combustion emissions from specific fuel type, metric tons CH_4 or N_2O per year.
Fuel	=	Mass or volume of fuel combusted per year (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV_D	=	Default high heat value specified by fuel type provided in Table 20-1, (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.
EF_c	=	Default CH_4 or N_2O emission factor for coal provided in Table 20-6 (grams CH_4 or N_2O per metric ton of coal)
0.000001	=	Factor to convert grams to metric tons.

(b) If the heat content of the fuel is measured or provided by the fuel supplier for CO_2 estimation, calculate CH_4 and N_2O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times HHV_p \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = \sum_{p=1}^{n} Fuel_p \times EF_c \times 0.000001 \qquad \textbf{Equation 20-11}$$

Where:

CH_4 or N_2O	=	CH_4 or N_2O emissions from a specific fuel type, metric tons CH_4 or N_2O per year.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period "p" (express mass in metric tons for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kiloliters for liquid fuel)..

HHV_p	=	High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type (GJ per metric ton for solid fuel, GJ per kiloliter for liquid fuel, or GJ per cubic meter for gaseous fuel).
EF	=	Default CH_4 or N_2O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH_4 or N_2O per GJ.
EF_c	=	CH_4 or N_2O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH_4 or N_2O per metric ton of coal
0.000001	=	Factor to convert grams to metric tons.

(c) For biomass and municipal solid waste combustion, the operator may elect to use Equation 20-10 of this section to estimate CH_4 and N_2O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001 \qquad \textbf{Equation 20-10}$$

Where:

CH_4 or N_2O	=	Annual CH_4 or N_2O emissions from the combustion of a municipal solid waste (metric tons).
Steam	=	Total mass of steam generated by municipal solid waste combustion during the reporting year (metric tons steam).
B	=	Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/metric ton steam).
EF	=	Fuel-specific emission factor for CH_4 or N_2O, from Tables 20-2, 20-4 or 20-6, as applicable (grams CH_4 or N_2O per GJ).
0.000001	=	Conversion factor from grams to metric tons.

(d) The operator may elect to calculate CH_4 or N_2O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of (*jurisdiction*). Upon approval of a source test plan, the source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

(e) Use of the Four CO_2 Calculation Methodologies. Use of the four CH_4 and N_2O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

(1) WCI.24(a) may not be used by a facility that is subject to the verification requirements of WCI.8, except for stationary combustion units that combust natural gas with a higher heating value between 975 and 1,150 Btu per cubic foot. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH_4 or N_2O emission factor (Tables 20-2, 20-4 or 20-6) and a default higher heat value (Table 20-3) is specified.
(2) WCI.24(b) may be used for a unit of any size combusting any type of fuel.
(3) WCI.24(c) may only be used for biomass or municipal solid waste combustion.
(4) WCI.24(d) may be used for a unit of any size combusting any type of fuel.

§ WCI.25 Sampling, Analysis, and Measurement Requirements

(a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Once for each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).
(2) Monthly for natural gas, associated gas, and mixtures of low MJ gas.
(3) Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
(4) Monthly for solid fuels, as specified below:

(A) The monthly solid fuel sample shall be a composite sample of weekly samples.
(B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
(D) 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.
(E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
(F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.

(5) For biomass fuels and waste-derived fuels, the following may apply in lieu of WCI.25(a)(4):

(A) If CO_2 emissions are calculated using WCI.23(c)(1), the source-specific carbon content is determined annually. Upon approval of a source test plan by [*jurisdiction*], the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually.
(B) If CO_2 emissions are calculated using WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO_2/MJ not less frequently than every third year, through a stack test measurement of CO_2 and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

(1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in MJ, liters, million standard cubic meters, metric tons or bone dry metric tons) 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

(2) Fuel consumption measured in MJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.
(3) All oil and gas flow meters (except for gas billing meters) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow meter test method listed in section WCI.6 or the calibration procedures specified by the flow meter manufacturer. Fuel flow meters shall be recalibrated either annually or at the minimum frequency specified by the manufacturer.
(4) For fuel oil, tank drop measurements may also be used.

(c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-11

Where:

HHV = fuel or fuel mixture high heat value (MJ/scm).
LHV = fuel or fuel mixture low heat value (MJ/scm).
CF = conversion factor.

For natural gas, a CF of 1.11 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

(A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
(B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(2) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), or ASTM D4809-06 (Reapproved 2005).
(3) For solid biomass-derived fuels, use ASTM D5865-07a.
(4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO_2 emissions using the method specified in section WCI.23(f), if applicable

(d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and either molecular weight or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the operator, in either case using an applicable analytical method listed in section WCI.6.

(1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.
(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "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 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).
(3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). The operator may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.

(e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in sections WCI.20 through WCI.XXX 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.

(1) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
(2) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections WCI.20 through WCI.XXX, 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.

(f) Procedure for Interim Fuel Analytical Data Collection.

(1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections WCI.20 through WCI.XXX, [jurisdiction] may authorize an operator to use an interim data collection procedure if [jurisdiction] determines that the operator has satisfactorily demonstrated that:
(A) The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of section WCI.8;
(B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
(D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to [jurisdiction] that includes all of the following:
   (A) The proposed start date and end date of the interim procedure;
   (B) A detailed description of what data are affected by the breakdown;
   (C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;
   (D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
   (E) A demonstration that the proposed interim procedure meets the criteria specified in section WCI.25(f)(1).
(3) *[The jurisdiction]* may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section WCI.25(f)(1) are met.
(4) When approving an interim data collection procedure, *[jurisdiction]* shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section WCI.8(o).

Table 20-1: Default Carbon Content and High Heat Value by Fuel Type

Liquid Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/kl)**
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/metric ton)**
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	**Carbon Content (kg C /GJ)**	**High Heat Value (GJ/m3)**
Natural Gas	14.12	0.03832
Coke Oven Gas	23.03	0.01914
Still Gas - Refineries	13.34	0.03608
Still Gas - Upgraders	13.34	0.04324
Landfill Gas	14.97	0.0359

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada.

~~Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada~~

Table 20-2: Default Emission Factors by Fuel Type

Liquid Fuels	CO2 Emission Factor (kg /L)	CO2 Emission Factor (kg /GJ)	CH4 Emission Factor (g/L)	CH4 Emission Factor (g/GJ)	N20 Emission Factor (g/L)	N20 Emission Factor (g/GJ)
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass and Other Solid Fuels	**CO2 Emission Factor (kg /kg)**	**CO2 Emission Factor (kg /GJ)**	**CH4 Emission Factor (g/kg)**	**CH4 Emission Factor (g/GJ)**	**N20 Emission Factor (g/kg)**	**N20 Emission Factor (g/GJ)**
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada)[1]	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA)[2]	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulping Liquor	1.428	102.0	0.05	3.571	0.02	1.429

(Env.Canada)						
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	**CO2 Emission Factor (kg /m3)**	**CO2 Emission Factor (kg /GJ)**	**CH4 Emission Factor (g/m3)**	**CH4 Emission Factor (g/GJ)**	**N20 Emission Factor (g/m3)**	**N20 Emission Factor (g/GJ)**
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829
Still Gas - Refineries	1.75	48.50	N/A	N/A	0.0222	0.615
Still Gas - Upgraders	2.14	49.49	N/A	N/A	0.0222	0.513

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007, unless otherwise stated

[1] Assumes 50% moisture content of wood waste

[2] Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	**Marketable Gas (kg/GJ)**	**Non-Marketable Gas (kg/m3)**	**Non-Marketable Gas (kg/GJ)**
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH4 (g/m3)	**CH4 (g/GJ)**	**N20 (g/m3)**	**N20 (g/GJ)**
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH4 Emission Factor (g/kg)	N2O Emission Factor (g/kg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

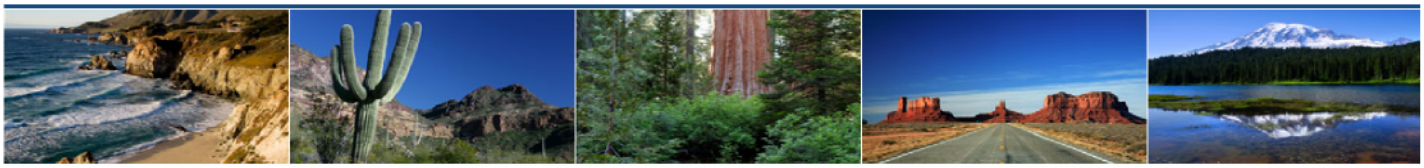
Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO2 Emission Factor (kg/GJ)	CH4 Emission Factor (g/GJ)	N2O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, unless otherwise stated

The ~~RC~~WCI notes the significant difference in both the black liquor and solid biomass emission factors published by the EPA and Environment Canada (as well as those submitted by industry associations). In lieu of recommending a single emission factor at this time (as there is no certainty as to which is most accurate) the RC is presenting both for information purposes. The RC will be working with experts in the two federal agencies and other organizations to ascertain the most accurate emission factor to use for both Metric and English unit versions of the Essential Requirements of Mandatory Reporting.



§ WCI.30 REFINERY FUEL GAS COMBUSTION

WCI.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

WCI.32 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the emissions data report shall include the following information at the facility level:

(a) Annual CO_2, CH_4, and N_2O emissions from refinery fuel gas combustion in metric tons.

(b) Annual fuel consumption in units of million standard cubic feet or cubic meters.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions.

(d) Average high heat value of each fuel, if used to compute CO_2 emissions.

WCI.33 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Owners and operators shall calculate daily CO_2 emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO_2 emissions from combustion of all fuel gas by summing the CO_2 emissions from each fuel gas system.

(1) Use a CEMS that complies with the provisions in section WCI.23(d).

(2) Calculate CO_2 emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$ **Equation 30-1 (English Units)**

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scf).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel.
MVC = Molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

$$CO_2 = \sum_{i=1}^{n} Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001$$ **Equation 30-1 (Metric Units)**

Where:

CO_2 = Carbon dioxide emissions, metric tons/year.
$Fuel_i$ = Daily refinery fuel or flexigas combusted (scm).
CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
MW = Daily sample of molecular weight of fuel.
MVC = Molar volume conversion factor (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664 = Conversion factor for carbon to carbon dioxide.
0.001 = Conversion factor for kg to metric tons.
n = Number of days in a year.

(A) For refinery fuel gas, the daily carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in WCI.34.
(B) For flexigas, the daily carbon content shall be determined once per day using the methods specified in WCI.34.

(3) Calculate CO_2 emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heat value that is monitored using a continuous on-line instrument.

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i} \times 0.000001$$ **Equation 30-2 (English Units)**

Where:

CO_2 = CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (Btu/scf).
$Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system (scf/d).
$EF_{CO2,i}$ = Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MMBtu).
0.000001 = Conversion factor for Btu to MMBtu.
n = Number of days per year.

Equation 30-2 (Metric Units)

$$CO_2 = \sum_{i=1}^{n} HHV_i \times Fuel_i \times EF_{CO2,i}$$

Where:

CO_2	=	CO_2 emissions resulting from the combustion of fuel gas from an individual fuel gas system (metric tons/yr).
HHV_i	=	Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period (MJ/m^3).
$Fuel_i$	=	Daily fuel consumption from all fuel combustion units burning gas from the system (m^3/d).
$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system, developed using Equation 30-3 (metric tons CO_2/MJ).
n	=	Number of days per year.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 1{,}000$$ **Equation 30-3 (English Units)**

Where:

$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MMBtu).
CC	=	Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV	=	Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (Btu/scf).
MW	=	Refinery fuel A molecular weight (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
1,000	=	Conversion factor for kg/Btu to metric tons/MMBtu.

$$EF_{CO2,i} = CC/HHV \times MW/MVC \times 3.664 \times 0.001$$ **Equation 30-3 (Metric Units)**

Where:

$EF_{CO2,i}$	=	Daily CO_2 emission factor for an individual fuel gas system (metric tons CO_2/MJ).
CC	=	Daily sample of gas carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (kg carbon/kg fuel).
HHV	=	Daily sample of gas high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section (MJ/m^3).
MW	=	Refinery fuel A molecular weight (kg/kg-mole).
MVC	=	Molar volume conversion (24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere).
3.664	=	Conversion factor for carbon to carbon dioxide.
0.001	=	Conversion factor for kg/MJ to metric tons/MJ.

(A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in WCI.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.

(B) For facilities that meet the definition of a small refiner in WCI.10, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.

(4) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in WCI .23(b) or (c), as appropriate for each fuel.

(5) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO_2 emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the operator must determine the fuel flow rate and appropriate fuel specific parameters (e.g. carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO_2 emissions from the mixture. CO_2 emissions for each fuel stream must be estimated using the following methods:

(A) For natural gas and associated gas, use the appropriate methodology specified in section WCI.23(b) or (c).

(B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.

(C) For low heat content gas, use the methodology in paragraph (a)(2) of this section.

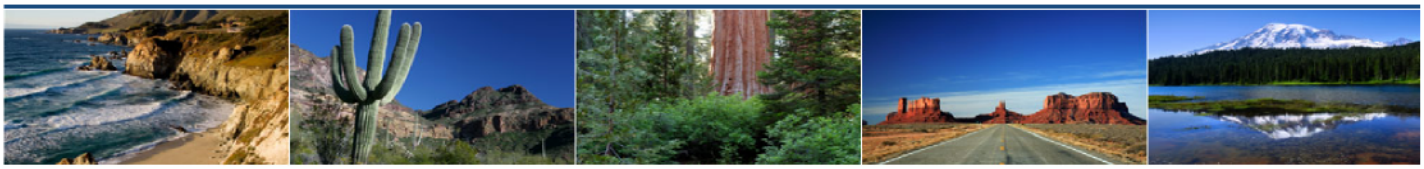
(b) Calculation of CH_4 and N_2O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions.

WCI.34 Sampling, Analysis, and Measurement Requirements

(a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).

(b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 (Reapproved 2006) or ASTM D1946-90 (Reapproved 2006). Where these methods do not adequately quantify all major hydrocarbons, then an owner or operator may request use of an alternative ASTM or other method to be approved by *[the jurisdiction]*.

(c) Measure high heat value using the monitoring requirements specified in WCI.25(c) for gaseous fuels.



§ WCI.40 ELECTRICITY GENERATION (ENGLISH UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of million standard cubic feet.

(2) For liquids, report in units of gallons.

(3) For non-biomass solids, report in units of short tons.

(4) For biomass-derived solid fuels, report in units of bone dry short tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in mmBtu. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in mmBtu. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of HFC from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 975 and less than or equal to 1,100 Btu/scf use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 975 or greater than 1,100 Btu/scf, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default carbon content emission factor in Table 20-1, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-1 and 20-2 and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor in Table 20-3.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2\,MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
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) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.53 \times Heat \times 0.001 \qquad \textbf{Equation 40-3}$$

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.53 = Default fugitive CO_2 emission factor for geothermal facilities, kg per mmBtu; and
Heat = Heat taken from geothermal steam and/or fluid, mmBtu/yr.

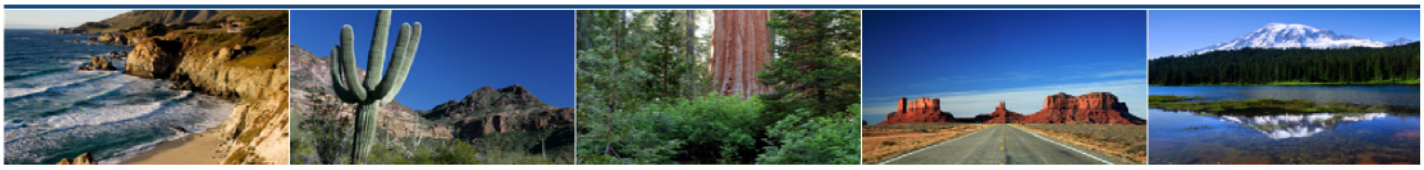
(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].



§ WCI.40 ELECTRICITY GENERATION (METRIC UNITS)

§ WCI.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

§ WCI.42 Greenhouse Gas Reporting Requirements

For each electricity generating unit, the emissions data report shall include the following information:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

(1) Total CO_2 emissions for fossil fuels, reported by fuel type.

(2) Total CO_2 emissions for all biomass fuels combined.

(3) Total CH_4 emissions for fuels combined.

(4) Total N_2O emissions for all fuels combined.

(b) Annual fuel consumption:

(1) For gases, report in units of standard cubic meters.

(2) For liquids, report in units of kiloliters.

(3) For non-biomass solids, report in units of metric tons.

(4) For biomass-derived solid fuels, report in units of bone dry metric tons.

(c) Average carbon content of each fuel, if used to compute CO_2 emissions as specified in WCI.43.

(d) Average high heating value of each fuel, if used to compute CO_2 emissions as specified WCI.43.

(e) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.

(f) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).

(g) Process CO_2 emissions from acid gas scrubbers and acid gas reagent.

(h) Fugitive emissions of HFC from cooling units that support power generation.

(i) Fugitive CO_2 emissions from geothermal facilities.

(j) Fugitive CO_2 emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section WCI.100.

§ WCI.43 Calculation of Greenhouse Gas Emissions

(a) Calculation of CO_2 Emissions. Operators shall use CEMS to measure CO_2 emissions if required to operate a CEMS by any other federal, state, provincial, or local regulation. Operators not required to operate a CEMS by another regulation may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). Operators using CEMS to determine CO_2 emissions shall comply with the provisions in section WCI.23(d).

(1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:

(A) If the high heat value is greater than or equal to 36.3 and less than or equal to 40.98 MJ/scm use either:

(i) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(ii) The measured heat content of the fuel and the calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(B) If the high heat value is less than 36.3 or greater than 40.98 MJ/scm, use the measured carbon content of the fuel and the calculation methodology 3 in section WCI.23(c).

(2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c).

(3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section WCI.30.

(5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

(A) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(B) The measured heat content of the fuel and calculation methodology 2 in section WCI.23(b) provided the facility is not subject to the verification requirements of WCI.8.

(6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in WCI.20 Table 20-7, and the calculation methodology in section WCI.23(b)(2) provided the facility is not subject to the verification requirements of WCI.8. If the facility is subject to the verification requirements of WCI.8, the operator shall use CEMS to measure CO_2 emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO_2 emission factor according to the provisions of WCI.23(c)(2).

(7) Start-up Fuels. The operators of generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO_2 emissions from fossil fuel combustion using one of the following methods:

(A) The default emission factors from Tables 20-2, 20-3, 20-5 or 20-7, as applicable, and calculation methodology 1 provided in section WCI.23(a);

(B) The measured heat content of the fuel and calculation methodology 2 provided in section WCI.23(b);

(C) The measured carbon content of the fuel and calculation methodology 3 provided in section WCI.23(c); or

(D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section WCI.30.

(8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO_2 emissions as follows.

(A) For co-fired electricity generators that burn only fossil fuels, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method need not report emissions separately for each fossil fuel.

(ii) For units not equipped with a continuous emission system, calculate the CO2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.

(B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO_2 emissions shall be determined using one of the following methods:

(i) A continuous emission monitoring system in accordance with calculation methodology 4 in section WCI.23(d). Operators using this method shall determine the portion of the total CO_2 emissions attributable to the biomass-derived fuel and portion of the total CO_2 emissions attributable to the fossil fuel using the methods specified in section WCI.23(d)(4).

(ii) For units not equipped with a continuous emission system, calculate the CO_2 emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

(b) Calculation of CH_4 and N_2O Emissions. Operators of electricity generating units shall use the methods specified in section WCI.24 to calculate the annual CH_4 and N_2O emissions. For coal combustion, use the default CH_4 emission factor(s) in Table 20-6.

(c) Calculation of CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO_2 emissions from these processes using Equation 40-1 if these emissions are not already captured in CO_2 emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times \left(CO_{2MW} / Sorbent_{MW}\right)$$ **Equation 40-1**

Where:

CO_2	=	CO_2 emitted from sorbent for the report year, metric tons;
S	=	Limestone or other sorbent used in the report year, metric tons;
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) Calculating Fugitive HFC Emissions from Cooling Units. Operators of electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The Operator is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions:

$$HFC = HFC_{inventory} + HFC_{purchases/acquisitions} - HFC_{sales/disbursements} + HFC_{\Delta capacity}$$ **Equation 40-2**

Where:

HFC	=	Annual fugitive HFC emission, metric tons;
$HFC_{inventory}$	=	The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year.
$HFC_{purchases/acquisitions}$	=	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
$HFC_{sales/disbursements}$	=	The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment.

$HFC_{\Delta capacity}$ = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year.

(2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;
$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;
HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;
R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;
C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;
$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;
$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;
C_{retire} = Nameplate capacity of the retired unit, kilograms; and
R_{retire} = HFC recovered from the retired unit, kilograms.

(e) Fugitive CO_2 Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO_2 emissions using one of the following methods:

(1) Calculate the fugitive CO_2 emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001 \qquad \textbf{Equation 40-3}$$

Where:

CO_2 = CO_2 emissions, metric tons per year;
7.14 = Default fugitive CO_2 emission factor for geothermal facilities, kg per GJ; and
Heat = Heat taken from geothermal steam and/or fluid, GJ/yr.

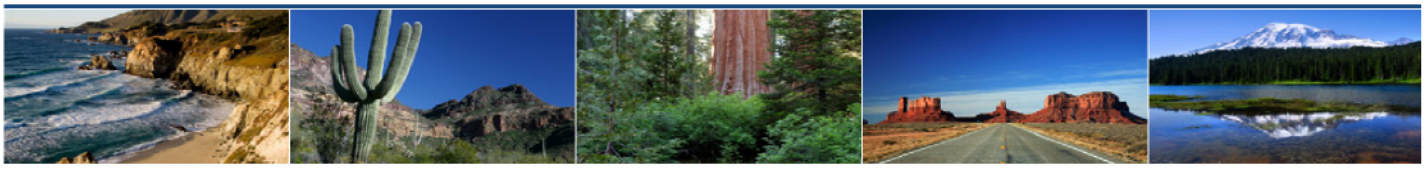
(2) Calculate CO_2 emissions using [*insert jurisdiction*] approved source specific emission factor.

§ WCI.44 Sampling, Analysis, and Measurement Requirements

(a) CO_2, CH_4 and N_2O Emissions from Fuel Combustion. Operators using CEMS to estimate CO_2 emissions from fuel combustion shall comply with the requirements in section WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section WCI.25.

(b) CO_2 Emissions from Acid Gas Scrubbing. Operators of electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.

(c) CO_2 Emissions from Geothermal Facilities. Operators of geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the operator shall conduct an annual test of the CO_2 emission rate using a method approved by [*insert jurisdiction*]. The operator shall submit a test plan to the [*insert jurisdiction*] for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*insert jurisdiction*].



§ WCI.60 IMPORTED ELECTRICITY

[*The requirements in this attachment do not include the default emissions factors necessary for reporting imported electricity from asset-controlling suppliers or imports from unspecified sources. Default factors for unspecified sources are under development by the Electricity Committee and asset-controlling suppliers will need to approach each jurisdiction for approval of a differentiated default factor.*]

§ WCI.61 Definitions

"Asset-controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number for its fleet of generating facilities by [*the jurisdiction*].

"Balancing authority" means a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

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

"Busbar" means a power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

"Electricity generating facility" means a facility that generates electricity and includes one or more electricity generating units at the same location.

"Electricity importer" means [common boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Region or; [individual boundary FJD] an owner of imported electricity [*or electricity wheeled through the WCI Region*] as it is delivered to the first point of delivery in the WCI Partner jurisdiction of the final point of delivery. [The definition used may vary by jurisdiction.]

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

"Electricity wheeled through the WCI Region" means electricity that is imported into the WCI Region but is simultaneously exported out of the WCI Region and has a final point of delivery in a location outside of the WCI Region.

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

"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.

“Final point of delivery” means the last point of delivery for a given electricity transaction.

“First Jurisdictional Deliverer” means the owner or operator of an electricity generating facility in a WCI Partner jurisdiction or an electricity importer that is jurisdictional to the regulatory authority of a WCI Partner jurisdiction or the immediate downstream purchaser or recipient of electricity from a non-jurisdictional electricity importer.

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

“Imported electricity” means electric power generated outside the WCI Region, delivered into the WCI Region and having a final point of delivery in the WCI Region.

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

“Multi-jurisdictional retail provider” means a retail provider that provides electricity to consumers in [*the jurisdiction*] and in one or more other non-WCI jurisdictions in a contiguous service territory.

“Nameplate generating capacity” means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

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

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

“Point of delivery” means a point on an electricity transmission or distribution 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, or a distribution substation where electricity is imported into the WCI region over a multi-jurisdictional retail provider’s distribution system.

“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.

“Purchasing/selling entity” means an entity that purchases or sells energy or capacity and reserves transmission services between or among balancing authority areas.

“Renewable energy” means 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.

"Renewable energy certificate" or "renewable energy credit" means a certificate of proof issued by an approved generation information system or third-party verifier that one MWh of electricity was generated by a renewable energy source.

"Retail provider" means an entity that provides electricity to retail end users in [*the jurisdiction*].

"Specified source" means a specific electricity generating unit or electricity generating facility which can be matched to a reported electricity transaction due to full or partial ownership by the first jurisdictional deliverer or due to its identification in a power contract with the first jurisdictional deliverer.

"Unspecified source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit. Unspecified sources of electricity may include electricity 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.

"Western Climate Initiative" or "WCI" means a collaborative effort of the U.S. states and Canadian provinces that comprise the WCI Region to reduce greenhouse gas emissions in their respective jurisdictions.

"WCI Region" means the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec plus the U.S. states of Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington, excluding lands that are not subject to state or provincial jurisdiction.

§ WCI.62 Greenhouse Gas Emissions Data Report: First Jurisdictional Deliverers of Imported Electricity

(a) General Requirements. First jurisdictional deliverers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. When reporting emissions and electricity transactions, first jurisdictional deliverers, excluding imported electricity that is imported at the distribution level by multi-jurisdictional retail providers, shall:

(1) Specify the amount of greenhouse gas emissions in metric tons CO_2e;

(2) Specify the amount of electricity in MWh;

(3) Aggregate imported electricity and emissions from specified sources by electricity generating facility or electricity generating unit, as applicable;

(4) For electricity from specified sources, specify the facility name, the facility ID, and, if applicable, the electricity generating unit ID for the unit generating the electricity;

(5) Report the amount of imported electricity from specified sources as measured at the busbar;

(6) For imported electricity transactions from specified sources where measurements at the busbar are not known, report the amount of imported electricity from the applicable specified sources as measured at the first point of delivery in [*the jurisdiction]* and report estimated transmission losses for each specified source;

(7) Report the amount of electricity from unspecified sources as measured at the first point of delivery in [*the jurisdiction*];

(8) For electricity from unspecified sources, disaggregate imported electricity by the balancing authority area or other geographic area as defined by [*the jurisdiction*] from which the electricity originated;

(9) Report the amount of electricity from asset-controlling suppliers as measured at the first point of delivery in [*the jurisdiction*];

(10) For electricity from asset-controlling suppliers, disaggregate imported electricity by the asset-controlling or asset-owning supplier from which the electricity was purchased;

(11) Report the number of renewable energy certificates from sources not in the WCI region that are retired, or whose greenhouse gas source specification fields are retired, as applicable, associated with imported electricity from an unspecified source or imported electricity from a specified source having an emission rate equal to or less than the default rate for the balancing authority where the specified generating facility is located;

(12) Specify electricity imported under exchange agreements as you would other import transactions;

(13) Report quantities of electricity wheeled through the WCI Region as measured at the first point of delivery inside [*the jurisdiction*];

(14) Retain for purposes of verification NERC E-tags, power contracts, settlements data, and all other information needed to confirm the transactions.

(b) Report Content. First Jurisdictional Deliverers shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Specified Imported Electricity Transactions. Imported electricity and emissions from specified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(A) Electricity imported into the WCI Region from a specified hydroelectric generating facility with nameplate capacity of greater than 30 MW that was operational prior to January 1, 2008 or from a specified nuclear facility that was operational prior to January 1, 2008 shall be listed as one of the following:

(i) Electricity purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;

(ii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) and that is not associated with an increase in the facility's generating capacity;

(iii) Electricity purchased not meeting WCI.62(b)(1)(A)(i) that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;

(iv) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;

(v) Electricity purchased that does not meet WCI.62(b)(1)(A)(i) due to federal power redistribution polices for federally owned resources and not related to

price bidding.

(2) Unspecified Imported Electricity Transactions. Imported electricity and emissions from unspecified sources for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(3) Imported Electricity from Asset-Controlling Suppliers. Imported electricity and emissions from asset-controlling suppliers for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

(4) Electricity Wheeled Through the WCI Region. Electricity wheeled through the WCI Region for which the First Jurisdictional Deliverer is the electricity importer or that the First Jurisdictional Deliverer purchased or received immediately downstream from a non-jurisdictional electricity importer.

§ WCI.63 Calculation of Emissions from Specified Sources

For each specified source, calculate CO_2 mass emissions using one of the two calculation methodologies specified in this section.

(a) Calculation Methodology 1: If the specified source reports emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act calculate emissions using Equation 60-1:

$$CO_2 = CO_{2t} \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-1}$$

Where:

CO_2 = Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).

CO_{2t} = Total annual CO_2 mass emissions from the specified source (metric tons) reported, in order of preference, to [*the jurisdiction*], The Climate Registry, or to the U.S.EPA or Environment Canada.

MWh_{imp} = Megawatt-hours of electricity imported from the specified source, including estimated losses for transactions not measured at the busbar.

MWh_t = Total megawatt-hours of net power generated by the specified source.

(b) Calculation Methodology 2: If the specified source does not report emissions to [*the jurisdiction*], The Climate Registry, the U.S.EPA under 40 CFR Part 75 or to Environment Canada under Section 71 of the Canadian Environmental Protection Act, calculate emissions using Equation 60-2:

$$CO_2 = \sum HHV_f \times EF_f \times 0.001 \times \frac{MWh_{imp}}{MWh_t} \qquad \textbf{Equation 60-2}$$

Where:

CO_2	=	Annual CO_2 mass emissions for a specific fuel type (metric tons).
HHV_f	=	Higher heating value of the fuel *f* consumed for electricity production as reported in U.S. EIA Form 923, or its successor (mmBtu).
EF_f	=	Fuel-specific default CO_2 emission factor, from column 5 of Table 20-1 or from Table 20-2 (kg CO_2/mmBtu).
0.001	=	Conversion factor from kilograms to metric tons.
MWh_{imp}	=	Megawatt-hours of electricity imported from the specified source.
MWh_t	=	Total megawatt-hours of net power generated by the specified source as reported in U.S. EIA Form 923, or its successor.

§ WCI.64 Calculation of Emissions from Asset-Controlling Suppliers and Unspecified Sources

For imported electricity from asset-controlling suppliers or unspecified sources, calculate emissions using the methodology specified in this section.

(a) Calculation Methodology: Calculate the annual CO_2 mass emissions by multiplying the reported quantities of imported electricity from each asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*] by the appropriate default emission factor according to Equation 60-3:

$$CO_2 = MWh \times DEF \qquad \textbf{Equation 60-3}$$

Where:

CO_2	=	Annual CO_2 mass emissions for imported electricity from the specified source (metric tons).
MWh	=	Megawatt-hours of electricity imported from the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].
DEF	=	The default emission factor corresponding to the asset-controlling supplier, balancing authority area, or other geographic region defined by [*the jurisdiction*].

§ WCI.65 Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only

[*This section is optional. It is intended for any WCI jurisdiction that wishes to collect information about high-GHG generating facilities in other jurisdictions owned by retail providers serving its own jurisdiction.*]

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 the sections above.

(a) If the retail provider holds a contract that entitles the retail provider to a specified percentage of the generation in the report year from an electricity generating facility not located in the WCI Region, the retail provider shall include electricity purchased or sold from that facility as being from a partially owned facility.

(b) For electricity generating facilities not located in the WCI Region that are fully or partially owned by the retail provider that have CO2 emissions greater than 500 kg of CO2 per MWh based on the most recent greenhouse gas emissions data report that received a positive

verification opinion or on CO2 emissions reported to U.S.EPA under 40 CFR Part 75 or reported to Environment Canada under Section 71 of the Canadian Environmental Protection Act, the retail provider shall include:

(1) Facility name, state/province designated facility ID, state/province designated generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and both net and gross power generated in the report year;

(2) Quantity of electricity sold by the retail provider or on behalf of the retail provider from the electricity generating facility or electricity generating unit having a final point of delivery outside the WCI Region, as measured at the busbar.

§ WCI.66 Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers Only.

[*This section applies only to jurisdictions with Multi-Jurisdictional Retail Providers, as defined.*]

Multi-jurisdictional retail providers that import electricity into the WCI Region at the distribution level shall include the following information in the greenhouse gas emissions data report for each report year in addition to the information identified in the sections above. Multi-jurisdictional retail providers meeting this condition shall provide:

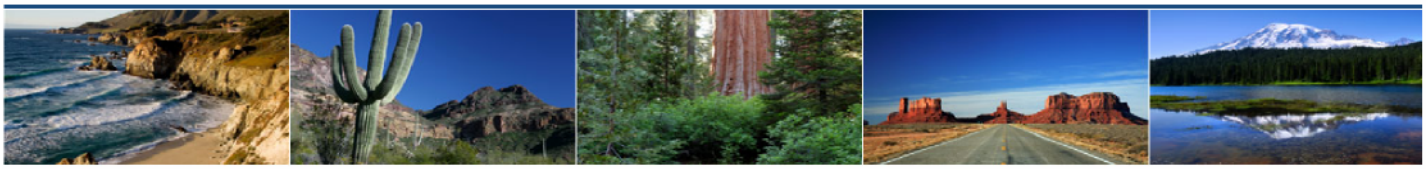
(a) A report of the greenhouse gas emissions associated with serving the load of the service territory that includes consumers in [*the jurisdiction*] following [*the jurisdiction's*] reporting protocol for retail providers or The Climate Registry's Electric Power Sector Protocol;

(b) The total retail load served by the multi-jurisdictional retail provider in the service territory that includes consumers in [*the jurisdiction*];

(c) The retail load of customers served in [*the jurisdiction's*] portion of the service territory;

(d) The greenhouse gas emissions associated with the imported electricity as the quantity of emissions reported in WCI.64(a) multiplied by the ratio of the quantity of electricity reported in WCI.64(b) to the quantity of electricity reported in WCI.64(c); and

(e) If the average emission rates differ among the various state or provincial portions of the service territory due to mandatory factors such as different Renewable Portfolio Standard requirements in [*the jurisdiction*] and the other jurisdictions, the multi-jurisdictional retail provider may report an adjusted quantity of greenhouse emissions and file a report that describes how the quantity reported in WCI.64(d) was adjusted.



§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using electrolysis.

§ WCI.72 Greenhouse Gas Reporting Requirements

For each facility that includes a primary aluminum production process, the emissions data report must contain the following information:

(a) CO_2 emissions from anode consumption from prebaked and Søderberg electrolysis cells.

(b) CO_2 emissions from anode and cathode baking.

(c) CF_4 and C_2F_6 emissions for anode effects.

(d) CO_2 emissions from green coke calcination.

(e) SF_6 emissions from cover gas consumption.

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

(g) Annual aluminum production.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO_2 emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} [NCC \times MP \times \frac{(100 - S_a - Ash_a - Imp_a)}{100} \times 3.664]_i$$ **Equation 70-1**

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
NCC	=	Net anode consumption per metric ton of aluminum for month i (metric ton/ metric ton aluminum).
MP	=	Aluminum production for month i (metric ton).
S_a	=	Sulfur content in baked anodes for month i (wt %).
Ash_a	=	Ash content in baked anodes for month i (wt %).
Imp_a	=	Content of fluorine and other impurities in baked anodes for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\begin{array}{l} (PC \times MP) - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \\ - \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right) \end{array} \right]_i \times 3.664$$

Equation 70-2

Where:

E_{CO2}	=	Annual CO_2 emissions (metric tons).
PC	=	Paste consumption for month i (metric tons paste/metric ton aluminum).
MP	=	Aluminum production for month i (metric tons).
BSM	=	Emissions of benzene-soluble matter (kilograms benzene-soluble matter/metric ton aluminum).
BC	=	Average binder (pitch) content in paste for month i (wt %).
S_p	=	Sulfur content in pitch for month i (wt %).
Ash_p	=	Ash content in pitch (wt %).
H_p	=	Hydrogen content in pitch (wt %).
S_c	=	Sulfur content in calcinated coke (wt %).
Ash_c	=	Ash content in calcinated coke (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(b) If anode or cathode baking is performed onsite, calculate CO_2 emissions as specified in paragraphs (b)(1) or (2) as applicable. Total emissions as specified in paragraph (b)(3) if both (b)(1) and (2) are applicable.

(1) Calculate CO_2 emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc} - Imp}{100} \right)_i \times 3.664$$

Equation 70-3

Where:

EC_{CO2}	=	Annual CO_2 emissions (metric tons pre year).
PCC	=	Packing coke consumption per metric ton of baked anode for month i (metric tons coke/metric ton anodes).
BAP	=	Baked anode production for month i (metric tons).
Ash_{pc}	=	Ash content in packing coke for month i (wt %).
S_{pc}	=	Sulfur content in packing coke for month i (wt %).
Imp	=	Content of other impurities for month i (wt %).
3.664	=	Conversion factor from carbon to CO_2.

(2) Calculate CO_2 emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664$$ **Equation 70-4**

Where:

EP_{CO2} = CO_2 emissions (metric tons pre year).
GAW = Green anode consumption for month i (metric tons).
BAP = Baked anode production for month i (metric tons).
H_p = Hydrogen content in pitch for moth i (wt %).
PC = Pitch content in green anode for month i (wt %).
RT = Recovered tar for month i (metric tons).
3.664 = Conversion factor from carbon to CO_2.

(3) Calculate total CO_2 emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO2} + EP_{CO2}$$ **Equation 70-5**

Where:

$E_{anodebaking}$ =Total annual CO_2 emissions from anode baking (metric tons).

EC_{CO2} = Annual CO_2 emissions from packing coke (metric tons).

EP_{CO2} = Annual CO_2 emissions from pitch coking (metric tons).

(c) Calculate CF_4 and C_2F_6 emissions from anode effects for each pot line using either the Slope Method in paragraph (c)(1) or the Pechiney Method in paragraph (c)(2).

(1) **Slope Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-6.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n} [slope_{CF_4,C_2F_6} \times AEF \times AED \times MP]_i$$ **Equation 70-6**

Where:

$E_{CF4, C2F6}$ = Annual emissions of CF_4 or C_2F_6 (metric tons/yr).
$slope_{CF4, C2F6}$ = Measured slope coefficient ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/[anode effect minutes/pot-days]).
AEF = Anode effect frequency (number of anode effects per pot per day).
AED = Anode effect duration (minutes per anode effect).
MP = Aluminum production per day (metric tons).
n = Number of operating days per year.

(2) **Pechiney Method:** Calculate the CF_4 and C_2F_6 emissions using Equation 70-7.

$$E_{CF_4,C_2F_6} = \sum_{i=1}^{n} [Over-voltage \quad coefficient_{CF_4,C_2F_6} \times \frac{AEO}{CE} \times MP]_i$$ **Equation 70-8**

Where:

$Emission_{CF4, C2F6}$	=	Emissions of CF_4 or C_2F_6 (metric tons/yr).
Over-voltage $coefficient_{CF4, C2F6}$	=	Experimentally measured ([Metric tons of CF_4 or C_2F_6 /metric ton Aluminum]/mV).
AEO	=	Anode effect over-voltage (millivolts per pot per day).
CE	=	Current efficiency of aluminum production process, expressed as a fraction.
MP	=	Aluminum production per day (metric tons).
n	=	Number of operating days per year.

(d) Calculate CO_2 emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_2O_{gc} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100} \right] \times 3.664 \right]_i + \left[GC \times 0.035 \times \frac{44}{16} \right]_i$$ **Equation 70-9**

Where:

E_{CO2}	=	CO_2 emissions (metric tons pre year).
GC	=	Green coke feed for month i (metric tons).
H_2O_{gc}	=	Humidity in green coke feed for month i (wt %).
V_{gc}	=	Volatiles in green coke feed for month i (wt %).
S_{gc}	=	Sulfur content in green coke feed in month i (wt %).
S_{cc}	=	Sulfur content in calcinated coke in month i (wt %).
CC	=	Calcinated coke produced in month i (metric tons).
UCC	=	Under-calcinated coke produced in month i (metric tons).
DE	=	Coke dust emissions for month i (metric tons).
3.664	=	Conversion factor from carbon to CO_2.
0.035	=	Assumed CH_4 and tar content in coke volatiles, contributing to CO_2 emissions.
44/16	=	Conversion factor from methane to CO_2.

(e) Calculate SF_6 emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF_6 emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped}$$ **Equation 70-10**

Where:

E_{SF6}	=	SF_6 emissions from cover gas (metric tons).

$S_{Purchased}$ = Quantity of SF_6 purchased (metric tons).
$S_{Shipped}$ = Quantity of SF_6 shipped offsite (metric tons).
$S_{Inv\text{-}Begin}$ = Quantity of SF_6 in storage at the beginning of the year, (metric tons).
$S_{Inv\text{-}End}$ = Quantity of SF_6 in storage at the end of the year (metric tons).

(2) Calculate the annual SF_6 emissions using Equation 70-11 and direct measurement of the SF6 input to electrolysis cells and the SF6 waste gases collected and transferred off-site:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \qquad \textbf{Equation 70-11}$$

Where:
E_{SF6} = SF_6 emissions from cover gas (metric tons).
$Q_{in;put}$ = Quantity of SF_6 input to the electrolysis cell for month i (metric tons).
C_{Input} = Concentration of SF_6 input to the electrolysis cell for month i (metric tons).
Q_{Output} = Quantity of SF_6 gas collected during month i (if applicable) (metric tons).
C_{Output} = Concentration of SF_6 gas collected and sent off-site during month i (metric tons).

§ WCI.74 Monitoring Requirements

(a) Except as specified in paragraphs (b) through (c) of this section, all parameters must be measured monthly.

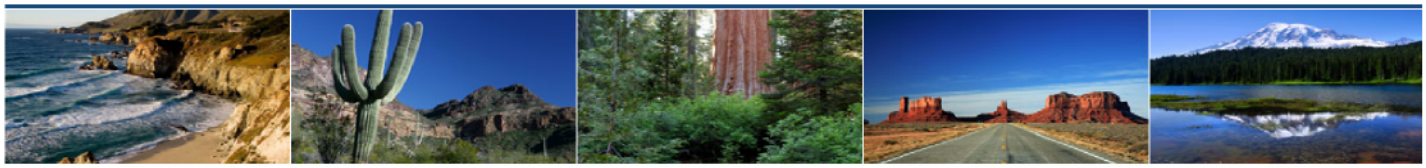
(b) Conduct performance tests once every 36 months to determine the slope or Pechiney coefficients for each pot line using the *Protocol for Measurement of Tetrafluoromethane and Hexafluoroethane Emissions from Primary Aluminum Production*, U.S. Environmental Protection Agency and International Aluminum Institute. April 2008. The test must be repeat whenever:

(1) Thirty-six months have passed since the last measurements;

(2) A change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine; or

(3) Changes occur in the distribution or duration of anode effects (e.g. when the percentage of manual kills changes or if, over time, the number of anode effects decreases and results in a fewer number of longer anode effects) or, for Rio Tinto Alcan control technology, when the algorithm for bridge movements and anode effect overvoltage accounting changes.

(c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF_6 emissions from cover gas consumption, you must measure the quantity of SF_6 gas input to the electrolysis cell month and the quantity and SF_6 concentration of any waste gas collected and sent off-site.



§ WCI.90 CEMENT MANUFACTURING

§ WCI.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

§ WCI.92 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from calcination (metric tons) and the following information:

(1) Plant specific clinker emission factor (kg CO_2/metric ton clinker).

(A) Quantity of clinker produced (metric tons).

(B) Total lime (CaO) content of clinker (wt. fraction).

(C) Total magnesium Oxide (MgO) content of clinker (wt. fraction).

(D) Total carbonate (CO_2) content of clinker (wt. fraction).

(2) Cement kiln dust (CKD) emission factor (kg CO_2/metric ton CKD discarded).

(A) Plant specific CKD calcination rate (unitless ratio).

(B) Quantity of CKD discarded (metric tons).

(c) CO_2 process emissions from organic carbon oxidation (metric tons) and the following information:

(1) Amount of raw material consumed in the report year (metric tons).
(2) Organic carbon content of raw material (wt. fraction).

(d) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (metric tons).

(e) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(f) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO_2. Cement plants that measure CO_2 emissions using CEMS shall report fuel usage by fuel type for kilns.

(g) Operators of cement plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.50.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

(a) Determine CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Use a continuous emissions monitoring system (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$CO_2 \text{ process} = CO_2 \text{ calcination} + CO_2 \text{ raw material} \qquad \textbf{Equation 90-0}$$

(1) Calcination Emissions. Calculate CO_2 process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$CO_{2-C} = \sum_{i=1}^{12} [(Cli) \times (EF_{Cli})] + [(Q_{CKD}) \times (EF_{CKD})] \qquad \textbf{Equation 90-1}$$

Where:

CO_{2-C}	=	CO_2 emissions from calcination, metric tones.
Cli	=	Monthly quantity of clinker produced, metric tons.
EF_{Cli}	=	Monthly clinker emission factor, metric tons CO_2/metric ton clinker computed as specified in paragraph (b)(1)(A) of this section.
Q_{CKD}	=	Monthly quantity CKD discarded (i.e., not recycled to the kiln), metric tons.
EF_{CKD}	=	Monthly CKD emission factor, computed as specified in paragraph (b)(1)(B) of this section.

(A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each report year based on monthly measurements of the weight fraction of CaO, MgO and CO_2 (carbonate) content in the clinker and using Equation 90-2, which assumes all carbonate remaining in the clinker is associated with the calcium.

$$EF_{Cli} = [(CaO\ content - \frac{CO2\ Content}{Molecular\ ratio\ CO2/CaO}) \times Molecular\ ratio\ of\ CO_2/CaO] + [(MgO\ Content) \times Molecular\ ratio\ of\ CO_2/MgO] \qquad \textbf{Equation 90-2}$$

Where:

CaO Content (by weight)	=	Total CaO content of Clinker (including calcined and uncalcined) (wt. fraction).
CO_2 Content (by weight)	=	Total CO_2 content of Clinker (wt. fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Clinker (including calcined and uncalcined) (wt. fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on monthly sampling. The CKD emission factor shall be calculated using Equation 90-3 and a plant-specific CKD calcination rate as specified in Equation 90-4.

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1 + EF_{Cli}} \times d}{1 - \left(\frac{EF_{Cli}}{1 + EF_{Cli}} \times d\right)}$$ **Equation 90-3**

Where:

EF_{CKD}	=	Monthly CKD emission factor, kg CO_2/metric ton CKD discarded.
EF_{Cli}	=	Clinker emission factor, determined according to Equation 90-2.
d	=	CKD calcination rate, determined according to Equation 90-4.

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}}$$ **Equation 90-4**

Where:

d	=	CKD calcination rate (unitless ratio).
fCO_{2CKD}	=	Weight fraction of carbonate CO_2 in the CKD.
fCO_{2RM}	=	Weight fraction of carbonate CO_2 in the raw material.

(2) Organic Carbon Oxidation Emissions. Calculate CO_2 process emissions from the total organic content in raw materials by using Equation 90-5.

$$CO_{2-RM} = TOC_{RM} \times RM \times 3.664$$ **Equation 90-5**

Where:

$CO_{2\text{-}RM}$	=	CO_2 emissions from raw material oxidation, metric tons.
TOC_{RM}	=	Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(c) or using a default of 0.002 (0.2%).
RM	=	Amount of raw material consumed (metric tons/yr).
3.664	=	The CO_2 to carbon molar ratio.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion following the calculation methods specified in WCI.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a). "Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

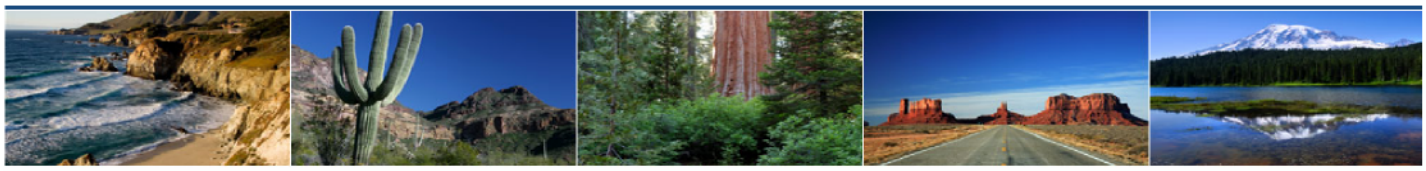
(a) Determine the plant-specific weight fractions of total CaO, total MgO, total carbonate CO_2 in clinker using ASTM C114-07. Determine the weight fraction of carbonate CO_2 in the CKD and the weight fraction of carbonate CO_2 in the raw material using ASTM C114-07. The monitoring must be conducted monthly from clinker and CKD samples drawn from bulk storage.

(b) If not using the default value of 0.002 for TOC_{RM} in Equation 90-5, the total organic carbon contents of raw materials must be determined annually using ASTM Method C114-07. The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.

(c) The quantity of clinker produced must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) The quantity of CKD discarded must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(e) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.



§ WCI.100 COAL STORAGE

§ WCI.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive CH_4 emissions. Within natural coal deposits, CH_4 is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH_4 to the atmosphere; adsorbed CH_4 is also released until the CH_4 in the coal reaches equilibrium with the surrounding atmospheric conditions.

§ WCI.102 Greenhouse Gas Reporting Requirements

The emissions data report shall include the following information at the facility level:

(a) Annual greenhouse gas emissions in metric tons, reported as follows:

  (1) Total CH_4 emissions.

(b) Annual coal purchases (tons for U.S.; metric tons for Canada).

(c) Source of coal purchases:

  (1) Coal basin.

  (2) State/province.

  (3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH_4 Emissions

Note that this methodology for calculation of methane emissions uses emission factors for post-mining operations including all processes occurring after mining at the coal deposit and prior to combustion (e.g., preparation, handling, processing, transportation, storage, etc.) even though coal storage piles are only a subset of the overall post-mining operations. This follows the approach in the California Climate Action Registry, attributing all post-mining fugitive methane emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility.

Calculate fugitive CH_4 emissions from coal storage piles as specified under paragraph (a), (b), or (c) of this section.

(a) For coal purchased from U.S. sources, calculate fugitive CH_4 emissions using Equation 100-1 (English) and Table 100-1, or Equation 100-1 (Metric) and Table 100-2.

(b) For coal purchased from Canadian sources, calculate fugitive CH_4 emissions using Equation 100-1 (Metric) and Table 100-3.

(c) For coal purchased from non-U.S. and non-Canadian sources, owners or operators should use either WCI.103(a) or WCI.103(b), whichever is the most applicable. This chosen approach is subject to approval by [*the jurisdiction*].

$$CH_4 = \sum_i \left(PC_i \times EF_i\right) \times 0.04228 / 2{,}204.6$$ **Equation 100-1 (English Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i* (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 (scf CH_4 per ton of coal);
0.04228	=	Methane conversion factor to convert scf to lbs;
2,204.6	=	Factor to convert lbs to metric tons.

$$CH_4 = \sum_i \left(PC_i \times EF_i\right) \times 0.6772 / 1{,}000$$ **Equation 100-1 (Metric Units)**

Where:

CH_4	=	Fugitive emissions from coal storage piles for each coal category *i*, (metric tons CH_4 per year);
PC_i	=	Purchased coal for each coal category *i* (metric tons per year);
EF_i	=	Default CH_4 emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-2 or Table 100-3 (m^3 CH_4 per metric ton of coal);
0.6772	=	Methane conversion factor to convert m^3 to kg;
1,000	=	Factor to convert kg to metric tons.

§ WCI.104 Sampling, Analysis, and Measurement Requirements

(a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-2. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987

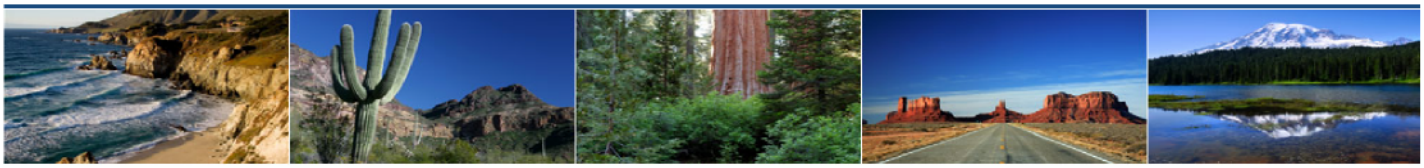
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH_4 Emission Factors (ft^3 per Short Ton; converted to m^3 per metric ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

Table 100-3. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 m^3 per Metric Ton)

Coal Origin		Coal Mine Type	
Province	**Coalfield**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923

Source: *Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options*. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Darmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), , but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).



§ WCI.130 HYDROGEN PRODUCTION

§ WCI.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

§ WCI.132 Greenhouse Gas Reporting Requirements

For each facility, the annual emissions report must contain the following information:

(a) Process CO_2 Emissions. The CO_2 process emissions from the hydrogen produced process.

(b) Feedstock Consumption (if estimating emissions using mass balance approach in WCI.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(c) Production. Annual hydrogen produced.

(d) Stationary Combustion Units. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO_2 process emissions using the methods in paragraphs (a) or (b) of this section.

(a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO_2 process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.20.

(b) Feedstock Material Balance. The owner or operator may calculate CO_2 process emissions using the following method. The factor S shall be used only for CO_2 and/or CH_4 emissions that are calculated and reported using applicable methods specified in this regulation. For example, carbon species in uncoverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO_2 and/or CH_4 emissions are reported using other methods in this regulation.

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[(FS_j * CF_j) - S_j \right] * 3.664 * 0.001$$ **Equation 130-1 (English Units)**

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (scf/day).
CF_j	=	Carbon content of feedstock j (kg C/scf feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CO_2(Feedstock) = \sum_{i=1}^{n} \sum_{j=1}^{y} \left[(FS_j * CF_j) - S_j \right] * 3.664 * 0.001$$ **Equation 130-1 (Metric Units)**

Where:

CO_2 (Feedstock)	=	CO_2 emitted from feedstock (metric tons/year).
n	=	Days of operation per year.
FS_j	=	Feedstock b consumption rate (m^3/day).
CF_j	=	Carbon content of feedstock j (kg C/m^3 feedstock).
y	=	Total number of feedstocks.
S_j	=	Carbon accounted for elsewhere (kg C/day).
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

WCI.134 Sampling, Analysis, and Measurement Requirements

(a) Owners or operators using CEMS to estimate CO_2 emissions shall comply with the monitoring requirements in section WCI.20.

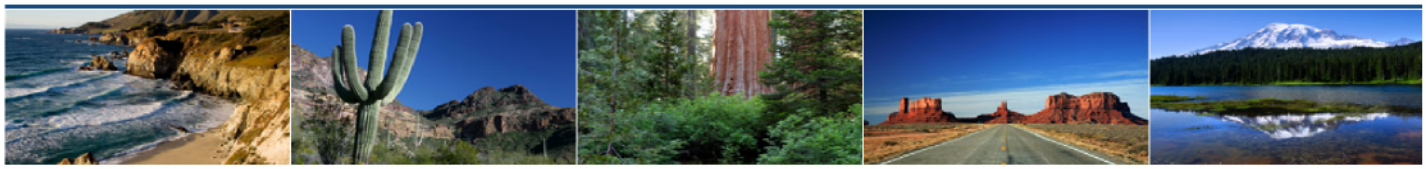
(b) Owners or operators using the method in section WCI.133 (b) shall perform the following monitoring:

(1) The owner or operator shall measure the feedstock consumption rate daily.
(2) The owner or operator shall collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in WCI.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the

feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.

(3) Owners or operators shall measure the hydrogen produced daily.

(4) Owners or operators shall measure the CO_2 and CO collected daily.



§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises four categories: primary facilities that produce both iron and steel, secondary steelmaking facilities, iron production facilities, and offsite production of metallurgical coke. These processes may occur together in an "integrated" facility or they may occur in separate offsite facilities.

§ WCI.152 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2 and CH_4 in metric tons at the facility level.

(b) CO_2 and CH_4 emissions from coke production (metric tons) and the following information:

- (1) Quantity of coking coal consumed in coke production (metric tons)
- (2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production (metric tons)
- (3) Quantity of blast furnace gas consumed in coke production (metric tons)
- (4) Quantity of coke produced (metric tons)
- (5) Quantity of coke oven gas transferred offsite (metric tons)
- (6) Quantity of other coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) transferred offsite (metric tons)
- (7) Carbon content of material inputs and outputs listed in (b)(1) through (b)(6) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(c) CO_2 and CH_4 emissions from iron and steel production (metric tons) and the following information:

- (1) Quantity of coke consumed in iron and steel production (excluding sinter production) (metric tons)
- (2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace (metric tons)
- (3) Quantity of coal directly injected into blast furnace (metric tons)
- (4) Quantity of limestone directly injected into blast furnace (metric tons)
- (5) Quantity of dolomite directly injected into blast furnace (metric tons)
- (6) Quantity of carbon electrodes consumed in EAFs (metric tons)
- (7) Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)

(8) Quantity of other carbonaceous or process material (e.g., sinter, waste plastic, etc.) consumed in iron and steel production (metric tons)

(9) Quantity of coke oven gas consume in blast furnace (metric tons)

(10) Quantity of steel produced (metric tons)

(11) Quantity of iron production not converted to steel (metric tons)

(12) Quantity of blast furnace gas transferred offsite (metric tons)

(13) Carbon content of material inputs and outputs listed in (c)(1) through (c)(12) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(d) Process CO_2 and CH_4 emissions from sinter production (metric tons) and the following information:

(1) Quantity of coke breeze (purchased and produced on-site) used for sinter production (metric tons)

(2) Quantity of coke oven gas consumed in blast furnace in sinter production (metric tons)

(3) Quantity of blast furnace gas consumed in sinter production (metric tons)

(4) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in sinter production (metric tons)

(5) Quantity of sinter off gas transferred offsite (metric tons)

(6) Carbon content of material inputs and outputs listed in (d)(1) through (d)(5) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(e) Process CO_2 and CH_4 emissions from direct reduced iron production (metric tons) and the following information:

(1) Energy from natural gas used in direct reduced iron production (gigajoules [GJ])

(2) Energy from coke breeze used in direct reduced iron production (GJ)

(3) Energy from metallurgical coke used in direct reduced iron production (GJ)

(4) Quantity of direct reduced iron produced (metric tons)

(5) Carbon content of material inputs listed in (e)(1) through (e)(3) (metric tons of C per GJ)

(6) Carbon content of direct reduced iron produced per e(4) (metric tons of C per metric ton of material [equivalent to wt% C/100])

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20.

§ WCI.153 Calculation of CO_2 Emissions

(a) Process CO_2 emissions. Determine process CO_2 emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

[CEMS and mass balance approach are based on IPCC Tier 3 methods.)

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions using the following mass balance approach:

(b) Calculate the coke production CO_2 (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{coke} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

E_{coke}	=	Emissions of CO_2 from coke production (metric tons);
CC	=	Quantity of coking coal (metric tons);
PM_a	=	Quantity of other process material *a* (not included as separate terms), such as natural gas or fuel oil (metric tons);
BG	=	Quantity of blast furnace gas consumed in coke ovens (metric tons);
CO	=	Quantity of coke produced (metric tons)
COG	=	Quantity of coke oven gas transferred offsite (metric tons);
COB_b	=	Quantity of coke oven by-product *b* transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(c) Calculate the iron and steel production CO_2 emissions using Equation 150-2:

$$E_{iron,steel} = \left[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + (DRI \times C_{DRI}) + \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \right] \times 3.664$$

Equation 150-2

Where:

$E_{iron,steel}$	=	Emissions of CO_2 from iron and steel production (metric tons);
CO	=	Quantity of coke consumed (excluding sinter production) (metric tons);
COB_a	=	Quantity of coke oven by-product *a* consumed in blast furnace (metric tons);
CI	=	Quantity of coal directly injected into blast furnace (metric tons);
L	=	Quantity of limestone consumed (metric tons);
D	=	Quantity of dolomite consumed (metric tons);
CE	=	Quantity of carbon electrodes consumed in EAFs (metric tons);
DRI	=	Quantity of direct reduced iron introduced to an EAF or BOF (metric tons)
O_b	=	Quantity of other carbonaceous and process material *b*, such as sinter or waste plastic (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace (metric tons);

S	=	Quantity of steel produced (metric tons);
IP	=	Quantity of iron production not converted to steel (metric tons);
BG	=	Quantity of blast furnace gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(d) Calculate the sinter production CO_2 emissions using Equation 150-3 (if applicable):

$$E_{sinter} = \left[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \right] \times 3.664$$

Equation 150-3

Where:

E_{sinter}	=	Emissions of CO_2 from sinter production (metric tons);
CBR	=	Quantity of purchased and onsite produced coke breeze used for sinter production (metric tons);
COG	=	Quantity of coke oven gas consumed in blast furnace for sinter production (metric tons);
BG	=	Quantity of blast furnace gas consumed for sinter production (metric tons);
PM_a	=	Quantity of other process material *a* consumed for sinter production (not included as separate terms), such as natural gas or fuel oil (metric tons);
SOG	=	Quantity of sinter off gas transferred offsite (metric tons);
C_x	=	Carbon content of material input or output *x* (metric tons C/metric tons of *x*);
3.664	=	Conversion factor from metric tons of C to metric tons of CO_2.

(e) Calculate the direct reduced iron production CO_2 emissions using Equation 150-4 (if applicable):

$$E_{DRI} = \left[(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK}) - (DRI \times C_{DRI}) \right] \times 3.664$$

Equation 150-4

Where:

E_{DRI}	=	Emissions of CO_2 from direct reduced iron production (metric tons);
DRI_{NG}	=	Energy from natural gas used in direct reduced iron production (GJ);
DRI_{BZ}	=	Energy from coke breeze used in direct reduced iron production (GJ);
DRI_{CK}	=	Energy from metallurgical coke used in direct reduced iron production (GJ);
DRI	=	Quantity of direct reduced iron produced (metric tons)
C_{NG}	=	Carbon content of natural gas (metric ton C/GJ);
C_{BZ}	=	Carbon content of coke breeze (metric ton C/GJ);
C_{CK}	=	Carbon content of metallurgical coke (metric ton C/GJ);
C_{DRI}	=	Carbon content of direct reduced iron produced (metric tons of C per metric ton of direct reduced iron)

3.664 = Conversion factor from metric tons of C to metric tons of CO_2.

(f) Calculate the total CO_2 emissions using Equation 150-5:

$$E_{CO2} = E_{coke} + E_{iron,steel} + E_{sinter} + E_{DRI}$$ **Equation 150-5**

Where:

E_{CO2} = Total CO_2 emissions (metric tons);
E_{coke} = Emissions from coke production (metric tons);
$E_{iron,steel}$ = Emissions from iron and steel production (metric tons);
E_{sinter} = Emissions from sinter production (metric tons);
E_{DRI} = Emissions from direct reduced iron production (metric tons).

§ WCI.154 Calculation of CH_4 Emissions

(a) Process CH_4 emissions. Determine process CH_4 emissions as specified under either paragraph (1) or paragraph (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Site-specific emission factors.

§ WCI.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

(a) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from § WCI.25):

(1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02 (Reapproved 2007).

(2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "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 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2007).

(3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006).

(b) By-Product Carbon Content Requirements. Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in the following manner:

[Methodology to be determined.]

(c) Flux Carbon Content Requirements. Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:

(1) For limestone and dolomite, use ASTM C25-06.

(d) Electrode Carbon Content Requirements. Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:

(1) Vendor specifications of carbon content in EAF carbon electrodes.

(e) Finished Product Carbon Content Requirements. Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:

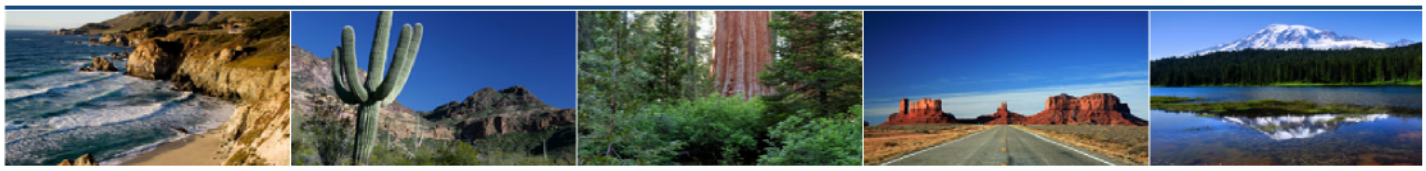
(1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.

(f) Quantity Measurement Requirements. The quantities of process inputs, outputs, and by-products must be determined using the following methods:

(1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

(3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.



§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quick lime (i.e. calcium oxide or calcium-magnesium oxide). Lime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of CO_2, CH_4, and N_2O in metric tons.

(b) CO_2 process emissions from quick lime production (metric tons) and the following information:

(1) For lime production:

(A) The emission factor (kg CO_2/metric ton) for each lime type for each month.

(B) The quantity of lime produced (metric tons) each month.

(C) The calcium oxide (CaO) content (weight fraction) of each lime type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each lime type for each month.

(2) For the production of calcined byproducts and wastes:

(A) The emission factor (kg CO_2/metric ton) for each calcined byproduct/waste type for each month.

(B) The quantity of each type of calcined byproduct/waste type produced each month.

(C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each month.

(D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each month.

(c) CO_2, CH_4, and N_2O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (metric tons).

(d) CO_2, CH_4, and N_2O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (metric tons).

(e) If a continuous emissions monitor is used to measure CO_2 emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO_2.

(f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed at WCI.1(a), including but not limited to the following:

(1) Coal fuel storage as specified in WCI.100.

(2) Electricity generating as specified in WCI.40.

(3) Cogeneration systems as specified in WCI.42(f).

§ WCI.173 Calculation of greenhouse Gas Emissions from Kilns

(a) Determine process CO_2 emissions as specified under either paragraph (a)(1) or (a)(2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).

(2) Calculate the sum of CO_2 process emissions from kilns and CO_2 fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section**.**

(b) Process CO_2 Emissions Calculation Methodology. Calculate total CO_2 process emissions as the sum of emissions from quick lime production, using the method specified in paragraph (b)(1) of this section.

(1) CO_2 Process Emissions. Calculate CO_2 emissions from quick lime production from each kiln using Equation 170-1 and a plant-specific quick lime emission factor and a plant-specific lime kiln dust (LKD) emission factor as specified in this section.

$$CO_2 = \sum_{i}^{12}\sum_{j}^{y}\left[QL_{ij} \times EF_{QL_{ij}}\right] + \sum_{k}^{4}\sum_{l}^{z}\left[LKD_{kl} \times EF_{LKD_{kl}}\right] \qquad \textbf{Equation 170-1}$$

Where:

CO_2	=	CO_2 emissions in metric tons/yr.
QL	=	Monthly Quantity of quick lime produced, metric tons.
EF_{QL}	=	Monthly Quick lime emission factor, metric tons CO_2/metric ton quick lime computed as specified in paragraph (b)(2) of this section.
LKD	=	Quarterly Quantity of calcined byproduct/waste, including LKD, scrubber sludge and other calcined wastes, produced annually, metric tons.
EF_{LKD}	=	Quarterly calcined byproduct/waste emission factor, computed as specified in paragraph (b)(3) of this section.
i	=	Month.
j	=	Lime type.
k	=	Quarter.
l	=	Calcined byproduct/waste type.
y	=	Total number of lime types.
z	=	Total number of calcined byproduct/waste types.

(2) Monthly Quick Lime Emission Factor. Calculate a plant-specific quick lime emission factor (EF_{QL}) for each kiln and month based on the percent of measured CaO and MgO content in quick lime and using Equation 170-2.

$$EF_{QL} = (CaO\ \ content \times Molecular\ \ ratio\ \ of\ CO_2 / CaO) + (MgO\ \ content \times Molecular\ \ ratio\ \ CO_2 / MgO)$$

Equation 170-2

Where:

CaO Content (by weight)	=	Total CaO content of Quick Lime.
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of Quick Lime.
Molecular ratio of CO_2/MgO	=	1.092.

(3) Monthly LKD Emission Factor. If LKD is generated and not recycled back to the kiln, then calculate a plant-specific LKD emission factor for each kiln and month. The LKD emission factor shall be calculated using Equation 170-3.

$$EF_{LKD} = [(CaO\ \ content - uncalcined\ \ CaO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / CaO] + [(MgO\ \ Content - uncalcined\ \ MgO) \times Molecular\ \ ratio\ \ of\ \ CO_2 / MgO]$$

Equation 170-3

Where:

EF_{LKD}	=	LKD emission factor.
CaO Content (by weight)	=	Total CaO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined CaO (by weight)	=	Uncalcined CaO content of LKD (weight fraction).
Molecular ratio of CO_2/CaO	=	0.785.
MgO Content (by weight)	=	Total MgO content of LKD, including calcined and uncalcined (weight fraction).
Uncalcined MgO	=	Uncalcined MgO content of LKD (weight fraction).
Molecular ratio of CO_2/MgO	=	1.092.

(c) Fuel Combustion Emissions in Kilns. Calculate CO_2, CH_4, and N_2O emissions from stationary fuel combustion emissions following the calculation methods specified in WCI.20. Operators of lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO_2 emissions from fossil fuels using the emission factor methodology in WCI.23(a).

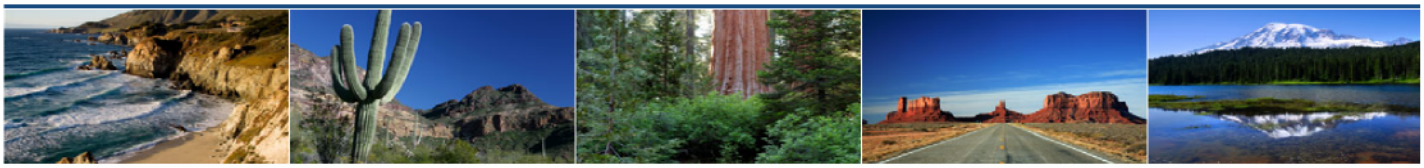
"Pure" means that the biomass-derived fuels account for 97 percent of the total amount of carbon in the fuels burned.

§ WCI.174 Sampling, Analysis, and Measurement Requirements

Determine the chemical composition (percent total CaO and percent total MgO) of each lime type and each calcined byproduct/waste type by laboratory analysis on a monthly basis for each lime type, and a quarterly basis for each calcined byproduct/waste type. This determination must be performed according to ASTM Methods C25, C1301 or C1271. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct/waste type produced during the quarter.

(a) The quantity of lime produced and sold is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each lime type. The inventory period shall be annual at a minimum.

(b) The quantity of calcined byproduct/waste sold is to be estimated quarterly using direct measurements (such as rail and truck scales) of byproduct/waste sales for each byproduct/waste type, and adjusted to take into account the difference in beginning- and end-of-period inventories of each calcined byproduct/waste type. The inventory period shall be annual at a minimum. The quantity of calcined byproduct/waste not sold is to be determined no less often than quarterly for each calcined/byproduct waste type using direct measurements (such as rail and truck scales), or a calcined byproduct/waste generation rate (i.e. calcined byproduct produced as a factor of lime production).



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

A petroleum refinery consists of all processes used to produce 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.

WCI.202 Greenhouse Gas Reporting Requirements

The annual emissions report must contain the following information reported at the facility level:

(a) Catalyst Regeneration. Report CO_2 emissions.

(b) Process Vents. Report CO_2, N_2O, and CH_4 emissions.

(c) Asphalt Production. Report CO_2 and CH_4 emissions.

(d) Sulfur Recovery. Report CO_2 emissions.

(e) Stationary Combustion Units Other than Flares and Control Devices. Report CO_2, N_2O, and CH_4 emissions as specified in WCI.23.

(f) Flares and Other Control Devices. Report CO_2, N_2O, and CH_4 emissions.

(g) Above-Ground Storage Tanks. Report CH_4 emissions.

(h) Wastewater Treatment. Report CH_4 and N_2O emissions.

(i) Oil-Water Separators. Report CH_4 emissions.

(j) Equipment Leaks. Report CH_4 emissions.

(k) Feedstock Consumption: Report feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

(l) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

WCI.203 Calculation of Greenhouse Gas Emissions

The operator shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

(a) Catalyst Regeneration. For units equipped with CEMS, operators shall calculate CO_2 process emissions resulting from catalyst regeneration using CEMS in accordance with WCI.20. In

the absence of CEMS data, the operator shall use the methods in paragraphs (a)(1) through (a)(3).

(1) The operator shall calculate process CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$CO_2 = \sum_{d=1}^{n} CR_d \times CF \times 3.664 \times 0.001$$ **Equation 200-1**

Where:

CO_2	=	CO_2 emissions (metric tons/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
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

$$CR_d = \left[\sum_{i=1}^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})]_i \right] / n$$

Equation 200-2

Where:

CR_d	=	daily average coke burn rate (kg/day or lb/day)
K_1, K_2, K_3	=	material balance and conversion factors (K_1, K_2, and K_3 from Table 200-1
n	=	number of hours per day
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)
$\%CO_2$	=	CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$	=	O_2 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

$$Q_r = (79 \times Q_a + (100 - \%Q_{xy}) \times Q_{oxy}) / (100 - \%CO_2 - \%CO - \%O_2)$$ **Equation 200-3**

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)
$\%Q_{xy}$	=	oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)
$\%CO_2$	=	carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO 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

(2) The operator shall calculate process CO_2 emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$CO_2 = \sum_{i=1}^{n} CRR \times \left(CF_{spent} - CF_{regen}\right)_i \times 3.664 \times 0.001$$ **Equation 200-4**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CRR	=	mass of catalyst regenerated (mass/regeneration cycle)
CF_{spent}	=	weight fraction carbon on spent catalyst
CF_{regen}	=	weight fraction carbon on regenerated catalyst (default = 0)
n	=	number of regeneration cycles
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator shall calculate process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$CO_2 = CC_{irc} \times (CF_{spent} - CF_{regen}) \times H \times 3.664$$ **Equation 200-5**

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
CC_{irc}	=	average catalyst regeneration rate (metric tons/hr)
CF_{spent}	=	weight carbon fraction on spent catalyst
CF_{regen}	=	weight carbon fraction on regenerated catalyst (default = 0)
H	=	hours regenerator was operational (hr/yr)
3.664	=	ratio of molecular weights, CO_2 to carbon

(b) Process Vents. Except for process emissions reported under other requirements of this regulation, the operator shall calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 200-6.

Equation 200-6

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001$$

Where:

E_x	=	emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4
VR_i	=	vent rate for venting event i (scf/unit time or m^3/unit time)
F_{xi}	=	molar fraction of x in vent gas stream during event i
MW_x	=	molecular weight of x (kg/kg-mole)
MVC	=	molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
VT_i	=	time duration of venting event i
n	=	number of venting events
0.001	=	conversion factor – kg to metric tons

(c) Asphalt Production. The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

Equation 200-7

$$CH_4 = (M_A \times EF \times MW_{CH4} / MVC) \times (1 - DE) \times 0.001$$

Where:

CH_4	=	CH_4 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)
MVC	=	molar volume conversion factor (849.5 scf/kg- mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001	=	conversion factor – kg to metric tons

Equation 200-8

$$CO_2 = (M_A \times EF \times MW_{CH4} / MVC) \times DE \times 2.743 \times 0.001$$

Where:

CO_2	=	CO_2 emissions (metric tons/yr)
M_A	=	mass of asphalt blown (10^3 bbl/yr)
EF	=	emission factor (EF = 2,555 scf $CH_4/10^3$ bbl or 72.35 m^3 $CH_4/10^3$ bbl)
MW_{CH4}	=	CH_4 molecular weight (16.04 kg/kg-mole)

MVC	=	molar volume conversion factor (849.5 scf/kg mole, for STP of 20°C and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
DE	=	control measure destruction efficiency (DE = 98% expressed as 0.98)
2.743	=	CH_4 to CO_2 conversion factor
0.001	=	conversion factor – kg to metric tons

(d) Sulfur Recovery. The operator shall calculate CO_2 process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value approved by [*insert jurisdiction*] and derived from source tests conducted at least once per calendar year under the supervision of [*insert jurisdiction*].

$$CO_2 = FR \times MW_{CO2} / MVC \times MF \times 0.001$$ **Equation 200-9**

Where:

CO_2	=	emissions of CO_2 (metric tons/yr)
FR	=	volumetric flow rate of acid gas to SRU (scf/year or m^3/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°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
MF	=	molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001	=	conversion factor – kg to metric tons

(e) Flares and Other Control Devices.

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections WCI.20.

(2) The operator shall calculate and report CO_2 emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Use Equation 200-10 if the flare is equipped with a continuous flow and high heat value monitors:

$$CO_2 = Flare_N \times HHV \times (0.001 \times EmF)$$ **Equation 200-10**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
HHV	=	High heat value for refinery fuel or flare gas (MMBtu/MMscf or J/m^3)
0.001	=	conversion factor – kg to metric tons
EmF	=	default CO_2 emission factor (60 kg CO_2/MMBtu or 5.7 kg/kJ)

(B) Use Equation 200-11 if the flare is equipped with a continuous flow and carbon content monitors:

$$CO_2 = Flare_N \times CC_N \times (MW_n / MVC) \times 3.664 \times 0.001$$ **Equation 200-11**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
$Flare_N$	=	volume of flare gas (m^3/yr)
CC_N	=	carbon content of flare gas (kg of carbon/kg of fuel)
MW_N	=	molecular weight of flare gas
MVC	=	molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

a. Use Equation 200-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor:

$$CO_2 = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$ **Equation 200-12**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
RFT	=	refinery feed input (m^3/yr)
EF_{NMHC}	=	non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 throughput)
CF_{NMHC}	=	conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(3) The operator who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO_2 emissions using Equation 200-13. The operator shall determine CC_A and MW_A quarterly using methods specified in section WCI.20 and use the annual average values of CC_A and MW_A to calculate CO_2 emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001$$ **Equation 200-13**

Where:

CO_2	=	CO_2 emissions (metric tons/year)
GV_A	=	volume of gas A destroyed annually (scf/year or m^3/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°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere or 24.06 m^3/kg-mole for STP of 20°C and 1 atmosphere, or 23.67 m^3/kg-mole for STP of 60°F and 1 atmosphere)
3.664	=	ratio of molecular weights, CO_2 to carbon
0.001	=	conversion factor – kg to metric tons

(f) Storage Tanks. For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the operator shall calculate CH_4 emissions using the U.S. EPA TANKS Model (Version 4.09D). For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:

(1) A default conversion factor of 0.6 (CH_4 = 0.6 * VOC); or
(2) Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology approved by [*insert jurisdiction*].

(g) Wastewater Treatment.

(1) The operator shall calculate CH_4 emissions from wastewater treatment using Equation 200-14.

$$CH_4 = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$ **Equation 200-14**

Where:

CH_4	=	emission of methane (tons/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 (B = 0.25 kg CH_4/kg COD)
MCF	=	methane correction factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	conversion factor – kg to metric tons

(2) The operator shall calculate N_2O emissions from wastewater treatment using Equation 200-15.

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$ **Equation 200-15**

Where:

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

(h) Oil-Water Separators. The operator shall calculate CH_4 emissions from oil-water separators using Equation 200-16. For the CF_{NMHC} conversion factor, operators shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using a sampling and analysis methodology approved by [*jurisdiction*].

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \qquad \textbf{Equation 200-16}$$

Where:

CH_4	=	emission of methane (tons/yr)
EF_{sep}	=	NMHC (non methane hydrocarbon) emission factor (kg/m^3) from Table 200-3.
V_{water}	=	volume of waste water treated by the separator (m^3/yr)
CF_{NMHC}	=	NMHC to CH_4 conversion factor
0.001	=	conversion factor – kg to metric tons

(i) Equipment leaks. The operator shall calculate CH_4 emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:

(1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in Method 3 in CAPCOA (1999) *[or the method in CCME EPC-73E for Canadian jurisdictions]*, which are incorporated by reference in WCI.6. Operators shall conduct screenings at the frequency interval required by *[insert jurisdiction]*. Operators shall measure and record emissions using instrumentation capable of detecting methane.

(2) The VOC emissions shall be calculated using the following methods:

(C) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, operators shall calculate VOC emissions using Equation 200-17:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t \qquad \textbf{Equation 200-17}$$

Where:

E_{VOC-0}	=	zero component VOC emission (kg/screening period)
i	=	component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)

CC_i = number of i components where SV = 0
ZF_{i0} = zero VOC emission factor (kg/hr) for component i from Table 200-5
t = time (hours) since last screening

(D) For leaking components, operators shall calculate VOC emissions using the following methods:

(i) For screening values between background and 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-18.

$$E_{VOCL-C} = \sum_{i=1}^{6}\sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i}\right) \times t$$ **Equation 200-18**

Where:

E_{VOCL-C} = leaking components VOC emissions (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n = number of i components
σ_i = correlation equation coefficient for component type i from Table 200-5
SV_n = screening value for component n
βi = correlation equation exponent for component type i from Table 200-5
t = time (hours) component has been leaking – default value is time from last screening

(ii) For screening values greater than 9,999 ppmv, the operator shall calculate the VOC emissions using Equation 200-19.

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 200-19**

Where:

E_{VOCP} = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i = number of i components pegged over 9,999 ppmv
PF_{iP} = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv from Table 200-5
t = time component has been leaking (hours) – default value is time since last screening

(E) The operator shall calculate CH_4 emissions using Equation 200-20. Operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas), where available, to determine a CF_{VOC} value. The sampling and analysis methodology must be approved

by *[jurisdiction]*. When representative data is not available, operators shall use the default value of 0.6 for CF_{VOC}.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP} \right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 200-20}$$

Where:

CH_4	=	methane emissions (metric tons/year)
n	=	number of screenings/year
E_{VOC-0}	=	zero component VOC emissions (kg/screening period)
E_{VOC-LC}	=	leaking component VOC emissions (kg/screening period)
E_{VOCP}	=	VOC emissions for components pegged over 9,999 ppmv (kg/screening period)
CF_{VOC}	=	VOC to CH_4 conversion factor (default CF_{VOC}=0.6)
0.001	=	conversion factor – kg to metric tons

WCI.204 Sampling, Analysis, and Measurement Requirements

(a) Catalyst Regeneration.

(1) For FCCUs and fluid coking units, the operators shall measure the following parameters:

(A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
(B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
(C) Continuous or weekly periodic measurements of the CO_2, CO and O_2 concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.
(D) Daily determinations of the carbon content of the coke burned.
(E) The number of days of operation.

(2) For periodic catalyst regeneration, the operators shall measure the following parameters.

(A) The mass of catalyst regenerated in each regeneration cycle.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.

(3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the operators shall measure the following parameters.

(A) The hourly catalyst regeneration rate.
(B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
(C) The number of hours of operation.

(b) Process vents. Operators shall measure the following parameters for each process vent.

(1) The vent flow rate for each venting event.
(2) The molar fraction of CO_2, N_2O, and CH_4 in the vent gas stream during each venting event.
(3) The duration of each venting event.

(c) Asphalt Production. Operators shall measure the mass of asphalt blown.

(d) Sulfur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molecular faction value instead of the default factor, the operator shall conduct an annual test of the CO_2 content using methods approved by [insert jurisdiction]. The operator shall submit a test plan to the *[jurisdiction]* for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the [*jurisdiction*].

(e) Flares and Other Control Devices. The operator shall measure the following:

(1) If using the method specified in WCI.203(e)(2)(a), monitor the flow rate and high heat value of the flare gas using continuous monitors.
(2) If using the method specified in WCI.203(e)(2)(b), monitor the flow rate and carbon content of the flare gas using continuous monitors.
(3) If using the method specified in WCI.203(e)(3), monitor the volume of gas destroyed annually (determined to accuracy of ± 7.5%) and the carbon content.

(f) Storage Tanks. The operator shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow meters.

(g) Wastewater Treatment. Operators shall measure the following parameters.

(1) The daily volume of waste water treated.
(2) The quarterly chemical oxygen demand of the wastewater.
(3) The amount of sludge removed and the organic content of the sludge.
(4) The quarterly nitrogen content of the wastewater.

(h) Oil-Water Separators. Operators shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in WCI.2(d).

(i) Equipment Leaks. Operators shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method *[or the method in CCME EPC-73E for Canadian jurisdictions]* and an instrument capable of detecting methane. Operators shall conduct screenings at the frequency interval required by *[jurisdiction]*.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062

Table 200-2. 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 CH_4 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

For CH_4 generation capacity (B) in kg CH_4/kg COD, use default factor of 0.25 kg CH_4/kg COD.

The emission factor for N_2O from discharged wastewater (EF_{N2O}) is 0.005 kg N_2O-N/kg-N.

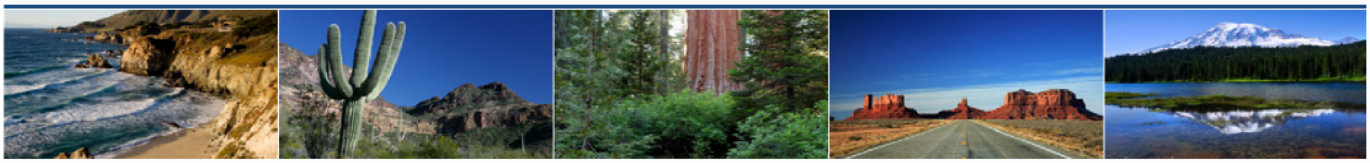
MCF = methane conversion factor (the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m^3).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	**Emission factor (EF_{sep})[a] kg NMHC/m^3 wastewater treated**
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF[b] of IAF[c] - uncovered	4.00e-03[d]
DAF or IAF - covered	1.20e-04[d]
DAF or Iaf – covered and connected to a destruction device	0

[a] EFs do not include ethane
[b] DAF = dissolved air flotation type
[c] IAF = induced air flotation device
[d] EFs for these types of separators apply where they are installed as secondary treatment systems

Table 200-4. Data for Preparing the Asphalt Chemical Database	
Parameter	**Database Entry**
Liquid Molecular Weight	**1000**
Vapor Molecular Weight	**105**
Liquid Density (lb/gal. at 60 ^{o}F)	**8.0925**
Antoine's Equation Constants (using K)	**A = 75350.06**
	B = 9.00346

Table 200-5. 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**
	Zf_{i0}	**σ_i and β_i**	**(SV > 9,999) PF_{iP-10}**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033



§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual biogenic CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213.

(b) Annual fossil CO_2 process emissions from all recovery furnaces and kilns in metric tons, as specified in WCI.213

(c) CO_2, N_2O, and CH_4 emissions from stationary combustion units in metric tons, as specified in WCI.23.

(d) Annual consumption of carbonate in metric tons.

(e) Annual black liquor production in metric tons.

(f) Under consideration: Annual N_2O, and CH_4 emissions from onsite wastewater treatment plants in metric tons, as specified in WCI.200(g).

§ WCI.213 Calculation of GHG Emissions

(a) Calculate biogenic CO_2 process emissions from recovery furnaces and kilns using Equation 210-1:

$$CO_{2,biogenic} = \sum_{i=1}^{12} (BL_i \times CC_i \times 3.664) \qquad \textbf{Equation 210-1}$$

Where:

$CO_{2,\ biogenic}$	=	Biogenic CO_2 process emissions from recovery furnaces and kilns (metric tons/year).
BL_i	=	Black liquor produced in month i (metric tons/month).
CC_i	=	Carbon content of the black liquor (weight fraction)..
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(b) Calculate fossil CO_2 process emissions from make-up carbonates used in the recovery furnace and kiln system using Equation 210-2:

$$CO_{2,\,fossil} = \sum_{i=1}^{12} \left(\sum_{j=1}^{n} RM_j \times EF_j \right)_i \qquad \textbf{Equation 210-2}$$

Where:

$CO_{2,\,fossil}$	=	Fossil CO_2 process emissions from recovery furnace and kiln systems (metric tons/year).
RM_j	=	Amount of make-up carbonate j consumed in month i (metric tons/month).
EF_j	=	Carbonate content of carbonate material j for month i (weight fraction as CO_2).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

§ WCI.214 Monitoring Requirements

(a) Measure the quantity of black liquor produced each month.

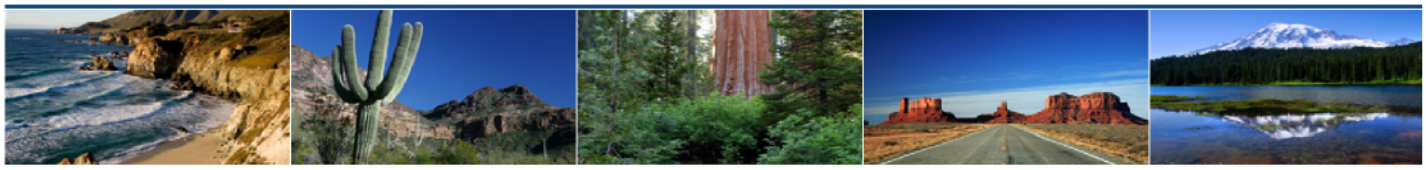
(b) Collect monthly samples of black liquor and analyze each sample for carbon content using ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal.

(c) For the amount of carbonate material consumed, either use records provided by the material supplier or monitor carbonate material consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

(d) For the carbonate content of each carbonate material consumed, either use carbonate content data provided by the supplier, the appropriate default factor from Table 1, or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM Methods C25, C1301 or C1271.

Table 1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species.

Carbonate	Mineral Name	Formula Weight	Emission Factor (metric tons CO_2/metric ton Carbonate)
$CaCO_3$	Calcite	100.1	0.4397
$CaMg(CO_3)_2$	Dolomite	184.4	0.4773
Na_2CO_3	Soda ash (sodium carbonate)	106.0	0.4149



§ WCI.230 SODA ASH PRODUCTION

§ WCI.231 Source Category Definition

The soda ash production source category consists of facilities that produce soda ash by calcining sodium carbonate bearing ore or brine.

§ WCI.232 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) Annual CO_2 process emissions from all soda ash calcining kilns combined, as specified in WCI.233 (metric tons).

(b) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the calcining kilns, as specified in WCI.20 (metric tons).

(c) Annual consumption of trona ore or sodium carbonate-rich brine (metric tons).

(d) Annual soda ash production (metric tons).

(e) Annual mass of waste material output from calcining kilns (metric tons).

(f) For plants recycling the CO_2 generated from calcination for use in the carbonation towers, report annual CO_2 recycled within the process (metric tons).

§ WCI.233 Calculation of GHG Emissions

(a) You must calculate CO_2 emissions using the methods in either paragraphs (a)(1) or (a)(2) of this section.

(1) **Continuous Emission Monitoring Systems.** The owner or operator may measure CO_2 emissions using CEMS, as specified WCI.23(d).

(2) **Feedstock Material Balance.** The owner or operator may estimate CO_2 process emissions using Equation 230-1 and the measured carbon content and feedstock input of the trona ore or carbonate-rich brine.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cs_j \times Ts_j) - (Cw_j \times Tw_j)] \qquad \textbf{Equation 230-1}$$

Where:

CO_2	=	CO_2 process emissions from soda ash production (metric tons/year).
Ci_j	=	Carbon content of feedstock (trona ore or carbonate-rich brine) input (percent by weight, expressed as a decimal fraction).
Ti_j	=	Weight of feedstock (trona ore or carbonate-rich brine) input (metric tons/month).
Cs_j	=	Carbon content of soda ash output (percent by weight, expressed as a decimal fraction).
Ts_j	=	Weight of soda ash output (metric tons/month).
Cw_j	=	Carbon content of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (percent by weight, expressed as a decimal fraction).
Tw_j	=	Weight of waste material output from the kiln (i.e. kiln dust collected in control devices and not combined with the soda ash product) (metric tons/month).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

(b) If you operate a soda ash production facility in which CO_2 generated in calcining kilns is recycled to carbonate towers for brine pre-treatment, you must calculate recycled CO_2 using Equation 230-2.

$$CO_2 = \sum_{j=1}^{12} (3.664)[(Ci_j \times Ti_j) - (Cb_j \times Tb_j)] \qquad \textbf{Equation 230-2}$$

Where:

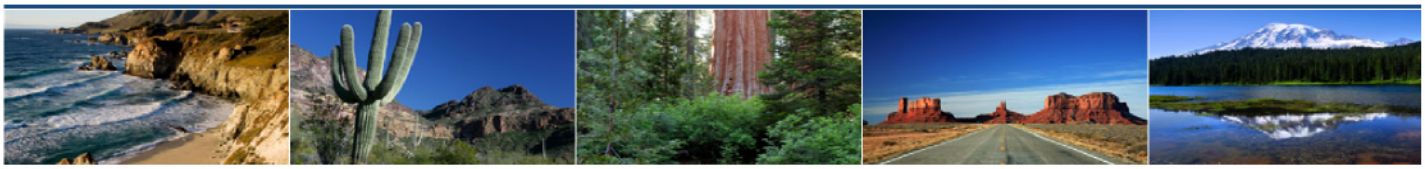
CO_2	=	Recycled CO_2 from the ore calcining kiln (metric tons/year).
Ci_j	=	Carbon content of bicarbonate kiln input (percent by weight, expressed as a decimal fraction).
Ti_j	=	Weight of bicarbonate kiln input (metric tons/month).
Cb_j	=	Carbon content of sodium carbonate-rich brine input (percent by weight, expressed as a decimal fraction).
Tb_j	=	Weight of sodium carbonate-rich brine input (metric tons/month).
3.664	=	Ratio of molecular weights, CO_2 to carbon.

§ WCI.234 Monitoring Requirements

Owners and operators using the mass balance method must comply with the following monitoring requirements:

(a) Measure the quantity of ore, soda ash, waste material, and carbonate-rich brine (as applicable) by direct measurement using the same instruments used for accounting purposes.

(b) Collect monthly samples of ore, soda ash, waste material, and carbonate-rich brine (as applicable) and analyze each sample for carbon content. For the carbon content of the brine ore and carbonate-rich brine, use a total organic carbon analyzer according to the ultraviolet light/chemical (sodium persulfate) oxidation method in ASTM D4839-03. Use method ASTM E359-00(2005) for the carbon content of trona ore, soda ash, and waste material.



§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

The petrochemical manufacturing source category consists of any facility that manufacturers petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions report must contain the following information:

(a) CO_2, N_2O, and CH_4 emissions from combustion of fuels in the stationary combustion unit in metric tons, as specified in WCI.20.

(b) CO_2, N_2O, and CH_4 emissions from flares and other oxidizers in metric tons, as specified in WCI.303(a).

(c) CO_2, N_2O, and CH_4 emissions from process vents in metric tons, as specified in WCI.303(b).

(d) CH_4 emissions tons from equipment leaks in metric, as specified in WCI.303(c).

(e) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solid fuels.

§ WCI.303 Calculation of GHG Emissions

(a) **Flares and Other Oxidizers.** You must calculate GHG emissions from flares and oxidation control devices as follows:

(1) Calculate CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in WCI.20.

(2) Calculate CO_2 emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

Equation 300-1

$$CO_2 = \sum_{i=1}^{n} GV_i \times CC_i \times MW_i / MVC \times 3.664 \times 0.001$$

Where:

CO_2 = CO_2 emissions (metric tons/year).
GV_i = Volume of gas *i* destroyed annually (scf/year).
CC_i = Average annual carbon content of gas *i* (kg C/kg fuel).

MW_i	=	Average annual molecular weight of gas *i*.
MVC	=	Molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor, kg to metric tons.
n	=	Number of gases destroyed.

(b) **Process Vents.** Except for process emissions calculated pursuant to WCI.303(a) or (c), you must calculate process emissions of CO_2, CH_4, and N_2O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^{n} VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \qquad \textbf{Equation 300-2}$$

Where:

E_x	=	Emissions of x (metric tons/yr), where x = CO_2, N_2O, or CH_4.
VR_i	=	Vent rate for venting event i (scf/unit time).
F_{xi}	=	Molar fraction of x in vent gas stream during event i.
MW_x	=	Molecular weight of x (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere).
VT_i	=	Time duration of venting event i (same units of time used for VR_i).
n	=	Number of venting events.
0.001	=	Conversion factor, kg to metric tons.

(c) **Equipment Leaks.** You must calculate CH_4 emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

(1) Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in WCI.304. Components identified as "other" components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.

(2) Use the results of the component screening and the following equations to calculate VOC emissions:

(A) For components where the measured screening value is equal to zero when corrected for background, calculate VOC emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i \times ZF_{i0} \times t \qquad \textbf{Equation 300-3}$$

Where:

E_{VOC-0} = Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).

i = Component type (valve, pump seal, other, connector, flange, open-ended line).

CC_i = Number of i components where the screening value is 0.

ZF_{i0} = Default zero factor for component i from Table 300-1 (kg/hr).

t = Time since last screening (hours/screening period).

(B) For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1:

$$E_{VOCL-C} = \sum_{i=1}^{6}\sum_{n=1}^{n} \left(\sigma_i \times SV_n^{\beta i}\right) \times t$$ **Equation 300-4**

Where:

E_{VOCL-C} = Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).

i = Component type (valve, pump seal, others, connector, flange, open ended-line).

n = Number of *i* components.

σ_i = Correlation equation coefficient for component type *i* from Table 300-1.

SV_n = Screening value for component *n.*

βi = Correlation equation exponent for component type *i* from Table 300-1.

t = Time component has been leaking (default value is time from last screening) (hours/screening period).

(C) For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1:

$$E_{VOCP} = \sum_{i=1}^{6} CC_i \times PF_{iP} \times t$$ **Equation 300-5**

Where:

E_{VOCP} = Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).

i = Component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line).

CC_i = Number of *i* components with screening values greater than 9,999 ppmv.

PF_{iP} = VOC emission factor for component type *i* pegged over 9,999 ppmv from Table 300-1 (kg/hr).

t = Time component has been leaking (default value is time since last screening) (hours/screening period).

(3) Calculate CH_4 emissions using Equation 300-6 and either a default factor of 0.6 for CF_{VOC} or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$CH_4 = \sum_{1}^{n} \left(E_{VOC-0} + E_{VOC-LC} + E_{VOCP}\right)_n \times CF_{VOC} \times 0.001 \qquad \textbf{Equation 300-6}$$

Where:

CH_4	=	CH_4 emissions (metric tons/year).
n	=	Number of screenings/year.
E_{VOC-0}	=	Emissions from components with a screening value equal to zero, when corrected for background (kg/screening period).
E_{VOC-LC}	=	Emissions from components with screening values, corrected for background, between 0 and 10,000 (kg/screening period).
E_{VOCP}	=	Emissions from components with screening values, corrected for background, greater than or equal to 10,000 ppmv (kg/screening period).
CF_{VOC}	=	VOC to CH_4 conversion factor (default $CF_{VOC} = 0.6$).
0.001	=	Conversion factor (kg to metric tons).

§ WCI.304 Monitoring Requirements

(a) Flares and Other Oxidizers. You must measure:

(1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.

(2) The carbon content and molecular weight of each gas quarterly using the methods specified in WCI.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.

(b) Process **Vents.** You must measure the following parameters for each process vent:

(1) The gas flow rate for each venting event.

(2) The molar fraction of CO2, N2O, and CH4 in the vent gas stream during each venting event.

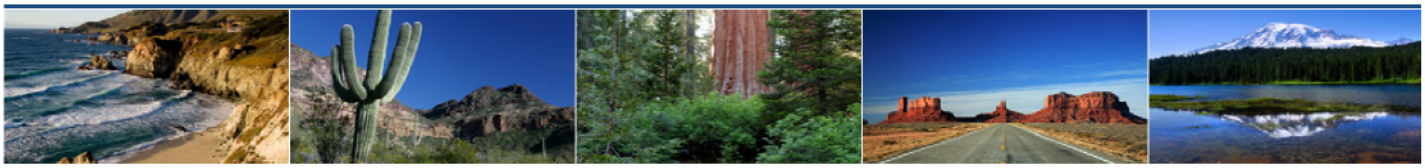
(3) The duration of each venting event.

(c) **Equipment Leaks.** You must screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CAPCOA (1999) Method 3: Correlation Equation Method and an instrument capable of detecting methane. Screenings must be performed at the frequency interval required by [*insert jurisdiction*]. The instrumentation used for screening must be capable of detecting methane.

(d) **Feedstock Consumption.** You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 300-1. Fugitive Emissions from Gas Service Components			
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**
	(SV = 0) Zf_{i0}	**(SV > 0 and < 10,000)** σ_i **and** β_i	**(SV ≥ 10,000)** PF_{iP-10}
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
Others[a]	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

[a] The "other" component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The "other" component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters, and polished rods stuffing boxes.



§ WCI.XX0 ADIPIC ACID MANUFACTURING

§ WCI.XX1 Source Category Definition

Adipic acid ($HOOC(CH_2)_4COOH$) is a dicarboxylic acid used in the production of a large number of products including synthetic fibers (primarily nylon 6,6), coatings, plastics, urethane foams, and synthetic lubricants. Adipic acid is produced by oxidizing a mixture of cyclohexanone ($(CH_2)_5CO$) and cyclohexanol ($(CH_2)_5CHOH$) with nitric acid in the presence of a catalyst; nitrous oxide (N_2O) is formed as an unwanted by-product.

§ WCI.XX2 Greenhouse Gas Reporting Requirements

In addition to the information required by WCI.3, the annual emissions data report shall contain the following information:

(a) Total emissions of N_2O at the facility level (metric tons)

(b) Total quantity of adipic acid production (metric tons)

(c) Facility-specific N_2O emission factor derived from periodic emissions monitoring or irregular emissions sampling (metric tons N_2O per metric ton of adipic acid)

(d) Destruction factor for facility-specific abatement technology (e.g., catalytic destruction, thermal destruction, nitric acid recycling, adipic acid recycling, etc.)

(e) Abatement system utilization factor for facility-specific abatement technology

(f) CO_2, N_2O, and CH_4 emissions from stationary combustion units as specified in WCI.20

§ WCI.XX3 Calculation of N_2O Emissions

(a) Process N_2O emissions. Determine process N_2O emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS).

(2) Calculation methodologies specified in paragraph (b) of this section.

(b) Process N_2O Emissions Calculation Methodology. Calculate total N_2O process emissions using the following equation:

$$E_{N2O} = EF \times AAP \times (1 - DF \times ASUF)$$

Equation XX0-1

Where:

E_{N2O}	=	Emissions of N_2O from adipic acid production (metric tons);
EF	=	N_2O emission factor (metric tons N_2O/metric ton of adipic acid produced) derived from periodic emissions monitoring or irregular emissions sampling;
AAP	=	Adipic acid production (metric tons);
DF	=	Destruction factor (dimensionless);
ASUF	=	Abatement system utilization factor (dimensionless).

§ WCI.XX4 Sampling, Analysis, and Measurement Requirements

The following measurement methods shall be used.

(a) Facility N_2O emissions tests. All facilities must conduct testing using:

(1) U.S. EPA Method 320 (40 CFR part 63, Appendix A) or ASTM D6348-03; or

(2) Continuous emissions monitor system (CEMS) to determine either the uncontrolled emissions to derive an emission factor (for use with the documented abator destruction efficiency), or the controlled emissions. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the [jurisdiction].

(b) Adipic acid production rates. Production rates may be determined through sales records, or through direct measurement using flow meters or weigh scales.