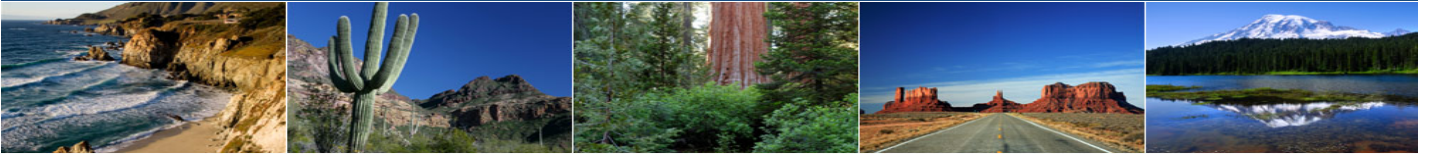


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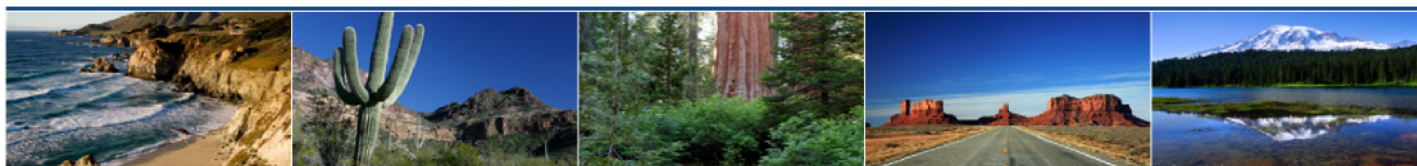


Final Essential Requirements of Mandatory Reporting

Amended for Canadian Harmonization

December 17, 2010

Western Climate Initiative



GENERAL PROVISIONS

§ WCI.0 through § WCI.10

EMISSIONS QUANTIFICATION, AND SAMPLING, ANALYSIS AND MEASUREMENT

§ WCI.20	General Stationary Combustion
§ WCI.30	Refinery Fuel Gas Combustion
§ WCI.40	Electricity Generation
§ WCI.50	Adipic Acid Manufacturing
§ WCI.60	Imported Electricity
§ WCI.70	Primary Aluminum Production
§ WCI.80	Ammonia Manufacturing
§ WCI.90	Cement Manufacturing
§ WCI.100	Coal Storage
§ WCI.110	Electronics Manufacturing
§ WCI.120	HCFC-22 Production and HFC-23 Destruction
§ WCI.130	Hydrogen Production
§ WCI.140	Glass Production
§ WCI.150	Iron and Steel Manufacturing
§ WCI.160	Lead Production
§ WCI.170	Lime Manufacturing
§ WCI.180	Carbonates Use
§ WCI.200	Petroleum Refineries
§ WCI.210	Pulp and Paper Manufacturing
§ WCI.220	Soda Ash Manufacturing
§ WCI.230	Electricity Transmission (and Emissions from Electrical Equipment in Electricity Generation)
§ WCI.240	Zinc Production

- § WCI.250 Underground Coal Mines
- § WCI.260 Nickel and Copper Metal Production
- § WCI.270 Ferroalloy Production
- § WCI.280 Mobile Equipment at Facilities
- § WCI.290 Magnesium Production
- § WCI.300 Petrochemical Manufacturing
- § WCI.310 Nitric Acid Manufacturing
- § WCI.340 Phosphoric Acid Production
- § WCI.350 Natural Gas Transmission and Distribution
- § WCI.360 Petroleum and Natural Gas Production and Natural Gas Processing

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§ WCI.0 through § WCI.10

Refer to the Essential Requirements for Reporting published July 15, 2009, with the following changes:

WCI.1(a)(1) is replaced by the following:

(1) Any facility that emits 10,000 metric tons CO₂e 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.

Adipic acid manufacturing [WCI.050]
Aluminum manufacturing [WCI.070]
Ammonia manufacturing [WCI.080]
Carbon dioxide transfer recipients [still being assessed]
Cement manufacturing [WCI.090]
Coal storage [WCI.100]
Copper and nickel [WCI.260]
Electricity generation [WCI.040]
Electricity transmission [WCI.230]
Electronics manufacturing [WCI.110]
Ferroalloy production [WCI.270]
General stationary fuel combustion [WCI.020]
Glass Production [WCI.140] HCFC-22 production [WCI.120]
Hydrogen production [WCI.130]
Industrial wastewater [WCI.203(g)]
Iron and steel manufacturing [WCI.150]
Lead production [WCI.160]
Lime manufacturing [WCI.170]
Magnesium production [WCI.290]
Miscellaneous uses of carbonates [WCI.180]
Natural gas transmission and distribution systems [WCI.350]
Nitric acid manufacturing [WCI.310]
Mobile equipment [WCI.280]
Petroleum and natural gas systems [WCI.360]
Petrochemical production [WCI.300]
Petroleum refineries [WCI.200]
Phosphoric acid production [WCI.340]
Pulp and paper manufacturing [WCI.210]
Refinery fuel gas [WCI.030]
Soda ash manufacturing [WCI.220]

Underground coal mines [WCI.250]
Zinc production [WCI.240]

WCI.1(g) is added:

- 1(g): The following emissions data shall be submitted for information only and may not be subject to cap-and-trade requirements¹:
- (1) Data submitted by a source category designated as “reporting only.” This provision does not apply to emissions from general stationary combustion at a source in a “reporting only” category.
 - (2) Emissions data calculated with a methodology identified as “reporting only.”
 - (3) Reporting only sources are identified as the following:
 - Carbon dioxide from biomass determined to be carbon neutral by the jurisdiction
 - Fugitive HFC emissions in electrical generation
 - Coal storage
 - Asphalt blowing at refineries
 - Equipment leaks at refineries
 - Storage tanks at refineries
 - Industrial wastewater treatment
 - Product loading at refineries
 - Mobile equipment

WCI.2(b)(2)(B) is modified to read:

“For reporting years 2012 and later, ~~{date to be determined}~~ by September 1 of the year following the reporting year.’

WCI.2(h) is added:

- (j) The following shall apply unless in conflict with any other provision in the quantification methods
- (1) Samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.
 - (2) A weighted average of the values derived from the samples must be calculated and reported by using the following formula:

$$V_E = \frac{\sum_{j=1}^n (V_j \times M_j)}{\sum_{j=1}^n M_j}$$

Where:

¹ The identification of data as “reporting only” may be subject to possible revision before the adoption of a cap-and-trade program. On adoption the jurisdiction will likely substitute a citation to the rules implementing the program for the words “cap-and-trade requirements.” Further analysis of reporting only sources is occurring, particularly for specific emission sources within the Petroleum and Natural Gas Systems and Natural Gas Transmission and Distribution quantification methods.

- VE = The value of the parameter to be reported under the quantification method for period E.
 - j = Each period during period E for which a sample is required by [jurisdiction] under the applicable quantification method
 - n = The number of periods j in period E.
 - Vj = The value of the sample for period j.
 - Mj = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.
- (3) You must keep records of the date and result for each sample and mass measurement used in the equation in subsection (2) and of the calculation of each weighted average included in your report must be kept.

WCI.4(b) is modified to read:

- (b) Upon request by [jurisdiction], the operator shall provide within ~~10-20 working~~ days all documents and data used to develop an emissions data report.

WCI.5(c) is added

- (c) Notwithstanding the missing data procedures in the quantification methods the failure to conduct monitoring in accordance with these methods shall constitute a violation.

WCI.8(a)(1) is modified to read:

- (1) Except as provided in WCI.8(a)(2) through (44.1) 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 CO₂e 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.

WCI.8(a)(4.1) is added:

“Emissions designated “reporting only” in this article shall be excluded from the determination regarding verification applicability.

WCI.8(b)(4)(C) Accreditation Requirements for Verification Bodies is revised to read:

- (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 in [the jurisdiction] if
- (A) it has demonstrated knowledge of [the WCI jurisdiction] reporting requirements; and
 - (B) it has the characteristics and capabilities deemed necessary by [the jurisdiction] to perform verification services; and
 - (C) it is accredited to ISO 14065 through
 - (i) a program developed under ISO 17011 by an accreditation body that is a member of the International Accreditation Forum.; or
 - (ii) a program developed or authorized [the jurisdiction] under [the jurisdiction’s] required statutory or regulatory process that is at least as stringent as the process defined in ISO 17011.

[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.]

WCI.8(p)(1) and (2) are revised as follows:

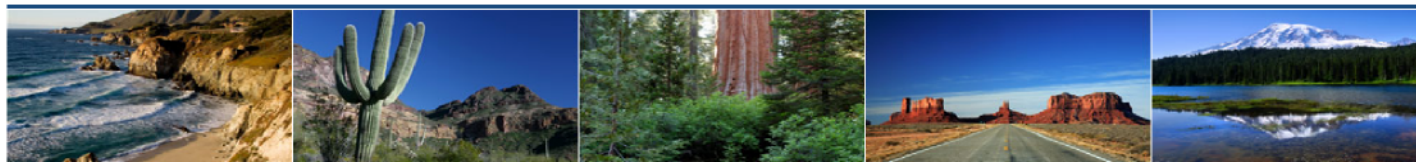
(p) Completion of verification services shall include:

(1) Verification Statement. Upon completion of the verification services required by WCI.8, the verification body shall prepare either a positive or adverse verification statement, for each emissions data report, based on its findings during the verification process. The verification body shall provide the verification statement(s) to the reporter and to the AVA [alternatively, this could be the reporter's responsibility to submit the statement to the AVA], according to the schedule specified in section WCI.2(b). Before each 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.

~~(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.~~

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§ WCI.20 GENERAL STATIONARY COMBUSTION

§ WCI.21 Source Category Definition

Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources are boilers, simple and combined cycle combustion turbines, engines, incinerators (including units that combust hazardous waste), process heaters, and any other stationary combustion device that is not specifically addressed under the methods for another source category. This source category does not include portable equipment, emergency generators, and emergency equipment (including emergency flares).

§ 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 tonnes, reported as follows:
 - (1) Total CO₂ emissions for fossil fuels, reported by fuel type.
 - (2) Total CO₂ emissions for biomass, reported by fuel type.
 - (3) Total CH₄ emissions, reported by fuel type.
 - (4) Total N₂O 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 kilolitres.
 - (3) For non-biomass solids, report in units of tonnes.
 - (4) For biomass solid fuels, report in units of bone dry tonnes.
- (c) Annual weighted average carbon content of each fuel, if used to compute CO₂ emissions.
- (d) Annual weighted average high heat value of each fuel, if used to compute CO₂ emissions.
- (e) Annual steam generation in kilograms, for units that burn biomass fuels or municipal solid waste and generate steam.

§ WCI.23 Calculation of CO₂ Emissions

For each fuel, calculate CO₂ mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in WCI.23(e). If a fuel or fuels is not listed in all of Tables 20-1 through 20-7; or in Table C-1 or C-2 of U.S. EPA 40 CFR Part 98, Subpart C, then emissions from such fuels do not need to be reported so long as total emissions of these

fuels do not exceed 0.5% of total facility emissions. If emissions from the sum of these fuels exceeds 0.5% of total facility emissions, then the requirements of WCI.023 stand so long as only a maximum of 0.5% of total facility emissions from unlisted fuels is not reported.

- (a) Calculation Methodology 1. Calculate the annual CO₂ mass emissions for each type of fuel by substituting a fuel-specific default CO₂ emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1:

$$CO_2 = Fuel \times HHV \times EF \times 0.001 \quad \text{Equation 20-1}$$

Where:

- CO₂ = Annual CO₂ mass emissions for the specific fuel type (tonnes).
 Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
 HHV = Default high heat value of the fuel, from Table 20-1 and 20-1a (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
 EF = Fuel-specific default CO₂ emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO₂/GJ).
 (HHV x EF) instead of using separate HHV and EF values, you can replace the two values by using default emission factors from Tables 20-2, 20-3, or 20-5, as applicable (in units of kg CO₂ per tonne for solid fuel, kg CO₂ per kilolitre for liquid fuel, or kg CO₂ per cubic meter for gaseous fuel)
 0.001 = Conversion factor from kilograms to tonnes.

- (b) Calculation Methodology 2. Calculate the annual CO₂ mass emissions using a default fuel-specific CO₂ 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, for which the operator may instead elect to use the method shown in Equation 20-3. For use of Calculation Methodology 2 for municipal solid waste, Equation 20-3 must be used.

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

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

Where:

- CO₂ = Annual CO₂ mass emissions for a specific fuel type (tonnes).
 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 tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).

- HHV_p = High heat value of the fuel for the measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
 EF = Fuel-specific default CO₂ emission factor, from Tables 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable (kg CO₂/GJ).
 0.001 = Conversion factor from kilograms to tonnes.

- (2) For units that combust municipal solid waste and that produce steam, use Equation 20-3. Equation 20-3 of this section may also be used for any solid biomass fuel listed in Table 20-2 of this subpart provided that steam is generated by the unit.

$$CO_2 = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-3}$$

Where:

- CO₂ = Annual CO₂ mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
 Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
 B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
 EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable (kg CO₂/GJ).¹
 0.001 = Conversion factor from kilograms to tonnes.

- (c) Calculation Methodology 3. Calculate the annual CO₂ mass emissions for each fuel 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.

- (1) For a solid fuel, except for the combustion of municipal solid waste, use Equation 20-4 of this section:

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times 3.664 \quad \text{Equation 20-4}$$

Where:

- CO₂ = Annual CO₂ mass emissions from the combustion of the specific solid fuel (tonnes).
 n = Number of carbon content determinations for the year.
 Fuel_i = Mass of the solid fuel combusted in measurement period *i* (tonnes).
 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, CO₂ to carbon.

- (2) For biomass fuels, in units that produce steam, use either Equation 20-4 above or Equation 20-5; for municipal solid waste combustion in units that produce steam, use Equation 20-5:

¹ The ER required development of a site-specific emission factor for MSW. For harmonization with Part 98, Subpart C, this requirement was deleted. However, jurisdictions may allow or require testing to develop a site-specific emission factor as an alternative to the default emission factors in Subpart C, Table C-1.

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

Equation 20-5

Where:

- CO₂ = Annual CO₂ mass emissions from biomass solid fuel or municipal solid waste combustion (tonnes).
- Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year (tonnes steam).
- B = Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity (GJ/tonne steam).
- EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO₂/GJ), adjusted no less often than every third year as provided in WCI.25(a)(7)(B).
- 0.001 = Conversion factor from kilograms to tonnes.

(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:

- CO₂ = Annual CO₂ mass emissions from the combustion of the specific liquid fuel (tonnes).
- 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* (kilolitres).
- CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period *i* (tonne C per kilolitre of fuel).
- 3.664 = Ratio of molecular weights, CO₂ 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:

- CO₂ = Annual CO₂ mass emissions from combustion of the specific gaseous fuel (tonnes).
- 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) (m³) at the reference temperature and pressure conditions used by the facility. If a mass flow meter is used, measure the fuel combusted in period *i* in kg and replace the term "MW/MVC" with "1".
- 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 at the reference conditions Fuel_i (m³/kg-mole).
= $8.3145 \times [273.16 + \text{reference temperature in } ^\circ\text{C}]/[\text{reference pressure in kilopascals}]$
(which is 23.64 m³ per kg-mole for STP of 15 °C and 1 atmosphere).
3.664 = Ratio of molecular weights, CO₂ to carbon.
0.001 = Conversion factor from kg to tonnes.

(d) Calculation Methodology 4. Calculate the annual CO₂ 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). This methodology requires a CO₂ concentration monitor and a stack gas volumetric flow monitor, except as otherwise provided in paragraph (d)(2) of this section.

- (1) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO₂ or O₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).
- (2) The operator shall report CO₂ emissions for the reporting year in tonnes based on the sum of hourly CO₂ mass emissions over the year, converted to tonnes.
- (3) An oxygen (O₂) concentration monitor may be used in lieu of a CO₂ concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO₂ concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO₂ emissions or CO₂ emissions from acid gas control are mixed with the combustion products) and if only the following fuels are combusted in the unit: coal, petroleum coke, oil, natural gas, propane, butane, wood bark, or wood residue.
 - (A) If the unit combusts waste-derived fuels (as defined in the General Provisions and including municipal solid waste), emissions calculations shall not be based on O₂ concentrations.
 - (B) If the operator of a facility that combusts biomass fuels uses O₂ concentrations to calculate CO₂ concentrations, annual source testing must demonstrate that calculated CO₂ concentrations, when compared to measured CO₂ concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded).
- (4) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO₂ mass emissions separately, as described in paragraph (f) of this section.
- (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 for continuous monitoring of gaseous emissions, 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 appropriate requirements for the facility as applicable in Canada.
 - (7) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO₂ concentrations, the operator shall select and operate the CEMS pursuant to the appropriate requirements or equivalent requirements as applicable in Canada. Operators who add CEMS under this paragraph are subject to the specifications in paragraphs (d)(1) through (d)(5), if applicable.
- (e) Use of the Four CO₂ Calculation Methodologies. Use of the four CO₂ emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:
- (1) Calculation Methodology 1 (Equation 20-1).
 - (A) May be used by a facility that is not subject to the verification requirements by regulation for any type of fuel for which a default high heat value (Table 20-1 and 20-1a) and a default CO₂ emission factor (Tables 20-1a, 20-2, 20-3, or 20-5, as applicable) is specified.
 - (B) May be used for a facility emitting at any level for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, and for the combustion of any of the fuels listed in Table 20-1a.
 - (C) May be used for a facility emitting at any level for the combustion of municipal solid waste in a unit that does not generate steam.
 - (D) May be used for the combustion of biomass listed in Table 20-2 that is exempted from verification requirements by the jurisdiction, unless it is specifically addressed under the provisions for another source category (e.g., spent pulping liquor from pulp and paper facilities).
 - (E) May not be used at a facility emitting at any level for a fuel for which you routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel high heat value from the fuel supplier at the minimum frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Method 2, 3 or 4 shall be used for those fuels.
 - (2) Calculation Methodology 2 (Equations 20-2 and 20-3).
 - (A) May not be used by a facility that is subject to the verification requirements by regulation, except as specified in paragraphs (e)(2)(B) through (E) of this section. 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 20-1a, 20-2, 20-3, 20-5, or 20-7, as applicable.

- (B) Calculation Methodology 2 may be used for the combustion of natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter at a facility emitting at any level. Notwithstanding the provisions in paragraph (e)(1) of this section, Calculation Methodology 2, 3, or 4 shall be used for combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter.
 - (C) Calculation Methodology 2 may be used at a facility emitting at any level for the combustion of any of the fuels listed in Table 20-1a, and for biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.
 - (D) Equation 20-3 may be used for the combustion of municipal solid waste only at facilities that are not subject to verification by regulation.
 - (E) Equation 20-2 may not be used for the combustion of municipal solid waste.
- (3) Calculation Methodology 3 (Equations 20-4 through 20-7) may be used for the combustion of any type of fuel, except as specified in paragraph (e)(3)(A) through (E) of this section.
- (A) Notwithstanding the provisions in paragraph (e)(1) and (e)(2) of this section, Calculation Methodology 3 or 4 must be used at a facility subject to verification for all combustion in any unit with a rated heat input capacity greater than 264 GJ/hr (250mmBtu/hr) and that has operated for more than 1,000 hours in any of the past three years, except when the fuel is natural gas with a high heat value between 36.3 and 40.98 MJ per cubic meter, the fuel is listed in Table 20-1a, or the fuel is biomass that has been determined by [the jurisdiction] not to be subject to a compliance obligation under the cap-and-trade program.
 - (B) Must be used for all other combustion at a facility subject to verification, except for combustion of fuels for which Calculation Methodology 1 or 2 is permitted, as described in paragraphs (e)(1) and (e)(2) of this section.
 - (C) May not be used when the use of Calculation Methodology 4 is required.
 - (D) Equation 20-4 may not be used for the calculation of emissions from combustion of municipal solid waste.
 - (E) Equation 20-5 may be used for the combustion of municipal solid waste at a facility emitting at any level; however, it must be used for the combustion of municipal solid waste if the facility is subject to verification by regulation, unless Calculation Methodology 4 is required.
- (4) Calculation Methodology 4 may be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs (e)(1) through (3) of this section, Calculation Methodology 4 must be used for a combustion unit with a CEMS that is required by any federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor.
- (5) You may elect to use any applicable higher calculation methodology for one or more of the fuels combusted in a unit. For example, if a unit combusts natural gas and distillate

fuel oil, you may elect to use Calculation Methodology 1 for natural gas and Calculation Methodology 2 for the fuel oil, even though Calculation Methodology 1 could have been used for both fuels. However, for units that use Calculation Methodology 4, CO₂ emissions from the combustion of all fuels shall be based solely on CEMS measurements.

- (f) CO₂ emissions from combustion of mixtures of biomass or biomass fuel and fossil fuel. Use the procedures of this paragraph (f) to estimate biogenic CO₂ emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels (e.g., municipal solid waste, tires, etc.) that are partially biomass.
 - (1) If CEMS are not used to measure CO₂ and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Calculation Methodology 1, 2, or 3, as applicable, to calculate the annual biogenic CO₂ mass emissions from the combustion of biomass fuels. Determine the mass of biomass combusted using either company records, or, for premixed fuels that contain biomass and fossil fuels (e.g., mixtures containing biodiesel), use best available information to determine the mass of biomass fuels and document the procedure.
 - (2) If a CEMS is used to measure CO₂ (or O₂ as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels (as defined in the General Provisions), use Calculation Methodology 1, 2, or 3 to calculate the annual CO₂ mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO₂ emissions determined from the CEMS-based methodology.
 - (3) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (e.g., municipal solid waste, tire-derived fuel, etc.), or if the owner or operator combusts a biomass fuel for which a CO₂ emission factor is not provided in Table 20-2, use the following to estimate biogenic CO₂ emissions:
 - (A) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO₂ mass emissions, as applicable.
 - (B) Determine the biogenic portion of the CO₂ emissions using ASTM D6866-08 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”, 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 CO₂ emissions.
 - (C) The operator shall conduct ASTM D6866-08 analysis on a representative fuel or exhaust gas sample at least every three months. The exhaust gas samples shall be collected over at least 24 consecutive hours following the standard practice specified by 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.” If municipal solid waste is

combusted, the ASTM D6866-08 analysis must be performed on the exhaust gas stream.

- (D) The operator shall divide total CO₂ 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.
 - (E) If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for only one of the units sharing the common fuel source.
- (4) If Equation 20-1 of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation 20-8 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$(Fuel)_p = \frac{[H \times S] - (HI)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}} \quad \text{Equation 20-8}$$

Where:

- (Fuel)_p = Quantity of biomass consumed during the measurement period *p* (tonnes/year or tonnes/month, as applicable).
- H = Average enthalpy of the boiler steam for the measurement period (GJ/tonne).
- S = Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable).
- (HI)_{nb} = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable).
- (HHV)_{bio} = Default or measured high heat value of the biomass fuel (GJ/tonne).
- (Eff)_{bio} = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

(g) Calculation of CO₂ from sorbent.

- (1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection, use Equation 20-9 of this section to calculate the CO₂ emissions from the sorbent, if those CO₂ emissions are not monitored by CEMS:

$$CO_2 = S \times R \times \left(\frac{MW_{CO_2}}{MW_S} \right) \quad \text{Equation 20-9}$$

Where:

- CO₂ = CO₂ emitted from sorbent for the reporting year (tonnes).
- S = Limestone or other sorbent used in the reporting year, from company records (tonnes).
- R = 1.00, the calcium-to-sulphur stoichiometric ratio.

MW_{CO2} = Molecular weight of carbon dioxide.
 MW_S = Molecular weight of sorbent.

- (2) The annual CO₂ mass emissions for the unit shall be the sum of the CO₂ emissions from the combustion process and the CO₂ emissions from the sorbent.

§ WCI.24 Calculation of CH₄ and N₂O Emissions

Calculate the annual CH₄ and N₂O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), or (c), as appropriate. You are not required to calculate the annual CH₄ and N₂O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6. However, you may use engineering estimates to calculate the annual CH₄ and N₂O emissions for fuels that are not listed in Tables 20-2, 20-3, 20-4 and 20-6.

- (a) If the high heat value of the fuel is not measured for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF \times 0.000001 \quad \text{Equation 20-10}$$

$$CH_4 \text{ or } N_2O = Fuel \times EF_c \times 0.001 \quad \text{Equation 20-11}$$

Where:

CH₄ or N₂O = Combustion emissions from specific fuel type (tonnes CH₄ or N₂O per year).
 Fuel = Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
 HHV_D = Default high heat value specified by fuel type provided in Table 20-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
 EF = Default CH₄ or N₂O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH₄ or N₂O per GJ. The facility may also use equipment-specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
 EF_c = Default CH₄ or N₂O emission factor for coal provided in Table 20-6 (grams CH₄ or N₂O per kg of coal). The facility may also use equipment specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
 0.000001 = Factor to convert grams to tonnes in Equation 20-10.
 0.001 = Factor to convert g/kg to tonne/tonne in Equation 20-11.

- (b) If the high heat value of the fuel is measured or provided by the fuel supplier for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-12 for all fuels except coal. For coal, use Equation 20-13:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.000001 \quad \text{Equation 20-12}$$

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times EF_c \times 0.000001 \quad \text{Equation 20-13}$$

Where:

- CH₄ or N₂O = CH₄ or N₂O emissions from a specific fuel type (tonnes CH₄ or N₂O per year).
- Fuel_p = Mass or volume of the fuel combusted during the measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres 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 tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Default CH₄ or N₂O emission factor provided in Tables 20-2 or 20-4, as applicable (grams CH₄ or N₂O per GJ). The facility may also use equipment-specific factors from U.S. EPA AP-42 for the specific equipment as appropriate.
- EF_c = CH₄ or N₂O emission factor for coal, either measured directly or provided by the fuel supplier (grams CH₄ or N₂O per tonne of coal).
- 0.000001 = Factor to convert grams to tonnes.

- (c) For biomass and municipal solid waste combustion where Equation 20-3 or 20-5 are used to calculate CO₂ emissions, use Equation 20-14 of this section to estimate CH₄ and N₂O emissions:

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001 \quad \text{Equation 20-14}$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a municipal solid waste (tonnes).
- Steam = Total mass of steam generated by municipal solid waste combustion during the reporting year (tonnes steam).
- B = Ratio of the boiler's design rated heat input capacity to its design rated steam output (GJ/tonne steam).
- EF = Fuel-specific emission factor for CH₄ or N₂O, from Tables 20-2, 20-4, or 20-6, as applicable (grams CH₄ or N₂O per GJ).
- 0.000001 = Conversion factor from grams to tonnes.

- (d) Use Equation 20-15 of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year round basis.

$$CH_4 \text{ or } N_2O = (HI)_A \times EF \times 0.000001 \quad \text{Equation 20-15}$$

Where:

- CH₄ or N₂O = Annual CH₄ or N₂O emissions from the combustion of a particular type of fuel (tonnes).
- (HI)_A = Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.).
- EF = Fuel-specific emission factor for CH₄ or N₂O, from Tables 20-2, 20-4, or 20-6, as applicable (grams CH₄ or N₂O per GJ).
- 0.000001 = Conversion factor from grams to tonnes.

- (1) If only one type of fuel is combusted during normal operation, substitute the cumulative annual heat input from combustion of the fuel into Equation 20-15 of this section to calculate the annual CH₄ or N₂O emissions.
 - (2) If more than one type of fuel listed is combusted during normal operation, use Equation 20-15 of this section separately for each type of fuel.
- (e) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations 20-8, 20-9, 20-10, or 20-11 of this section (as applicable) to obtain the total annual CH₄ and N₂O emissions, in tonnes.
- (f) The operator may elect to calculate CH₄ or N₂O emissions using source-specific emission factors derived from source tests conducted at least annually under the supervision of the regulator. 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.
- (g) Use of the four CH₄ and N₂O Calculation Methodologies. Use of the four CH₄ and N₂O 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 36.3 and 40.98 MJ per cubic meter. Otherwise, WCI.24(a) may be used for any type of fuel for which a default CH₄ or N₂O emission factor (Tables 20-2, 20-4, 20-6, and 20-7) and a default higher heat value (Table 20-1 and 20-1a) 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. WCI.24(c) must be used instead of WCI.24(a) for any unit combusting municipal solid waste that generates steam.
 - (4) WCI.24(d) may be used for a unit of any size combusting any type of fuel, and must be used for any units for which Calculation Methodology 4 is used to estimate CO₂ emissions and heat input is monitored on a year round basis.

§ 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 minimum at the frequency specified in paragraphs (a)(1) through (a)(7) of this section, subject to the requirements of WCI.23(e) and WCI.24(g). All fuel samples shall be taken at a location in the fuel handling system that provides a representative of the fuel combusted.
- (1) Once for each new fuel shipment or delivery for coal.
 - (2) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the fuels listed in Table 20-1a (when required).
 - (3) Semiannually for natural gas (when required).
 - (4) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 20-1a (when Table 20-1a is used).

- (5) Quarterly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
- (6) For gaseous fuels other than natural gas, gases derived from biomass, and biogas, daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if the necessary equipment is in place to make these measurements. For 2011 calendar year emissions only, if the necessary equipment is not in place to make the measurements, weekly sampling and analysis shall be performed. If on-line instrumentation is to be used, the equipment necessary to perform daily sampling and analysis of carbon content and molecular weight must determine fuel carbon content accurate to ± 5 percent.
- (7) Monthly for solid fuels other than coal and waste-derived fuels (including municipal solid waste), 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.
- (8) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of WCI.25(a)(5):
 - (A) If CO₂ emissions are calculated using Equation 20-2 in WCI.23(b)(1) or Equation 20-4 in WCI.23(c)(1), the source-specific high heat value or carbon content is determined annually. If CO₂ emissions are calculated using Equation 20-5 in WCI.23(c)(2) (biomass fuels and municipal solid waste only), the operator shall adjust the emission factor, in kg CO₂/GJ 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 MJ, litres, million standard cubic meters, tonnes or bone dry tonnes) using Equation 20-16. For facilities that are covered by WCI.360 (Petroleum and Natural Gas Production and

Gas Processing) but are less than 10,000 tonnes in individual size, an operator may calculate fuel consumption for propane and diesel without correcting for the difference in inventory at the beginning and end of the year.

Equation 20-16

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 by regulation 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) Fuel flow meters that measure mass flow rates may be used for liquid fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content, using ASTM D1298-99 (Reapproved 2005) “Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”
 - (6) Facilities using Calculation Methods 1 or 2 for CO₂ emissions may use the following default density values for fuel oil, in lieu of using the ASTM method in paragraph (b)(5) of this section: 0.81 kg/litre for No. 1 oil; 0.86 kg/litre for No. 2 oil; 0.97 kg/litre for No. 6 oil. These default densities may not be used for facilities using Calculation Method 3.
- (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 by regulation.
- (1) For gases, use ASTM D1826-94 (Reapproved 2003) “Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter”, ASTM D3588-98 (Reapproved 2003) “Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels”, or 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 20-17

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) “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter” or ASTM D4809-06 (Reapproved 2005) “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).”
- (3) For solid biomass-derived fuels, use ASTM D5865-07a “Standard Test Method for Gross Calorific Value of Coal and Coke.”
- (4) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007) “Standard Test Method for Gross Calorific and Ash Value of Waste Materials.” Operators who combust waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO₂ emissions using the method specified in WCI.23(f), if applicable
- (5) Use Equation 20-18 to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO₂ emissions.

$$(HHV)_{\text{annual}} = \frac{\sum_{p=1}^n (HHV)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-18}$$

Where:

- (HHV)_{annual} = Weighted annual average high heat value of the fuel (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- (HHV)_p = High heat value of the fuel, for measurement period *p* (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- (Fuel)_p = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
- n* = Number of measurement periods in the year that fuel is burned in the unit.

- (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 by regulation.

- (1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.
- (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 “Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements” or ASTM D2503-92 (Reapproved 2007) “Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.”
- (3) For gaseous fuels, use ASTM D1945-03 (Reapproved 2006) “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” or ASTM D1946-90 (Reapproved 2006) “Standard Practice for Analysis of Reformed Gas by Gas Chromatography.”
- (4) Use Equation 20-19 to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO₂ emissions.

$$(CC)_{\text{annual}} = \frac{\sum_{p=1}^n (CC)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p} \quad \text{Equation 20-19}$$

Where:

- (CC)_{annual} = Weighted annual average carbon content of the fuel (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).
- (CC)_p = Carbon content of the fuel, for measurement period *p* (percent C by weight for solid fuel, tonne C per kilolitre for liquid fuel, or kg C per kg fuel for gaseous fuel).
- (Fuel)_p = Mass or volume of the fuel combusted during measurement period *p* (express mass in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, or volume in kilolitres for liquid fuel).
- n* = Number of measurement periods in the years that fuel is burned in the unit.
- (e) Fuel Analytical Data Capture. When the applicable emissions estimation methodologies in WCI.23 and WCI.24 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 WCI.23 and WCI.24, the operator shall use the methods in WCI.26(b) to substitute for the missing values for the period of missing data.
- (f) Specific Requirements for Petroleum and Natural Gas Production and Gas Processing. For field or process gas combustion or general stationary combustion of natural gas within facilities covered by WCI.360, legislative or regulatory requirements, such as those required by the Petroleum and Natural Gas Act of British Columbia are sufficient for the points of measurement that are metered. For British Columbia, combustion sources specifically covered by the Petroleum and Natural Gas Act are to be calculated in the manner prescribed by the Act and its regulations, guidelines, and policies. Combustion sources not covered by the Act must be metered according to the following sampling and measurement requirements:
- (1) For combustion emission sources where meters are not required by legislation or regulation, a calculated shrinkage value is sufficient but must be assigned using engineering estimation techniques to the various sources, if required for reporting.
 - (2) For field, pipeline quality natural gas or process gas combustion emission sources where metering is not required by law or regulation and shrinkage is not calculated, engineering estimation techniques that consolidate to common meter points such as that at the input to a processing plant used for financial purposes are sufficient. As required, fuel use must be allocated (using equipment specifications, operating hours, and flow rates) to specific emission sources.
 - (3) For upstream sources, a meter is required at each installation or at a point where fuel use can be allocated to multiple combustion sources such that the aggregated of all combustion sources are metered.

All combustion estimates must be calculated in such a manner that ensures that fugitive, flaring, and venting emissions as calculated under WCI.360 are uniquely reported and that no double-counting of emissions in one or more categories occurs.

Carbon content and molecular weight of the field or process gas determined annually by a company or operator for a specific field for operational and regulatory purposes must be used as inputs to Equation 20-7. When this data is not available, the generic emission factors provided in Table 360-3 (or as provided by the jurisdiction) must be used by a company or operator for the specific gas field in question.

- (g) Specific Requirements for Natural Gas Transmission and Distribution. Measurement and Metering Act of Canada standards (or other appropriate standards if the Measurement and Metering Act is not applicable) are deemed to be sufficiently rigorous for the sampling,

analysis and measurement for the combustion of pipeline quality natural gas (including for derivation of standard gas composition) for facilities covered by WCI.350 – Natural Gas Transmission and Distribution. If a required meter is not covered by the Measurement and Metering Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

§ WCI.26 Procedures for Estimating Missing Data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

- (a) For all units subject to the requirements of WCI.20 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Protocols And Performance Specifications For Continuous Monitoring Of Gaseous Emissions From Thermal Power Generation* (Report EPS 1/PG/7 (Revised) December 2005) (or by other relevant document, if superseded) shall be followed for CO₂ concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.
- (b) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:
 - (1) For each missing value of the high heating value, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value has not been obtained by the time that the GHG emissions must be calculated, you may use the “before” value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
 - (2) For missing records of CO₂ concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

§ WCI.27 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response

procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.1 MJ/m³ or less than 40.98 MJ/m³, and which is at least 90 percent methane by volume, and which is less than 5 percent carbon dioxide by volume.

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

- (1) The equipment is attached to a foundation.
- (2) The equipment or a replacement resides at the same location for more than 12 consecutive months.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.
- (4) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

U.S. AP-42 means the Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, U.S. EPA., as amended from time to time

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

Liquid Fuels	High Heat Value (GJ/kl)
Asphalt & Road Oil	44.46
Aviation Gasoline	33.52
Diesel	38.3
Aviation Turbo Fuel	37.4
Kerosene	37.68
Propane	25.31
Ethane	17.22
Butane	28.44
Lubricants	39.16
Motor Gasoline – Off-Road	35
Light Fuel Oil	38.8
Residual Fuel Oil (No. 5 & No. 6)	42.5
Crude Oil	38.32
Naphtha	35.17
Petrochemical Feedstocks	35.17
Petroleum Coke – Refinery Use	46.35
Petroleum Coke – Upgrader Use	40.57
Ethanol (100%)	21.04
Biodiesel (100%)	32.06

Rendered Animal Fat	31.05
Vegetable Oil	30.05
Solid Fuels	High Heat Value (GJ/tonne)
Anthracite Coal	27.7
Bituminous Coal	26.33
Foreign Bituminous Coal	29.82
Sub-Bituminous Coal	19.15
Lignite	15
Coal Coke	28.83
Solid Wood Waste	18
Spent Pulping Liquor	14
Municipal Solid Waste	11.57
Tires	31.18
Agricultural By-products	8.6
Solid By-products	26.93
Gaseous Fuels	High Heat Value (GJ/m³)
Natural Gas	0.03832
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (captured methane)	0.0359
Biogas (captured methane)	0.0281

¹ The default high heat value for “propane” is only for the pure gas species. For the product commercially sold as propane, the value for liquefied petroleum gas in Table 20-1a should be used instead.

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO₂ Emission Factor
Petroleum Products	GJ/kilolitre	kg CO₂/GJ
Distillate Fuel Oil No. 1	38.78	69.37
Distillate Fuel Oil No. 2	38.50	70.05
Distillate Fuel Oil No. 4	40.73	71.07
Kerosene	37.68	67.25
Liquefied Petroleum Gases (LPG)	25.66	59.65
Propane (pure, not mixtures of LPGs) ¹	25.31	59.66
Propylene	25.39	62.46
Ethane	17.22	56.68
Ethylene	27.90	63.86
Isobutane	27.06	61.48
Isobutylene	28.73	64.16
Butane	28.44	60.83
Butylene	28.73	64.15
Natural Gasoline	30.69	63.29
Motor Gasoline	34.87	65.40

Table 20-1a—Fuels for which Calculation Methodologies 1 or 2 may be used at a facility emitting at any level.

Fuel Type	Default High Heat Value	Default CO₂ Emission Factor
Aviation Gasoline	33.52	69.87
Kerosene-type Jet Fuel	37.66	68.40

[†] The default factors for “propane” are only for the pure gas species. For the product commercially sold as propane, the values for LPG should be used instead.

Table 20-2: Default Emission Factors by Fuel Type

	CO₂ Emission Factor (kg/l)	CO₂ Emission Factor (kg/GJ)	CH₄ Emission Factor (g/l)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/l)	N₂O Emission Factor (g/GJ)
Liquid Fuels						
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 (No. 5 & No. 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

	CO₂ Emission Factor (kg/kg)	CO₂ Emission Factor (kg/GJ)	CH₄ Emission Factor (g/kg)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/kg)	N₂O Emission Factor (g/GJ)
Biomass						
Landfill Gas	2.989	83.3	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 (Env. Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulping Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Agricultural By-products	NA	112	NA	NA	NA	NA
Solid By-products	NA	100	NA	NA	NA	NA
Biogas (captured methane)	NA	49.4	NA	NA	NA	NA
Ethanol (100%)	NA	64.9	NA	NA	NA	NA
Biodiesel (100%)	NA	70	NA	NA	NA	NA
Rendered Animal Fat	NA	67.4	NA	NA	NA	NA
Vegetable Oil	NA	77.3	NA	NA	NA	NA
Other Solid Fuels	CO₂ Emission Factor (kg/kg)	CO₂ Emission Factor (kg/GJ)	CH₄ Emission Factor (g/kg)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/kg)	N₂O Emission Factor (g/GJ)
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)	N₂O Emission Factor (g/m³)	N₂O 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)	N₂O (g/m³)	N₂O (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 CO ₂ /kg coal)	Emission Factor (kg CO ₂ /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

	CH ₄ Emission Factor (g/kg)	N ₂ O 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

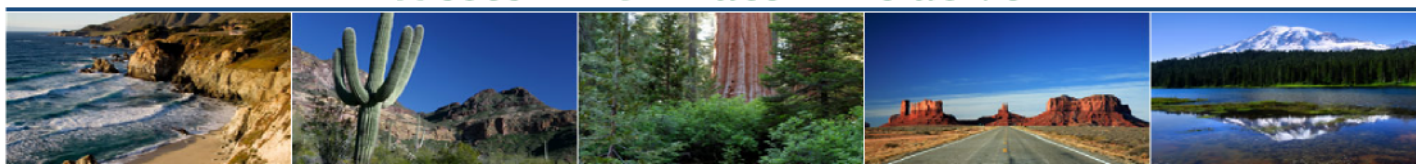
Table 20-7: Other Emission Factors

	CO ₂ Emission Factor (kg/GJ)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/GJ)
Municipal Solid Waste	85.6	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO₂ emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

The 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 WCI is presenting both. The WCI 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.

Western Climate Initiative



§ 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 the regulation, the emissions data report shall include the following information at the facility level:

- (a) Annual CO₂, CH₄, and N₂O emissions from refinery fuel gas combustion in tonnes.
- (b) Annual fuel consumption in units of standard cubic metres.
- (c) Average carbon content of each fuel used to compute CO₂ emissions.

§ WCI.33 Calculation of Greenhouse Gas Emissions

- (a) Calculation of CO₂ Emissions: Owners and operators shall calculate daily CO₂ emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(4) of this section. Calculate the total annual CO₂ emissions from combustion of all fuel gas by summing the CO₂ emissions from each fuel gas system.
 - (1) Use a CEMS that complies with the provisions in section WCI.23(d).
 - (2) Calculate CO₂ emissions from each refinery fuel gas system and flexigas system using measured carbon content and molecular weight of the gas and Equation 30-1.

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times \frac{MW}{MVC} \times 3.664 \times 0.001 \quad \text{Equation 30-1}$$

Where:

- CO₂ = Carbon dioxide emissions (tonnes/year).
- Fuel_i = Daily refinery fuel or flexigas combusted (Rm³) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the daily fuel combusted in kg and replace the term “MW/MVC” with “1”.
- CC_i = Daily sample of carbon content of the fuel (kg C/kg fuel).
- MW = Daily sample of molecular weight of fuel (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the variable Fuel_i (Rm³/kg-mole).
 - = 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
- 3.664 = Conversion factor for carbon to carbon dioxide.
- 0.001 = Conversion factor for kg to tonnes.
- n = Number of days in a year.

- (3) 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.
 - (4) Where individual fuels are mixed prior to combustion, the operator may choose to calculate CO₂ emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1) or (a)(2) 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 CO₂ emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO₂ emissions from the mixture. CO₂ 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, flexigas, and low heat content gas, use the methodology in paragraph (a)(2) of this section.
- (b) Calculation of CH₄ and N₂O Emissions. Owners and operators shall use the methods specified in section WCI.24 to calculate the annual CH₄ and N₂O emissions.

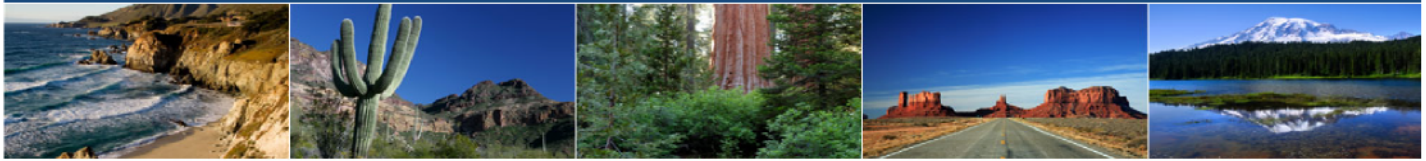
§ WCI.34 Sampling, Analysis, and Measurement Requirements

- (a) Measure the fuel consumption rate daily using methods specified in WCI.25(b).
- (b) Daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if there is sampling at a frequency of daily or more currently or if there is online instruments in place to monitor carbon content. Otherwise, weekly sampling and analysis of carbon content and molecular weight shall be performed. The equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas must be installed no later than January 1, 2012.
- (c) 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 regulator. Alternatively, the results of chromatographic analysis of the fuel gas may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in a plan.

§ WCI.35 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations by following the requirements of WCI.26.

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§ WCI.40 ELECTRICITY GENERATION

§ 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. This source category does not include portable or emergency generators less than 10 MW in nameplate generating capacity as defined in WCI.27.

§ 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 tonnes, reported as follows:
 - (1) Total CO₂ emissions for fossil fuels, reported by fuel type.
 - (2) Total CO₂ emissions for all biomass fuels combined.
 - (3) Total CH₄ emissions for all fuels combined.
 - (4) Total N₂O 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 kilolitres.
 - (3) For non-biomass solids, report in units of tonnes.
 - (4) For biomass-derived solid fuels, report in units of bone dry tonnes.
- (c) Annual weighted average carbon content of each fuel, if used to compute CO₂ emissions as specified in WCI.43.
- (d) Annual weighted average high heating value of each fuel, if used to compute CO₂ emissions as specified WCI.43.
- (e) The nameplate generating capacity in megawatts (MW) and net power generated in the reporting year in megawatt hours (MWh).
- (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, report this purpose and fuel consumption by fuel type using the units in WCI.42(b).
- (g) Process CO₂ emissions from acid gas scrubbers and acid gas reagent.

- (h) Fugitive emissions of each of the HFCs from cooling units that support power generation.
- (i) Fugitive CO₂ emissions from geothermal facilities.
- (j) Fugitive CH₄ 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

If a facility combusts natural gas or diesel in more than one electrical generating unit, and each unit is not individually metered (or, in the case of diesel, does not have a dedicated tank) and no CEMS is in place, the facility may calculate CO₂, CH₄, and N₂O emissions for each unit by using a common meter or tank that meets the requirement of this method, of WCI.020, and/or regulation, as appropriate.

To disaggregate emissions from the common meter for each unit, an engineering estimation approach that takes into account total emissions, relative operating hours of each unit, and combustion efficiency of each unit must be used. For diesel generating facilities in non-integrated remote areas, the disaggregation may be performed by calculation of MWh energy delivered by the facility and each diesel generating unit in combination with the amount of fuel used.

(a) Calculation of CO₂ Emissions.

Operators shall use CEMS to measure CO₂ emissions if required to operate a CEMS by any other federal, provincial, or local regulation and that includes both a stack gas volumetric flow rate monitor and a CO₂ concentration monitor. 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 may use such a CEMS for calculation of CO₂ emissions from electrical generating units for any fuel covered in WCI.43, if applicable to the situation at the facility. Operators using CEMS to determine CO₂ emissions shall comply with the provisions in section WCI.23(d).

- (1) Fuels Listed in Table 20-1a and Natural Gas. For electric generating units combusting natural gas (with a high heat value greater than or equal to 36.3 MJ/scm and less than or equal to 40.98 MJ/scm) or fuels in Table 20-1a, use methods in accordance with WCI.23.
 - (A) Calculation Methodology 1 may not be used at a facility for a fuel for which you routinely perform fuel sampling and analysis for the fuel high heat value or can obtain the results of fuel sampling and analysis for the fuel heat value from the fuel supplier at the frequency specified in WCI.25(a), or at a greater frequency. In such cases, Calculation Methodologies 2, 3, or 4 shall be used for those fuels.
 - (B) Natural Gas. For electric generating units combusting natural gas with a high heat value less than 36.3 MJ/scm or greater than 40.98 MJ/scm use the measured carbon content of the fuel and the Calculation Methodology 3 in WCI.23(c) or Calculation Methodology 4 in WCI.23(d).

- (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 WCI.23(c).
- (3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 20-1a. For electric generating units combusting middle distillates, gasoline, residual oil, or LPG, that are not listed in Table 20-1a, use one of the following methods:
 - (A) The measured carbon content of the fuel and Calculation Methodology 3 in WCI.23(c); or
 - (B) The measured heat content of the fuel and Calculation Methodology 2 in WCI.23(b), provided the facility is not subject to verification requirements by regulation.
- (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 WCI.30.
- (5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use methods in accordance with WCI.23.
- (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 WCI.23(b)(2), provided the facility is not subject to verification requirements by regulation. If the facility is subject to verification requirements by regulation, the operator shall use CEMS to measure CO₂ emissions in accordance with WCI.23(d), or calculate emissions using steam flow and a CO₂ 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 CO₂ emissions from fossil fuel combustion using one of the following methods. Malfunction means the unplanned outage of equipment; breakdown of equipment; or failure of equipment to operate normally, associated with the operation of a combustion device for an electricity generation unit(s). It does not include normal changes in operation conditions such as variations in combustion temperature, oxygen levels or moisture content of the fuel.
 - (A) The default emission factors from Tables 20-1a, 20-2, 20-3, 20-5 or 20-7, and default HHV from Tables 20-1 or 20-1a, as applicable, and calculation methodology 1 provided in WCI.23(a);
 - (B) The measured heat content of the fuel and Calculation Methodology 2 provided in WCI.23(b);
 - (C) The measured carbon content of the fuel and Calculation Methodology 3 provided in 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 WCI.30.

- (8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the operator shall calculate CO₂ emissions as follows.
- (A) For co-fired electricity generators that burn only fossil fuels, CO₂ emissions shall be determined using one of the following methods:
- (i) A continuous emission monitoring system in accordance with Calculation Methodology 4 in 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, CO₂ emissions shall be determined using one of the following methods:
- (i) A continuous emission monitoring system in accordance with Calculation Methodology 4 in WCI.23(d). Operators using this method shall determine the portion of the total CO₂ emissions attributable to the biomass-derived fuel and portion of the total CO₂ emissions attributable to the fossil fuel using the methods specified in WCI.23(d)(4).
 - (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)(7) of this section.
- (b) Calculation of CH₄ and N₂O Emissions. Operators of electricity generating units shall use the methods specified in WCI.24 to calculate the annual CH₄ and N₂O emissions. For coal combustion, use the default CH₄ emission factor(s) in Table 20-6.
- (c) Calculation of CO₂ 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 CO₂ emissions from these processes using Equation 40-1 if these emissions are not already captured in CO₂ emissions determined using a continuous emissions monitoring system.

$$CO_2 = S \times R \times (CO_{2\text{MW}} / \text{Sorbent}_{\text{MW}}) \quad \text{Equation 40-1}$$

Where:

- CO₂ = CO₂ emitted from sorbent for the report year (tonnes).
S = Limestone or other sorbent used in the report year (tonnes).
R = Ratio of moles of CO₂ released upon capture of one mole of acid gas.
CO₂ 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 or

from heating ventilation and air conditioning systems used for cooling of control rooms, offices and buildings at the facility.

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

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

Where:

- HFC = Annual fugitive HFC emission (tonnes).
 $HFC_{inventory}$ = 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.

$$HFC_{Install} = R_{new} - C_{new} \quad \text{Equation 40-2a}$$

$$HFC_{Service} = R_{recharge} - R_{recover} \quad \text{Equation 40-2b}$$

$$HFC_{Retire} = C_{retire} - R_{retire} \quad \text{Equation 40-2c}$$

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).
R_{retire}	=	HFC recovered from the retired unit (kilograms).

(e) Fugitive CO₂ Emissions from Geothermal Facilities. Operators of geothermal electricity generating facilities shall calculate the fugitive CO₂ emissions using one of the following methods:

(1) Calculate the fugitive CO₂ emissions using Equation 40-3:

$$CO_2 = 7.14 \times Heat \times 0.001 \quad \text{Equation 40-3}$$

Where:

CO ₂	=	CO ₂ emissions (tonnes per year).
7.14	=	Default fugitive CO ₂ emission factor for geothermal facilities (kg per GJ).
Heat	=	Heat taken from geothermal steam and/or fluid (GJ/yr).
0.001	=	Conversion factor from kg to tonnes.

(2) Calculate CO₂ emissions using source specific emission factor approved by the regulator for this rule..

§ WCI.44 Sampling, Analysis, and Measurement Requirements

- (a) CO₂, CH₄ and N₂O Emissions from Fuel Combustion. Operators using CEMS to estimate CO₂ emissions from fuel combustion shall comply with the requirements in WCI.23(d). Operators using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methods specified in WCI.25.
- (b) CO₂ 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) CO₂ 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 CO₂ emission rate using a method approved by the regulator. The operator shall submit a test plan to the regulator for approval. Once approved, the annual tests shall be conducted in accordance with the approved test plan under the supervision of the regulator .

§ WCI.45 Procedures for estimating missing data.

Whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

- (a) For all units using CEMS to measure CO₂ emissions, follow the missing data procedures in WCI.26(a)
- (b) For all other missing parameters used to calculate GHG emissions, follow the missing data procedures in WCI.26(b).

§ WCI.46 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

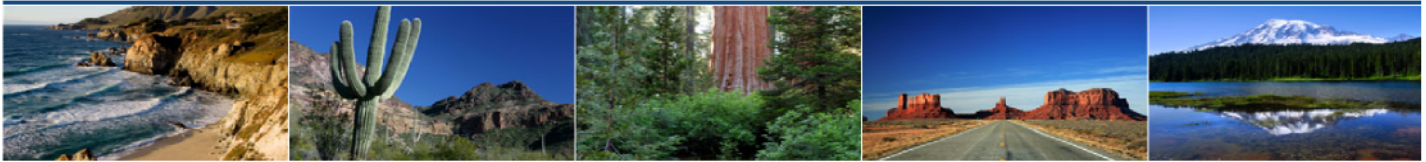
Bottoming cycle plant means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the rejected heat emerging from the application or process is then used for electricity production.

Cogeneration unit means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (a) used by the operator of the facility where the cogeneration unit is located; or (b) 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.

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.

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§ WCI.50 ADIPIC ACID MANUFACTURING

§ WCI.51 Source Category Definition

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ WCI.52 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for adipic acid manufacturing shall include the following information at the facility level calculated in accordance this method:

- (a) Annual process N₂O emissions from adipic acid production (tonnes).
- (b) Annual adipic acid production (tonnes).
- (c) Emissions of CO₂, CH₄, and N₂O from stationary combustion must report under WCI.20 (General Stationary Fuel Combustion Sources) following the requirements of WCI.20.

§ WCI.53 Calculation of N₂O Emissions

- (a) You must determine annual N₂O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.
 - (1) Use a site-specific emission factor and production data according to paragraphs (b) through (g) of this section.
 - (2) Request approval by the Director for an alternative method of determining N₂O emissions.
- (b) You must conduct an annual performance test or use continuous monitors according to paragraphs (b)(1) through (b)(3) of this section.
 - (1) You must conduct the test on the waste gas stream from the nitric acid oxidation step of the process using the methods specified in WCI.54 (b) through (d) or use a continuous monitoring system.
 - (2) You must conduct the performance test under normal process operating conditions and without using N₂O abatement technology or use a continuous monitoring system.
 - (3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period or the continuous monitoring period in tonnes per hour.
- (c) You must determine an N₂O emissions factor to use in Equation 50-2 of this section according to paragraphs (c)(1) or (c)(2) of this section.
 - (1) You may request Director approval for an alternative method of determining N₂O concentrations according to the procedures in paragraphs (a)(2) of this section.

- (2) Using the results of the test or continuous monitors in paragraph (b) of this section, you must calculate a facility-specific emissions factor according to Equation 50-1 for performance testing and 50-1a for continuous monitors of this section:

$$EF_{N_2O} = \frac{\sum_{i=1}^n \frac{C_{N_2O} * 1.826 \times 10^{-6} * Q}{P}}{n}$$

Equation 50-1

$$EF_{N_2O} = \frac{C_{N_2O} * 1.826 \times 10^{-6} * Q}{P}$$

Equation 50-1a

Where:

- EF_{N_2O} = Average facility-specific N_2O emissions factor (kg N_2O generated/tonne adipic acid produced).
- C_{N_2O} = N_2O concentration per test run during the performance test or average hourly concentrations for continuous monitors (ppm N_2O).
- 1.828×10^{-6} = Conversion factor (kg/dsm³-ppm N_2O).
- Q = Volumetric flow rate of effluent gas per test run during the performance test or hourly readings for continuous monitor (dsm³/hr).
- P = Production rate per test run during the performance test or the average hourly production rate for continuous monitors (tonnes adipic acid produced/hr).
- n = Number of test runs.

- (d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology used at your facility according to paragraphs (d)(1), (d)(2), (d)(3) or (d)(4) of this section.

- (1) Use the manufacturer's specified destruction efficiency.
- (2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.
- (3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.
- (4) Calculate the destruction efficiency by the use of continuous monitors on the controlled and uncontrolled emissions.

- (e) If applicable, you must determine the abatement factor for each N_2O abatement technology used at your facility. The abatement factor is calculated for each adipic acid facility according to Equation 50-2 of this section.

$$AF = \frac{P_{a \text{ Abate}}}{P_a} \quad \text{Equation 50-2}$$

Where:

- AF = Abatement factor of N₂O abatement technology (fraction of annual production that abatement technology is operating).
- P_{a Abate} = Annual adipic acid production during which N₂O abatement was used (tonne acid produced).
- P_a = Total annual adipic acid production (tonne acid produced).

- (f) You must determine the annual amount of adipic acid produced and the annual adipic acid production during which N₂O abatement is operating.
- (g) You must calculate annual adipic acid production process emissions of N₂O by multiplying the emissions factor (determined using Equation 50-1 of this section) by the adipic acid production for each period and accounting for N₂O abatement, according to Equation 50-3 of this section:

$$N_2O = \sum_{i=1}^N \frac{EF_{N2O_i} * P_{ai} * (1 - (DF_i * AF_i))}{1000} \quad \text{Equation 50-3}$$

Where:

- N₂O = Annual N₂O mass emissions from adipic acid production (tonnes).
- EF_{N2O_i} = Facility-specific N₂O emissions factor for the period *i* (kg N₂O generated/tonne adipic acid produced).
- P_{ai} = Adipic acid produced in the period *i* (tonnes).
- DF_{*i*} = Destruction efficiency of N₂O abatement technology for the period *i* (abatement device destruction efficiency, percent of N₂O removed from air stream).
- AF_{*i*} = Abatement factor of N₂O abatement technology for the period *i* (fraction of annual production abatement technology is operating).
- 1000 = Conversion factor (kg/tonne).
- N = Number of different periods in the year. For performance test, the period would be the time between each test (e.g., N is 1 year if performance test conducted annually). For continuous monitors, N would be the number of months in the year (or more) with P_{ai}, EF_{N2O_i}, DF_{*i*} and AF_{*i*} to be calculated for each month.

§ WCI.54 Monitoring Requirements

- (a) You must conduct a new performance test and calculate a new facility-specific emissions factor according to the frequency specified in paragraphs (a)(1) of this section, or use

continuous monitors to calculate a facility-specific emissions factor and destruction efficiency according to paragraphs (a)(2) of this section.

(1) Performance Test

- (i) Conduct the performance test annually.
- (ii) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(2) Continuous Monitors

- (i) Use continuous monitors to determine the uncontrolled emissions and the controlled N₂O emissions to derive an N₂O emission factor and abatement system destruction factor.
- (ii) The continuous monitors shall be operated in accordance with quality assurance and quality control program approved by the Director.

(b) You must measure the N₂O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

- (1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63 (U.S.), Appendix A;
- (2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy; or
- (3) An equivalent method or continuous monitors, with Director approval.

(c) You must determine the production rate(s) during the performance test according to paragraph (c)(1) or (c)(2) of this section.

- (1) Direct measurement (such as using flow meters or weigh scales).
- (2) Existing plant procedures used for accounting purposes.

(d) You must conduct all required performance tests according to the methods in WCI.54(b). For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

- (1) Analysis of samples, determination of emissions, and raw data.
- (2) All information and data used to derive the emissions factor.
- (3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly adipic acid production quantity and the monthly adipic acid production during which N₂O abatement technology is operating according to the methods in paragraphs (c)(1) or (c)(2) of this section.

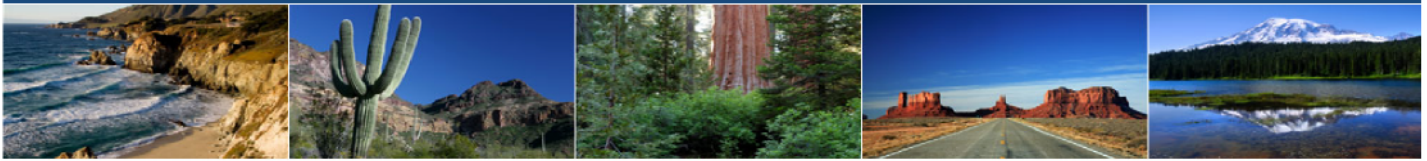
(f) You must determine the annual adipic acid production quantity and the annual adipic acid production quantity during which N₂O abatement technology is operating by summing the respective monthly adipic acid production quantities.

§ WCI.55 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

- (a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).
- (b) For missing values related to the performance test, including emission factors, production rate, and N₂O concentration, you must conduct a new performance test according to the procedures in §98.54 (a) through (d).

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§ 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 CO₂e;
 - (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 policies 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 CO₂ 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:

$$CO_2 = CO_{2t} \times \frac{MWh_{imp}}{MWh_t} \quad \text{Equation 60-1}$$

Where:

- CO₂ = Annual CO₂ mass emissions for imported electricity from the specified source (metric tons).
- CO_{2t} = Total annual CO₂ 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:

$$CO_2 = \sum HHV_f \times EF_f \times 0.001 \times \frac{MWh_{imp}}{MWh_t} \quad \text{Equation 60-2}$$

Where:

CO ₂	=	Annual CO ₂ mass emissions for a specific fuel type (metric tons).
HHV _f	=	Higher heating value of the fuel <i>f</i> 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 CO₂ 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:

$$CO_2 = MWh \times DEF \quad \text{Equation 60-3}$$

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 [<i>the jurisdiction</i>].
DEF	=	The default emission factor corresponding to the asset-controlling supplier, balancing authority area, or other geographic region defined by [<i>the jurisdiction</i>].

§ 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.

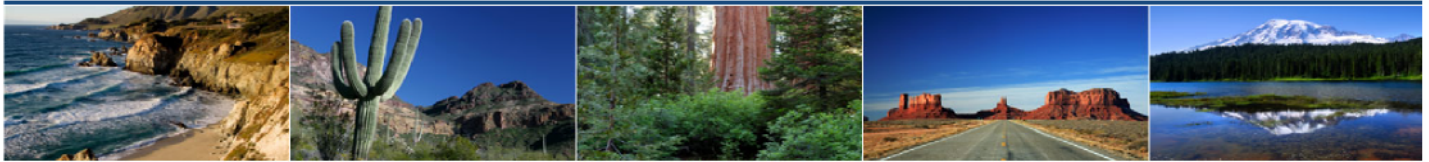
§ WCI.66 Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers Only.

[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.

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§ WCI.70 PRIMARY ALUMINUM PRODUCTION

§ WCI.71 Source Category Definition

A primary aluminum production process converts alumina mineral to aluminum metal using the Hall-Héroult manufacturing process, which includes electrolysis in prebake and Søderberg cells and anode baking for prebake cells.

§ 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) CO₂ emissions from anode consumption from prebaked and Søderberg electrolysis cells.
- (b) CO₂ emissions from anode and cathode baking.
- (c) CF₄ and C₂F₆ emissions for anode effects.
- (d) CO₂ emissions from green coke calcination.
- (e) SF₆ emissions from cover gas consumption.
- (f) CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in WCI.20.
- (g) Annual aluminum production.
- (h) Type of smelter technology used.
- (i) CF₄ and C₂F₆ emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.
- (j) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), and anode effect duration (minutes); alternatively, anode effect overvoltage factor (kg CF₄/metric ton Al) , potline overvoltage (mV/cell day), and current efficiency (%).
- (k) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific slope coefficients (or overvoltage emission factors) were measured.
- (l) Method used to measure the frequency and duration of anode effects (or overvoltage).
- (m) Annual anode consumption for prebake cells.
- (n) Annual CO₂ emissions from the smelter for prebake cells.
- (o) Annual paste consumption for Søderberg cells.
- (p) Annual CO₂ emissions from the smelter for Søderberg cells.
- (q) Smelter-specific inputs to the CO₂ process equations (e.g., levels of sulphur and ash) that were used in the calculation, on an annual basis.

§ WCI.73 Calculation of GHG Emissions

(a) Calculate CO₂ emissions from anode consumption using either Equation 70-1 or 70-2, as applicable.

(1) For Prebaked Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[NCC \times MP \times \frac{(100 - S_a - Ash_a)}{100} \times 3.664 \right]_i \quad \text{Equation 70-1}$$

Where:

- E_{CO_2} = Annual CO₂ emissions (tonnes).
- NCC = Net anode consumption per metric ton of aluminum for month i (tonne/tonne aluminum).
- MP = Aluminum production for month i (tonne).
- S_a = Sulphur content in baked anodes for month i (wt %).
- Ash_a = Ash content in baked anodes for month i (wt %).
- 3.664 = Conversion factor from carbon to CO₂.

(2) For Søderberg Anodes:

$$E_{CO_2} = \sum_{i=1}^{12} \left[\left(PC \times MP - \left(BSM \times \frac{MP}{1000} \right) - \left(\frac{BC}{100} \times PC \times MP \times \left(\frac{S_p + Ash_p + H_p}{100} \right) \right) \right) - \left(\frac{100 - BC}{100} \times PC \times MP \times \frac{S_c + Ash_c}{100} \right) - (CD \times MP) \right] \times 3.664 \quad \text{Equation 70-2}$$

Where:

- E_{CO_2} = Annual CO₂ emissions (tonnes).
- PC = Paste consumption for month i (tonnes paste/tonne aluminum).
- MP = Aluminum production for month i (tonnes).
- BSM = Emissions of benzene-soluble matter (kilograms benzene-soluble matter/tonne aluminum).
- BC = Average binder (pitch) content in paste for month i (wt %).
- S_p = Sulphur content in pitch for month i (wt %).
- Ash_p = Ash content in pitch (wt %).
- H_p = Hydrogen content in pitch (wt %).
- S_c = Sulphur content in calcinated coke (wt %).
- Ash_c = Ash content in calcinated coke (wt %).
- CD = Carbon in skimmed dust from Søderberg cells (tonne C/tonne aluminum).
- 3.664 = Conversion factor from carbon to CO₂.

(b) If anode or cathode baking is performed onsite, calculate CO₂ 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 CO₂ emissions from packing coke using Equation 70-3.

$$EC_{CO_2} = \sum_{i=1}^{12} \left(PCC \times BAP \times \frac{100 - Ash_{pc} - S_{pc}}{100} \right)_i \times 3.664 \quad \text{Equation 70-3}$$

Where:

- EC_{CO_2} = Annual CO₂ emissions (tonnes pre year).
- PCC = Packing coke consumption per tonne of baked anode for month i (tonnes coke/tonne anodes).
- BAP = Baked anode production for month i (tonnes).
- Ash_{pc} = Ash content in packing coke for month i (wt %).
- S_{pc} = Sulphur content in packing coke for month i (wt %).
- 3.664 = Conversion factor from carbon to CO₂.

(2) Calculate CO₂ emissions from pitch coking using Equation 70-4.

$$EP_{CO_2} = \sum_{i=1}^{12} \left(GAW - BAP - \left(\frac{H_p}{100} \times \frac{PC}{100} \times GAW \right) - RT \right)_i \times 3.664 \quad \text{Equation 70-4}$$

Where:

- EP_{CO_2} = CO₂ emissions (tonnes pre year).
- GAW = Green anode consumption for month i (tonnes).
- BAP = Baked anode production for month i (tonnes).
- H_p = Hydrogen content in pitch for month i (wt %).
- PC = Pitch content in green anode for month i (wt %).
- RT = Recovered tar for month i (tonnes).
- 3.664 = Conversion factor from carbon to CO₂.

(3) Calculate total CO₂ emissions for anode baking using Equation 70-5.

$$E_{anodebaking} = EC_{CO_2} + EP_{CO_2} \quad \text{Equation 70-5}$$

Where:

- $E_{anodebaking}$ = Total annual CO₂ emissions from anode baking (tonnes).
- EC_{CO_2} = Annual CO₂ emissions from packing coke (tonnes).
- EP_{CO_2} = Annual CO₂ emissions from pitch coking (tonnes).

(c) Calculate CF₄ emissions using either paragraph (c)(1) or (c)(2) and calculate C₂F₆ emissions using paragraph (c)(3).

(1) Calculate CF₄ emissions from anode effect duration using Equation 70-6.

$$E_{CF_4} = \sum_{i=1}^{12} [S_{CF_4} \times AEM \times MP]_i \quad \text{Equation 70-6}$$

Where:

- E_{CF_4} = Annual emissions of CF₄ (tonnes/yr).
- S_{CF_4} = Slope coefficient ([tonnes of CF₄/tonne aluminum]/[AE minutes/cell-days]).

AEM = Anode effect frequency (AE-minutes/cell-day), calculated monthly.
 MP = Monthly aluminum production (tonnes).

(2) Calculate CF₄ emissions from overvoltage using Equation 70-7.

$$E_{CF_4} = \sum_{i=1}^{12} [EF_{CF_4} \times MP]_i \quad \text{Equation 70-7}$$

Where:

E_{CF₄} = Annual emissions of CF₄ (tonnes/yr).
 EF_{CF₄} = Overtoltage emission factor (tonnes of CF₄/tonne aluminum).
 MP = Monthly aluminum production (tonnes).

(3) Calculate C₂F₆ emissions from anode effects using Equation 70-8.

$$E_{C_2F_6} = \sum_{i=1}^{12} [E_{CF_4} \times F_{C_2F_6 / CF_4}]_i \quad \text{Equation 70-8}$$

Where:

E_{C₂F₆} = Annual emissions of C₂F₆ (tonnes/yr).
 E_{CF₄} = Monthly emissions of CF₄ (tonnes/yr).
 F_{C₂F₆/CF₄} = Weight fraction of C₂F₆/CF₄ (kg C₂F₆/kg CF₄).

(d) Calculate CO₂ emissions from onsite green coke calcination furnaces using Equation 70-9.

$$E_{CO_2} = \sum_{n=1}^{12} \left[\left[GC \times \frac{(100 - H_{2O_{gc}} - V_{gc} - S_{gc})}{100} - (CC + UCC + DE) \times \frac{(100 - S_{cc})}{100} \right] \times 3.664 \right]_i + \left[GC \times 0.035 \times \frac{44}{16} \right]_i \quad \text{Equation 70-9}$$

Where:

E_{CO₂} = CO₂ emissions (tonnes pre year).
 GC = Green coke feed for month *i* (tonnes).
 H₂O_{gc} = Humidity in green coke feed for month *i* (wt %).
 V_{gc} = Volatiles in green coke feed for month *i* (wt %).
 S_{gc} = Sulphur content in green coke feed in month *i* (wt %).
 S_{cc} = Sulphur content in calcinated coke in month *i* (wt %).
 CC = Calcinated coke produced in month *i* (tonnes).
 UCC = Under-calcinated coke produced in month *i* (tonnes).
 DE = Coke dust emissions for month *i* (tonnes).
 3.664 = Conversion factor from carbon to CO₂.
 0.035 = Assumed CH₄ and tar content in coke volatiles, contributing to CO₂ emissions.
 44/16 = Conversion factor from methane to CO₂.

(e) Calculate SF₆ emissions from cover gas consumption using one of the following methods:

(1) Calculate the annual SF₆ emissions using inventory records and Equation 70-10:

$$E_{SF6} = S_{Inv-Begin} - S_{Inv-End} + S_{Purchased} - S_{Shipped} \quad \text{Equation 70-10}$$

Where:

- E_{SF6} = SF₆ emissions from cover gas (tonnes).
- S_{Purchased} = Quantity of SF₆ purchased (tonnes).
- S_{Shipped} = Quantity of SF₆ shipped offsite (tonnes).
- S_{Inv-Begin} = Quantity of SF₆ in storage at the beginning of the year, (tonnes).
- S_{Inv-End} = Quantity of SF₆ in storage at the end of the year (tonnes).

(2) Calculate the annual SF₆ 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:

$$E_{SF6} = \sum_{i=1}^{12} [(Q_{Input} \times C_{Input}) - (Q_{Output} \times C_{Output})]_i \quad \text{Equation 70-11}$$

Where:

- E_{SF6} = SF₆ emissions from cover gas (tonnes).
- Q_{in:put} = Quantity of SF₆ input to the electrolysis cell for month *i* (tonnes).
- C_{Input} = Concentration of SF₆ input to the electrolysis cell for month *i* (tonnes).
- Q_{Output} = Quantity of SF₆ gas collected during month *i* (if applicable) (tonnes).
- C_{Output} = Concentration of SF₆ gas collected and sent off-site during month *i* (tonnes).

§ 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 repeated 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.

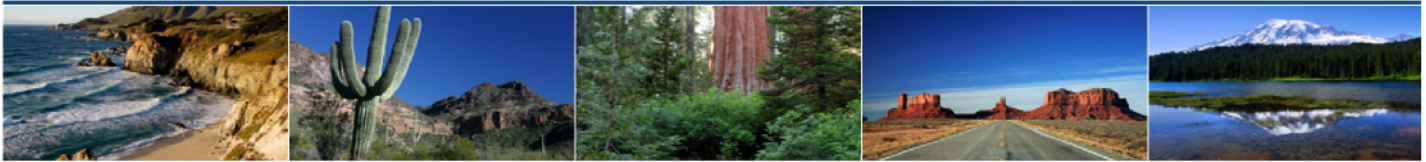
- (c) If using the direct measurement approach in WCI.73(e)(2) to calculate SF₆ emissions from cover gas consumption, the quantity of SF₆ gas input to the electrolysis cell month and the quantity and SF₆ concentration of any waste gas collected and sent off-site must be measured.

§ WCI.75 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.
- (b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

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§ WCI.80 AMMONIA MANUFACTURING

§ WCI.81 Source Category Definition

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

- (a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.
- (b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§ WCI.82 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for ammonia acid manufacturing shall include the following information at the facility level calculated in accordance this method:

- (a) CO₂ process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material following the requirements in this subpart.
- (b) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.
- (c) If a CEMS is used to measure CO₂ emissions, then you must report the relevant information required under WCI.23 for Calculation Methodology 4 and the following information:
Annual quantity of each type of feedstock consumed for ammonia manufacturing (sm³ of feedstock or kilolitres of feedstock or tonnes of feedstock).
- (d) If a CEMS is not used to measure emissions, then you must report the following information:
 - (1) Whether carbon content for each feedstock is based on reports from the supplier or analysis of carbon content.
 - (2) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month *n*, (kg C per sm³ of feedstock).
 - (3) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month *n*, (kg C per kilolitre of feedstock).
 - (4) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month *n*, (kg C per kg of feedstock).
 - (5) Annual CO₂ emissions associated with the waste recycle stream (tonnes).
 - (6) Carbon content of the waste recycle stream (kg C per kg of waste recycle stream).
 - (7) Volume of the waste recycle stream (sm³).

(e) Annual urea production (tonnes).

§ WCI.83 Calculating GHG emissions

You must calculate and report the annual process CO₂ emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

- (a) Calculate and report under this subpart the process CO₂ emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology specified in WCI.23 and all associated requirements for Tier 4 in WCI.20 (General Stationary Fuel Combustion Sources).
- (b) Calculate and report under this subpart process CO₂ emissions using the procedures in paragraphs (b)(1) through (b)(6) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.
- (1) Gaseous feedstock. You must calculate the CO₂ process emissions from gaseous feedstock according to Equation 80-1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad \text{Equation 80-1}$$

Where:

- CO_{2,G,k} = Annual CO₂ emissions arising from gaseous feedstock consumption (tonnes).
- Fdstk_{n,k} = Volume of the gaseous feedstock used in month *n* (Rm³ of feedstock) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock used in the month *n* as kg feedstock and replace the term “MW/MVC” with “1”.
- CC_n = Carbon content of the gaseous feedstock, for month *n*, (kg C per kg of feedstock), determined according to WCI.84(c).
- MW = Molecular weight of the gaseous feedstock (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above Fdstk_{n,k} (Rm³/kg-mole).
- = 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal]
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- 0.001 = Conversion factor from kg to tonnes.
- k = Processing unit.
- n = Number of months.

- (2) Liquid feedstock. You must calculate, from each ammonia manufacturing unit, the CO₂ process emissions from liquid feedstock according to Equation 80-2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n \right) * 0.001 \quad \text{Equation 80-2}$$

Where:

$CO_{2,L,k}$	=	Annual CO_2 emissions arising from liquid feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Volume of the liquid feedstock used in month n (kilolitres of feedstock). If a mass flow meter is used, measure the feedstock used in month n as kg of feedstock and measure the carbon content of feedstock in kg C per kg of feedstock.
CC_n	=	Carbon content of the liquid feedstock, for month n as determined according to WCI.84(c) (kg of C per kilolitre of feedstock when feedstock consumption is measured in kilolitres or kg of C per kg of feedstock when feedstock consumption is measured in kg).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of months.

- (3) Solid feedstock. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation 80-3 of this section:

$$CO_{2,S,k} = \left(\sum_{n=1}^{12} 3.664 * Fdstk_{n,k} * CC_n \right) * 0.001 \quad \text{Equation 80-3}$$

Where:

$CO_{2,S,k}$	=	Annual CO_2 emissions arising from solid feedstock consumption (tonnes).
$Fdstk_{n,k}$	=	Mass of the solid feedstock used in month n (kg of feedstock).
CC_n	=	Carbon content of the solid feedstock, for month n , (kg C per kg of feedstock), determined according to WCI.84(c).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.
k	=	Processing unit.
n	=	Number of months.

- (4) You must calculate the annual process CO_2 emissions from each ammonia processing unit k at your facility summing emissions, as applicable from Equation 80-1, 80-2, and 80-3 of this section using Equation 80-4.

$$E_{CO_2k} = CO_{2,G} + CO_{2,S} + CO_{2,L} \quad \text{Equation 80-4}$$

Where:

E_{CO_2k}	=	Annual CO_2 emissions from each ammonia processing unit k (tonnes).
k	=	Processing unit.

- (5) You must determine the combined CO_2 emissions from all ammonia processing units at your facility using Equation 80-5 of this section.

$$CO_2 = \sum_{k=1}^n E_{CO2k}$$

Equation 80-5

Where:

- CO_2 = Annual combined CO_2 emissions from all ammonia processing units (tonnes).
 E_{CO2k} = Annual CO_2 emissions from each ammonia processing unit k (tonnes).
 k = Processing unit.
 n = Total number of ammonia processing units.

- (6) If applicable, ammonia manufacturing facilities that utilize the waste recycle stream as a fuel must calculate emissions associated with the waste stream for each ammonia process unit according to Equation 80-6 of this section:

$$CO_2 = \left(\sum_{n=1}^{12} 3.664 * RecycleStream_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad \text{Equation 80-6}$$

Where:

- CO_2 = Annual CO_2 contained in waste recycle stream (tonnes).
 $RecycleStream_n$ = Volume of the waste recycle stream in month n (Rm^3) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the waste recycle stream in month n as kg and replace the term “MW/MVC” with “1”.
 CC_n = Carbon content of the waste recycle stream, for month n , (kg C per kg of waste recycle stream) determined according to WCI.84(f).
 MW = Molecular weight of the waste recycle stream (kg/kg-mole).
 MVC = Molar volume conversion factor at the same reference conditions as the above $RecycleStream_n$ (Rm^3/kg -mole).
= $8.3145 * [273.16 + \text{reference temperature in } ^\circ C] / [\text{reference pressure in kilopascal}]$.
3.664 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to tonnes.
 n = Number of month

- (c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in WCI.23 (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in WCI.23 and all associated requirements for Methods 4 in WCI.23.

§ WCI.84 Monitoring and QA/QC Requirements

- (a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.
- (b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.
- (c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.
 - (1) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see regulation).
 - (2) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see regulation).
 - (3) ASTM D2502-04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, see regulation).
 - (4) ASTM D2503-92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see regulation).
 - (5) 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 (incorporated by reference, see regulation).
 - (6) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, regulation).
 - (7) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see regulation).
 - (8) ASTM D5373-08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see regulation).
- (d) Calibrate all oil and gas flow meters (except for gas billing meters) and perform oil tank measurements according to the monitoring and QA/QC requirements for Method 3 in WCI.25.
- (e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.
- (f) Facilities must continuously measure the quantity of waste gas recycled using a flow meter, as applicable. You must determine the carbon content and the molecular weight of the waste

recycle stream by collecting a sample of each waste recycle stream on a monthly basis and analyzing the carbon content using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

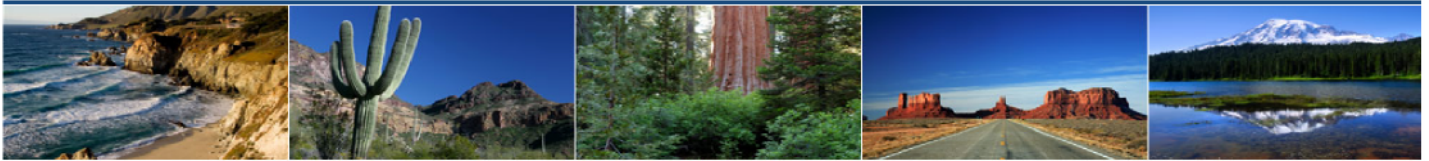
- (g) If CO₂ from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

§ WCI.85 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in WCI.84 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.
- (b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

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§ 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 regulation, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CH₄, and N₂O in tonnes.
- (b) Annual CO₂ process emissions from calcination (tonnes) and the following information:
 - (1) Monthly plant specific clinker emission factors (tonnes CO₂/tonnes clinker).
 - (A) Monthly quantities of clinker produced (tonnes).
 - (B) Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).
 - (C) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne MgO/tonne clinker).
 - (D) Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).
 - (E) Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).
 - (F) Monthly quantity of non-carbonate raw materials entering the kiln (tonnes).
 - (2) Quarterly cement kiln dust (CKD) emission factor (tonne CO₂/tonne CKD not recycled back to the kiln).
 - (A) Quarterly quantity of CKD not recycled back to the kiln (tonnes).
- (c) Annual CO₂ process emissions from organic carbon oxidation (tonnes) and the following information:
 - (1) Amount of raw material consumed in the report year (tonnes).
 - (2) Annual organic carbon content of raw material (weight fraction).
- (d) Annual CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.93(c) (tonnes).
- (e) Annual CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (tonne).

- (f) If a continuous emissions monitor is used to measure CO₂ emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO₂. Cement plants that measure CO₂ 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 by regulation, 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).
- (h) Number of times missing data procedures were used to determine clinker production, non-calcined calcium oxide, magnesium oxide content of clinker, CKD not recycled, non-calcined calcium oxide, magnesium oxide content of CKD, organic carbon content, and raw material consumption.

§ WCI.93 Calculation of Greenhouse Gas Emissions From Kilns

- (a) Determine CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
 - (1) Calculate the total process and combustion CO₂ emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d) and combustion CO₂ emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ 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 90-1).

$$E_{CO_2-P} = E_{CO_2-C} + E_{CO_2-F} \quad \text{Equation 90-1}$$

Where:

- E_{CO_2-P} = Annual process CO₂ emissions (tonne/year).
- E_{CO_2-C} = Annual process CO₂ emissions from calcination (tonne/year).
- E_{CO_2-F} = Annual process CO₂ emissions from feed oxidation (tonne/year).

- (1) Calcination Emissions. Calculate CO₂ process emissions from calcination using Equation 90-2 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{CO_2-C} = \sum_{m=1}^{12} [Q_{cli,m} \times EF_{cli,m}] + \sum_q^4 [Q_{CKD,q} \times EF_{CKD,q}] \quad \text{Equation 90-2}$$

Where:

- E_{CO_2-C} = Annual process CO₂ emissions from calcination (tonnes).
 $Q_{Cli,m}$ = Quantity of clinker produced in month m (tonnes).
 $EF_{Cli,m}$ = CO₂ emission factor for clinker produced in month m , computed as specified in paragraph (b)(1)(A) of this section (tonnes CO₂/tonne clinker).
 $Q_{CKD,q}$ = Quantity CKD not recycled to the kiln in quarter q (tonnes).
 $EF_{CKD,q}$ = CO₂ emission factor for CKD not recycled to the kiln in quarter q , computed as specified in paragraph (b)(1)(B) of this section (tonne CO₂/tonne CKD).

- (A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor (EF_{Cli}) for each month based on monthly measurements of the weight fractions of calcium (as CaO) and magnesium (as MgO) content in the clinker and in the non-carbonate raw materials entering the kiln, using Equation 90-3.

$$EF_{Cli} = (CaO_{Cli} - CaO_f) \times 0.785 + (MgO_{Cli} - MgO_f) \times 1.092 \quad \text{Equation 90-3}$$

Where:

- EF_{Cli} = Monthly CO₂ emission factor for clinker (tonne CO₂/tonne clinker).
 CaO_{Cli} = Monthly total calcium content of clinker expressed as calcium oxide (tonne CaO/tonne clinker).
 CaO_f = Monthly non-calcined calcium oxide content of clinker (tonne CaO/tonne clinker).
 MgO_{Cli} = Monthly total magnesium content of clinker expressed as magnesium oxide (tonne MgO/tonne clinker).
 MgO_f = Monthly non-calcined magnesium oxide content of clinker (tonne MgO/tonne clinker).
0.785 = Ratio of molecular weights of CO₂ to CaO.
1.092 = Ratio of molecular weights of CO₂ to MgO.

- (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 quarterly sampling. The CKD emission factor shall be calculated using Equation 90-4.

$$EF_{CKD} = (CaO_{CKD} - CaO_f) \times 0.785 + (MgO_{CKD} - MgO_f) \times 1.092$$

Equation 90-4

Where:

- EF_{CKD} = Quarterly CO₂ emission factor for CKD not recycled to the kiln (tonne CO₂/tonne CKD).
 CaO_{CKD} = Quarterly total calcium oxide content of CKD (tonne CaO/tonne CKD).
 CaO_f = Quarterly non-calcined calcium oxide content of CKD (tonne CaO/tonne CKD).
 MgO_{CKD} = Quarterly total magnesium oxide content of CKD (tonne MgO/tonne CKD).
 MgO_f = Quarterly non-calcined magnesium oxide content of CKD (tonne MgO/tonne CKD).
0.785 = Ratio of molecular weights of CO₂ to CaO.
1.092 = Ratio of molecular weights of CO₂ to MgO.

- (2) Organic Carbon Oxidation Emissions. Calculate CO₂ process emissions from the total organic content in raw materials by using Equation 90-5.

$$E_{CO_2-F} = TOC_{RM} \times RM \times 3.664 \quad \text{Equation 90-5}$$

Where:

- E_{CO_2-F} = Annual process CO₂ emissions from raw material oxidation (tonnes).
 TOC_{RM} = Total organic carbon content in raw material (wt. fraction), measured using the method in WCI.94(g) or using a default of 0.002 (0.2%).
 RM = Amount of raw material consumed (tonnes/year).
3.664 = CO₂ to carbon molar ratio.

- (c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O 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 CO₂ emissions from fossil fuels using the emission factor methodology in WCI.23(a). “Pure” means that the biomass-derived fuels account for at least 97 percent of the total amount of carbon in the fuels burned.

§ WCI.94 Sampling, Analysis, and Measurement Requirements

- (a) Determine monthly, the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker using ASTM C114, an equivalent industry method, or a method approved by the Director. The monitoring must be conducted either daily from clinker drawn from the exit of the kiln or monthly from clinker drawn from bulk storage.
- (b) Determine quarterly, the plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in CKD using ASTM C114, an equivalent industry method, or a method approved by the Director. The monitoring must be conducted daily from CKD samples drawn from the exit of the kiln or quarterly from CKD samples drawn from bulk storage.
- (c) Determine monthly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to clinker by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.
- (d) Determine quarterly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that enters the kiln as a non-carbonate species to CKD by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.
- (e) Determine monthly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in clinker by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.
- (f) Determine quarterly, the plant-specific weight fractions of calcium oxide (CaO) and magnesium oxide (MgO) that remains in CKD by chemical analysis of feed material using documented analytical method, the appropriate industrial standard practice, or a value of 0.0.

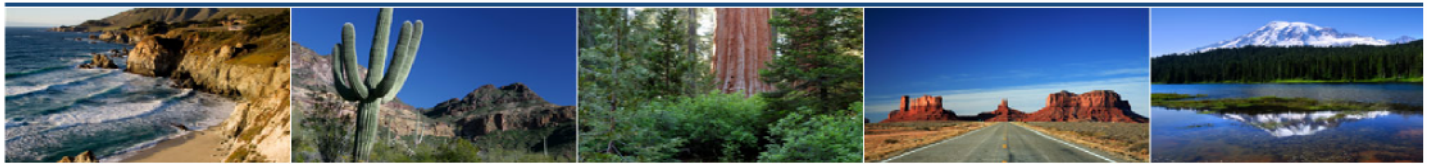
- (g) Determine annually, the total organic carbon contents of raw materials using ASTM C114, an equivalent industry method, method approved for total organic carbon determination in raw mineral material, or use a default value of 0.002 (0.2%). The analysis must be conducted on sample material drawn from bulk raw material storage for each category of raw material.
- (h) The quantity of clinker produced must be determined monthly by either:
 - (1) Direct weight measurement using the same plant techniques used for accounting purposes, such as reconciling weigh hoppers or belt weigh feeders measurements against inventory measurements, or
 - (2) Direct measurement of raw kiln feed and application of a kiln-specific feed-to-clinker factor. Facilities that opt to use a feed to clinker factor must verify the accuracy of this factor on a monthly basis.
- (i) The quantity of CKD not recycled back to the kiln must be determined quarterly by either using the same plant techniques used for accounting purposes, such as direct weight measurement using weigh hoppers or belt weigh feeders, and/or material balances.
- (j) The quantity of raw materials consumed (i.e. limestone, sand, shale, iron oxide, alumina, and non-carbonate raw material) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

§ WCI.95 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

- (a) If the CEMS approach is used to determine combined process and combustion CO₂ emissions, the missing data procedures in WCI.20 apply.
- (b) For CO₂ process emissions from cement manufacturing facilities calculated according to WCI.93(b), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.
- (c) For each missing value of monthly clinker production, the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.
- (d) For each missing value of monthly raw material consumption, the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.

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§ 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 CH₄ emissions. Within natural coal deposits, CH₄ 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 CH₄ to the atmosphere; adsorbed CH₄ is also released until the CH₄ 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 tonnes, reported as follows:
 - (1) Total CH₄ emissions.
- (b) Annual coal purchases (tons for U.S.; tonnes for Canada).
- (c) Source of coal purchases:
 - (1) Coal basin.
 - (2) State/province.
 - (3) Coal mine type (surface or underground).

§ WCI.103 Calculation of CH₄ 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 Climate Action Reserve reporting protocol, 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 CH₄ 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 CH₄ emissions using Equation 100-1 and Table 100-1.
- (b) For coal purchased from Canadian sources, calculate fugitive CH₄ emissions using Equation 100-1 and Table 100-2.
- (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 regulator.

$$CH_4 = \sum_i (PC_i \times EF_i) \times 0.6772 / 1,000 \quad \text{Equation 100-1}$$

Where:

- CH₄ = Fugitive emissions from coal storage piles for each coal category *i*, (tonnes CH₄ per year);
- PC_{*i*} = Purchased coal for each coal category *i* (tonnes per year);
- EF_{*i*} = Default CH₄ emission factor for each coal category *i* specified by location and mine type that coal originated from, provided in Table 100-1 or Table 100-2 (m³ CH₄ per tonne of coal);
- 0.6772 = Methane conversion factor to convert m³ to kg;
- 1,000 = Factor to convert kg to tonnes.

§ 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.

§ WCI.105 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (a) of this section. You must document and keep records of the procedures used for all such estimates.

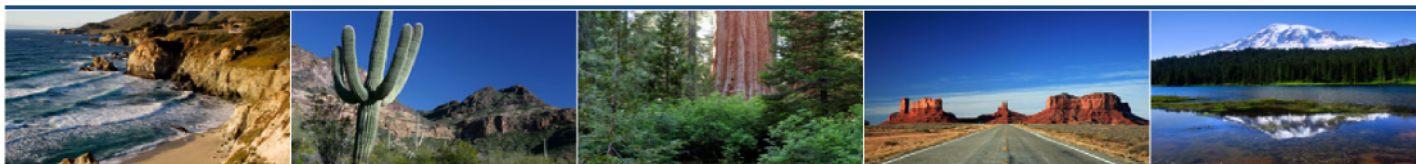
- (a) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Tonne)			
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,	0.3372	1.9917
Rockies (Uinta Basin)	New Mexico, Utah	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: <i>Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005</i> 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 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH₄ m³ per Tonne)			
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: <i>Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options</i> . Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Dartmouth, 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).			

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§ WCI.110 ELECTRONICS MANUFACTURING

§ WCI.111 Source Category Definition

Electronics manufacturing facilities include, but are not limited to, facilities that manufacture semiconductors, liquid crystal displays (LCDs), micro-electro-mechanical systems (MEMS), and photovoltaic cells (PV). The electronics source category consists of any of the processes listed in paragraphs (a) through (f) of this section that are located at electronics manufacturing facilities.

- (a) Processes in which the etching process uses plasma-generated fluorine atoms and other reactive fluorine-containing fragments, which chemically react with exposed thin-films (e.g., dielectric, metals) and silicon to selectively remove portions of material.
- (b) Processes in which chambers used for depositing thin films are cleaned periodically using plasma-generated fluorine atoms and other reactive fluorine-containing fragments from fluorinated and other gases.
- (c) Processes in which wafers are cleaned using plasma-generated fluorine atoms or other reactive fluorine-containing fragments to remove residual material from wafer surfaces.
- (d) Processes in which some fluorinated compounds can be transformed in the plasma processes into different fluorinated compounds which are then exhausted, unless abated, into the atmosphere.
- (e) Processes in which the chemical vapor deposition process or other manufacturing processes use N_2O .
- (f) Processes in which fluorinated GHGs are used as heat transfer fluids to cool process equipment, control temperature during device testing, and solder semiconductor devices to circuit boards.

§ WCI.112 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of N_2O and fluorinated GHGs. The fluorinated GHGs that are emitted from electronics production processes include, but are not limited to, those listed in Table 110-1 of this subpart. The process that must be reported include: fluorinated GHGs from plasma etching, fluorinated GHGs from chamber cleaning, fluorinated GHGs from wafer cleaning, N_2O from chemical vapor deposition and other manufacturing processes, and fluorinated GHGs from heat transfer fluid use.
- (b) CO_2 , N_2O , and CH_4 emissions from stationary combustion units as specified in WCI.20.
- (c) The method of emissions calculation used in WCI.113.
- (d) Production in terms of substrate surface area (e.g., silicon, PV-cell, LCD).

- (e) Emission factors used for process utilization and by-product formation rates and the source for each factor for each fluorinated GHG and N₂O.
- (f) Where process categories for semiconductor facilities as defined in WCI.113(a)(1)(i) through (a)(1)(iii) are not used, descriptions of individual processes or process categories used to estimate emissions.
- (g) For each fluorinated GHG and N₂O, annual gas consumed during the reporting year and facility-wide gas-specific heel-factors used.
- (h) The apportioning factors for each process category (i.e., fractions of each gas fed into each individual process or process category used to calculate fluorinated GHG and N₂O emissions) and a description of the engineering model used for apportioning gas usage per WCI.114(b). If the method used to develop the apportioning factors permits the development of facility-wide consumption estimates that are independent of the estimates calculated in Equation 110-6 of this subpart (e.g., that are based on wafer passes for each individual process or process category), report the independent facility-wide consumption estimate for each fluorinated GHG and N₂O.
- (i) Fraction of each gas fed into each process type that is fed into tools with abatement systems.
- (j) Description of all abatement systems through which fluorinated GHGs or N₂O flow at the facility, including the number of devices of each manufacturer, model numbers, manufacturers guaranteed destruction or removal efficiencies, if any, and record of destruction or removal efficiency measurements over its in-use life. The inventory of abatement systems shall also include a description of the associated tools and/or processes for which these systems treat exhaust.
- (k) For each abatement system through which fluorinated GHGs or N₂O flow at the facility, for which controlled emissions are reported, the following:
 - (1) Certification that each abatement system used at the facility is installed, maintained, and operated in accordance with manufacturers' specifications.
 - (2) The uptime and the calculations to determine uptime for that reporting year.
 - (3) The default destruction or removal efficiency value or properly measured destruction or removal efficiencies for each abatement system used in that reporting year to reflect controlled emissions.
 - (4) Where the default destruction or removal efficiency value is used to report controlled emissions, certification that the abatement systems for which controlled emissions are being reported are specifically designed for fluorinated GHG and N₂O abatement.
 - (5) Where properly measured destruction or removal efficiencies or class averages of destruction or removal efficiencies are used to report controlled emissions, the following:
 - (i) A description of the class including the abatement system manufacturer and model number, and the fluorinated GHG and N₂O in the process effluent stream;
 - (ii) The total number of systems in that class for the reporting year.
 - (iii) The total number of systems for which destruction or removal efficiency was measured in that class for the reporting year.

- (iv) A description of the calculation used to determine the class average, including all inputs of the calculation.
 - (v) A description of method of randomly selecting class members for testing.
- (l) For heat transfer fluid emissions, inputs to the mass-balance equation, Equation 110-8 of this subpart for each fluorinated GHG.
- (m) Example calculations for fluorinated GHG, N₂O, and heat transfer fluid emissions.

§ WCI.113 Calculation of GHG Emissions

- (a) For each fluorinated GHG and each process type used at the facility (i.e., plasma etching, chamber cleaning, or wafer cleaning) as appropriate, calculate annual facility-level emissions using Equations 110-1 and 110-2 of this section and according to the procedures in paragraph (a)(1), (a)(2), or (a)(3) of this section.

$$processtypeE_i = \sum_{j=1}^N E_{ij} \quad \text{Equation 110-1}$$

Where:

- processtypeE_i = Annual emissions of input gas *i* from the processes type (tonnes);
- E_{ij} = Annual emissions of input gas *i* from individual process *j* or process category *j* (tonnes); and
- N = Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

$$processtypeBE_k = \sum_{j=1}^N \sum_i BE_{kij} \quad \text{Equation 110-2}$$

Where:

- processtypeBE_k = Annual emissions of by-product gas *k* from the processes type (tonnes);
- BE_{kij} = Annual emissions of by-product *k* formed from input gas *i* during individual process *j* or process category *j* (tonnes); and
- N = Total number of individual processes *j* or process categories *j*, which depend on the electronics manufacturing facility and emission calculation methodology.

- (1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each fluorinated GHG-using process type, either from all individual processes at that facility in accordance with WCI.114(c), or from process categories as defined in this paragraph (a)(1).
- (i) All etching process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(i).

- (A) Oxide etch means any process using fluorinated GHG reagents to selectively remove SiO_2 , SiO_x -based, or fully organic-based thin-film material that has been deposited on a wafer during semiconductor device manufacturing.
 - (B) Nitride etch means any process using fluorinated GHG reagents to selectively remove SiN , SiON , Si_3N_4 , SiC , SiCO , SiCN , etc. (represented by the general chemical formula, $\text{Si}_w\text{O}_x\text{N}_y\text{X}_z$ where w , x , y and z are zero or integers and X can be some other element such as carbon) that has been deposited on a wafer during semiconductor manufacturing.
 - (C) Silicon etch also often called polysilicon etch, means any process using fluorinated GHG reagents to selectively remove silicon during semiconductor manufacturing.
 - (D) Metal etch means any process using fluorinated GHG reagents associated with removing metal films (such as aluminum or tungsten) that have been deposited on a wafer during semiconductor manufacturing.
- (ii) All chamber cleaning process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(ii).
- (A) In situ plasma means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is dissociated into its cleaning constituents by a plasma generated inside the chamber where the film was produced.
 - (B) Remote plasma system means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent dissociated by a remotely located (e.g., upstream) plasma source.
 - (C) In situ thermal means cleaning thin-film production chambers, after processing one or more wafers, with a fluorinated GHG cleaning reagent that is thermally dissociated into its cleaning constituents inside the chamber where the thin-film (or thin films) was (were) produced.
- (iii) All wafer cleaning process categories for which annual fluorinated GHG emissions shall be calculated are defined in this paragraph (a)(1)(iii) .
- (A) Bevel cleaning means any process using fluorinated GHG reagents with plasma to clean the edges of wafers during semiconductor manufacture.
 - (B) Ashing means any process using fluorinated GHG reagents with plasma to remove photoresist materials during wafer manufacture.
- (2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for all individual processes at that facility in accordance with WCI.114(c).
- (3) All other electronics facilities shall calculate annual facility-level emissions of each fluorinated GHG used at a facility for each process type, including etching and chemical vapor deposition chamber cleaning.

- (b) For each fluorinated GHG and each individual process, process category, or process type used at the facility as appropriate, calculate annual facility-level emissions using Equations 110-3 and 110-4 of this section, and according to the procedures in either paragraph (b)(1), (b)(2), or (b)(3) of this section.

$$E_{ij} = C_{ij} (1 - U_{ij}) (1 - a_{ij} \times d_{kj}) \times 0.001$$

Equation 110-3

Where:

E_{ij}	=	Annual emissions of input gas i from individual process, process category, or process type j (tonnes);
C_{ij}	=	Amount of input gas i consumed in individual process, process category, or process type j , as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to WCI.114(b);
U_{ij}	=	Process utilization for input gas i during individual process, process category, or process type j ;
a_{ij}	=	Fraction of input gas i used in individual process, process category, or process type j with abatement systems;
d_{ij}	=	Fraction of input gas i destroyed in abatement systems connected to individual process, process category, or process type j , accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

$$BE_{ijk} = B_{ijk} \times C_{ij} \times (1 - a_{ij} \times d_{kj}) \times 0.001$$

Equation 110-4

Where:

BE_{ijk}	=	Annual emissions of by-product k formed from input gas i during individual process, process category, or process type j (tonnes);
B_{ijk}	=	Amount of gas k created as a by-product per amount of input gas i (kg) consumed in individual process, process category, or process type j (kg);
C_{ij}	=	Amount of input gas i consumed in individual process, process category, or process type j , as calculated in Equation 110-6 (kg) of this section and apportioned pursuant to WCI.114(b);
a_{ij}	=	Fraction of input gas i used in individual process, process category, or process type j with abatement systems;
d_{kj}	=	Fraction of by-product gas k destroyed in abatement systems connected to individual process, process category, or process type j , accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

- (1) Semiconductor facilities that fabricate devices on wafers measuring 300 mm or less in diameter shall use the procedures in either paragraph (b)(1)(i) or (b)(1)(ii) of this section.
 - (i) Except as provided in paragraph (b)(1)(ii), use default process category emission factors for process utilization and by-product formation rates shown in Tables 110-2, 110-3, and 110-4 of this subpart as appropriate.
 - (ii) Recipe-specific measurements may be used instead of the process category default factors provided that the methods in WCI.114(c) are followed.
 - (2) Semiconductor facilities that fabricate devices on wafers measuring greater than 300 mm in diameter shall use recipe-specific measurements and follow methods in WCI.114(c) to calculate emissions from each fluorinated GHG-using process type. Equations 110-1 through 110-4 shall be used to calculate fluorinated GHG emissions from all fluorinated GHG-using process recipes.
 - (3) All other electronics facilities shall use the default process type-specific emission factors for process utilization and by-product formation rates shown in Tables 110-5, 110-6, and 110-7 of this subpart for MEMS, LCD, and PV manufacturing, respectively.
- (c) Calculate annual facility-level N₂O emissions from electronics manufacturing processes, using Equation 110-5 of this section and the methods in this paragraph (c).
- (1) Use a factor for N₂O utilization for chemical vapor deposition processes pursuant to either paragraph (c)(1)(i) or (c)(1)(ii) of this section.
 - (i) Develop a facility-specific N₂O utilization factor averaged over all N₂O-using recipes used for chemical vapor deposition processes in accordance with WCI.114(d).
 - (ii) If a facility-specific N₂O utilization factor for chemical vapor deposition processes is not available, a value of 20 percent must be used as the default utilization factor for N₂O from chemical vapor deposition processes.
 - (2) Use a factor for N₂O utilization for other manufacturing processes pursuant to either paragraph (c)(2)(i) or (c)(2)(ii) of this section.
 - (i) Develop a facility-specific N₂O utilization factor averaged over all N₂O-using recipes used for manufacturing processes other than chemical vapor deposition processes in accordance with WCI.114(d).
 - (ii) If a facility-specific N₂O utilization factor for manufacturing processes other than chemical vapor deposition is not available, a value of 0 percent must be used as a default utilization factor for N₂O from manufacturing processes other than chemical vapor deposition.
 - (3) If a facility employs abatement systems and wishes to quantify and document N₂O emission reductions due to these systems, it must adhere to the requirements in WCI.114(e).
 - (4) Calculate annual facility-level N₂O emissions for all processes at the facility using Equation 110-5 of this section.

$$E(N_2O) = \sum_j C_{N_2O,j} (1 - U_{N_2O,j}) (1 - a_{N_2O,j} \times d_{N_2O,j}) \times 0.001$$

Equation 110-5

Where:

$E(N_2O)$	=	Annual emissions of N_2O (tonnes/year);
$C_{N_2O,j}$	=	Amount of N_2O consumed for N_2O -using process j , as calculated in Equation 110-6 of this section and apportioned to N_2O -using process j (kg);
$U_{N_2O,j}$	=	Process utilization for N_2O -using process j ;
$a_{N_2O,j}$	=	Fraction of N_2O used in N_2O -using process j with abatement systems;
$d_{N_2O,j}$	=	Fraction of N_2O for N_2O -using process j destroyed by abatement systems connected to process j , accounting for uptime as specified in WCI.114(e)(2). This is zero unless the facility adheres to requirements in WCI.114(e); and
0.001	=	Conversion factor from kg to tonnes.

- (d) Calculate gas consumption for each fluorinated GHG and N_2O used at the facility using facility-wide gas-specific heel factors, as determined in WCI.114(a), and using Equation 110-6 of this section.

$$C_i = (I_{Bi} - I_{Ei} + A_i - D_i) \times 0.001$$

Equation 110-6

Where:

C_i	=	Annual consumption of input gas i (tonnes /year);
I_{Bi}	=	Inventory of input gas i stored in cylinders or other containers at the beginning of the year, including heels (kg);
I_{Ei}	=	Inventory of input gas i stored in cylinders or other containers at the end of the year, including heels (kg);
A_i	=	Acquisitions of gas i during the year through purchases or other transactions, including heels in cylinders or other containers returned to the electronics manufacturing facility (kg);
D_i	=	Disbursements under exceptional circumstances of gas i through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the chemical supplier, calculated using Equation 110-7 of this section (kg); and
0.001	=	Conversion factor from kg to tonnes.

- (e) Calculate disbursements of gas i using Equation 110-7 of this section.

$$D_i = h_i \times N_i \times F_i + X_i$$

Equation 110-7

Where:

- D_i = Disbursements of gas i through sales or other transactions during the year, including heels in cylinders or other containers returned by the electronics manufacturing facility to the gas distributor (kg);
- h_i = Facility-wide gas-specific heel factor for input gas i (%), as determined in WCI.114 of this subpart;
- N_i = Number of cylinders or other containers returned to the gas distributor containing the standard heel of gas i ;
- F_i = Full capacity of cylinders or other containers containing gas i (kg); and
- X_i = Disbursements under exceptional circumstances of gas i through sales or other transactions during the year. These include returns of containers whose contents have been weighed due to an exceptional circumstance as specified in WCI.114(a)(5) of this subpart (kg).

- (f) For facilities that use fluorinated heat transfer fluids, you shall report the annual emissions of fluorinated GHG heat transfer fluids using the mass balance approach described in Equation 110-8 of this section.

$$E_i = \rho_i (I_{ib} + P_i - N_i + R_i - I_{ie} - D_i) \times 0.001 \quad \text{Equation 110-8}$$

Where:

- E_i = Emissions of fluorinated GHG heat transfer fluid i , (tonnes/year);
- ρ_i = Density of fluorinated heat transfer fluid i (kg/litre);
- I_{ib} = Inventory of fluorinated heat transfer fluid i (in containers, not equipment) at the beginning of the reporting year (litres). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year;
- P_i = Acquisitions of fluorinated heat transfer fluid i during the current reporting year (litres). Includes amounts purchased from chemical suppliers, amounts purchased from equipment suppliers with or inside of equipment, and amounts returned to the facility after off-site recycling;
- N_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid i and that is newly installed during the reporting year (litres);
- R_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid i and that is removed from service during the current reporting year (litres);
- I_{ie} = Inventory of fluorinated heat transfer fluid i (in containers, not equipment) at the end of current reporting year (litres);
- D_i = Disbursements of fluorinated heat transfer fluid i during the current reporting year (litres). Includes amounts returned to chemical suppliers, sold with or inside of equipment, and sent off site for verifiable recycling or destruction. Disbursements should include only amounts that are properly stored and transported so as to prevent emissions in transit; and
- 0.001 = Conversion factor from kg to tonnes.

§ WCI.114 Sampling, Analysis, and Measurement Requirements

(a) For purposes of Equation 110-6 of this section, you must estimate facility-wide gas-specific heel factors for each cylinder/container type for each gas used according to the procedures in paragraphs (a)(1) through (a)(6) of this section.

- (1) Base the facility-wide gas-specific heel factors on the residual weight or pressure of a gas cylinder/container that the facility uses to change out that cylinder/container for each cylinder/container type for each gas used.
- (2) The residual weight or pressure used for WCI.114(a)(1) shall be determined by monitoring the mass or the pressure of your cylinders/containers. If monitoring the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation 110-9 of this section, with an appropriately selected Z value.

$$pV = ZnRT$$

Equation 110-9

Where:

p	=	Absolute pressure of the gas (Pa);
V	=	Volume of the gas (m ³);
Z	=	Compressibility factor;
n	=	Amount of substance of the gas (moles);
R	=	Gas constant (8.314 Joule/Kelvin mole); and
T	=	Absolute temperature (K).

- (3) Use the facility-wide gas-specific cylinder/container residual mass, determined from WCI.114(a)(1) and (a)(2), to calculate the unused gas for each container, which when expressed as fraction of the initial mass in the cylinder/container is the heel factor.
 - (4) The initial mass used to calculate the facility-wide gas-specific heel factor may be based on the weight of the gas provided in the gas supplier documents; however, the facilities remain responsible for the accuracy of these masses and weights under this subpart.
 - (5) In the exceptional circumstance that a cylinder/container is changed at a residual mass or pressure that differs by more than 20 percent from the facility-wide gas-specific determined values, that cylinder shall be weighed, or the pressure of that cylinder shall be measured with a pressure gauge, in place of using a heel factor.
 - (6) Recalculate facility-wide gas-specific heel factors applied at the facility in the event that the residual weight or pressure of the gas cylinder/container that the facility uses to change out that cylinder/container differs by more than 1 percentage point from that used to calculate the previous gas-specific heel factor.
- (b) Semiconductor facilities shall apportion fluorinated GHG consumption by process category, as defined in WCI.113(a)(1)(i) through (a)(1)(iii), or by individual process using a facility-specific engineering model based on wafer passes.

- (c) If factors for fluorinated GHG process utilization and by-product formation rates are used other than the defaults provided in Tables 110-2 through 110-4 of this subpart, the factors must have been measured using the “International SEMATECH Manufacturing Initiative’s Guideline for Environmental Characterization of Semiconductor Process Equipment” (December 2006). Factors for fluorinated GHG process utilization and by-product formation rates measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (c)(1) and (c)(2) of this section are met.
- (1) The manufacturing equipment supplier has measured the GHG emission factors for process utilization and by-product formation rates using the “International SEMATECH Manufacturing Initiative’s Guideline for Environmental Characterization of Semiconductor Process Equipment” (December 2006).
 - (2) The conditions under which the measurements were made are representative of the facility’s fluorinated GHG emitting processes.
- (d) If N₂O utilization factors other than those defaults provided in WCI.113(c)(1)(ii) or (c)(2)(ii) are used, factors that have been measured using the “International SEMATECH Manufacturing Initiative’s Guideline for Environmental Characterization of Semiconductor Process Equipment” (December 2006) must be used. Utilization factors measured by manufacturing equipment suppliers may be used if the conditions in paragraphs (d)(1) and (d)(2) of this section are met.
- (1) The manufacturing equipment supplier has measured the N₂O utilization factors using the “International SEMATECH Manufacturing Initiative’s Guideline for Environmental Characterization of Semiconductor Process Equipment” (December 2006).
 - (2) The conditions under which the measurements were made are representative of the facility’s N₂O emitting processes.
- (e) If the facility employs abatement systems and wishes to reflect emission reductions due to these systems in appropriate calculations in WCI.113, the facility must adhere to the procedures in paragraphs (e)(1) and (e)(2) of this section. If the facility uses the default destruction or removal efficiency of 60 percent, the facility must adhere to procedures in paragraph (e)(3) of this section. If the facility uses either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, the facility must adhere to procedures in paragraph (e)(4) of this section.
- (1) The facility must certify and document that the systems are properly installed, operated, and maintained according to manufacturers’ specifications by adhering to the procedures in paragraphs (e)(1)(i) and (e)(1)(ii) of this section.
 - (i) Proper installation must be verified by certifying the systems are installed in accordance with the manufacturers’ specifications.
 - (ii) Proper operation and maintenance must be verified by certifying the systems are operated and maintained in accordance with the manufacturers’ specifications.
 - (2) The facility must take into account and report the uptime of abatement systems when using destruction or removal efficiencies to reflect emission reductions. Abatement system uptime is expressed as the sum of an abatement system’s operational productive, standby, and engineering times divided by the total operations time of its associated

manufacturing tool(s) as referenced in SEMI Standard E-10-0340 “Specification for Definition and Measurement of Equipment Reliability, Availability, and Maintainability” (2004).

- (3) To report controlled emissions using the default destruction or removal efficiency, the facility must certify and document that the abatement systems at the facility for which it is reporting controlled emissions are specifically designed for fluorinated GHG and N₂O abatement and you shall use a default destruction or removal efficiency of 60 percent for those abatement systems.
- (4) If the facility does not use the default destruction or removal efficiency value to report controlled emissions, the facility must use either a properly measured destruction or removal efficiency, or a class average of properly measured destruction or removal efficiencies during a reporting year, determined in accordance with procedures in paragraphs (e)(4)(i) through (e)(4)(v) of this section.
 - (i) Destruction or removal efficiencies must be properly measured in accordance with EPA’s “Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing” (March 2010).
 - (ii) A facility must annually select and properly measure the destruction or removal efficiency for a random sample of abatement systems to include in a Random Sampling Abatement System Testing Program (RSASTP) in accordance with procedures in paragraphs (e)(4)(ii)(A) and (e)(4)(ii)(B) of this section.
 - (A) Each reporting year a random sample of three or 20 percent of installed abatement systems, whichever is greater, for each abatement system class shall be tested. In instances where 20 percent of the total number of abatement systems in each class does not equate to a whole number, the number of systems to be tested shall be determined by rounding up to the nearest integer.
 - (B) The facility must select the random sample each reporting year for the RSASTP without repetition of systems in the sample, until all systems in each class are properly measured in a 5-year period.
 - (iii) If a facility has measured the destruction or removal efficiency of a particular abatement system during the previous two-year period, the facility shall calculate emissions from that system using the destruction or removal efficiency most recently measured for that particular system.
 - (iv) If an individual abatement system has not yet undergone proper destruction or removal efficiency testing during the previous two-year period, the facility may apply a simple average of the properly measured destruction or removal efficiencies for all systems of that class, in accordance with the RSASTP. The facility shall maintain or exceed the RSASTP schedule and regime if it wishes to apply class average destruction or removal efficiency factors to abatement systems that have not been properly measured as per the RSASTP.
 - (v) In instances where redundant abatement systems are used, the facility may account for the total abatement system uptime calculated for a specific exhaust stream during the reporting year.

- (f) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG and N₂O emissions from all electronics manufacturing processes:
- (1) Facilities must follow the QA/QC procedures in the “International SEMATECH Manufacturing Initiative’s Guideline for Environmental Characterization of Semiconductor Process Equipment” (December 2006) when estimating facility-specific, recipe-specific fluorinated GHG and N₂O utilization and by-product formation rates.
 - (2) Facilities must follow the QA/QC procedures in EPA’s “Protocol for Measuring Destruction or Removal Efficiency of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing” (March 2010) when estimating abatement systems destruction or removal efficiency.
 - (3) Facilities must certify that gas consumption is tracked to a high degree of precision as part of normal facility operations ensuring that the inventory at the beginning of the reporting is the same as the inventory at the end of the previous year.
- (g) Facilities must adhere to the QA/QC procedures of this paragraph when estimating fluorinated GHG emissions from heat transfer fluid use and annual gas consumption for each fluorinated GHG and N₂O used at the facility:
- (1) Facilities must review all inputs to Equations 110-6 and 110-8 of this section to ensure that all inputs and outputs to the facility’s system are accounted for.
 - (2) Facilities must not enter negative inputs into the mass balance Equations 110-6 and 110-8 of this section and shall ensure that no negative emissions are calculated.
 - (3) Facilities must ensure that the beginning of year inventory matches the end of year inventory from the previous year.
- (h) All instruments (e.g., mass spectrometers and fourier transform infrared measuring systems) used to determine the concentration of fluorinated GHG and N₂O in process streams shall be calibrated just prior to destruction or removal efficiency, gas utilization, or by-product formation measurement through analysis of certified standards with known concentrations of the same chemicals in the same ranges (fractions by mass) as the process samples. Calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205, 40 CFR part 51, Appendix M may also be used.
- (i) All flowmeters, weigh scales, pressure gauges, and thermometers used to measure quantities that are monitored under this section or used in calculations under §WCI.113 shall have an accuracy and precision of one percent of full scale or better.

§ WCI.115 Missing Data Procedures

- (a) Except as provided in paragraph WCI.115(b), a complete record of all measured parameters used in the fluorinated GHG and N₂O emissions calculations in WCI.113 and WCI.114 is required.
- (b) If a facility uses heat transfer fluids and is missing data for one or more of the parameters in Equation 110-8 of this subpart, the facility must estimate heat transfer fluid emissions using the arithmetic average of the emission rates for the year immediately preceding the period of

missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the heat transfer fluid supplier. The facility must document the method used and values estimated for all missing data values.

Table 110-1. Examples of Fluorinated GHGs Used by the Electronics Industry

Product Type	Fluorinated GHGs used during manufacturing
Electronics	CF ₄ , C ₂ F ₆ , C ₃ F ₈ , c-C ₄ F ₈ , c-C ₄ F ₈ O, C ₄ F ₆ , C ₅ F ₈ , CHF ₃ , CH ₂ F ₂ , NF ₃ , SF ₆ , and HTFs [CF ₃ -(O-CF(CF ₃)-CF ₂) _n -(O-CF ₂) _m -O-CF ₃ , C _n F _{2n+2} , C _n F _{2n+1} (O)C _m F _{2m+1} , C _n F _{2n} O, (C _n F _{2n+1}) ₃ N].

Table 110-2. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 150 mm Wafer Size

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
PATTERNING/ETCHING											
Oxide etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
1-U _i	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	0.05-0.3	0.05-0.3	NA	NA	0.05-0.2	0.05-0.2
BCF ₄	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-3. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 200 mm Wafer Size

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
PATTERNING/ETCHING											
Oxide etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.5	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
1-U _i	0.2-0.8	0.2-0.7	0.1-0.7	0.02-0.3	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.02-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.005-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
1-U _i	0.8-0.95	0.4-0.8	NA	NA	0.2-0.6	0.05-0.3	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
BCF ₄	NA	0.05-0.2	NA	NA	0.05-0.2	0.05-0.2	0.05-0.1	NA	NA	0.05-0.2	0.05-0.2
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.02-0.08
Remote plasma cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	0.005-0.03	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	0.0001-0.2	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
1-U _i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-4. Default Emission Factors for Refined Process Categories for Semiconductor Manufacturing for 300 mm Wafer Size

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
PATTERNING/ETCHING											
Oxide etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.05-0.3	0.1-0.4	0.1-0.4	0.05-0.3	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.005-0.03	0.001-0.01	NA	0.005-0.1	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.005-0.1	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nitride etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.4	0.1-0.8	NA	0.08-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.003-0.1	0.01-0.1	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.02-0.3	NA	NA	0.05-0.4	0.05-0.4	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Silicon etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Metal etch											
1-U _i	0.2-0.8	0.2-0.7	0.2-0.7	0.02-0.3	NA	0.1-0.3	0.1-0.4	0.1-0.4	0.05-0.2	0.05-0.3	NA
BCF ₄	NA	0.05-0.5	0.01-0.8	0.05-0.1	NA	0.01-0.3	NA	NA	0.02-0.4	0.02-0.4	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	0.01-0.3	NA	NA	0.02-0.3	0.02-0.3	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CHAMBER CLEANING											
In situ plasma cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA

Refined Process Category	Process Gas <i>i</i>										
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃	SF ₆	C ₄ F ₆	C ₅ F ₈	C ₄ F ₈ O
BCF ₄	NA	NA	NA	NA	NA	NA	0.001-0.6	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	0.002-0.03	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	0.001-0.05	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning											
1-U _i	NA	NA	NA	NA	NA	NA	0.1-0.4	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	0.005-.05	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
WAFER CLEANING											
Bevel cleaning											
1-U _i	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ashing											
1-U _i	0.3-0.8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF ₄	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₂ F ₆	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA denotes not applicable based on currently available information.

Table 110-5. Default Emission Factors for MEMS Manufacturing

Process Type Factors	Process Gas <i>i</i>											
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃ Remote	NF ₃	SF ₆	C ₄ F ₆ ^a	C ₅ F ₈ ^a	C ₄ F ₈ O ^a
Etch 1-U _i	0.7	0.4 ¹	0.4 ¹	0.06 ¹	NA	0.2 ¹	NA	0.2	0.2	0.1	0.2	NA
Etch BCF ₄	NA	0.4 ¹	0.07 ¹	0.08 ¹	NA	0.2	NA	NA	NA	0.3 ¹	0.2	NA
Etch BC ₂ F ₆	NA	NA	NA	NA	NA	0.2	NA	NA	NA	0.2 ¹	0.2	NA
CVD 1-U _i	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1
CVD BCF ₄	NA	0.1	NA	NA	0.1	0.1	0.02 ²	0.1 ²	NA	NA	0.1	0.1
CVD BC ₃ F ₈	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.4

Notes: NA denotes not applicable based on currently available information.

¹ Estimate includes multi-gas etch processes.

² Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing fluorinated GHG additive.

Table 110-6. Default Emission Factors for LCD Manufacturing

Process Type Factors	Process Gas <i>i</i>								
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃ Remote	NF ₃	SF ₆
Etch 1-U _i	0.6	NA	0.2	NA	NA	0.1	NA	NA	0.3
Etch BCF ₄	NA	NA	0.07	NA	NA	0.009	NA	NA	NA
Etch BCHF ₃	NA	NA	NA	NA	NA	0.02	NA	NA	NA
Etch BC ₂ F ₆	NA	NA	0.05	NA	NA	NA	NA	NA	NA
CVD 1-U _i	NA	NA	NA	NA	NA	NA	0.03	0.3	0.9

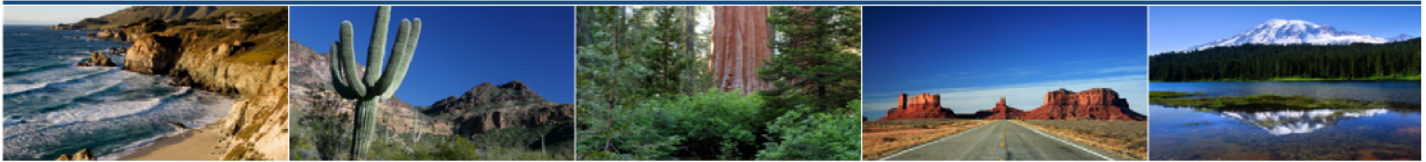
Notes: NA denotes not applicable based on currently available information.

Table 110-7. Default Emission Factors for PV Manufacturing

Process Type Factors	Process Gas <i>i</i>								
	CF ₄	C ₂ F ₆	CHF ₃	CH ₂ F ₂	C ₃ F ₈	c-C ₄ F ₈	NF ₃ Remote	NF ₃	SF ₆
Etch 1-U _i	0.7	0.4	0.4	NA	NA	0.2	NA	NA	0.4
Etch BCF ₄	NA	0.2	NA	NA	NA	0.1	NA	NA	NA
Etch BC ₂ F ₆	NA	NA	NA	NA	NA	0.1	NA	NA	NA
CVD 1-U _i	NA	0.6	NA	NA	0.1	0.1	NA	0.3	0.4
CVD BCF ₄	NA	0.2	NA	NA	0.2	0.1	NA	NA	NA

Notes: NA denotes “not applicable” based on currently available information.

Western Climate Initiative



§ WCI.120 HCFC-22 PRODUCTION AND HFC-23 DESTRUCTION

§ WCI.121 Source Category Definition

The HCFC-22 production and HFC-23 destruction source category consists of HCFC-22 production processes and HFC-23 destruction processes. An HCFC-22 production process produces HCFC-22 (CHClF_2 or chlorodifluoromethane) from chloroform (CHCl_3) and hydrogen fluoride (HF). An HFC-23 destruction process is any process in which HFC-23 (CHF_3 or trifluoromethane) undergoes destruction. An HFC-23 destruction process may or may not be co-located at the same facility with an HCFC-22 production process.

§ WCI.122 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) HFC-23 emissions from HCFC-22 production processes and HFC-23 destruction processes (tonnes).
- (b) HCFC-22 production facilities shall report the following information at the facility level:
 - (1) Annual mass of HCFC-22 produced (tonnes).
 - (2) Loss Factor used to account for the loss of HCFC-22 upstream of the measurement.
 - (3) Annual mass of reactants fed into the process (tonnes).
 - (4) Mass of materials other than HCFC-22 and HFC-23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process (tonnes).
 - (5) Method for tracking startups, shutdowns, and malfunctions and HFC-23 generation/emissions during these events.
 - (6) Names and addresses of facilities to which any HFC-23 was sent for destruction, and the quantities of HFC-23 (tonnes) sent to each.
 - (7) Annual mass of the HFC-23 generated (tonnes).
 - (8) Annual mass of any HFC-23 sent off site for sale (tonnes).
 - (9) Annual mass of any HFC-23 sent off site for destruction (tonnes).
 - (10) Mass of HFC-23 in storage at the beginning and end of the year (tonnes).
 - (11) Annual mass of HFC-23 emitted (tonnes).
 - (12) Annual mass of HFC-23 emitted from equipment leaks (tonnes).
 - (13) Annual mass of HFC-23 emitted from process vents (tonnes).

- (c) Each HFC-23 destruction facility shall report the concentration (mass fraction) of HFC-23 measured at the outlet of the destruction device during the facility's annual HFC-23 concentration measurements at the outlet of the device..
- (d) By the date of the first report or within 60 days of commencing HFC-23 destruction, HFC-23 destruction facilities shall submit a one-time report including the following information for each destruction process:
 - (1) Destruction efficiency (DE).
 - (2) Methods used to determine destruction efficiency.
 - (3) Methods used to record the mass of HFC-23 destroyed.
 - (4) Name of other relevant federal or provincial regulations that may apply to the destruction process.
 - (5) If any changes are made that affect HFC-23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to regulators within 60 days of the change.

§ WCI.123 Calculation of GHG Emissions

- (a) The mass of HFC-23 generated from each HCFC-22 production process shall be estimated using either paragraph (1) or (2) of this section.
 - (1) Where the mass flow of the combined stream of HFC-23 and another reaction product (e.g., HCl, etc.) is measured, multiply the weekly (or more frequent) HFC-23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC-23 and the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. This calculation is shown in Equation 120-1.

$$G_{23} = \sum_{p=1}^n c_{23} \times F_p \times 10^{-3}$$

Equation 120-1

Where:

G_{23}	=	Mass of HFC-23 generated annually (tonnes).
c_{23}	=	Fraction HFC-23 by weight in HFC-23/other product stream.
F_p	=	Mass flow of HFC-23/other product stream during the period p (kg).
p	=	Period over which mass flows and concentrations are measured.
n	=	Number of concentration and flow measurement periods for the year.
10^{-3}	=	Conversion factor from kilograms to tonnes.

- (2) Where the mass of only a reaction product other than HFC-23 (either HCFC-22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC-23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC-23 production, sum the weekly (or more frequent) estimates of the quantities of HFC-23 produced over the year. If the other product is HCFC-22, then use Equation 120-2. If the other product is HCl, then use Equations 120-2 and 120-3 substituting HCl for HCFC-22.

$$G_{23} = \sum_{p=1}^n \left(\frac{c_{23}}{c_{22}} \right) \times P_{22} \times 10^{-3}$$

Equation 120-2

Where:

G_{23}	=	Mass of HFC-23 generated annually (tonnes).
c_{23}	=	Fraction HFC-23 by weight in HCFC-22/HFC-23 stream.
c_{22}	=	Fraction HCFC-22 by weight in HCFC-22/HFC-23 stream.
P_{22}	=	Mass of HCFC-22 produced over the period p (kg) (calculated using Equation 120-3).
p	=	Period over which mass flows and concentrations are measured.
n	=	Number of concentration and flow measurement periods for the year.
10^{-3}	=	Conversion factor from kilograms to tonnes.

- (b) The mass of HCFC-22 produced over the period p shall be estimated using Equation 120-3.

$$P_{22} = LF \times (O_{22} - U_{22})$$

Equation 120-3

Where:

P_{22}	=	Mass of HCFC-22 produced over the period p (kg).
O_{22}	=	Mass of HCFC-22 that is measured coming out of the production process over the period p (kg).
U_{22}	=	Mass of used HCFC-22 that is added to the production process upstream of the output measurement over the period p (kg).
LF	=	Factor to account for the loss of HCFC-22 upstream of the measurement. The loss factor shall either have the value of 1.015 or another value that can be demonstrated to account for losses of HCFC-22 between the reactor and the point of measurement at the facility where production is being estimated.

- (c) For HCFC-22 production facilities that do not use a thermal oxidizer or that have a thermal oxidizer that is not directly connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation 120-4.

$$E_{23} = G_{23} - (S_{23} + OD_{23} + D_{23} + I_{23})$$

Equation 120-4

Where:

E_{23}	=	Mass of HFC-23 emitted annually (tonnes).
G_{23}	=	Mass of HFC-23 generated annually (tonnes).
S_{23}	=	Mass of HFC-23 sent off site for sale annually (tonnes).
OD_{23}	=	Mass of HFC-23 sent off site for destruction (tonnes).
D_{23}	=	Mass of HFC-23 destroyed on site (tonnes).
I_{23}	=	Increase in HFC-23 inventory (HFC-23 in storage at end of year – HFC-23 in storage at beginning of year (tonnes)).

- (d) For HCFC-22 production facilities that use a thermal oxidizer connected to the HCFC-22 production equipment, HFC-23 emissions shall be estimated using Equation 120-5.

$$E_{23} = E_L + E_{PV} + E_D$$

Equation 120-5

Where:

E_{23}	=	Mass of HFC-23 emitted annually (tonnes).
E_L	=	Mass of HFC-23 emitted annually from equipment leaks (tonnes) (calculated using Equation 120-6).
E_{PV}	=	Mass of HFC-23 emitted annually from process vents (tonnes) (calculated using Equation 120-7).
E_D	=	Mass of HFC-23 emitted annually from thermal oxidizer (tonnes) (calculated using Equation 120-8).

- (1) The mass of HFC-23 emitted annually from equipment leaks (for use in Equation 120-5) shall be estimated by using Equation 120-6.

$$E_L = \sum_{p=1}^n \sum_t c_{23} \times (F_{Gt} \times N_{Gt} + F_{Lt} \times N_{Lt}) \times 10^{-3}$$

Equation 120-6

Where:

E_L	=	Mass of HFC-23 emitted annually from equipment leaks (tonnes).
c_{23}	=	Fraction HFC-23 by weight in the streams in the equipment.
F_{Gt}	=	Applicable leak rate specified in Table 120-1 for each source of equipment type and service t with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).
N_{Gt}	=	Number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv (kg/hr/source).
F_{Lt}	=	Applicable leak rate specified in Table 120-1 for each source of equipment type and service t with a screening value less than 10,000 ppmv (kg/hr/source).
N_{Lt}	=	Number of sources of equipment type and service t with screening values less than 10,000 ppmv (kg/hr/source).
p	=	One hour.
n	=	Number of hours during the year during which equipment contained HFC-23.
t	=	Equipment type and service as specified in Table 120-1.
10^{-3}	=	Conversion factor from kilograms to tonnes.

(2) The mass of HFC-23 emitted annually from process vents (for use in Equation 120-5) shall be estimated by using Equation 120-7.

$$E_{pV} = \sum_{p=1}^n ER_T \times \left(\frac{PR_p}{PR_T} \right) \times l_p \times 10^{-3}$$

Equation 120-7

Where:

E_{pV}	=	Mass of HFC-23 emitted annually from process vents (tonnes).
ER_T	=	HFC-23 emission rate from the process vents during the period of the most recent test (kg/hr).
PR_p	=	HCFC-22 production rate during the period p (kg/hr).
PR_T	=	HCFC-22 production rate during the most recent test period (kg/hr).
l_p	=	Length of period p (hours).
10^{-3}	=	Conversion factor from kilograms to tonnes.

(3) The mass of HFC-23 emitted from destruction devices (for use in Equation 120-5) shall be estimated by using Equation 120-8.

$$E_D = F_D - D_{23}$$

Equation 120-8

Where:

E_D	=	Mass of HFC-23 emitted annually from destruction device (tonnes).
F_D	=	Mass of HFC-23 annual fed into the destruction device (tonnes).
D_{23}	=	Mass of HFC-23 destroyed annually (tonnes).

- (4) For facilities that destroy HFC-23, the total mass of HFC-23 destroyed (for use in Equations 120-4 and 120-8) shall be estimated by using Equation 120-9.

$$D_{23} = F_D \times DE$$

Equation 120-9

Where:

D_{23}	=	Mass of HFC-23 destroyed annually (tonnes).
F_D	=	Mass of HFC-23 annual fed into the destruction device (tonnes).
DE	=	Destruction efficiency of the destruction device (fraction).

§ WCI.124 Sampling, Analysis, and Measurement Requirements

The measurements that are reported for this category or used to estimate quantities used in the WCI.123 calculation methodologies shall be determined as specified in paragraphs (a) through (q).

(a) The concentrations (fractions by weight) of HFC23 (c_{23} in Equations 120-1 and 120-2) and HCFC-22 (c_{22} in Equation 120-2) in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC-23 (F_p in Equation 120-1) shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC-22 (O_{22} in Equation 120-3) or HCl (substituted value for O_{22} in Equation 120-3) coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC-22 added back into the production process upstream of the output measurement in paragraph (c) of this section (U_{22} in Equation 120-3) shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as

well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated HCFC-22 for purposes of this paragraph (d) of this section and WCI.123(b).

(e) The loss factor LF of this subpart for the mass of HCFC-22 produced (LF in Equation 120-3) shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the jurisdiction, to account for losses of HCFC-22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC-23 sent off site for sale (S_{23} in Equation 120-4) shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC-23 sent off site for destruction (OD_{23} in Equation 120-4) shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC-23, the concentration of the fluorinated GHG shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 sent to another facility for destruction.

(h) The masses of HFC-23 in storage at the beginning and end of the year (I_{23} in Equation 120-4) shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv (N_{Gt} in Equation 120-6) shall be determined using EPA Method 21 at 40 CFR part 60, appendix A-7, and defining a leak as follows:

- (1) A leak source that could emit HFC-23, and
- (2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv (N_{Lt} in Equation 120-6) shall be the difference between the number of leak sources of equipment type t that could emit HFC-23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (i) of this section.

(k) The mass of HFC-23 emitted from process vents (E_{PV} in Equation 120-5) shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation 120-7 of this subpart. HCFC-22 production facilities that use a destruction device connected to the HCFC-22 production equipment shall conduct emissions tests at process vents at least once

every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC-23 if sustained over one year.

(l) For purposes of Equation 120-9 of this subpart, the destruction efficiency must be equated to the destruction efficiency (*DE*) determined during a new or previous performance test of the destruction device. HFC-23 destruction facilities shall conduct annual measurements of HFC-23 concentrations at the outlet of the destruction device in accordance with EPA Method 18 at 40 CFR part 60, appendix A-6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC-23 shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC-23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC-23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

- (1) Substitute the higher HFC-23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or
- (2) Estimate the mass emissions of HFC-23 from the destruction device based on the measured HFC-23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1, or Method 26 at 40 CFR part 60, appendix A-2. Determine the mass rate of HFC-23 into the destruction device by measuring the HFC-23 concentration and volumetric flow rate at the inlet or by a metering device for HFC-23 sent to the device. Determine a new destruction efficiency based on the mass flow rate of HFC-23 into and out of the destruction device.

(m) HCFC-22 production facilities shall account for HFC-23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC-23 generation and emissions during these events, or documenting that these events do not result in significant HFC-23 generation and/or emissions.

(n) The mass of HFC-23 fed into the destruction device (F_D in Equations 120-8 and 120-9) shall be measured at least weekly using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC-23, the concentrations of the HFC-23 shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC-23 destroyed.

(o) In their estimates of the mass of HFC-23 destroyed, HFC-23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or destruction device manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC-23 in process streams (c_{23} in Equations 120-1 and 120-2) shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC-23 concentrations that are in the same range (fractions by mass) as the process samples.

§ WCI.125 Missing Data Procedures

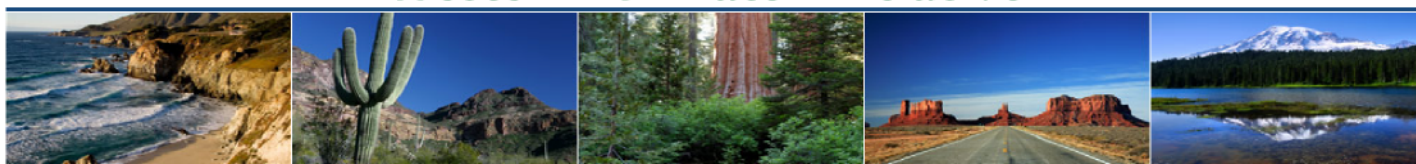
(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

- (1) For each missing value of the HFC-23 or HCFC-22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
- (2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement where such a measurement is available. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

Table 120-1 – Emission Factors for Equipment Leaks

Equipment Type	Service	Emission Factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

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§ 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 CO₂ Emissions. The CO₂ process emissions from the hydrogen production 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 metres for gases, litres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
- (c) Production. Annual hydrogen produced (tonnes).
- (d) Stationary Combustion Units. Report CO₂, N₂O, and CH₄ emissions as specified in WCI.20.

§ WCI.133 Calculation of Greenhouse Gas Emissions

The owner or operator shall calculate and report CO₂ process emissions using the methods in paragraphs (a) or (b) of this section.

- (a) Continuous Emission Monitoring Systems. The owner or operator may calculate CO₂ process emissions using CEMS. The owner or operator must comply with the requirements in section WCI.23.
- (b) Feedstock Material Balance. The owner or operator may calculate CO₂ process emissions using the following method.

(1) Gaseous fuel and feedstock. You must calculate the annual CO₂ process emissions from gaseous fuel and feedstock according to Equation 130-1 of this section:

$$CO_2 = \left(\sum_{n=1}^k \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \quad \text{Equation 130-1}$$

Where:

CO₂ = Annual CO₂ process emissions arising from fuel and feedstock consumption (tonnes/yr).

$Fdstk_n$	=	Volume of the gaseous fuel and feedstock used in month n (m^3 at standard conditions of 20°C and 1 atmosphere) of fuel and feedstock).
CC_n	=	Weighted average carbon content of the gaseous fuel and feedstock, from the results of one or more analyses for month n (Rm^3 at reference temperature and pressure conditions as used by the facility). If a mass flow meter is used, measure the feedstock used in month n in kg and replace the term “MW/MVC” with “1”.
MW	=	Molecular weight of the gaseous fuel and feedstock (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $Fdstk_n$ (Rm^3/kg -mole). MVC can be $8.3145 * [273.16 + \text{reference temperature in } ^\circ C] / [\text{reference pressure in kilopascal}]$.
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(2) Liquid fuel and feedstock. You must calculate the annual CO_2 process emissions from liquid fuel and feedstock according to Equation 130-2 of this section:

$$CO_2 = \left(\sum_{n=1}^k \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \quad \text{Equation 130-2}$$

Where:

CO_2	=	Annual CO_2 emissions arising from fuel and feedstock consumption (tonnes/yr).
$Fdstk_n$	=	Volume of the liquid fuel and feedstock used in month n (m^3 of fuel and feedstock). If a mass flow meter is used, measure the fuel and feedstock used in month n in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.
CC_n	=	Weighted average carbon content of the liquid fuel and feedstock, from the results of daily analyses for month n (kg of C per m^3 of fuel and feedstock when the usage is measured in m^3 , or kg of C per kg of feedstock and fuel when the usage is measured in kg).
k	=	Months in the year.
44/12	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Conversion factor from kg to tonnes.

(3) Solid fuel and feedstock. You must calculate the annual CO_2 process emissions from solid fuel and feedstock according to Equation 130-3 of this section:

$$CO_2 = \sum_{n=1}^k \frac{44}{12} * (Fdstk_n * CC_n) * 0.001 \quad \text{Equation 130-3}$$

Where:

CO_2	=	Annual CO_2 emissions from fuel and feedstock consumption in tonnes per year (tonnes/yr).
$Fdstk_n$	=	Mass of solid fuel and feedstock used in month n (kg of fuel and feedstock).
CC_n	=	Weighted average carbon content of the solid fuel and feedstock, from the results of daily analyses for month n (kg carbon per kg of fuel and feedstock).
k	=	Months in the year.

44/12 = Ratio of molecular weights, CO₂ to carbon.
0.001 = Conversion factor from kg to tonnes.

- (c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO₂ emissions using a CEMS that complies with WCI.23, then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report the combined stack emissions according to the CEMS methodology in WCI.23.

§ WCI.134 Sampling, Analysis, and Measurement Requirements

- (a) Owners or operators using CEMS to estimate CO₂ emissions shall comply with the monitoring requirements in section WCI.23.
- (b) Owners or operators using the methods in section WCI.133 (b) or paragraph (c) of this section 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(c). 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 and a weighted average established for month *n*. Daily samples may be combined to generate a monthly composite sample for carbon analysis. 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 quantify the hydrogen produced daily.
 - (4) Owners or operators shall quantify the CO₂ and CO collected and transferred off-site quarterly.
- (c) You must use the following methods, as applicable, to determine the carbon content of the feedstocks:
- (1) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis.
 - (2) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal.
 - (3) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.
 - (4) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke.
 - (5) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products.

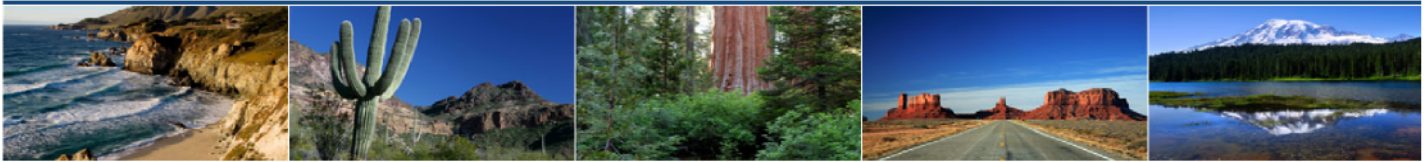
- (6) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.
- (7) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal.
- (8) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles.
- (9) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal.
- (10) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography.
- (11) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.
- (12) ISO 3170: Petroleum Liquids— Manual sampling—Third Edition.
- (13) ISO 3171: Petroleum Liquids— Automatic pipeline sampling—Second Edition.

§ WCI.135 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation, etc.), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

- (a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.
- (b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.
- (c) For missing CEMS data, you must use the missing data procedures in WCI.20.

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§ WCI.140 GLASS PRODUCTION

§ WCI.141 Source Category Definition

A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more glass melting furnaces to produce glass. A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§ WCI.142 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information:

- (a) Total CO₂ process emissions from all glass melting furnaces.
- (b) Total CO₂, CH₄ and N₂O combustion emissions from all glass melting furnaces. You must calculate and report these emissions under WCI.20 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.
- (c) Total CO₂, CH₄, and N₂O emissions from all stationary fuel combustion units other than glass melting furnaces. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources) by following the requirements of WCI.20.
- (d) If a CEMS is used to measure CO₂ emissions, then you must report under this method the relevant information required under WCI.23(d) for the Calculation Methodology 4 and the following information:
 - Annual quantity of glass produced (tonnes).
- (e) If a CEMS is not used to determine CO₂ emissions from glass melting furnaces, and process CO₂ emissions are calculated according to the procedures specified in WCI.143(b), then you must report the following information:
 - (1) Annual quantity of each carbonate-based raw material charged (tonnes) for all furnaces combined.
 - (2) Annual quantity of glass produced (tonnes) from all furnaces combined.
 - (3) Total number of glass melting furnaces.
- (f) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for each glass melting furnace

§ WCI.143 Calculation of GHG Emissions

You must calculate the annual process CO₂ emissions from each glass melting furnace using the procedure in paragraphs (a) and (b) of this section.

- (a) For each glass melting furnace that meets the conditions specified in WCI.23(e)(4), you must calculate under this source the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Calculation Methodology 4 specified in WCI.23(d) and all associated requirements in WCI.20 (General Stationary Fuel Combustion Sources).
- (b) For each glass melting furnace that is not subject to the requirements in paragraph (a) of this section, use either the procedure in paragraph (b)(1) or (b)(2) of this section.
 - (1) Calculate the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to the Calculation Methodology 4 specified in WCI.23(d) (General Stationary Fuel Combustion Sources).
 - (2) Calculate the process and combustion CO₂ emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.
 - (i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.
 - (ii) Determine the quantity of each carbonate-based raw material charged to the furnace.
 - (iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table 140-1 to this subpart.
 - (iv) Use Equation 140-1 of this section to calculate process mass emissions of CO₂ for each furnace:

$$E_{CO_2} = \sum_{i=1}^n (M_i \times MF_i \times EF_i \times F_i) \quad \text{Equation 140-1}$$

Where:

- | | | |
|------------|---|---|
| E_{CO_2} | = | Process emissions of CO ₂ from the furnace (tonnes). |
| n | = | Number of carbonate-based raw materials charged to furnace. |
| MF_i | = | Annual average mass fraction of carbonate-based mineral i in carbonate-based raw material i (weight fraction). |
| M_i | = | Annual amount of carbonate-based raw material i charged to furnace (tonnes). |
| EF_i | = | Emission factor for carbonate-based mineral i (tonnes CO ₂ per tonne carbonate-based mineral as shown in Table 140-1). |
| F_i | = | Fraction of calcination achieved for carbonate-based mineral i , 1.0 for completed calcination (weight fraction). |

- (v) You must calculate and report the total process CO₂ emissions from glass melting furnaces at the facility using Equation 140-2 of this section:

$$CO_2 = \sum_{i=1}^k E_{CO_2i}$$

Equation 140-2

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (tonnes).

E_{CO_2i} = Annual CO_2 emissions from glass melting furnace i (tonnes).

k = Number of glass melting furnaces.

- (vi) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in WCI.20.

§ WCI.144 Sampling, Analysis, and Measurement Requirements

- (a) You must measure annual amounts of carbonate-based raw materials charged to each glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.
- (b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis conducted by a certified laboratory using ASTM D3682-01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, see regulation).
- (c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.
- (d) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the monthly mass fraction (MF_i) of carbonate-based mineral i in Equation 140-1 of this section.
- (e) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

§ WCI.145 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in WCI.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

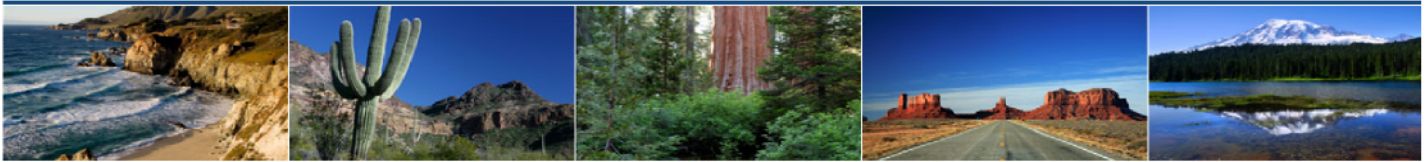
- (a) For missing data on the monthly amounts of carbonate-based raw materials charged to any glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.
- (b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

Table 140-1 —CO₂ Emission Factors for Carbonate-Based Minerals

Carbonate-Based Raw Material – Mineral	CO₂ Emission Factor^a
Limestone – CaCO ₃	0.43971
Dolomite – CaMg(CO ₃) ₂	0.47732
Sodium carbonate/soda ash – Na ₂ CO ₃	0.41492

^a Emission factors in units of tonnes of CO₂ emitted per tonne of carbonate-based mineral charged to the furnace.

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§ WCI.150 IRON AND STEEL MANUFACTURING

§ WCI.151 Source Category Definition

Iron and steel manufacturing comprises five categories: taconite iron ore processing, 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 regulation, the annual emissions data report shall contain the following information:

(a) Annual process CO₂ emissions (tonnes) for the following processes:

- (1) Taconite indurating furnace
- (2) Basic oxygen furnace (BOF)
- (3) Coke making operation
- (4) Sinter process
- (5) Electric arc furnace (EAF)
- (6) Argon-oxygen decarburization vessel
- (7) Direct reduction furnace
- (8) Blast furnace

(b) Annual production/usage quantities (tonnes) for the following processes:

- (1) Taconite indurating furnace – fired pellets produced on-site
- (2) BOF – steel produced on-site
- (3) Coke making operation – coke produced and coal charged
- (4) Sinter process – sinter produced
- (5) EAF – steel produced on-site
- (6) Argon-oxygen decarburization vessel – molten steel charged
- (7) Direct reduction furnace – iron produced
- (8) Blast furnace – iron produced

- (c) CO₂, N₂O, and CH₄ emissions, not accounted for elsewhere in WCI.150, from stationary combustion units as specified in WCI.20. Report these emissions from stationary combustion for each of the following devices:
- (1) Taconite indurating furnace
 - (2) BOF
 - (3) Coke making operation (coke oven batteries)
 - (4) Sinter process (sintering furnace)
 - (5) EAF
 - (6) Argon-oxygen decarburization vessel
 - (7) Direct reduction furnace
 - (8) Blast furnace
 - (9) Any other stoves, boiler, process heaters, reheat furnaces and other combustion sources.

§ WCI.153 Calculation of CO₂ Emissions

- (a) Process CO₂ emissions. Determine process CO₂ 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 CO₂ Emissions Calculation Methodology. Calculate CO₂ process emissions for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, argon-oxygen decarburization vessel, blast furnace, and direct reduction furnace using the following mass balance approaches specified in paragraphs (b)(1) through (b)(8). Specific process inputs or outputs that contribute less than 1 percent of the total mass of carbon into or out of the process do not have to be included in the paragraphs (b)(1) through (b)(8) mass balances.
- (1) Calculate taconite indurating furnace CO₂ emissions using Equation 150-1:

$$E_T = [(T \times C_T) - (P \times C_P) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-1}$$

Where:

- | | | |
|----------------|---|--|
| E _T | = | Annual CO ₂ emissions from taconite indurating furnace (tonnes); |
| T | = | Annual mass of greenball (taconite) pellets fed to furnace (tonnes); |
| C _T | = | Carbon content of greenball (taconite) pellets (tonnes C/tonnes taconite pellets); |
| P | = | Annual mass of fired pellets produced by the furnace (tonnes); |
| C _P | = | Carbon content of fired pellets (tonnes C/tonnes fired pellets); |
| R | = | Annual mass of air pollution control residue collected (tonnes); |

C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(2) Calculate basic oxygen process furnace CO₂ emissions using Equation 150-2:

$$E_{BOF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (BOG \times C_{BOG}) - (R \times C_R)] \times 3.664$$

Equation 150-2

Where:

E_{BOF} = Annual CO₂ emissions from basic oxygen furnaces (tonnes);
 I = Annual mass of molten iron charged to furnace (tonnes);
 C_I = Carbon content of molten iron (tonnes C/tonnes molten iron);
 SC = Annual mass of ferrous scrap charged to furnace (tonnes);
 C_{SC} = Carbon content of ferrous scrap (tonnes C/tonnes ferrous scrap);
 FL = Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
 C_{FL} = Carbon content of flux materials (tonnes C/tonnes flux material);
 CAR = Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
 C_{CAR} = Carbon content of carbonaceous material (tonnes C/tonnes carbonaceous material);
 ST = Annual mass of molten raw steel produced by furnace (tonnes);
 C_{ST} = Carbon content of steel (tonnes C/tonnes steel);
 SL = Annual mass of slag produced by furnace (tonnes);
 C_{SL} = Carbon content of slag (tonnes C/tonnes slag);
 BOG = Annual mass of basic oxygen furnace gas transferred off site (tonnes);
 C_{BOG} = Carbon content of basic oxygen furnace gas transferred off site (tonnes C/tonnes basic oxygen furnace gas);
 R = Annual mass of air pollution control residue collected (tonnes);
 C_R = Carbon content of air pollution control residue (tonnes C/tonnes residue);
 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

(3) Calculate coke oven battery CO₂ emissions using Equation 150-3:

$$E_{coke} = [(CC \times C_{CC}) - (CO \times C_{CO}) - (BY \times C_{BY}) - (R \times C_R) - (COG \times C_{COG})] \times 3.664$$

Equation 150-3

Where:

E_{coke} = Annual CO₂ emissions from coke production (tonnes);

CC	=	Annual mass of coking coal charged to battery (tonnes);
C _{CC}	=	Carbon content of coking coal (tonnes C/tonnes coking coal);
CO	=	Annual mass of coke produced (tonnes);
C _{CO}	=	Carbon content of coke (tonnes C/tonnes coke);
BY	=	Annual mass of by-product from by-product coke oven battery (tonnes);
C _{BY}	=	Carbon content of by-product (tonnes C/tonnes by-product);
R	=	Quantity of air pollution control residue collected (tonnes);
C _R	=	Carbon content of air pollution control residue (tonnes C/tonnes residue);
COG	=	Annual mass of coke oven gas transferred off site (tonnes);
C _{COG}	=	Carbon content of coke oven gas transferred off site (tonnes C/tonnes coke oven gas);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(4) Calculate sinter process CO₂ emissions using Equation 150-4:

$$E_{sinter} = [(CAR \times C_{CAR}) + (FE \times C_{FE}) - (S \times C_S) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-4}$$

Where:

E _{sinter}	=	Annual CO ₂ emissions from sinter process (tonnes);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C _{CAR}	=	Carbon content of carbonaceous material (tonnes C/ tonnes carbonaceous material);
FE	=	Annual mass of sinter feed material (tonnes);
C _{FE}	=	Carbon content of sinter feed material (tonnes C/tonnes sinter feed material);
S	=	Annual mass of sinter produced (tonnes);
C _S	=	Carbon content of sinter produced (tonnes C/tonnes sinter);
R	=	Quantity of air pollution control residue collected (tonnes);
C _R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(5) Calculate electric arc furnace (EAF) CO₂ emissions using Equation 150-5:

$$E_{EAF} = [(I \times C_I) + (SC \times C_{SC}) + (FL \times C_{FL}) + (EL \times C_{EL}) + (CAR \times C_{CAR}) - (ST \times C_{ST}) - (SL \times C_{SL}) - (R \times C_R)] \times 3.664$$

Equation 150-5

Where:

E _{EAF}	=	Annual CO ₂ emissions from EAF (tonnes);
I	=	Annual mass of direct reduced iron (if any) charged to furnace (tonnes);
C _I	=	Carbon content of direct reduced iron (tonnes C/ tonnes direct reduced iron);
SC	=	Annual mass of ferrous scrap charged to furnace (tonnes);
C _{SC}	=	Carbon content of ferrous scrap (tonnes C/ tonnes ferrous scrap);

FL	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C _{FL}	=	Carbon content of flux materials (tonnes C/ tonnes flux material);
EL	=	Annual mass for carbon electrodes consumed (tonnes);
C _{EL}	=	Carbon content of carbon electrodes (tonnes C/ tonnes carbon electrode);
CAR	=	Annual mass of carbonaceous material (e.g., coal, coke, etc.) charged to furnace (tonnes);
C _{CAR}	=	Carbon content of carbonaceous material (tonnes C/ tonnes carbonaceous material);
ST	=	Annual mass of molten raw steel produced by furnace (tonnes);
C _{ST}	=	Carbon content of steel (tonnes C/ tonnes steel);
SL	=	Annual mass of slag produced by furnace (tonnes);
C _{SL}	=	Carbon content of slag (tonnes C/ tonnes slag);
R	=	Annual mass of air pollution control residue collected (tonnes);
C _R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(6) Calculate argon-oxygen decarburization vessel CO₂ emissions using Equation 150-6:

$$E_{AOD} = [Steel \times (C_{in} - C_{out}) - (R \times C_R)] \times 3.664 \quad \text{Equation 150-6}$$

Where:

E _{AOD}	=	Annual CO ₂ emissions from argon-oxygen decarburization vessels (tonnes);
Steel	=	Annual mass of molten steel charged to vessel (tonnes);
C _{in}	=	Carbon content of molten steel before decarburization (tonnes C/ tonnes molten steel);
C _{out}	=	Carbon content of molten steel after decarburization (tonnes C/ tonnes molten steel);
R	=	Annual mass of air pollution control residue collected (tonnes);
C _R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(7) Calculate direct reduction furnace CO₂ emissions using Equation 150-7:

$$E_{DR} = [(Ore \times C_{Ore}) + \sum (CAR \times C_{CAR}) + \sum (OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (R \times C_R)] \times 3.664$$

Equation 150-7

Where:

E _{DR}	=	Annual CO ₂ emissions from direct reduction furnace (tonnes);
Ore	=	Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
C _{Ore}	=	Carbon content of iron ore or iron ore pellets (tonnes C/ tonnes iron ore or iron ore pellets);
CAR	=	Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);

C_{CAR}	=	Carbon content of non-fuel carbonaceous materials (tonnes C/ tonnes non-fuel carbonaceous material);
OT	=	Annual mass of other materials charged to furnace (tonnes);
C_{OT}	=	Carbon content of other materials (tonnes C/ tonnes other materials);
I	=	Annual mass of iron produced (tonnes);
C_I	=	Carbon content of iron (tonnes C/ tonnes iron);
NM	=	Annual mass for non-metallic materials produced (tonnes);
C_{NM}	=	Carbon content of non-metallic materials (tonnes C/ tonnes non-metallic minerals);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(8) Calculate blast furnace CO₂ emissions using Equation 150-8:

$$E_{BF} = [(Ore \times C_{Ore}) + \sum (CAR \times C_{CAR}) + \sum (F \times C_F) + \sum (OT \times C_{OT}) - (I \times C_I) - (NM \times C_{NM}) - (BG \times C_{BG}) - (R \times C_R)] \times 3.664$$

Equation 150-8

Where:

E_{BF}	=	Annual CO ₂ emissions from blast furnace (tonnes);
Ore	=	Annual mass of iron ore or iron ore pellets fed to the furnace (tonnes);
C_{Ore}	=	Carbon content of iron ore or iron ore pellets (tonnes C/ tonnes iron ore or iron ore pellets);
CAR	=	Annual mass of non-fuel carbonaceous materials (e.g., coal, coke, by-products, etc.) charged to furnace (tonnes);
C_{CAR}	=	Carbon content of non-fuel carbonaceous materials (tonnes C/ tonnes non-fuel carbonaceous material);
F	=	Annual mass for flux materials (e.g., limestone, dolomite, etc.) charged to furnace (tonnes);
C_F	=	Carbon content of flux materials (tonnes C/ tonnes flux material);
OT	=	Annual mass of other materials charged to furnace (tonnes);
C_{OT}	=	Carbon content of other materials (tonnes C/ tonnes other materials);
I	=	Annual mass of iron produced (tonnes);
C_I	=	Carbon content of iron (tonnes C/ tonnes iron);
NM	=	Annual mass for non-metallic materials produced (tonnes);
C_{NM}	=	Carbon content of non-metallic materials (tonnes C/ tonnes non-metallic minerals);
BG	=	Annual mass for blast furnace gas transferred off-site (tonnes);
C_{BG}	=	Carbon content of blast furnace gas (tonnes C/ tonnes blast furnace gas);
R	=	Annual mass of air pollution control residue collected (tonnes);
C_R	=	Carbon content of air pollution control residue (tonnes C/ tonnes residue);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(9) Calculate total CO₂ emissions using Equation 150-9:

$$E_{CO_2} = E_T + E_{BOF} + E_{coke} + E_{sinter} + E_{EAF} + E_{AOD} + E_{DR} + E_{BF}$$
Equation 150-9

Where:

E_{CO_2}	=	Total CO ₂ emissions (tonnes);
E_T	=	Emissions from taconite indurating furnace (tonnes);
E_{BOF}	=	Emissions from basic oxygen furnace (BOF) (tonnes);
E_{coke}	=	Emissions from coke production (tonnes);
E_{sinter}	=	Emissions from sinter production (tonnes);
E_{EAF}	=	Emissions from electric arc furnace (EAF) (tonnes);
E_{AOD}	=	Emissions from argon-oxygen decarburization vessels (tonnes);
E_{DR}	=	Emissions from direct reduction furnace (tonnes);
E_{BF}	=	Emissions from blast furnace (tonnes);

§ WCI.154 Calculation of CH₄ Emissions

- (a) Process CH₄ emissions. Determine process CH₄ 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

The annual mass of each material used in the WCI.153 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
- (1) For iron ore, taconite pellets, and other iron-bearing materials, use ASTM E1915-07a “Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry”.
 - (2) For iron and ferrous scrap, use ASTM E1019-08 “Standard Test Methods for Determination of Carbon, Sulphur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques”.
 - (3) For coal, coke, and other carbonaceous materials (e.g., electrodes, etc.), use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal” or ASTM D5142-09 “Standard Test Methods for Proximate Analysis of the Analysis Sample of Coal and

Coke by Instrumental Procedures”, for petroleum liquid based fuels and liquid waste-derived fuels.

- (4) For steel, use one of the methods described in subparagraph (i) through (iv):
 - (i) ASM CS-104 UNS No. G10460 “Carbon Steel of Medium Carbon Content”.
 - (ii) 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) (1998-10-15) – First Edition”.
 - (iii) 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) (1998-10-15) – First Edition”.
 - (iv) ASTM E415-08 “Standard Test Method for Atomic Emission Vacuum Spectrometric Analysis of Carbon and Low-Alloy Steel”.
- (5) For flux (i.e., limestone or dolomite) and slag, use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.
- (6) For fuels, determine carbon content and molecular weight (if applicable) using the applicable methods listed in §WCI.20.
- (7) For steel production by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, sinter off gas, slag dust, etc.), use an online instrument that determines carbon content to $\pm 5\%$, or use sampling and analysis as contained in WCI.25(a) and WCI.25(d).

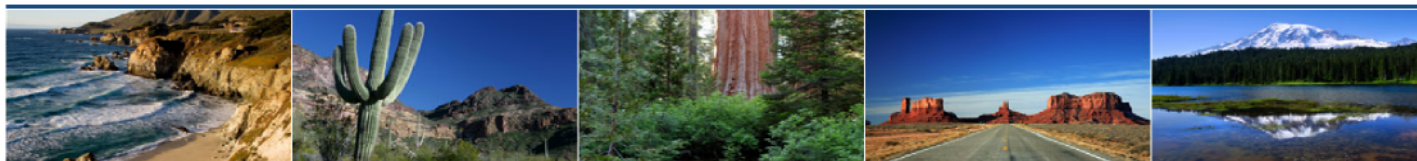
(b) Obtain carbon content from material vendor or supplier.

§ WCI.156 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Whenever the sampling procedures in WCI.155 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in accordance with paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For missing data on monthly carbon contents of feedstock or the waste recycle stream, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data is available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.
- (b) For missing feedstock supply rates or waste recycle stream used to determine monthly feedstock consumption or monthly waste recycle stream quantity, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

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§ WCI.160 LEAD PRODUCTION

§ WCI.161 Source Category Definition

The lead production category includes two primary production processes used to produce lead from lead concentrates (i.e., the sintering/smelting process and the direct smelting process). In addition, secondary production or recycling of lead (primarily from scrapped lead acid batteries) is included in the category.

§ WCI.162 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation the annual emissions data report shall contain the following information:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each material used (tonnes).
- (c) Carbon content of each material used (tonnes C/ tonne reducing agent).
- (d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).
- (e) If you use the missing data procedures in WCI.165(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.
- (f) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.163 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
- (b) Calculate total CO₂ emissions using Equation 160-1. Specific materials that in aggregate contribute less than 0.5% of the total carbon into the process may be excluded from the calculation performed using Equation 160-1.

$$E_{pb} = \sum_x (RA_x \times C_x) \times 3.664$$

Equation 160-1

Where:

E_{Pb} = Annual CO₂ emissions from lead production (tonnes);
 RA_x = Annual quantity of material x used (tonnes);
 C_x = Carbon content of material x (tonnes C/ tonnes of x);
 3.664 = Conversion factor from tonnes of C to tonnes of CO₂.

§ WCI.164 Sampling, Analysis, and Measurement Requirements

The annual mass of each material introduced into the smelting furnace shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

The average carbon content of each material introduced into the smelting furnace shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
 - (1) For solid carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.
 - (2) For liquid reducing agents, use one of the methods described in subparagraph (i) through (iv):
 - i. ASTM D2502-04 (Reapproved 2002) “Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements”.
 - ii. ASTM D2503-92 (Reapproved 2002) “Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure”.
 - iii. 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”.
 - iv. ASTM D5291-02 (Reapproved 2007) “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants”.
 - (3) For gaseous reducing agents, use one of the methods described in subparagraph (i) or (ii):
 - i. ASTM D1945-03 “Standard Test Method for Analysis of Natural Gas by Gas Chromatography”.
 - ii. ASTM D1946-90 “Standard Practice for Analysis of Reformed Gas by Gas Chromatography”.
 - (4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
 - i. To ensure representativeness of waste-based carbon-containing material variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction.

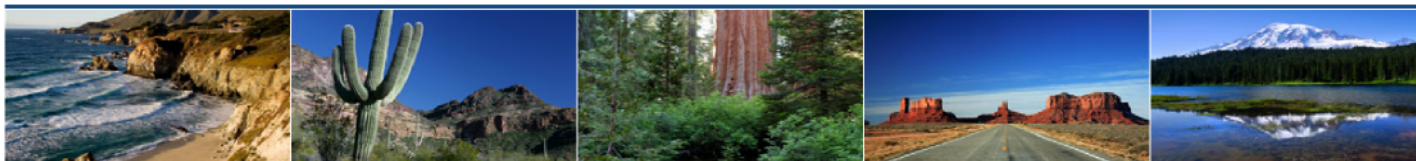
- (b) Obtain carbon content from material vendor or supplier.

§ WCI.165 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations in WCI.163 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO₂ emissions using the carbon mass balance procedure in WCI.163, 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.164 if data are missing.
- (b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based on the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

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§ WCI.170 LIME MANUFACTURING

§ WCI.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture a lime product (e.g., calcium oxide, high calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, dolomitic hydrate, or other products) by calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

This source category includes all lime manufacturing plants unless the plant is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

Lime kilns at pulp and paper manufacturing facilities must report emissions under WCI.210 (Pulp and Paper Manufacturing).

§ WCI.172 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CH₄, and N₂O in tonnes.
- (b) CO₂ process emissions from lime production (tonnes) for all kilns combined and the following information:
 - (1) For lime production:
 - (A) The emission factor (kg CO₂/ tonne) for each lime type for each month.
 - (B) The quantity of each type of lime produced (tonnes) 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 CO₂/ tonne) for each calcined byproduct/waste type for each quarter.
 - (B) The quantity of each type of calcined byproduct/waste type produced each quarter.
 - (C) The calcium oxide (CaO) content (weight fraction) of each calcined byproduct/waste type for each quarter.
 - (D) The magnesium oxide (MgO) content (weight fraction) of each calcined byproduct/waste type for each quarter.

- (3) Number of times during the reporting year that missing data procedures were followed to measure lime production.
- (c) CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in WCI.173(c) (tonnes).
- (d) CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in WCI.20 (tonnes).
- (e) If a continuous emissions monitor is used to measure CO₂ emissions from kilns, then the requirements of paragraph (b) of this section do not apply for CO₂.
- (f) Operators of lime plants shall also comply with the reporting requirements for any other applicable source category listed by regulation, 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 CO₂ 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 CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- (b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from lime production, using the method specified in paragraph (b)(1) of this section.
 - (1) CO₂ Process Emissions. Calculate CO₂ emissions from the production of each type of lime using Equation 170-1 and a plant-specific lime emission factor and a plant-specific calcined byproduct/waste emission factor as specified in this section.

$$CO_2 = \sum_m \sum_i [QL_{mi} \times EF_{QL_{mi}}] + \sum_q \sum_j [CBW_{qj} \times EF_{CBW_{qj}}] \quad \text{Equation 170-1}$$

Where:

- | | | |
|--------------------------------|---|--|
| CO ₂ | = | CO ₂ emissions in tonnes/yr. |
| QL _{mi} | = | Quantity of lime type <i>i</i> produced in month <i>m</i> , tonnes. |
| EF _{QL_{mi}} | = | Emission factor of lime type <i>i</i> produced in month <i>m</i> , tonnes CO ₂ /tonne lime computed as specified in paragraph (b)(2) of this section. |
| CBW _{qj} | = | Quantity of calcined byproduct/waste type <i>j</i> , including LKD, scrubber sludge and other calcined wastes produced in quarter <i>q</i> , tonnes. |
| EF _{CBW_{qj}} | = | Emission factor of calcined byproduct/waste type <i>j</i> produced in quarter <i>q</i> , computed as specified in paragraph (b)(3) of this section. |

- (2) Monthly Lime Emission Factor. Calculate a plant-specific lime emission factor (EF_{QL}) for each type of lime and month based on the measured CaO and MgO contents in lime and using Equation 170-2.

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-2}$$

Where:

EF_{QL}	=	Process CO ₂ emission factor for lime produced, tonnes CO ₂ / tonnes lime.
f_{CaO}	=	CaO content of lime, calculated by subtracting CaO content of lime in uncalcined CaCO ₃ remaining in lime from total CaO content of lime, tonnes CaO/ tonne lime
0.785	=	Ratio of molecular weights of CO ₂ to CaO.
f_{MgO}	=	MgO content of lime, calculated by subtracting MgO content of lime in uncalcined MgCO ₃ remaining in lime from total MgO content of lime, tonnes MgO/ tonne lime.
1.092	=	Ratio of molecular weights of CO ₂ to MgO

- (3) Quarterly Calcined Byproduct/Waste Emission Factor. The calcined byproduct/waste emission factor shall be calculated using Equation 170-3.

$$EF_{CBW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-3}$$

Where:

EF_{CBW}	=	Calcined byproduct/waste emission factor.
f_{CaO}	=	CaO content of byproduct and waste, calculated by subtracting CaO content of byproduct and waste in uncalcined CaCO ₃ remaining in calcined byproduct and waste from total CaO content of byproduct and waste, tonnes CaO/ tonne byproduct and waste.
0.785	=	Ratio of molecular weights of CO ₂ to CaO .
f_{MgO}	=	MgO content of byproduct and waste, calculated by subtracting MgO content of byproduct and waste in uncalcined MgCO ₃ remaining in byproduct and waste from total MgO content of byproduct and waste, tonnes MgO/ tonnes byproduct and waste .
1.092	=	Ratio of molecular weights of CO ₂ to MgO

- (c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O 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 CO₂ 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

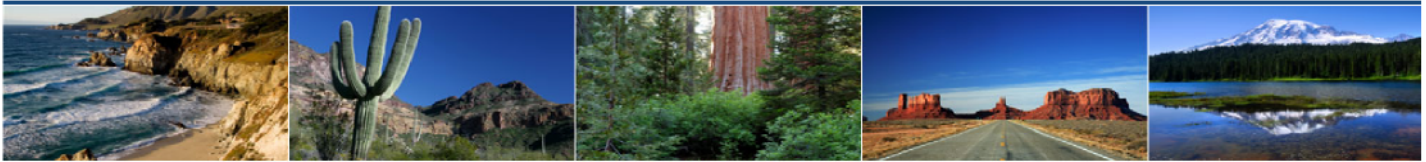
- (a) You must determine the chemical composition (CaO and MgO contents) of each type of lime and each type of calcined byproduct/waste according to paragraph (a)(1) and (a)(2) of this section. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct/waste 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.
- (1) ASTM C25-06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime.
- (2) The National Lime Association’s CO₂ Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.
- (b) 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.
- (c) The quantity of calcined byproduct/waste sold is to be estimated monthly using direct measurements (such as rail and truck scales) of calcined byproduct/waste sales for each calcined 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 annually 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).
- (d) Follow the quality assurance/quality control procedures (including documentation) in National Lime Association’s CO₂ Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision – National Lime Association.

§ WCI.175 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For each missing value of the quantity of lime produced (by lime type), and quantity of byproduct/waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.
- (b) For missing values related to the CaO and MgO content, you must conduct a new composition test.

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§ WCI.180 CARBONATES USE

§ WCI.181 Source Category Definition

This source category includes any equipment that uses carbonates listed in Table 180-1 in manufacturing processes that emit carbon dioxide. Table 180-1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO₂ if they consume at least 1,800 tonnes per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

This source category does not include equipment that uses carbonates or carbonate-containing minerals that are consumed in the production of cement, copper and nickel, electricity generation, ferroalloys, glass, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under WCI.20 (Stationary Fuel Combustion Sources).

§ WCI.182 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation, the annual emissions data report for carbonate use shall include the following information at the facility level calculated in accordance with this method:

- (a) Annual CO₂ emissions from miscellaneous carbonate use (tonnes).
- (b) Annual mass of each carbonate type consumed (tonnes).
- (c) If you followed the calculation method of WCI.183(a), you must report the following information:
 - (1) Annual carbonate consumption by carbonate type (tonnes).
 - (2) Annual calcination fractions used in calculations.
- (d) If you followed the calculation method of WCI.183(b), you must report the following information:
 - (1) Annual carbonate input by carbonate type (tonnes).
 - (2) Annual carbonate output by carbonate type (tonnes).
- (e) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§ WCI.183 Calculating GHG emissions.

You must determine CO₂ process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

- (a) Calculate the process emissions of CO₂ using calcination fractions with Equation 180-1 of this section.

$$E_{CO_2} = \sum_{i=1}^n (M_i \times EF_i \times F_i)$$

Equation 180-1

Where:

- ECO₂ = Annual CO₂ mass emissions from consumption of carbonates (tonnes).
M_i = Annual mass of carbonate type *i* consumed (tonnes).
EF_i = Emission factor for the carbonate type *i*, as specified in Table 180-1 to this Subpart, tonnes CO₂/tonne carbonate consumed.
F_i = Fraction calcination achieved for each particular carbonate type *i* (weight fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.
n = Number of carbonate types.

- (b) Calculate the process emissions of CO₂ using actual mass of output carbonates with Equation 180-2 of this section.

$$E_{CO_2} = \left[\sum_{k=1}^m (M_k \times EF_k) - \sum_{j=1}^n (M_j \times EF_j) \right]$$

Equation 180-2

Where:

- ECO₂ = Annual CO₂ mass emissions from consumption of carbonates (tonnes).
M_k = Annual mass of input carbonate type *k* (tonnes).
EF_k = Emission factor for the input carbonate type *k*, as specified in Table 180-1 of this method (tonnes CO₂/tonne carbonate input).
M_j = Annual mass of output carbonate type *j* (tonnes).
EF_j = Emission factor for the output carbonate type *j*, as specified in Table 180-1 of this method (tonnes CO₂/tonne carbonate input).
m = Number of input carbonate types.
n = Number of output carbonate types.

§ WCI.184 Monitoring and QA/QC requirements.

- (a) The annual mass of carbonate consumed (for Equation 180-1 of this subpart) or carbonate inputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.
- (b) The annual mass of carbonate outputs (for Equation 180-2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for

accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

- (c) If you follow the procedures of WCI.183(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

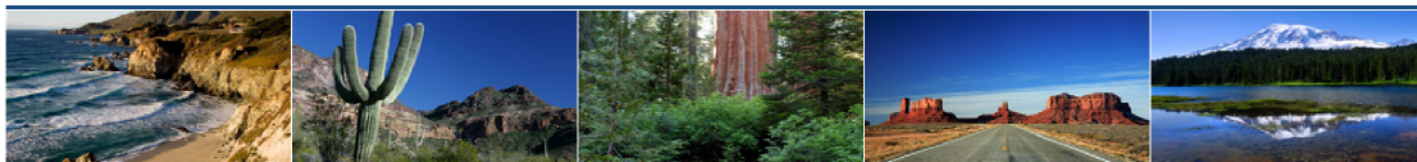
§ WCI.185 Procedures for estimating missing data.

- (a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.
- (b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

Table 180-1 — CO₂ Emission Factors for Common Carbonates

Mineral Name - Carbonate	CO₂ Emission Factor (tonnes CO₂/tonne carbonate)
Limestone - CaCO ₃	0.43971
Magnesite - MgCO ₃	0.52197
Dolomite - CaMg(CO ₃) ₂	0.47732
Siderite - FeCO ₃	0.37987
Ankerite - Ca(Fe,Mg,Mn)(CO ₃) ₂	0.47572
Rhodochrosite - MnCO ₃	0.38286
Sodium Carbonate/Soda Ash – Na ₂ CO ₃	0.41492
Others	Facility specific factor to be determined through analysis or supplier information

Western Climate Initiative



§ WCI.200 PETROLEUM REFINERIES

§ WCI.201 Source Category Definition

- (a) 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.
- (b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.
- (c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulphur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§ WCI.202 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions report must contain the following information reported at the facility level:

- (a) Catalyst Regeneration. Report CO₂, CH₄, and N₂O emissions.
- (b) Process Vents. Report CO₂, CH₄, and N₂O emissions.
- (c) Asphalt Production. Report CO₂ and CH₄ emissions.
- (d) Sulphur Recovery. Report CO₂ emissions.
- (e) Flares and Other Control Devices. Report CO₂, CH₄, and N₂O emissions.
- (f) Above-Ground Storage Tanks. Report CH₄ emissions.
- (g) Wastewater Treatment. Report CH₄ and N₂O emissions from anaerobic treatment.
- (h) Oil-water separators. Report CH₄ emissions from oil-water separators.
- (i) Equipment Leaks. Report CH₄ emissions.
- (j) Coke calcining units. Report CO₂, CH₄, and N₂O emissions.
- (k) Uncontrolled blowdown systems. Report CH₄ emissions.
- (l) Loading Operations. Report CH₄ emissions.

- (m) Delayed Coking Units. Report CH₄ emissions.
- (n) Stationary Combustion Units Other than Flares and Control Devices. CO₂, CH₄, and N₂O emissions as specified in WCI.30 for combustion of refinery fuel gas, still gas, flexigas, or associated gas and WCI.20 for combustion of all other fuels.
- (o) 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 cubic meters for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
- (p) Fuel Consumption: Report fuel consumption by fuel type consumed in the reporting year in units of cubic meters for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes 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 (m) of this section. If a continuous emissions monitor is used to measure CO₂ emissions from process vents, asphalt production, sulphur recovery, or other control devices then the operator shall calculate the CO₂ emissions from these processes using a continuous emissions monitoring system (CEMS) as specified in WCI.23(d). When the flue gas from two or more processes or stationary combustion sources are discharged through a common stack or duct before exiting to the atmosphere and if CEMS as specified in WCI.23(d) are used to continuously monitor the CO₂ emissions, you may report the combined emissions from the processes or stationary combustion sources sharing the common stack or duct in lieu of separately reporting the GHG emission from individual processes or stationary combustion sources.

- (a) Catalyst Regeneration. Operators shall calculate the CO₂, CH₄, and N₂O process emissions resulting from catalyst regeneration using the methods in paragraph (a)(1), (a)(2) and (a)(3), respectively.
 - (1) For units equipped with CEMS, operators shall calculate CO₂ 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)(A) through (a)(1)(C).
 - (A) (i) The person shall calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-1b, 200-2, and 200-3

$$CO_2 = \sum_{i=1}^n CR_i \times CF \times 3.664 \times 0.001 \quad \text{Equation 200-1}$$

Where:

- CO₂ = CO₂ emissions (tonnes/yr).
- n = Number of hours of operation in the report.
- CR_i = Hourly coke burn rate in kg/week.
- CF = Carbon fraction in coke burned.

- 3.664 = Ratio of molecular weights, CO₂ to carbon.
 0.001 = Conversion factor from kg to tonnes.

- (ii) Alternatively, the person may calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1b and 200-2.

$$CO_2 = \sum_{p=1}^n \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \quad \text{Equation 200-1b}$$

Where:

- CO₂ = CO₂ emissions (tonnes/yr).
 Q_r = Volumetric flow rate of exhaust gas before entering the emission control system using Equation 200-2 and at reference temperature and pressure conditions as used by the facility (dRm³/hr).
 %CO₂ = Average hourly CO₂ concentration in regenerator exhaust, per cent by volume – dry basis.
 %CO = Average hourly CO concentration in regenerator exhaust, per cent by volume – dry basis. When there is no post-combustion device, assume %CO to be zero.
 44 = Molecular weight of CO₂ (kg/kg-mole).
 MVC = Molar volume conversion factor at the same reference conditions as the above Q_r (Rm³/kg-mole).
 = 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
 0.001 = Conversion factor from kg to tonnes.
 n = Number of hours of operation in the report year.

- (iii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation 200-2 of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad \text{Equation 200-2}$$

Where:

- Q_r = Volumetric flow rate of exhaust gas from regenerator before entering the emission control system at reference temperature and pressure conditions as used by the facility (dRm³/min).
 Q_a = Volumetric flow rate of air to regenerator, as determined from control room instrumentation at reference temperature and pressure conditions as used for variable Q_r (dRm³/min).

- O_{oxy} = 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 at reference temperature and pressure conditions used for variable Q_r (dRm^3/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.

- (iv) Calculate the hourly coke burn rate using Equation 200-3 or from facility measurement or engineering estimate:

$$CR_i = K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [\%CO / 2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{oxy})$$

Equation 200-3

Where:

- CR_i = Hourly coke burn rate in kg/hour.
 K_1, K_2, K_3 = Material balance and conversion factors (K_1, K_2 , and K_3 from Table 200-1 or from facility measurement or engineering estimate).
 Q_r = Volumetric flow rate of exhaust gas before entering the emission control system from Equation 200-2 (dRm^3/min)
 Q_a = Volumetric flow rate of air to regenerator as determined from control room instrumentation at reference temperature and pressure conditions used in variable Q_r (dRm^3/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 at reference temperature and pressure conditions used in variable Q_r (dRm^3/min)
 $\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

- (B) 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 200-4.

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

Equation 200-4

Where:

CO ₂	=	CO ₂ emissions (tonnes/yr)
CC _{irc}	=	Average catalyst regeneration rate (tonnes/hr)
CF _{spent}	=	Weight carbon fraction of spent catalyst
CF _{regen}	=	Weight carbon fraction of regenerated catalyst (default = 0)
H	=	Hours regenerator was operational (hr/yr)
3.664	=	Ratio of molecular weights, CO ₂ to carbon

- (C) The operator shall calculate process CO₂ emissions resulting from periodic catalyst regeneration using Equations 200-5

$$CO_2 = \sum_1^n \left[(CB_Q)_n \times CC \times 3.664 \times 0.001 \right] \quad \text{Equation 200-5}$$

Where:

O ₂	=	Annual CO ₂ emissions (tonnes/year).
CB _Q	=	Coke burn-off quantity per regeneration cycle from engineering estimates (kg coke/cycle).
n	=	Number of regeneration cycles in the calendar year.
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
3.664	=	Ratio of molecular weights, CO ₂ to carbon
0.001	=	Conversion factor (tonne/kg).

- (2) Calculate CH₄ emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-6 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_2}{EmF_1} \right) \quad \text{Equation 200-6}$$

Where:

CH ₄	=	Annual methane emissions from coke burn-off (tonnes CH ₄ /year).
CO ₂	=	Emission rate of CO ₂ from coke burn-off calculated in paragraph (a)(1) of this section, as applicable (metric tons/year).
EmF ₁	=	Default CO ₂ emission factor for petroleum coke of 97 kg CO ₂ /GJ.
EmF ₂	=	Default CH ₄ emission factor of 2.8 x 10 ⁻³ kg CH ₄ /GJ.

- (3) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-7 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_3}{EmF_1} \right) \quad \text{Equation 200-7}$$

Where:

- N_2O = Annual nitrous oxide emissions from coke burn-off (tonnes N_2O /year).
 CO_2 = Emission rate of CO_2 from coke burn-off calculated in paragraphs (a)(1) of this section, as applicable (tonnes/year).
 EmF_1 = Default CO_2 emission factor for petroleum coke of 97 kg CO_2 /GJ.
 EmF_3 = Default N_2O emission factor of 5.7×10^{-4} kg N_2O /GJ.

(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 200-8 for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O .

$$E_x = \sum_{i=1}^n VR_i \times F_{xi} \times (MW_x / MVC) \times VT_i \times 0.001 \quad \text{Equation 200-8}$$

Where:

- E_x = Annual emissions of x (tonnes/yr), where $x = CO_2, N_2O$, or CH_4 .
 VR_i = Average volumetric flow rate for venting event i from measurement data, process knowledge or engineering estimates at reference temperature and pressure conditions as used by the facility (Rm^3 /unit time). If a mass flow meter is used, measure the flow rate in kg/unit time and replace the term " MW_x/MVC " with "1".
 F_{xi} = Molar fraction of x in vent gas stream during event i from measurement data, process knowledge or engineering estimates.
 MW_x = Molecular weight of x (kg/kg-mole).
 MVC = Molar volume conversion factor at the same reference conditions as the above VR_i (Rm^3 /kg-mole).
 VT_i = Time duration of venting event i , in same units of time as VR_i .
 n = Number of venting events in report year.
 0.001 = Conversion factor from kg to tonnes.

(c) **Asphalt Production.** The operator shall calculate CO_2 and CH_4 process emissions from asphalt blowing activities using either process vent method specified in paragraph (b) or according to the applicable provisions in paragraphs (c)(1) and (c)(2) of this section.

- (1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO_2 and CH_4 emissions using Equations 200-9 and 200-10 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB.CO_2}) \quad \text{Equation 200-9}$$

Where:

- CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (tonnes CO_2 /year).
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CO_2} = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (tonnes CO_2 /MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH_4}) \quad \text{Equation 200-10}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (tonnes CH_4 /year).
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4 /MMbbl asphalt blown); default = 580.

- (2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 and CH_4 emissions using Equations 200-11 and 200-12 of this section, respectively, provided these emissions are not already included in the flare emissions calculated in paragraph (e) of this section or in the stationary combustion unit emissions required under WCI.20.

$$CO_2 = 0.98 \times (Q_{AB} \times CEF_{AB} \times 3.664) \quad \text{Equation 200-11}$$

Where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (tonnes CO_2 /year).
0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
 Q_{AB} = Quantity of asphalt blown (MMbbl/year).
 CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (tonnes C/MMbbl asphalt blown); default = 2,750.
3.664 = ratio of molecular weights, carbon dioxide to carbon

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH_4}) \quad \text{Equation 200-12}$$

Where:

CH_4 = Annual methane emissions from controlled asphalt blowing (tonnes CH_4 /year).
0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
 Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
 EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (tonnes CH_4 /MMbbl asphalt blown); default = 580.

- (d) **Sulphur Recovery.** The operator shall calculate CO_2 process emissions from sulphur recovery units (SRUs) using Equation 200-13. For the molar fraction (MF) of CO_2 in the sour gas, use either a default factor of 0.20 or a source specific molar fraction value approved by the regulator and derived from source tests conducted at least once per calendar year under the supervision of the regulator.

$$CO_2 = FR \times MW_{CO_2} / MVC \times MF \times 0.001 \quad \text{Equation 200-13}$$

Where:

CO ₂	= Emissions of CO ₂ (tonnes/yr).
FR	= Volumetric flow rate of acid gas to SRU at reference temperature and pressure conditions as used by the facility (Rm ³ /year). If a mass flow meter is used, measure the acid gas flow in kg per year and replace the term “MW _{CO2} /MVC” with “1”.
MW _{CO2}	= Molecular weight of CO ₂ (44 kg/kg-mole).
MVC	= Molar volume conversion factor at the same reference conditions as the FR variable (Rm ³ /kg-mole). = $8.3145 * [273.16 + \text{reference temperature in } ^\circ\text{C}] / [\text{reference pressure in kilopascal}]$.
MF	= Molar fraction (%) of CO ₂ in sour gas based on measurement or engineering estimate (default MF = 20% expressed as 0.20).
0.001	= Conversion factor from kg to tonnes.

(e) Flares and Other Control Devices.

- (1) The operator shall calculate and report CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in section WCI.20.
- (2) The operator shall calculate and report CO₂ emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:
 - (A) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (e)(2)(A)(i) and (e)(2)(A)(ii).
 - (i) If you monitor gas composition, calculate the CO₂ emissions from the flare using Equation 200-14 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-14 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[3.664 \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \text{Equation 200-14}$$

Where:

CO ₂	= Annual CO ₂ emissions for a specific fuel type (tonnes/year).
0.98	= Assumed combustion efficiency of a flare.
0.001	= Unit conversion factor (tonnes per kilogram).
n	= Number of measurement periods. The minimum value for <i>n</i> is 52 (for weekly measurements); the maximum value for <i>n</i> is 366 (for daily measurements during a leap year).
p	= Measurement period index.
3.664	= Ratio of molecular weights, carbon dioxide to carbon

- (Flare)_p = Volume of flare gas combusted during measurement period at reference temperature and pressure conditions as used by the facility (Rm³/period) . If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term “(MW)_p/MVC” with “1”.
- (MW)_p = Average molecular weight of the flare gas combusted during measurement period *p* (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- MVC = Molar volume conversion factor at the same reference conditions as the above (Flare)_p (Rm³/kg-mole).
 = $8.3145 * [273.16 + \text{reference temperature in } ^\circ\text{C}] / [\text{reference pressure in kilopascal}]$.
- (CC)_p = Average carbon content of the flare gas combusted during measurement period *p* (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- (ii) If you monitor heat content but do not monitor gas composition, calculate the CO₂ emissions from the flare using Equation 200-15 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation 200-15 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^n [(Flare)_p \times (HHV)_p \times EmF] \quad \text{Equation 200-15}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (tonnes/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Unit conversion factor (tonnes per kilogram).
- n* = Number of measurement periods. The minimum value for *n* is 52 (for weekly measurements); the maximum value for *n* is 366 (for daily measurements during a leap year).
- p* = Measurement period index.
- (Flare)_p = Volume of flare gas combusted during measurement period *p* at reference temperature and pressure conditions as used by the facility (Rm³/period). If a mass flow meter is used, the person must also measure molecular weight and convert the mass flow to a volumetric flow as follows: Flare[m³] = Flare[kg] × MVC/(MW)_p, where MVC is the molar volume conversion factor at the same reference conditions as (Flare)_p (Rm³/kg-mole) and (MW)_p is the average molecular weight of the flare gas combusted during measurement period *p* (kg/kg-mole).
- (HHV)_p = Higher heating value for the flare gas combusted during measurement period *p* (GJ per m³). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- EmF = Default CO₂ emission factor of 57 kilograms CO₂/GJ (HHV basis).

(B) Alternative Method. For startup, shutdown, and malfunctions during which you were unable to measure the parameters required by Equations 200-14 and 200-15 of this section, you must determine the quantity of gas discharged to the flare separately for each start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (e)(2)(B)(i) and (e)(2)(B)(ii) of this section.

- (i) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event.
- (ii) For the reporting of emissions from normal operation flares in the year 2011, you may use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculation. If you are unable to use the methods in WCI.203(e)(2) in 2012 due to health or safety reasons, you may use the alternate method in the subsection in 2012 if it is consented to in writing by the Director.
- (iii) Calculate the CO₂ emissions using Equation 200-16 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[3.664 \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad \text{Equation 200-16}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (tonnes/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Unit conversion factor (tonnes per kilogram, mt/kg).
- n = Number of start-up, shutdown, and malfunction events during the reporting year.
- p = Start-up, shutdown, and malfunction event index.
- (Flare_{SSM})_p = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event *p* from engineering calculations, at reference temperature and pressure conditions as used by the facility (Rm³/event). If a mass flow meter is used, measure the flare gas combusted in kg per event and replace the term “(MW)_p/MVC” with “1”.
- (MW)_p = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event *p* (kg/kg-mole).
- MVC = Molar volume conversion factor at the same reference conditions as the above (Flare_{SSM})_p (Rm³/kg-mole).
= 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
- (CC)_p = Average carbon content of the flare gas, from analysis results or engineering calculations for the event *p* (kg C per kg flare gas).
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon.

- (3) The operator shall calculate and report CH₄ and N₂O emissions resulting from the combustion of hydrocarbons routed to flares for destruction using the methods specified in paragraphs (e)(3)(A) and (e)(3)(B):

- (A) Calculate CH₄ using Equation 200-17 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH_4} \quad \text{Equation 200-17}$$

Where:

- CH₄ = Annual methane emissions from flared gas (tonnes CH₄/year).
 CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).
 EmF_{CH₄} = Default CH₄ emission factor for petroleum products of 2.8 x 10⁻³ kg/GJ.
 EmF = Default CO₂ emission factor for flare gas of 57 kilograms CO₂/GJ (HHV basis).
 0.02/0.98 = Correction factor for flare combustion efficiency.
 16/44 = Correction factor ratio of the molecular weight of CH₄ to CO₂
 f_{CH₄} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

- (B) Calculate N₂O emissions using Equation 200-18 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF} \right) \quad \text{Equation 200-18}$$

Where:

- N₂O = Annual nitrous oxide emissions from flared gas (tonnes N₂O/year).
 CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (e)(1) and (e)(2) of this section (tonnes/year).
 EmF_{N₂O} = Default N₂O emission factor for petroleum products of 5.7 x 10⁻⁴ kg/GJ.
 EmF = Default CO₂ emission factor for flare gas of 57 kilograms CO₂/GJ (HHV basis).

- (4) 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 CO₂ emissions using Equation 200-19. The operator shall determine CC_A and MW_A quarterly using methods specified in WCI.20 and use the annual average values of CC_A and MW_A to calculate CO₂ emissions.

$$CO_2 = GV_A \times CC_A \times MW_A / MVC \times 3.664 \times 0.001 \quad \text{Equation 200-19}$$

Where:

CO ₂	=	CO ₂ emissions (tonnes/year).
GV _A	=	Volume of gas <i>A</i> destroyed annually at reference temperature and pressure conditions as used by the facility (Rm ³ /year). If a mass flow meter is used, measure the gas destroyed in kg and replace the term “MW _A /MVC” with “1”.
CC _A	=	Carbon content of gas <i>A</i> (kg C/kg fuel).
MW _A	=	Molecular weight of gas <i>A</i> .
MVC	=	Molar volume factor at the same reference conditions as the GV _A variable (Rm ³ /kg-mole).
	=	8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
3.664	=	Ratio of molecular weights, CO ₂ to carbon.
0.001	=	Conversion factor – kg to tonnes.

(f) **Storage Tanks.** For storage tanks other than those processing unstabilized crude oil except as provided in paragraph (f)(3) of this section, calculate CH₄ emissions using the applicable methods in paragraphs (f)(1) and (f)(2) of this section.

- (1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH₄ emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: “Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources”, including TANKS Model (Version 4.09D) or similar programs, or estimate CH₄ emissions from storage tanks using Equation 200-20 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad \text{Equation 200-20}$$

Where:

CH ₄	=	Annual methane emissions from storage tanks (tonnes/year).
0.1	=	Default emission factor for storage tanks (tonne CH ₄ /MMbbl).
Q _{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

- (2) For storage tanks that process unstabilized crude oil, calculate CH₄ emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation 200-21 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad \text{Equation 200-21}$$

Where:

CH ₄	=	Annual methane emissions from storage tanks (tonnes/year).
Q _{un}	=	Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP	=	Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
MF_{CH_4}	=	Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4 /kg-mole gas); use 0.27 as a default if measurement data are not available.
995,000	=	Correlation Equation factor (scf gas per MMbbl per psi).
16	=	Molecular weight of CH_4 (kg/kg-mole).
MVC	=	Molar volume conversion (849.5 scf/kg-mole).
0.001	=	Conversion factor (tonne/kg).

- (3) You do not need to calculate CH_4 emissions from storage tanks that meet any of the following descriptions:
- (A) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
 - (B) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
 - (C) Bottoms receivers or sumps;
 - (D) Vessels storing wastewater; or
 - (E) Reactor vessels associated with a manufacturing process unit.

(g) Industrial Wastewater Processing.

- (1) The operator shall calculate CH_4 emissions from anaerobic wastewater treatment (such as anaerobic reactor, digester, or lagoon) using Equation 200-22 or Equation 200-23.

$$CH_4 = Q \times COD_{qave} \times B \times MCF \times 0.001 \quad \text{Equation 200-22}$$

$$CH_4 = Q \times BOD_{5qave} \times B \times MCF \times 0.001 \quad \text{Equation 200-23}$$

Where:

CH_4	=	Emission of methane (tonnes/yr).
Q	=	Volume of wastewater treated (m^3 /yr).
COD_{qave}	=	Average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3).
BOD_{5qave}	=	Average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m^3).
B	=	Methane generation capacity ($B = 0.25 \text{ kg } CH_4/\text{kg } COD$ and $0.06 \text{ kg } CH_4/\text{kg } BOD_5$).
MCF	=	Methane correction factor for anaerobic decay (0-1.0) from Table 200-2.
0.001	=	Conversion factor – kg to tonnes.

- (2) For anaerobic processes from which biogas is recovered and not emitted, you must adjust the CH₄ emissions calculated in paragraph (g)(1) by the amount of CH₄ collected.
- (3) The operator shall calculate N₂O emissions from wastewater treatment using Equation 200-24.

$$N_2O = Q \times N_{qave} \times EF_{N_2O} \times 1.571 \times 0.001 \quad \text{Equation 200-24}$$

Where:

N ₂ O	=	Emissions of N ₂ O (tonnes/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 ₂ O from discharged wastewater (0.005 kg N ₂ O-N/kg N).
1.571	=	Conversion factor – kg N ₂ O-N to kg N ₂ O.
0.001	=	Conversion factor – kg to tonnes.

(h) Oil-Water Separators. The operator shall calculate CH₄ emissions from oil-water separators using Equation 200-25. 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 regulator.

$$CH_4 = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001 \quad \text{Equation 200-25}$$

Where:

CH ₄	=	Emission of methane (tonnes/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 from kg to tonnes.

(i) Equipment leaks. Calculate CH₄ emissions using the method specified in either paragraph (i)(1) or (i)(2) of this section.

- (1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

- (2) Use Equation 200-26 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad \text{Equation 200-26}$$

Where:

CH ₄	=	Annual methane emissions from equipment leaks (tonnes/year)
N _{CD}	=	Number of atmospheric crude oil distillation columns at the facility.

- N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
- N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
- N_{H2} = Total number of hydrogen plants at the facility.
- N_{FGS} = Total number of fuel gas systems at the facility.

(j) **Coke Calcining.** The operator shall calculate GHG emissions according to the applicable provisions in paragraphs (j)(1) through (j)(3) of this section.

- (1) If you operate and maintain a CEMS that measures CO₂ emissions according to WCI.20, you must calculate and report CO₂ emissions for coke calcining by following the CEMS Calculation Methodology specified in WCI.20. If the coke calcining unit is not equipped with CEMS must either install a CEMS that complies with the CEMS requirements in WCI.23, or follow the requirements of paragraph (j)(2) of this section.
- (2) Calculate the CO₂ emissions from the coke calcining unit using Equation 200-27 of this section.

$$CO_2 = 3.664 \times (M_{in} \times CC_{GC} - (M_{out} + M_{dust}) \times CC_{MPC}) \quad \text{Equation 200-27}$$

Where:

- CO_2 = Annual CO₂ emissions (tonnes/year).
- M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (tonnes/year).
- CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (tonne carbon/tonne green coke).
- M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (tonnes petroleum coke/year).
- M_{dust} = Annual mass of petroleum coke dust collected in the dust collection system of the coke calcining unit from facility records (tonne petroleum coke dust/year)
- CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (tonne carbon/tonne petroleum coke).
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon

- (3) For all coke calcining units, use the CO₂ emissions from the coke calcining unit calculated in paragraphs (j)(1) or (j)(2), as applicable, and calculate CH₄ and N₂O using the following methods:
 - (A) Calculate CH₄ emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-28 of this section.

$$\text{CH}_4 = \left(\text{CO}_2 \times \frac{\text{EmF}_2}{\text{EmF}_1} \right) \quad \text{Equation 200-28}$$

Where:

- CH₄ = Annual methane emissions (tonnes CH₄/year).
- CO₂ = Emission rate of CO₂ calculated in paragraphs (j)(1) and (j)(2) of this section, as applicable (tonnes/year).
- EmF₁ = Default CO₂ emission factor for petroleum coke (97 kg CO₂/GJ).
- EmF₂ = Default CH₄ emission factor of 2.8 x 10⁻³ kg CH₄/GJ.

- (B) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation 200-29 of this section.

$$\text{N}_2\text{O} = \left(\text{CO}_2 \times \frac{\text{EmF}_3}{\text{EmF}_1} \right) \quad \text{Equation 200-29}$$

Where:

- N₂O = Annual nitrous oxide emissions (tonnes N₂O/year).
- CO₂ = Emission rate of CO₂ from paragraphs (j)(1) and (j)(2) of this section, as applicable (tonnes/year).
- EmF₁ = Default CO₂ emission factor for petroleum coke (97 kg CO₂/GJ)
- EmF₃ = Default N₂O emission factor of 5.7 x 10⁻⁴ kg N₂O/GJ.

- (k) **Uncontrolled Blowdown Systems.** For uncontrolled blowdown systems, you must use the methods for process vents in paragraph (b) of this section.
- (l) **Loading Operations.** For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH₄ emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.
- (m) **Delayed coking units.** Calculate the CH₄ emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to the atmosphere using either of the methods provided in paragraphs (m)(1) or (m)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (m)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.
 - (1) Use the process vent method in paragraph (b) of this section and also calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section. If you have coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums

or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 101.325)}{101.325} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH_4} \times 0.001 \right) \quad \text{Equation 200-30}$$

Where:

- CH₄ = Annual methane emissions from the delayed coking unit vessel opening (tonnes/year).
- N = Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
- H = Height of coking unit vessel (metres).
- P_{CV} = Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (m)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (kilopascals).
- 101.325 = Assumed atmospheric pressure (kilopascals).
- f_{void} = Volumetric void fraction of coking vessel prior to steaming based on engineering judgement at reference temperature and pressure conditions as used by the facility (Rm³ gas/m³ of vessel).
- D = Diameter of coking unit vessel (metres).
- 16 = Molecular weight of CH₄ (kg/kg-mole).
- MVC = Molar volume factor at the same reference conditions as the cooking vessel (Rm³/kg-mole).
- = 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
- MF_{CH₄} = Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH₄/kg-mole gas, wet basis).
- 0.001 = Conversion factor (tonne/kg).

- (2) Calculate the CH₄ emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation 200-30 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation 200-30 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

§ WCI.204 Sampling, Analysis, and Measurement Requirements

Where the ASTM or other consensus based organization analysis or other measurement methods specified in this subsection are not offered by any supplier in the Jurisdiction, you may request approval by the Director in writing for another equivalent method.

- (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) Weekly periodic measurements of the CO₂, CO and O₂ concentrations in the regenerator exhaust gas (or continuous measurements if the equipment necessary to make continuous measurements is already in place).
 - (D) Daily determinations of the carbon content of the coke burned.
 - (E) The number of hours of operation.
 - (F) The measured daily or weekly values can be used to derive the minute or hourly parameters as required by the corresponding equations.
- (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 from measurement data, process knowledge or engineering estimates.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event from measurement data, process knowledge or engineering estimates.
 - (3) The duration of each venting event.
- (c) Asphalt Production. Operators shall measure the mass of asphalt blown.
- (d) Sulphur Recovery. The operator shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molar fraction value that is based on measurements value instead of the default factor or engineering estimates, the person shall conduct an annual test of the molar fraction value.
- (e) Flares and Other Control Devices. The operator shall measure the following:
 - (1) If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the

measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

- (2) If using the method specified in WCI.203(e)(2)(A)(i), monitor the carbon content of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).
 - (3) If using the method specified in WCI.203(e)(2)(A)(ii), monitor the high heat value of the flare gas daily if the flare is already equipped with the necessary measurement devices (at least weekly if not).
- (f) Storage Tanks. The operator shall determine the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using company record or applicable plant instruments.
- (g) Wastewater Treatment. Operators shall measure the following parameters.
- (1) You must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (e.g., after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). You must collect and analyze samples for COD or BOD₅ concentration once each calendar week.
 - (2) You must measure the flowrate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD₅ concentration.
 - (3) 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 .
- (i) Coke Calcining. Determine the mass of petroleum coke as required using measurement equipment used for accounting purposes. Determine the carbon content of petroleum coke as using any one of the following methods:
- (1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke.
 - (2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.
 - (3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal

§ WCI.205 Procedures for Estimating Missing Data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore,

whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

- (a) For stationary combustion sources, use the missing data procedures in WCI.20.
- (b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.
- (c) For missing CO₂, CO, O₂, CH₄, or N₂O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

§ WCI.206 Definitions

Except as specified in this section, all terms used in this subpart have the same meaning given in the General Provisions.

Unstabilized crude oil means crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg min)/(hr dRm ³ %)	(lb min)/(hr dscf %)
K ₁	0.2982	0.0186
K ₂	2.0880	0.1303
K ₃	0.0994	0.0062

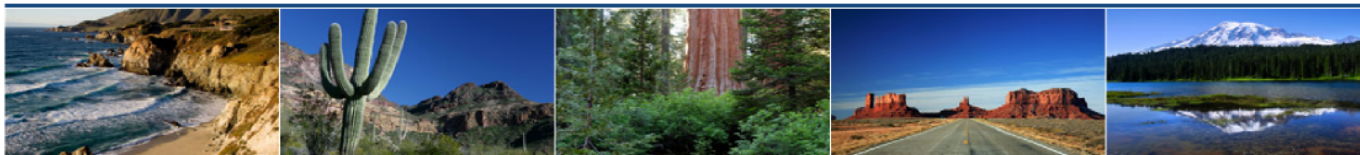
Table 200-2. Default MCF Values for Industrial Wastewater

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 N₂O from discharged wastewater (EF_{N2O}) is 0.005 kg N₂O-N/kg-N.
MCF = methane conversion factor (the fraction of waste treated anaerobically).
COD = chemical oxygen demand (kg COD/m³).

Table 200-3. Emission Factors for Oil/Water Separators	
Separator Type	Emission factor (EF_{sep})^a kg NMHC/m³ wastewater treated
Gravity type - uncovered	1.11 x 10 ⁻¹
Gravity type - covered	3.30 x 10 ⁻³
Gravity type – covered and connected to destruction device	0
DAF ^b or IAF ^c - uncovered	4.00 x 10 ^{-3d}
DAF or IAF - covered	1.20 x 10 ^{-04d}
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	

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§ WCI.210 PULP AND PAPER MANUFACTURING

§ WCI.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fibre from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

§ WCI.212 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions report must contain the following information:

- (a) Annual CO₂, biogenic CO₂, CH₄, and N₂O process emissions from all recovery units and kilns combined in tonnes, as specified in WCI.213.
- (b) Annual CO₂ emissions from addition of makeup chemicals (CaCO₃ and Na₂CO₃) in the chemical recovery areas of chemical pulp mills.
- (c) CO₂, N₂O and CH₄ emissions from electricity generation units in tonnes, as specified in WCI.43. CO₂, N₂O, and CH₄ emissions from stationary combustion units in tonnes, as specified in WCI.23.
- (d) Annual consumption of carbonate in tonnes.
- (e) Annual black liquor production in tonnes.
- (f) Annual CH₄ and N₂O emissions from onsite wastewater treatment plants in tonnes, as specified in WCI.200 (if required by regulation)

§ WCI.213 Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semichemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (d) of this section. CH₄ and N₂O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

- (a) Calculate fossil-fuel based CO₂ emissions from direct measurement of fossil fuels consumed and the methodology for stationary combustion sources specified by WCI.20, or the methodology for electricity generation specified by WCI.43, for the appropriate fuel type. For kraft or soda pulp mill lime kilns, if WCI.20 allows the use of default emission factors, use the default CO₂ emission factors listed in Table 210-1.
- (b) Calculate fossil-fuel based CH₄ and N₂O emissions from direct measurement of fossil fuels consumed, default HHV, and default emission factors according to the methodology specified by WCI.20 or WCI.43. For kraft or soda pulp mill lime kilns, use the default CH₄ and N₂O emission factors listed in Table 210-1.

(c) Calculate biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass as specified under subparagraphs (1) through (3).

(1) For kraft or soda chemical recovery furnaces, calculate emissions using Equation 210-1:

$$Emissions = Solids \times HHV \times EF \quad \text{Equation 210-1}$$

Where:

Emissions = Biogenic CO₂ emissions and emissions of CH₄ and N₂O from biomass (spent liquor solids) combustion (tonnes/year).
 Solids = Mass of spent liquor solids combusted (tonnes/year).
 HHV = Annual high heat value of spent liquor solids (GJ/kg).
 EF = Default emission factor for CO₂, CH₄, and N₂O from Table 210-2 (kg/GJ)

(2) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate CO₂ emissions using Equation 210-2:

$$E_{CO_2} = 3.664 \times Solids \times CC \quad \text{Equation 210-2}$$

Where:

E_{CO₂} = Biogenic CO₂ emissions from spent liquor solids combustion (tonnes/year).
 3.664 = Ratio of molecular weights, CO₂ to carbon.
 Solids = Mass of spent liquor solids combusted (tonnes/year).
 CC = Annual carbon content of spent liquor solids (percent by weight, expressed as a decimal fraction).

(3) For sulfite or stand-alone semichemical chemical recovery combustion units, calculate emissions of CH₄ and N₂O from biomass using Equation 210-1.

(d) For make-up chemical use, calculate CO₂ emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO₂ and make-up chemicals using Equation 210-3:

$$CO_2 = \left(\left[M_{CaCO_3} \times \frac{44}{100} \right] + \left[M_{Na_2CO_3} \times \frac{44}{105.99} \right] \right) \quad \text{Equation 210-3}$$

Where:

CO₂ = CO₂ emissions from make-up chemicals (tonnes/year).
 M_{CaCO₃} = Make-up quantity of CaCO₃ used for reporting year (tonnes/year).
 M_{Na₂CO₃} = Make-up quantity of Na₂CO₃ used for reporting year (tonnes/year).
 44 = Molecular weight of CO₂.
 100 = Molecular weight of CaCO₃.
 105.99 = Molecular weight of Na₂CO₃.

§ WCI.214 Sampling, Analysis, and Measurement Requirements

At least annually, determine the following fuel properties. If measurements are performed more frequently than annually, then fuel properties must be based on the average of the representative measurements made during the year.

- (a) Determine high heat values of black liquor using Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-06 “Gross High Heating Value of Black Liquor”.
- (b) Determine annual mass of spent liquor solids using one of the methods specified in subparagraph (1) or (2)
 - (1) Measure mass of annual spent liquor solids using TAPPI T650 om-05 “Solids Content of Black Liquor”.
 - (2) Determine mass of annual spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit. Measure the quantity of black liquor produced each month.
- (c) Determine carbon content using ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”, or ASTM 5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants.

§ WCI.215 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

- a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.
- b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.
- c) For the use of makeup chemicals (CaCO_3 and Na_2CO_3), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

Table 210-1 . Kraft Lime Kiln and Calciner Emissions Factors for Fossil Fuel-Based CO₂, CH₄, and N₂O

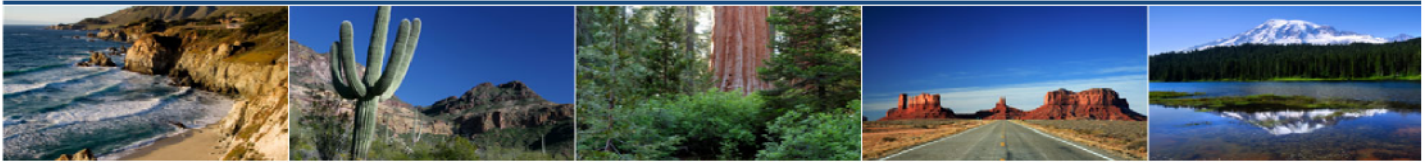
Fuel	Fossil Fuel-Based Emissions Factors (kg/GJ HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O
Residual Oil	72.7	0.0026	0	72.7	0.0026	0.00028
Distillate Oil	69.7			69.7		0.00038
Natural Gas	53.1			53.1		0.00009
Biogas	0			0		0.00009

Table 210-2. Kraft Pulping Liquor Emissions Factors for Biomass-Based CO₂, CH₄, and N₂O

Wood Furnish	Biomass-Based Emissions Factors (kg/GJ HHV)		
	CO ₂ ^a	CH ₄	N ₂ O
North American Softwood	89.5	0.028	0.0047
North American Hardwood	88.8		
Bagasse	90.5		
Bamboo	88.8		
Straw	90.2		

^a Includes emissions from both the recovery furnace and pulp mill lime kiln.

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§ WCI.220 SODA ASH MANUFACTURING

§ WCI.221 Source Category Definition

A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a) through (c) of this section:

- (a) Calcining trona.
- (b) Calcining sodium sesquicarbonate.
- (c) Using a liquid alkaline feedstock process that directly produces CO₂.

In the context of the soda ash manufacturing sector, “calcining” means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ WCI.222 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, each annual report must contain the following information

- (a) CO₂ process emissions from the soda ash manufacturing facility.
- (b) CO₂, CH₄ and N₂O combustion emissions must be calculated and reported under WCI.20 (General Stationary Combustion) by following the requirements of WCI.20.
- (c) If a CEMS is used to measure CO₂ emissions, then you must report under this method the relevant information required under WCI.23.
- (d) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (tonnes).
- (e) Annual production of soda ash (tonnes).
- (f) Annual quantity of generated CO₂ recycled to carbonation towers (tonnes), if applicable.
- (g) Number of times missing data procedures were used.

§ WCI.223 Calculation of Greenhouse Gas Emissions

Calculate and report the annual process CO₂ emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

- (a) For each soda ash manufacturing line that meets the conditions specified in WCI.23(e), calculate and report under this method the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to Calculation Methodology 4 specified in WCI.23(d) and all associated requirements.
- (b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO₂ emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this

section; and the combustion CO₂ emissions using the procedure in paragraph (b)(4) of this section.

- (1) Calculate and report under this method the combined process and combustion CO₂ emissions by operating and maintaining a CEMS to measure CO₂ emissions according to Calculation Methodology 4 specified in WCI.23(d) and all associated requirements for Calculation Method 4 in WCI.23(d) (General Stationary Combustion).
- (2) Use either Equation 220-1 or Equation 220-2 of this section to calculate annual CO₂ process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} [(IC_T)_n * (T_t)_n] * \frac{0.097}{1}$$

Equation 220-1

$$E_k = \sum_{n=1}^{12} [(IC_{sa})_n * (T_{sa})_n] * \frac{0.138}{1}$$

Equation 220-2

Where:

- E_k = Annual CO₂ process emissions from each manufacturing line, k (tonnes).
- $(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n . This represents the ratio of trona to trona ore.
- $(IC_{sa})_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n . This represents the purity of the soda ash produced.
- $(T_t)_n$ = Mass of trona input in month n (tonnes).
- $(T_{sa})_n$ = Mass of soda ash output in month n (tonnes).
- 0.097/1 = Ratio of tonne of CO₂ emitted for each tonne of trona.
- 0.138/1 = Ratio of tonne of CO₂ emitted for each tonne of soda ash produced.

- (3) Site-specific emission factor method. Use Equations 220-3, 220-4, and 220-5 of this section to determine annual CO₂ process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO₂ emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO₂ emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.
 - (i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in tonnes per hour.
 - (ii) Using the test data, you must calculate the hourly CO₂ emission rate using Equation 220-3 of this section:

$$ER_{CO_2} = [(C_{CO_2} * 10000) * 4.16 \times 10^{-8} * 44] * (Q * 60) * 0.001 \quad \text{Equation 220-3}$$

Where:

ER_{CO_2}	=	CO ₂ mass emission rate (tonnes/hour).
C_{CO_2}	=	Hourly CO ₂ concentration (per cent CO ₂) as determined by WCI.224(c).
10000	=	Conversion factor from per cent to parts per million
4.16×10^{-8}	=	Conversion factor from ppm to kg-mole/dsm ³ (kg-mole/dsm ³ /ppm).
44	=	kg per kg-mole of carbon dioxide.
Q	=	Stack gas volumetric flow rate per minute (dsm ³ per minute).
60	=	Minutes per hour
0.001	=	Conversion factor from kg to tonnes (tonnes/kg)

- (iii) Using the test data, you must calculate a CO₂ emission factor for the process using Equation 220-4 of this section:

$$EF_{CO_2} = \frac{ER_{CO_2}}{V_t} \quad \text{Equation 220-4}$$

Where:

EF_{CO_2}	=	CO ₂ emission factor (tonnes CO ₂ /tonne of process vent flow from mine water stripper/evaporator).
ER_{CO_2}	=	CO ₂ mass emission rate (tonnes/hour).
V_t	=	Process vent mass flow rate from mine water stripper/evaporator during annual performance test (tonnes/hour).

- (iv) Calculate annual CO₂ process emissions from each manufacturing line using Equation 220-5 of this section:

$$E_k = EF_{CO_2} * V_a * H \quad \text{Equation 220-5}$$

Where:

E_k	=	Annual CO ₂ process emissions for each manufacturing line, k (tonnes).
EF_{CO_2}	=	CO ₂ emission factor (tonnes CO ₂ /tonne of process vent flow from mine water stripper/evaporator).

V_a = Annual process vent mass flow rate from mine water stripper/evaporator (tonnes/hour).

H = Annual operating hours for the each manufacturing line.

- (4) Calculate and report under WCI.20 (General Stationary Fuel Combustion Sources) the combustion CO_2 , CH_4 , and N_2O emissions in the soda ash manufacturing line according to the applicable requirements of WCI.20.

§ WCI.224 Sampling, Analysis, and Measurement Requirements

Section WCI.223 provides four different procedures for emission calculations. The appropriate paragraphs (a) through (d) of this section should be used for the procedure chosen.

(a) If you determine your emissions using WCI.223 (b)(2), Equation 220-1 of this subpart you must:

- (1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359-00(Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). ASTM E359-00(Reapproved 2005)e1 is designed to measure the total alkalinity in soda ash, not in trona. The modified method of ASTM E359-00 adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359-00(Reapproved 2005)e1 uses manual titration, suitable autotitrators may also be used for this determination.
- (2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.
- (3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production using WCI.223(b)(2), Equation 220-2 of this subpart, you must:

- (1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359-00(Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate). Although ASTM E359-00(Reapproved 2005) uses manual titration, suitable autotitrators may also be used for this determination.
- (2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail load out points of your facility, or methods used for accounting purposes.
- (3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in WCI.223(b)(3), you must:

- (1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.
- (2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

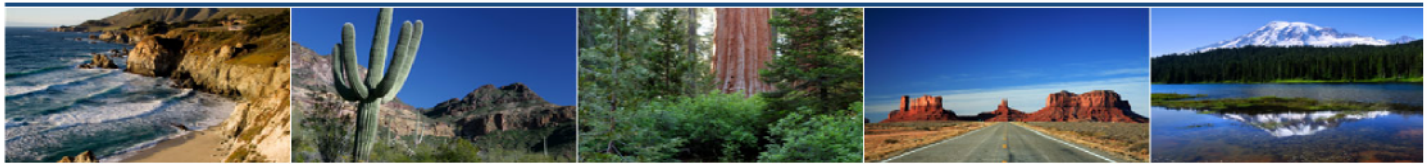
- (3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A-2 to measure the CO₂ concentration; and Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A-1 or Method 26 at 40 CFR part 60, appendix A-2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.
 - (i) Analysis of samples, determination of emissions, and raw data.
 - (ii) All information and data used to derive the emissions factor(s).
 - (iii) You must determine the average process vent flow rate from the mine water stripper/evaporator during each test and document how it was determined.
- (4) You must also determine the annual vent flow rate from the mine water stripper/evaporator from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

WCI.225 Procedures for Estimating Missing Data

For the emission calculation methodologies in WCI.223(b)(2) and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

- (a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.
- (b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.
- (c) For each missing value collected during the performance test (hourly CO₂ concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under WCI.223(b)(3) and WCI.224(c).
- (d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

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§ WCI.230 ELECTRICITY TRANSMISSION (AND EMISSIONS FROM ELECTRICAL EQUIPMENT IN ELECTRICITY GENERATION)

§ WCI.231 Source Category Definition

Sulfur hexafluoride (SF₆) and perfluorocarbons (PFCs) are used as gaseous dielectric mediums for electric power distribution equipment, including transmission and distribution systems, substations, high-voltage circuit breakers, switches, and other electrical equipment. This category includes fugitive emissions from equipment that is located at a facility that the operator is responsible for maintaining in proper working order.

§ WCI.232 Greenhouse Gas Reporting Requirements

For each facility, the emissions data report shall include the following information:

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

- (1) Fugitive SF₆ emitted from equipment.
- (2) Fugitive PFCs emitted from equipment

§ WCI.233 Calculation of SF₆ Emissions

SF₆ emissions must be calculated using either a mass-balance or direct measurement approach. Section (a) describes the mass balance approach; section (b) describes the direct measurement approach.

(a) Mass Balance Approach.

- (1) Calculate the annual SF₆ emissions using a mass balance approach that tracks and systematically accounts for all operator uses of SF₆, as follows. Any quantity of SF₆ that cannot be accounted for is then assumed to have been emitted into the atmosphere.
- (2) Calculate the change in inventory of SF₆ in storage using Equation 230-1.

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End} \quad \text{Equation 230-1}$$

Where:

ΔS_{Inv} = Change in inventory of SF₆ in storage, kilograms (“Storage” includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF₆ increases during the year);

$S_{Inv-Begin}$ = Quantity of SF₆ in storage at the beginning of the year, kilograms;

$S_{Inv-End}$ = Quantity of SF₆ in storage at the end of the year, kilograms.

- (3) Calculate the sum of all SF₆ acquired from other entities during the year either in storage containers or in equipment using Equation 230-2.

Equation 230-2

$$S_{PA} = S_{Cyl} + S_{Equip} + S_{Recyc-ret}$$

Where:

- S_{PA} = Sum of all SF₆ acquired from other entities during the year either in storage containers or in equipment, kilograms;
- S_{Cyl} = Quantity of SF₆ purchased from producers or distributors in cylinders, kilograms;
- S_{Equip} = Quantity of SF₆ provided by equipment manufacturers with/inside equipment, kilograms;
- $S_{Recyc-ret}$ = Quantity of SF₆ returned to site after off-site recycling, kilograms.

- (4) Calculate the sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment using Equation 230-3.

Equation 230-3

$$S_{SD} = S_{Sales} + S_{Returns} + S_{Destruct} + S_{Recyc-off}$$

Where:

- S_{SD} = Sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
- S_{Sales} = Quantity of SF₆ sold to other entities (including gas left in equipment that is sold), kilograms;
- $S_{Returns}$ = Quantity of SF₆ returned to suppliers, kilograms;
- $S_{Destruct}$ = Quantity of SF₆ sent to destruction facilities, kilograms;
- $S_{Recyc-off}$ = Quantity of SF₆ sent off-site for recycling, kilograms.

- (5) Calculate the net increase in nameplate capacity of equipment using Equation 230-4.

Equation 230-4

$$\Delta S_{Cap} = S_{Cap-new} - S_{Cap-retire}$$

Where:

- ΔS_{Cap} = Net increase in total nameplate capacity of equipment using SF₆ in storage, kilograms (“Total nameplate capacity” refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);
- $S_{Cap-new}$ = Total nameplate capacity (proper full charge) of new equipment, kilograms;
- $S_{Cap-retire}$ = Total nameplate capacity (proper full charge) of retired or sold equipment, kilograms.

(6) Calculate total annual emissions using Equation 230-5.

$$S = (\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap}) / 1,000 \quad \text{Equation 230-5}$$

Where:

- S = Annual SF₆ emissions, tonnes;
- ΔS_{Inv} = Change in inventory of SF₆ in storage, kilograms (“Storage” includes cylinders, gas carts, and other storage containers, but excludes equipment. Value will be negative if quantity of SF₆ increases during the year);
- S_{PA} = Sum of all SF₆ acquired during the year either in storage containers or in equipment, kilograms;
- S_{SD} = Sum of all SF₆ sold or otherwise disbursed during the year either in storage containers or in equipment, kilograms;
- ΔS_{Cap} = Net increase in total nameplate capacity of equipment using SF₆ in storage, kilograms (“Total nameplate capacity” refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage.);
- 1,000 = Factor to convert kilograms to tonnes.

(b) Direct Measurement Approach.

SF₆ emissions are estimated by directly measuring the mass of SF₆ added to electrical equipment during operation (operation phase) and the amount of SF₆ collected from any decommissioned equipment (decommissioning phase).

In the operation phase, SF₆ added to equipment can be measured using one of two methods: automated mass-flow measurement or weigh-scale measurement. In automated mass-flow measurement, mass-flow meters attached to electrical equipment directly measure the amount of SF₆ added to equipment. In weigh-scale measurement, an SF₆ cylinder is measured before and after its contents are added to electrical equipment with the difference being equal to the SF₆ added to the equipment. Annual SF₆ emissions for both methods are calculated according to Equation 230-6.

$$S_O = \sum_i^N s_i \quad \text{Equation 230-6}$$

Where:

- S_O = Annual SF₆ emissions during operation phase, kilograms;
- N = Number of SF₆ additions in a given year;
- s_i = SF₆ added to equipment during addition *i*, kilograms.

Annual SF₆ emissions during the decommissioning phase are calculated according to Equation 230-7.

$$S_D = \sum_i^N (NC_i - S_i)$$

Equation 230-7

Where:

- S_D = Annual SF₆ emissions during decommissioning phase, kilograms;
- N = Number of equipment decommissioned in a given year;
- NC_i = Nameplate capacity of decommissioned equipment i , kilograms;
- S_i = SF₆ collected from decommissioned equipment i , kilograms.

Total annual SF₆ emissions are calculated as the sum of SF₆ emissions from equipment operation and decommissioning, according to Equation 230-8.

$$S = \frac{S_O + S_D}{1,000}$$

Equation 230-8

Where:

- S = Annual SF₆ emissions, tonnes;
- S_O = Annual SF₆ emissions during operation phase, kilograms;
- S_D = Annual SF₆ emissions during decommissioning phase, kilograms.

- (c) The methods in either paragraph (a) or (b) of this section shall be used to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF₆ in Equations 230-1 through 230-8.

§ WCI.234 Sampling, Analysis, and Measurement Requirements

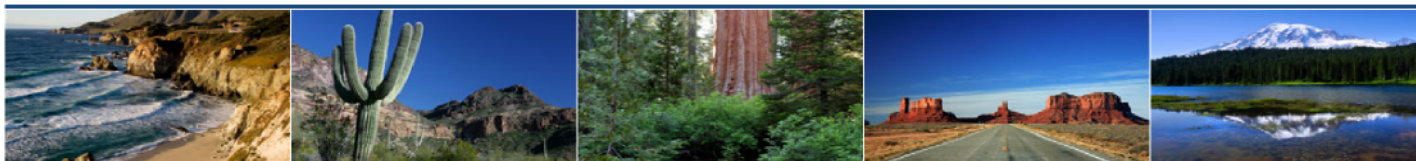
Calibration of equipment used to measure the mass of SF₆ or PFCs used for top-ups to electrical equipment must be conducted as specified in paragraphs (a) and (b) of this section.

- a) For automated mass-flow measurement, equipment must be calibrated according to regulation.
- b) For weigh-scale measurement, equipment must be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

§ WCI.235 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF₆ and PFCs, and from similar equipment repair, replacement, and maintenance operations.

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§ WCI.240 ZINC PRODUCTION

§ WCI.241 Source Category Definition

The zinc production category includes three primary production processes used to produce zinc (i.e., electro-thermic distillation, pyrometallurgical, and electrolytic). In addition, secondary zinc production is also included in this category.

§ WCI.242 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each carbon-containing input material used (tonnes).
- (c) Carbon content of each carbon-containing input material used (tonnes C/ tonne reducing agent).
- (d) Inferred waste-based carbon-containing material emission factor (if waste-based reducing agent quantification method used).
- (e) If you use the missing data procedures in WCI.245(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.
- (f) CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit. You must report these emissions under WCI.20 (General Stationary Fuel Combustion Sources), by following the requirements of WCI.20.

§ WCI.243 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- (a) Determine facility CO₂ emissions using continuous emissions monitoring systems (CEMS) as specified in WCI.23(d).
- (b) Calculate total CO₂ emissions using Equation 240-1. Specific materials that in aggregate contribute less than 0.5% of the total carbon into the process may be excluded from the calculation performed using Equation 240-1.

$$E_{CO_2} = \sum_i (Q_i \times C_i) \times 3.664$$

Equation 240-1

Where:

- E_{CO_2} = Annual CO_2 emissions from carbon-containing materials (tonnes);
- Q_i = Annual quantity of carbon-containing material i (tonnes);
- C_i = Carbon content of carbon-containing material i (tonnes C/ tonne process input);
- 3.664 = Stoichiometric conversion factor from C to CO_2 .

§ WCI.244 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

(a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:

- (1) For zinc-bearing materials, use ASTM E1941-04 “Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys”.
- (2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.
- (3) For flux materials (i.e., limestone or dolomite), use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.
- (4) For waste-based carbon-containing material, determine carbon content by operating the smelting furnace both with and without the waste-reducing agents while keeping the composition of other material introduced constant.
 - i. To ensure representativeness of waste-based reducing agent variability, the specific testing plan (e.g. number of test runs, other process variables to keep constant, timing of runs) for these trials must be approved by the jurisdiction.

(b) Obtain carbon content from material vendor or supplier.

§ WCI.245 Procedures for Estimating Missing Data

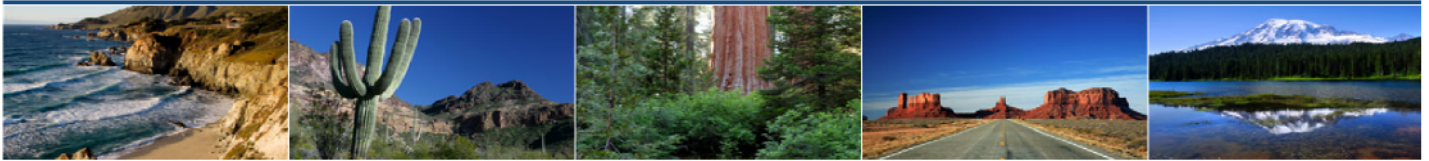
For the carbon input procedure in WCI.243, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.243; 100 percent data availability is required.

You must repeat the test for average carbon contents of inputs according to the procedures in WCI.245(b) if data are missing.

- (b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.243, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

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§ WCI.250 UNDERGROUND COAL MINES

§ WCI.251 Source Category Definition

The underground coal mine source category consists of active underground coal mines, and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to the coalbed, which is then mined with underground mining equipment such as cutting machines and continuous, longwall, and shortwall mining machines, and transported to the surface.

- (a) Underground coal mines are categorized as active if any one of the following five conditions apply:
 - (1) Mine development is underway.
 - (2) Coal has been produced within the last 90 days.
 - (3) Mine personnel are present in the mine workings.
 - (4) Mine ventilation fans are operative.
 - (5) The mine operates on an intermittent basis.
- (b) The underground coal mine source category includes the following:
 - (1) Each ventilation well or shaft, including both those wells and shafts where gas is emitted and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).
 - (2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area. This includes both those wells and shafts where gas is emitted, and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).
- (c) The underground coal mine source category does not include abandoned or closed mines, surface coal mines, or post-coal mining activities (i.e., storage or transportation of coal).

§ WCI.252 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Quarterly CH₄ destruction at all ventilation and degasification system destruction devices or point of offsite transport (tonnes CH₄).
- (b) Quarterly CH₄ emissions (net) from all ventilation and degasification systems (tonnes CH₄).
- (c) Quarterly CO₂ emissions from onsite destruction of coal mine gas CH₄, where the gas is not a fuel input for energy generation or use (e.g., flaring) (tonnes CO₂).

§ WCI.253 Calculation of GHG Emissions

- (a) For each ventilation shaft, vent hole, or centralized point into which CH₄ from multiple shafts and/or vent holes are collected, calculate the quarterly CH₄ liberated from the ventilation system using Equation 250-1 of this section. Measure CH₄ content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in WCI.254.

$$CH_{4V} = n \times \left(V \times MCF \times \frac{C}{100\%} \times 0.6775 \times \frac{288.71K}{T} \times \frac{P}{1 \text{ atm}} \times 1,440 \right)$$

Equation 250-1

Where:

CH _{4V}	=	Quarterly CH ₄ liberated from a ventilation monitoring point (tonnes CH ₄);
V	=	Daily volumetric flow rate for the quarter (cubic meters) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace “288.71K/T × P/1 atm” with “1”;
MCF	=	Moisture correction factor for the measurement period, volumetric basis;
	=	1 when V and C are measured on a dry basis or if both are measured on a wet basis.
	=	1 - (f _{H2O}) _n when V is measured on a wet basis and C is measured on a dry basis.
	=	1/[1-(f _{H2O})] when V is measured on a dry basis and C is measured on a wet basis.
(f _{H2O})	=	Moisture content of the CH ₄ emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);
C	=	Daily CH ₄ concentration of ventilation gas for the quarter (% wet basis);
n	=	Number of days in the quarter where active ventilation of mining operations is taking place at the monitoring point;
0.6775	=	Density of CH ₄ at 288.71 K (15.56 °C) and 1 atm (kg/m ³);
288.71K	=	288.71 Kelvin;
T	=	Temperature at which flow is measured (K) for the quarter;
P	=	Pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

- (1) Unless required to be modified to meet existing regulatory inspection schedules, the quarterly periods are:
 - (i) January 1 – March 31.
 - (ii) April 1 – June 30.
 - (iii) July 1 – September 30.
 - (iv) October 1 – December 31.
- (2) Daily values of V, MCF, C, T, and P must be based on measurements taken at least once each quarter with no fewer than 6 weeks between measurements. If measurements are taken more frequently than once per quarter, then use the average value for all

measurements taken. If continuous measurements are taken, then use the average value over the time period of continuous monitoring.

- (3) If a facility has more than one monitoring point, the facility must calculate total CH₄ liberated from ventilation systems (CH_{4VTotal}) as the sum of the CH₄ from all ventilation monitoring points in the mine, as follows in Equation 250-2:

$$CH_{4VTotal} = \sum_{i=1}^m (CH_{4V})_i$$

Equation 250-2

Where:

- CH_{4VTotal} = Total quarterly CH₄ liberated from ventilation systems (tonnes CH₄);
 CH_{4V} = Quarterly CH₄ liberated from each ventilation monitoring point (tonnes CH₄);
 and
 m = Number of ventilation monitoring points.

- (b) For each monitoring point in the degasification system (this could be at each degasification well and/or vent hole, or at more centralized points into which CH₄ from multiple wells and/or vent holes are collected), calculate the weekly CH₄ liberated from the mine using CH₄ measured weekly or more frequently (including by CEMS) according to WCI.254(c), CH₄ content, flow rate, temperature, pressure, and moisture content, and Equation 250-3 of this section.

$$CH_{4D} = \sum_{i=1}^n \left(V_i \times MCF_i \times \frac{C_i}{100\%} \times 0.6775 \times \frac{288.71K}{T_i} \times \frac{P_i}{1 \text{ atm}} \times 1,440 \right)$$

Equation 250-3

Where:

- CH_{4D} = Weekly CH₄ liberated from a monitoring point (tonnes CH₄);
 V_i = Daily measured total volumetric flow rate for the days in the week when the degasification system is in operation at that monitoring point, based on sampling or a flow rate meter (cubic meters). If a flow rate meter is used and the meter automatically corrects for temperature and pressure, replace “288.71K/T × P/1 atm” with “1”;
 MCF_i = Moisture correction factor for the measurement period, volumetric basis;
 = 1 when V_i and C_i are measured on a dry basis or if both are measured on a wet basis.
 = 1-(f_{H2O})_i when V_i is measured on a wet basis and C_i is measured on a dry basis.
 = 1/[1-(f_{H2O})_i] when V_i is measured on a dry basis and C_i is measured on a wet basis.
 (f_{H2O})_i = Moisture content of the CH₄ emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas);

C_i	=	Daily CH ₄ concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (% wet basis);
n	=	Number of days in the week that the system is operational at that measurement point.
0.6775	=	Density of CH ₄ at 288.71 K (15.56 °C) and 1 atm (kg/m ³);
288.71K	=	288.71 Kelvin;
T_i	=	Daily temperature at which flow is measured (K);
P_i	=	Daily pressure at which flow is measured (atm); and
1,440	=	Conversion factor (min/day).

- (1) Daily values for V, MCF, C, T, and P must be based on measurements taken at least once each calendar week with at least 3 days between measurements. If measurements are taken more frequently than once per week, then use the average value for all measurements taken that week. If continuous measurements are taken, then use the average values over the time period of continuous monitoring when the continuous monitoring equipment is properly functioning.
- (2) Quarterly total CH₄ liberated from degasification systems for the mine should be determined as the sum of CH₄ liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows in Equation 250-4:

$$CH_{4DTotal} = \sum_{i=1}^m \sum_{j=1}^w (CH_{4D})_{i,j} \quad \text{Equation 250-4}$$

Where: :

$CH_{4DTotal}$	=	Quarterly CH ₄ liberated from all degasification monitoring points (tonnes CH ₄);
CH_{4D}	=	Weekly CH ₄ liberated from a degasification monitoring point (tonnes CH ₄);
m	=	Number of monitoring points; and
w	=	Number of weeks in the quarter during which the degasification system is operated.

- (c) If gas from degasification system wells or ventilation shafts is sold, used onsite, or otherwise destroyed (including by flaring), calculate the quarterly CH₄ destroyed for each destruction device and each point of offsite transport to a destruction device, using Equation 250-5 of this section. You must measure CH₄ content and flow rate according to the provisions in WCI.254.

$$CH_{4Destroyed} = CH_4 \times DE$$

Equation 250-5

Where:

$CH_{4Destroyed}$	=	Quarterly CH ₄ destroyed (tonnes);
CH_4	=	Quarterly CH ₄ routed to the destruction device or offsite transfer point (tonnes); and

DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

- (d) Calculate total CH₄ destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using Equation 250-6 of this section.

$$CH_{4DestroyedTotal} = \sum_{i=1}^d (CH_{4Destroyed})_d$$

Equation 250-6

Where:

CH_{4DestroyedTotal} = Quarterly total CH₄ destroyed at the mine (tonnes CH₄);
 CH_{4Destroyed} = Quarterly CH₄ destroyed from each destruction device or offsite transfer point; and
 d = Number of onsite destruction devices and points of offsite transport.

- (e) Calculate the quarterly measured net CH₄ emissions to the atmosphere using Equation 250-7 of this section.

$$CH_{emitted(net)} = CH_{4VTotal} + CH_{4DTotal} - CH_{4DestroyedTotal}$$

Equation 250-7

Where:

CH_{4emitted(net)} = Quarterly CH₄ emissions from the mine (tonnes).
 CH_{4VTotal} = Quarterly sum of the CH₄ liberated from all mine ventilation monitoring points (CH_{4V}), calculated using Equation 250-2 of this section (tonnes).
 CH_{4DTotal} = Quarterly sum of the CH₄ liberated from all mine degasification monitoring points (CH_{4D}), calculated using Equation 250-4 of this section (tonnes).
 CH_{4DestroyedTotal} = Quarterly sum of the measured CH₄ destroyed from all mine ventilation and degasification systems, calculated using Equation 250-6 of this section (tonnes).

- (f) For the methane collected from degasification and/or ventilation systems that is destroyed on site and is not a fuel input for energy generation or use (those emissions are monitored and reported under WCI.20), estimate the CO₂ emissions using Equation 250-8 of this section.

$$CO_2 = CH_{4Destroyed\ on\ site} \times \left(\frac{44}{16} \right)$$

Equation 250-8

Where:

- CO_2 = Total quarterly CO_2 emissions from CH_4 destruction (tonnes);
- $\text{CH}_4_{\text{Destroyed on site}}$ = Quarterly sum of the CH_4 destroyed, calculated as the sum of CH_4 destroyed for each onsite, non-energy use, as calculated individually in Equation 250-5 of this section (tonnes); and
- 44/16 = Ratio of molecular weights of CO_2 to CH_4 .

§ WCI.254 Sampling, Analysis, and Measurement Requirements

Emissions may be estimated by monitoring as specified under paragraphs (a) through (g).

- (a) For CH_4 liberated from ventilation systems, CH_4 must be monitored from each ventilation well and shaft, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one ventilation well or shaft, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor using one of the following options:
- (1) Collect quarterly or more frequent grab samples (with no fewer than 6 weeks between measurements) and make quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same locations as MSHA inspection samples are taken (or appropriate equivalent in Canada), and should be taken when the mine is operating under normal conditions. Follow MSHA sampling procedures as set forth in the MSHA Handbook “General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number PH-08-V-1”, January 1, 2008 or appropriate equivalent in Canada. Record the date of sampling, airflow, temperature, and pressure measured, the hand-held methane and oxygen readings (percent), the bottle number of samples collected, and the location of the measurement or collection.
 - (2) Obtain results of the quarterly (or more frequent) testing performed by appropriate equivalent to MSHA in Canada (if any).
 - (3) Monitor emissions through the use of one or more continuous emission monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.
- (b) For CH_4 liberated at degasification systems, CH_4 must be monitored from each well and gob gas vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one well or gob gas vent hole, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor both gas volume and methane concentration by one of the following two options:
- (1) Monitor emissions through the use of one or more continuous emissions monitoring systems (CEMS).
 - (2) Collect weekly (once each calendar week, with at least three days between measurements) or more frequent samples, for all degasification wells and gob gas vent

holes. Determine weekly or more frequent flow rates and methane composition from these degasification wells and gob gas vent holes. Methane composition should be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification well site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in WCI.254(a)(1).

(c) Monitoring must adhere to one of the following standards:

- (1) ASTM D1945–03 “Standard Test Method for Analysis of Natural Gas by Gas Chromatography”
- (2) ASTM D1946–90 (Reapproved 2006) “Standard Practice for Analysis of Reformed Gas by Gas Chromatography”
- (3) ASTM D4891–89 (Reapproved 2006) “Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion”
- (4) ASTM UOP539–97 “Refinery Gas Analysis by Gas Chromatography”

(d) All fuel flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using the applicable methods specified in paragraphs (d)(1) through (7) of this section. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. For fuel, flare, or sour gas flow meters, the operator shall operate, maintain, and calibrate the flow meter using any of the following test methods or follow the procedures specified by the flow meter manufacturer. Flow meters must meet the accuracy requirements specified by regulation in the jurisdiction.

- (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–6M–1998 “Measurement of Fluid Flow in Pipes Using Vortex Flowmeters”
- (4) ASME MFC–7M–1987 (Reaffirmed 1992) “Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles”
- (5) ASME MFC–11M–2006 “Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters”
- (6) ASME MFC–14M–2003 “Measurement of Fluid Flow Using Small Bore Precision Orifice Meters”
- (7) ASME MFC–18M–2001 “Measurement of Fluid Flow using Variable Area Meters”

(e) For CH₄ destruction, CH₄ must be monitored at each onsite destruction device and each point of offsite transport for combustion using continuous monitors of gas routed to the device or point of offsite transport.

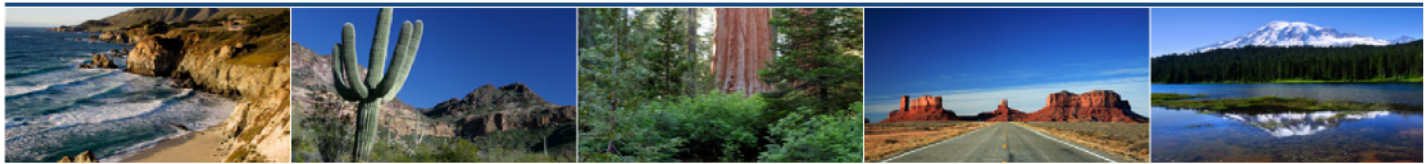
- (f) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer.
- (g) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of fuel flow meters, and other measurement devices. The estimated accuracy of measurements, and the technical basis for the estimated accuracy shall be recorded.

§ WCI.255 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, in accordance with the following.

- (a) For each missing value of CH₄ concentration, flow rate, temperature, and pressure for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

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§ WCI.260 NICKEL AND COPPER METAL PRODUCTION

§ WCI.261 Source Category Definition

The nickel and copper metal production category includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this category.

The nickel and copper metal production category includes three main processes that produce CO₂ emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (i.e., limestone [CaCO₃] or dolomite [CaCO₃·MgCO₃]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), and the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production category. Fuels used for combustion are reported in WCI.020.

§ WCI.262 Greenhouse Gas Reporting Requirements

In addition to the information required by the Reporting Regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of CO₂ at the facility level (tonnes).
- (b) Annual quantities of each carbonate flux reagent used (tonnes).
- (c) Fractional purity of each carbonate flux reagent used (tonnes carbonate/tonnes raw material).
- (d) Annual quantities of other reducing agents used (tonnes).
- (e) Carbon content of other reducing agent used or material used for slag cleaning (tonnes C/tonne reducing agent or material for slag cleaning).
- (f) Annual quantity of ore processed (tonnes).
- (g) Carbon content of ore processed (tonnes C/tonne ore).

§ WCI.263 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) through (d) of this section.

- (a) Calculate CO₂ emissions from carbonate flux reagents using Equation 260-1.

$$E_{cf} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100} \right) + Q_d \times f_d \times \left(\frac{88}{184} \right) \quad \text{Equation 260-1}$$

Where:

- E_{cf} = Annual CO₂ emissions from carbonate flux reagents (tonnes);
 Q_{ls} = Annual quantity of limestone consumed (tonnes);
 f_{ls} = Fractional purity of limestone (tonnes CaCO₃/tonnes of raw material);
44/100 = Stoichiometric conversion factor from CaCO₃ to CO₂;
 Q_d = Annual quantity of dolomite consumed (tonnes);
 f_d = Fractional purity of dolomite (tonnes CaCO₃·MgCO₃/tonnes of raw material);
88/184 = Stoichiometric conversion factor from CaCO₃·MgCO₃ to CO₂.

(b) Calculate CO₂ emissions from other reducing agents or material used in slag cleaning using Equation 260-2.

$$E_{ra} = Q_a \times C_a \times 3.664$$

Equation 260-2

Where:

- E_{ra} = Annual CO₂ emissions from other reducing agents or material used for slag cleaning (tonnes);
 Q_a = Annual quantity of other reducing agents or material used for slag cleaning (tonnes);
 C_a = Carbon content of other reducing agents or material used for slag cleaning (tonnes C/tonne of reducing agent or material used for slag cleaning);
3.664 = Stoichiometric conversion factor from C to CO₂.

(c) Calculate CO₂ emissions from release of carbon from metal ores using Equation 260-3.

$$E_{ore} = Q_{ore} \times C_{ore} \times 3.664$$

Equation 260-3

Where:

- E_{ore} = Annual process CO₂ emissions from metal ore, tonnes
 Q_{ore} = Annual quantity of nickel or copper metal ore consumed (tonnes);
 C_{ore} = Carbon content of nickel or copper metal ore (tonnes C/tonne of nickel or copper ore);
3.664 = Stoichiometric conversion factor from C to CO₂.

(d) Calculate CO₂ emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 260-4.

$$E_{ce} = Q_{ce} \times C_{ce} \times 3.664$$

Equation 260-4

Where:

- E_{ce} = Annual CO₂ emissions from carbon electrode consumption in EAFs (tonnes);
- Q_{ce} = Quantity of carbon electrodes consumed (tonnes);
- C_{ce} = Carbon content of carbon electrodes (tonnes C/tonne carbon electrodes);
- 3.664 = Stoichiometric conversion factor from C to CO₂.

§ WCI.264 Sampling, Analysis, and Measurement Requirements

The annual mass of each solid carbon-containing input material consumed shall be determined using facility instruments, procedures, or records used for accounting purposes, including either direct measurement of the quantity of the material consumed or by calculations using process operating information.

The average carbon content of each material consumed shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
- (1) For coal and coke, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke”.
 - (2) 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).
 - (4) For carbonate flux reagents (i.e., limestone and dolomite), use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.
- (b) Obtain carbon contents of the material, including carbon electrodes, from the vendor or supplier.

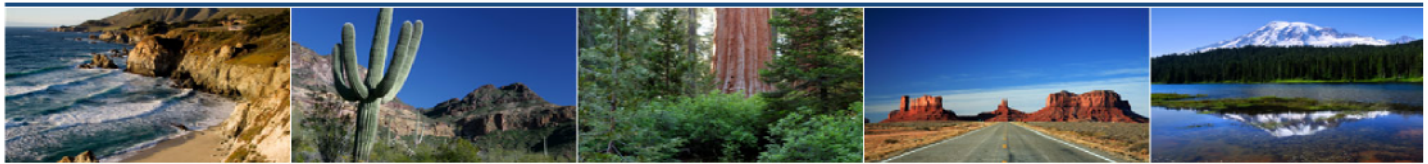
§ WCI.265 Procedures for Estimating Missing Data

For the carbon input procedure in WCI.263, a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in WCI.263; 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in WCI.264 if data are missing.

- (b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in WCI.263, the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

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§ WCI.270 FERROALLOY PRODUCTION

§ WCI.271 Source Category Definition

Ferroalloy production consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ WCI.272 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Annual process CO₂ emissions (tonnes) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in WCI.271.
- (b) Annual process CH₄ emissions (tonnes) from each electric arc furnace (EAF) used in the production of any ferroalloy listed in Table 270-1 (i.e., ferrosilicon [65%, 75%, or 90%] or silicon metal).
- (c) CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in WCI.20.
- (d) Annual facility ferroalloy product production capacity (tonnes).
- (e) Annual production for each ferroalloy product from each EAF (tonnes).
- (f) Total number of EAFs at facility used for production of ferroalloy products.
- (g) Identification number of each EAF
- (h) Annual material quantity for each material included for the calculation of annual process CO₂ emissions for each EAF.
- (i) Annual average of the carbon content determinations for each material included for the calculation of annual process CO₂ emissions for each EAF.
- (j) Method used for determination of carbon content for each material reported (e.g., supplier provided information, representative samples analyses, etc.)
- (k) If missing data procedures used (WCI.275), how monthly mass of carbon-containing inputs and output with missing data was determined and the number of months the missing data procedures were used.

§ WCI.273 Calculation of GHG Emissions

- (a) Process CO₂ emissions. Determine process CO₂ 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.

(b) Process CO₂ Emissions Calculation Methodology. Calculate electric arc furnace (EAF) CO₂ emissions using the mass balance approach specified in paragraphs (b)(1) and (b)(2). Specific process inputs or outputs that contribute less than 1 percent of the total carbon into or out of the process do not have to be included in the paragraph (b)(1) and (b)(2) mass balances

(1) Calculate EAF CO₂ emissions using Equation 270-1:

$$E_{EAF} = [(RA \times C_{RA}) + (EL \times C_{EL}) + (Ore \times C_{Ore}) + (FL \times C_{FL}) - (PR \times C_{PR}) - (NP \times C_{NP})] \times 3.664$$

Equation 270-1

Where:

E_{EAF}	=	Annual CO ₂ emissions from EAF (tonnes);
RA	=	Annual mass of reducing agent charged or introduced to EAF (tonnes);
C_{RA}	=	Carbon content of reducing agent (tonnes C/ tonnes reducing agent);
EL	=	Annual mass of carbon electrodes consumed (tonnes);
C_{EL}	=	Carbon content of carbon electrodes (tonnes C/ tonnes carbon electrode);
Ore	=	Annual mass of ore charged to EAF (tonnes);
C_{Ore}	=	Carbon content of ore (tonnes C/ tonnes carbon electrode);
FL	=	Annual mass of flux materials charged or introduced to EAF (tonnes);
C_{FL}	=	Carbon content of flux materials (tonnes C/ tonnes flux material);
PR	=	Annual mass of alloy product tapped from EAF (tonnes);
C_{PR}	=	Carbon content of alloy product (tonnes C/ tonnes alloy product);
NP	=	Annual mass of outgoing non-product material removed from EAF (tonnes);
C_{NP}	=	Carbon content of outgoing non-product material (tonnes C/tonnes non-product);
3.664	=	Conversion factor from tonnes of C to tonnes of CO ₂ .

(2) Determine combined annual CO₂ emissions from all EAFs at the facility using Equation 270-2:

$$E_{CO2-Fac} = \sum_{k=1}^k E_{EAF-k}$$

Equation 270-2

Where:

$E_{CO2-Fac}$	=	Annual process CO ₂ emissions from EAFs at facility used for the production of any ferroalloy listed in listed in WCI.271 (tonnes).
E_{EAF-k}	=	Annual process CO ₂ emissions calculated from EAF k using Equation 270-1 (tonnes).
k	=	Total number of EAFs at facility used for the production of any ferroalloy listed in WCI.271 (tonnes).

(c) Process CH₄ Emissions Calculation Methodology. For any ferroalloy listed in Table 270-1, calculate emissions using procedure specified in paragraphs (c)(1) and (c)(2).

(1) For each EAF, calculate annual CH₄ emissions using Equation 270-3:

$$E_{CH4} = \sum_1^i (M_i \times EF_i)$$

Equation 270-3

Where:

- E_{CH4} = Annual process CH₄ emissions from an individual EAF (tonnes).
 M_i = Annual mass of alloy product i produced in the EAF (tonnes).
 EF_i = CH₄ emission factor for alloy product i from Table 270-1 (tonne CH₄/ tonne of alloy product i).

- (2) Determine combined annual CH₄ emissions from all EAFs at the facility using Equation 270-4:

$$E_{CH4-Fac} = \sum_1^j E_{CH4-j}$$

Equation 270-4

Where:

- $E_{CH4-Fac}$ = Annual process CH₄ emissions from EAFs at facility used for the production of ferroalloys listed in Table 270-1 (tonnes).
 E_{CH4-j} = Annual process CH₄ emissions calculated from EAF j using Equation 270-3 (tonnes).
 j = Total number of EAFs at facility used for the production of ferroalloys listed in Table 270-1.

§ WCI.274 Sampling, Analysis, and Measurement Requirements

The annual mass of each material used in the WCI.273 mass balance methodologies shall be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of material used in the process or by calculations using process operating information.

The average carbon content of each material used shall be determined as specified under paragraph (a) or (b) of this section.

- (a) Obtain carbon content by collecting and analyzing at least three representative samples of the material each year using one of the following methods:
- (1) For metal ore and alloy product, use ASTM E1941-04 “Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys”.
 - (2) For carbonaceous reducing agents and carbon electrodes, use ASTM D5373-08 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”.

(3) For flux materials (e.g., limestone, dolomite, etc.), use ASTM C25-06 “Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime”.

(b) Obtain carbon content from material vendor or supplier.

§ WCI.275 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

- (a) If CO₂ emissions for EAFs are estimated using the carbon mass balance in WCI.273(b)(1), 100 percent data availability is required for the carbon content of the input and output materials. The test for average carbon contents according to WCI.274 must be repeated if data are missing.
- (b) For each missing value of monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of inputs and outputs from all available process data or data used for accounting purposes.
- (c) If CH₄ emissions for EAFs are required to be calculated, the estimate is based on an annual quantity of certain alloy products, so 100 percent data availability is required.

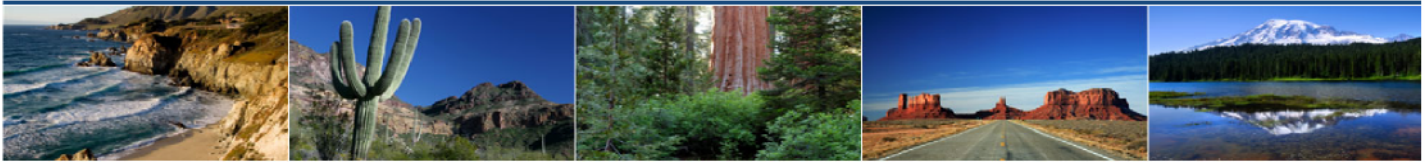
Table 270-1 —Electric Arc Furnace (EAF) CH₄ Emission Factors.

Alloy product produced in EAF	CH ₄ Emission Factor (metric ton CH ₄ per metric ton product)		
	EAF Operation		
	Batch-Charging	Sprinkle-Charging ^a	Sprinkle-Charging and >750°C ^b
Silicon metal	0.0015	0.0012	0.0007
Ferrosilicon 90%	0.0014	0.0011	0.0006
Ferrosilicon 75%	0.0013	0.0010	0.0005
Ferrosilicon 65%	0.0013	0.0010	0.0005

^a Sprinkle-charging is charging intermittently every minute.

^b Temperature measured in off-gas channel downstream of the furnace hood.

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§ WCI.280 MOBILE EQUIPMENT AT FACILITIES

§ WCI.281 Source Category Definition

The mobile equipment at facilities category includes:

- (a) Mobile equipment used for the on-site transportation or movement of substances, materials or products, and
 - (b) Other mobile equipment such as tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes and bulldozers, and other industrial equipment,
- but *does not include* on-road vehicles, aircraft, or marine vessels.

For clarity, an on-road vehicle means a motor vehicle that:

- (a) Can exceed a speed of 40 kilometers per hour on a level paved surface, and
- (b) Has features customarily associated with safe and practical highway use such as a reverse gear (unless the vehicle is a motorcycle), a differential, and safety features required by federal or provincial laws,

but *does not include* vehicles that exhibit features that render use on a highway unsafe, impractical, or highly unlikely, such as tracked road contact or inordinate size.

Mobile equipment that is part of normal facility operations that are operated by contractors is also included, as it is managed or controlled by the facility.

§ WCI.282 Greenhouse Gas Reporting Requirements

In addition to the information required by the British Columbia Reporting Regulation, the annual emissions data report shall contain the following information:

- (a) Total emissions of CO₂, CO₂ from biomass, CH₄, and N₂O at the facility level by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (tonnes).
- (b) Annual and quarterly quantities of fuel used by fuel type (including differentiation of biodiesel and ethanol from conventional fuel types) (litres) from the sum of mobile equipment at the facility.

§ WCI.283 Calculation of CO₂ Emissions

Calculate the annual CO₂ mass emissions from mobile equipment using the procedures in paragraph (a) or (b). If neither (a) or (b) is appropriate for a source(s), method (c) may be used. Use method (d) as required.

- (a) If fossil fuel quantities are measured, calculate total CO₂ emissions using Equation 280-1.

$$E_{i,CO_2} = Q_i \times EF_i$$

Equation 280-1

Where:

- E_{i,CO_2} = Quarterly CO₂ emissions from mobile equipment for fuel *i* (metric tons);
 Q_i = Quarterly quantity of fuel *i* used in mobile equipment (litres);
 EF_i = Emission factor for the fuel (metric tons CO₂e/litre, required emission factors provided in WCI.020).

- (b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CO₂ emissions using Equations 280-2 and 280-3.

$$E_{i,k,CO_2} = (h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,CO_2} \quad \text{Equation 280-2}$$

$$E_{Total,i,CO_2} = \sum_k E_{i,k,CO_2} \quad \text{Equation 280-3}$$

Where:

- E_{i,k,CO_2} = Quarterly CO₂ emissions from mobile equipment *k* for fuel *i* (metric tons);
 $h_{i,k}$ = Quarterly hours of operation for mobile equipment *k* for fuel *i* (hours);
 $hp_{i,k}$ = Rated equipment horsepower for mobile equipment *k* for fuel *i* (horsepower);
 $LF_{i,k}$ = Load factor for mobile equipment *k* for fuel *i* (unitless; ranges between 0 and 1);
 $BSFC_{i,k}$ = Brake-specific fuel consumption for mobile equipment *k* for fuel *i* (litres/horsepower-hour);
 EF_{i,CO_2} = Emission factor for fuel *i* (metric tons CO₂e/litre, required emission factors provided in WCI.020);
 E_{Total,i,CO_2} = Total quarterly CO₂ emissions for fuel *i* (metric tons).

- (c) If neither methods (a) or (b) is appropriate for a source(s), determine emissions using the site-specific emission factor method. Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.

- (i) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., including the type of mobile equipment in operation).
- (ii) The average hourly fuel use rate for each of the typical operations must be calculated.
- (iii) The number of hours of each type of operation at the facility in the year must be determined.

- (iv) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

(d) CO₂ Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CO₂ emissions as specified in paragraph (1) of this section.

- (1) The owner or operator that combusts fuels or fuel mixtures where there is a mixture of biofuel (i.e. biodiesel and ethanol) and other fuels shall determine the portion of the biofuel used by broad fuel category (i.e. gasoline and diesel) and use the appropriate emission factors for each of the biofuel and the conventional fuel. When reporting emissions, CO₂ from the biomass component of biofuels shall be reported separately from CO₂ from fossil fuels.

§ WCI.284 Calculation of CH₄ and N₂O Emissions

Calculate the annual CH₄ and N₂O mass emissions from mobile equipment using the procedures in paragraph (a) or (b), as appropriate. If neither (a) or (b) is appropriate, method (c) may be used. Annual emissions for each fuel type and GHG are calculated as the sum of the quarterly emissions. Annual emissions are reported by fuel and by GHG.

- (a) If fossil fuel quantities are measured, calculate total CH₄ and N₂O emissions using Equation 280-4 and the emission factors provided in WCI.020.

$$E_{i,g} = Q_i \times EF_{i,g} \times \left(\frac{1}{10^6} \right) \quad \text{Equation 280-4}$$

Where:

- $E_{i,g}$ = Quarterly emissions of greenhouse gas g (CH₄ or N₂O) from mobile equipment for fuel i (metric tons);
- Q_i = Quarterly quantity of fuel i (litres);
- $EF_{i,g}$ = Greenhouse gas g (CH₄ or N₂O) mobile equipment emission factor for fuel i (grams/litre) (required emission factors provided in WCI.020);
- $(1/10^6)$ = Conversion factor from grams to metric tons.

- (b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CH₄ or N₂O emissions using Equations 280-5 and 280-6.

$$E_{i,k,g} = (h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,g} \times \left(\frac{1}{10^6} \right) \quad \text{Equation 280-5}$$

$$E_{Total,i,g} = \sum_k E_{i,k,g}$$

Equation 280-6

Where:

- $E_{i,k,g}$ = Quarterly greenhouse gas g (CH_4 or N_2O) emissions from mobile equipment k for fuel i (metric tons);
- $h_{i,k}$ = Quarterly hours of operation for mobile equipment k for fuel i (hours);
- $hp_{i,k}$ = Rated equipment horsepower for mobile equipment k for fuel i (horsepower);
- $LF_{i,k}$ = Load factor for mobile equipment k for fuel i (unitless; ranges between 0 and 1);
- $\text{BSFC}_{i,k}$ = Brake-specific fuel consumption for mobile equipment k for fuel i (litres/horsepower-hour);
- $\text{EF}_{i,g}$ = Emission factor for greenhouse gas g (CH_4 or N_2O) for fuel i (grams/litre, required emission factors provided in WCI.020);
- $(1/10^6)$ = Conversion factor from grams to metric tons;
- $E_{Total,i,g}$ = Total quarterly emissions greenhouse gas g (CH_4 or N_2O) for fuel i (metric tons).

(c) If neither methods (a) or (b) is appropriate, determine emissions using the *site-specific emission factor method*. Conduct analysis of hourly fuel use from mobile sources at the facility during a range of typical operations.

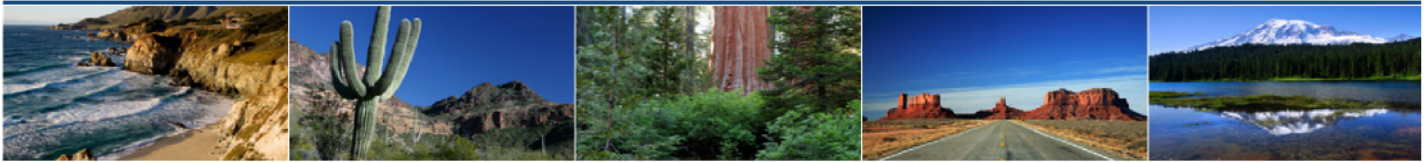
- (i) A range of typical operating conditions for the mobile source(s) at the facility must be documented and analyzed (e.g., include the type of mobile equipment in operation).
- (ii) The average hourly fuel use rate for each of the typical operations must be calculated.
- (iii) The number of hours of each type of operation at the facility in the year must be determined.
- (iv) The annual total mobile emissions must be calculated by multiplying the hours of operation with the average fuel use rate and the fuel-specific emission factor for each of the typical operations.

§ WCI.285 Sampling, Analysis, and Measurement Requirements

Fuel use and emission factors shall be determined as specified under paragraphs (a), (b) and (c) of this section.

- (a) For biofuels, the portion(s) of ethanol or biodiesel from vendor specifications.
- (b) For conventional fuels and biofuels, required emission factors listed in WCI.020.
- (c) Fuel volumes used shall be determined by vendor receipts, dipstick measurement, or other appropriate means on a quarterly basis, starting on January 1 of the calendar year.

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§ WCI.290 MAGNESIUM PRODUCTION

§ WCI.291 Source Category Definition

Magnesium production and processing source category consists of any process in which magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations or in which molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

Two important sector-specific definitions are the following:

- (a) *Cover gas* means SF₆, HFC-134a, fluorinated ketone (FK 5-1-12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that feeds a casting operation.
- (b) *Carrier gas* means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO₂, N₂, and/or dry air.

§ WCI.292 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Annual emissions of the following gases in tonnes per year resulting from their use as cover gases or carrier gases in magnesium production or processing:
 - (1) Sulfur hexafluoride (SF₆).
 - (2) HFC-134a.
 - (3) FK 5-1-12 (a fluorinated ketone).
 - (4) Carbon dioxide (CO₂).
 - (5) Any other GHGs (as defined by regulation).
- (b) CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in WCI.20.
- (c) Types of production processes at the facility (e.g., primary, secondary, die casting, etc.).
- (d) Amount of magnesium produced or processed in metric tons for each process type, including the output of primary and secondary magnesium production processes and the input to magnesium casting processes.
- (e) For any missing data, the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.
- (f) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (e.g., installation of new melt protection technology, leak discovered in the cover gas delivery system that resulted in increased emissions, etc.).

- (g) Description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.

§ WCI.293 Calculation of GHG Emissions

- (a) Calculate the mass of each GHG emitted from magnesium production or processing over the calendar year using either Equation 290-1 or Equation 290-2 of this section, as appropriate. Both of these equations equate emissions of cover gases or carrier gases to consumption of cover gases or carrier gases.

- (1) To estimate emissions of cover gases or carrier gases by monitoring changes in container masses and inventories, emissions of each cover gas or carrier gas shall be estimated using Equation 290-1 of this section:

$$E_x = (I_{B,x} - I_{E,x} + A_x - D_x) \times 0.001$$

Equation 290-1

Where:

E_x	=	Emissions of each cover gas or carrier gas x over the reporting year (tonnes);
$I_{B,x}$	=	Inventory of each cover gas or carrier gas x stored in cylinders or other containers at the beginning of the year, including heels (kg);
$I_{E,x}$	=	Inventory of each cover gas or carrier gas x stored in cylinders or other containers at the end of the year, including heels (kg);
A_x	=	Acquisitions of each cover gas or carrier gas x during the year through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility (kg);.
D_x	=	Disbursements of each cover gas or carrier gas x to sources and locations outside the facility through sales or other transactions during the year, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier (kg);
0.001	=	Conversion factor from kg to tonnes; and
x	=	Each cover gas or carrier gas that is a GHG.

- (2) To estimate emissions of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, emissions of each cover gas or carrier gas shall be estimated using Equation 290-2 of this section:

$$E_x = \sum_{p=1}^n Q_p \times 0.001$$

Equation 290-2

Where:

E_x	=	Emissions of each cover gas or carrier gas x over the reporting year (tonnes);
Q_p	=	Mass of the cover or carrier gas consumed (kg) over the container-use period p as estimated using Equation 290-3;
n	=	Number of container-use periods in the year;
	=	Inventory of each cover gas or carrier gas x stored in cylinders or other containers at the beginning of the year, including heels (kg);
0.001	=	Conversion factor from kg to tonnes; and
x	=	Each cover gas or carrier gas that is a GHG.

- (b) For purposes of Equation 290-2 of this section, the mass of the cover gas used over the period p for an individual container shall be estimated by using Equation 290-3 of this section:

$$Q_p = M_B - M_E$$

Equation 290-3

Where:

Q_p	=	Mass of the cover or carrier gas consumed (kg) over the container-use period p (e.g., one month, etc.);
M_B	=	Mass of the container's contents (kg) at the beginning of period p ; and
M_E	=	Mass of the container's contents (kg) at the end of period p .

- (c) If a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the mass of cover or carrier gas consumed (Q_p), in kg for period p in Equation 290-2 of this section.

§ WCI.294 Sampling, Analysis, and Measurement Requirements

Emissions (consumption) of cover gases and carrier gases may be estimated by monitoring as specified under paragraphs (a) through (c). Emissions must be estimated at least annually.

- (a) Monitor the changes in container weights and inventories using Equation 290-1 of this subpart as follows:
- (1) All quantities required by Equation 290-1 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.
 - (2) Gas masses or weights provided by the gas supplier (e.g., for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.

- (b) Monitor the changes in individual container weights as the contents of each container are used using Equations 290-2 and 290-3 of this subpart. The container identities and masses must be monitored and recorded as follows:
- (1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.
 - (2) All the quantities required by Equations 290-2 and 290-3 of this subpart must be measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers.
 - (3) Gas masses or weights provided by the gas supplier (e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met. However, the facility remains responsible for the accuracy of these masses or weights under this subpart.
- (c) Monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system. When estimating emissions by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system, gas flow meters, or mass flow controllers, with an accuracy of 1 percent of full scale or better must be used.

All flow meters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using calibration procedures specified by the flow meter, scale, or load cell manufacturer. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at the minimum frequency specified by the manufacturer.

§ WCI.295 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

- (a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.
- (b) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover or carrier gas using Equation 290-4 of this section:

$$R_x = \left(\frac{C_x}{Mg} \right) \times 0.001$$

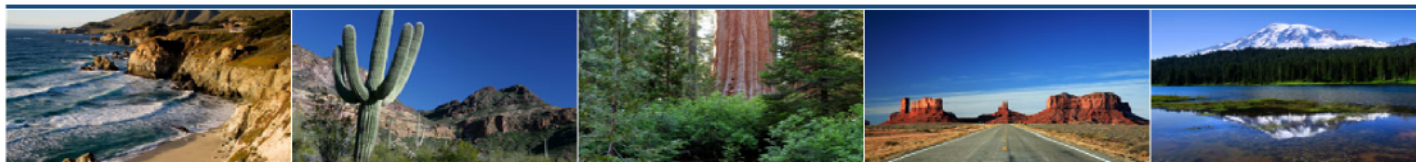
Equation 290-4

Where:

- R_x = Usage rate of a particular cover gas or carrier gas x over the period of comparable operation (tonnes gas/tonne Mg);
- C_x = Consumption of a particular cover gas or carrier gas x over the period of comparable operation (kg);
- Mg = Magnesium produced or fed into the process over the period of comparable operation (tonnes);
- 0.001 = Conversion factor from kg to tonnes; and
- x = Each cover gas or carrier gas that is a GHG.

- (c) If the precise before and after weights are not available, it should be assumed that the container was emptied in the process (i.e., quantity purchased should be used, less heel).

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§ WCI.300 PETROCHEMICAL MANUFACTURING

§ WCI.301 Source Category Definition

- (a) The petrochemical manufacturing source category consists of any facility that manufactures petrochemicals, including acrylonitrile, carbon black, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feedstocks derived from petroleum, or petroleum and natural gas liquids.
- (b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.
- (c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas should report under this section if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility should report under WCI.130 (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility should report under WCI.80 (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.
- (d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.
- (e) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

§ WCI.302 Greenhouse Gas Reporting Requirements

In addition to the information required by the regulation, the annual emissions report must contain the following information:

- (a) CO₂, N₂O, and CH₄ emissions from combustion of fuels in the stationary combustion units in tonnes, as specified in WCI.20.
- (b) CO₂, N₂O, and CH₄ emissions from flares or other combustion devices in tonnes using methods WCI.303(a)(1), WCI.303(a)(2) or WCI.303(c).
- (c) CO₂, N₂O, and CH₄ process emissions from vents in tonnes using method WCI.303(a)(3).
- (d) CO₂, N₂O, and CH₄ process emissions from equipment leaks in tonnes using method WCI.303(a)(4).
- (e) CO₂ process emissions in tonnes using method WCI.303(b).
- (f) CO₂, N₂O, and CH₄ process emissions from ethylene production facilities in tonnes using WCI.303(c).
- (g) Annual consumption of feedstock by type for all feedstocks that result in GHG emissions in standard cubic meters for gases, kilolitres for liquids, and tonnes for solid fuels.

§ WCI.303 Calculation of GHG Emissions

Calculate GHG emissions using one of the methods in paragraphs (a), (b), or (c):

- (a) **Method 1:** Calculate the GHG emissions from petrochemical production processes using the methods specific in paragraphs (a)(1) through (a)(3) of this section.
- (1) For flares, calculate CO₂, CH₄ and N₂O emissions using the methods specified in WCI.203(e).
 - (2) For combustion devices other than flares, calculate CO₂, CH₄ and N₂O emissions resulting from the combustion of fuels and process off-gas as specified in paragraphs (a)(2)(i) through (a)(2)(iii):
 - (i) Calculate CO₂ emissions from fuels and process off-gas in accordance with the methods in specified in WCI.20.
 - (ii) Calculate CH₄ and N₂O emissions from combustion of fuels using the applicable methods in WCI.24. Use the appropriate default emission factors for CH₄ and N₂O from Tables 20-2, 20-4, 20-6, and 20-7.
 - (iii) Calculate CH₄ and N₂O emissions from process off-gas using the applicable equation 20-12 in WCI.24, and the default emission factors of 2.8×10^{-3} kg/GJ for CH₄ and 5.7×10^{-4} kg/GJ for N₂O.
 - (3) Calculate the emissions from process vents using the method specified in WCI.203(b) for each process vent that can be reasonably expected to contain greater than 2 percent by volume CO₂ or greater than 0.5 percent by volume of CH₄ or greater than 0.01 percent by volume (100 parts per million) of N₂O.
 - (4) Calculate the emissions from equipment leaks using the method specified in WCI.203(i)(1).
- (b) **Method 2:** Calculate the emissions of CO₂ from each process unit, for each calendar month as described in paragraphs (b)(1) through (b)(5) of this section.
- (1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter. Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid). Fuels used for combustion purposes are not considered to be feedstocks. The emissions from the combustion of fuels (other than process off-gas) in stationary combustion units must be calculated in accordance with the methods specified in WCI.23 for CO₂ and the methods specified in WCI.24 for CH₄ and N₂O.
 - (2) For each solid feedstock and product, measure the mass used or produced each calendar month.
 - (3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample. Alternatively, you may use the results of analyses conducted by a fuel or feedstock supplier, provided the sampling and analysis is

conducted at least once per month. If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically.

- (4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume (or mass for liquids and solids), then as an alternative to the sampling and analysis specified in paragraph (b)(3) of this section, you may calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound during periods of normal operation. You must maintain records of any determination made in accordance with this paragraph (b)(4) along with all supporting data, calculations, and other information. This alternative may not be used for products during periods of operation when off-specification product is produced. You must reevaluate determinations made under this paragraph (b)(4) after any process change that affects the feedstock or product composition. You must keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.
- (5) Calculate the CO₂ mass emissions for each petrochemical process unit using Equations 300-1 through 300-4 of this section.
 - (i) Gaseous feedstocks and products. Use Equation 300-1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} \left[(F_{gf})_{i,n} * (CC_{gf})_{i,n} * \frac{(MW_f)_i}{MVC} - (P_{gp})_{i,n} * (CC_{gp})_{i,n} * \frac{(MW_p)_i}{MVC} \right] \right]$$

Equation 300-1

Where:

- | | | |
|-------------------|---|--|
| C_g | = | Annual net contribution to calculated emissions from carbon (C) in gaseous materials (kg/yr). |
| $(F_{gf})_{i,n}$ | = | Volume of gaseous feedstock i introduced in month n (Rm ³) at reference temperature and pressure conditions as used by the facility. If a mass flow meter is used, measure the feedstock introduced in month n in kg and replace the term “(MW _f) _i /MVC” with “1”. |
| $(CC_{gf})_{i,n}$ | = | Average carbon content of the gaseous feedstock i for month n (kg C per kg of feedstock). |
| $(MW_f)_i$ | = | Molecular weight of gaseous feedstock i (kg/kg-mole). |
| MVC | = | Molar volume conversion factor at the same reference conditions as the above $(F_{gf})_{i,n}$ (Rm ³ /kg-mole). |
| | = | 8.3145 * [273.16 + reference temperature in °C] / [reference pressure in kilopascal] |
| $(P_{gp})_{i,n}$ | = | Volume of gaseous product i produced in month n (Rm ³) at the same reference conditions as the above $(F_{gf})_{i,n}$. If a mass flow meter is used, |

- measure the gaseous product produced in month n in kg and replace the term “(MW_p)_i/MVC” with “1”.
- $(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i , including streams containing CO₂ recovered for sale or use in another process, for month n (kg of C per m³ of product when liquid product is measured in m³, or kg of C per kg of product when product is measured in kg)
- $(MW_p)_i$ = Molecular weight of gaseous product i (kg/kg-mole).
- j = Number of feedstocks.
- k = Number of products.

- (ii) Liquid feedstocks and products. Use Equation 300-2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12} \left[\sum_{i=1}^{j \text{ or } k} [(F_{lf})_{i,n} * (CC_{lf})_{i,n} - (P_{lp})_{i,n} * (CC_{lp})_{i,n}] \right] \quad \text{Equation 300-2}$$

Where:

- C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).
- $(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month n (m³ of feedstock). If a mass flow meter is used, measure the liquid feedstock in month n introduced in kg and measure the carbon content of feedstock in kg of C per kg of feedstock.
- $(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month n (kg C of C per m³ of feedstock when feedstock usage is measured in m³, or kg of C per kg of feedstock when feedstock usage is measured in kg).
- $(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month n (m³). If a mass flow meter is used, measure the liquid product produced in kg and measure the carbon content of liquid product in kg of C per kg of product.
- $(CC_{lp})_{i,n}$ = Average carbon content of liquid product i , including organic liquid wastes, for month n (kg C of C per m³ of product when liquid product is measured in m³, or kg of C per kg of product when product is measured in kg)
- j = Number of feedstocks.
- k = Number of products.

- (iii) Solid feedstocks and products. Use Equation 300-3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12} \left\{ \sum_{i=1}^{j \text{ or } k} [(F_{sf})_{i,n} * (CC_{sf})_{i,n} - (P_{sp})_{i,n} * (CC_{sp})_{i,n}] \right\} \quad \text{Equation 300-3}$$

Where:

C_s	=	Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).
$(F_{sf})_{i,n}$	=	Mass of solid feedstock i introduced in month n (kg).
$(CC_{sf})_{i,n}$	=	Average carbon content of solid feedstock i for month n (kg C per kg of feedstock).
$(P_{sp})_{i,n}$	=	Mass of solid product i produced in month n (kg).
$(CC_{sp})_{i,n}$	=	Average carbon content of solid product i in month n (kg C per kg of product).
j	=	Number of feedstocks.
k	=	Number of products.

- (iv) Annual emissions. Use the results from Equations 300-1 through 300-3 of this section, as applicable, in Equation 300-4 of this section to calculate annual CO₂ emissions.

$$CO_2 = 0.001 * 3.664 * (C_g + C_l + C_s) \quad \text{Equation 300-4}$$

Where:

CO ₂	=	Annual CO ₂ mass emissions from process operations and process off-gas combustion (tonnes/year).
0.001	=	Conversion factor from kg to tonnes.
3.664	=	Ratio of molecular weight, carbon dioxide to carbon.

- (c) **Method 3:** (Optional combustion methodology for ethylene production processes) For ethylene production processes, calculate CO₂, CH₄, and N₂O emissions as specified in paragraphs (c)(1) and (c)(2):
- (1) For each flare, calculate CO₂, CH₄, and N₂O emissions using the methodology for flares specified in WCI.203(e).
 - (2) For all other combustion units, calculate the CO₂ emissions from combustion of fuel that contains ethylene process off-gas using either Calculation Methodology 3 or Calculation Methodology 4 in WCI.23(c) and (d), respectively. Calculate CH₄ and N₂O emissions using the applicable method in WCI.24 and the emission factors of 2.8×10^{-3} kg/GJ for CH₄ and 5.7×10^{-4} kg/GJ for N₂O. You are not required to use the same calculation method for each stationary combustion unit that burns ethylene process off-gas.

§ WCI.304 Monitoring Requirements

- (a) If you calculate emissions using the method specified in WCI.303(a):
- (1) **Flares.** You must comply with the monitoring requirements for flares specified in WCI.204(e). The person may monitor the carbon content or the high heat value of the flares gas of flares in a petrochemical production facility on a quarterly basis.
 - (2) **Process Vents.** You must comply with the monitoring requirements for process vents specified in WCI.204(b).

(b) If you calculate emissions using the method specified in WCI.303(b):

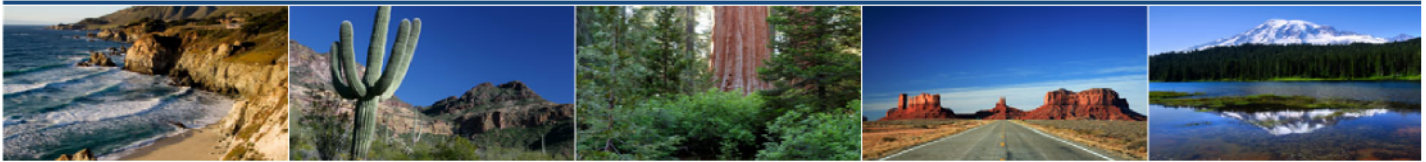
- (1) **Feedstock Consumption.** You must measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.
- (2) **Product Production.** You must measure the amount of product produced using the same plant instruments used for accounting purposes, such as weigh hoppers, belt weigh feeders, or flow meters.
- (3) **Carbon Content.** Except as allowed by WCI.303(b)(4), the carbon content of each feedstock and product must be measured at least once per month.

§ WCI.305 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

- (a) For each missing value of the carbon content and molecular weight, the substitute data value shall be the arithmetic average of the quality assured values of the parameter immediately preceding and immediately following the missing data incident. If no quality assured data are available prior to the missing data incident, the substitute data value shall be the first quality assured data value obtained after the missing data period.
- (b) For missing feedstock and production values, the substitute data value shall be the best available estimate of the parameter, based on all available process data. You must document and retain records of the procedures used for all such estimates.

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§ WCI.310 NITRIC ACID MANUFACTURING

§ WCI.311 Source Category Definition

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§ WCI.312 Greenhouse Gas Reporting Requirements

For the purpose of the Regulation the annual emissions data report shall include the following information at the facility level calculated in accordance this method

- (a) You must report facility wide N_2O process emissions as required by this method.
- (b) Annual nitric acid production from the nitric acid facility (tonnes, 100 percent acid basis).
- (c) You must report under WCI.20 (General Stationary Fuel Combustion Sources) the emissions of CO_2 , CH_4 , and N_2O from each stationary combustion unit by following the requirements of WCI.20.

§ WCI.313 Calculation of GHG emissions

- (a) You must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.
 - (1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.
 - (2) Request Director approval for an alternative method of determining N_2O emissions according to paragraphs.
- (b) You must conduct an annual performance test according to paragraphs (b)(1) through (b)(3) of this section.
 - (1) You must measure N_2O emissions from the absorber tail gas vent for each nitric acid train using the methods specified in WCI.314(b) through (d).
 - (2) You must conduct the performance test under normal process operating conditions and without using N_2O abatement technology (if applicable).
 - (3) You must measure the production rate during the performance test and calculate the production rate for the test period in metric tons (100 percent acid basis) per hour.
- (c) You must determine an N_2O emissions factor to use in Equation 310-3 of this section according to paragraphs (c)(1) or (c)(2) of this section.
 - (1) You may request Director approval for an alternative method of determining N_2O concentration according to the procedures in paragraphs (a)(2) of this section. Alternative methods include the use of N_2O CEMs.

- (2) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train “t” according to Equation 310-1 of this section:

$$EF_{N_2O_t} = \frac{\sum_1^n \frac{C_{N_2O} * 1.828 \times 10^{-6} * Q}{P}}{n}$$

Equation 310-1

Where:

- $EF_{N_2O_t}$ = Average site-specific N_2O emissions factor for nitric acid train t (kg N_2O generated/tonne nitric acid produced, 100 percent acid basis).
- C_{N_2O} = N_2O concentration for each test run during the performance test (ppm N_2O).
- 1.828×10^{-6} = Conversion factor (kg/dsm³-ppm N_2O).
- Q = Volumetric flow rate of effluent gas for each test run during the performance test (dsm³/hr).
- P = Production rate for each test run during the performance test (tonnes nitric acid produced per hour, 100 percent acid basis).
- n = Number of test runs.

- (d) If applicable, you must determine the destruction efficiency for each N_2O abatement technology according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

- (1) Use the manufacturer’s specified destruction efficiency.
- (2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balance, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.
- (3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

- (e) If applicable, you must determine the abatement factor for each N_2O abatement technology. The abatement factor is calculated for each nitric acid train according to Equation 310-2 of this section.

$$AF_{N_t} = \frac{P_{a\ t\ Abate}}{P_{a\ t}}$$

Equation 310-2

Where:

- AF_{N_t} = Abatement factor of N_2O abatement technology at nitric acid train t (fraction of annual production that abatement technology is operating).
- $P_{a\ t}$ = Total annual nitric acid production from nitric acid train t (tonne acid produced, 100 percent acid basis).

$P_{at \text{ Abate}}$ = Annual nitric acid production from nitric acid train t during which N_2O abatement was used (tonne acid produced, 100 percent acid basis).

- (f) You must determine the annual amount of nitric acid produced and the annual amount of nitric acid produced while each N_2O abatement technology is operating from each nitric acid train (100 percent basis).
- (g) You must calculate N_2O emissions for each nitric acid train by multiplying the emissions factor (determined in Equation 310-1 of this section) by the annual nitric acid production and accounting for N_2O abatement, according to Equation 310-3 of this section:

$$E_{N_2O t} = \sum_{N=1}^z \frac{EF_{N2Ot} * P_{at} * (1 - (DF_{Nt} * AF_{Nt}))}{1000} \quad \text{Equation 310-3}$$

Where:

- E_{N2Ot} = N_2O mass emissions per year for nitric acid train t (tonnes).
- EF_{N2Ot} = Average site-specific N_2O emissions factor for nitric acid train t (kg N_2O generated/tonne acid produced, 100 percent acid basis).
- P_{at} = Annual nitric acid production from the train t (tonne acid produced, 100 percent acid basis).
- DF_{Nt} = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train t (percent of N_2O removed from air stream).
- AF_{Nt} = Abatement factor of N_2O abatement technology for nitric acid train t (fraction of annual production that abatement technology is operating).
- 1000 = Conversion factor (kg/tonne).
- z = Number of different N_2O abatement technologies.

- (h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation 310-4 of this section:

$$N_2O = \sum_{t=1}^m E_{N2Ot} \quad \text{Equation 310-4}$$

Where:

- N_2O = Annual process N_2O emissions from nitric acid production facility (tonnes)
- E_{N2Ot} = N_2O mass emissions per year for nitric acid train t (tonnes).
- m = Number of nitric acid trains.

§ WCI.314 Sampling, Analysis, and Measurement Requirements

- (a) You must conduct a new performance test and calculate a new site-specific emissions factor according to a test plan as specified in paragraphs (a)(1) through (a)(3) of this section.
- (1) Conduct the performance test annually.

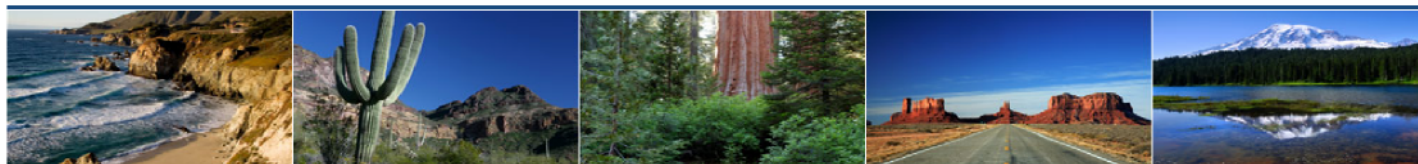
- (2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.
 - (3) If you requested Director approval for an alternative method of determining N₂O concentration under WCI.313(a)(2), you must conduct the performance test if your request has not been approved by the Director within 150 days of the end of the reporting year in which it was submitted.
- (b) You must measure the N₂O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.
- (1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.
 - (2) ASTM D6348-03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy.
 - (3) An equivalent method, with Director approval.
- (c) You must determine the production rate(s) (100 percent basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (c)(2) of this section.
- (1) Direct measurement of production and concentration (such as using flow meters or weigh scales, for production and concentration measurements).
 - (2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).
- (d) You must conduct all performance tests in conjunction with the applicable methods approved by the Director. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.
- (1) Analysis of samples, determination of emissions, and raw data.
 - (2) All information and data used to derive the emissions factor(s).
 - (3) The production rate during each test and how it was determined.
- (e) You must determine the monthly nitric acid production and the monthly nitric acid production during which N₂O abatement technology is operating from each nitric acid train according to the methods in paragraphs (c)(1) or (c)(2) of this section.
- (f) You must determine the annual nitric acid production and the annual nitric acid production during which N₂O abatement technology is operating for each train by summing the respective monthly nitric acid production quantities.

§ WCI.315 Procedures for Estimating Missing Data

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

- (a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).
- (b) For missing values related to the performance test, including emission factors, production rate, and N₂O concentration, you must conduct a new performance test according to the procedures in WCI.314 (a) through (d).

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§ WCI.340 PHOSPHORIC ACID PRODUCTION

§ WCI.341 Source Category Definition

The phosphoric acid production source category consists of facilities that use a wet-process phosphoric acid process line to produce phosphoric acid by reacting phosphate rock with acid.

§ WCI.342 Greenhouse Gas Reporting Requirements

In addition to the information required by regulation, the annual emissions data report shall contain the following information:

- (a) Annual CO₂ process emissions from all wet-process phosphoric acid production lines, as specified in WCI.343 (tonnes).
- (b) CO₂, N₂O, and CH₄ emissions from stationary combustion units, as specified in WCI.20 (tonnes).
- (c) Annual phosphoric acid production (tonnes).
- (d) Annual phosphoric acid permitted production capacity (tonnes).
- (e) Annual arithmetic average percent inorganic carbon in phosphate rock from monthly records (%).
- (f) Annual phosphate rock consumption from monthly records (tonnes).
- (g) Number of times missing data procedures were used to estimate phosphate rock consumption (months) and inorganic carbon contents of the phosphate rock (month).

§ WCI.343 Calculation of CO₂ Emissions

- (a) Calculate CO₂ process emissions using Equation 340-1 and the measured inorganic carbon content and feedstock input of the phosphate rock.

$$CO_2 = \sum_{i=1}^{12} \frac{FS_i * CF_i * 3.664}{c}$$

Equation 340-1

Where:

- CO₂ = Annual carbon dioxide emitted (tonnes/year).
- FS_i = Feedstock consumption in month *i* (tonnes/month).
- CF_i = Carbonate content of feedstock (kg C/tonne feedstock) for month *i*.
- 3.664 = Ratio of molecular weights, CO₂ to carbon.
- c = Conversion factor (1,000 kg/tonne).

§ WCI.344 Sampling, Analysis, and Measurement Requirements

The monthly mass of phosphate rock consumed shall be determined using either existing plant procedures that are used for accounting purposes (such as sales records) or data from existing monitoring equipment that is used to measure total mass flow of phosphorus-bearing feed.

The monthly inorganic carbon content shall be obtained as specified under paragraphs (a) and (b) of this section.

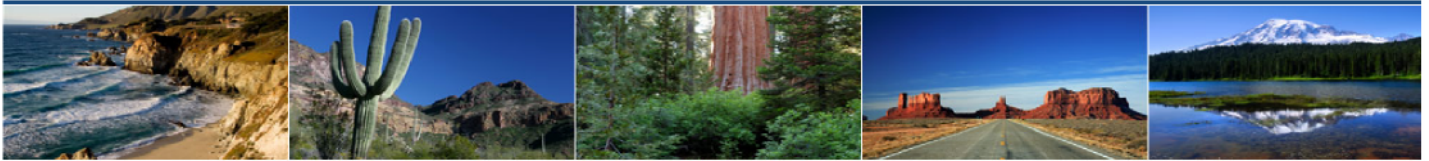
- (a) Obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line according to the following requirements:
 - (1) Follow the applicable standard method in “Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9”.
 - (2) If phosphate rock is obtained from more than one origin in a month, a sample must be obtained from each origin of rock or a composite representative sample must be obtained.
- (b) Determine the inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid) using the applicable standard method in “Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists AFPC Manual 10th Edition 2009 – Version 1.9”.

§ WCI.345 Missing Data Procedures

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. Records must be documented and kept of the procedures used for all such estimates.

- (a) A substitute data value must be determined by calculated the arithmetic average of the quality-assured values of inorganic carbon contents of phosphate rock of origin *i* from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents of phosphate rock of origin *i* are available prior to the missing data incident, then the substitute data value shall be the first quality-assured value of inorganic carbon contents for phosphate rock of origin *i* obtained after the missing data period.
- (b) For each missing value of monthly mass consumption of phosphate rock (by origin), the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

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Due to the U.S. EPA finalizing publication of Part 98, Subpart W in November, 2010, the WCI has not yet performed detailed analyses on it for harmonization with cap and trade reporting. These analyses will be occurring in 2011. As such, for some specific emission sources identified in this quantification method option is given to facilities to report – for 2011 calendar year emissions only - using EPA equations and/or methods where these methods will give as or more accurate estimates of emissions than the otherwise prescribed methods.

§ WCI.350 NATURAL GAS TRANSMISSION AND DISTRIBUTION

§ WCI.351 Source Category Definition

This source category consists of the following:

- (a) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. In addition, transmission compressor station may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.
- (b) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.
- (c) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vapourization units for re-gasification of the liquefied natural gas.
- (d) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in Canada.

- (e) *Natural gas distribution.* Natural gas distribution consists of all natural gas equipment downstream of the station yard inlet shut-off valves of natural gas transmission pipelines at stations where pressure reduction and/or measuring first occurs for eventual delivery of natural gas to consumers.
- (f) *Natural gas transmission pipelines.* Natural gas transmission pipelines means a high pressure pipeline (and associated equipment) transporting sellable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering and/or regulating stations before delivery to customers.

§ WCI.352 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (h) below, then the reported emissions for the specific source shall be reported as zero or “not applicable”.

In addition to the information required by regulation, the annual emissions data report for both each individual facility over 10,000 tonnes, and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

- (a) CO₂ and CH₄ (and N₂O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (f) of this section and from stationary and portable combustion equipment identified in paragraphs (g) and (h) of the section.
- (b) For onshore natural gas transmission compression and natural gas transmission pipelines, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:
 - (1) Compressor venting (from the following sources):
 - (i) Reciprocating compressors. [WCI.353(f)]
 - (ii) Centrifugal compressors. [WCI.353(e)]
 - (iii) Blowdown vent stacks. [WCI.353(c)]
 - (iv) Natural gas pneumatic continuous high bleed devices and pumps. [WCI.353(a)]
 - (v) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. [WCI.353(b)]
 - (vi) Other venting emission sources.* [WCI.353(l)]
 - (2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. [WCI.353(g)]
 - (3) Compressor station flaring. [WCI.353(d)]
 - (4) Compressor other fugitive emission sources.*[WCI.353(l)]
 - (5) Pipeline above ground meters and regulators at custody transfer city gate stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. [WCI.353(g)]

- (6) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(h)]*
 - (7) Pipeline flaring. *[WCI.353(d)]*
 - (8) Pipeline below ground meters and regulators and valve fugitives. *[WCI.353(h)]*
 - (9) Pipeline other fugitive emission sources not covered in (b)(5), (b)(6), (b)(7), or (b)(8) above (including, but not limited to, third party hits, farm taps, tubing systems less than one half inch diameter, pipe leaks, and customer meter sets).* *[WCI.353(l)]*
 - (10) Pipeline other venting emission sources.* *[WCI.353(l)]*
 - (11) Transmission storage tanks [Reserved].
- (c) For underground natural gas storage, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:
- (1) Venting (from the following sources):
 - (i) Reciprocating compressors. *[WCI.353(f)]*
 - (ii) Centrifugal compressors. *[WCI.353(e)]*
 - (iii) Natural gas pneumatic continuous high bleed devices and pumps. *[WCI.353(a)]*
 - (iv) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed devices. *[WCI.353(b)]*
 - (v) Other venting emission sources.* *[WCI.353(l)]*
 - (2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.353(g)]*, *[WCI.353(h)]*
 - (3) Flares. *[WCI.353(d)]*
 - (4) Other fugitive emission sources.* *[WCI.353(l)]*
- (d) For LNG storage, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:
- (1) Venting (from the following sources):
 - (i) Reciprocating compressors. *[WCI.353(f)]*
 - (ii) Centrifugal compressors. *[WCI.353(e)]*
 - (iii) Other venting emission sources.* *[WCI.353(l)]*
 - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)]*, *[WCI.353(h)]*
 - (3) Flares. *[WCI.353(d)]*

- (4) Other fugitive emission sources.* *[WCI.353(l)]*
- (e) LNG import and export equipment, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:
 - (1) Venting (from the following sources):
 - (i) Reciprocating compressors. *[WCI.353(f)]*
 - (ii) Centrifugal compressors. *[WCI.353(e)]*
 - (iii) Blowdown vent stacks. *[WCI.353(c)]*
 - (iv) Other venting emission sources.* *[WCI.353(l)]*
 - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. *[WCI.353(g)], [WCI.353(h)]*
 - (3) Flares. *[WCI.353(d)]*
 - (4) Other fugitive emission sources.* *[WCI.353(l)]*
- (f) For natural gas distribution, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:
 - (1) Above ground meters and regulators, at custody transfer city gate stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(g)]*
 - (2) Above ground meters and regulators at non-custody transfer city gate stations, including station equipment leaks. Customer meters are excluded and instead are reported under WCI.352(f)(9). *[WCI.353(h)]*
 - (3) Below ground meters and regulators and vault fugitives. *[WCI.353(h)]*
 - (4) Pipeline main fugitive equipment leaks. *[WCI.353(h)]*
 - (5) Service line fugitive equipment leaks. *[WCI.353(h)]*
 - (6) Pipeline flaring. *[WCI.353(d)]*
 - (7) Flares. *[WCI.353(d)]*
 - (8) Other venting emission sources.* *[WCI.353(l)]*
 - (9) Other fugitive emission sources (including but not limited to third party hits, farm taps, tubing systems less than one half inch diameter, and customer meter sets).* *[WCI.353(l)]*

- (g) Report CO₂, CH₄, and N₂O emissions from each stationary fuel combustion source type combusting field gas or process vent gas [*WCI.363(w)*] and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.
- (h) Report CO₂, CH₄, and N₂O emissions from each portable equipment combustion source type combusting field gas or process vent gas [*WCI.363(w)*] and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.
- (i) Report data for each aggregated source type within paragraph (b) through (f) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):
- (1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.
 - (2) Facility- and company-specific emission factors used in place of Tables 350-1 to 350-5.
 - (3) Count of natural gas pneumatic continuous high bleed devices.
 - (4) Count of natural gas pneumatic continuous low bleed devices.
 - (5) Count of natural gas pneumatic intermittent (low and high) bleed devices.
 - (6) Count of natural gas driven pneumatic pumps.
 - (7) Total pipeline length.
 - (8) For each dehydrator unit report the following:
 - (i) Glycol dehydrators:
 - (A) The number of glycol dehydrators less than and greater than or equal to 11,328 Sm³/day operated
 - (ii) Desiccant dehydrators:
 - (A) The number of desiccant dehydrators operated.
 - (9) For each compressor report the following:
 - (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
 - (ii) Compressor capacity in horsepower.
 - (iii) Number of blowdowns per year.
 - (iv) Operating mode(s) during the year

- (10) For fugitive equipment leaks and population count/emission factor sources using emission factors are used for estimating emissions in WCI.353(g) and (h), report the following:
- (i) Component count for each source for which an emission factor is provided in this document. Approximate counts may be provided for the 2011 calendar year (reported in 2012) in preparation for full counts in the 2012 calendar year.
 - (ii) Total counts of leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- (11) For natural gas distribution, report the following in addition to other requirements:
- (i) Number of custody transfer gate stations.
- (12) Number of non-custody transfer gate stations.
- (13) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
- (i) Acquired during the reporting year;
 - (ii) Sold, decommissioned, or shut-in during the reporting year;
and,
 - (iii) Greenhouse gas emissions for the facility in the previous year.

** other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

§ WCI.353 Calculation of Greenhouse Gas Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or “not applicable”. Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

- (a) Natural gas pneumatic continuous high bleed device venting and natural gas driven pneumatic pump venting.

- (1) Calculate emissions from a natural gas pneumatic continuous high bleed flow control device venting as follows:
 - (i) Estimate gas consumption for all continuous high bleed natural gas powered devices using statistically defensible emission factors that are reviewed every three to five years*. Factors should be developed using separate representative samples of the populations of high-bleed devices. Samples do not necessarily need to be repeated over time at a given location. Prior to 2013, Calculation Methodology 2 may be used.
 - (ii) Calculate CH₄ and CO₂ emissions from continuous high bleed pneumatic devices using Equation 350-1 of this section.

$$E_{GHGi} = V_{NG} \times M_i \times \left(\frac{MW_i}{MVC} \right) \times 0.001 \quad \text{Equation 350-1}$$

Where:

E_{GHGi}	=	Emissions of GHG <i>i</i> (CH ₄ or CO ₂) (tonnes).
V_{NG}	=	Volume of natural gas consumed by continuous high bleed pneumatic devices (m ³ /year).
M_i	=	Mole fraction of CH ₄ or CO ₂ in natural gas supply.
MW_i	=	Molecular weight of GHG _{<i>i</i>} .
MVC	=	Molar volume conversion factor.
0.001	=	Conversion factor from kg to tonnes

- (2) For pneumatic pumps and if in 2011 or 2012 the statistically defensible emission factor is not available for continuous high bleed pneumatic devices, use the following method to estimate emissions from continuous high bleed devices and natural gas driven pneumatic pumps.
 - (i) For continuous high bleed devices, calculate vented emissions using manufacturer data.
 - (A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rate during normal operation.
 - (B) Calculate the natural gas emissions for each continuous bleed device using Equation 350-2 of this section.

$$E_{s,n} = B_s \times t \quad \text{Equation 350-2}$$

Where:

$E_{s,n}$	=	Annual natural gas emissions at standard conditions (m ³).
B_s	=	Natural gas driven pneumatic device bleed rate volume at standard conditions, as provided by the manufacturer (m ³ /minute).
T	=	Amount of time that the pneumatic device has been operational through the reporting period (minutes).

- (C) If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics (or published default values) to estimate emissions.
- (ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:
 - (A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer “gas consumption”) per unit volume of liquid circulation rate at pump speeds and operating pressures.
 - (B) Maintain a log of the amount of liquid pumped annually from individual pumps.
 - (C) Calculate the natural gas emissions for each pump using Equation 350-3 of this section.

$$E_{s,n} = F_s \times V \quad \text{Equation 350-3}$$

Where:

- $E_{s,n}$ = Annual natural gas emissions at standard conditions (m³/year).
- F_s = Natural gas driven pneumatic pump gas emission in “emission per volume of liquid pumped at operating pressure” at standard conditions, as provided by the manufacturer (m³/liter).
- V = Volume of liquid pumped annually (liters/year).

- (D) If manufacturer data for a specific pump in Equation 350-3 is not available, then use data for a similar pump model, size and operational characteristics (or published default values) to estimate emissions.
- (iii) Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (3) Provide the total number of continuous high bleed natural gas pneumatic devices and pneumatic pumps of each type as follows:
 - (i) In the first calendar year, all continuous high bleed natural gas pneumatic devices and pneumatic pumps must be counted.
 - (ii) For the calendar year immediately following first calendar year, and for calendar years thereafter, facilities must update the total count of continuous high bleed pneumatic devices and pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.
- * [a phased in metering approach per that in WCI.364(a) is being considered for potential application for continuous high bleed devices covered by WCI.350 in place of the statistically defensible emission factor approach.]*
- (b) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic low continuous bleed, and

intermittent (low and high) bleed device venting (separately) using Equation 350-4 of this section.

$$Mass_{s,i} = Count \times EF \times GHG_i \times t \times \rho_i \times 0.001 \quad \text{Equation 350-4}$$

Where:

Mass _{s,i}	=	Annual total mass GHG emissions at standard conditions from all natural gas pneumatic continuous low bleed, and intermittent (low and high) bleed device venting, for GHG <i>i</i> (tonnes/year).
Count	=	Total number of natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed devices.
EF	=	Population volumetric emission factors for natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed device venting listed in Tables 350-1 and 350-2 of this section for onshore natural gas transmission and underground natural gas storage facilities, respectively.
GHG _i	=	For sources covered by WCI.350 (natural gas transmission), the value for GHG _i is 1.
t	=	Total time the continuous low bleed, or intermittent (low and high) bleed device was operating during the year (hours).
ρ _i	=	Density of GHG <i>i</i> , (1.861 kg/m ³ for CO ₂ and 0.678 kg/m ³ for CH ₄ at STP of 15 °C and 1 atmosphere).
0.001	=	Conversion factor from kilograms to tonnes.

- (1) Provide the total number of continuous low bleed and intermittent (low and high) bleed natural gas pneumatic devices of each type as follows:
 - (i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.
 - (ii) In the second calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.
 - (iii) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.
- (c) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases) as follows:
 - (1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.

- (2) If the total volume between isolation valves is greater than or equal to 1.42 Sm³, retain logs of the number of blowdowns for each equipment type (including, but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 1.42 Sm³ are exempt from reporting under paragraph (g) of this section
- (3) Calculate the total annual venting emissions for each equipment type using Equation 350-5 of this section:

$$E_{s,n} = N \times \left(V_v \left[\frac{(273.15 + T_s)P_a}{(273.15 + T_a)P_s} \right] - V_v \times C \right) \quad \text{Equation 350-5}$$

Where:

$E_{s,n}$	=	Annual natural gas venting emissions at standard conditions from blowdowns (m ³).
N	=	Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves (m ³).
C	=	Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s	=	Temperature at standard conditions (°C).
T_a	=	Temperature at actual conditions in the blowdown equipment chamber (°C).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions in the blowdown equipment chamber (kPa).

- (4) Calculate both CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (5) Blowdowns that are directed to flares use the WCI.353(d) flare stacks calculation method rather than WCI.353(c) blowdown vent stacks calculation method.

(d) Flare stacks. Calculate CO₂, CH₄, and N₂O emissions from a flare stack as follows:

- (1) If there is a continuous flow measurement device on the flare, measured flow volumes can be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or use engineering calculations based on process knowledge, company records, and best available data can be used.

- (2) If there is a continuous gas composition analyzer on gas to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on gas to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:
 - (i) When the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.
 - (ii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus and mixed hydrocarbons, then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.
- (3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.
- (4) Calculate GHG volumetric emissions at actual conditions using Equations 350-6, 350-7, 350-8, and 350-9 of this section.

$$E_{a,CH_4} = V_a \times (1 - \eta) \times X_{CH_4} \quad \text{Equation 350-6}$$

$$E_{a,CO_2}(\text{noncombusted}) = V_a \times X_{CO_2} \quad \text{Equation 350-7}$$

$$E_{a,CO_2}(\text{combusted}) = \sum_j \eta \times V_a \times Y_j \times R_j \quad \text{Equation 350-8}$$

$$E_{a,CO_2}(\text{total}) = E_{a,CO_2}(\text{combusted}) + E_{a,CO_2}(\text{noncombusted}) \quad \text{Equation 350-9}$$

Where:

E_{a,CH_4}	=	Contribution of annual noncombusted CH_4 emissions from flare stack under ambient conditions (m^3).
$E_{a,CO_2}(\text{noncombusted})$	=	Contribution of annual CO_2 emissions from CO_2 in the inlet gas passing through the flare noncombusted under ambient conditions (m^3).
$E_{a,CO_2}(\text{combusted})$	=	Contribution of annual emissions from combustion from flare stack under ambient conditions (m^3).
V_a	=	Volume of natural gas sent to flare during the year (m^3).
η	=	Percent of natural gas combusted by flare (default is 98 percent). For gas sent to an unlit flare, η is zero.
X_i	=	Mole fraction of GHG i in gas to the flare.
Y_j	=	Mole fraction of natural gas hydrocarbon constituents j (i.e., methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent j ; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

- (5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (i) of this section.
- (6) Calculate both CH₄ and CO₂ mass emissions from volumetric CH₄ and CO₂ emissions using calculation in paragraph (k) of this section.
- (7) Calculate N₂O emissions using the Equation 350-10.

$$E_{N_2O} = Fuel \times HHV \times EF \times 0.001$$

Equation 350-10

Where:

E_{N_2O}	=	Annual N ₂ O emissions from the combustion of a particular type of fuel (tonnes).
$Fuel$	=	Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV	=	High heat value of the fuel from paragraphs (d)(7)(i), (d)(7)(ii) or (d)(7)(iii) of this section (units must be consistent with Fuel).
EF	=	Use 9.52×10^{-5} kg N ₂ O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (i) For fuels listed in Table 20-1, use the provided default HHV in the table.
- (ii) For field gas or process vent gas, use 4.579×10^{-2} GJ/m³ for HHV.
- (iii) For fuels not listed in Table 20-1 and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in WCI.20 to determine HHV.

- (8) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in this section. Where gas to be flared is manifolded from multiple sources in WCI.353 to a common flare, report all flaring emissions under WCI.353(d).

(e) Centrifugal compressor venting. Calculate emissions from centrifugal compressor vents as follows:*

- (1) For each centrifugal compressor determine the volume of vapours from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.354(b).
- (2) Estimate annual emissions using meter flow measurement using Equation 350-11 of this section.

$$E_{a,i} = MT \times t \times M_i \times (1 - B)$$

Equation 350-11

Where:

- $E_{a,i}$ = Annual GHG i (either CH₄ or CO₂) volumetric emissions at ambient conditions.
 MT = Meter reading of gas emissions per unit time.
 t = Total time the compressor associated with the wet seal(s) is operational in the reporting year.
 M_i = Mole percent of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.
 B = Percentage of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system.

- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT variable in place of actual metered values for centrifugal compressors that are isolated for extended periods of time and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.
- (4) Calculate CH₄ and CO₂ volumetric emissions at standard conditions using paragraph (i) of this section.
- (5) Calculate both CH₄ and CO₂ mass emissions from volumetric emissions using calculations in paragraph (k) of this section.
- (6) Calculate emissions from degassing vent vapours to flares as follows:
 - (i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (e)(1) through (3) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine degassing vent vapour emissions from the flare.
- (7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented are covered under WCI.353(l).

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(o) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

- (f) Reciprocating compressor venting. Calculate annual CH₄ and CO₂ emissions from all reciprocating compressor vents as follows.* Where venting emissions are sent to a common flare, calculate emissions using WCI.352(d).

- (1) Estimate annual emissions using the flow measurement in (f)(2) or (f)(3) below and Equation 350-12.

$$E_{a,i,m} = MT \times t \times M_i$$

Equation 350-12

Where:

- $E_{a,i,m}$ = Annual volumetric emissions of GHG i (either CH₄ or CO₂) at ambient conditions.
- MT = Measured volumetric gas emissions (m³/hour) under ambient conditions.
- t = Total time the compressor is in the mode for which $E_{a,i,m}$ is being calculated, in the calendar year (hours).
- M_i = Mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.

- (2) If the reciprocating rod packing and blowdown vent is connected to an open ended vent line then use one of the following two methods to calculate emissions.
- (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in WCI.354(c) and (d).
 - (ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.354(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.354(a).
- (3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:
- (i) Use the methods described in WCI.354(a) to conduct a progressive sample leak detection of fugitive equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.
 - (ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.354(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents.
- (i) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.
 - (ii) Operating mode, reciprocating rod packing emissions.
 - (iii) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not

found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode

- (5) Calculate CH₄ and CO₂ volumetric emissions at standard conditions using calculations in paragraph (i) of this section.
- (6) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.
- (7) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.
 - (i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(p) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

- (g) Leak detection and leaker emission factors. Existing legislative or regulatory requirements or progressive sampling methods described in WCI.354(a) must be used to conduct a leak detection of fugitive equipment leaks from all sources listed in WCI.352(b)(2), b(6), (c)(2), (d)(2), (e)(2), and (f)(1). This paragraph (g) applies to emissions sources in streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas content less than 10 percent CH₄ plus CO₂ by weight need to be reported instead under WCI.354(l). Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (g) need to be reported under WCI.354(l).

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate emissions using Equation 350-13 (for volumetric emission factor [m³/hour/component]) or Equation 350-14 (for mass emission factors [tonnes/hour/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x \times \rho_i \times 0.001$$

Equation 350-13

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x$$

Equation 350-14

Where:

$E_{s,i}$	=	Annual total mass emissions of GHG i (CH ₄ or CO ₂) at standard conditions from each fugitive equipment leak source (tonnes/year).
Count	=	Total number of this type of emission source found to be leaking during t_x .
EF_s	=	Leaker emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section or facility/company-specific emission factors used in place of Tables 350-1 to 350-5 (m ³ /component/year for Equation 350-13 and tonnes/component/year for Equation 350-14).
GHG_i	=	For volumetric emissions in Equation 350-13, use 1 for CH ₄ and 1.1×10^{-2} for CO ₂ . For mass emissions in Equation 350-14, use mass fractions of CH ₄ and CO ₂ from operation/facility specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual. ¹
t_x	=	Total time the component was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey, or the beginning of the calendar year. For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.
ρ_i	=	Density of GHG i (1.861 kg/m ³ for CO ₂ and 0.678 kg/m ³ for CH ₄ at STP of 15 °C and 1 atmosphere*).
0.001	=	Conversion factor from kilograms to tonnes.

- (1) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 350-1 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.
- (2) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 350-2 of this section for fugitive equipment leaks detected from connectors, valves, pressure relief valves, meters, and open ended lines.
- (3) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 350-3 of this section for fugitive equipment leaks detected from valves, pump seals, connectors, and other equipment.
- (4) LNG import and export facilities shall use the appropriate default leaker emission factors listed in Table 350-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.

¹ Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007

- (5) Natural gas distribution facilities for above ground meters and regulators at city gate stations at custody transfer shall use the appropriate default leaker emission factors listed in Table 350-5 of this section for fugitive equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

- (h) Population count and emission factors. This paragraph applies to emissions sources listed in WCI.352 b(7), b(9), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4) and (f)(5) on streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas content less than 10 percent CH₄ plus CO₂ by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (h) of this section and instead are to be reported under WCI.353(l).

Calculate emissions from all sources listed in this paragraph using Equation 350-15 (for volumetric emission factor [m³/hour/component]) or Equation 350-16 (for mass emission factors [tonnes/hour/component]) of this section, as appropriate.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t \times \rho_i \times 0.001$$

Equation 350-15

$$E_{s,i} = Count \times EF_s \times GHG_i \times t$$

Equation 350-16

Where:

- $E_{s,i}$ = Annual total mass GHG emissions of GHG i (CH₄ or CO₂) at standard conditions from each fugitive source (tonnes/year).
- Count = Total number of this type of emission source at the facility. Average component counts by major equipment pieces from the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual (or other relevant Canadian Gas Association and/or Canadian Association of Petroleum Producers documentation) may be used as appropriate for operations and required by (h)(1) through (h)(5), below. If facility or company specific major equipment count data that meet or exceed the quality of the relevant CGA default count data are available, they must be used in its place.
- EF_s = Population emission factor for specific sources listed in Table 350-1 through Table 350-5 of this section (m³/component/year for Equation 350-15 and tonnes/component/year for Equation 350-16). EF for non-custody transfer city gate stations is determined in Equation 350-17. The direction on the use of Tables 350-1 through 350-5 provided prior to the tables must be followed.
- GHG_i = For volumetric emissions in Equation 350-15, use 1 for CH₄ and 1.1×10^{-2} for CO₂. For mass emissions in Equation 350-16, use mass fractions of CH₄ and CO₂ from operation/facility specific data or the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual.

- t = Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (hours).
- ρ_i = Density of GHG *i* (1.861 kg/m³ for CO₂ and 0.678 kg/m³ for CH₄ at STP of 15 °C and 1 atmosphere*).
- 0.001 = Conversion factor from kilograms to tonnes.

- (1) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table 350-2 of this section for fugitive equipment leaks from connectors, valves, pressure relief valves, and open ended lines.
- (2) LNG storage facilities shall use the appropriate default population emission factors listed in Table 350-3 of this section for fugitive equipment leaks from vapour recovery compressors.
- (3) LNG import and export facilities shall use the appropriate default population emission factor listed in Table 350-4 of this section for fugitive equipment leaks from vapour recovery compressors.
- (4) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (h)(5) of this section.
 - (i) Below grade meters and regulators; mains; and services, shall use the appropriate default population emission factors listed in Table 350-5 of this section.
 - (ii) Above grade meters and regulators at city gate stations not at custody transfer as listed WCI.352(f)(5), must use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph (i)(6) of this section to develop facility emission factors using Equation 350-17 of this section. The calculated facility emission factor from Equation 350-17 of this section shall be used in Equations 350-15 and 350-16 of this section.

$$EF = \sum \frac{E_{s,i}}{Count} \quad \text{Equation 350-17}$$

Where:

- EF* = Facility emission factor for a meter at above grade M&R at city gate stations not at custody transfer in meters cubed per meter per year.
- E_{s,i}* = Annual volumetric GHG emissions at standard condition from all equipment leak sources at all above grade M&R city gate stations at custody transfer, from paragraph (i) of this section.
- Count* = Total number of meter runs at all above grade M&R city gate stations at custody transfer

- (iii) To ensure proper calculation of emissions from pipeline main equipment leaks, Equations 350-15 and 350-16 and their inputs may be modified as necessary to

meet 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual standards. For example, the length of the installed underground pipeline should be used in place of count and company specific leak data is permitted.

- (i) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

- (1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure (15 °C and 1 atmosphere in Canada) natural gas using Equation 350-18 of this section.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-18

Where:

$E_{s,n}$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (m ³).
$E_{a,n}$	=	Natural gas volumetric emissions at ambient conditions (m ³).
T_s	=	Temperature at standard conditions (°C).
T_a	=	Temperature at actual emission conditions (°C).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

- (2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 350-19 this section.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 350-19

Where:

$E_{s,i}$	=	GHG <i>i</i> volumetric emissions at standard temperature and pressure (STP) conditions (m ³).
$E_{a,i}$	=	GHG <i>i</i> volumetric emissions at actual conditions (m ³).
T_s	=	Temperature at standard conditions. (°C).
T_a	=	Temperature at actual emission conditions. (°C).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

(j) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (j)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH₄ and CO₂ emissions from natural gas emissions using Equation 350-20 of this section.

$$E_{s,i} = E_{s,n} \times M_i$$

Equation 350-20

Where:

$E_{s,i}$ = GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions.
 $E_{s,n}$ = Natural gas volumetric emissions at standard conditions.
 M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation 350-20 of this section, the mole fraction, M_i , shall be the annual average mole fraction for each facility, as specified in paragraphs (j)(2)(i) through (v) of this section.

- (i) GHG mole fraction in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.
- (ii) GHG mole fraction in natural gas stored in underground natural gas storage facilities.
- (iii) GHG mole fraction in natural gas stored in LNG storage facilities.
- (iv) GHG mole fraction in natural gas stored in LNG import and export facilities.
- (v) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(k) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 350-21 of this section.

$$Mass_{s,i} = E_{s,i} \times \rho_i \times GWP \times 0.001$$

Equation 350-21

Where:

$Mass_{s,i}$ = GHG i (either CH₄ or CO₂) mass emissions at standard conditions (tonnes CO₂e).
 $E_{s,i}$ = GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions (m³).
 ρ_i = Density of GHG i (1.861 kg/m³ for CO₂ and 0.678 kg/m³ for CH₄ at STP of 15 degrees celsius and 1 atmosphere*).
 GWP = Global warming potential of GHG i , (1 for CO₂ and 21 for CH₄, and 310 for N₂O).

0.001 = Conversion factor from kilograms to tonnes.

* gas densities calculated using the 12th edition of the Gas Processors Suppliers Association Engineering Data Book.

- (l) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.353 must be calculated by methodologies consistent with those presented here, in the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual² (as amended from time to time), or in other relevant Canadian Gas Association documentation.

§ WCI.354 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

- (a) (i) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or similar standard Canadian Gas Association methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein.
- (ii) If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.353(f), (g), and (h) as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling, modeling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode during a reporting period.

- (1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant

² Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007.

standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

- (i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
 - (ii) Provide a date and time stamp for video records of every monitoring event.
 - (2) Bubble tests.
 - (3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions
 - (4) Other methods as outlined in standard Canadian Gas Association methodologies or the CAPP Best Management Practices for Fugitive Emissions may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary for operational circumstances provided that sufficient documentation as to the method used, results on tests, its reliability and accuracy is maintained and updated at regular intervals.
- (b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as Canadian Standards Association (CSA), Canadian Gas Association, Canadian Energy Pipeline Association (CEPA), ASTM International, American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, Canadian Association of Petroleum Producers (CAPP), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.
- (c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

- (1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.
 - (2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.
 - (3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.353(i).
 - (4) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).
- (d) Use a high volume sampler to measure emissions within the capacity of the instrument.
- (1) A technician following (and competent to follow) manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
 - (2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then you shall use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
 - (3) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.353(j) and (k).
 - (4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer's instructions for calibration.

§ WCI.355 Procedures for Estimating Missing Data

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data

for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.356 Definitions

Blowdown vent stack emissions mean natural gas and/or CO₂ released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

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

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO₂ by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO₂ from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO₂ released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seal degassing venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO₂. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

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

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

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

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

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

Farm taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. The gas may or may not be metered, but always does not pass through a city gate station

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

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.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

High-bleed pneumatic devices are automated continuous bleed control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

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

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

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

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

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

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

Pipeline quality natural gas means natural gas having a high heat value equal to or greater than 36.3 MJ/m³ or less than 40.98 MJ/m³, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

Portable means the same as defined in WCI.27 and WCI.361(a)(2)

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

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

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

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

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

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

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

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

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

Directions for the use of Tables 350-1 to 350-5

- (a) Starting with 2013 calendar year emissions, for each component listed in the Tables 350-1 to 350-5, or otherwise required by the quantification method referencing Tables 350-1 and 350-2:
 - (i) If statistically valid facility specific emission factors for a component type are available or can be safely or reasonably developed they must be used
 - (ii) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors if they can be safely or reasonably developed.
 - (iii) If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Tables 350-1 to 350-5 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as some booster stations used only sporadically during a year) may continue to use the default tables.
- (b) For 2011 and 2012 calendar year emissions,
 - (i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 350-1 to 350-5 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.
- (c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place
- (d) Any changes from facility-specific factors to company-specific or table factors, or from company specific factors to the defaults in Tables 350-1 to 350-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question
- (e) If an emission factor required by the quantification method referencing Tables 350-1 through 350-5 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 or the 2007 Canadian Gas Association Methodology Manual may be used (as converted for use in the relevant equation).
- (f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request
- (g) All emission factors or data collection for emission factors must be developed using Canadian Gas Association (CGA) standard methods, or other methods if CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.

- (h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.
- (i) The default emission factors provided in Tables 350-1 to 350-5 below are industry average emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

TABLE 350-1 –DEFAULT EMISSION FACTORS FOR TRANSMISSION

Transmission	Emission Factor (tonnes/hour/component) Direct conversion of EF's in CGA Manual³ Table 6 (kg to tonnes)
Leaker Emission Factors - All Components, Gas Service	
Connector	4.471 E-7
Block valve	4.131 E-6
Control valve	1.650 E-2
Compressor blowdown valve	3.405 E-3
Pressure relief valve	1.620 E-4
Orifice meter	4.863 E-5
Other meter	9.942 E -6
Regulator	7.945 E-6
Open-ended line	9.183 E-5
Population Emission Factors - Other Components, Gas Service	
	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-3 (scf to Sm³)
Low-bleed pneumatic device vents	3.99 E-2
High continuous bleed pneumatic device vents	5.32 E-1
Intermittent (low and high) bleed pneumatic device vents	5.32 E-1

* The distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

³ Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

TABLE 350-2 –DEFAULT METHANE EMISSION FACTORS FOR UNDERGROUND STORAGE*

Underground Storage	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-4 (scf to Sm³)
Leaker Emission Factors - Storage Station, Gas Service	
Valve ¹	4.268 E-1
Connector	1.60 E-1
Open-ended line	4.967 E-1
Pressure relief valve	1.140
Meter	5.560 E-1
Population Emission Factors - Storage Wellheads, Gas Service	
Connector	2.8 E-4
Valve	2.8 E-3
Pressure relief valve	4.8 E-3
Open-ended line	8.5 E-4
Population Emission Factors - Other Components, Gas Service	
Low-bleed pneumatic device vents	3.99 E-2
High continuous bleed pneumatic device vents	5.32 E-1
Intermittent (low and high) bleed pneumatic device vents	5.32 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-4.

¹ Valves include control valves, block valves and regulator valves

TABLE 350-3 –DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE*

LNG Storage	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm³)
Leaker Emission Factors - LNG Storage Components, LNG Service	
Valve	3.43 E-2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other ¹	5.10 E-2
Population Emission Factors - LNG Storage Compressor, Gas Service	
Vapour Recovery Compressor	1.20 E-1

¹ The “other” equipment type should be applied for any equipment type other than connectors, pumps, or valves.

* Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-5.

TABLE 350-4—DEFAULT METHANE EMISSION FACTORS FOR LNG TERMINALS*

LNG Terminals	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm³)
Leaker Emission Factors - LNG Terminals Components, LNG Service	
Valve	3.43 E -2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other	5.10 E-2
Population Emission Factors - LNG Terminals Compressor, Gas Service	
Vapour recovery compressor	1.20 E-1

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-6.

TABLE 350-5 –DEFAULT EMISSION FACTORS FOR DISTRIBUTION

Distribution	Emission Factor** (tonnes/hour/component) Direct conversion of EF's in CGA Manual⁴ Table 6 (kg to tonnes)
Leaker Emission Factors - Above Grade M&R Stations Components, Gas Service	
Connector	8.227 E-8
Block valve	5.607 E-7
Control valve	1.949 E-5
Pressure relief valve	3.944 E-6
Orifice meter	3.011 E-6
Regulator	6.549 E-7
Open-ended line	6.077 E-5
Population Emission Factors - Below Grade M&R Stations Components, Gas Service¹	
	Emission Factor (Sm³/hour/component) Direct conversion of EF's in EPA Subpart W Table W-7 (scf to Sm³)
Below grade M&R station, inlet pressure > 300 psig	3.74 E-2
Below grade M&R station, inlet pressure 100 to 300 psig	5.7 E-3
Below grade M&R station, inlet pressure < 100 psig	2.8 E-3

⁴ Clearstone Engineering Ltd. *Methodology Manual: Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System*. Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI). 2007. As these emission factors are updated from time to time, the intention is to incorporate such updates here.

Population Emission Factors - Distribution Mains, Gas Service^{2*}	Emission Factor (Sm³/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-3 to 6 (scf to Sm³) except where noted
Unprotected steel	1.83 E-1
Protected steel	7.22 E-2
Plastic	7.76 E-2
Cast iron [*]	7.836 E-1
Population Emission Factors - Distribution Services, Gas Service[*]	Emission Factor (Sm³/hour/component) Direct conversion of Leak Rates in CGA Forms 4.2.1-7 to 10 (scf to Sm³) except where noted
Unprotected steel	7.08 E-2
Protected steel	3.23 E-2
Plastic	1.04 E-2
Copper	2.7 E-2

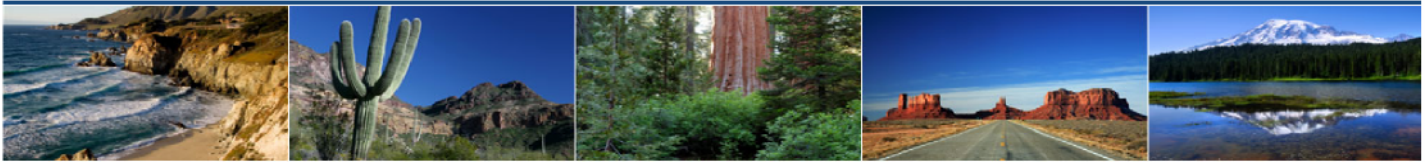
¹ Emission Factor is in units of “sm³/hour/station”

² Emission Factor is in units of “sm³/hour/service”

*Emission factors are conversions of those contained in the U.S. EPA Subpart W Table W-7.

** the distribution emission factors in Table 350-5 should be used for equipment in odourized service and the transmission factors in Table 350-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

Western Climate Initiative



Due to the U.S. EPA finalizing publication of Part 98, Subpart W in November, 2010, the WCI has not yet performed detailed analyses on it for harmonization with cap and trade reporting. These analyses will be occurring in 2011. As such, for some specific emission sources identified in this quantification method option is given to facilities to report – for 2011 calendar year emissions only - using EPA equations and/or methods where these methods will give as or more accurate estimates of emissions than the otherwise prescribed methods.

§WCI.360 PETROLEUM AND NATURAL GAS PRODUCTION AND GAS PROCESSING

§ WCI.361 Source Category Definition

(a) This source category consists of the following:

- (1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.
- (2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including but not limited to compressors, generators, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including but not limited to well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all EOR operations using CO₂, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.
- (3) *Onshore natural gas processing.* Natural gas processing plants separates and/or recovers natural gas liquids (NGLs) and/or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulphur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the

capture of CO₂ separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including but not limited to flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants may be considered a part of the processing plant if emissions are not calculated under onshore petroleum and natural gas production. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within onshore natural gas processing for the purposes of emissions calculation. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

- (b) This source category does not include natural gas transmission and distribution (i.e., onshore natural gas transmission compression, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export equipment, and natural gas distribution). These are included in WCI.350 (Natural Gas Transmission and Distribution).

§ WCI.362 Greenhouse Gas Reporting Requirements

Where greenhouse gases are not emitted from a specific emission source identified in paragraphs (a) to (f), below then the reported emissions for the specific source shall be reported as zero or “not applicable”.

In addition to the information required by regulation, the annual emissions data report, for both each individual facility over 10,000 tonnes and the aggregate of facilities less than 10,000 tonnes (or as otherwise specified by regulation), must contain the following information:

- (a) CO₂ and CH₄ (and N₂O, if applicable) emissions (in tonnes) from each industry segment specified in paragraph (b) through (d) of this section and from stationary and portable combustion equipment identified in paragraphs (e) and (f) of the section.
- (b) For offshore petroleum and natural gas production, report CO₂, CH₄, and N₂O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions *[WCI.363(p), reserved]*
- (c) For onshore petroleum and natural gas production, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following source types:
 - (1) Natural gas pneumatic continuous high bleed device venting. *[WCI.363(a)]*
 - (2) Natural gas driven pneumatic pump venting. *[WCI.363(a)]*
 - (3) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. *[WCI.363(b)]*

- (4) Acid gas removal venting and incineration process. *[WCI.363(c)]*
 - (5) Dehydrator vents. *[WCI.363(d)]*
 - (6) Well venting for liquids unloading. *[WCI.363(e)]*
 - (7) Gas well venting during well completions or workovers with hydraulic fracturing, except where vent gas is sent to a flare. *[WCI.363(f)]*
 - (8) Gas well venting during well completions or workovers without hydraulic fracturing, except where vent gas is sent to a flare. *[WCI.363(f)]*
 - (9) Blowdown vent stacks. *[WCI.363(g)]*
 - (10) Storage tanks. *[WCI.363(h)]*
 - (11) Well testing venting and flaring. *[WCI.363(i)]*
 - (12) Associated gas venting and flaring. *[WCI.363(j)]*
 - (13) Flare stacks. *[WCI.363(k)]*
 - (14) Centrifugal compressor venting. *[WCI.363(l)]*
 - (15) Reciprocating compressor venting. *[WCI.363(m)]*
 - (16) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*
 - (17) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other fugitive equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps). *[WCI.363(o)]*
 - (18) EOR injection pump blowdown. *[WCI.363(t)]*
 - (19) Hydrocarbon liquids dissolved CO₂ from flashing [Reserved]. *[WCI.363(u)]*
 - (20) Produced water dissolved CO₂ [Reserved]. *[WCI.363(v)]*
 - (21) Coal bed methane produced water emissions [Reserved]. *[WCI.363(v)]*
 - (22) Other venting emission sources.* *[WCI.363(x)]*
 - (23) Other fugitive emission sources.**[WCI.363(x)]*
- (d) For onshore natural gas processing, report CO₂ and CH₄ (and N₂O, if applicable) emissions from the following sources:

- (1) Acid gas removal venting or incineration. *[WCI.363(c)]*
 - (2) Dehydrator vents. *[WCI.363(d)]*
 - (3) Blowdown vent stacks. *[WCI.363(g)]*
 - (4) Storage tanks. *[WCI.363(h)]*
 - (5) Flare stacks. *[WCI.363(k)]*
 - (6) Centrifugal compressor venting. *[WCI.363(l)]*
 - (7) Reciprocating compressor venting. *[WCI.363(m)]*
 - (8) Gathering pipeline fugitive equipment leaks. *[WCI.363(o) or WCI.363(x) for emission sources not covered by WCI.363(o)]*
 - (9) Fugitive equipment leaks from: valves, connectors, open ended lines, pressure relief valves and meters. *[WCI.363(n)]*
 - (10) Other fugitive emission sources (including reciprocating compressor rod packing fugitives, centrifugal compressor dry and wet seals, etc).**[WCI.363(x)]*
 - (11) Other venting emission sources.**[WCI.363(x)]*
- (e) Report CO₂, CH₄, and N₂O emissions from each stationary fuel combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report stationary combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.**
- (f) Report CO₂, CH₄, and N₂O emissions from each portable equipment combustion source type combusting field gas or process vent gas *[WCI.363(w)]* and fuels other than field gas or process vent gas. Report portable equipment combustion sources that combust fuels other than field gas or process vent gas using WCI.20 (General Stationary Combustion Sources) quantification methods.**
- (g) Report data for each aggregated source type within paragraph (b) through (d) of this section as follows (for each individual facility or aggregate of facilities reported, as required by regulation):
- (1) Where there is a choice of quantification method used for a source, the specific method(s) used and under what circumstances.
 - (2) Facility and company-specific emission factors used in place of Tables 360-1 and 360-2.
 - (3) Count of natural gas pneumatic continuous high bleed devices.

- (4) Count of natural gas pneumatic continuous low bleed devices.
- (5) Count of natural gas intermittent (low and high) bleed devices.
- (6) Count of natural gas driven pneumatic pumps.
- (7) Total throughput of acid gas removal units.
- (8) For each dehydrator unit report the following:
 - (i) Glycol dehydrators:

The number of glycol dehydrators less than and greater than or equal to 11,328 Sm³/day operated.
 - (ii) Desiccant dehydrators:
 - (A) The number of desiccant dehydrators operated.
- (9) Count of wells vented to the atmosphere for liquids unloading.
- (10) Count of wells venting during well completions:
 - (i) Number of conventional completions.
 - (ii) Number of completions employing hydraulic fracturing.
- (11) Count of wells venting during well workovers:
 - (i) number well workovers involving well venting to the atmosphere.
- (12) For each compressor report the following:
 - (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
 - (ii) Compressor capacity in horse powers (except for well site natural gas production compressors).
 - (iii) Number of blowdowns per year (except for well site natural gas production compressors).
 - (iv) Operating mode(s) during the year (except for well site natural gas production compressors).
- (13) Number of EOR injection pump blowdowns per year.
- (14) Count of wells tested in the reporting period.
- (15) Count of wells venting or flaring associated natural gas in the reporting period.
- (16) Count of wells being unloaded for liquids in the reporting year.
- (17) Count of wells completed (worked over) in the reporting year.
- (18) For fugitive equipment leaks and population count/emission factor sources where emission factors are used for estimating emissions in WCI.363(n) and (o), report the following:

- (i) Component count for each source for which an emission factor is provided in this document. Approximate counts may be provided for the 2011 calendar year (reported in 2012) in preparation for full counts in the 2012 calendar year.
 - (ii) Total counts of fugitive equipment leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- (19) Barrels of oil equivalent throughput/processed as determined by engineering estimate based on best available data.
- (20) Identification (including geographic coordinates) of any facility that was above 1,000 tonnes of greenhouse gas emissions in the previous year that was:
- (i) Acquired during the reporting year;
 - (ii) Sold, decommissioned or shut-in during the reporting year;
 - and,
 - (iii) Greenhouse gas emissions for the facility in the previous year .

** Other venting emission or other fugitive sources not specifically listed are not required to be reported if a specific other venting or other fugitive source type is reasonably estimated to be below 0.5% of total operation emissions and total emissions not reported under this clause do not exceed 1% of total operation emissions (if an individual facility is part of a larger reporting operation, the 0.5% or 1% should be interpreted as 0.5% or 1% of the reporting operation emissions, otherwise interpret as 0.5% or 1% of the facility emissions). The applicable regulator may, upon request and provision of sufficient information, provide a list of sources believed to be below these thresholds for all operations for which reporting and verification would not be required.*

*** Portable equipment is portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at an onshore production facility. Stationary or portable equipment include the following equipment which are integral to the extraction, processing or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters*

§ WCI.363 Calculating GHG Emissions

If greenhouse gases are not emitted from one or more of the following emission sources, the reporter will not need to calculate emissions from the emission source(s) in question and reported emissions for the emission source(s) will be zero or “not applicable”. Where a quantification method is not provided for a specific source (such as for other venting and other fugitive sources), industry inventory practices must be used to estimate emissions. For ambient conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

- (a) Natural gas pneumatic continuous high bleed device venting and natural gas driven pneumatic pump venting. Calculate emissions from a natural gas pneumatic continuous high bleed flow control device venting and natural gas driven pneumatic pump venting as follows.

Natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to report emissions under paragraph (a) of this section:

- (1) Calculation Methodology 1. Calculate vented emissions from a natural gas pneumatic continuous high bleed control devices or pneumatic pumps as follows:
 - (i) Measure gas consumption for all continuous high bleed natural gas powered devices (except pneumatic pumps not equipped with a meter) using a meter or meters that meet accuracy requirements specified by relevant oil and gas metering requirements in the jurisdiction (even if a meter is not prescribed for this circumstance in the relevant requirements). In 2013, reporters are required to meter gas consumption for at least 50% of all continuous high bleed devices. Metering of gas consumption for all continuous high bleed devices is required in 2014. Prior to 2013 and for up to 50% of continuous high bleed devices in 2013, Calculation Methodology 2 may be used. Common meters may be used where possible.
 - (ii) Calculate CH₄ and CO₂ emissions from continuous high bleed pneumatic devices and pumps using Equation 360-1.

$$E_{GHGi} = V_{NG} \times M_i \times \left(\frac{MW_i}{MVC} \right) \times 0.001 \quad \text{Equation 360-1}$$

Where:

E_{GHGi}	=	Emissions of GHG <i>i</i> (CH ₄ or CO ₂) (tonnes)
V_{NG}	=	Volume of natural gas consumed by metered continuous high bleed pneumatic devices and pumps (m ³ /year).
M_i	=	Mole fraction of CH ₄ or CO ₂ in natural gas supply.
MW_i	=	Molecular weight of GHG <i>i</i> .
MVC	=	Molar volume conversion factor.
0.001	=	Conversion factor from kg to tonnes.

- (2) Calculation Methodology 2. Emissions from continuous high bleed devices and natural gas driven pneumatic pumps that are not equipped with meters must be calculated using the following methods.
 - (i) For continuous high bleed devices, calculate vented emissions using manufacturer data.
 - (A) Obtain from the manufacturer specific pneumatic device model natural gas bleed rates during normal operation.
 - (B) Calculate the natural gas emissions for each continuous bleed device using Equation 360-2.

$$E_{s,n} = B_s \times t \quad \text{Equation 360-2}$$

Where:

- $E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3).
 B_s = Natural gas driven pneumatic device bleed rate volume at standard conditions, as provided by the manufacturer (m^3/minute).
 t = Amount of time that the pneumatic device has been operational through the reporting period (minutes).

If manufacturer data for a specific device is not available, then use data for a similar device model, size and operational characteristics to estimate emissions.

(ii) Calculate emissions from natural gas driven pneumatic pump venting as follows:

- (A) Obtain from the manufacturer specific pump model natural gas emission (or manufacturer “gas consumption”) per unit volume of liquid circulation rate at pump speeds and operating pressures.
(B) Maintain a log of the amount of liquid pumped annually from individual pumps.
(C) Calculate the natural gas emissions for each pump using Equation 360-3.

$$E_{s,n} = F_s \times V \quad \text{Equation 360-3}$$

Where:

- $E_{s,n}$ = Annual natural gas emissions at standard conditions (m^3/year).
 F_s = Natural gas driven pneumatic pump gas emission in “emission per volume of liquid pumped at operating pressure” at standard conditions, as provided by the manufacturer (m^3/liter).
 V = Volume of liquid pumped annually (liters/year).

If manufacturer data for a specific pump is not available, then use data for a similar pump model, size and operational characteristics to estimate emissions.

(iii) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

- (3) Provide the total number of continuous high bleed natural gas pneumatic devices and pneumatic pumps of each type as follows:
(i) In the first calendar year, all continuous high bleed natural gas pneumatic devices and pneumatic pumps must be counted.
(ii) For the calendar year immediately following first calendar year, and for calendar years thereafter, facilities must update the total count of continuous high bleed

pneumatic devices and pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

- (b) Natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic continuous low bleed and intermittent (low and high) bleed device venting (separately) using Equation 360-4 of this section.

$$Mass_{s,i} = Count \times EF \times GHG_i \times t$$

Equation 360-4

Where:

Mass _{s,i}	=	Annual total mass GHG emissions at standard conditions from all natural gas pneumatic continuous low bleed, and intermittent (low and high) bleed device venting, for GHG <i>i</i> (tonnes/year).
Count	=	Total number of natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed devices.
EF	=	Population emission factors for natural gas pneumatic continuous low bleed, or intermittent (low and high) bleed device venting listed in Table 360-1 (tonnes of natural gas/component-hour).
GHG _i	=	Mass fraction of GHG <i>i</i> (CH ₄ or CO ₂), in produced natural gas (tonnes of GHG <i>i</i> /tonnes of natural gas).
t	=	Total time the continuous low bleed device, or intermittent (low and high) bleed device was operating during the year (hours).

- (1) Provide the total number of continuous low bleed and intermittent (low and high) bleed natural gas pneumatic devices of each type as follows:
 - (i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.
 - (ii) In the second calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.
 - (iii) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

- (c) Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field, calculate CO₂ emissions only (not CH₄) for AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and adsorbents) using Equation 360-5.*

$$E_{a,CO_2} = (V + \alpha \times (V \times (Vol_I - Vol_O))) \times (Vol_I - Vol_O) \quad \text{Equation 360-5}$$

Where:

E_{a,CO_2}	=	Annual volumetric CO ₂ emissions at actual condition (m ³ /year).
V	=	Metered total annual volume of natural gas flow into or out of AGR unit (m ³ /year) as determined in paragraph (c)(1) of this section.
α	=	Factor is 1 if outlet stream flow is measured. Factor is 0 if inlet stream flow is measured.
Vol_I	=	Volume fraction of CO ₂ in natural gas into the AGR unit as determined in paragraph (c)(2) of this section.
Vol_O	=	Volume fraction of CO ₂ in natural gas out of the AGR unit as determined in paragraph (c)(3) of this section.

- (1) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in WCI.364(b).
- (2) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in WCI.364(b).
- (3) Determine volume fraction of CO₂ content in natural gas out of the AGR units using one of the methods specified in paragraph (c)(3) of this section.
 - (i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.
 - (ii) If a continuous gas analyzer is not available or installed, monthly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in WCI.364(b).
- (4) Calculate CO₂ volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (5) Mass CO₂ emissions shall be calculated from volumetric CO₂ emissions using calculations in paragraphs (r) and (s) of this section.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(d) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(d) Dehydrator vents. For dehydrator vents, calculate annual mass CH₄, CO₂ and N₂O (when flared) emissions at standard temperature and pressure (STP) conditions as follows*:

- (1) Calculate annual mass emissions from dehydrator vents using a simulation software package of similar accuracy to GRI-GLYCalc Version 4.0 or AspenTech HYSYS®, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH₄ and CO₂ emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters must be used for characterizing emissions from dehydrators:
 - (i) Feed natural gas flow rate.
 - (ii) Feed natural gas water content.
 - (iii) Outlet natural gas water content.
 - (iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
 - (v) Absorbent circulation rate.
 - (vi) Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
 - (vii) Use of stripping natural gas.
 - (viii) Use of flash tank separator (and disposition of recovered gas).
 - (ix) Hours operated.
 - (x) Wet natural gas temperature, pressure, and composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(x) of this section.
 - (A) Use the wet natural gas composition as defined in paragraph (r)(2)(i) of this section.
 - (B) If wet natural gas composition cannot be determined using paragraph (r)(2)(i) of this section, select a representative analysis.
 - (C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in WCI.364(b) to sample and analyze wet natural gas composition.
 - (D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.
- (2) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(2) of this section downward by the magnitude of emissions captured.
- (3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:
 - (i) Use the dehydrator vent stack volume and gas composition as determined in paragraph (d)(1) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

- (4) Dehydrators that use desiccant shall calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using Equation 360-6.

$$E_{s,n} = \left(\frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times t} \right) / 100$$

Equation 360-6

Where:

$E_{s,n}$	=	Annual natural gas emissions at standard conditions (m^3).
H	=	Height of the dehydrator vessel (m).
D	=	Inside diameter of the vessel (m).
P_1	=	Atmospheric pressure (kPa).
P_2	=	Pressure of the gas (kPa).
π	=	pi (3.14).
%G	=	Percent of packed vessel volume that is gas.
365	=	Conversion from days to years.
t	=	Time between refilling (days).
100	=	Conversion of %G to fraction.

- (5) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(e) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

- (e) Well venting for liquids unloading. The CO_2 and CH_4 emissions for well venting for liquids unloading shall be determined using one of the following calculation methodologies:

- (1) Calculation Methodology 1. For one well* of each well tubing diameter and producing horizon/formation combination in each gas producing field where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank) according to the methods set forth in the WCI.364(b). Calculate emission from well venting for liquids unloading using Equation 360-7.

$$E_{a,n} = \sum_h \sum_t t_{h,t} \times FR_{h,t}$$

Equation 360-7

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions (m^3).
 $t_{h,t}$ = Cumulative amount of time in hours of venting from all wells of the same tubing diameter (t) and producing horizon (h)/formation combination during the year.
 $FR_{h,t}$ = Average flow rate (m^3) of the measured well venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (e)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (e)(1)(i) of this section.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field by averaging the recorded flow rates for the recorded for one well venting to the atmosphere.

(B) This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year (if necessary) for each reporting field and horizon starting the first calendar year of data collection.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

(2) Calculation Methodology 2. Calculate emissions from each well venting for liquids unloading using Equation 360-8.

$$E_{a,n} = \left(\left[7.854 \times 10^{-5} \right] \times CD^2 \times WD \times \left[\frac{SP}{101.325} \right] \times N_v \right) + (SFR \times [HR - 1.0] \times Z)$$

Equation 360-8

Where:

$E_{a,n}$ = Annual natural gas emissions at actual conditions (m^3 /year).
 7.854×10^{-5} = $(\pi/4)/(10000)$
 CD = Casing diameter (cm).
 WD = Well depth (m).
 SP = Shut-in pressure (kPa-gage).
 N_v = Number of vents per year.
 SFR = Average sales flow rate of gas well (m^3 /hr).
 HR = Hours that the well was left open to the atmosphere during unloading.
 1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
 Z = If HR is less than 1.0, then Z is equal to 0. If HR is greater than or equal to 1.0, then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

- (3) Calculation Methodology 3. Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 360-9.

$$E_{a,n} = \left([7.854 \times 10^{-5}] \times TD^2 \times WD \times \left[\frac{SP}{101.325} \right] \times N_v \right) + (SFR \times [HR - 0.5] \times Z) \quad \text{Equation 360-9}$$

Where:

$E_{a,n}$	=	Annual natural gas emissions at actual conditions (m ³ /year).
7.854×10^{-5}	=	($\pi/4$)/(10000)
TD	=	Tubing diameter (cm).
WD	=	Tubing depth to plunger bumper (meters).
SP	=	Sales line pressure (kPa-gage).
N_v	=	Number of vents per year.
SFR	=	Average sales flow rate of gas well (m ³ /hr).
HR	=	Hours that the well was left open to the atmosphere during unloading.
0.5	=	Hours for average well to blowdown tubing volume at sales line pressure.
Z	=	If HR is less than 0.5 then Z is equal to 0. If HR is greater than or equal to 0.5 then Z is equal to 1.

(i) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.

- (4) Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

* the number of wells required to create an unbiased sample is being considered for future amendment

- (f) Gas well venting during well completions and workovers with or without hydraulic fracturing. Calculate emissions from gas conventional or unconventional (from hydraulic fracturing) well venting during well completions and workovers using Equation 360-10. Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section. Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.*

$$E_{a,n} = (t \times FR) - EnF - SG$$

Equation 360-10

Where:

$E_{a,n}$	=	Annual natural gas vented emissions at ambient conditions (m^3).
t	=	Cumulative amount of time in hours of well venting during the year.
FR	=	Flow rate under ambient conditions, as required in paragraph (f)(1) of this section (m^3/hr).
EnF	=	Volume of CO_2 or N_2 injected gas (Sm^3) that was injected into the reservoir during an energized fracture job. If the fracture process did not inject gas into the reservoir, then EnF is 0. If injected gas is CO_2 then EnF is 0.
SG	=	Volume of natural gas (Sm^3) that was recovered into a sales pipeline. If no gas was recovered for sales, SG is 0.

- (1) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing shall be determined using either of the calculation methodologies described in this paragraph (f)(1). The same calculation methodology must be used for the entire volume for the reporting year.
 - (i) Calculation Methodology 1. For a statistically valid sample of well completions and well workovers, a recording flow meter shall be installed on the vent line during each well unloading event according to methods set forth in WCI.364(b). The average flow rate for each well in the field ($m^3/minute$ of venting) is calculated based on the statistically valid sample of well completions and well workovers.
 - (ii) Calculation Methodology 2. For a statistically valid sample of well completions and well workovers, record the pressures measured before and after the well choke according to methods set forth in WCI.364(b). The average flow rate across the choke ($m^3/minute$ of venting) is calculated for each well completion and each well workover.
 - (iii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
 - (iv) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (2) Calculate annual emissions from gas well venting during well completions and workovers to flares as follows:
 - (i) Use the gas well venting volume during well completions and workovers as determined in paragraph (f)(1) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine gas well venting during well completions and workovers emissions from the flare.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(g) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(f.1) Gas well venting during well completions and workovers without hydraulic fracturing.

Reserved [paragraph (f) indicated to be appropriate for use in Canada for gas wells without hydraulic fracturing]

(g) Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to the atmosphere (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (d)(4) of this section) as follows:

- (1) Calculate the total volume (including, but not limited to, pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves determined by engineering estimates based on best available data.
- (2) If the total volume between isolation valves is greater than or equal to 1.42 Sm^3 , retain logs of the number of blowdowns for each equipment type (including, but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Blowdown volumes smaller than 1.42 Sm^3 are exempt from reporting under paragraph (g) of this section.
- (3) Calculate the total annual venting emissions for each equipment type using Equation 360-11:

$$E_{s,n} = N \times \left(V_v \left[\frac{(273.15 + T_s)P_a}{(273.15 + T_a)P_s} \right] - V_v \times C \right)$$

Equation 360-11

Where:

$E_{s,n}$	=	Annual natural gas venting emissions at standard conditions from blowdowns (m^3).
N	=	Number of repetitive blowdowns for each equipment type of a unique volume in calendar year.
V_v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, compressors and vessels) between isolation valves (m^3).
C	=	Purge factor that is 1 if the equipment is not purged or zero if the equipment is purged using non-GHG gases.
T_s	=	Temperature at standard conditions ($^{\circ}\text{C}$).
T_a	=	Temperature at actual conditions in the blowdown equipment chamber ($^{\circ}\text{C}$).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at actual conditions in the blowdown equipment chamber (kPa).

- (4) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.

- (5) Blowdowns that are directed to flares use the WCI.363(k) Flare stacks calculation method rather than WCI.363(g) Blowdown vent stacks calculation method.

(h) Onshore production and processing storage tanks. For emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore natural gas processing facilities, calculate annual CH₄ and CO₂ emissions as specified in paragraphs (h)(1) or (h)(2). For atmospheric storage tanks vented to flares, use the calculation methodology for flare stacks in paragraph (k) of this section. Storage tanks equipped with vapour recovery units (VRU) are exempt from the requirements of this paragraph.

- (1) CH₄ and CO₂ emissions at storage tank batteries where the oil production rate is 10 barrels per day or greater shall be calculated using Equation 360-12.

$$E_{GHGi} = GOR \times PR \times \left(\frac{1}{MVC} \right) \times MW_g \times MF_i \times 0.001$$

Equation 360-12

Where:

E _{GHGi}	=	Annual emissions of greenhouse gas <i>i</i> (CO ₂ or CH ₄) (tonnes/year).
GOR	=	Gas Oil Ratio (m ³ gas/m ³ oil).
PR	=	Oil production rate (m ³ /measurement period).
MVC	=	Molar volume conversion.
MW _g	=	Molecular weight of the gas (kg/kg-mole).
MF _i	=	Mass fraction of greenhouse gas <i>i</i> (CO ₂ or CH ₄) in gas (kg <i>i</i> /kg gas).
0.01	=	Conversion factor (tonnes/kg).

- (2) Methane and carbon dioxide emissions at storage tank batteries where the oil production rate is less than 10 barrels per day shall calculate methane emissions using the latest software package for E&P Tank. A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

- (i) Separator oil composition.
- (ii) Separator temperature.
- (iii) Separator pressure.
- (iv) Sales oil API gravity.
- (v) Sales oil production rate.
- (vi) Sales oil Reid vapour pressure.
- (vii) Ambient air temperature.
- (viii) Ambient air pressure.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(j) so long as the method is as accurate or

more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

- (i) Well testing venting and flaring. Calculate CH₄, CO₂, and N₂O (when flared) well testing venting and flaring emissions as follows:

- (1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.
- (2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (i)(2) of this section to determine GOR:
 - (i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
 - (ii) Or you may use an industry standard practice as described in WCI.364(b).
- (3) Estimate venting emissions using Equation 360-13.

$$E_{a,n} = GOR \times FR \times D$$

Equation 360-13

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from well testing ambient conditions (m ³).
GOR	=	Gas to oil ratio (m ³ gas/m ³ oil); oil here refers to hydrocarbon liquids produced of all API gravities.
FR	=	Flow rate (m ³ oil/day) for the well being tested.
D	=	Number of days during the year the well is tested.

- (4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
 - (5) Calculate both CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
 - (6) Calculate emissions from well testing to flares as follows:
 - (i) Use the well testing emissions volume and gas composition as determined in paragraphs (i)(1) through (3) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing emissions from the flare.
- (j) Associated gas venting and flaring. Calculate associated gas venting and flaring emissions not in conjunction with well testing (refer to section (i): Well testing venting and flaring) as follows:

- (1) Determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same field shall be used.
- (2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (j)(2) of this section to determine GOR:
 - (i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.
 - (ii) Or you may use an industry standard practice as described in WCI.364(b).
- (3) Estimate venting emissions using the Equation 360-14.

$$E_{a,n} = GOR \times V$$

Equation 360-14

Where:

$E_{a,n}$	=	Annual volumetric natural gas emissions from associated gas venting under ambient conditions (m^3).
GOR	=	Gas to oil ratio (m^3 gas/ m^3 oil); oil here refers to hydrocarbon liquids produced of all API gravities.
V	=	Total volume of oil produced for the calendar year during which associated gas was flared or vented (m^3 oil/year)..

- (4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (5) Calculate both CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (6) Calculate emissions from associated natural gas to flares as follows:
 - (i) Use the associated natural gas volume and gas composition as determined in paragraph (j)(1) through (4) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine associated gas emissions from the flare.

(k) Flare stacks. Calculate CO₂, CH₄, and N₂O emissions from a flare stack as follows:

- (1) If there is a continuous flow measurement device on the flare, measured flow volumes must be used to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If there is not a continuous flow measurement device on the flare, a flow measuring device can be installed on the flare or engineering calculations based on process knowledge, company records, and best available data can be used.
- (2) If there is a continuous gas composition analyzer on the gas to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas

composition analyzer on the gas to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:

- (i) For onshore natural gas production, determine natural gas composition using (r)(2)(i) of this section.
 - (ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities.
 - (iii) When the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus, and mixed light hydrocarbons then use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.
- (3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.
 - (4) Calculate GHG volumetric emissions at actual conditions using Equations 360-15, 360-16, 360-17, and 360-18.

$$E_{a,CH_4} = V_a \times (1 - \eta) \times X_{CH_4} \quad \text{Equation 360-15}$$

$$E_{a,CO_2}(\text{noncombusted}) = V_a \times X_{CO_2} \quad \text{Equation 360-16}$$

$$E_{a,CO_2}(\text{combusted}) = \sum_j \eta \times V_a \times Y_j \times R_j \quad \text{Equation 360-17}$$

$$E_{a,CO_2}(\text{total}) = E_{a,CO_2}(\text{combusted}) + E_{a,CO_2}(\text{noncombusted}) \quad \text{Equation 360-18}$$

Where:

E_{a,CH_4}	=	Contribution of annual noncombusted CH ₄ emissions from flare stack under ambient conditions (m ³).
$E_{a,CO_2}(\text{noncombusted})$	=	Contribution of annual CO ₂ emissions from CO ₂ in the inlet gas passing through the flare noncombusted under ambient conditions (m ³).
$E_{a,CO_2}(\text{combusted})$	=	Contribution of annual CO ₂ emissions from combustion from flare stack under ambient conditions (m ³).
V_a	=	Volume of natural gas sent to flare during the year (m ³).
η	=	Percent of natural gas combusted by flare (default is 98 percent). For gas sent to an unlit flare, η is zero.
X_i	=	Mole fraction of GHG i in gas to the flare.

Y_j	=	Mole fraction of natural gas hydrocarbon constituents j (i.e., methane, ethane, propane, butane, and pentanes plus).
R_j	=	Number of carbon atoms in the natural gas hydrocarbon constituent j (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus).

- (5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (6) Calculate both CH₄ and CO₂ mass emissions from volumetric CH₄ and CO₂ emissions using calculation in paragraph (s) of this section.
- (7) Calculate N₂O emissions using Equation 360-19.

$$E_{N_2O} = Fuel \times HHV \times EF \times 0.001$$

Equation 360-19

Where:

E_{N_2O}	=	Annual N ₂ O emissions from the combustion of a particular type of fuel (tonnes).
$Fuel$	=	Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV	=	High heat value of the fuel from paragraphs (k)(7)(i), (k)(7)(ii) or (k)(7)(iii) of this section (units must be consistent with Fuel).
EF	=	Use 9.52×10^{-5} kg N ₂ O/GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (i) For fuels listed in Table 20-1, use the provided default HHV in the table.
- (ii) For field gas or process vent gas, use 4.579×10^{-2} GJ/m³ for HHV.
- (iii) For fuels not listed in Table 20-1 and not field gas or process vent gas, you must use the methodology set forth in the Tier 2 methodology described in WCI.20 to determine HHV.

- (8) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in WCI.363. Where gas to be flared is manifolded from multiple sources in WCI.363 to a common flare, report all flaring emissions under WCI.363(k).

- (l) Centrifugal compressor venting. Calculate emissions from centrifugal compressor venting as follows:*

- (1) For each centrifugal compressor determine the volume of vapours from wet seal oil degassing tank sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as, but not limited to, a vane anemometer according to methods set forth in WCI.364(b).
- (2) Estimate annual emissions using meter flow measurement using Equation 360-20.

$$E_{a,i} = MT \times t \times M_i \times (1 - B)$$

Equation 360-20

Where:

$E_{a,i}$	=	Annual volumetric emissions of GHG i (either CH ₄ or CO ₂) at ambient conditions.
MT	=	Meter reading of gas emissions per unit time.
t	=	Total time the compressor associated with the wet seal(s) is operational in the reporting year.
M_i	=	Mole percent of GHG i in the degassing vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
B	=	Percentage of centrifugal compressor vent gas sent to vapour recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapour recovery system and the amount of vent gas that is directed to the fuel gas system.

- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT variable in place of actual metered values for centrifugal compressors that are isolated for extended periods of time and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.
- (4) Calculate CH₄ and CO₂ volumetric emissions at standard conditions using paragraph (q) of this section.
- (5) Calculate both CH₄ and CO₂ mass emissions from volumetric emissions using calculations in paragraph (s) of this section.
- (6) Calculate emissions from degassing vent vapours to flares as follows:
 - (i) Use the degassing vent vapour volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.
 - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine degassing vent vapour emissions from the flare.
- (7) Emissions from dry seal centrifugal compressor vents, blow down valve leakage and unit isolation valve leakage to open ended vented are covered under WCI.353(x).

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(o) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(m) Reciprocating compressor venting. Calculate annual CH₄ and CO₂ emissions from all reciprocating compressor vents as follows, except as specified in paragraph (m)(8), following*. Where venting emissions are sent to a common flare, calculate emissions using WCI.362(k).

- (1) Estimate annual emissions using the flow measurement in (m)(2) or (m)(3) below and Equation 360-21.

$$E_{a,i,m} = MT \times t \times M_i$$

Equation 360-21

Where:

$E_{a,i,m}$	=	Annual volumetric emissions of GHG i (either CH ₄ or CO ₂) at ambient conditions.
MT	=	Measured volumetric gas emissions (m ³ /hour) under ambient conditions.
t	=	Total time the compressor is in the mode for which $E_{a,i,m}$ is being calculated, in the calendar year (hours).
M_i	=	Mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.

- (2) If the reciprocating rod packing and blowdown vent is connected to an open ended vent line then use one of the following two methods to calculate emissions.
- (i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in WCI.364(c) and (d).
 - (ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents, unit isolation valves, and blowdown valves according to methods set forth in WCI.364(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in WCI.364(a).
- (3) If the rod packing case is not equipped with a vent line use the following method to estimate emissions:
- (i) Use the methods described in WCI.364(a) to conduct a progressive sample leak detection of fugitive equipment leaks from the packing case into an open distance

- piece, or from the compressor crank case breather cap or vent with a closed distance piece.
- (ii) Measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in WCI.364(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (m)(8) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents.
- (i) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.
 - (ii) Operating mode, reciprocating rod packing emissions.
 - (iii) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.
- (A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode
- (5) Calculate CH₄ and CO₂ volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (6) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.
- (7) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.
- (i) Adjust the emissions estimated in paragraphs (f)(1) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.
- (8) Onshore petroleum and natural gas production shall calculate emissions from well-site reciprocating compressors as follows using Equation 360-22:

$$E_{s,i} = Count \times EF_i$$

Equation 360-22

Where:

- $E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors (m³/year).
- Count = Total number of well-site reciprocating compressors for the reporter.

EF_i = Emission factor for GHG i (either CH_4 or O_2). Use 272.7 Sm^3 /year per compressor for CH_4 and 15.2 Sm^3 /year per compressor for CO_2 at 20 °C and 1 atmosphere or 268.5 Sm^3 /year per compressor for CH_4 and 14.9 Sm^3 /year per compressor for CO_2 . at 15.6 °C and 1 atmosphere, or as adjusted for different temperatures.

* For 2011 calendar year emissions only, an operator may use other equations and methods as presented by the EPA in 40 CFR Part 98.233(p) so long as the method is as accurate or more accurate as that presented here for the specific emission source in question and the appropriate regulator is notified of the choice.

(n) Leak detection and leaker emission factors. Existing legislative or regulatory requirements or progressive sampling methods described in WCI.364(a) must be used to conduct a leak detection of fugitive equipment leaks from all sources listed in §WCI.362(d)(9). This paragraph (n) applies to emissions sources in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight need to be reported instead under WCI.364(x). Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (n) and need to be reported under WCI.364(x).

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate emissions using Equation 360-23 for each source with fugitive equipment leaks.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t_x$$

Equation 360-23

Where:

$E_{s,i}$ = Annual total volumetric emissions of GHG i (either CH_4 or CO_2), at standard conditions from each fugitive equipment leak source (m^3).

Count = Total number of this type of emission source found to be leaking during time t_x .

EF_s = Leaker volumetric emission factor for specific sources listed in 40 CFR Part 98 Table W-2, relevant Canadian Association of Petroleum Producers (CAPP) methodology manuals, if available or facility/company-specific emission factors used (as converted for use in Equation 360-23).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i (either CH_4 or CO_2) in the total hydrocarbon of the feed natural gas.

t_x = Total time the component was found leaking and operational (hours). If one leak detection survey is conducted, assume the component was leaking from the start of the year until the leak was repaired and then zero for the remainder of the year. If the leak was not repaired, assume the component was leaking for the entire year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey, or the beginning of the calendar year. For the last leak detection

survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year or until the component was repaired and then zero until the end of the year.

- (1) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (s) of this section.
 - (2) Onshore natural gas processing facilities shall use the appropriate default volumetric leaker emission factors listed in 40 CFR Part 98 Table W-2 (as converted to metric) or relevant Canadian Association of Petroleum Producer methodology manuals, if available for fugitive equipment leaks detected from valves; connectors; open ended lines; pressure relief valves; and meters.
- (o) Population count and emission factors. This paragraph applies to emissions sources listed in §WCI.362(c)(3), (c)(16), (c)(17), (c)(21), and (d)(8) on streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas content less than 10 percent CH₄ plus CO₂ by weight do not need to be reported. Tubing systems equal or less than one half inch diameter are exempt from the requirements of paragraph (o) of this section and instead need to be reported under WCI.363(x). Calculate emissions from all sources listed in this paragraph using Equation 360-24.

$$E_{s,i} = Count \times EF_s \times GHG_i \times t$$

Equation 360-24

Where:

$E_{s,i}$	=	Annual total mass emissions of GHG i (CH ₄ or CO ₂) at standard conditions from each fugitive source (tonnes/year).
Count	=	Total number of this type of emission source at the facility. Average component counts by major equipment pieces for Canada from Table 360-3 may be used as appropriate. If facility or company specific major equipment count data that meet or exceed the quality of the relevant default count data are available, they must be used instead. To ensure proper use of kg/km units in emission factors for underground gathering pipelines, the length of the installed underground pipeline should be used in place of count.
EF_s	=	Population mass emission factor for specific major equipment sources listed in Table 360-1 or Table 360-2. The direction on the use of Tables 360-1 and 360-2 provided prior to these tables must be followed.
GHG_i	=	Mass fraction of GHG i (CH ₄ or CO ₂) in produced natural gas or feed natural gas.
t	=	Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (hours).

- (1) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 360-1 or 360-2 for fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other equipment. Where facilities conduct EOR operations the emissions factors listed in Table 360-1 or Table 360-2 shall be used to estimate all streams of gases, including the recycle CO₂ stream. The component count can be determined using either of the methodologies described in this paragraph (o)(1). The same methodology must be used for the entire calendar year..

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table 360-3 of this section.

(B) Multiply major equipment counts by the average component counts listed in Table 360-3 of this section for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor Table 360-1 or Table 360-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Tables 360-1 or 360-2.

- (2) Onshore natural gas processing facilities shall use the appropriate default population emission factor listed in Table 360-1, Table 360-2 or from CAPP methodology manuals for fugitive equipment leaks from gathering pipelines.

(p) Offshore petroleum and natural gas production facilities in both provincial and federal waters.

[reserved]

(q) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2) determined by engineering estimate based on best available data unless otherwise specified.

- (1) Calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure (15 °C and 1 atmosphere in Canada) natural gas using Equation 360-25 of this section.

$$E_{s,n} = \frac{E_{a,n} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-25

Where:

$E_{s,n}$	=	Natural gas volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,n}$	=	Natural gas volumetric emissions at ambient conditions (m^3).
T_s	=	Temperature at standard conditions ($^{\circ}C$).
T_a	=	Temperature at actual emission conditions ($^{\circ}C$).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

- (2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using Equation 360-26.

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Equation 360-26

Where:

$E_{s,i}$	=	GHG i volumetric emissions at standard temperature and pressure (STP) conditions (m^3).
$E_{a,i}$	=	GHG i volumetric emissions at actual conditions (m^3).
T_s	=	Temperature at standard conditions ($^{\circ}C$).
T_a	=	Temperature at actual emission conditions ($^{\circ}C$).
P_s	=	Absolute pressure at standard conditions (kPa).
P_a	=	Absolute pressure at ambient conditions (kPa).

- (r) GHG volumetric emissions. Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (r)(1) and (2) of this section determined by engineering estimate based on best available data unless otherwise specified.

- (1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 360-27.

$$E_{s,i} = E_{s,n} \times M_i$$

Equation 360-27

Where:

$E_{s,i}$	=	GHG i (CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$	=	Natural gas volumetric emissions at standard conditions.

M_i = Mole fraction of GHG i in the natural gas.

- (2) For Equation 360-27 of this section, the mole fraction, M_i , shall be the annual average mole fraction for each facility, as specified in paragraphs (r)(2)(i) and (ii) of this section.
- (i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use these values in calculating emissions. If you do not have a continuous gas composition analyzer, then either the known composition for the company or operator for the specific field from Table 360-4 (or as referenced in Table 360-4 (as Table 360-4 is under development)), or the methods set forth in WCI.364(b) must be used.
 - (ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. If you have a continuous gas composition analyzer on feed natural gas, you must use these values in calculating emissions. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole percent. If you do not have a continuous gas composition analyzer, then the known composition for the company or operator for the specific field must be used as taken according to methods set forth in WCI.364(b).

- (s) GHG mass emissions. Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions by converting the GHG volumetric emissions into mass emissions using Equation 360-28.

$$Mass_{s,i} = E_{s,i} \times \rho_i \times GWP_i \times 0.001$$

Equation 360-28

Where:

$Mass_{s,i}$ = GHG i (either CH₄ or CO₂) mass emissions at standard conditions (tonnes CO₂e).
 $E_{s,i}$ = GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions (m³).
 ρ_i = Density of GHG i , (1.861 kg/m³ for CO₂ and 0.678 kg/m³ for CH₄)*.
 GWP_i = Global warming potential of GHG i (1 for CO₂ and 21 for CH₄, and 310 for N₂O).0.001 = Conversion factor from kilograms to tonnes.

* gas densities calculated using the 12th edition of the Gas Processors Suppliers Association Engineering Data Book.

- (t) EOR injection pump blowdown. Calculate pump blowdown emissions as follows:

- (1) Calculate the total volume in cubic meters (including, but not limited to, pipelines, manifolds and vessels) between isolation valves.
- (2) Retain logs of the number of blowdowns per reporting period.
- (3) Calculate the total annual venting emissions using Equation 360-29.

$$Mass_{c,i} = N \times V_v \times R_c \times GHG_i \times 0.001$$

Equation 360-29

Where:

Mass _{c,i}	=	Annual EOR injection gas venting emissions at critical conditions <i>c</i> from blowdowns (tonnes).
N	=	Number of blowdowns for the equipment in reporting year.
V _v	=	Total volume of blowdown equipment chambers (including, but not limited to, pipelines, manifolds and vessels) between isolation valves (m ³).
R _c	=	Density of critical phase EOR injection gas (kg/m ³). Use an appropriate standard method published by a consensus-based standards organization if such a method exists or otherwise an industry standard to determine density of super critical EOR injection gas.
GHG _i	=	Mass fraction of GHG _i in critical phase injection gas.
0.001	=	Conversion factor from kilograms to tonnes.

(u) [Reserved]

(v) [Reserved]

(w) Field gas or process vent gas combustion. For combustion units that combust field gas or process vent gas or any blend of field gas and process vent gas, you must comply with following requirements:

- (1) Measure the higher heating value of the field gas or process vent gas annually.
- (2) If the measured higher heating value is equal to or greater than 36.3 MJ/m³ and less than 40.98 MJ/m³, then calculate the CO₂, CH₄, and N₂O emissions using the methods in WCI.20 (General Stationary Combustion Sources) following the methods required for pipeline quality natural gas.
- (3) If the measured higher heating value is less than 36.3 MJ/m³ or greater than 40.98 MJ/m³, then calculate the CO₂ and CH₄ emissions using either the Tier 3 or Tier 4 methodology in WCI.20 (General Stationary Combustion Sources). Sampling, analysis

and measurement requirements (including for gas composition) required for WCI.360 in WCI.025(f) apply in place of those indicated for Equation 20-7. For N₂O, use 4.579×10^{-2} GJ/m³ for HHV.

- (x) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in WCI.363 must be calculated by methodologies consistent with those presented here, the 2009 API Compendium¹, or other similar resource documents.

§ WCI.364 Sampling, Analysis, and Measurement Requirements

Instruments used for sampling, analysis and measurement must be operated and calibrated according to legislative, manufacturer's, or other written specifications or requirements. All sampling, analysis and measurement must be conducted only by, or under the direct supervision of individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

- (a) (i) If a documented leak detection or integrity management standard or requirement that is required by legislation or regulation such as CSA Z662-07 Oil & Gas Pipeline Systems or the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) is used, the documented standard or requirement must be followed – including service schedules for different components and/or facilities - with reporting as required for input to the calculation methods herein.
- (ii) If there is no such legal requirement, then progressive sampling is required using one of the methods outlined below in combination with best industry practices for use of the method– including service schedules for different components - to determine the count of leaks (and time leaking) required in WCI.363(m), (n), and (o), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions for the 2011 and 2012 calendar years, with subsequent sampling determined based random or spot sampling modelling or measurement of leaks under normal operating conditions. A minimum of 18 months and a maximum of 36 months is allowed between surveys. This interval is determined based on whether there are indications of leaks. If a leak found and immediately repaired, the existing schedule may be maintained.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode during a reporting period.

- (1) Optical gas imaging instrument. Use an optical gas imaging instrument for fugitive equipment leaks detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2) *Alternative work practice for monitoring equipment leaks* (or per relevant standard in Canada). In addition, the optical gas imaging instrument must be operated to image the source types required by this proposed reporting rule in accordance with

¹ American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

the instrument manufacturer's operating parameters. The optical gas imaging instrument must comply with the following requirements:

- (i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in the relevant best practices. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.
 - (ii) Provide a date and time stamp for video records of every monitoring event.
 - (2) Bubble tests
 - (3) Portable organic vapour analyzer. Use a portable organic vapour analyzer in accordance with US EPA Method 21 or as outlined in the CAPP Best Management Practices for Fugitive Emissions
 - (4) Other methods as outlined in the CAPP Best Management Practices for Fugitive Emissions or similar standard CAPP Methodologies (as amended from time to time) may be used as necessary for operational circumstances. Other methods that are deemed to be technically sound based on an engineering assessment may also be used as necessary provided that sufficient documentation as to the method used, test results, its reliability, and accuracy is maintained and updated at regular intervals.
- (b) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations shall use measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year using an appropriate standard method published by a consensus standards organization such as ASTM International, Canadian Standards Association (CSA), American National Standards Institute (ANSI), the relevant provincial or national oil and gas regulator, Measurement Canada, Canadian Association of Petroleum Producers (CAPP), Canadian Gas Association (CGA), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If a consensus based standard is not available, industry standard practices such as manufacturer instructions must be used.
- (c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and hydrogen sulphide levels are such that it is safe to handle and can capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.
- (1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.
 - (2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

- (3) Estimate natural gas volumetric emissions at standard conditions using calculations in WCI.363(q).
 - (4) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).
- (d) Use a high volume sampler to measure emissions within the capacity of the instrument.
- (1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
 - (2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source, then anti-static wraps or other aids must be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
 - (3) Estimate CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using the calculations in WCI.363(r) and (s).
 - (4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH₄ by using calibrated gas samples and by following manufacturer's instructions for calibration.
- (e) Peng Robinson Equation of State means the equation of state defined by Equation 360-30 of this section.

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \quad \text{Equation 360-30}$$

Where:

p	=	Absolute pressure.
R	=	Universal gas constant.
T	=	Absolute temperature.
V_m	=	Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 R T_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2 \right) \left(1 - \sqrt{\frac{T}{T_c}} \right) \right)^2$$

Where:

ω = Acentric factor of the species.
 T_c = Critical temperature.
 P_c = Critical pressure.

(f) Onshore Production and Processing Storage Tanks.

- (1) A pressurized sample of produced liquids shall be collected from the separator at a location upstream of the storage tank. This point would typically be at the final separation device before produced oil transitions from separator outlet pressure to atmospheric pressure and enters a production storage tank. This may require the installation of a sampling valve at the appropriate location. Sampling protocol specific to the collection of separator liquid can be found in the following publications:
 - (i) Appendix C Sampling Protocol section (page 33) of the *E&P TANK Version 2.0 User's Manual*.
 - (ii) Wyoming Department of Environmental Quality Air Quality Division guidance document *Oil and Gas Production Facilities, Chapter 6, Section 2 Permitting Guidance (revised August 2001), Appendix D Sampling and Analysis of Hydrocarbon Liquids and Natural Gas*.
 - (iii) Gas Processors Association (GPA) Standard 2174-93, *Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography*.
- (2) The sample collection pressure shall be determined at the time of collection and again prior to processing in the laboratory to insure that sample integrity has been maintained. Liquid temperature should also be determined and recorded at the time of collection.
- (3) Sampling and laboratory based determination of the gas to oil ratio GOR shall be conducted at prescribed intervals and at a time when operational parameters of the storage tank battery are representative and consistent with normal operating conditions. Sampling shall be annual for oil production rates between 1.75 and 15.9 m³/day, semi-annual for oil production rates between 15.9 and 79.5 m³/day, and quarterly for oil production rates greater than 79.5 m³/day.
- (4) An additional sample shall be collected and analyzed if:
 - (i) The oil production rate at the storage tank battery changes more than 20 percent for time periods in excess of one week (e.g., in cases where a well or wells feeding the storage tank battery stop or start production).
 - (ii) The separator operating pressures change by more than 10 percent.
- (5) The volume (barrels) of liquid produced during the sampling interval shall be determined using a calibrated liquid meter or industry standard method to an accuracy of $\pm 5\%$.

§ WCI.365 *Procedures for Estimating Missing Data*

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the estimation or measurement activity for those sources must be repeated as soon as possible, including in the subsequent reporting year if missing data are not discovered until after December 31 of the reporting year, until valid data for reporting is obtained. Data developed and/or collected in a subsequent reporting year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data that are continuously monitored or measured (for example flow meters), or for missing temperature and pressure data, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§ WCI.366 *Definitions*

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

Acid gas means hydrogen sulphide (H₂S) and carbon dioxide (CO₂) contaminants that are separated from sour natural gas by an acid gas removal unit.

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

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

Blowdown vent stack emissions mean natural gas and/or CO₂ released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

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

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO₂ by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO₂ from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO₂ released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor venting emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO₂. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

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

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO₂ by drawing in low pressure natural gas or CO₂ and discharging significantly higher pressure natural gas or CO₂.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions..

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

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

Dehydrator vent emissions means natural gas and CO₂ released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

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

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

E&P Tank means the most current version of an exploration and production field tank emissions equilibrium program that estimates flashing, working and standing losses of hydrocarbons, including methane, from produced crude oil and gas condensate. Equal or successors to E&P Tank Version 2.0 for Windows Software. Copyright (C) 1996-1999 by The American Petroleum Institute and The Gas Research Institute.

Engineering estimation, for the purposes of WCI.350 and WCI.360 means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

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

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

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

Field means the surface area underlaid or appearing to be underlaid by one or more pools, and the subsurface regions vertically beneath that surface area;

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

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.

Fugitive equipment leak means the those fugitive emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas gathering/booster stations mean centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

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

High-bleed pneumatic devices are automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

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

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

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

Low-bleed pneumatic devices mean automated control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.

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

Offshore means seaward of the terrestrial borders of the Canada, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of Canada.

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

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

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

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

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

Reciprocating compressor means a piece of equipment that increases the pressure of a gas stream by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of the compressed gas stream that escapes to the atmosphere.

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

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

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

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

Separator means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulphide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Sweet gas is natural gas with low concentrations of hydrogen sulphide (H₂S) and/or carbon dioxide (CO₂) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

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

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

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

Vapourization unit means a process unit that performs controlled heat input to vapourize LNG to supply transmission and distribution pipelines or consumers with natural gas.

Vented emissions means the same as defined in the relevant greenhouse gas reporting regulation, including but not limited to process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices), but not including stationary combustion flue gas.

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

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

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

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

Directions for the use of Tables 360-1 to 360-2

(a) Starting with 2013 calendar year emissions, for each component listed in the Tables 360-1 to 360-2 or otherwise required by the quantification method referencing Tables 360-1 and 360-2:

- (i) If statistically valid facility specific emission factors for a component type are available or can safely or reasonably developed, they must be used.
- (ii) If facility specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors, if they can be safely or reasonably developed.

If statistically valid facility or company specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default tables 360-1 to 360-2 may be used. Equipment or facilities that have low temporal utilization (e.g. equipment such as booster stations used only sporadically during a year) may continue to use the default tables.

(b) For 2011 and 2012 calendar year emissions:

- (i) An operator may use the default factors specified below, company or facility-specific emissions factors (if such emission factors are available). If the default factors in Tables 360-1 to 360-2 are used, an explanation as to why company or facility specific emission factors are cannot be used must be provided to the jurisdiction.
- (c) If a facility-specific emission factor has been used in a previous reporting year, it must continue to be used until updated. If a company-specific emission factor has been used in a previous reporting year, it must continue to be used until updated or a facility-specific emission factor is used in its place
- (d) Any changes from facility-specific factors to company-specific or the defaults in Tables 360-1 to 360-2, or from company specific factors to the defaults in Tables 360-1 to 360-2 must be approved by the jurisdiction and substantiated by evidence that the new approach is more accurate for the facility or facilities in question.
- (e) If an emission factor required by the quantification method referencing Tables 360-1 and 360-2 is not provided in the tables, emission factors from either the U.S. EPA 40 CFR Part 98.230 Tables W-1A or W-2 or the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H₂S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004 may be used (as converted for use in the relevant equation).
- (f) Documentation on the method used to update the emission factors, input data, sampling methodology and other relevant information must be kept by the operator and provided to the jurisdiction or verifier upon request.

- (g) All emission factors or data collection for emission factors must be developed using CAPP (CAPP) or Canadian Gas Association (CGA) standard methods, or other methods if CAPP or CGA methods are not available or applicable. Facility and company-specific emission factors must be updated at a minimum on a three year cycle, with the first update to the original facility and company-specific emission factors for the 2016 reporting period, at the latest.
- (h) Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.
- (i) The default emission factors provided in Tables 360-1 to 360-2 below are published emission factors for Canada as of the 2010 calendar year. The factors will be updated every 3-5 years based on new data, methods and statistically valid samples of the entire industry and developed in collaboration with industry groups.

Table 360-1. Additional Natural Gas Facility Average Emission Factors

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas	2.81E-06
Valves - light liquid	3.52E-06
Valves - gas/vapor - all	2.46E-06
Valves - gas/vapor - sour	1.16E-06
Valves - gas/vapor - sweet	2.81E-06
Connectors - fuel gas	8.18E-07
Connectors - light liquid	5.51E-07
Connectors - gas/vapor - all	7.06E-07
Connectors - gas/vapor - sour	1.36E-07
Connectors - gas/vapor - sweet	8.18E-07
Control valves - fuel gas	1.62E-05
Control valves - light liquid	1.77E-05
Control valves - gas/vapor - all	1.46E-05
Control valves - gas/vapor - sour	9.64E-06
Control valves - gas/vapor - sweet	1.62E-05
Pressure relief valves - fuel gas and gas/vapor	1.70E-05
Pressure relief valves - light liquid	5.39E-06
Pressure regulators - fuel gas and gas/vapor	8.11E-06
Pressure regulators - gas/vapor - sour	4.72E-08
Pressure regulators - gas/vapor - sweet	8.39E-06
Open ended lines - fuel gas	4.67E-04
Open ended lines - light liquid	1.83E-05
Open ended lines - gas/vapor - all	4.27E-04
Open ended lines - gas/vapor - sour	1.89E-04
Open ended lines - gas/vapor - sweet	4.67E-04
Chemical injection pumps - fuel gas and gas/vapor	1.62E-04

Compressor seals - fuel gas and gas/vapor	7.13E-04
Compressor starts - fuel gas	6.34E-06
Controllers - fuel gas and gas/vapor	2.38E-04
Pump seals - light liquid	2.32E-05

Footnotes and Sources:

* American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-21 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Table 360-2. Additional Oil Facility Average Emission Factors

Component – Service	Emission Factor, tonnes THC/component-hr
Valves - fuel gas and gas/vapor	1.51E-06
Valves - heavy liquid	8.40E-09
Valves - light liquid	1.21E-06
Connectors - fuel gas and gas/vapor	2.46E-06
Connectors - heavy liquid	7.50E-09
Connectors - light liquid	1.90E-07
Control valves - fuel gas and gas/vapor	1.46E-05
Control valves - light liquid	1.75E-05
Pressure relief valves - fuel gas and gas/vapor	1.63E-05
Pressure relief valves - heavy liquid	3.20E-08
Pressure relief valves - light liquid	7.50E-05
Pressure regulators - fuel gas and gas/vapor	6.68E-06
Open ended lines - fuel gas and gas/vapor	3.08E-04
Open ended lines - light liquid	3.73E-06
Chemical injection pumps - fuel gas and gas/vapor	1.62E-04
Compressor seals - fuel gas and gas/vapor	8.05E-04
Compressor starts - fuel gas	6.34E-06
Controllers - fuel gas and gas/vapor	2.38E-04
Pump seals - heavy liquid	3.20E-08
Pump seals - light liquid	2.32E-05

Footnotes and Sources:

* American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*. August 2009. Table 6-22 (from Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.)

Table 360-3. Default Major Equipment Component Counts for Canada

(for further average component counts required by the methods in this quantification method, please refer to the Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004, as updated from time to time.)

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
ABSORPTION (LEAN OIL)	Gas/Vapour	200	4	0	82	0	0	0	0
ABSORPTION (LEAN OIL)	Light Liquid	46	0	1	21	0	0	0	0
ADSORPTION	Gas/Vapour	243	8	0	63	0	0	0	0
ADSORPTION	Light Liquid	0	0	0	2	0	0	0	0
AERIAL COOLER	Gas/Vapour	2937	0	0	19	0	0	0	0
BULLET	Gas/Vapour	39	1	0	15	0	0	0	0
BULLET	Light Liquid	60	1	0	27	0	0	0	0
CENTRIFUGAL COMPRESSOR	Gas/Vapour	495	1	0	32	4	2	0	0
CENTRIFUGAL COMPRESSOR	Light Liquid	11	0	0	5	0	0	0	0
COLD BED ABSORPTION	Gas/Vapour	134	1	0	31	0	0	0	0
COLD BED ABSORPTION	Light Liquid	12	0	0	7	0	0	0	0
DE-BUTANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-BUTANIZER	Light Liquid	208	0	2	80	0	0	0	0
DEEP GAS WELL (>1000 M)	Gas/Vapour	19	0	0	6	0	0	0	0
DEEP GAS WELL (>1000 M)	Light Liquid	1	0	0	0	0	0	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Gas/Vapour	241	10	0	131	0	2	0	0
DEEPCUT (WITH TURBO-EXPANDER)	Light Liquid	386	0	2	121	0	0	0	0
DE-ETHANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-ETHANIZER	Light Liquid	208	0	2	80	0	0	0	0
DE-PROPANIZER	Gas/Vapour	177	6	0	79	0	0	0	0
DE-PROPANIZER	Light Liquid	208	0	2	80	0	0	0	0
DESICCANT	Gas/Vapour	100	1	0	24	0	0	0	0
DESICCANT	Light Liquid	14	0	0	7	0	0	0	0
FLARE KNOCK OUT DRUM	Gas/Vapour	26	0	0	3	0	0	0	0
FLARE KNOCK OUT DRUM	Light Liquid	20	0	0	1	0	0	0	0
FLOW LINE HEADER TIE-IN	Gas/Vapour	0	0	0	0	1	0	0	0
FLOW LINE HEADER TIE-IN	Heavy Liquid	10	0	0	3	0	0	0	0

Final Essential Requirements of Mandatory Reporting

Amended for Canadian Harmonization

December 17, 2010

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MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
FLOW LINE HEADER TIE-IN	Light Liquid	10	0	0	3	0	0	0	0
FLOWING OIL WELL	Heavy Liquid	57	0	0	14	0	0	0	0
FLOWING OIL WELL	Light Liquid	57	0	0	14	0	0	0	0
FRACTIONATION	Gas/Vapour	241	10	0	131	0	0	0	0
FRACTIONATION	Light Liquid	386	0	2	121	0	0	0	0
GAS BOOT	Gas/Vapour	37	0	0	2	0	0	0	0
GAS BOOT	Light Liquid	40	0	0	2	0	0	0	0
GAS INJECTION WELL	Gas/Vapour	19	0	0	6	0	0	0	0
GAS LINE HEADER TIE-IN	Gas/Vapour	10	0	0	3	1	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Gas/Vapour	702	2	0	60	3	0	0	0
GAS SWEETENING: AMINE/SULFINOL	Light Liquid	3	0	1	1	0	0	0	0
GAS SWEETENING: IRON SPONGE	Gas/Vapour	134	1	0	31	0	0	0	0
GAS SWEETENING: IRON SPONGE	Heavy Liquid	0	0	0	7	0	0	0	0
GAS SWEETENING: IRON SPONGE	Light Liquid	12	0	0	7	0	0	0	0
GAS-FIRED UNIT HEATER	Fuel Gas	10	0	0	1	0	0	0	0
GLYCOL DEHYDRATOR	Gas/Vapour	100	1	0	24	0	0	0	0
GLYCOL DEHYDRATOR	Light Liquid	14	0	0	7	0	0	0	0
GROUP TREATER	Gas/Vapour	178	0	0	21	1	0	0	0
GROUP TREATER	Heavy Liquid	56	0	0	17	1	0	0	0
GROUP TREATER	Light Liquid	56	0	0	17	1	0	0	0
HEAT EXCHANGER - GAS	Gas/Vapour	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Heavy Liquid	13	0	0	7	0	0	0	0
HEAT EXCHANGER - LIQUID	Light Liquid	13	0	0	7	0	0	0	0
HEAVY OIL WELL - PRIMARY	Heavy Liquid	22	0	0	9	0	0	0	0
HEAVY OIL WELL - THERMAL	Heavy Liquid	22	0	0	9	0	0	0	0
INCINERATOR	Gas/Vapour	10	0	0	1	0	0	0	0
INLET SEPARATOR	Gas/Vapour	66	0	0	11	0	0	0	0
INLET SEPARATOR	Heavy Liquid	41	0	0	11	0	0	0	0
INLET SEPARATOR	Light Liquid	41	0	0	11	0	0	0	0
JOULE-THOMSON REFRIGERATION	Gas/Vapour	79	0	0	19	0	0	0	0
JOULE-THOMSON REFRIGERATION	Light Liquid	41	0	0	11	0	0	0	0
LINE HEATER	Fuel Gas	145	0	0	10	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
LINE HEATER	Gas/Vapour	40	1	0	10	0	0	0	0
METERING	Gas/Vapour	70	2	0	24	0	0	0	0
MOLECULAR SIEVE	Gas/Vapour	100	1	0	24	0	0	0	0
MOLECULAR SIEVE	Light Liquid	14	0	0	7	0	0	0	0
OIL PUMP	Heavy Liquid	10	0	1	3	0	0	0	0
OIL PUMP	Light Liquid	10	0	1	3	0	0	0	0
PIG TRAP	Gas/Vapour	11	0	0	3	0	0	0	0
PIPELINE HEADER	Gas/Vapour	0	0	0	0	1	0	0	0
PIPELINE HEADER	Heavy Liquid	10	0	0	3	0	0	0	0
PIPELINE HEADER	Light Liquid	10	0	0	3	0	0	0	0
POP TANK	Heavy Liquid	24	0	1	10	0	0	0	0
POP TANK	Light Liquid	24	0	1	10	0	0	0	0
PROCESS BOILER	Fuel Gas	25	0	0	2	0	0	0	0
PRODUCTION TANK	Gas/Vapour	2	0	0	1	0	0	0	0
PRODUCTION TANK	Heavy Liquid	24	0	1	0	0	0	0	0
PRODUCTION TANK	Light Liquid	24	0	1	0	0	0	0	0
PUMP JACK	Heavy Liquid	57	0	1	14	0	0	0	0
PUMP JACK	Light Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Heavy Liquid	57	0	1	14	0	0	0	0
PUMPING OIL WELL	Light Liquid	57	0	1	14	0	0	0	0
RECIPROCATING COMPRESSOR	Fuel Gas	145	0	0	6	0	0	0	0
RECIPROCATING COMPRESSOR	Gas/Vapour	275	0	0	20	4	2	0	0
RECIPROCATING COMPRESSOR	Light Liquid	2	0	0	1	0	0	0	0
REFRIGERATION	Gas/Vapour	170	2	0	65	0	2	0	0
REFRIGERATION	Light Liquid	31	0	2	13	0	0	0	0
REGULATOR STATION	Gas/Vapour	24	0	0	10	0	0	0	0
SALT BATH HEATER	Fuel Gas	25	0	0	2	0	0	0	0
SCREW COMP CS TO FLARE	Gas/Vapour	228	2	0	35	0	0	1	2
SCREW COMPRESSOR	Gas/Vapour	228	2	0	35	0	1	1	2
SHALLOW GAS WELL (<1000 M)	Gas/Vapour	10	0	0	3	0	0	0	0
STABILIZATION	Gas/Vapour	80	3	0	20	0	0	0	0
STABILIZATION	Light Liquid	247	0	1	77	0	0	0	0

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Vales	Pump Seals	Valves	Open-Ended Lines	Compressor Seals	Control Valves	Pressure Regulators
SULPHUR RECOVERY	Gas/Vapour	100	0	0	10	0	0	0	0
TAIL GAS CLEANUP	Gas/Vapour	25	0	0	5	0	0	0	0
TANK FARM	Heavy Liquid	190	0	6	94	0	0	0	0
TANK FARM	Light Liquid	190	0	6	94	0	0	0	0
TANK HEATER	Fuel Gas	10	0	0	2	0	0	0	0
TANK HEATER	Heavy Liquid	2	0	0	0	0	0	0	0
TANK HEATER	Light Liquid	2	0	0	0	0	0	0	0
TEST SEPARATOR	Gas/Vapour	49	1	0	15	0	0	0	0
TEST SEPARATOR	Heavy Liquid	25	0	0	15	0	0	0	0
TEST SEPARATOR	Light Liquid	25	0	0	15	0	0	0	0
TEST TREATER	Gas/Vapour	178	1	0	21	1	0	0	0
TEST TREATER	Heavy Liquid	56	0	0	17	0	0	0	0
TEST TREATER	Light Liquid	56	0	0	17	0	0	0	0
TURBO EXPANDER	Gas/Vapour	123	6	0	48	0	2	0	0
TURBO EXPANDER	Light Liquid	9	0	0	2	0	0	0	0
UNIT HEATER	Fuel Gas	10	0	0	2	0	0	0	0
UNIT HEATER	Light Liquid	2	0	0	0	0	0	0	0
UTILITY BOILER	Fuel Gas	25	0	0	2	0	0	0	0
VAPOUR RECOVERY COMPRESSOR	Gas/Vapour	25	0	0	5	0	1	0	0
VAPOUR RECOVERY COMPRESSOR	Light Liquid	2	0	0	3	0	0	0	0
WATER PUMP	Light Liquid	5	0	1	2	0	0	0	0

Footnotes and Sources:

* Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004. Table 4.1,

TABLE 360-4 –DEFAULT EMISSION FACTORS FOR SPECIFIC FIELDS

Table 360-4 is currently being developed and is likely to be incorporated in WCI.360 in the future. In the interim, please refer to default emission factors for specific fields within the jurisdiction as posted by the regulator during the reporting year.