



# Standards for Quantification, Reporting, and Verification of Greenhouse Gas Emissions

Government of Nova Scotia  
Nova Scotia Environment

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## DEFINITIONS

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# Definitions

“ <b>Barrel</b> ” ( <b>bbl</b> ) means a volume equal to 159 litres or 42 U.S. gallons.
“ <b>Biogenic emissions</b> ” means the emissions from the combustion of biomass.
“ <b>Biofuel</b> ” means a fuel that contains carbon originating from a biomass.
“ <b>Bottoming cycle plant</b> ” means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.
“ <b>Calcination</b> ” means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide
“ <b>Calcine</b> ” means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.
“ <b>Calcined byproduct/waste type</b> ” means lime kiln dust and other partially calcined materials and co-products generated during the production of quicklime.
“ <b>CAS number</b> ” means the Chemical Abstracts Service Registry number.
“ <b>Catalytic cracking</b> ” means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.
“ <b>Catalytic reforming</b> ” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.
“ <b>Cogeneration unit</b> ” means a stationary fuel combustion device which simultaneously generates multiple forms of useful energy (electrical and thermal – e.g., steam, hot water) that is (i) used by the person where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.
“ <b>Cogeneration system</b> ” 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.
“ <b>Coke</b> ” means a solid residue consisting mainly of carbon, which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulphur bituminous coal (coal coke).
“ <b>Coke breeze</b> ” means a solid consisting mainly of carbon, which is derived from the production of metallurgical coke produced in the iron and steel industry.
“ <b>Combustion emissions</b> ” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.
“ <b>Continuous emissions monitoring system (CEMS)</b> ” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.
“ <b>Consensus Based Standards Organization</b> ” means American Society for Testing and Materials (ASTM International), the American Gas Association (AGA), the American Petroleum Institute (API), the CSA Group, the Gas Processors Association (GPA), the Canadian General Standards Board (CGSB), the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), Environment Canada, United State Environmental Protection Agency (EPA), British Standard Institution (BSI), or Measurement Canada.
“ <b>Distillate fuel oil</b> ” means fuels oils No. 1, 2 and 4 and diesel fuel.
“ <b>dSm3</b> ” means dry standard cubic metre – the amount of gas that would occupy a volume of one cubic metre if free of combined water at standard conditions.
“ <b>Electricity generating unit</b> ” (“ <b>EGU</b> ”) 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 includes cogeneration (combined heat and power) units. This source does not include portable or emergency generators less than 10 megawatt (MW) in nameplate generating capacity.

<b>“Emergency generator”</b> 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 person 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.
<b>“Emergency equipment”</b> means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.
<b>“Emission factors” (“EF”)</b> means the rate at which a pollutant is released into the atmosphere (or captured) as a result of some process activity or unit throughput.
<b>“Engineering estimates”</b> means estimating emissions from engineering principles and judgment, using knowledge of the chemical and physical processes involved, the design features of the source, and an understanding of the applicable physical and chemical laws.
<b>“Equipment leak”</b> means fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.
<b>“Fluid catalytic cracking unit” (“FCCU”)</b> means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.
<b>“Fluid coking”</b> means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.
<b>“Fuel analytical data”</b> means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.
<b>“Fuel gas system”</b> means a system of compressors, piping, knock-out pots, mix drums, sulphur removal units and flaring units that collects fuel gas from one or more sources for treatment, and transports it to a stationary combustion unit.
<b>“General stationary combustion”</b> means the combustion of solid, liquid or gaseous fuel for the purposes of producing electricity, generating steam or providing useful heat or energy for industrial, commercial, or institutional use; or providing energy for pollution control; or reducing the volume of waste by removing combustible matter.
<b>“GHG”</b> means greenhouse gases.
<b>“Global warming potential (GWP)”</b> is a measure of relative of amount of heat-trapping potential of a greenhouse gas. GWP is calculated as the ratio of the time-integrated radiative forcing (i.e., the amount of heat-trapping potential, measured in units of power per unit of area, e.g., watts per square metre) that would result from the emission of 1 kg of a given greenhouse gas to that from the emission of 1 kg of carbon dioxide.
<b>“High heat value” (“HHV”)</b> means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel.
<b>“Hydrogen plant”</b> means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.
<b>“Industrial process emissions”</b> means releases from an industrial process that involves a chemical or physical reaction other than combustion, and the purpose of which is not to produce useful heat or work. This does not include venting from hydrogen production associated with fossil fuel production and processing.
<b>“Kiln”</b> means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of lime and other products, and which includes any associated preheater or precalciner devices.

<p><b>“Lime kiln dust” (“LKD”)</b> means lime dust produced in the course of production of quick lime. LKD may be captured and contained in particulate matter (PM) emission control devices.</p>
<p><b>“Lime type”</b> means three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:</p> <ul style="list-style-type: none"><li>• High calcium quicklime, which is derived from limestone containing 0 to 5 per cent magnesium carbonate.</li><li>• Magnesium quicklime, which is derived from limestone containing 5 to 35 per cent magnesium carbonate.</li><li>• Dolomitic quicklime, which is derived from limestone containing 35 to 46 per cent magnesium carbonate.</li></ul>
<p><b>“Liquefied petroleum gas” (LPG)</b> means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.</p>
<p><b>“Low heat content gas”</b> means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.</p>
<p><b>“Low Heat Value” (LHV)</b> means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.</p>
<p><b>“Mass balance”</b> means the application of the law of conservation of mass to a facility, process or piece of equipment to determine emissions based on the difference in the input and output of a unit operation, where the accumulation and depletion of a substance are included in the calculations.</p>
<p><b>“Measurement uncertainty”</b> means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.</p>
<p><b>“Nameplate generating capacity”</b> means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).</p>
<p><b>“Net emissions”</b> means the total of GHG emissions from all sources for which calculation methods are documented in this Standard less the carbon dioxide emissions from the combustion of biomass. Net emissions are used to establish the threshold for calculating and reporting annual GHG emissions to the Government of Nova Scotia.</p>
<p><b>“Net power generated”</b> means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value includes internal consumption of electricity for the purposes of a production process, as well as including power put on the grid.</p>
<p><b>“Non-calcined calcium oxide”</b> means calcium oxide that remains in the lime or LKD in the form of calcium carbonate (<math>\text{CaCO}_3</math>).</p>
<p><b>“Owner”</b> means the person(s) that own a facility.</p>
<p><b>“Operator”</b> means the person(s) that operate a facility.</p>
<p><b>“Pipeline quality natural gas”</b> means natural gas having a high heat value equal to or greater than 36.3 MJ/m<sup>3</sup> or less than 40.98 MJ/m<sup>3</sup>, and which is at least ninety per cent methane by volume, and which is less than five per cent carbon dioxide by volume.</p>
<p><b>“Portable”</b> 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:</p> <ul style="list-style-type: none"><li>• The equipment is attached to a foundation.</li><li>• The equipment or a replacement resides at the same location for more than 12 consecutive months.</li><li>• 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. The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.</li></ul>
<p><b>“Prime mover”</b> means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.</p>
<p><b>“Process”</b> means the intentional or unintentional reactions between substances or their transformation, including, but not limited to: the chemical or electrolytic reduction of metal ores; the thermal decomposition of substances; and the formation of substances for use as product or feedstock.</p>

<b>“Process emissions”</b> means the emissions from industrial processes (e.g., hydrogen production) involving chemical or physical transformations other than fuel combustion. Examples are: the calcination of carbonates in a kiln during lime production; the oxidation of methane in a hydrogen production process; and calcination of heated carbonates contained, which result in the release of process CO <sub>2</sub> emissions to the atmosphere as process emissions. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment from which the “process emissions” are generated.
<b>“Process vent”</b> means an opening where a gas stream is continuously or periodically discharged during normal operation.
<b>“Purge gas”</b> means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or used to provide sufficient exit velocity to prevent regressive flame travel back into the flare header.
<b>“Quicklime”</b> means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone or other highly calcareous materials such as aragonite, chalk, coral, marble and shell.
<b>“Refinery fuel gas”</b> means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.
<b>“Rm3”</b> means reference cubic metre - the amount of gas that would occupy a volume of one cubic metre under standard or specified reference temperature and pressure conditions.
<b>“Standard conditions”</b> means either a temperature of 15 degrees Celsius and a pressure of 101.325 kPa. unless otherwise stated or required in the standard quantification, testing or analytical methods.
<b>“Standard Temperature and Pressure”</b> has the same meaning as standard conditions.
<b>“STP”</b> means Standard Temperate and Pressure.
<b>“Sm3”</b> means standard cubic metre - the amount of gas that would occupy a volume of one cubic metre under standard conditions.
<b>“Steam reforming”</b> means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.
<b>“Still gas”</b> has the same meaning as “Refinery Fuel Gas”
<b>“Sulphur recovery unit” (“SRU”)</b> means a process unit that recovers elemental sulphur from gases that contain reduced sulphur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulphur dioxide and hydrogen sulfide.
<b>“Supplemental firing”</b> means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.
<b>“Topping cycle plant”</b> 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.
<b>“Useful thermal output”</b> means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.
<b>“Wastewater separator”</b> means equipment used to separate oils and water from locations downstream of process drains.

## Acronyms and Abbreviations

ASTM	American Standards for Testing and Materials International
Btu	British thermal units
CCEE	Climate Change and Energy Efficiency
CH <sub>4</sub>	Methane
CO <sub>2</sub>	Carbon dioxide
CO <sub>2e</sub>	Carbon dioxide equivalent
GHG	Greenhouse gas(es)
GJ	Gigajoule
GWP	Global warming potential
h, hr	Hour
HFC	Hydrofluorocarbon
HHV	Higher Heating Value
IP	Industrial process
IPCC	Intergovernmental Panel on Climate Change
ISAE	International Standard on Assurance Engagements
ISO	International Organization for Standardization
J	Joule
kg	Kilogram
kJ	Kilojoule
kt	Kilotonne
LHV	Lower heating value
MM	Million
MWh	Megawatt-hour
N <sub>2</sub> O	Nitrous oxide
N/A	Not applicable
NAICS	North American Industry Classification System
NCASI	National Council for Air and Stream Improvement
NGCC	Natural gas combined cycle
psia	Pounds per square inch absolute
PFC	Perfluorocarbon
SF <sub>6</sub>	Sulphur hexafluoride
t	Metric tonnes
TAPPI	Technical Association of the Pulp and Paper Industry
WCI	Western Climate Initiative Inc.

# 1. Introduction

## 1.1 Disclaimer

This Standard is not a substitute for legal requirements. Users should consult the *Environment Act* and *Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulations*. In the event there is a discrepancy between this standard and the Act or the Regulations, the Act and Regulations will prevail.

## 1.2 Background

On October 26, 2017, Bill No. 15, *An Act to Amend Chapter 1 of the Acts of 1994-95, the Environment Act*, was passed in the Nova Scotia General Assembly. This Act provides for the establishment of a greenhouse gas emissions cap-and-trade program to satisfy the requirement under the Pan-Canadian Framework on Clean Growth and Climate Change that every province and territory of Canada establish a mechanism for pricing carbon. The Act is available at [http://nslegislature.ca/legc/bills/63rd\\_1st/3rd\\_read/b015.htm](http://nslegislature.ca/legc/bills/63rd_1st/3rd_read/b015.htm)

The *Quantification, Reporting and Verification of Greenhouse Gas Emissions Regulations* (The Regulation) are implemented pursuant to section 112M of the Act. Among other provisions, the *Regulations* define who is required to report and verify, reporting requirements, including timelines and items to be contained within GHG reports to be submitted, verification requirements, including timelines and items to be contained in the verification reports, requirements for verification bodies, and requirements for records retention.

This document provides guidance that is similar to that contained in comparable guidelines prepared by other Canadian provinces, including Ontario, British Columbia and Quebec. The Western Climate Initiative (WCI) guidance is aligned with the guidance provided in this document. Furthermore, the guidance provided in this document is similar to the guidance provided by Environment and Climate Change Canada<sup>1</sup>, and as such is generally consistent with reporting requirements under the Federal “Greenhouse Gas Emissions Reporting Program”.<sup>2</sup>

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<sup>1</sup> Environment and Climate Change, Sector-Specific Guidance Manuals, <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=07B0E55A-1>

<sup>2</sup> Environment and Climate Change Canada, Facility Greenhouse Gas Reporting: Greenhouse Gas Emissions Reporting Program. <http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=040E378D-1>

## **2. General Guidance and Requirements**

### **2.1 Introduction**

This section provides general guidance and instructions related to calculating and reporting annual greenhouse gas emissions.

Where the Regulation requires the use of standard quantification methods to quantify greenhouse gas emissions from an activity, those standard quantification methods are set out in this standard.

The Regulation also provides for the use of best alternative quantification. The table in section 2.2 of this standard sets out these best alternative quantification methods.

Section 3.1 of the standard lists technical reference documents referred to within the standard quantification methods.

### **2.2 Alternative Calculation Methods**

Person(s) that own or operate a facility and Natural Gas Distributors may identify one or more GHG emissions sources for which they may quantify using methods other than the standard quantification methods set out in this Standard, if the total amount of all GHG (expressed as CO<sub>2</sub>e) quantified using the methods that are not set out in the Standard does not exceed the lesser of:

- (a) three per cent (3%) of the total facility CO<sub>2</sub>e generated from all sources identified in this Standard; and
- (b) 20,000 tonnes per year.

Petroleum Product Suppliers must use the standard quantification methods set out in this standard.

Where the Regulation provides for the use of a best alternative quantification method, the person required to report pursuant to the regulation shall use the latest version of one of the following methods.

Best Alternative Quantification Method
1. U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP
2. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use
3. Environment Canada, Sector Specific Protocols and Guidance Manuals, posted on the Environment Canada website

4. CO <sub>2</sub> Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision— National Lime Association
5. 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), by Clearstone Engineering.,
6. American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009
7. CO <sub>2</sub> Accounting and Reporting Standard for the Cement Industry, June 2005, Version 2.0, World Business Council for Sustainable Development
8. Calculation tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills – Version 1.1, ICFPA/NCASI

## 2.3 Consistency Requirement

Person(s) that calculate emissions and submit a GHG report should select one calculation method for each emission source and continue to use that method for all subsequent GHG reports, unless by using another method the accuracy of the quantified emissions is improved and is approved by the Minister. Changes in methodology should be communicated in the GHG report and corrections or adjustments to previous year estimates should be calculated and reported to the Government of Nova Scotia.

## 2.4 Standard Reporting Form

This Standard is accompanied with a standard reporting form, which is available in a spreadsheet format from the Government of Nova Scotia at the following website: <https://climatechange.novascotia.ca>

The standard reporting form must be used by all persons required to submit a GHG report. Submitting a standard reporting form is considered as submitting a GHG report.

## 2.5 Reporting Deadline

Person(s) whose GHG emissions exceed the reporting threshold in 2018, are required to submit a GHG report to the Government of Nova Scotia no later than:

- **June 1, 2019;** and
- May 1 of each subsequent calendar year for previous calendar year emissions.

## **2.6 Verification Requirements**

Person(s) that are required to submit a GHG report in the province with GHG emissions exceeding the verification threshold for the calendar year 2017 and each year thereafter is required to have their calculated and reported emissions verified to a reasonable level of assurance (as defined in the Regulation) by a qualified third-party verifier. Qualified verifiers may include professional engineers, certified accountants, or a verification body (e.g., company) that has been accredited under ISO 14065:2013 - Greenhouse gases - Requirements for Greenhouse Gas Validation and Verification Bodies for Use in Accreditation or Other Forms of Recognition; Second Edition.

Third-party verification statements and verification reports, signed by the verifier(s), must be submitted to the Government of Nova Scotia no later than:

- **September 1, 2019** for the year 2017 emissions; and
- May 1 of each subsequent calendar year for previous year emissions.

## **3. Technical References and Standards**

### **3.1 Technical References**

Table 3-1 lists technical references that contain emission factors, conversion factors, and other useful information for calculating GHG emissions. Some of these resources are referenced in this Standard and may be specified for the calculation methodology required. These technical references may be modified from time to time, and as such, it is the responsibility of the person(s) calculating annual emissions to obtain and use the most up-to-date versions of the documents.

**Table 3-1: Reference Quantification Methodology Resources**

<b>Quantification Method Resources</b>	<b>Link</b>
Alberta Environment and Parks (2009) Technical Guidance for Completing Baseline Emissions Intensity Applications: Specified Gas Emitters Regulation	<a href="http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6">http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6</a>
Alberta Environment and Parks (January 2013) Technical Guidance for Greenhouse Gas Verification at Reasonable Level Assurance	<a href="http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6">http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6</a>
Alberta Environment and Parks, (2014) Technical Guidance for Completing Specified Gas Compliance Reports Version 7.0 (and accompanying quantification methodology protocols)	<a href="http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6">http://environment.gov.ab.ca/info/listing.asp?page=9&amp;categoryid=6</a>
American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009	<a href="http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf">http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf</a>
American Society of Mechanical Engineers, ASME Performance Test Codes (For Power Production,	<a href="https://www.asme.org/about-asme/standards/performance-test-codes">https://www.asme.org/about-asme/standards/performance-test-codes</a>

Quantification Method Resources	Link
Combustion and Heat Transfer, Fluid Handling, and Emissions)	
B.C. Ministry of Environment (December 2009) B.C. Reporting Regulation - Methodology Manual, Version 1 (Superseded by Western Climate Initiative Inc. methodologies.)	<a href="http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/one-window/methodology-manual.pdf">http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/one-window/methodology-manual.pdf</a>
B.C. Ministry of the Environment (2011) British Columbia Reporting Regulation Standard	<a href="http://www2.gov.bc.ca/gov/content/environment/climate-change/stakeholder-support/reporting-regulation">http://www2.gov.bc.ca/gov/content/environment/climate-change/stakeholder-support/reporting-regulation</a>
Environment Canada, Sector Specific Protocols and Guidance Manuals	<a href="https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&amp;n=07B0E55A-1">https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&amp;n=07B0E55A-1</a>
Environment Canada (2004) Base Metals Smelting/Refining - Guidance Manual for Estimating Greenhouse Gas Emissions	<a href="http://publications.gc.ca/site/eng/257700/publication.html">http://publications.gc.ca/site/eng/257700/publication.html</a>
Environment Canada (2004) Lime Production - Guidance Manual for Estimating Greenhouse Gas Emissions	<a href="http://publications.gc.ca/site/eng/257572/publication.html">http://publications.gc.ca/site/eng/257572/publication.html</a>
Environment Canada (2004) Metal mining: a guidance manual for estimating greenhouse gas emissions.	<a href="http://publications.gc.ca/collections/Collection/En49-2-9-2E.pdf">http://publications.gc.ca/collections/Collection/En49-2-9-2E.pdf</a>
Environment Canada (2008) Sulphur hexafluoride (SF6) Emission Estimation and Reporting Protocol for Electric Utilities	<a href="http://publications.gc.ca/collections/collection_2013/ec/En4-229-2008-eng.pdf">http://publications.gc.ca/collections/collection_2013/ec/En4-229-2008-eng.pdf</a>
Environment Canada (October 2014) Facility Greenhouse Gas Emissions Reporting: Technical Guidance on Reporting Greenhouse Gas Emissions	<a href="https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&amp;n=47B640C5-1">https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&amp;n=47B640C5-1</a>
Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7	<a href="https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf">https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf</a>
European Union, Monitoring & Reporting Guidelines for EU Emission Trading System, Annex I - General Guidelines.	<a href="http://ec.europa.eu/clima/policies/ets/monitoring/documentat ion_en.htm">http://ec.europa.eu/clima/policies/ets/monitoring/documentat ion_en.htm</a>
Intergovernmental Panel on Climate Change (2006) 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use	<a href="http://www.ipcc-nngip.iges.or.jp/public/2006gl/vol3.html">http://www.ipcc-nngip.iges.or.jp/public/2006gl/vol3.html</a>
Intergovernmental Panel on Climate Change (IPCC) (2006) IPCC Guidelines for National Greenhouse Gas Inventories	<a href="http://www.ipcc-nngip.iges.or.jp/public/2006gl/">http://www.ipcc-nngip.iges.or.jp/public/2006gl/</a>
Intergovernmental Panel on Climate Change (IPCC), Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories	<a href="http://www.ipcc-nngip.iges.or.jp/public/2006gl/">http://www.ipcc-nngip.iges.or.jp/public/2006gl/</a>
International Standards Organization, ISO 14064-1, Greenhouse Gases: Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals.	<a href="http://www.iso.org/iso/">http://www.iso.org/iso/</a>
International Standards Organization, ISO 14064-2, Greenhouse gases -- Part 2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements	<a href="http://www.iso.org/iso/">http://www.iso.org/iso/</a>
International Standards Organization, ISO 14064-3: Greenhouse gases — Part 3: Specification with Guidance for the Validation and Verification of Greenhouse Gas Assertions) by a qualified third-party verifier.	<a href="http://www.iso.org/iso/">http://www.iso.org/iso/</a>

Quantification Method Resources	Link
International Standards Organization, ISO 14065:2013 - Greenhouse gases - Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition; Second Edition.	<a href="http://www.iso.org/iso/">http://www.iso.org/iso/</a>
Mining Association of Canada (2015) Energy and GHG Emissions Management Reference Guide	<a href="http://mining.ca/documents/energy-and-ghg-emissions-management-reference-guide">http://mining.ca/documents/energy-and-ghg-emissions-management-reference-guide</a>
NCASI (2005) Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills (Version 1.1 updated)	<a href="http://www.ncasi.org/Programs/Climate-Change/Resources/GHG-Calculation-Tools/Index.aspx">http://www.ncasi.org/Programs/Climate-Change/Resources/GHG-Calculation-Tools/Index.aspx</a>
Ontario Ministry of the Environment (December 2015) Guideline for Greenhouse Gas Emissions Reporting	<a href="http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2015/012-4549_d_Guideline.pdf">http://www.downloads.ene.gov.on.ca/envision/env_reg/er/documents/2015/012-4549_d_Guideline.pdf</a>
Quebec Ministry of the Environment (October 2015) Regulation Respecting Mandatory Reporting of Certain Emissions of Contaminants into the Atmosphere	<a href="http://www.mddelcc.gouv.qc.ca/publications/lois-reglementen.htm">http://www.mddelcc.gouv.qc.ca/publications/lois-reglementen.htm</a>
The Climate Registry (TCR), (May 2008) General Reporting Protocol (GRP) for the Voluntary Reporting Program	<a href="https://www.theclimateregistry.org/tools-resources/reporting-protocols/general-reporting-protocol/">https://www.theclimateregistry.org/tools-resources/reporting-protocols/general-reporting-protocol/</a>
U.S. EPA, (2009) Technical Support Document for the Lime Manufacturing Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases	<a href="http://www.epa.gov/sites/production/files/2015-07/documents/subpartstd.pdf">http://www.epa.gov/sites/production/files/2015-07/documents/subpartstd.pdf</a>
U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP	<a href="http://www.epa.gov/ghreporting">http://www.epa.gov/ghreporting</a>
U.S. EPA, Mandatory Reporting of Greenhouse Gases, Final Rule, 40 CFR 98, Oct. 30, 2009.	<a href="http://www.epa.gov/sites/production/files/2014-09/documents/ghg-mrr-finalrule.pdf">http://www.epa.gov/sites/production/files/2014-09/documents/ghg-mrr-finalrule.pdf</a>
Western Climate Initiative (December 21, 2011) Final Essential Requirements of Mandatory Reporting 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions	<a href="http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/">http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/</a>
Western Climate Initiative (November 12, 2010) Harmonization of Essential Requirements for Mandatory Reporting in U.S. Jurisdictions with EPA Mandatory Reporting Rule.	<a href="http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/">http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/</a>
Western Climate Initiative (WCI) (2010) Final Harmonization of Essential Reporting Requirements in Canadian Jurisdictions (Quantification Methods)	<a href="http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/">http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/</a>
Western Climate Initiative (WCI) (2013) Revised Canadian Quantification Methods	<a href="http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/">http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/</a>
Western Climate Initiative (WCI), (2011) Final Essential Requirements for Mandatory Reporting, 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions	<a href="http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/">http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/</a>

Note: Some web links may not be current.

### 3.2 Technical Testing and Analytical Standards

Table 2 lists technical testing and analytical standards developed and published by consensus-based standards organizations, such as ASTM. These contain specific procedures for sampling, analyzing and calculating concentrations of carbon in materials, other elements, heating values and other input data required to develop GHG emissions estimates. Some of these standards are referenced in this Standard and may be specified for the required calculation methodology. Other or newly developed standards

that would result in more accurate calculations of a facility's GHG emissions might be relevant to a facility's fuels, raw materials, products, wastes and processes. Furthermore, these standards may be modified from time to time, and as such, it is the responsibility of the person(s) calculating annual emissions for the facility to obtain and use the most up-to-date and most appropriate standards available.

Where no appropriate standard is published by a consensus-based standards organization, the person(s) calculating facility emissions shall use an industry standard method, noting which methods have been used for the specific emission source calculations.

**Table 3-2: Technical Testing and Analytical Standards**

Reference Titles
ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime
ASTM D70 - Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)
ASTM D240 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre
ASTM D1298 - Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method
ASTM D1826 - Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre
ASTM D1945 - Standard Test Method for Analysis of Natural Gas by Gas Chromatography
ASTM D1946 - Standard Practice for Analysis of Reformed Gas by Gas Chromatography
ASTM D2013 - Standard Practice of Preparing Coal Samples for Analysis.
ASTM D2163 - Standard Test Method for Determination of Hydrocarbons in Liquefied Petroleum (LP) Gases and Propane/Propene Mixtures by Gas Chromatography
ASTM D2234/D2234M - Standard Practice for Collection of a Gross Sample of Coal
ASTM D2502 - Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements
ASTM D2503 - Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements
ASTM D2597 - Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography.
ASTM D3176 - Standard Practice for Ultimate Analysis of Coal and Coke.
ASTM D3238 - Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method
ASTM D3588 - Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels
ASTM D3682 - Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes.
ASTM D4057 - Standard Practice for Manual Sampling of Petroleum and Petroleum Products
ASTM D4177 - Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.
ASTM D4809 - Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)
ASTM D4891 - Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion
ASTM D5142 - 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
ASTM D5291 - Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants
ASTM D5373 - Standard Test Methods for Determination of Carbon, Hydrogen and Nitrogen in Analysis Samples of Coal and Carbon in Analysis Samples of Coal and Coke
ASTM D5468 - Standard Test Method for Gross Calorific and Ash Value of Waste Materials
ASTM D5580 - Standard Test Method for Determination of Benzene, Toluene, Ethylbenzene, p/m-Xylene, o-Xylene, C9 and Heavier Aromatics, and Total Aromatics in Finished Gasoline by Gas Chromatography
ASTM D5865 - Standard Test Method for Gross Calorific Value of Coal and Coke
ASTM D6348 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy
ASTM D6609 - Standard Guide for Part-Stream Sampling of Coal.

<b>Reference Titles</b>
ASTM D6866 - Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis
ASTM D6883 - Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles
ASTM D7430 - Standard Practice for Mechanical Sampling of Coal
ASTM D7459 - Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources
ASTM D7633 - Standard Test Method for Carbon Black Carbon Content
ASTM D7662 - Standard Test Method for Carbon Content in Carbon Black Feedstock Oils
ASTM E415 - Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry
ASTM E1019 - Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques
ASTM E1915 - Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials for Carbon, Sulfur, and Acid-Base Characteristics
ASTM E1941 - Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys by Combustion Analysis
ASTM UOP539 - Refinery Gas Analysis by Gas Chromatography
CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993)
Environment Canada, "Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 ("EPS 1/PG/7")
Gas Processors Association (GPA) 2261-00, Revised 2000 - Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.
Gas Processors Association (GPA) 2172:1996, Calculation of Gross Heating Value, Relative Density and Compressibility For Natural Gas Mixtures From Compositional Analysis
ISO 13909 - All Parts: Hard coal and coke -- Mechanical sampling
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)
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)
ISO 3170: Petroleum Liquids— Manual sampling.
ISO 3171: Petroleum Liquids— Automatic pipeline sampling.
National Lime Association, CO <sub>2</sub> Emissions Calculation Protocol for the Lime Industry, English Units Version.
U.S. EPA Method 320 (40 CFR part 63, Appendix A), Test Methods Pollutant Measurement Methods From Various Waste Media
U.S. EPA TANKS Version 4.09D, U.S. Environmental Protection Agency, October 2005
U.S. EPA AP 42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources

## **4. General Stationary Fuel Combustion**

### **4.1 Activity Definition**

Stationary fuel combustion emission sources are devices that combust solid, liquid, or gaseous fuel generally for the purpose of generating steam, producing electricity, 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, furnaces, and any other stationary combustion device that is not specifically addressed under the methods for another activity. Stationary fuel combustion includes the combustion of biomass fuels, although the CO<sub>2</sub> from biomass fuel combustion is reported separately from the CO<sub>2</sub> from fossil-fuel stationary combustion. The stationary fuel combustion activity does not include portable equipment, mobile vehicles, emergency generators, and emergency equipment (including emergency flares, explosives blasting).

### **4.2 Greenhouse Gas Reporting Requirements**

Except as noted in the previous paragraph, 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 CO<sub>2</sub> emissions for fossil fuels, reported by fuel type.
  - (2) Total CO<sub>2</sub> emissions for biomass, reported by fuel type.
  - (3) Total CH<sub>4</sub> emissions, reported by fuel type.
  - (4) Total N<sub>2</sub>O emissions, reported by fuel type.
- B. Annual fuel consumption:
  - (1) For gases, report in units of standard cubic metres.
  - (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 energy consumption:
  - (1) Energy input from 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)
  - (2) Energy input from 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)
- D. Fuel properties
  - (1) Weighted average high heat values of each fuel for measurement period if used to calculate CO<sub>2</sub> emissions.
  - (2) Annual steam in kilograms, for units that burn biomass fuels and generate steam, where Equation 4-3 and Equation 4-5 are used.

- (3) Periodic weighted average carbon content of each fuel, if used to calculate CO<sub>2</sub> emissions.
- E. Properties of recovered ash for solid fuels
  - (1) Weighted average carbon content of fly ash for the measurement period, related to solid fuel combustion where the ash is recovered, and **Equation 4-19** is used to compute CO<sub>2</sub> emissions
  - (2) Weighted average carbon content of bottom ash for the measurement period, related to solid fuel combustion where the ash is recovered, and **Equation 4-19** is used to compute CO<sub>2</sub> emissions.
  - (3) Annual total weight of fly ash and bottom ash in tonnes from all measurement periods recovered from solid fuel combustion where **Equation 4-19** is used.

## 4.3 Calculation of CO<sub>2</sub> emissions

For each fuel, calculate CO<sub>2</sub> mass emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in section 4.3.4 (CEMS). If a fuel or fuels is not listed in all of Table 4-1 through Table 4-8, 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 the sum of emissions from these fuels does not exceed 0.5% of total facility emissions. If the sum of emissions from these fuels exceeds 0.5% of total facility emissions, then calculate and report emissions from one or more of these fuels as needed so that the sum of emissions from the remaining unlisted fuels does not exceed 0.5% of total facility emissions.

The person should refer to section 4.3.5 “Use of the Four CO<sub>2</sub> Calculation Methodologies” regarding the requirements (conditions) and restrictions applicable to use of the calculation methodologies described below.

### 4.3.1 Calculation Methodology 1

Calculate the annual CO<sub>2</sub> mass emissions for each type of fuel by substituting a fuel-specific default CO<sub>2</sub> emission factor, a default high heat value, and the annual fuel consumption into **Equation 4-1** or **4-1a**:

**Equation 4-1:**

$$CO_2 = Fuel \times HHV_D \times EF_D \times 0.001$$

**Equation 4-1a:**

$$CO_2 = Fuel \times EF_{DP} \times 0.001$$

**Where:**

- CO<sub>2</sub> = Annual CO<sub>2</sub> 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 metres for gaseous fuel, or volume in kilolitres for liquid fuel).

$HHV_D$	= Default high heat value of the fuel, from Table 4-1 (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
$EF_D$	= Fuel-specific default energy-based CO <sub>2</sub> emission factor, from Table 4-3, Table 4-4, Table 4-6, or Table 4-8, as applicable (kg CO <sub>2</sub> /GJ).
$EF_{DP}$	= Fuel-specific default physical-based CO <sub>2</sub> emission factor, from Table 4-3 or Table 4-6 (kg CO <sub>2</sub> per tonne for solid fuel, kg CO <sub>2</sub> per kilolitre for liquid fuel, or kg CO <sub>2</sub> per cubic meter for gaseous fuel).
0.001	= Conversion factor from kilograms to tonnes.

### 4.3.2 Calculation Methodology 2

Calculate the annual CO<sub>2</sub> mass emissions using a default fuel-specific CO<sub>2</sub> emission factor, a high heat value measured by the operator or provided by the supplier, using **Equation 4-2**, except for emissions from the combustion of biomass fuels, for which the operator may instead elect to use the method shown in **Equation 4-3**:

- (a) For any type of fuel for which an emission factor is provided in Table 4-2, except biomass fuels when the operator elects to use the method in Section 4.3.2 paragraph (b), use **Equation 4-2**.

**Equation 4-2:**

$$CO_2 = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001$$

**Where:**

$CO_2$	= Annual CO <sub>2</sub> mass emissions for the specific fuel type (tonnes).
$n$	= Number of required heat content measurements for the year as specified in Section 4.5.
$Fuel_p$	= Mass or volume of the fuel combusted during the measurement period “ $p$ ” (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
$HHV_p$	= High heat value (measured or provided by supplier) of the fuel for the measurement period “ $p$ ” (GJ per tonne for solid fuel, GJ per bone-dry tonne biomass solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
$EF$	= Fuel-specific default CO <sub>2</sub> emission factor, from Table 4-2 (kg CO <sub>2</sub> /GJ).
0.001	= Conversion factor from kilograms to tonnes.

- (b) **Equation 4-3** of this section may also be used for any biomass solid fuel listed in Table 4-3 of this subpart provided that steam is generated by the unit. CO<sub>2</sub> emissions from biomass fuel combustion should be calculated and reported separately.

**Equation 4-3:**

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

**Where:**

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from biomass solid combustion (tonnes).  
Steam = Total mass of steam generated by biomass solid 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<sub>D</sub> = Default emission factor for biomass solid, from Table 4-3 or Table 4-8, as applicable (kg CO<sub>2</sub>/GJ). Site-specific emission factor determined through measurements may be used if updated no less often than every third year as provided in Section 4.5.1 paragraph (g)(2).  
0.001 = Conversion factor from kilograms to tonnes.

#### 4.3.3 Calculation Methodology 3

Calculate the annual CO<sub>2</sub> mass emissions for each fuel by using measured fuel carbon content or molar fraction (for gaseous fuels only), measured by the operator or provided by the supplier, and the quantity of fuel combusted.

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

**Equation 4-4:**

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

**Where:**

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from the combustion of the specific solid fuel (tonnes).  
n = Number of carbon content determinations for the year.  
Fuel<sub>i</sub> = Mass of the solid fuel combusted in measurement period "i" (tonnes)  
CC<sub>i</sub> = Carbon content of the solid fuel, from the fuel analysis results for measurement period "i" (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).  
3.664 = Ratio of molecular weights, CO<sub>2</sub> (44.01) to carbon (12.01).

- (b) For biomass fuels which is combusted in units for producing steam, either use either **Equation 4-5** or **Equation 4-3**: above. **Equation 4-5** of this section may also be used for any solid biomass fuel listed in Table 4-3 provided that steam is generated by the unit.

**Equation 4-5:**

$$CO_2 = Steam \times EF_m \times 0.001$$

**Where:**

- $CO_2$  = Annual  $CO_2$  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).  
 $EF_m$  = Measured emission factor for biomass solid fuel or municipal solid waste, as applicable (kg  $CO_2$ /tonne steam), adjusted no less often than every third year.  
0.001 = Conversion factor from kilograms to tonnes.

(c) For a liquid fuel, use **Equation 4-6** of this section:

**Equation 4-6:**

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

**Where:**

- $CO_2$  = Annual  $CO_2$  mass emissions from the combustion of the specific liquid fuel (tonnes)  
 $n$  = Number of required carbon content determinations for the year, as specified in Section 4.5.  
 $Fuel_i$  = 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,  $CO_2$  (44.01) to carbon (12.01).

(d) For a gaseous fuel, use **Equation 4-7** of this section. Alternatively, use **Equation 4-7a** and **Equation 4-7b** together, which provide an easier calculation method for the same result.

**Equation 4-7:**

$$CO_2 = \sum_{i=1}^n Fuel_i \times CC_i \times 3.664 \times 0.001$$

**Where:**

- $CO_2$  = Annual  $CO_2$  mass emissions from combustion of the specific gaseous fuel (tonnes).  
 $n$  = Number of required carbon content determinations for the year, as specified in Section 4.5.

- Fuel<sub>i</sub> = Fuel combusted in measurement period “*i*” (a day or month, as applicable) (volume of the gaseous fuel in Rm<sup>3</sup> at reference temperature and pressure conditions as used by the facility, or mass of the gaseous fuel in kg if a mass flow meter is used).  
 CC<sub>i</sub> = Average carbon content of the gaseous fuel, from the fuel analysis results for the measurement period “*i*” (day or month, as applicable) (kg C per Rm<sup>3</sup> or kg C per kg of fuel if a mass flow meter is used).  
 3.664 = Ratio of molecular weights, CO<sub>2</sub> (44.01) to carbon (12.01).  
 0.001 = Conversion factor from kilograms to tonnes.

#### **Equation 4-7a:**

$$\text{CO}_2 = \sum_{i=1}^n (\text{Fuel}_i \times \text{EF}_{\text{CO}_2,i}) \times 0.001$$

#### **Where:**

- CO<sub>2</sub> = Annual CO<sub>2</sub> mass emissions from combustion of the specific gaseous fuel (tonnes).  
 n = Number of required carbon content determinations for the year, as specified in Section 4.5.  
 Fuel<sub>i</sub> = Fuel combusted in measurement period “*i*” (a day or month, as applicable) (volume of the gaseous fuel in Rm<sup>3</sup> at reference temperature and pressure conditions as used by the facility, or mass of the gaseous fuel in kg if a mass flow meter is used).  
 EF<sub>CO<sub>2</sub>,i</sub> = CO<sub>2</sub> emission factor of the gaseous fuel, calculated using **Equation 4-7b** (below) from the fuel analysis results for the measurement period “*i*” (day or month, as applicable) (kg C per Rm<sup>3</sup>).  
 0.001 = Conversion factor from kilograms to tonnes.

#### **Equation 4-7b:**

$$\text{EF}_{\text{CO}_2,i} = \sum_{j=1}^J (\text{MF}_{j,i} \times \text{NC}_j) \times \frac{44.01}{23.645}$$

#### **Where:**

- EF<sub>CO<sub>2</sub>,i</sub> = CO<sub>2</sub> emission factor of the gaseous fuel for the measurement period “*i*” (day or month, as applicable) (kg CO<sub>2</sub> per Rm<sup>3</sup>).  
 J = Number of measured components, *j*, in gaseous fuel;  
 MF<sub>j,i</sub> = Molar fraction of component *j* in gaseous fuel (including CO<sub>2</sub>, sulphides, nitrogen, and other inert gases), for measurement period *i*, such that the sum of all molar fractions = 1.0  
 NC<sub>j</sub> = Number of carbons contained in fuel component *j*, including CO<sub>2</sub> and all other gas components (e.g. CH<sub>4</sub>=1, C<sub>2</sub>H<sub>6</sub>=2, C<sub>3</sub>H<sub>8</sub>=3, ..., C<sub>7</sub>H<sub>16</sub>=7, CO<sub>2</sub>=1, N<sub>2</sub>=0, H<sub>2</sub>S=0);  
 44.01 = Molecular weight of CO<sub>2</sub> (kg per kg-mole);  
 23.645 = Standard molar volume of 1 kg-mole of gas at standard conditions of 15°C and 1 atm (sm<sup>3</sup> per kg-mole).

#### **4.3.4 Calculation Methodology 4**

Calculate the annual CO<sub>2</sub> mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (a) through (g). This methodology requires a CO<sub>2</sub> monitor and a flow monitoring subsystem except as otherwise provided in paragraph (c) of this section. CEMS shall use methodologies provided in Environment and Climate Change Canada's *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation* (Reference Method) (June 2012) (or by other document that supersedes it).

- (a) For a facility that operates CEMS in response to federal, state, provincial, or local regulation, use CO<sub>2</sub> or O<sub>2</sub> concentrations and flue gas flow measurements to determine hourly CO<sub>2</sub> mass emissions using methodologies provided in the Reference Method.
- (b) The operator shall report CO<sub>2</sub> emissions for the reporting year in tonnes based on the sum of hourly CO<sub>2</sub> mass emissions over the year, converted to tonnes.
- (c) An oxygen (O<sub>2</sub>) concentration monitor may be used in lieu of a CO<sub>2</sub> concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO<sub>2</sub> concentrations, if the effluent gas stream monitored by the CEMS consists solely of combustion products (i.e., no process CO<sub>2</sub> emissions or CO<sub>2</sub> 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.
  - (1) If the unit combusts waste-derived fuels (e.g. waste oils, plastics, solvents, dried sewage, municipal solid waste, tires), emissions calculations shall not be based on O<sub>2</sub> concentrations.
  - (2) If the operator of a facility that combusts biomass fuels uses O<sub>2</sub> concentrations to calculate CO<sub>2</sub> concentrations, annual source testing must demonstrate that the calculated CO<sub>2</sub> concentrations, when compared to measured CO<sub>2</sub> concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in the Reference Guidance or superseding standard.
- (d) If both biomass fuel (including fuels that are partially biomass) and fossil fuel are combusted during the year, determine and report the biogenic CO<sub>2</sub> mass emissions separately, as described in Section 4.3.6.
- (e) For any units for which CO<sub>2</sub> 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.
- (f) 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 CO<sub>2</sub>

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.

- (g) If a facility does not have a CEMS and the operator chooses to add one in order to measure CO<sub>2</sub> 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 (a) through (e) of Section 4.3.4, if applicable.

#### **4.3.5 Use of the Four CO<sub>2</sub> Calculation Methodologies**

Use of the four CO<sub>2</sub> emissions calculation methodologies described in sections 4.3.1 through 4.3.4 of this section is subject to the following requirements and restrictions:

a. Calculation Methodology 1 (**Equation 4-1** and **4-1a**)

- (1) May be used only by facilities that emit under 50,000 tonnes of CO<sub>2</sub>e per year.
- (2) May be used for the combustion of municipal solid waste in a stationary combustion unit that does not generate steam.
- (3) May not be used at a facility emitting at any level from a fuel for which you routinely perform fuel sampling and analysis for the fuel's high heat value or can obtain the results (i.e. high heat value) of fuel sampling and analysis from the fuel supplier at the minimum frequency specified in Section 4.5.1, or at a greater frequency. In such cases, Calculation Method 2 shall be used for those fuels.

b. Calculation Methodology 2 (**Equation 4-2** and **Equation 4-3**)

- (1) May be used by facilities for the combustion of any of the fuels listed in Table 4-2.
- (2) Equation 4.3 may be used for the combustion of biomass and municipal solid waste provided that steam is generated by the unit.

c. Calculation Methodology 3 (**Equation 4-4** through **Equation 4-7**)

- (1) Must be used by facilities that emit equal to or over 50,000 tonnes of CO<sub>2</sub>e per year for the combustion of any fuel not listed in Table 4-2, except when Calculation Methodology 4 is used.
- (2) May be used by facilities that emit equal to or over 50,000 tonnes of CO<sub>2</sub>e per year for the combustion of any fuel any fuel not listed in Table 4-2, except when Calculation Methodology 4 is required.
- (3) Equation 4.5 may be used for the combustion of biomass and municipal solid waste provided that steam is generated by the unit.

d. Calculation Methodology 4

- (1) May be used for a unit combusting any type of fuel. Notwithstanding the provisions in paragraphs Section 4.3.5(a) through (c), Calculation Methodology 4 should 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 CO<sub>2</sub> concentration monitor.
- e. 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. Where CEMS data is not available or in cases where there is need to separate emissions by emission source, or fuel type, Calculation method 3 should be used in lieu of methodology 4.

#### **4.3.6 CO<sub>2</sub> Emissions from Combustion of Mixtures of Biomass or Biomass Fuel and Fossil Fuel**

Use the procedures of this Section (4.3.6) to estimate biogenic CO<sub>2</sub> 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.

- (a) If CEMS are not used to measure CO<sub>2</sub> 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 CO<sub>2</sub> 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.
- (b) If a CEMS is used to measure CO<sub>2</sub> (or O<sub>2</sub> as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels, use Calculation Methodology 1, 2, or 3 to calculate the annual CO<sub>2</sub> mass emissions from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO<sub>2</sub> emissions determined from the CEMS-based methodology.
- (c) If the owner or operator that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented, or if the owner or operator combusts a biomass fuel for which a CO<sub>2</sub> emission factor is not provided in Table 4-3, use the following to estimate biogenic CO<sub>2</sub> emissions:
  - (1) Use Calculation Methodology 1, 2, 3, or 4 to calculate the total annual CO<sub>2</sub> mass emissions, as applicable.

- (2) Determine the biogenic portion of the CO<sub>2</sub> 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 CO<sub>2</sub> emissions.
  - (3) 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.
  - (4) The operator shall divide total CO<sub>2</sub> 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.
  - (5) 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.
- (d) If **Equation 4-1** or **4-1a** of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, **Equation 4-8**: 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.

#### **Equation 4-8:**

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

#### **Where:**

- (Fuel)<sub>p</sub> = 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)<sub>nb</sub> = Heat input from co-fired fossil fuel 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)<sub>bio</sub> = Default or measured high heat value of the biomass fuel (GJ/tonne)

$(\text{Eff})_{\text{bio}}$  = Efficiency of biomass-to-energy conversion, expressed as a decimal fraction

## 4.4 Calculation of CH<sub>4</sub> and N<sub>2</sub>O emissions

Calculate the annual CH<sub>4</sub> and N<sub>2</sub>O mass emissions from stationary fuel combustion sources using the procedures in paragraphs (a) through (f), as appropriate. You may use engineering estimates or emission factors measured directly or provided by the fuel supplier or equipment manufacturer to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions for fuels that are not listed in Table 4-3, Table 4-4, Table 4-5 and Table 4-7.

### 4.4.1 Calculation Methodology 5

When the High Heat Value (HHV) for fuels is not measured directly, use either Equation 4-9 or Equation 4-10 to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions from the combustion of each fuel.

- (a) **For fuel(s) other than coal:** If the High Heat Value (HHV) for fuels is not measured directly, use **Equation 4-9** and default HHV to calculate the emissions for each fuel type.

#### Equation 4-9:

$$CH_4 \text{ or } N_2O = Fuel \times HHV_D \times EF_D \times 0.000001$$

- (b) **For coal:** If the emission factors are not measured directly or provided by suppliers, use **Equation 4-10** and default physical emission factors to calculate the emissions for each type of coal.

#### Equation 4-10:

$$CH_4 \text{ or } N_2O = Fuel \times EF_{DP} \times 0.001$$

#### Where:

CH<sub>4</sub> or N<sub>2</sub>O = Combustion emissions from specific fuel type (tonnes CH<sub>4</sub> or N<sub>2</sub>O per year).

Fuel = Mass or volume of fuel type combusted (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).

HHV<sub>D</sub> = Default high heat value specified by fuel type provided in Table 4-1, (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).

EF<sub>D</sub> = Default energy-based CH<sub>4</sub> or N<sub>2</sub>O emission factor for each fuel type provided in Table 4-3 or Table 4-5, as applicable, grams CH<sub>4</sub> or N<sub>2</sub>O per GJ. Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.

EF<sub>DP</sub> = Default physical-unit CH<sub>4</sub> or N<sub>2</sub>O emission factor for each coal type provided in Table 4-7 (grams CH<sub>4</sub> or N<sub>2</sub>O per kg of coal). Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.

0.000001 = Factor to convert grams to tonnes in **Equation 4-9**.

0.001 = Factor to convert kg to tonne in **Equation 4-10**.

#### 4.4.2 Calculation Methodology 6

When the High Heat Value (HHV) for fuels is measured directly or provided by suppliers, use either Equation 4-11 or Equation 4-12 to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions from the combustion of each fuel.

- (a) **For fuels other than coal:** If the HHVs for fuels are measured directly or provided by suppliers then use **Equation 4-11** and measured HHV to calculate the emissions for each type of fuel:

##### Equation 4-11:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.000001$$

- (b) **For coal only:** If the emission factors are measured directly or provided by suppliers then use  
(c)  
(d) **Equation 4-12:** and measured or provided emission factors to calculate the emissions for each coal type:

##### Equation 4-12:

$$CH_4 \text{ or } N_2O = \sum_{p=1}^n Fuel_p \times EF_c \times 0.000001$$

##### Where:

- CH<sub>4</sub> or N<sub>2</sub>O = Combustion emissions from specific fuel type (tonnes CH<sub>4</sub> or N<sub>2</sub>O per year).
- Fuel<sub>p</sub> = Mass or volume of fuel type during measurement period “*p*” (express mass in tonnes for solid fuel, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid fuel).
- HHV<sub>p</sub> = High heat value of the specific fuel during measurement period “*p*” measured directly or provided by supplier(s) (GJ per tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ per cubic meter for gaseous fuel).
- EF = Default energy-based CH<sub>4</sub> or N<sub>2</sub>O emission factor for fuel other than coal provided in Table 4-3 or Table 4-5, as applicable, grams CH<sub>4</sub> or N<sub>2</sub>O per GJ. Equipment-specific factors from U.S. EPA AP-42 may also be used for specific equipment, as appropriate.
- EF<sub>c</sub> = CH<sub>4</sub> or N<sub>2</sub>O emission factor for each coal type during measurement period “*p*” measured directly or provided by supplier(s) (grams CH<sub>4</sub> or N<sub>2</sub>O per tonne of coal)
- 0.000001 = Factor to convert grams to tonnes in **Equation 4-11** and

##### Equation 4-12.:

#### **4.4.3 Calculation Methodology 7**

For biomass combustion where either Equation 4-3 or Equation 4-5 is used to calculate CO<sub>2</sub> emissions, use Equation 4-13 of this section to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions:

##### **Equation 4-13:**

$$CH_4 \text{ or } N_2O = Steam \times B \times EF \times 0.000001$$

##### **Where:**

CH <sub>4</sub> or N <sub>2</sub> O	= Annual CH <sub>4</sub> or N <sub>2</sub> O emissions from the combustion of a biomass or municipal solid waste (tonnes).
Steam	= Total mass of steam generated by biomass 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 (GJ/tonne steam).
EF	= Fuel-specific emission factor for CH <sub>4</sub> or N <sub>2</sub> O, from Table 4-3, Table 4-5, Table 4-7, or Table 4-8 as applicable (grams per GJ).
0.000001	= Conversion factor from grams to tonnes.

#### **4.4.4 Calculation Methodology 8**

Use **Equation 4-14** of this section for units that use Calculation Methodology 4 and for which heat input is monitored on a year-round basis.

##### **Equation 4-14:**

$$CH_4 \text{ or } N_2O = (HI)_A \times EF \times 0.000001$$

##### **Where:**

CH <sub>4</sub> or N <sub>2</sub> O	= Annual CH <sub>4</sub> or N <sub>2</sub> O emissions from the combustion of a particular type of fuel (tonnes).
(HI) <sub>A</sub>	= Cumulative annual heat input from the fuel (GJ), derived from the electronic data reports or estimated from the best available information used for accounting purposes (e.g., fuel feed rate measurements, fuel heating values, engineering analysis, etc.). For coal, cumulative mass of coal (kilograms) from the best available information (e.g., fuel feed rate measurements, cumulative heat input, fuel heating values, engineering analysis).
EF	= Fuel-specific emission factor for CH <sub>4</sub> or N <sub>2</sub> O, from Table 4-3, Table 4-5, or Table 4-7, as applicable (grams per GJ or grams per kilogram for coal).
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 4-14** of this section to calculate the annual CH<sub>4</sub> or N<sub>2</sub>O emissions.

- (2) If more than one type of fuel listed is combusted during normal operation, use **Equation 4-14** of this section separately for each type of fuel.

#### **4.4.5 Use of the Four CH<sub>4</sub> and N<sub>2</sub>O Calculation Methodologies**

Use of the four CH<sub>4</sub> and N<sub>2</sub>O emissions calculation methodologies described as Calculation Methodologies 5 through 8 of Section 4.4 is subject to the following requirements and restrictions:

- (a) **Equation 4-9** and **Equation 4-10** may only be used by facilities that emit under 100,000 tonnes of CO<sub>2</sub>e per year.
- (b) **Equation 4-11** and **Equation 4-12** may be used for a unit of any size combusting any type of fuel.
- (c) **Equation 4-13** may only be used for biomass or municipal solid waste combustion.
- (d) **Equation 4-14**: 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 CO<sub>2</sub> emissions and heat input is monitored on a year-round basis.

#### **4.4.6 Calculations with Multiple Fuels**

When multiple fuels are combusted during the reporting year, sum the fuel-specific results from **Equation 4-9**, **Equation 4-10**, **Equation 4-11**, **Equation 4-12** and **Equation 4-13** or **Equation 4-14** of this section (as applicable) to obtain the total annual CH<sub>4</sub> and N<sub>2</sub>O emissions, in tonnes.

### **4.5 Sampling, Analysis, Measurement and Monitoring Requirements**

#### **4.5.1 Fuel Sampling Requirements**

Fuel sampling must be conducted, or fuel sampling results must be received from the fuel supplier at the minimum frequency specified in paragraphs (a) through (g) of this section, subject to the requirements of Section 4.3.5 and Section 4.4 paragraph (h). All fuel samples shall be taken at a location in the fuel handling system that is representative of the fuel combusted.

- (a) Once for each new fuel shipment or delivery for coal.
- (b) Once for each new fuel shipment or delivery of fuels, or quarterly for each of the liquid fuels listed in Table 4-3.
- (c) Monthly for natural gas.
- (d) Quarterly for liquid fuels and fossil fuel-derived gaseous fuels other than fuels listed in Table 3 (when Table 4-3 is used).
- (e) Annual for gases derived from biomass including landfill gas and biogas from wastewater treatment.
- (f) 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. 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  $\pm 5$  percent.

(g) Monthly for solid fuels other than coal and waste-derived fuels, as specified below:

- (1) The monthly solid fuel sample shall be a composite sample of weekly samples.
- (2) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel combustion, and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
- (3) 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.
- (4) 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.
- (5) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
- (6) 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.
- (7) If it is impractical to obtain monthly representative samples and an appropriate method is not published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

(h) For biomass fuels and waste-derived fuels (including municipal solid waste), the following may apply in lieu of Section 4.5.1 paragraph (e):

- (1) If CO<sub>2</sub> emissions are calculated using **Equation 4-3** in Section 4.3.2 or **Equation 4-4** in 4.3.3 the fuel-specific high heat value or carbon content is determined annually. If CO<sub>2</sub> emissions are calculated using **Equation 4-5** in 4.3.3, the operator shall adjust the emission factor, in kg CO<sub>2</sub>/GJ not less frequently than every third year, through a stack test measurement of CO<sub>2</sub> 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.

## 4.5.2 Fuel Consumption Monitoring Requirements

(a) 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 metres, tonnes or bone dry tonnes) using **Equation 4-15**. Alternatively, facilities may calculate fuel consumption using **Equation 4-15a**.

### **Equation 4-15:**

*Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored (or reading) at Beginning of Year – Amount Stored (or reading) at Year End*

### **Equation 4-15a:**

$$Fuel = \sum_{j=1}^n \frac{P_{rated_j}}{\eta_j} \times \frac{LD_j}{HHV_j} \times OH_j \times 0.0036$$

**Where:**

Fuel	= Annual theoretical volume of liquid fuel combusted by fired equipment $j$ ( $\text{m}^3/\text{year}$ ).
$P_{rated_j}$	= Maximum rated power for fired equipment $j$ (kW).
$\eta_j$	= Thermal efficiency for fired equipment $j$ .
$LD_j$	= Average Load for fired equipment $j$ (load fraction).
$HHV_j$	= High heat value of the liquid fuel combusted by fired equipment $j$ ( $\text{GJ}/\text{m}^3$ ).
$OH_j$	= Annual operating hours for fired equipment $j$ (hours/year).
n	= Number of fired equipment units.
0.0036	= Conversion factor from kWh to GJ.

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

- (b) Table 4-1.
- (c) All fuel 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 calibration procedures specified by the flow meter manufacturer.
- (d) Fuel flow meters shall be recalibrated once every three years, upon replacement of a previously calibrated meter or at the minimum frequency specified by the manufacturer. For orifice, nozzle, and venturi flow meters, the calibration shall consist of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas. For clarity, this provision also applies to flow meters used in upstream oil and gas, and natural gas transmission and distribution applications.
- (e) For fuel oil, tank drop measurements may also be used.
- (f) 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.”
- (g) Facilities using Calculation Methods 1 or 2 for  $\text{CO}_2$  emissions may use the following (Table 4-9) default density values for fuel oil, in lieu of using the ASTM method in paragraph (f) of this section. These default densities may not be used for facilities using Calculation Method 3.

#### 4.5.3 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, using an applicable analytical method listed by regulation. For fuel heat content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

- (a) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists. Specific test procedures that may be required to be used include ASTM D1826 “Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter”, ASTM D3588 “Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels”, or ASTM D4891-, GPA Standard 2261 “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used. The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within  $\pm 5.0$  percent. Where existing on-line instrumentation provides only low heat value, the operator shall convert the low heat value to high heat value as follows:

**Equation 4-16:**

$$HHV = LHV \times CF$$

**Where:**

HHV	= Higher heating value of gaseous fuel or fuel mixture (MJ/sm <sup>3</sup> ).
LHV	= Lower heating value of gaseous fuel or fuel mixture (MJ/sm <sup>3</sup> ).
CF	= Conversion factor

- (1) 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:
  - i. By concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
  - ii. 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 the most appropriate method published by consensus-based standards organization. Specific test procedures that may be required to use include ASTM D240 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter” or ASTM D4809 “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method).” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (3) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM D5865 “Standard Test Method for Gross Calorific Value of Coal and Coke.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- (4) For waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use

include ASTM D5865 and ASTM D5468 “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 CO<sub>2</sub> emissions using the method specified in Section 4.3.6, if applicable. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

- (5) Use **Equation 4-17** to calculate the weighted annual average heat content of the fuel, if the measured heat content is used to calculate CO<sub>2</sub> emissions

**Equation 4-17:**

$$(HHV)_{annual} = \frac{\sum_{p=1}^n (HHV)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p}$$

**Where:**

- (HHV)<sub>annual</sub> = 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)<sub>p</sub> = 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)<sub>p</sub> = Mass or volume of the fuel combusted during measurement period “p” (express mass in tonnes for solid fuel, volume in standard cubic metres 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.

#### 4.5.4 Fuel Carbon Content Monitoring Requirements

The determination of 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, using an applicable analytical method listed by regulation. For carbon content monitoring of natural gas, the facilities may follow the requirements under the laws and regulation of Measurement Canada for electricity and gas.

- 1) For coal and coke, solid biomass fuels, and waste-derived fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required to use include ASTM 5373 “Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal”. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- 2) For liquid fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required include the following ASTM

methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291 “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, and either ASTM D2502 “Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements” or ASTM D2503 “Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

- 3) For gaseous fuels, use the most appropriate method published by a consensus-based standards organization. Specific test procedures that may be required include ASTM D1945 “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” or ASTM D1946 “Standard Practice for Analysis of Reformed Gas by Gas Chromatography.” If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.
- 4) Use **Equation 4-18** to calculate the weighted annual average carbon content of the fuel, if the measured carbon content is used to calculate CO<sub>2</sub> emissions.

**Equation 4-18:**

$$(CC)_{annual} = \frac{\sum_{p=1}^n (CC)_p \times (Fuel)_p}{\sum_{p=1}^n (Fuel)_p}$$

**Where:**

- (CC)<sub>annual</sub> = 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)<sub>p</sub> = 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)<sub>p</sub> = Mass or volume of the fuel combusted during measurement period “p” (mass in tonnes for solids, volume in standard cubic metres for gaseous fuel, or volume in kilolitres for liquid).
- n = Number of measurement periods in the year that fuel is burned in the unit.

#### 4.5.5 Fuel Analytical Data Capture

When the applicable emissions estimation methodologies in Section 4.3 and Section 4.4 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 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 Section 4.3 and Section 4.4, the operator shall use the methods in Section 4.5.8 paragraph (b) to substitute for the missing values for the period of missing data.

#### **4.5.6 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 Section 6, existing legislative or regulatory requirements are sufficient for the points of measurement that are metered. Combustion sources covered by legislation or regulation are to be metered, sampled and analyzed in the manner prescribed by the legislation, regulations, guidelines, and policies. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. Combustion sources not specifically covered by the legislative or regulatory requirements must be measured according to the following requirements:

- (1) For combustion emissions 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 as defined in Section 13, or process gas combustion emissions 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 emissions 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 aggregate of all combustion sources is metered.

All combustion estimates must be calculated in a manner that ensures that fugitive, flaring, and venting emissions as calculated under Section 6 and Section 13 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 facility following paragraphs (c)(1) and (d)(3) of this section for operational and regulatory purposes must be used as inputs to Equation 4-7:.

#### **4.5.7 Specific requirements for general stationary combustion using solid fuels with recovered and weighted ash residue.**

Persons may use **Equation 4-19** to calculate the annual CO<sub>2</sub> mass emissions from the combustion of a specific solid fuel, in tonnes where the weight and unburned carbon content of ash recovered from the combustion of solid fuel have been determined by

- (i) Any applicable method listed in the Technical Reference Document section of this standard;
- (ii) The most appropriate method published by a consensus-based standards organization;
- (iii) Using methods and requirements in accordance with the requirements under the laws and regulation of Measurement Canada for electricity and gas; or
- (iv) The manufacturer's directions.

#### **Equation 4-19**

$$CO_2 = \sum_{i=1}^n (Fuel_i \times CC_{fuel\ i}) \times 3.664 - ((fly\ ash \times CC_{fly\ ash\ i} - A) + (bottom\ ash \times CC_{bottom\ ash\ i})) \times 3.664$$

#### **Where:**

$CO_2$	= Annual $CO_2$ mass emissions from the combustion of the specific solid fuel with weighted associated ash (tonnes).
$n$	= Number of carbon content determinations for solid fuel for the year.
$Fuel_i$	= Mass of the solid fuel combusted in measurement period “ $i$ ” (tonnes)
$CC_{fuel\ i}$	= Carbon content of the solid fuel, from the fuel analysis results for measurement period “ $i$ ” (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
3.664	= Ratio of molecular weights, $CO_2$ (44.01) to carbon (12.01).
$CC_{fly\ ash\ i}$	= Weighted average carbon content of fly ash calculated with Equation 4-20
$CC_{bottom\ ash\ i}$	= Weighted average carbon content of bottom ash calculated with Equation 4-20
A	= Mass of additional carbon present in ash not associated to solid fuel combustion e.g. Powdered Activated Carbon
Fly ash	= Total annual Weight of Fly ash transferred to landfill (tonnes).
Bottom ash	= Total annual Weight of Bottom ash transferred to landfill (tonnes).
3.664	= Ratio of molecular weights, $CO_2$ (44.01) to carbon (12.01).

#### **Equation 4-20**

$$(CC)_{ash} = \frac{\sum_{p=1}^n (CC_{ash\ p})_p \times (Ash)_p}{\sum_{p=1}^n (Ash)_p}$$

#### **Where:**

$(CC)_{ash}$	= Weighted annual average carbon content of the fly ash or bottom ash (as a decimal fraction)
$(CC_{ash\ p})_p$	= Carbon content of the fly ash or bottom ash, for measurement period “ $p$ ” during the year (as a decimal fraction)
$(Ash)_p$	= Weight of the fly ash or bottom ash recovered during measurement period “ $p$ ” in tonnes

n = Number of measurements of carbon content of fly ash or bottom ash in the year that fuel is burned in the unit.

#### **4.5.8 Specific Requirements for operation of equipment related to the transmission, storage and transportation of natural gas**

Weights and Measures Act of Canada standards (or other appropriate standards if the Weights and Measures Act is not applicable) are deemed to be sufficiently rigorous for the sampling, analysis and measurement for the combustion of pipeline quality natural gas as defined in Section 13 (including for derivation of standard gas composition) for facilities covered by Section 13 – Natural Gas Transmission. Calibration for all meters used in emissions quantification (whether covered by legislative or regulatory requirements, or not) must be conducted annually, or at the minimum frequency specified by the manufacturer, if appropriate for emissions quantification. If a required meter is not covered by the Weights and Measures Act, it must exist and meet the requirements of the applicable greenhouse gas reporting regulation for the jurisdiction.

#### **4.5.9 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.

- 1) For all units subject to the requirements of Section 4 that monitor and report emissions using a CEMS, the missing data backfilling procedures in *Reference Method for Source Testing: Quantification of Carbon Dioxide Releases by Continuous Emission Monitoring Systems from Thermal Power Generation* (June 2012) (or by other relevant document, if superseded) shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content.
- 2) For units that use Calculation Methodologies 1, 2, 3, or 4, perform missing data substitution as follows for each parameter:
  - a. For each missing value of the high heat 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.
  - b. For missing records of CO<sub>2</sub> concentration, stack gas flow rate, moisture percentage, and fuel usage, the substitute data value shall be the best available estimate of that 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.

## 4.6 Tables

**Table 4-1: 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
Ethane	18.91
Propane	25.48
Butane	28.80
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 (at 0% moisture content) <sup>1</sup>	19.2
Spent Pulping Liquor (at 0% moisture content) <sup>2</sup>	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/m <sup>3</sup> )
Natural Gas	0.0394
Coke Oven Gas	0.01914
Still Gas – Refineries	0.03608
Still Gas – Upgraders	0.04324
Landfill Gas (methane fraction)	0.0359
Biogas (methane fraction)	0.0359

1 HHV can be readily calculated for any moisture content as  $\text{HHV}_{\text{dry}} = \text{HHV}_{\text{wet}} / (1 - \text{percent\_moisture}/100)$ .

2 A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment.

**Table 4-2: Default CO<sub>2</sub> Emission Factors for Non-Variable Fuels for which Calculation Methodology 2 Can Be Used  
(Non-Variable Fuels)**

Fuel Type	Default CO <sub>2</sub> Emission Factor
	kg CO <sub>2</sub> /GJ
Ethane	56.68
Propane	59.66
Butane	60.83
Diesel	69.53
Motor Gasoline	65.40
Ethanol	64.9
Biodiesel	70
kg CO <sub>2</sub> /GJ	
Wood Fuel/Wood Waste	93.71
Spent pulp liquor (at 0% moisture content)	91.81

**Table 4-3: Default Emission Factors by Fuel Type**

Liquid Fuels	Physical-Based Emission Factors			Energy-Based Emission Factors		
	CO <sub>2</sub> (kg/L)	CH <sub>4</sub> (g/L)	N <sub>2</sub> O (g/L)	CO <sub>2</sub> (kg/GJ)	CH <sub>4</sub> (g/GJ)	N <sub>2</sub> O (g/GJ)
Aviation Gasoline	2.342	2.2	0.23	69.87	65.63	6.862
Diesel	2.663	0.133	0.4	69.53	3.473	10.44
Aviation Turbo Fuel	2.534	0.08	0.23	67.75	2.139	6.150
Kerosene						
- Electric Utilities	2.2560	0.006	0.031	67.25	0.159	0.823
- Industrial	2.560	0.006	0.031	67.25	0.159	0.823
- Producer Consumption	2.560	0.006	0.031	67.25	0.159	0.823
- Forestry, Construction, and Commercial/Institutional	2.560	0.026	0.031	67.25	0.69	0.823
Propane						
- Residential	1.51	0.027	0.108	59.66	1.067	4.267
- All other uses	1.51	0.024	0.108	59.66	0.948	4.267
Ethane	0.976	N/A	N/A	56.68	N/A	N/A
Butane	1.73	0.024	0.108	60.83	0.844	3.797
Lubricants	1.41	N/A	N/A	36.01	N/A	N/A
Motor Gasoline – Off-Road	2.289	2.7	0.05	65.40	77.14	1.429
Light Fuel Oil						
- Electric Utilities	2.753	0.18	0.031	70.23	4.639	0.799
- Industrial	2.753	0.006	0.031	70.23	0.155	0.799
- Producer Consumption	2.670	0.006	0.031	68.12	0.155	0.799
- Forestry, Construction, and Commercial/Institutional	2.753	0.026	0.031	70.23	0.67	0.799
Residual Fuel Oil (No. 5 & No. 6)						
- Electric Utilities	3.124	0.034	0.064	73.51	0.800	1.506

	Physical-Based Emission Factors			Energy-Based Emission Factors		
Liquid Fuels	CO <sub>2</sub> (kg/L)	CH <sub>4</sub> (g/L)	N <sub>2</sub> O (g/L)	CO <sub>2</sub> (kg/GJ)	CH <sub>4</sub> (g/GJ)	N <sub>2</sub> O (g/GJ)
- Industrial	3.124	0.12	0.064	73.51	2.824	1.506
- Producer Consumption	3.158	0.12	0.064	74.31	2.824	1.506
- Forestry, Construction, and Commercial/Institutional	3.124	0.057	0.064	73.51	1.341	1.820
Naphtha	0.625	N/A	N/A	17.77	N/A	N/A
Petrochemical Feedstocks	0.5	N/A	N/A	14.22	N/A	N/A
Biomass	CO <sub>2</sub> (kg/kg)	CH <sub>4</sub> (g/kg)	N <sub>2</sub> O (g/kg)	CO <sub>2</sub> (kg/GJ)	CH <sub>4</sub> (g/GJ)	N <sub>2</sub> O (g/GJ)
Landfill Gas	2.989	0.6	0.06	54.63	1.0	0.1
Wood Waste (at 0% moisture content)	1.81	0.576	0.077	93.71	30.2	4.2
Spent Pulping Liquor (at 0% moisture content)	1.239	0.039	0.026	91.81	2.93	1.93
Agricultural By-products	NA	NA	NA	112	NA	NA
Solid By-products	NA	NA	NA	100	NA	NA
Biogas (captured methane)	NA	NA	NA	49.4	NA	NA
Ethanol (100%)	NA	NA	NA	64.9	NA	NA
Biodiesel (100%)	NA	NA	NA	70	NA	NA
Rendered Animal Fat	NA	NA	NA	67.4	NA	NA
Vegetable Oil	NA	NA	NA	77.3	NA	NA
Other Solid Fuels						
Coal Coke	2.48	0.03	0.02	86.02	1.041	0.694
Petroleum Coke - Refinery Coke				82.55	2.589	0.572
Petroleum Coke - Upgrader Coke				86.12	2.958	0.569
Tires	N/A	N/A	N/A	85	N/A	N/A
Gaseous Fuels	CO <sub>2</sub> (kg/m <sup>3</sup> )	CH <sub>4</sub> (g/m <sup>3</sup> )	N <sub>2</sub> O (g/m <sup>3</sup> )	CO <sub>2</sub> (kg/GJ)	CH <sub>4</sub> (g/GJ)	N <sub>2</sub> O (g/GJ)
Coke Oven Gas	1.6	0.037	0.035	83.60	1.933	1.829
Still Gas – Refineries	1.75	N/A	0.0222	48.50	N/A	0.615
Still Gas – Upgraders	2.14	N/A	0.0222	49.49	N/A	0.513

1 A Review of Biomass Emissions Factors (2011). Clarity Works Ltd. Prepared for BC Ministry of Environment.

2 US EPA (2009). U.S. Environmental Protection Agency. *Mandatory reporting of greenhouse gases, final rule*. Washington, DC, 2009.

3 IPCC (2006). Intergovernmental Panel on Climate Change. 2006 *IPCC Guidelines for National Greenhouse Gas Inventories*. Japan, 2006.

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

**Table 4-4: Default Carbon Dioxide Emission Factors for Natural Gas by Province**

	<b>Marketable Gas (kg/m3)</b>	<b>Marketable Gas (kg/GJ)</b>	<b>Non-Marketable Gas (kg/m3)</b>	<b>Non-Marketable Gas (kg/GJ)</b>
Quebec	1.887	49.24	Not occurring	Not occurring
Ontario	1.888	49.27	Not occurring	Not occurring
Manitoba	1.886	49.22	Not occurring	Not occurring
British Columbia	1.926	50.26	2.162	56.13
Saskatchewan	1.829		2.441	
Nova Scotia	1.961	51.16	Not occurring	
New Brunswick	1.901		Not occurring	Not occurring
Newfoundland and Labrador	1.901	49.61	2.494	

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2015

1. The term “marketable” applies to fuel consumed by the Electric Utilities, Manufacturing Industries, Residential/Commercial and Transport subsectors.

2. The term “non-marketable” applies to raw gas consumption, mainly by natural gas producers.

**Table 4-5: Default Methane and Nitrous Oxide Emission Factors for Natural Gas**

	<b>CH<sub>4</sub> (g/m3)</b> (grams/m3)	<b>CH<sub>4</sub> (g/GJ)</b> (grams/GJ)	<b>N<sub>2</sub>O</b> (grams/m3)	<b>N<sub>2</sub>O (g/GJ)</b> (grams/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non-marketable)	6.4	167.05	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, 1990-2015

**Table 4-6: Default Carbon Dioxide Emission Factors for Coal**

	Emission Factor (kg CO <sub>2</sub> /kg coal)	Emission Factor (kg CO <sub>2</sub> /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
Newfoundland and Labrador		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3

Newfoundland and Labrador emission factors assumed the same as those for Quebec.

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

**Table 4-7: Default Methane and Nitrous Oxide Emission Factors for Coal**

	CH <sub>4</sub> Emission Factor (g/kg)	N <sub>2</sub> 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 4-8: Other Emission Factors - Municipal Solid Waste and Peat**

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

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, except the CO<sub>2</sub> emission factor for municipal solid waste is from the U.S. EPA from table C-1 of 40 CFR 98 subpart C.

**Table 4-9: Fuel Oil Default Density Values**

<b>Fuel Oil</b>	<b>No.1 Oil</b> (kg/litre)	<b>No.2 Oil</b> (kg/litre)	<b>No.6 Oil</b> (kg/litre)
Default Density	0.81	0.86	0.97

## **5. Mobile Equipment at Facilities (for reference purposes only)**

### **5.1 Activity Definition**

The mobile equipment at facilities includes:

- (a) Mobile equipment used for the on-site transportation or movement of substances, materials or products; and
- (b) Other on-site mobile equipment such as rail locomotives, tractors, mobile cranes, log transfer equipment, mining machinery, graders, backhoes, bulldozers, and other mobile industrial equipment, but does not include on-road vehicles, aircraft, or marine vessels.

The meaning of an on-road vehicle is that which is included in the *On-Road Vehicle and Engine Emission Regulations* (Canada), for instance on-road vehicles are those 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. However, vehicles used for activities that are not directly or indirectly connected with production (whether operated by the facility or by contractors), such as lawn maintenance and snow clearing vehicles, are excluded.

### **5.2 Greenhouse Gas Reporting Requirements**

This standard quantification method is included for reference purposes only and the use of mandatory language, such as “shall”, throughout this method is also included for reference purposes only and is not intended to create any substantive obligations.

The annual emissions data report shall contain the following information:

- (a) Total emissions of CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O 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.

### 5.3 Calculation of CO<sub>2</sub> Emissions

Calculate the annual CO<sub>2</sub> 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. Method (d) may be used only if data is not available to utilize methods (a), (b) or (c). Use method (e) as required (i.e. when mixtures of biomass fuel and fossil fuel are utilized). Annual emissions for each fuel type are calculated as the sum of the quarterly emissions.

- (a) If fossil fuel quantities are measured, calculate total CO<sub>2</sub> emissions using **Equation 5-1**.

#### **Equation 5-1:**

$$E_{i,CO2} = Q_i \times EF_i$$

Where:

- E<sub>i,CO<sub>2</sub></sub> Quarterly CO<sub>2</sub> emissions from mobile equipment for fuel *i* (metric tonnes);
- Q<sub>i</sub> Quarterly quantity of fuel *i* used in mobile equipment (litres);
- EF<sub>i</sub> Emission factor for the fuel (metric tonnes CO<sub>2</sub>e/litre, required emission factors provided in Section 4).

- (b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CO<sub>2</sub> emissions using **Equation 5-2** and **Equation 5-3**.

#### **Equation 5-2:**

$$E_{i,k,CO2} = (h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,CO2}$$

#### **Equation 5-3:**

$$E_{Total,i,CO2} = \sum_k E_{i,k,CO2}$$

Where:

$E_{i,k,\text{CO}_2}$	Quarterly $\text{CO}_2$ emissions from mobile equipment $k$ for fuel $i$ (metric tonnes)
$h_{i,k}$	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);
$EF_{i,\text{CO}_2}$	Emission factor for fuel $i$ (metric tonnes $\text{CO}_2\text{e}/\text{litre}$ , required emission factors provided in Section 4);
$E_{\text{Total},i,\text{CO}_2}$	Total quarterly $\text{CO}_2$ emissions for fuel $i$ (metric tonnes).

- (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.
- (1) 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).
  - (2) The average hourly fuel use rate for each of the typical operations must be calculated.
  - (3) The number of hours of each type of operation at the facility in the year must be determined.
  - (4) 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) Environment and Climate Change Canada Reporting. If methods (a), (b) or (c) cannot be utilized at the facility, then report  $\text{CO}_2$  emissions as specified in paragraph (1) of this section.
- (1) Determine the total annual  $\text{CO}_2$  emissions reported to Environment and Climate Change Canada's Greenhouse Gas Emissions Reporting Program pursuant to any submissions that the facility was required to make to the Federal government under section 46 or 71 of the *Canadian Environmental Protection Act, 1999* for each fuel type used by all mobile sources at the facility expressed in tonnes.
- (e)  $\text{CO}_2$  Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass  $\text{CO}_2$  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, CO<sub>2</sub> from the biomass component of biofuels shall be reported separately from CO<sub>2</sub> from fossil fuels.

## 5.4 Calculation of CH<sub>4</sub> and N<sub>2</sub>O emissions

Calculate the annual CH<sub>4</sub> and N<sub>2</sub>O mass emissions from mobile equipment using the procedures in paragraph (a) or (b), as appropriate. If neither (a) or (b) is appropriate for a source, method (c) may be used. Method (d) may be used only if data is not available to utilize methods (a), (b) or (c). Use method (e) as required (i.e. when mixtures of biomass fuel and fossil fuel are utilized). Annual emissions for each fuel type and GHG are calculated as the sum of the quarterly emissions. For mixtures of biomass fuels and fossil fuels, the CH<sub>4</sub> and N<sub>2</sub>O emissions attributable to the biomass fuel portion and to the fossil fuel portion must be calculated separately.

- (a) If fossil fuel quantities are measured, calculate total CH<sub>4</sub> and N<sub>2</sub>O emissions using **Equation 5-4:** and the emission factors provided in Section 4.

### **Equation 5-4:**

$$E_{i,g} = Q_i \times EF_{i,g} \times \left( \frac{1}{10^6} \right)$$

Where:

$E_{i,g}$       Quarterly emissions of greenhouse gas  $g$  (CH<sub>4</sub> or N<sub>2</sub>O) from mobile equipment for fuel  $i$  (metric tonnes)

$Q_i$       Quarterly quantity of fuel  $i$  (litres)

$EF_{i,g}$       Greenhouse gas  $g$  (CH<sub>4</sub> or N<sub>2</sub>O) mobile equipment emission factor for fuel  $i$  (grams/litre) (required emission factors provided in Table 4-3).

$(1/10^6)$       Conversion factor from grams to metric tonnes.

- (b) If fossil fuel quantities are not measured, use hours of operation for each mobile equipment to calculate total CH<sub>4</sub> or N<sub>2</sub>O emissions using **Equation 5-5** and **Equation 5-6.**

### **Equation 5-5:**

$$E_{i,k,g} = (h_{i,k} \times hp_{i,k} \times LF_{i,k} \times BSFC_{i,k}) \times EF_{i,g} \times \left( \frac{1}{10^6} \right)$$

**Equation 5-6:**

$$E_{Total,i,g} = \sum_k E_{i,k,g}$$

Where:

$E_{i,k,g}$	Quarterly greenhouse gas $g$ ( $\text{CH}_4$ or $\text{N}_2\text{O}$ ) emissions from mobile equipment $k$ for fuel $i$ (metric tonnes)
$h_{i,k}$	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)
$EF_{i,g}$	Emission factor for greenhouse gas $g$ ( $\text{CH}_4$ or $\text{N}_2\text{O}$ ) for fuel $i$ (grams/litre, required emission factors provided in Table 4-3)
$(1/10^6)$	Conversion factor from grams to metric tonnes
$E_{Total,i,g}$	Total quarterly emissions greenhouse gas $g$ ( $\text{CH}_4$ or $\text{N}_2\text{O}$ ) for fuel $i$ (metric tonnes)

- (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.
  - (1) 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).
  - (2) The average hourly fuel use rate for each of the typical operations must be calculated.
  - (3) The number of hours of each type of operation at the facility in the year must be determined.
  - (4) 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) Environment and Climate Change Canada Reporting. If methods (a), (b) or (c) cannot be utilized at the facility, then report  $\text{CH}_4$  and  $\text{N}_2\text{O}$  emissions as specified in paragraph (1) of this section.
  - (1) Determine the total annual  $\text{CH}_4$  and  $\text{N}_2\text{O}$  emissions reported to Environment and Climate Change Canada's Greenhouse Gas Emissions Reporting Program pursuant to any submissions that the facility was required to make to the Federal government under section 46 or 71 of the *Canadian Environmental Protection Act, 1999* for each fuel type used by all mobile sources at the facility expressed in tonnes.

- (e) CH<sub>4</sub> and N<sub>2</sub>O Emissions Calculation Methodology for Mixtures of Biomass Fuel and Fossil Fuel. Calculate biomass and non-biomass CH<sub>4</sub> and N<sub>2</sub>O 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, CH<sub>4</sub> and N<sub>2</sub>O from the biomass component of biofuels shall be reported separately from CH<sub>4</sub> and N<sub>2</sub>O from fossil fuels.

## **5.5 Sampling, Analysis and Measurement Requirements**

Fuel use, emission factors and hours of operation shall be determined as specified under paragraphs (a), (b), (c) and (d) of this section.

- (a) For biofuels, the portion(s) of ethanol or biodiesel from vendor specifications for each delivery of fuel. If this information is not available, the facility may use engineering estimates when determining the portion of the biofuel in a mixture of biofuel and fossil fuel.
- (b) For conventional fuels and biofuels, required emission factors listed in Section 4. Where applicable, a mobile-operator-specific emission factor may also be used, provided the necessary information to establish this emission factor is available.
- (c) Fuel volumes used shall be determined by vendor receipts, dipstick measurement, gauge readings (for each unit of mobile equipment) or other appropriate means on a quarterly basis, starting on January 1 of the calendar year.
- (d) The facility shall use the records kept by the facility setting out the hours of operation for the mobile equipment subject to the report when implementing methodology (b) to estimate both CO<sub>2</sub> and CH<sub>4</sub>/N<sub>2</sub>O emissions.

## **5.6 Procedures for Estimating Missing Data**

Where the missing data concerns fuel quantity, the facility shall generate the replacement data from best estimates based on all of the data relating to the mobile equipment and processes used.

## **6. Onshore Petroleum and Natural Gas Production and Natural Gas Processing**

### **6.1 Activity Definition**

This activity does not include emissions from offshore production, drilling, exploration and all activities that are conducted in the offshore area.

This activity includes onshore facilities, including the following.

- (2) Onshore petroleum and natural gas production equipment, including 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 enhanced oil recovery (EOR) operations using CO<sub>2</sub>, 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 natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, separation of natural gas liquids, sulphur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO<sub>2</sub> 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 petroleum and natural gas production. This activity includes fractionators that produce natural gas liquids, such as propane, butane and other hydrocarbons. Gathering and boosting stations that send the natural gas to a natural gas transmission compression facility, or natural gas distribution facility, or to an end user are also considered within 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.

This activity does not include natural gas transmission and distribution, 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 Section 13 (Equipment related to Natural Gas Transmission and Distribution).

#### **6.1.1 Definitions Relevant to Onshore Petroleum and Natural Gas Production and Natural Gas Processing**

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 ( $H_2S$ ) and carbon dioxide ( $CO_2$ ) 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  $CO_2$  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  $CO_2$  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  $CO_2$  from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or  $CO_2$  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  $CO_2$ . 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 natural gas or CO<sub>2</sub> by drawing in low pressure natural gas or CO<sub>2</sub> and discharging significantly higher pressure natural gas or CO<sub>2</sub>.

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 CO<sub>2</sub> 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 Section 13 and Section 6 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.

Farm taps means pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

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, for the purposes of Section 6, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

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 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 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 in excess of 0.17 standard cubic meters 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, deltapressure 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.

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. Pressure groupings are defined as follows: less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig.

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals mean 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 mean 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 means natural gas with low concentrations of hydrogen sulphide (H<sub>2</sub>S) and/or carbon dioxide (CO<sub>2</sub>) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scraper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

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.

Tubing diameter groupings are defined as follows: less than or equal to 1 inch; greater than 1 inch and less than 2 inch; and greater than or equal to 2 inch.

Tubing systems mean piping equal to or less than one half inch diameter as per nominal pipe size

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 completion 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 that 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 testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined (i.e. the well testing) through a choke (an orifice restriction). If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

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".

## 6.2 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 50,000 tonnes and the aggregate of facilities less than 50,000 tonnes (or as otherwise specified by regulation), must contain the following information:

- a. **Production parameter:** Annual quantity of natural gas feed that is processed in the plant
- b. CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, 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.
- c. For petroleum and natural gas production, report CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions from the following source types:
  - (1) Natural gas pneumatic continuous high-bleed device venting. [6.3(a)]
  - (2) Natural gas-driven pneumatic pump venting. [6.3(a.1)]
  - (3) Natural gas pneumatic continuous low-bleed device venting. [6.3(b)]
  - (4) Natural gas pneumatic intermittent (low and high) bleed device venting. [6.3(b.1)]
  - (5) Acid gas removal venting or incineration process. [6.3(c)]
  - (6) Dehydrator vents. [6.3(d)]
  - (7) Well venting for liquids unloading. [6.3(e)]
  - (8) Gas well venting during well completions or workovers. [6.3(f)]
  - (9) Blowdown vent stacks. [6.3(g)]
  - (10) Third party line hits. [6.3(g.1)]
  - (11) Production and processing storage tanks. [6.3(h)]
  - (12) Transmission storage tanks [6.3(h.1)]
  - (13) Well testing venting and flaring. [6.3(i)]
  - (14) Associated gas venting and flaring. [6.3(j)]
  - (15) Flare stacks. [6.3(k)]
  - (16) Centrifugal compressor venting. [6.3(l)]
  - (17) Reciprocating compressor venting. [6.3(m)]
  - (18) Gathering pipeline fugitive equipment leaks. [6.3(o) or (x) for emission sources not covered by (o)]
  - (19) 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). [6.3(o)]
  - (20) Enhanced oil recovery (EOR) injection pump blowdown. [6.3(t)]
  - (21) Hydrocarbon liquids dissolved CO<sub>2</sub> from flashing [Reserved]. [6.3(u)]
  - (22) Produced water dissolved CO<sub>2</sub> [Reserved]. [6.3(v)]
  - (23) Coal bed methane produced water emissions [Reserved]. [6.3(v)]
  - (24) Other venting emission sources.\* [6.3(x)]
  - (25) Other fugitive emission sources.\*[ 6.3(x)]
- d. For natural gas processing, report CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, if applicable) emissions from the following sources:
  - 1) Acid gas removal venting or incineration. [6.3(c)]
  - 2) Dehydrator vents. [6.3(d)]
  - 3) Blowdown vent stacks. [6.3(g)]
  - 4) Storage tanks. [6.3(h)]
  - 5) Flare stacks. [6.3(k)]
  - 6) Centrifugal compressor venting. [6.3(l)]

- 7) Reciprocating compressor venting. [6.3(m)]
- 8) Gathering pipeline fugitive equipment leaks. [6.3(o)] or [(x)] for emission sources not covered by [(o)]
- 9) Fugitive equipment leaks from: valves, connectors, open ended lines, pressure relief valves and meters. [6.3(n)]
- 10) Other fugitive emission sources (including reciprocating compressor rod packing fugitives, centrifugal compressor dry and wet seals, etc).\*[ 6.3(x)]
- 11) Other venting emission sources.\*[ 6.3(x)]
- e) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary fuel combustion source type combusting field gas or process vent gas [6.3(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 the General Stationary Fuel Combustion quantification methods (Section 4). The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. \*\*
- f) Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each portable equipment combustion source type combusting field gas or process vent gas [6.3(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 General Stationary Fuel Combustion quantification methods (Section 4). The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas. \*\*
- 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 or emissions information, as appropriate, used in place of Tables 6-1 and 6-2.
  - 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:
      - (A) The number of glycol dehydrators with throughput less than 11,328 Sm<sup>3</sup>/day operated, and
      - (B) The number of glycol dehydrators with throughput greater than or equal to 11,328 Sm<sup>3</sup>/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 third party line hits
    - i) Engineering distribution of number of line hits by volume of gas released by hit
  - 11) Count of wells venting during well completions:

- i) The number of conventional completions.
  - ii) The number of completions employing hydraulic fracturing.
- 12) Count of wells venting during well workovers:
- i) The number well workovers involving well venting to the atmosphere.
- 13) For each compressor report the following:
- i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal (for all compressors).
  - ii) Compressor driver capacity in horsepower (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - iii) Number of blowdowns per year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - iv) Operating mode(s) (i.e., operating, not operating and pressurized or not operating and depressurized) during the year (where the total horsepower (as aggregated) for the facility has rated power greater than or equal to 250 hp).
  - v) Number of compressor starts per year.
- 14) Number of EOR injection pump blowdowns per year.
- 15) Count of wells tested in the reporting period.
- 16) Count of wells venting or flaring associated natural gas in the reporting period.
- 17) Count of wells being unloaded for liquids in the reporting year.
- 18) Count of wells completed (worked over) in the reporting year.
- 19) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in (n) and (o) of 6.3, report the following:
- i) (for sources quantified using 6.3 (o) only) Component counts for which an emission factor is provided in Tables 6-1, 6-2 or 6-3 in this document. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years. An operator may use one or more P&ID diagrams to determine component counts for groupings of similar sites.
  - ii) (for sources quantified using 6.3(n) only) Total counts of fugitive equipment leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- 20) Barrels of oil equivalent throughput/processed as determined by engineering estimate based on best available data.
- 21) Identification (including geographic coordinates) of any facility that had 1,000 tonnes or greater 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) The greenhouse gas emissions for the facility in the previous year.
  - iv) The purchaser or seller, as appropriate

*\* 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.*

*\*\* Portable equipment is portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that are located at a 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.*

### 6.3 Calculation of 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. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 6-6.

- a. Natural gas pneumatic continuous high-bleed device venting. Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. Natural gas consumption must be metered for all of the operator’s pneumatic high-bleed devices. For the purposes of this reporting requirement, high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m<sup>3</sup>/hr. For unmetered devices the operator must use the method specified in paragraph (a)(2).
  - (1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

#### Equation 6-1

$$E_s = Q_j$$

Where:

E<sub>s</sub> Annual natural gas volumetric emissions for pneumatic high-bleed devices and pneumatic pumps where gas is metered (Sm<sup>3</sup>/y).

Q<sub>j</sub> Natural gas consumption for meter j (Sm<sup>3</sup>/y).

- (2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

**Equation 6-2**

$$E_s = EF_j \times t_j$$

Where:

$E_s$  Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered ( $\text{Sm}^3/\text{y}$ ).

$EF_j$  Natural gas-drive pneumatic device (or equivalent device), j, bleed rate volume in Table 6-5 (data within Table as revised from time to time and provided by the regulator) ( $\text{Sm}^3/\text{h/device}$ ).

i. For individual pneumatic high-bleed controllers, except as noted in subparagraph 1 below, use the device (or equivalent device)-specific emission factor provided in Table 6-5.

1. The  $EF_j$  parameter may be calculated using **Equation 6-2a**:

**Equation 6-2a**

$$EF_j = m \times SP_j$$

Where:

$M$  The supply pressure coefficient in Table 6-5.

$SP_j$  the supply pressure (kPa) of controller j.

ii. For pumps, except as noted in subparagraphs 1 and 2 below, use the pump (or equivalent pump)-specific emission factor provided in Table 6-5.

$t_j$  Total time that the pneumatic device, j, has been in service the (i.e. the time that gas flows to the device) through the reporting period (h).

- (3) 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. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 6-4 for high-bleed pneumatic devices
- (4) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section
- (5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:

- (i) Facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.
- (a.1) Natural gas pneumatic pump venting. Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. Natural gas consumption must be metered for all of the operator's pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.
- (1) The operator must calculate vented emissions for metered pneumatic pumps using **Equation 6-1**.
  - (2) The operator must calculate vented emissions for unmetered pneumatic pumps using **Equation 6-3**.
    - (i) 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. 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.
    - (ii) Maintain a log of the amount of liquid pumped annually from individual pumps.
    - (iii) Calculate the natural gas emissions for each pump using **Equation 6-3**.

### **Equation 6-3**

$$E_s = EF_j \times Q_j$$

Where:

- $E_s$  Annual natural gas volumetric emissions ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  Natural gas-drive pneumatic device (or equivalent device), j, bleed rate volume in Table 6-5 (data within Table as revised from time to time and provided by the regulator) ( $\text{Sm}^3/\text{h}/\text{device}$ ).
- i. For individual pneumatic high-bleed controllers, except as noted in subparagraph 1 below, use the device (or equivalent device)-specific emission factor provided in Table 6-5.
    1. The  $EF_j$  parameter for pumps may be calculated using Equation 6-3a<sup>3</sup>:

### **Equation 6-3a**

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<sup>3</sup> If the pump is operating at less than five strokes per minute, this equation is not applicable and the mean bleed rate or volume of chemical equation should be used instead.

$$EF_j = (g \times SP_j) + (n \times DP_j) + (p \times SPM_j)$$

Where:

Bleed Rate<sub>j</sub> The volume of natural gas bled per hour for pneumatic pump (or equivalent pump), j ( $\text{Sm}^3\text{NG}/\text{h}$ ).

G The supply pressure coefficient provided in Table 6-5 (kPa).

SP<sub>j</sub> The fuel supply pressure for pump (or equivalent pump) j.

n The discharge pressure coefficient provided in Table 6-5 (kPa).

DP<sub>j</sub> The discharge pressure of pump (or equivalent pump) j.

p The strokes per minute coefficient provided in Table 6-5.

SPM<sub>j</sub> The strokes per minute of pump (or equivalent pump) j (spm).

2. The EF<sub>j</sub> parameter may be calculated using Equation 6-3b:

### **Equation 6-3b**

$$EF_j = Q_j \times R_j$$

Where:

Q<sub>j</sub> The volume rate of chemical injection for pump, j (L/h).

R<sub>j</sub> The pump specific factor expressed as the volume of gas vented per liter of chemical injected. The factor takes into account fuel supply pressure, piston size, and discharge pressure and is based on the chart published by the pump j manufacturer ( $\text{Sm}^3\text{NG}/\text{L}$ ).

Q<sub>j</sub> Volume of liquid pumped annually by pump j (liters/y).

(3) If the device, or equivalent device, is not listed in Table 6-5, use the generic high bleed emission factor for all high bleed controllers and use the generic bleed rate for diaphragm or piston pumps, as appropriate.

(4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section

(5) Provide the total number of natural gas pneumatic pumps as follows:

(i) Facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.

- b. Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using **Equation 6-4** of this section.

### **Equation 6-4**

$$E_s = EF_j \times t_j$$

Where:

- $E_s$  Annual natural gas volumetric emissions for pneumatic continuous low-bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  Population emission factor for natural gas-driven pneumatic continuous low-bleed device,  $j$ , as provided in Table 6-4 ( $\text{Sm}^3/\text{h/device}$ ).
- $t_j$  Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).
- (1) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
  - (2) Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:
    - (i) Facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

b.1) Natural gas pneumatic intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.

- (1) The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta pressure or temperature using **Equation 6-5**:

### **Equation 6-5**

- $E_s$  Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  Natural gas-drive pneumatic device (or equivalent device),  $j$ , bleed rate volume in Table 6-5 (data within Table as revised from time to time and provided by the regulator) ( $\text{Sm}^3/\text{h/device}$ ).
  - i. For individual intermittent pneumatic devices, except as noted below, use the device (or equivalent device)-specific emission factor provided in Table 6-5.
    1. The  $EF_j$  parameter may be calculated using emissions from these devices may be calculated using **Equation 6-5a**.

### **Equation 6-5a**

$$EF_j = m \times SP_j$$

Where:

- m The supply pressure coefficient in Table 6-5.
- SP<sub>j</sub> The supply pressure (kPa) of controller j.
- ii. If the device (or equivalent device) is not present in Table 6-5, use the generic intermittent (high or low, as appropriate) bleed emission factor in Table 6-4.
- t<sub>j</sub> Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).
- (2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using **Equation 6-6\***:

### **Equation 6-6**

$$E_s = EF_j \times t_j$$

Where:

- E<sub>s</sub> Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices (Sm<sup>3</sup>/y).
- EF<sub>j</sub> Emission factor for natural gas-driven pneumatic compressor starter, *j*, as provided by the manufacturer for the operating condition (Sm<sup>3</sup>/min/device). If an emission factor is not available from the manufacturer, an emission factor for a similar compressor starter may be used in its place.
- t<sub>j</sub> Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

*Note: The volume of gas per start provided by the manufacturer may be used in place of the EF<sub>j</sub> and t variables.*

- (3) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- (4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:
- (i) Facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment each year.
  - c. Acid gas removal (AGR) venting or incineration process. Except for AGRs where the acid gases are re-injected into the oil/gas field or manifolded to a common flare stack, calculate CO<sub>2</sub> emissions only (not CH<sub>4</sub>) for AGR (including but not limited to processes such as amine, membrane, molecular sieve or other absorbents and

adsorbents) using any of the calculation methodologies described in this section, as applicable.

- (1) Calculation Methodology 1. If you operate and maintain a CEMS on the AGR vent or incinerator stack that has both a CO<sub>2</sub> concentration analyzer and volumetric flow rate meter CO<sub>2</sub> emissions under this subpart must be calculated by following Calculation Methodology 4 and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Calculation Methodology 4 in Section 4. If a CO<sub>2</sub> concentration analyzer and volumetric flow rate meter are not available, a CO<sub>2</sub> concentration analyzer and a volumetric flow rate meter that comply with all of the requirements specified for the Calculation Methodology 4 in Section 4 may be installed.
- (2) Calculation Methodology 2. If CEMS is not available but a vent meter is available, use the CO<sub>2</sub> composition and annual volume of vent gas to calculate emissions using **Equation 6-7**.

### **Equation 6-7**

$$E_{CO_2} = Q \times Y_{CO_2}$$

Where:

- E<sub>CO<sub>2</sub></sub> Annual volumetric CO<sub>2</sub> emissions (Sm<sup>3</sup>/y).  
Q Metered total annual volume of acid gas flow out of the AGR unit (Sm<sup>3</sup>/y) as determined in paragraph (c)(5) of this section.  
Y<sub>CO<sub>2</sub></sub> Mole fraction of CO<sub>2</sub> in acid gas out of the AGR unit as determined in paragraph (c)(6) of this section.

- (3) Calculation Methodology 3. If a CEMS or a vent meter is not available, the outlet gas flow rate of the acid gas removal unit must be used to calculate emissions for CO<sub>2</sub> using **Equation 6-8**. If the outlet flow rate of the acid gas removal unit is not available, then the inlet gas flow rate and **Equation 6-8A** may be used, however volume correction must be made to account for gas combusted, vented, flared or leaked in the unit.

### **Equation 6-8**

$$E_{CO_2} = \frac{Y_{CO_2,in} \times (1 - Y_{H_2S,spec}) - Y_{CO_2,out} \times (1 - Y_{H_2S,in})}{1 - Y_{CO_2,in} - Y_{H_2S,in}} \times Q_{out}$$

### Equation 6-8A

$$E_{CO_2} = \frac{Q_{in} \times [Y_{CO_2\_in} \times (1 - Y_{H_2S\_spec}) - Y_{CO_2\_out} \times (1 - Y_{H_2S\_in})]}{(1 - Y_{H_2S\_spec} - Y_{CO_2\_out})}$$

Where

- $E_{CO_2}$  Annual volumetric CO<sub>2</sub> emissions (Sm<sup>3</sup>/y).
- $Q_{in}$  Metered total annual volume of natural gas flow into the AGR unit (Sm<sup>3</sup>/y) as determined in paragraph (c)(4) of this section.
- $Q_{out}$  Metered total annual volume of gas flow out of AGR unit (Sm<sup>3</sup>/y) as determined in paragraph (c)(5) of this section.
- $Y_{CO_2\_in}$  Mole fraction of CO<sub>2</sub> in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.
- $Y_{CO_2\_out}$  Mole fraction of CO<sub>2</sub> in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.
- $Y_{H_2S\_spec}$  Mole fraction of H<sub>2</sub>S in the natural gas out of the AGR unit as determined by the performance specifications of the AGR. If the actual molar fraction of H<sub>2</sub>S in the gas stream out of the ARG unit is known, it must be used instead of that from the performance specifications. If H<sub>2</sub>S content is insignificant (as in the case of sweet natural gas), then  $Y_{H_2S,spec}$  and  $Y_{H_2S,in}$  are zero.
- $Y_{H_2S\_in}$  Mole fraction of H<sub>2</sub>S in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.
- (4) Record the gas flow rate, referenced to standard conditions, of the inlet and outlet natural gas or acid gas stream of an AGR unit using a meter according to methods set forth in 6.4(b). If inlet flow quantity is used to calculate the AGR emissions, ensure that the flow meter or vent meter monitoring the inlet stream is as accurate as that which otherwise would be installed and used at the outlet stream. Due to the presence of CO<sub>2</sub> in the inlet stream, the calibration frequency for the inlet stream meter should be reasonably higher than for the outlet stream.
- (5) 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 YCO<sub>2</sub>\_in according to methods set forth in 6.4(b).
- (6) Determine volume fraction of CO<sub>2</sub> content in natural gas or acid gas out of the AGR units using one of the methods specified in paragraph (c)(6) 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 must be taken from the outlet gas stream to determine YCO<sub>2</sub> according to methods set forth in 6.4(b).
  - (7) Determine volume fraction of H<sub>2</sub>S content in natural gas or acid gas into the AGR units using continuous gas analyzer data (if available), or other known or commonly accepted method (if continuous gas analyzer data is not available).
  - (8) Mass CO<sub>2</sub> emissions shall be calculated from volumetric CO<sub>2</sub> emissions using calculations in paragraph (s) of this section.
- d. Dehydrator vents. For dehydrator vents, calculate annual mass CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) emissions 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 CH<sub>4</sub> and CO<sub>2</sub> 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 gas.
    - (viii) Use of flash tank separator (and disposition of recovered gas).
    - (ix) Hours operated.
    - (x) Wet natural gas temperature and pressure.
    - (xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (d)(1)(xi) 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 6.4(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)(4) of this section downward by the magnitude of emissions captured.
  - (3) Calculate annual emissions from dehydrator vents to flares or regenerator firebox/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 6-9**.

#### **Equation 6-9**

$$E_s = \left( \frac{H \times D^2 \times \pi \times P_2 \times \%G \times 365}{4 \times P_1 \times t} \right) / 100$$

- $E_s$  Annual natural gas volumetric emissions ( $\text{Sm}^3/\text{y}$ ).
- 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).
- $\pi$  pi (3.14).
- %G Percent of packed vessel volume that is gas.
- 365 Conversion from days to years.
- t Time between refilling (days) ( $365/t$  represent the refilling times during the reporting year).
- 100 Conversion of %G to fraction.

- (5) Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- e. Well venting for liquids unloading. The  $\text{CO}_2$  and  $\text{CH}_4$  emissions for well venting for liquids unloading shall be determined using one of the following calculation methodologies:
  - (1) Calculation Methodology 1. For one representative well of each unique well tubing diameter grouping, pressure grouping 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 6.4(b). Calculate emission from well venting for liquids unloading using **Equation 6-10**.

### **Equation 6-10**

$$E_a = Q_j \times t_j$$

Where:

- E<sub>a</sub> Annual natural gas volumetric emissions from well *j* at actual conditions (m<sup>3</sup>/y).
- t<sub>j</sub> Cumulative amount of time in hours of venting from well *j* during the reporting period (h).
- Q<sub>j</sub> Average flow rate 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 (m<sup>3</sup>/h).

- (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 grouping and pressure grouping in each producing horizon/formation combination in each producing field by dividing the recorded total flow by the recorded time (in hours) for a single liquid unloading with venting to the atmosphere.
  - (B) This average flow rate is applied to all wells in the same pressure grouping that have the same tubing diameter grouping, for the number of hours in the calendar year of venting these wells.
  - (C) A new average flow rate is calculated every other calendar year (if necessary) for each reporting field and horizon combination starting the first calendar year of data collection. For a new producing reporting field and horizon combination, an average flow rate is calculated beginning in the first year of production.
- (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 to the atmosphere for liquids unloading with plunger lift assist using
- (3)
- (4) **Equation 6-11.**

### Equation 6-11

$$E_{a,n} = \left( [7.854 \times 10^5] \times D_t^2 \times WD \times \left[ \frac{P_{sales}}{101.325} \right] \times N_V \right) + (Q_{str} \times [t_{open} - 0.5] \times Z)$$

$E_{a,n}$	Annual natural gas volumetric emissions at actual conditions ( $m^3/y$ ).
$7.854 \times 10^{-5}$	$(\pi/4)/(10,000)$
$D_t$	Tubing diameter (cm).
WD	Tubing depth to plunger bumper (meters).
$P_{sales}$	Sales line pressure (kPa-gage).
$N_V$	Number of vents per year.
$Q_{sfr}$	Average sales flow rate of gas well at actual conditions ( $m^3/h$ ).
$t_{open}$	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 $t_{open}$ is less than 0.5 then Z is equal to 0. If $t_{open}$ 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.
- (5) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
- f. Gas well venting during well completions and workovers. Calculate emissions from gas conventional or unconventional (from hydraulic fracturing) well venting during well completions and workovers using one of the following methods. Sum all events to determine total annual venting that occurred in the reporting year.
  - (1) Calculation Methodology 1.
    - (i) The operator must measure total gas flow with a recording flow meter (analog or digital) installed in the vent line.
    - (ii) The operator must correct total gas volume vented for the volume of CO<sub>2</sub> or N<sub>2</sub> injected and the volume of gas recovered into a sales lines as follows:

### Equation 6-12

$$E_a = V_M - V_{CO_2,N_2} - V_{SG}$$

Where:

$E_a$	Natural gas emissions during the well completion or workover at actual conditions ( $m^3$ ).
$V_M$	Volume of vented gas measured during well completion or workover ( $m^3$ ).
$V_{CO_2,N_2}$	Volume of CO <sub>2</sub> or N <sub>2</sub> injected during well completion or workover ( $m^3$ ).

- $V_{SG}$  Volume of natural gas recovered into a sales pipeline ( $m^3$ ).
- (iii) All gas volumes must be corrected to standard temperature and pressure using methods in paragraph (q) of this section.
  - (iv) The operator must calculate  $CO_2$  and  $CH_4$  mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.
- (2) Calculation Methodology 2.
- (i) The operator must make a series of measurements of upstream pressure ( $P_1$ ) and downstream pressure ( $P_2$ ) across a choke installed in the vent line and upstream gas temperature according to methods in section 6.4(b) during each well completion and well workover where venting occurs. The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes. Sonic flow is defined as the flow regime where  $P_2/P_1 \leq 0.542$ . Subsonic flow is defined as the flow regime where  $P_2/P_1 > 0.542$ . The operator must then calculate flow rate for both sonic and subsonic flow regimes using the following equations:
- (A) Sonic flow regime.
- (1) The operator must calculate the average flow rate during sonic flow conditions as follows:

### Equation 6-13

$$Q_{S,avg} = 3600 \times A \times \sqrt{187.08 \times T_u}$$

Where:

- $Q_{S,avg}$  Average flow rate of natural gas during sonic flow conditions ( $m^3/h$ ).
- 3600 Conversion factor from  $m^3/\text{second}$  to  $m^3/\text{hour}$ .
- A Cross sectional area of the orifice ( $m^2$ ).
- 187.08 Constant with units of  $m^2/(\text{sec}^2 * K)$
- $T_u$  Upstream gas temperature (degrees Kelvin).

- (2) The operator must calculate total natural gas volume vented during sonic flow conditions as follows:

### Equation 6-14

$$V_s = Q_{S,avg} \times t_s$$

Where:

- $V_s$  Volume of gas vented during sonic flow conditions ( $m^3$ ).

$t_s$  Duration of venting during sonic flow conditions (h). The operator must correct QS to standard conditions using the methodology in paragraph (q) of this section.

(B) Subsonic flow regime.

- (1) The operator must calculate the instantaneous gas flow rate during subsonic flow conditions as follows:

**Equation 6-15**

$$Q_{SS,inst} = 3600 \times A \times \sqrt{3430 \times T_u [(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]}$$

Where:

$Q_{SS,inst}$	Instantaneous flow rate of natural gas at time $t_{inst}$ during subsonic flow conditions ( $m^3/h$ ).
3600	Conversion factor from $m^3/\text{second}$ to $m^3/\text{hour}$ .
A	Cross sectional area of the orifice ( $m^2$ ).
3430	Constant with units of $m^2/(\text{sec}^2 * K)$ .
$T_u$	Upstream gas temperature (degrees Kelvin).
$P_2$	Downstream pressure (kPa).
$P_1$	Upstream pressure (kPa).

- (2) The operator must determine total gas volume vented during subsonic flow conditions (VSS) as the total volume under the curve of a plot of  $Q_{ss,inst}$  and time ( $t_{inst}$ ) for the time period during which the well was flowing during subsonic conditions.
- (3) The operator must correct VSS to standard conditions using the methodology in paragraph (q) of this section
- (ii) The operator must sum the vented volumes during sonic and subsonic flow and adjust emissions for the volume of CO<sub>2</sub> or N<sub>2</sub> injected and the volume of gas recovered into a sales line as follows:

**Equation 6-16**

$$E_s = V_s + V_{ss} - V_{CO2,N2} - V_{SG}$$

Where:

$E_s$	Natural gas emissions during the well completion or workover ( $Sm^3$ ).
$V_s$	Volume of gas vented during sonic flow conditions ( $Sm^3$ )
$V_{ss}$	Volume of gas vented during subsonic flow conditions ( $Sm^3$ )
$V_{CO2,N2}$	Volume of CO <sub>2</sub> or N <sub>2</sub> injected during well completion or workover ( $Sm^3$ ).
$V_{SG}$	Volume of natural gas recovered into a sales pipeline ( $Sm^3$ ).

- (iii) The operator must calculate CO<sub>2</sub> and CH<sub>4</sub> mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.
- (3) 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) or (f)(2) 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.
- g. Blowdown vent stacks. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (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 physical volume (including, but not limited to, pipe, 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 physical volume between isolation valves is greater than or equal to 1.42 Sm<sup>3</sup>, retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m<sup>3</sup> are exempt from reporting under paragraph (g) of this section.
  - (3) Calculate the venting emissions for each equipment type using **Equation 6-17**.

### **Equation 6-17**

$$E_s = V_v \left[ \frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)P_s} \right]$$

Where:

- E<sub>s</sub> Natural gas venting volumetric emissions from blowdown of an equipment system (Sm<sup>3</sup>).
- V<sub>v</sub> Total physical volume of blowdown equipment chambers (including, but not limited to, yard piping, pipelines, compressors and vessels) between isolation valves for the equipment system (m<sup>3</sup>).
- T<sub>s</sub> Temperature at standard conditions (°C).
- T<sub>a</sub> Temperature at actual conditions in the equipment system (C).
- P<sub>s</sub> Absolute pressure at standard conditions (kPa).
- P<sub>a,1</sub> Absolute pressure at actual conditions in the equipment system prior to depressurization (kPa).

$P_{a,2}$  Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPa).

- (4) Calculate both CH<sub>4</sub> and CO<sub>2</sub> 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 (k) Flare stacks calculation method rather than (g) Blowdown vent stacks calculation method.
- (g.1) Third party line hits. Calculate fugitive emissions from third party line hits as follows:
- (1) For transmission (Section 13) and gathering (Section 6) systems only. Use company gas release data used for regulatory purposes if available. If this data is not available, then for each dig-in incident (i.e., line hit) which results in gas release  $\geq 1.416 \text{ Sm}^3$ , calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below.<sup>4</sup>
    - (i) For catastrophic pipeline ruptures where the pipeline is severed use the following methodology:

### Equation 6-18

$$Q_s = \frac{3.6 \times 10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

### Equation 6-19

$$M = \sqrt{\frac{2 \left[ \left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1 \right]}{K-1}}, \text{ (for } M \leq 1\text{), } M=1, \text{ (for all other cases)}$$

Where:

- Q<sub>s</sub> Natural gas venting volumetric flow rate (Sm<sup>3</sup>/h).
- A Cross-sectional flow area of the pipe (m<sup>2</sup>, A=πD<sup>2</sup>/4000,000)
- D Inside diameter of the pipe (mm).
- K Specific heat ratio of the gas (dimensionless – 1.299 for methane).
- M Mach number of the flow (m/s).
- MW Molecular weight of the gas (kg/mole, 16.043 kg/mole for methane).

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<sup>4</sup> 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). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

$P_e$	Pressure at the damage point (local atmospheric pressure, kPaa).
$P_a$	Pressure inside the pipe at supply (kPaa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.
$R$	Universal gas constant (8.3145 kPam <sup>3</sup> /kmol/K).
$T_a$	Temperature inside pipe at the supply (°C).
$\rho_s$	Gas density at standard conditions (kg/m <sup>3</sup> ) (0.6785 kg/m <sup>3</sup> for CH <sub>4</sub> ).

(ii) For pipeline punctures use the following methodology either individually per puncture or in aggregate (using weighted averages) for all punctures of pipes of a given pressure and pipe type:

### Equation 6-20

$$Q_s = \frac{A_e}{\rho_s} \sqrt{\frac{2000 \times K}{K - 1} P_a \rho_a \left[ \left( \frac{P_{Atm}}{P_a} \right)^{2/K} - \left( \frac{P_{Atm}}{P_a} \right)^{K+1/K} \right]}$$

Where:

### Equation 6-21

$$\left( \frac{P_{Atm}}{P_a} \right) \geq \left( \frac{P_{Atm}}{P_a} \right)_{choked} = \left( \frac{2}{K+1} \right)^{\frac{K}{K-1}} = 0.546 \text{ (for methane)}$$

Where:

$A_e$	Size of the hole in the pipe (as either measured or estimated using engineering estimation techniques) (m <sup>2</sup> ).
$P_a$	Pressure inside the pipe (as either measured or estimated using engineering estimation techniques) at the puncture location (kPa)
$\rho_a$	Gas density inside the pipe at the puncture location (kg/m <sup>3</sup> ).
MW	Molecular weight of the natural gas (16.043 for methane).
$T_a$	Temperature inside the pipe (°C).
$(P_{ATM}/P_a)_c$	0.546 - lower limit for choked flow.

(iii) Determine which quantification method to use

(A) If  $(P_{ATM}/P_a) \geq 0.546$  or the third party line hit is on a distribution pipeline (Section 13) or gathering pipeline (Section 6), the reporter must use the equations in section (c.1) (ii) above.

- (B) If  $(P_{ATM}/P_a) < 0.546$  and the third party line hit is on a transmission main or intermediate pressure line, the reporter must use the equations in section (c.1)(i) above and A must be set to the cross sectional flow area of the pipe.
- (C) When flow is determined through a service tee drill or punch opening the reporter must use an appropriate industry standard quantification method.
- (iv) Calculate volumetric natural gas emissions by multiplying Qs for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.
- (v) Calculate GHG (CH<sub>4</sub> and CO<sub>2</sub> emissions) mass emissions using the methodologies in sections (r) and (s) of this section.
- (2) For distribution systems only: Until updated Canadian Energy Partnership for Environmental Innovation methods are published or otherwise made available and accepted, may use emission factors (45.32 m<sup>3</sup> natural gas/km-main year) and quantification methods available in the Radian Survey reports (Emission Factor Documentation Technical Memorandum, October 2001. Prepared by URS Corporation for the Canadian Energy Partnership for Environmental Innovation).
- h. Production and processing storage tanks. For emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from petroleum and natural gas production facilities and natural gas processing facilities, calculate annual CH<sub>4</sub>, CO<sub>2</sub> (and N<sub>2</sub>O, when flared) emissions as specified in paragraphs (h)(1), (h)(2), (h)(3) or (h)(4). 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) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing emissions using **Equation 6-22**.

### **Equation 6-22**

$$E_i = GOR \times Q_o \times Y_i \times \rho_i \times 0.001$$

Where:

E <sub>i</sub>	Annual emissions of greenhouse gas <i>i</i> (CO <sub>2</sub> or CH <sub>4</sub> ) (tonnes/y).
GOR	Gas Oil Ratio (Sm <sup>3</sup> gas/m <sup>3</sup> oil) measured following 6.4(f).
Q <sub>o</sub>	Oil production rate (m <sup>3</sup> /y).
ρ <sub>i</sub>	Density of GHG <i>i</i> (1.861 kg/m <sup>3</sup> for CO <sub>2</sub> and 0.678 kg.m <sup>3</sup> for CH <sub>4</sub> at standard conditions of 101.325 kPa and 15 °C).
Y <sub>i</sub>	Mole fraction of greenhouse gas <i>i</i> (CO <sub>2</sub> or CH <sub>4</sub> ) in tank vapour.
0.001	Conversion factor (tonnes/kg).

- (2) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing 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.
- (3) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing emissions using a combination of the Vasquez-Beggs Correlation and the Standing Correlation" (see page 16 to 18 of the CAPP Guide: Estimation of Flaring Venting Volumes from Upstream Oil and Gas Facilities, May 2002 for further detail on these correlations).
- (4) Calculate CH<sub>4</sub> and CO<sub>2</sub> flashing emissions using the California ARB Flash Liberation Test procedure in Appendix B of the California GHG reporting rule.

**(h.1) Transmission storage tanks.** For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in natural gas production and processing facilities calculate CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) annual emissions from compressor scrubber dump valve leakage as follows.

- (1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in 6.4(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in 6.4(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in 6.4(a)(4).
- (2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (h.1)(2) of this section to quantify annual emissions:
  - (i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in 6.4(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (h.1)(1) of this section to detect continuous leakage, this serves as the measurement.
  - (ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in 6.4(a)(4).
  - (iii) Use the appropriate gas composition in paragraph (r) of this section.
- (3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

- (4) Calculate annual emissions from storage tanks to flares as follows:
- (i) Use the storage tank emissions volume and gas composition as determined in paragraphs (h.1)(1) through (h.1)(3) of this section.
  - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine storage tank emissions sent to a flare.
- i. Well testing venting and flaring. Calculate CH<sub>4</sub>, CO<sub>2</sub>, and N<sub>2</sub>O (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 and follow paragraph (3). Otherwise follow paragraph (4):
    - (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 6.4(b).
  - (3) Calculation Methodology 1. Estimate venting emissions using **Equation 6-23**.

### **Equation 6-23**

$$E_a = GOR \times Q_o \times t$$

Where:

- E<sub>a</sub> Annual volumetric natural gas emissions from well testing at actual conditions (m<sup>3</sup>/y).
- GOR Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities (m<sup>3</sup> gas/m<sup>3</sup> oil).
- Q<sub>o</sub> Flow rate for the well being tested (m<sup>3</sup> oil/h).
- t Total hours during the year the well is tested (h).

- (4) Calculation Methodology 2. In cases where very little hydrocarbon liquids are produced and the GOR approaches infinity, estimate emissions using **Equation 6-24**. A recording flow meter shall be installed on the vent (or flare) line used to vent gas from the well (e.g. on the vent line off the well-test separator) according to the methods set forth in the 6.4(b).

### **Equation 6-24**

$$E_a = Q_g \times t$$

- E<sub>a</sub> Annual natural gas volumetric emissions at actual conditions (m<sup>3</sup>/y).
- t Total hours during the year the well is tested (h).

$Q_g$  Average flow rate of the measured well venting for the duration of the test at actual conditions ( $\text{m}^3 \text{ gas/h}$ ).

- (5) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
  - (6) Calculate both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (r) and (s) of this section.
  - (7) Calculate emissions from well testing to flares as follows:
    - (i) Use the well testing emissions volume as determined in paragraphs (i)(1) through (4) of this section.
    - (ii) Use the calculation methodology of flare stacks in paragraph (k) of this section to determine well testing gas composition and 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 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 6.4(b).
  - (3) Estimate venting emissions using the **Equation 6-25**.

### **Equation 6-25**

$$E_a = GOR \times Q_o$$

Where:

$E_a$  Annual volumetric natural gas emissions from associated gas venting at actual conditions ( $\text{m}^3/\text{y}$ ).

GOR Gas to oil ratio; oil here refers to hydrocarbon liquids produced of all API gravities ( $\text{m}^3 \text{ gas/m}^3 \text{ oil}$ ).

$Q_o$  Total volume of oil produced for the calendar year during which associated gas was flared or vented ( $\text{m}^3 \text{ oil/y}$ ).

- (4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (q) of this section.
- (5) Calculate both  $\text{CH}_4$  and  $\text{CO}_2$  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 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 composition and emissions from the flare.
- k. Flare stacks. Calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O 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.
  - (2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, the appropriate gas compositions for each stream of hydrocarbons going to the flare must be used as follows:
    - (i) For natural gas production, determine natural gas composition using (r)(2)(i) of this section.
    - (ii) For 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 natural gas processing facilities. For natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.
    - (iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as ethane, butane, pentane-plus, and mixed light hydrocarbons then a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data may be used.
  - (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 Equation 6-26:, Equation 6-27:, Equation 6-28:, and Equation 6-29:.

**Equation 6-26:**

$$E_{s,CH_4}(\text{noncumbusted}) = Q_s \times (1 - \eta) \times Y_{CH_4}$$

**Equation 6-27:**

$$E_{s,CO_2}(\text{noncumbusted}) = Q_s \times Y_{CO_2}$$

**Equation 6-28:**

$$E_{s,co2}(\text{combusted}) = \sum_i \eta \times Q_s \times Y_i \times n_i$$

**Equation 6-29:**

$$E_{s,co2}(\text{total}) = E_{s,co2}(\text{combusted}) + E_{s,co2}(\text{noncombusted})$$

Where:

$E_{s,CH_4}$ (noncombusted)	Contribution of annual noncombusted volumetric CH <sub>4</sub> emissions from flare stack (Sm <sup>3</sup> ).
$E_{s,CO_2}$ (noncombusted)	Contribution of annual volumetric CO <sub>2</sub> emissions from CO <sub>2</sub> in the inlet gas passing through the flare noncombusted (Sm <sup>3</sup> ).
$E_{s,CO_2}$ (combusted)	Contribution of annual CO <sub>2</sub> emissions from combustion from flare stack under ambient conditions (Sm <sup>3</sup> ).
$Q_s$	Volume of natural gas sent to flare during the year (Sm <sup>3</sup> ).
$\eta$	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, $\eta$ is zero.
$Y_{CH_4}$	Mole fraction of CH <sub>4</sub> in gas to the flare.
$Y_{CO_2}$	Mole fraction of CO <sub>2</sub> in gas to the flare.
$Y_i$	Mole fraction of hydrocarbon constituents $i$ (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
$n_i$	Number of carbon atoms in the hydrocarbon constituent $i$ (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

- (5) Calculate both CH<sub>4</sub> and CO<sub>2</sub> mass emissions from volumetric CH<sub>4</sub> and CO<sub>2</sub> emissions using calculation in paragraph (s) of this section.
- (6) Calculate N<sub>2</sub>O emissions using **Equation 6-30**.

**Equation 6-30**

$$E_{N2O} = Q_s \times HHV \times EF \times 0.001$$

Where:

$E_{N2O}$	Annual N <sub>2</sub> O mass emissions from flaring (tonnes/y).
$Q_s$	Volume of gas combusted by the flare in the reporting period (Sm <sup>3</sup> /y).
HHV	High heat value of the flared gas from paragraph (k)(2).
EF	N <sub>2</sub> O emission factor. Use $9.52 \times 10^{-5}$ kg N <sub>2</sub> O/GJ.
0.001	Conversion factor from kilograms to tonnes.

- (7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in 6.3. Where gas to be flared is manifolded from multiple sources in 6.3 to a common flare, report all flaring emissions under 6.3(k).
1. **Centrifugal Compressor Venting.** Calculate emissions from all centrifugal compressor vents as follows. Dry seal and wet seal centrifugal compressors can enter the following operating modes (1) “operating, pressurized”, (2) “stand-by, pressurized” and (3) “not-operating, depressurized”.
    - (1) The operator must calculate CO<sub>2</sub>, and CH<sub>4</sub>, and N<sub>2</sub>O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) where the aggregate rated power for the sum of compressors at the facility is 186.4 kW or greater using a temporary or permanent flow measurement meter such as, but not limited to, a portable utility grade (bellows) meter, high-flow sampler or a vane anemometer according to methods set forth in 6.4(b).
    - (2) Estimate annual emissions using flow meter measurement using **Equation 6-31**.

### **Equation 6-31**

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Where:

- E<sub>s,i</sub> Annual volumetric emissions of GHG i (either CH<sub>4</sub> or CO<sub>2</sub>) from all compressor venting modes (Sm<sup>3</sup>/y).
- Q<sub>s,m</sub> Measured volumetric gas emissions during operational mode m described in paragraph (l)(4) of this section (Sm<sup>3</sup>/h).
- m The operational mode of a centrifugal compressor.
- t<sub>m</sub> Total time the compressor is in operational mode m during the calendar year (h).
- Y<sub>i</sub> Mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
- CF Fraction 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.

(2.1) To ensure that emissions for modes not found during the annual measurement are included in reported estimates, **Equation 6-32a** must be used to calculate total emissions:

### **Equation 6-32a**

$$E_{s,i,c} = E_{s,i} + E_{m,nf}$$

Where:

$E_{s,i}$  Output of

**Equation 6-32.**

$E_{m,nf}$  Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used, in order of preference.

- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor. Alternatively, a source-specific emissions factor can be established by measuring the emissions from relevant sources during each operational mode.
- (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. As applicable, measure emissions from (including emissions manifolded to common vents) degassing vents, unit isolation-valve vents, and blowdown-valve vents. If there is a safety risk that cannot be (reasonably) mitigated with measuring emissions from a specific vent line, a request for exemption of measurement that is accompanied by documentation (including photos showing and written description of the issue and measurement options contemplated) must be provided to the regulatory Director who may indicate that an emission factor approach be used instead. Given that there is not a requirement to measure in the winter months, winter safety would not be applicable evidence unless the site were winter access only. Consideration of practices of industry peers would need to be considered.
  - (i) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and wet seal oil degassing vent (if applicable); for wet seal and dry seal compressors.
  - (ii) Standby pressurized mode.
  - (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 the compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance). 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 not operating

depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the not operating depressurized mode.

- (5) The operator must calculate CO<sub>2</sub>, and CH<sub>4</sub>, and N<sub>2</sub>O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) for all compressors where the aggregate rated power for the sum of all compressors at the facility is less than 186.4 kW (250 hp) using
- (6) **Equation 6-32.**
  - (i) Adjust the emissions estimated in paragraph (5) of this section downward by the magnitude of emissions recovered using a vapour recovery system as determined by an engineering estimate based on best available data.

### **Equation 6-32**

$$E_{s,i} = \text{Count} \times EF_i$$

Where:

E <sub>s,i</sub>	Annual total volumetric GHG i emissions at standard conditions from centrifugal compressors (m <sup>3</sup> /year).
Count	Total number of centrifugal compressors where their aggregate rated power is less than 186.4 kW.
EF <sub>i</sub>	Emission factor for GHG i (either CH <sub>4</sub> or O <sub>2</sub> ). Use 339,573.2 Sm <sup>3</sup> /year per compressor for CH <sub>4</sub> and 14,974.7 Sm <sup>3</sup> /year per compressor for CO <sub>2</sub> at 15 °C and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law if the default emission factor does not appropriately quantify emissions for the compressor, use the manufacturer default emission factor instead.

- (7) Calculate both CH<sub>4</sub> and CO<sub>2</sub> mass emissions from volumetric emissions using calculations in paragraph (s) of this section.
  - (i) Emissions from centrifugal compressor, blow down valve leakage and unit isolation valve leakage to open ended vents must be determined following the procedures set forth in 14.4(c) and (d), or other industry standard method, as appropriate.
- m. Reciprocating compressor venting. Calculate annual CH<sub>4</sub> and CO<sub>2</sub> emissions from all reciprocating compressor vents as follows, except as specified in paragraph (m)(7) . Where venting emissions are sent to a common flare, calculate emissions using 6.3(k). A reciprocating compressor's operational modes include "operating, pressurized", "standby, pressurized mode" and "not operating, depressurized".
  - (1) Estimate annual emissions using the flow measurement in (m)(2) or (m)(3) below and **Equation 6-33.**

### Equation 6-33

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Where:

- $E_{s,i}$  Annual volumetric emissions of GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>) from all compressor venting modes (Sm<sup>3</sup>/y).
- $Q_{s,m}$  Measured volumetric gas emissions during operational mode  $m$  described in paragraph (m)(4) (Sm<sup>3</sup>/h).
- $m$  The operational mode of a reciprocating compressor.
- $t_m$  Total time the compressor is in operational mode  $m$  during the calendar year (h).
- $Y_i$  Annual average mole fraction of GHG  $i$  in the vent gas; use the appropriate gas compositions in paragraph (r)(2) of this section.
- CF Fraction of reciprocating 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.

- (1.1) To ensure that emissions for modes not found during the annual measurement are included in reported estimates, **Equation 6-34a** must be used to calculate total emissions:

### Equation 6-34a

$$E_{s,i,c} = E_{s,i} + E_{m,nf}$$

Where:

- $E_{s,i}$  Output of **Equation 6-34**.
- $E_{m,nf}$  Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used, in order of preference.

- (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-flow Sampler according to methods set forth in 6.4(c) and (d).

- (ii) Use a temporary meter such as a portable utility grade (bellows) meter or 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 6.4(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 6.4(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 6.4(a) to conduct a progressive 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 6.4(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the operational mode in which it is found during the annual measurement, except as specified in paragraph (m)(7) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod-packing vents, unit isolation-valve vents, and blowdown-valve vents. If there is a safety risk that cannot be (reasonably) mitigated with measuring emissions from a specific vent line, a request for exemption of measurement that is accompanied by documentation (including photos showing and written description of the issue and measurement options contemplated) must be provided to the regulatory Director who may indicate that an emission factor approach be used instead. Given that there is not a requirement to measure in the winter months, winter safety would not be applicable evidence unless the site were winter access only. Consideration of practices of industry peers would need to be considered.
- (i) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and reciprocating rod packing emissions.
  - (ii) Standby pressurized mode.
  - (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 the compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance). 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 not operating depressurized mode without blind flanges in place and is not operated

- throughout the 3 year period, it must be measured in the not operating depressurized mode.
- (5) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (r) and (s) of this section.
  - (6) 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.
    - (ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the Q<sub>s,m</sub> variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year.
  - (7) Petroleum and natural gas production may calculate emissions from reciprocating compressors where the aggregate rated power for the sum of all compressors at the facility is less than 186.4 kW (250 hp) as follows using **Equation 6-34**.
    - (i) Adjust the emissions estimated in paragraph (7) of this section downward by the magnitude of emissions recovered using a vapour recovery system as determined by an engineering estimate based on best available data.

#### **Equation 6-34**

E <sub>s,i</sub>	Annual total volumetric GHG i emissions at standard conditions from reciprocating compressors (m <sup>3</sup> /year).
Count	Total number of reciprocating compressors considered under (m)(7) for the reporter.
EF <sub>i</sub>	Emission factor for GHG i (either CH <sub>4</sub> or O <sub>2</sub> ). Use 268.0 Sm <sup>3</sup> /year per compressor for CH <sub>4</sub> and 14.9 Sm <sup>3</sup> /year per compressor for CO <sub>2</sub> at 15 °C and 1 atmosphere, or as adjusted for different reference temperatures using ideal gas law. If the default emission factor does not appropriately quantify emissions for the compressor, use the manufacturer default emission factor instead.

- n. Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in 6.4(a)(0.1) or progressive sampling methods (described in 6.4(a)(0.2)) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in 6.2(d)(9). This paragraph (n) applies to emissions sources in streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight need to be reported instead under paragraph (x) of this section. \*\*

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using **Equation 6-35** for each source with fugitive equipment leaks.

### **Equation 6-35**

$$E_{s,i} = EF_{s,1} \times Y_i \times t_1$$

Where:

$E_{s,i}$  Annual total volumetric emissions of GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>), from each fugitive equipment leak source (Sm<sup>3</sup>/y).

$EF_{s,1}$  Leaker volumetric emission factor for specific component, 1, 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 6-35**).

$Y_i$  For natural gas processing facilities, mole fraction of GHG  $i$  (either CH<sub>4</sub> or CO<sub>2</sub>) in the total hydrocarbon of the feed natural gas.

$t_1$  Total time the component, 1, 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 last survey during which it was determined to be not leaking, 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) 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.

\* component-specific emission factors may equal leak rates quantified, following 6.4(c) or (d), during leak detection surveys.

\*\* tubing systems less than one half inch diameter may be quantified using 6.3(n), instead of 6.3(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using 6.3(x). Reporting must occur using the appropriate section of 6.2, dependent upon quantification method used.

- o. Population count and emission factors. This paragraph applies to emissions sources listed in 6.2 (c)(16), (c)(17) and (d)(8) on streams with gas containing greater than 10

percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight do not need to be reported. In addition, emission sources at which a leak detection has been conducted and reported under 6.3(n) (either voluntarily or required under Section 6.3(n)) are exempt from the following requirements).\*\*

- (1) Calculate emissions from all sources listed in this paragraph using **Equation 6-36** except for emissions from underground gathering pipelines that are calculated in paragraph (2).

### **Equation 6-36**

$$E_i = \sum_k \sum_l \left( N_{k,l} \times \frac{EF_{k,l}}{THC_k} \times X_{i,k} \right) \times t$$

Where:

- E<sub>i</sub> Annual total mass emissions of GHG i (CH<sub>4</sub> or CO<sub>2</sub>) at standard conditions from each major equipment or component count fugitive source at the facility (tonnes/year).
- N<sub>k,l</sub> Number of components in service k and component type l. Component counts for individual facilities must be used. 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. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts.
- EF<sub>k,l</sub> Population mass emission factor for components in service k and component type l listed in Table 6-1 or Table 6-2. The direction on the use of Table 6-1 and Table 6-2 provided prior to these tables must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used\* (tonnes total hydrocarbon (THC) / component / h).
- THC<sub>k</sub> Mass fraction of total hydrocarbons in service k.
- X<sub>i,k</sub> Mass fraction of GHG i (CH<sub>4</sub> or CO<sub>2</sub>) in service k.
- t Total time the specific source associated with the fugitive equipment leak was operational in the reporting year (h).

- (2) Calculate emissions from underground gathering pipelines using **Equation 6-37**.

### **Equation 6-37**

$$E_{s,i} = EF_{s,i} \times L \times t$$

Where:

$E_{s,i}$	Annual total volumetric emissions of GHG $i$ (either CH <sub>4</sub> or CO <sub>2</sub> ), from an underground gathering pipeline (Sm <sup>3</sup> /y).
EF <sub>s,i</sub>	Volumetric emission factors equal to $2.66 \times 10^{-5}$ t CH <sub>4</sub> /km/h and $3.63 \times 10^{-6}$ t CO <sub>2</sub> /km/h for pipeline leaks plus the portion of methane emitted from underground leaks that is oxidized to form carbon dioxide and equal to $2.72 \times 10^{-6}$ t CO <sub>2</sub> /km/h. These factors are published in Table 6-4 of the American Petroleum Institute (API) 2009 Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry.
L	Length of the underground gathering pipeline (km).
t	Total time the underground gathering pipeline was operational in the reporting year (h).

- (3) Petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table 6-1 or Table 6-2 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 6-1 or Table 6-2 shall be used to estimate all streams of gases, including the recycle CO<sub>2</sub> 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 petroleum and natural gas production operations in the facility perform the following activities:
    - (A) Count all major equipment listed in Table 6-3 of this section.
    - (B) Multiply major equipment counts by the average component counts in Gas/Vapour, Fuel Gas and Liquid service listed in Table 6-3 of this section for natural gas production and oil production, respectively. Use the appropriate total hydrocarbon (THC) factor in Table 6-1 or Table 6-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Table 6-1 or Table 6-2.
  - (ii) Component Count Methodology 2. Count each component individually for the facility. Use the appropriate factor Table 6-1 or Table 6-2 of this section or from CAPP methodology manuals, if the appropriate factor is not provided in Table 6-1 or Table 6-2.

\* facility/company-specific emission factors may equal leak rates quantified, following 6.4(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of 6.7 – Directions for the use of Tables 6-1 and 6-2.

\*\* tubing systems less than one half inch diameter may be quantified using 6.3(n), instead of 6.3(x) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using 6.3(x). Reporting must occur using the appropriate section of 6.2, dependent upon quantification method used.

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- q. Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (q)(1) or (2), with actual pressure and temperature determined by engineering estimate based on best available data unless otherwise specified.
- (1) Calculate natural gas volumetric emissions at standard conditions by converting the actual temperature and pressure to standard temperature and pressure (15 °C and 1 atmosphere in Canada) using **Equation 6-38** of this section.

### **Equation 6-38**

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Where:

- $E_s$  Natural gas volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).
- $E_a$  Natural gas volumetric emissions at actual conditions ( $\text{m}^3$ ).
- $T_s$  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 actual conditions (kPa).

- (2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using **Equation 6-39**.

### **Equation 6-39**

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Where:

- $E_{s,i}$  GHG  $i$  volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).
- $E_{a,i}$  GHG  $i$  volumetric emissions at actual conditions ( $\text{m}^3$ ).
- $T_s$  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 actual conditions (kPa).

- r. GHG volumetric emissions. If the GHG volumetric emissions at actual conditions are known, follow the method in (q)(2) to calculate their emissions at standard conditions.

If the GHG volumetric emissions are not yet known, then follow the methods below to 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<sub>4</sub> and CO<sub>2</sub> emissions from natural gas emissions using **Equation 6-40**.

#### **Equation 6-40**

$$E_{s,i} = E_s \times Y_i$$

Where:

E<sub>s,i</sub> GHG *i* (CH<sub>4</sub> or CO<sub>2</sub>) volumetric emissions at standard conditions.

E<sub>s</sub> Natural gas volumetric emissions at standard conditions.

Y<sub>i</sub> Mole fraction of GHG *i* in the natural gas.

- (2) For **Equation 6-40** of this section, the mole fraction, Y<sub>i</sub>, 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 petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in 6.4(b).
  - (ii)(a) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and (b) 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 natural gas processing facilities. For natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use an annual average of these values to determine the mole fraction in calculating emissions. If you do not have a continuous gas composition analyzer, then use an annual average of the known composition (in required order of preference) for the (i) facility; or (ii) company for the specific field must be used as taken according to methods set forth in 6.4(b).
- s. **GHG mass emissions.** Calculate GHG mass emissions in tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using **Equation 6-41**.

### **Equation 6-41**

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

Where:

$E_i$	GHG $i$ (either CH <sub>4</sub> , CO <sub>2</sub> , or, N <sub>2</sub> O mass emissions (tonnes CO <sub>2</sub> e)).
$E_{s,i}$	GHG $i$ (either CH <sub>4</sub> , CO <sub>2</sub> , or, N <sub>2</sub> O) volumetric emissions (Sm <sup>3</sup> ).
$\rho_{s,i}$	Density of GHG $i$ , (1.861 kg/m <sup>3</sup> for CO <sub>2</sub> and 0.678 kg/m <sup>3</sup> for CH <sub>4</sub> at standard conditions of T <sub>s</sub> =15 C and P <sub>s</sub> -101.325 kPa) $= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$
$WP_i$	Global warming potential of GHG $i$ (1 for CO <sub>2</sub> and 21 for CH <sub>4</sub> , and 310 for N <sub>2</sub> O).
$MW_i$	Molecular weight for GHG <sub>i</sub> taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).
$R_u$	Universal gas constant (8.31434 kJ/kmole K)
0.001	Conversion factor from kilograms to tonnes.

- 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 6-42**.

### **Equation 6-42**

$$E_i = N \times V_v \times \rho_c \times X_i \times 0.001$$

Where:

$E_i$	Annual EOR injection gas venting mass emissions at critical conditions c from blowdowns (tonnes/y).
$N$	Number of blowdowns for the equipment in reporting year.
$V_v$	Total physical volume of blowdown equipment chambers (including, but not limited to, pipelines, manifolds and vessels) between isolation valves (m <sup>3</sup> ).
$\rho_c$	Density of critical phase EOR injection gas (kg/m <sup>3</sup> ). 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.
$X_i$	Mass fraction of GHG <sub>i</sub> in critical phase injection gas.
0.001	Conversion factor from kilograms to tonnes.

- u. Hydrocarbon liquids dissolved CO<sub>2</sub> from flashing [Reserved]
- v. Produced water dissolved CO<sub>2</sub> / Coal bed methane produced water emissions [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.
    - (i) Calculate the CO<sub>2</sub> and CH<sub>4</sub> emissions using either the Tier 3 or Tier 4 methodology in Section 4. Sampling, analysis and measurement requirements (including for gas composition) required for Petroleum and Natural Gas Production and Natural Gas Processing in 4.5.6 apply in place of those indicated for **Equation 4-7:**, or
    - (ii) When measurement data is not available and if the measured higher heating value is equal to or greater than 36.3 MJ/m<sup>3</sup> and less than 40.98 MJ/m<sup>3</sup>, then calculate the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions using the methods in Section 4 following the methods required for pipeline quality natural gas.
  - (2) Maintain the General Stationary Fuel Combustion (section 4) methodology, required by paragraph (1) of this section, for subsequent reporting years.
- x. Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in 6.3 must be calculated by methodologies consistent with those presented here, the 2009 API Compendium, or other similar resource documents.

## 6.4 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 appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

- a. Leak Detection
  - (1) 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. A minimum of 12 months and a maximum of 36 months is allowed between surveys.
  - (2) If there is no such legal requirement (as specified in paragraph (a)(1) of this section), then representative 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 (g) or WCI.363(n), as applicable. Representative sampling means establishing the most valid or credible sample of leaks that accurately characterizes the number of fugitive equipment leaks required per sample interval, under operating conditions. A baseline representative sample of leaks must be established under normal operating conditions for the 2011 and 2012 calendar years or upon acquisition of previously operated equipment or within the first year of operation of newly constructed or acquired equipment. Subsequent representative sampling must be based on random or stratified sampling, modeling, detection or measurement of leaks under normal operating conditions. After establishing the baseline representative sample of leaks per sample interval a maximum of 36 months is allowed between sampling. The interval is determined based on whether there are leaks. If a leak is found and immediately repaired, the existing schedule may be maintained. If a leak is found and not repaired the maximum interval between sampling is 18 months and the leak must be monitored (and optionally measured) on a regular basis until repaired. If the equipment is replaced the maximum sampling interval is 18 months until a baseline representative sample of leaks has been established under normal operating conditions.

Leak detection for fugitive equipment leaks must be performed for all identified equipment in operation or on standby mode.

- (3) 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 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 inspection 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.
- (4) Bubble tests
- (5) 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.
- (6) 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, and the methods 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 appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to an appropriate standard 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, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB) . If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), Canadian Gas Association (CGA) or American Petroleum Institute (API) may be used. 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) Correct the natural gas volumetric emissions to standard conditions using the calculations in 6.3(q).
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in 6.3(r) and (s).
- d. Use a High-flow Sampler to measure emissions within the capacity of the instrument.
  - (1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH<sub>4</sub> by using calibrated gas samples and by following manufacturer's instructions for calibration.
  - (2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, including, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
  - (3) If the High-flow 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.

- (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in 6.3(r) and (s).
- e. Peng Robinson Equation of State means the equation of state defined by **Equation 6-43** of this section.

### Equation 6-43

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2}$$

Where:

$p$       Absolute pressure.  
 $R$       Universal gas constant.  
 $T$       Absolute temperature.  
 $V_m$     Molar Volume.

$$a = \frac{0.45724R^2T_c^2}{p_c}$$

$$b = \frac{0.7782RT_c}{p_c}$$

$$\alpha = \left( 1 + (0.37464 + 1.54226\omega - 0.26992\omega^2) \left( 1 - \sqrt{\frac{T}{T_c}} \right) \right)^2$$

Where:

$\omega$     Acentric factor of the species.  
 $T_c$     Critical temperature.  
 $P_c$     Critical pressure.

f. 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 standard 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 m<sup>3</sup>/day, semi-annual for oil production rates between 15.9 and 79.5 m<sup>3</sup>/day, and quarterly for oil production rates greater than 79.5 m<sup>3</sup>/day.
- (4) An additional sample shall be collected 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  $\pm 5\%$ .

## 6.5 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.

## **6.6 Tables Relevant to Petroleum and Natural Gas Production and Natural Gas Processing**

*\*Note for all tables: As the reference materials for these tables are updated periodically with newer information, all tables should be viewed to read “as amended from time to time”.*

### **Directions for the use of Tables 6-1 and 6-2**

- a. For each component listed in the Tables 6-1 to 6-2 or otherwise required by the quantification method referencing Tables 6-1 and 6-2:
  - (1) If statistically valid facility-specific emission factors for a component type are available they must be used. If statistically valid facility-specific emission factors can be reasonably developed using existing company leak detection data then they must be used.
  - (2) If facility-specific emissions factors for a component type are not available, an operator must use statistically valid company specific emission factors if they are available. If statistically valid company-specific emission factors can be reasonably developed using existing company leak detection data then they must be used.
- b. If statistically valid facility or company-specific emission factors for a specific component are not available, emission factors in the default Tables 350-1 to 350-5 / 6-1 to 6-2 may be used.
- c. If a facility-specific or company-specific emission factor has been used in a previous reporting year, it must continue to be used until any changes are approved by the jurisdiction.
- d. (For WCI.350) 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 the 2013 Canadian Energy Partnership for Environmental Innovation Methodology Manual (as amended from time to time) or U.S. EPA 40 CFR Part 98.230 Tables W-3 through W-7 (in order of preference), may be used (as converted for use in the relevant equation). (For WCI.360) If an emission factor required by the quantification method referencing Tables 6-1 to 6-2 is not provided in the tables, emissions factors from either U.S. EPA CFR Part 98.230 Tables W1A or W2 or the Clearstone Engineering Ltd. A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H<sub>2</sub>S) Emissions by the Upstream Oil and Gas Industry, Volume 5, September, 2004 (as amended from time to time, or in updated format) may be used (as converted for use in the relevant equation).
- e. 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.

- f. Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.

**Table 6-1: 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 vapour	1.70E-05
Pressure relief valves - light liquid	5.39E-06
Pressure regulators - fuel gas and gas/vapour	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
Pump seals - light liquid	2.32E-05

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 6-2: Additional Oil Facility Average Emission Factors**

<b>Component - Service</b>	<b>Emission Factor, tonnes THC/Component-hr</b>
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
Pump seals - heavy liquid	3.20E-08
Pump seals - light liquid	2.32E-05

**Directions for the Use of Table 6-3**

- a. Major equipment listed in Tables 6-3 includes components located between the first flange of the process identified and the last flange before the next process.
- b. When delineation between major equipment is not possible, individual component counts should be completed.

**Table 6-3: Default Major Equipment Component Counts for Canada**

MAJOR EQUIPMENT	SERVICE	Connectors	Pressure Relief Valves	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
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 Valves	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
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

**Table 6-4: Additional Natural Gas-Driven Pneumatic Device Average Emission Factors**

Pneumatic Device Type	Emission Factor (Sm <sup>3</sup> /hour/device) Prasino Final Pneumatic Field Sampling Report* or EPA Subpart W Table W-1A** or Table W-3***
Low-bleed pneumatic device vents**	0.0510
High continuous bleed pneumatic device vents*	0.2605
Intermittent high bleed pneumatic device vents*	0.2476
Intermittent low bleed pneumatic device vents***	6.65E-2
Diaphragm Pumps*	1.0542 E-0
Piston Pumps*	5.917 E-1

**Table 6-5: Original 2011 Average Manufacturer Bleed Rates for Pneumatic Controllers, Positioner, Transmitters and Transducers**

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate ( $\text{Sm}^3/\text{h}$ ) <sup>4</sup>
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (Sm <sup>3</sup> /h) <sup>4</sup>
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:

1 Canadian Association of Petroleum Producers. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.

2 United States Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. Washington, DC. 2006. Appendix A converted to metric units.

3 Various manufacturer specification publications.

4 Factors equal to zero indicate that the device does not vent gas.

**Table 6-5a Updated 2013 Average Manufacturer Bleed Rates for Pneumatic Controllers, Positioner, Transmitters and Transducers**

Pneumatic Device	Average Bleed Rate (m <sup>3</sup> /hr)	Coefficients (supply pressure, injection pressure, strokes per min)	Equivalent Device
Generic High Bleed Controller	0.2605	0.0012	-
Generic High Bleed Intermittent Controller	0.2476	0.0012	-
<b>Pressure Controllers</b>			
Fisher 4150	0.4209	0.0019	4150K, 4150R, 4160, CVS 4150
Fisher C1	0.0649	-	-
Fisher 4660	0.0151	0.0003	4660A
<b>Level Controllers</b>			
Fisher 2500	0.3967	0.0011	2500S, 2503, L3
Fisher 2680	0.2679	0.0014	2680A
Fisher 2900	0.1447	-	2900A, 2901, 2901A
Fisher L2	0.2641	0.0012	-
Murphy LS1200	0.2619	0.0012	LS1100, LS1200N, LS1200DVO
Norriseal 1001	0.1868	-	1001A, 1001XL
SOR 1530	0.0531	-	-
<b>Positioners</b>			
Fisher Fieldvue DVC6000	0.2649	0.0011	6030, 6020, 6010
<b>Temperature Controllers</b>			
Kimray HT-12	0.0351	-	-
<b>Transducers</b>			
Fairchild TXI7800	0.1543	0.0009	TXI7850
Fisher 546	0.3547	0.0017	546S
Fisher I2P-100	0.2157	0.0009	-
<b>Pumps</b>			
Generic Piston Pump	0.5917	0.00202, 0.000059, 0.0167	-
Generic Diaphragm Pump	1.0542	0.0005, 0.000027, 0.0091	-
Morgan HD312	1.1292	0.00418, 0.000034, 0.0073	HD312-3K, HD312-5K
Texsteam 5100	0.9670	0.0003, 0.000034, 0.0207	5100LP, 5100H
Williams P125	0.4098	0.00019, 0.000024, 0.0076	-
Williams P250	0.8022	0.00096, 0.000042, 0.0079	-
Williams P500	0.6969	0.00224, -0.000031, 0.0046	-

Notes:

1. If an updated version of this table is made available by the appropriate regulator, then the updated version must be used. If improved emission factors for pneumatic devices and pumps (such as low bleed devices and further intermittent devices) are published and then made available by the appropriate regulator, then they must be used in place of those listed in the combination of the table below and the existing Table 6-5

2. This table provides a list of equivalent pneumatic controllers. If a controller is listed in the equivalents column, then the emission factor or coefficient(s) for the equivalent manufacturer and model provided must be used

3. Controllers that do not have a coefficient should use the mean bleed rate instead of the bleed rate equation

**Table 6-6: Nomenclature (Subscripts, Variables and Their Descriptions)**

Variable Name	Description
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance.
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 °C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
$\rho$	Variable - density
$\square$	Variable – efficiency (fractional)

# 7. Pulp and Paper

## 7.1 Activity Definition

The production of market pulp or pulp and paper at a facility that has chemical recovery, semi-chemical recovery and lime kilns.

## 7.2 Greenhouse Gas Reporting Requirements

In addition to the reporting requirements specified in section 4: General Stationary Fuel Combustion and section 4 and section 5: Mobile Equipment, the following reporting requirements are compulsory.

A person shall set out the following information, calculated for the calendar year using standard quantification methods specified in this section, in an GHG report prepared for a calendar year in respect of pulp and paper production at a facility:

- (a) Annual CO<sub>2</sub>, biogenic CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O process emissions from all units at the facility combined in tonnes, as specified in Section 7.3.
- (b) Annual CO<sub>2</sub> emissions from addition of makeup chemicals (CaCO<sub>3</sub>, Na<sub>2</sub>CO<sub>3</sub>) in the chemical recovery areas of chemical pulp mills.
- (c) Annual consumption of carbonate in tonnes.
- (d) Annual black liquor production in tonnes.
- (e) **Production parameter:** Annual pulp production in tonnes of air dried pulp.

## 7.3 Calculation of GHG Emissions

Calculate emissions from each unit (i.e., kraft or soda chemical recovery furnace, sulfite chemical recovery combustion unit, stand-alone semi-chemical recovery combustion unit, or kraft or soda pulp mill lime kiln) as specified under paragraphs (a) through (e) of this section. CH<sub>4</sub> and N<sub>2</sub>O emissions shall be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

- a. Calculate and report fossil-fuel combustion emissions from direct measurement of fossil fuels consumed and the methodologies for general stationary combustion sources specified by Section 4: General Stationary Fuel Combustion.

- b. For kraft or soda pulp mill lime kilns, calculate fossil-fuel based CH<sub>4</sub> and N<sub>2</sub>O emissions from direct measurement of fossil fuels consumed. Use default HHV, and default emission factors in Table 7-1, where applicable but calculations should be according to the methodology specified in Section 4.
- c. For pulp and paper production, calculate biogenic CO<sub>2</sub> emissions and emissions of CH<sub>4</sub> and N<sub>2</sub>O from biomass as specified under subparagraphs (1) through (3).

- (1) For **kraft or soda chemical recovery furnaces**, calculate emissions using **Equation 7-1:**

**Equation 7-1:**

$$Emissions = Solids \times HHV \times EF$$

Where:

Emissions	Biogenic CO <sub>2</sub> emissions and emissions of CH <sub>4</sub> and N <sub>2</sub> O 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 CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O from Table 7-1 (kg/GJ)

- (2) For **sulfite or stand-alone semi-chemical or chemical recovery combustion units**, calculate CO<sub>2</sub> emissions using **Equation 7-2:**

**Equation 7-2:**

$$E_{CO_2} = 3.664 \times Solids \times CC$$

Where:

E <sub>CO<sub>2</sub></sub>	Biogenic CO <sub>2</sub> emissions from spent liquor solids combustion (tonnes/year).
3.664	Ratio of molecular weights, CO <sub>2</sub> to carbon.
Solids	Mass of spent liquor solids combusted (tonnes/year).
CC	Annual carbon content of spent liquor solids (per cent by weight, expressed as a decimal fraction).

- (3) For **sulfite or stand-alone semi-chemical or chemical recovery combustion units**, calculate CH<sub>4</sub> and N<sub>2</sub>O from biomass using **Equation 7-1:**

For make-up chemical use, calculate CO<sub>2</sub> emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO<sub>2</sub> and make-up chemicals using **Equation 7-3.**

**Equation 7-4:**

$$CO_2 = \left( \left[ M_{CaCO_3} \times \frac{44}{100} \right] + \left[ M_{Na_2CO_3} \times \frac{44}{105.99} \right] \right)$$

Where:

CO <sub>2</sub>	CO <sub>2</sub> emissions from make-up chemicals (tonnes/year).
M <sub>CaCO<sub>3</sub></sub>	Make-up quantity of CaCO <sub>3</sub> used for calendar year (tonnes/year).
M <sub>Na<sub>2</sub>CO<sub>3</sub></sub>	Make-up quantity of Na <sub>2</sub> CO <sub>3</sub> used for calendar year (tonnes/year).
44	Molecular weight of CO <sub>2</sub> .
100	Molecular weight of CaCO <sub>3</sub> .
106	Molecular weight of Na <sub>2</sub> CO <sub>3</sub> .

- d. Calculate and report fossil-fuel combustion emissions from mobile equipment sources operating within the facility boundary as specified by section 5: Mobile Equipment.

## **7.4 Sampling, Analysis, and Measurement Requirements**

At least annually, determine the high heat value, annual mass and carbon content of spent liquor solids using any of the following methods. If measurements are performed more frequently than annually, then fuel properties shall 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 one of the following methods:
  - (1) ASTM D5373;
  - (2) ASTM 5291;
  - (3) Any of the other analytical methods listed in the Technical Reference Document section of this Guideline (section 3);

- (4) The most appropriate method published by a consensus-based standards organization; or
- (5) If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

## 7.5 Procedures for Estimating Missing Data

- a. Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed above under “Sampling, Analysis, and Measurement Requirements”, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

### Determination of Quantity

- b. For all data that does not concern the quantity of spent pulping liquor, utilize the standard methods described under Chapter 16 – “Procedures for Estimating Missing Data”.
- c. When the missing data concerns the quantity of spent pulping liquor, the mass flow of spent pulping liquor, the annual production of each pulp and paper product manufactured or the quantity of carbonate material, the replacement data shall be estimated on the basis of all the data relating to the processes used.

## 7.6 Tables Relevant to Pulp and Paper

**Table 7-1: Kraft Lime Kiln and Calciner Emission Factors for Fossil Fuel-Based CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O**

Fuel	Fossil Fuel-Based Emission Factors (kg/GJ HHV)					
	Kraft Lime Kilns			Kraft Calciners		
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Residual Oil	72.7	0.0026	0	72.7	0.0026	0.00028
Distillate Oil	69.7			69.7		0.00038
Natural Gas	51.16			51.16		0.00009
Biogas	0			0		0.00009

**Table 7-2: Biomass-Based Emissions Factors for pulp and paper  
CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O**

Biomass Fuel	CO <sub>2</sub> Emission Factor kg/GJ	CH <sub>4</sub> Emission Factor g/GJ	N <sub>2</sub> O Emission Factor g/GJ
Wood Fuel/ Wood waste	76	0.009	0.006
Spent Pulping Liquor-softwood	89.5	0.0024	0.002
Spent Pulping Liquor- hardwood	88.8		
Spent Pulping Liquor- straw	90.1		

## **8. Coal Storage**

### **8.1 Activity Definition**

Coal storage piles release fugitive CH<sub>4</sub> emissions. Within natural coal deposits, CH<sub>4</sub> is either trapped under pressure within porous void spaces or adsorbed to the coal. Post coal mining activities (e.g. preparation, handling, processing, transportation and storage) release pressurized CH<sub>4</sub> to the atmosphere. Adsorbed CH<sub>4</sub> is released until the CH<sub>4</sub> in the coal reaches equilibrium with the surrounding atmospheric conditions.

For the purposes of this activity definition, coal storage activities are located at any facility that combusts coal. Therefore, coal storage activities at coal mines are excluded from this activity definition (as they do not combust coal). Note that the methodology below for the calculation of CH<sub>4</sub> 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 CH<sub>4</sub> emissions to the facility combusting the coal, which is ultimately responsible for the coal having been processed and delivered to the facility. As such, coal storage activities at coal mines are not included within this activity definition.

### **8.2 Greenhouse Gas Reporting Requirements**

A facility shall set out the following information, calculated for the calendar year using standard quantification methods set out in this chapter, in an emission report in respect of coal storage at a facility:

- a. Annual greenhouse gas emissions in tonnes, reported as follows:
  - (1) Total CH<sub>4</sub> 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).

### **8.3 Calculation of CH<sub>4</sub> Emissions**

Calculate fugitive CH<sub>4</sub> emissions from coal storage piles as specified under paragraph a), b), or c) of this section.

- a. For coal purchased from U.S. sources, calculate fugitive CH<sub>4</sub> emissions using **Equation 8-1** and Table 8-1.
- b. For coal purchased from Canadian sources, calculate fugitive CH<sub>4</sub> emissions using **Equation 8-1** and Table 8-2.
- c. For coal purchased from non-U.S. and non-Canadian sources, the facility shall use either (a) or (b) of this section (above), whichever is the most applicable.

#### **Equation 8-1**

$$CH_4 = \sum_i (PC_i \times EF_i) \times \frac{0.6772}{1,000}$$

Where:

CH <sub>4</sub>	Fugitive emissions from coal storage piles for each coal category <i>i</i> , (tonnes CH <sub>4</sub> per year)
PC <sub><i>i</i></sub>	Purchased coal for each coal category <i>i</i> (tonnes per year)
EF <sub><i>i</i></sub>	Default CH <sub>4</sub> emission factor for each coal category <i>i</i> specified by location and mine type that the coal originated from, provided in Table 8-1 or Table 8-2 (m <sup>3</sup> CH <sub>4</sub> per tonne of coal)
0.6772	Methane conversion factor to convert m <sup>3</sup> to kg
1,000	Factor to convert kg to tonnes

### **8.4 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.

## **8.5 Procedures for Estimating Missing Data**

A complete record of all measured parameters used in the CH<sub>4</sub> 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 section 8.3. A facility must document and retain records of the procedures used for all such estimates.

When the missing data is relating to the total quantity of coal purchased, the replacement data shall be generated from best estimates based on all of the data relating to the processes. A facility must document and retain records of the procedures used for all such estimates.

## **8.6 Tables**

**Table 8-1: U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH<sub>4</sub> m<sup>3</sup> per tonne)**

<b>Coal Origin Coal Basin</b>	<b>Coal Origin States</b>	<b>Coal Mine Type Surface Post- Mining Factors</b>	<b>Coal Mine Type Underground Post-Mining Factors</b>
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068

<b>Coal Origin Coal Basin</b>	<b>Coal Origin States</b>	<b>Coal Mine Type Surface Post- Mining Factors</b>	<b>Coal Mine Type Underground Post-Mining Factors</b>
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,	0.3465	0.6525
West Interior (Arkoma Basin)	Oklahoma, Texas	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
Columbia		0.9	-

Source:

*Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH<sub>4</sub> Emission Factors (ft<sup>3</sup> per Short Ton; converted to m<sup>3</sup> per tonne). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

**Table 8-2: Canada Default Fugitive Methane Emission Factors  
from Post-Mining Coal Storage and Handling (CH<sub>4</sub> m<sup>3</sup> per tonne)**

<b>Coal Origin Province</b>	<b>Coal Origin Coalfield</b>	<b>Coal Mine Type Surface Post- Mining Factors</b>	<b>Coal Mine Type Underground Post-Mining Factors</b>
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
	Smoky River	0.125	0.067
	Wabamun	0.176	n/a

<b>Coal Origin Province</b>	<b>Coal Origin Coalfield</b>	<b>Coal Mine Type Surface Post-Mining Factors</b>	<b>Coal Mine Type Underground Post-Mining Factors</b>
	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	0.9	2.923

Source:

Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options. Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, 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).

# **9. Electricity Generation**

## **9.1 Activity 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 activity includes cogeneration (combined heat and power) units. This activity does not include portable generators, emergency generators and other equipment used in an emergency with less than 10 MW in nameplate generating capacity.

Sulfur hexafluoride (SF<sub>6</sub>) 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 activity includes fugitive emissions of SF<sub>6</sub> and PFCs from equipment that is located within the boundary of a power generation facility. This excludes fugitive SF<sub>6</sub> and PFCs emissions from power transmission and distribution equipment. Guidance for this is provided in the “Operation of Equipment for an Electricity Transmission or Distribution System” section.

## **9.2 Greenhouse Gas Reporting Requirements**

For each electricity generating unit, the emissions data report (for each calendar year) shall include the following information:

- a. Annual greenhouse gas emissions in tonnes, reported as follows:
  - (1) Total CO<sub>2</sub> emissions for fossil fuels, reported by fuel type.
  - (2) Total CO<sub>2</sub> emissions for all biomass fuels combined.
  - (3) Total CH<sub>4</sub> emissions for all fuels combined.
  - (4) Total N<sub>2</sub>O 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.
  - (5) For municipal solid waste, report in units of tonnes.
- c. Annual weighted average carbon content of each fuel, if used to compute CO<sub>2</sub> emissions as specified in section 9.3.
- d. Annual weighted average high heating value of each fuel, if used to compute CO<sub>2</sub> emissions as specified in section 9.3.

- e. **Production parameter:** The nameplate generating capacity of each unit in megawatts (MW) and net power generated in the calendar year in megawatt hours (MWh).
- f. For each cogeneration unit,
  - (1) Indicate whether topping or bottoming cycle,
  - (2) Total thermal output including any output used for electricity generation, in MJ,
  - (3) Useful thermal output excluding any energy used for electricity generation, in MJ,
  - (4) Where useful thermal (i.e. steam or heat) output is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ.
  - (5) Where supplemental firing has been applied to support electricity generation, report this purpose and fuel consumption by fuel type using the units specified under 10(b).
- g. Process CO<sub>2</sub> emissions from acid gas scrubbers and acid gas reagent.
- h. Quantity of sorbent used in acid gas scrubbing equipment, in tonnes.
- i. Fugitive emissions of each HFC from cooling units that support power generation.
- j. Fugitive CO<sub>2</sub> emissions from geothermal facilities.

## **10.** The SF<sub>6</sub> and PFC emissions calculated in accordance with section 16: **Electricity Importation**

### **10.1 Activity Definitions**

“Balancing authority area” means the metered boundaries of the collection of generation, transmission, and loads of a balancing authority.

“Balancing authority” means an entity that maintains load-interchange-generation balance within a balancing authority area and supports frequency in real time.

“Electricity generating facility” means a facility that generates electricity and includes one or more electricity generating units at the same location.

“Electricity generation unit” is the physically connected equipment that operate together to produce electricity at the same location.

“Electricity importer” means a person to who imports electricity into the province as defined in the QRV Regulation.

“Electricity transaction” means the purchase, sale, import, export or exchange of electric power.

“e-tag” means North American Energy Standards Board (NAESB) energy tag.

“Frequency in real time” means maintaining interconnection frequency at 60 hertz (Hz).

“Load interchange generation balance” means the balance between electricity demand and supply from resources within the Balancing Authority Area, and the flow of electricity into or out of the Balancing Authority Area on tie lines.

“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.

“Metered boundaries” means boundaries between adjacent province or balancing authority areas as defined by tie line meters that record the flow of energy between the province or balancing authority areas.

“Power contract” means an arrangement for the purchase of electricity including but not limited to power purchase agreements and tariff provisions.

“Scheduled” means electricity that is scheduled to flow between the Nova Scotia grid and a neighbouring province or balancing authority area.

“Scheduled quantity” means the final amount listed in the e-tag that is approved by all balancing authority areas on the transmission path specified on the e-tag.

“Specified electricity generator” means an electricity generation unit, facility or new additional production outside of Nova Scotia that supplies specified imported electricity.

“Specified imported electricity” means electricity which:

- Is subject to a written contract between the electricity generator and the electricity importer; and:

- (1) Comes from an electricity generator built after January 1, 2018; or
- (2) Is the result of an increase in production from the electricity generator that occurred after January 1, 2018; or
- (3) Was imported from an electricity generator within the framework of a contract entered into before 1 January 2018 that is still in force or has been renewed, or was imported from that electricity generator after the end of the contract; or

“Unspecified imported electricity” means imported electricity that is not specified imported electricity.

“Wheeled electricity” is imported electricity that is identified in the e-tag of a transaction that shows Nova Scotian transmission on the transmission path and does not serve load in Nova Scotia.

## 10.2 Greenhouse Gas Reporting Requirements

- The electricity importer shall set out the following information, calculated for the calendar year using standard quantification methods 15.0-15.5, in the report prepared for a calendar year in respect of electricity importation:
  - (1) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, calculated using the methods in 15.3 and 15.4.
  - (2) Annual quantity of specified and unspecified imported electricity used in the calculations contained in 15.3 and 15.4, expressed in MWh.
  - (3) The following information for each specified electricity generator from which the electricity importer imports electricity:
    - (i) The facility name;
    - (ii) The facility ID;
    - (iii) If applicable, the electricity generating unit ID.
    - (iv) Annual scheduled quantity of specified imported electricity used in 15.3, expressed in MWh.

- (v) Annual quantity of specified imported electricity wheeled through Nova Scotia, expressed in MWh.
  - (vi) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, from the specified electricity generator.
- (4) Report the following information for each province or balancing authority area from which unspecified electricity originated:
- (i) The name of the province or balancing authority area;
  - (ii) Annual scheduled quantity of unspecified imported electricity used in 15.4, expressed in MWh; and
  - (iii) Annual quantity of unspecified imported electricity wheeled through Nova Scotia, expressed in MWh.
  - (iv) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, from unspecified electricity generation by province or balancing authority area.

### **10.3 Calculation of Specified Electricity**

The electricity importer shall use the following equations, as applicable to calculate the emissions from specified imported electricity. If data is not available or cannot be obtained to calculate the emissions using the methods from section 15.3, the electricity importer may use the calculation methods from section 15.4

- a. Calculation Methodology 1. Use **Equation 15-1** to calculate the total annual emissions of specified imported electricity.

**Equation 15-4**

$$E = \sum_{i=1}^n \left( CO2_{ti} \times AF \times \frac{MWh_{imp\_i}}{MWh_{t\_i}} \right)$$

Where:

E      Total annual emissions of specified imported electricity from specified electricity generators that report GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75, the U.S. Energy Information Administration, or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO<sub>2</sub>e.

CO2<sub>ti</sub>      Total annual emissions from specified electricity generator i during the calendar year, expressed in tonnes CO<sub>2</sub>e as reported to The Climate Registry,

	U.S.EPA, U.S. Energy Information Administration or Environment Canada and where provided to the person.
AF	Adjustment factor calculated in accordance with Equation 15-6.
MWh <sub>imp_i</sub>	Scheduled quantity of specified imported electricity imported from specified electricity generator i, recorded in all the e-tags from the specified electricity generator i, expressed in MWh. calculated in accordance with Equation 15-4.
MWh <sub>t_i</sub>	Total annual megawatt-hours of net power generated by specified electricity generator i, expressed in MWh.
n	The number of specified electricity generators.

- b. Calculation Methodology 2. Use **Equation 15-5** to calculate the total annual emissions from specified imported electricity where
- (1) The specified electricity generator from which the specified imported electricity is received has not reported emissions to The Climate Registry, the U.S.EPA using 40 CFR Part 75, U.S. Energy Information Administration or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33:

### Equation 15-5

$$E = \sum_{i=1}^n \sum_{f=1}^m \left( Fuel_{fi} \times HHV_{fi} \times EF_{fi} \times 0.001 \times AF \times \frac{MWh_{impi}}{MWh_{ti}} \right)$$

Where:

E	Total annual emissions from specified imported electricity from specified electricity generators that have NOT reported GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75, the U.S. Energy Information Administration or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO <sub>2</sub> e.
Fuel <sub>fi</sub>	Total annual mass or volume of fuel “f” combusted by specified electricity generator “i” expressed in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitre for liquid fuel.
HHV <sub>fi</sub>	Higher heating value of fuel “f” consumed for electricity production in GJ per unit of fuel or measured in accordance with section 4.5 for specified electricity generator “i”.
EF <sub>fi</sub>	Fuel-specific default CO <sub>2</sub> e emission factor for fuel “f” from Section 4 (General Stationary Fuel Combustion) expressed in kg CO <sub>2</sub> e/GJ for specified electricity generator “i”.

0.001	Conversion factor from kilograms to tonnes.
AF	Adjustment factor calculated in accordance with Equation 15-6.
MWh <sub>impi</sub>	Scheduled quantity of specified imported electricity from specified electricity generator i, recorded in all the e-tags from specified electricity generator i, expressed in MWh calculated in accordance with Equation 15-4.
MWh <sub>ti</sub>	Total annual megawatt-hours of net power generated by specified electricity generator "i".
n	The number of specified electricity generators
m	The number of fuels

For the purposes of Equation 15-1 and 15-2, when the electricity comes from a specified nuclear, hydroelectric, sea current, wind, solar or tidal power facility, E shall be deemed as 0 (Zero)

## 10.4 Calculation of Unspecified Electricity

The electricity importer shall use Equation 15-3 to calculate the emissions from unspecified imported electricity from each province or balancing authority area that serves load in Nova Scotia.

### Equation 15-6

$$E = MWh_{imp} \times EFD \times AF$$

Where:

E	Total annual emissions of unspecified imported electricity expressed in tonnes CO <sub>2</sub> e.
MWh <sub>imp</sub>	Annual scheduled quantity of unspecified imported electricity serving load in Nova Scotia, based on the e-tag expressed in MWh calculated in accordance with Equation 15-5.
EFD	The default emission factor for the province or balancing authority area from which the electricity comes, in metric tons of CO <sub>2</sub> per megawatt-hour, which is either — indicated in Table 15-1; — when the electricity comes from a nuclear, hydroelectric, sea current, wind, solar or tidal power generator, a factor of 0;
AF	Adjustment factor calculated in accordance with Equation 15-6.

**Table 15-2: Default greenhouse gas emission factors for Canadian provinces and certain balancing authority areas, in metric tons CO<sub>2</sub> equivalent per megawatt-hour**

Canadian provinces and balancing authority areas	Default emission factor (metric tons GHG/MWh)
Newfoundland and Labrador	0.032
New Brunswick	0.282
Québec	0.001
Ontario	0.041
Manitoba	0.003
New England Independent System Operator (NE-ISO), including all or part of the following states: - Connecticut - Massachusetts - Maine - Rhode Island - Vermont - New Hampshire	0.290
New York Independent System Operator (NY-ISO)	0.236
Pennsylvania Jersey Maryland Interconnection Regional Transmission Organization (PJM-RTO), including all or part of the following states: - North Carolina - Delaware - Indiana - Illinois - Kentucky - Maryland - Michigan - New Jersey - Ohio - Pennsylvania - Tennessee - Virginia - West Virginia - District of Columbia	0.554
Midwest Independent Transmission System Operator (MISO-RTO), including all or part of the following states: - Arkansas - North Dakota - South Dakota - Minnesota - Iowa - Missouri - Wisconsin - Illinois - Michigan - Nebraska - Indiana	0.596

<ul style="list-style-type: none"> <li>- Montana</li> <li>- Kentucky</li> <li>- Texas</li> <li>- Louisiana</li> <li>- Mississippi</li> </ul>	
Southwest Power Pool (SPP), including all or part of the following states: <ul style="list-style-type: none"> <li>- Kansas</li> <li>- Oklahoma</li> <li>- Nebraska</li> <li>- New Mexico</li> <li>- Texas</li> <li>- Louisiana</li> <li>- Missouri</li> <li>- Mississippi</li> <li>- Arkansas</li> </ul>	0.566

## 10.5 Calculation of Imported Electricity

### Equation 15-7

$$MWh_{imp\_i} = \sum (MWh_{total\_i} - MWh_{wheel\_i})$$

### Equation 15-8

$$MWh_{imp} = \sum \sum (MWh_{total} - MWh_{wheel})$$

Where:

- MWh<sub>imp\_i</sub> Annual Scheduled quantity of specified imported electricity imported into Nova Scotia by the electricity importer, expressed in MWh.
- MWh<sub>imp</sub> Annual Scheduled quantity of unspecified imported electricity imported into Nova Scotia by the electricity importer, expressed in MWh.
- MWh<sub>Total\_i</sub> Quantity of scheduled specified imported electricity recorded in each e-tag “i” that is imported into Nova Scotia by the electricity importer, expressed in MWh.
- MWh<sub>wheel\_i</sub> Scheduled quantity of specified imported electricity recorded in each e-tag “i” that is imported into Nova Scotia by the electricity importer that is wheeled through Nova Scotia, expressed in MWh.

MWh <sub>Total</sub>	Quantity of scheduled unspecified imported electricity recorded in each e-tag that is imported into Nova Scotia by the electricity importer, expressed in MWh..
MWh <sub>wheel</sub>	Scheduled quantity of unspecified imported electricity recorded in each e-tag that is imported into Nova Scotia by the electricity importer that is wheeled through Nova Scotia, expressed in MWh.

## 10.6 Calculation of Adjustment Factor

- a. An electricity importer that imports electricity from a jurisdiction with a carbon price in the calendar year shall calculate the adjustment factor (AF) as follows:

**Equation 15-9**

$$AF = \left(1 - \frac{P_{jurisdiction}}{P_{NS}}\right)$$

Where:

AF	Adjustment factor.
P <sub>jurisdiction</sub>	Average sale price of emission allowances at auctions held during the calendar year by a jurisdiction where the import is from a member of and offered allowances for sale in an auction carried out by the Regional Greenhouse Gas Initiative or Western Climate Initiative in the calendar year (in Canadian dollars).

Or

The carbon price applied to the electricity in the jurisdiction in which it was generated, established under the applicable federal or provincial legislation. (in Canadian dollars)

P <sub>NS</sub>	Average sale price of emission allowances at auctions held during the calendar year by Nova Scotia (in Canadian dollars).
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Or

Before the first auction, the minimum price of emission allowances at an auction established in Nova Scotia's Cap-and-Trade Program Regulations (in Canadian dollars).

- b. If a calculation for AF under paragraph (a) of 15.6 is less than zero, then the value of AF shall be equal to zero.

k. Operation of Equipment for an Electricity Transmission or Distribution System”.

## 10.7 Calculation of Greenhouse Gas Emissions

If a facility combusts natural gas, diesel or heavy fuel oil in more than one electrical generating unit, and each unit is not individually metered (or, in the case of diesel/heavy fuel oil, does not have a dedicated tank) and no CEMS is in place, the facility may calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions for each unit by using a common meter or tank that meets the requirement of the method as outlined under Section 4, 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 CO<sub>2</sub> Emissions. Operators shall use CEMS to measure CO<sub>2</sub> 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 CO<sub>2</sub> 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) below. Operators may use such a CEMS for calculation of CO<sub>2</sub> emissions from electrical generating units for any fuel covered in 10.3, if applicable to the situation at the facility. The facility using CEMS to determine CO<sub>2</sub> emissions shall comply with the provisions in Calculation Methodology 4 of 4.3.
  - (1) Natural Gas, and fuels in Table 4-3. For electricity generating units combusting natural gas or the fuels listed in Table 4-3, use methods in accordance with 4.3.
  - (2) Coal or Petroleum Coke. For electricity generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and Calculation Methodology 3 in section 4.3.
  - (3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases that are not listed in Table 4-3. For electricity generating units combusting middle distillates, gasoline, etc. use Calculation Methodology 2 or 3 in accordance with 4.3.
  - (4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electricity generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in section 4.
  - (5) Landfill Gas, Biogas, or Biomass. For electricity generating units combusting landfill gas, biogas, or biomass, use methods in accordance with 4.3.
  - (6) Municipal Solid Waste. Electricity generating units combusting municipal solid waste may use the measured steam generated, the default emission factor in Section 4 Table 4-8, and the Calculation Methodology 2 in section 4.3. The facility

can also use CEMS to measure CO<sub>2</sub> emissions in accordance with Calculation Methodology 4 of 4.3, or calculate emissions using steam flow and a CO<sub>2</sub> emission factor according to the provisions of 4.3.

- (7) Start-up Fuels. Generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO<sub>2</sub> 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.
- (i) The default emission factors from Table 4-3, Table 4-4, Table 4-6 or Table 4-8, and default HHV from Tables
  - (ii) Table 4-1, as applicable, and Calculation Methodology 1 provided in section 4.3;
  - (iii) The measured heat content of the fuel and Calculation Methodology 2 provided in section 4.3;
  - (iv) The measured carbon content of the fuel and Calculation Methodology 3 provided in section 4.3; or
  - (v) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section 4..
- (8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the facility shall calculate CO<sub>2</sub> emissions as follows.
- (i) For co-fired electricity generators that burn only fossil fuels, CO<sub>2</sub> emissions shall be determined using one of the following methods:
    - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section 4.3. The facility using this method need not report emissions separately for each fossil fuel.
    - (B) For units not equipped with a continuous emission monitoring system, calculate the CO<sub>2</sub> emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.
  - (ii) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO<sub>2</sub> emissions shall be determined using one of the following methods:
    - (A) A continuous emission monitoring system in accordance with Calculation Methodology 4 in section 4.3. The facility using this method shall determine the portion of the total CO<sub>2</sub> emissions attributable to the biomass-derived fuel and portion of the total CO<sub>2</sub> emissions attributable to the fossil fuel using the methods specified in Calculation Methodology 4 of 4.3.
    - (B) For units not equipped with a continuous emission monitoring system, calculate the CO<sub>2</sub> emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.

- b. Calculation of CH<sub>4</sub> and N<sub>2</sub>O Emissions. The facility shall use the methods specified in section 4.4 to calculate the annual CH<sub>4</sub> and N<sub>2</sub>O emissions. For coal combustion, use the default CH<sub>4</sub> and N<sub>2</sub>O emission factor(s) in Table 4-7.
- c. Calculation of CO<sub>2</sub> Emissions from Acid Gas Scrubbing. A facility that uses acid gas scrubbers or adds an acid gas reagent to the combustion unit shall calculate the annual CO<sub>2</sub> emissions from these processes using **Equation 9-1**: if these emissions are not already captured in CO<sub>2</sub> emissions determined using a continuous emissions monitoring system.

**Equation 9-1:**

$$CO_2 = S \times R \times \left( \frac{CO_{2MW}}{Sorbent_{MW}} \right)$$

Where:

CO <sub>2</sub>	CO <sub>2</sub> emitted from sorbent for the report year, tonnes.
S	Limestone or other sorbent used in the report year, tonnes.
R	Ratio of moles of CO <sub>2</sub> released upon capture of one mole of acid gas.
CO <sub>2MW</sub>	Molecular weight of carbon dioxide (44).
Sorbent <sub>MW</sub>	Molecular weight of sorbent (if calcium carbonate, 100).

- d. Calculating Fugitive HFC Emissions from Cooling Units. A facility 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 facility 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 9-2**: to calculate annual HFC emissions.

**Equation 9-2:**

$$HFC = HFC_{inventory} + HFC_{acquisitions} - HFC_{disbursements} + HFC_{\Delta capacity}$$

Where:

HFC	Annual fugitive HFC emission, tonnes.
HFC <sub>inventory</sub>	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 <sub>acquisitions</sub>	The sum of all HFC acquired from other entities during the year either in storage containers or in equipment.
HFC <sub>disbursements</sub>	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 <sub>Δcapacity</sub>	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 facility 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 facility shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

**Equation 9-2a:**

$$HFC_{service} = R_{recharge} - R_{recover}$$

**Equation 9-2b:**

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

**Equation 9-2c:**

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

Where:

HFC <sub>Install</sub>	HFC emitted during initial charging/installation of the unit, kilograms.
HFC <sub>Service</sub>	HFC emitted during use and servicing of the unit for the report year, kilograms.
HFC <sub>Retire</sub>	HFC emitted during the removal from service/retirement of the unit, kilograms.
R <sub>new</sub>	HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms.
C <sub>new</sub>	Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms.

$R_{\text{recharge}}$	HFC used to recharge the unit during maintenance and service, kilograms.
$R_{\text{recover}}$	HFC recovered from the unit during maintenance and service, kilograms.
$C_{\text{retire}}$	Nameplate capacity of the retired unit, kilograms.
$R_{\text{retire}}$	HFC recovered from the retired unit, kilograms.

- e. Fugitive CO<sub>2</sub> Emissions from Geothermal Facilities. A facility that operates geothermal electricity generating operations shall calculate the fugitive CO<sub>2</sub> emissions using one of the following methods:

- (1) Calculate the fugitive CO<sub>2</sub> emissions using **Equation 9-3:**

**Equation 9-3:**

$$CO_2 = 7.14 \times Heat \times 0.001$$

Where:

CO <sub>2</sub>	CO <sub>2</sub> emissions, tonnes per year.
7.14	Default fugitive CO <sub>2</sub> emission factor for geothermal facilities, kg per GJ.
Heat	Heat taken from geothermal steam and/or fluid, GJ/yr.
0.001	Conversion factor from kilograms to tonnes.

- (1) Calculate CO<sub>2</sub> emissions using a source specific emission factor derived from measurements of carbon dioxide emissions and heat from the geothermal steam.

SF<sub>6</sub> and PFC emissions: Calculate SF<sub>6</sub> and PFC emissions in accordance with section 15, “Operation of Equipment for an Electricity Transmission or Distribution System”

## 10.8 Sampling, Analysis, and Measurement Requirements

- a. CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O Emissions from Fuel Combustion. Facilities using CEMS to estimate CO<sub>2</sub> emissions from fuel combustion shall comply with the requirements in Calculation Methodology 4 of Section 4. Facilities using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, carbon content monitoring, and calculation methodologies specified in 4.5.
- b. CO<sub>2</sub> Emissions from Acid Gas Scrubbing. Facilities 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 calendar year.
- c. CO<sub>2</sub> Emissions from Geothermal Facilities. Facilities that operate geothermal facilities shall measure the heat recovered from geothermal steam. If using a source specific emission factor instead of the default factor, the facility shall conduct an annual test of the CO<sub>2</sub> emission rate using a method approved by the regulator. The facility shall

submit a test plan to the regulator for approval. Once approved, the annual test shall be conducted in accordance with the approved test plan under the supervision of the regulator.

- d. For refinery fuel gas, flexigas and associated gas, sampling, consumption measurements, carbon content measurements, and measurements to calculate high heat value and emission factors must be completed in accordance with the sampling, analysis and measurement requirements for the General Stationary Combustion section.

## 10.9 Procedures for Estimating Missing Data

### Unavailable Analytical Data

- a. Whenever analytical data relating to sampling is unavailable, the facility shall use the methods prescribed in 9.4, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

### Determination of Quantity

- b. Whenever sampling and measurement data required by 9.4 for the calculation of emissions is missing the facility shall ensure that the data is replaced using the following missing data procedures:
  - (1) When the missing data concerns sampled data, the facility shall
    - (i) Determine the sampling or measurement rate using **Equation 9-4:**

### **Equation 9-4:**

$$R = Q_{SAct}/Q_{SRequired}$$

Where:

R	Sampling or measurement rate that was used, expressed as a percentage
$Q_{SAct}$	Quantity of actual samples or measurements obtained by the facility
$Q_{SRequired}$	Quantity of samples or measurements required under section 10.4

(ii) Replace the missing data as follows:

- (A) If  $R \geq 0.9$ : replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the facility shall use the first available data from after the missing data period;
- (B) If  $0.75 \leq R < 0.9$ : replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;

- (C) If  $R < 0.75$ : replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns the quantity of energy transferred or a quantity of HFC, the replacement data shall be generated from best estimates based on all of the data relating to the processes.
- (3) For all units subject to the requirements of the Section 4 that monitor and report emissions using a CEMS, the missing data backfilling procedures "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7<sup>(5)</sup>" shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

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<sup>5</sup> Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7, Available at:  
<https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf>

# **11. Distributing natural gas and supplying petroleum products**

## **11.1 Activity Definition**

“Distributing natural gas” has the same meaning as in the Regulation, defined in Table 2 of Schedule 2.

“Natural gas” includes liquified natural gas and compressed natural gas.

“Petroleum product” includes all of the following, but does not include any fuel that is contained in the fuel tank installed as standard equipment to supply a vehicle’s engine, or is supplied in a sealed container of 1L or less:

- i) Automotive gasoline,
- ii) Diesels,
- iii) Light-fuel oils (Nos. 1,2),
- iv) Heavy fuel oils (Nos. 3,4,5,6),
- v) propane

“Supplying petroleum products” has the same meaning as in the Regulation, defined in Table 2 of Schedule 2.

GHG emissions attributed to fuel suppliers are those that result from the combustion of fuels supplied to persons who are not required to verify a GHG report and all fuels supplied to be used in mobile equipment at all facilities.

Fuel manufacturers are required to calculate the percentage of biomass that enters their manufacturing/fractionating facility. Blenders/importers are required to calculate the volume percentage of fuels they sell that are biomass-based. CO<sub>2</sub> emissions from the combustion of biomass are deducted from total reported CO<sub>2</sub> emissions.

## **11.2 Petroleum product supplier Greenhouse Gas Reporting Requirements**

- a. A petroleum product supplier shall set out the following information, calculated for the calendar year using standard quantification methods in this section, in an emission report prepared for a calendar year in respect of fuel supply:
  - (1) The total greenhouse gas emissions calculated using **Equation 11-4** and **Equation 11-5** expressed as tonnes of CO<sub>2</sub>e

- (2) The annual quantity in tonnes or kilolitres of each product<sub>i</sub> in Equation 10-1 that is first placed into the Nova Scotia market.
- (3) The volume of biomass-based fuel blended with each product<sub>i</sub> reported in (a)(2) of this section calculated in accordance with **Equation 11-7**.

The total annual greenhouse gas emissions, expressed in tonnes of CO<sub>2</sub>e, that would result from the complete combustion or oxidation of each fuel reported in section (a)(1) above, calculated in accordance with

- (4) **Equation 11-1.**

#### ATTESTATION REQUIREMENT

The organization name and facility location of each facility required to verify a GHG report to which the person has supplied fuels during the year, along with the volume of fuels that are not used in mobile equipment at each facility, calculated in accordance with

- (5) **Equation 11-3.**
  - (6) A copy of any attestation received by the supplier from facilities required to verify a GHG report to which fuel was supplied by the supplier either directly; or through a series of transactions that originated with the supplier for the purposes of the calculation in **Equation 10-3**. In order to be used for the purposes of
  - (7) **Equation 11-3** the attestations must:
    - a. be signed by the receiving facility; and
    - b. confirm the total quantity of fuels received in the year from the supplier that supplied the fuel either directly or through a chain of transactions that originated with the supplier.
    - c. confirm the quantity of fuels received in the year from the supplier to be used as fuel in mobile equipment at the receiving facility.
- b. In addition to the requirements in (a) of this section, refiners and fractionators shall include the following information in the annual report prepared pursuant to the regulation:
- (1) The volume of each type of biomass that was co-processed with petroleum feedstock to produce a fuel listed in **Error! Reference source not found.** expressed in tonnes or kilolitres.
  - (2) The CO<sub>2</sub> emissions expressed in tonnes that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported.

#### 11.2.1 Calculation of GHG Emissions

For each petroleum product, calculate CO<sub>2</sub> emissions using the methodology outlined in

**Equation 11-1** to **Equation 11-8** below (as well as

**Equation 11-17** to test for the carbon share of petroleum fuels).

**Equation 11-1:**

A petroleum product supplier shall calculate CO<sub>2</sub>e emissions for each fuel supplied using

a. **Equation 11-1:**

$$CO_{2i} = Product_i \times EF_i$$

Where:

- CO<sub>2i</sub> Total annual CO<sub>2</sub>e emissions that would result from the complete combustion or oxidation of each petroleum product “i” expressed in tonnes.
- Product<sub>i</sub> Total annual quantity of petroleum product “i” calculated in accordance with **Equation 11-7:** and **Equation 11-8:** that is placed into the Nova Scotia market by the supplier expressed in kilolitres
- EF<sub>i</sub> Product specific CO<sub>2</sub>e emission factor calculated in accordance with **Equation 11-5:** or as provided in Table 10-1, expressed in tonnes of CO<sub>2</sub>e per kilolitre

**Equation 11-2:**

- b. A supplier shall use **Equation 11-2:** to calculate CO<sub>2</sub>e emissions for each type of biomass that enters a manufacturing or fractionating facility and is co-processed.

$$CO_{2m_i} = Product_i \times EF_i \times \%Biomass_m \times 0.01$$

Where:

- CO<sub>2m\_i</sub> Total annual CO<sub>2</sub>e emissions that would result from the complete combustion or oxidation of petroleum product “i” produced from biomass “m” expressed in tonnes.
- Product<sub>i</sub> Total annual volume of fuel “i” first placed into the Nova Scotia market by the supplier expressed in kilolitres (calculated in accordance with **Equation 11-7:** and **Equation 11-8:**).

EF <sub>i</sub>	Product specific CO <sub>2e</sub> emission factor calculated in accordance with <b>Equation 11-5:</b> or as provided in Table 10-1, expressed in tonnes of CO <sub>2e</sub> per kilolitre
%Biomass <sub>m</sub>	Annual percent of biomass “m” that enters the manufacturing or fractionating facility that is co-processed with petroleum or natural gas liquid feedstocks to produce a petroleum product reported under

**Equation 11-1:**, expressed as per cent volume

**Equation 11-3:**

A supplier shall use

- c. **Equation 11-3:** to calculate CO<sub>2e</sub> emissions from fuels that are supplied to a person required to verify a GHG report.

$$CO_{2\_le\_i} = Product_{le\_i} \times EF_i$$

Where:

CO <sub>2_le_i</sub>	Total annual CO <sub>2e</sub> emissions that would result from the complete combustion or oxidation of fuel “i” supplied to a person required to verify a GHG report., expressed in tonnes.
Product <sub>le_i</sub>	Total annual volume of petroleum products that are not fuels used in mobile equipment first placed into the Nova Scotia market that are supplied to a person required to verify a GHG report and recorded in the attestation or attestations provided pursuant to 10.2.1(a)6.
EF <sub>i</sub>	Product specific CO <sub>2e</sub> emission factor calculated in accordance with <b>Equation 11-5:</b> or as provided in Table 10-1, expressed in tonnes of CO <sub>2e</sub> per kilolitre.

**Equation 11-4:**

- d. Manufacturers and fractionators shall calculate total CO<sub>2e</sub> emissions from all fuels supplied using **Equation 11-4:**.

$$CO_{2r} = \sum(CO_{2i}) - \sum(CO_{2m_i}) - \sum(CO_{2\_le\_i})$$

Where:

CO <sub>2r</sub>	Total CO <sub>2e</sub> emissions from all petroleum products supplied.
CO <sub>2i</sub>	Result of

**Equation 11-1:** – CO<sub>2</sub>e emissions for each fuel.

CO<sub>2m\_i</sub> Result of **Equation 11-2:** - CO<sub>2</sub> emissions for each type of biomass that enters a manufacturing or fractionating facility and is co-processed.

CO<sub>2\_le\_i</sub> Result of

**Equation 11-3:** - CO<sub>2</sub>e emissions from fuels that are supplied to a person

#### **Equation 11-5:**

- e. Importers shall calculate the total CO<sub>2</sub>e emissions from all fuels imported using **Equation 11-5:**.

$$CO_{2x} = \sum(CO_{2i}) - \sum(CO_{2m_i}) - \sum(CO_{2\_le\_i})$$

Where:

CO<sub>2x</sub> Total CO<sub>2</sub>e emissions from all petroleum products imported.

CO<sub>2i</sub> Result of

**Equation 11-1:** – CO<sub>2</sub>e emissions for each fuel.

CO<sub>2m\_i</sub> Result of **Equation 11-2:** - CO<sub>2</sub> emissions for each type of biomass that enters a manufacturing or fractionating facility and is co-processed.

CO<sub>2\_le\_i</sub> Result of

**Equation 11-3:** - CO<sub>2</sub>e emissions from fuels that are supplied to a facility required to verify a GHG report.

#### **Equation 11-6:**

- f. Fuel suppliers have the option to use default emission factors for their fuels (provided in **Error! Reference source not found.**.. Alternatively, **Equation 11-6:** can be utilized to calculate emission factors for fuels (EF<sub>i</sub> and EF<sub>CO<sub>2</sub></sub>).

$$EF_i = \left( Density \times carbon\ share \times \frac{44}{12} \right) + 0.001 \times (25 \times EF_{CH_4} + 298 \times EF_{N_2O})$$

Where:

EF<sub>i</sub> Emission factor of the fuel expressed in tonnes of CO<sub>2</sub>e per kilolitre or per tonne of petroleum product.

Density Density of the petroleum product or natural gas liquid expressed in tonnes per kilolitre for non-solid petroleum products

Carbon Share	Weight per cent of carbon in the petroleum product or calculated using Equation 10-17, expressed as a fraction such as expressing 75% as 0.75.
44/12	Conversion factor for carbon to carbon dioxide.
EF <sub>CH4</sub>	CH <sub>4</sub> emissions factor of the petroleum product expressed in grams of CH <sub>4</sub> per litre from the relevant table in Section 4.
EF <sub>N2O</sub>	N <sub>2</sub> O emissions factor of the petroleum product expressed grams of N <sub>2</sub> O per litre from the relevant table in Section 4.

### **Equations 10-7 and 10-8:**

- g. Where the petroleum product is produced by blending a petroleum-based product with a biomass-based fuel, calculate the volume of the petroleum product (product<sub>i</sub>) by using **Equation 11-7:** and **Equation 11-8:** **Equation 11-7:** is used to quantify the total volume of fuels that is biomass-based fuels (in kilolitres) and **Equation 11-8:** is used to calculate the total annual quantity of petroleum product (product<sub>i</sub>) placed into the Nova Scotia market.

#### **(1) Equation 11-7:**

$$Product_b = Product_t \times \%Vol_i \times 0.01$$

#### **(2) Equation 11-8:**

$$Product_i = Product_t - Product_b$$

Where:

Product <sub>b</sub>	Total volume of petroleum products that is biomass-based fuels in kilolitres.
Product <sub>t</sub>	Total volume of petroleum products and blended biomass-based fuels that is used as a fuel in kilolitres.
%Vol <sub>i</sub>	Percent volume of Product <sub>t</sub> that is biomass.
Product <sub>i</sub>	Total annual quantity of a petroleum product placed into the Nova Scotia market.

**Table 11-1: Default Factors for petroleum products**

Fuels	Emission Factor (tonnes CO <sub>2</sub> e/kL)
Automotive Gasoline	2.361
Diesels	3.007
Light fuel oils (No. 1,2)	2.735

Heavy fuel oils (No. 3, 4, 5, 6)	3.146
Propane	1.544

\*: The emission factor for propane is based on a reference condition of 15 C and saturation pressure.

Aviation fuels and fuel oil for ships are not included as fuels for the purpose of this reporting requirement.

### **11.3 Natural Gas Distributer greenhouse gas reporting requirements**

- a) The distributer shall set out the following information, calculated for the calendar year using standard quantification methods set out for natural gas distributers in this chapter, in an emission report prepared for a calendar year in respect of natural gas distribution:
  - 1. Annual CO<sub>2</sub> emissions expressed in tonnes that would result from the complete combustion or oxidation of the quantities of natural gas provided to end-users calculated in accordance with the Equation 10-9 or Equation 10-10
  - 2. Annual CH<sub>4</sub> and N<sub>2</sub>O emissions, expressed in tonnes that would result from the complete combustion or oxidation of the quantities of natural gas provided to end-users calculated in accordance with Equation 10-15 and Equation 10-16
  - 3. Annual quantity of natural gas, excluding any natural gas derived from biomass, received by the distributer at its custody transfer stations, expressed in Rm<sup>3</sup> or GJ.
  - 4. Annual quantity of natural gas, excluding any natural gas derived from biomass that is placed into storage, expressed in Rm<sup>3</sup> or GJ
  - 5. Annual quantity of natural gas, excluding any natural gas derived from biomass that is withdrawn from storage, expressed in Rm<sup>3</sup> or GJ.
  - 6. Annual quantity of natural gas delivered to another natural gas distributer or exported out of Nova Scotia, expressed in Rm<sup>3</sup> or GJ.

#### **ATTESTATION REQUIREMENT**

- 7. Report the following information for each facility required to verify a GHG report to which the natural gas distributer has supplied natural gas, including the distributer's own operations:

- i. Organization name;
- ii. Facility location;
- iii. Annual quantity of natural gas delivered, expressed in Rm<sup>3</sup> or GJ

### **11.3.1 Calculating GHG emissions**

For natural gas distributers, use the methodology outlined in **Equation 11-9** through to **Equation 11-16** must be applied.

- a) A distributor shall use one of the following methods to calculate annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the natural gas received at the custody transfer station “i” in the calendar year, expressed in tonnes. **Equation 11-10:** utilizes energy-based emission factors, while **Equation 11-11** uses volume-based emission factors.

#### **(1) Equation 11-9:**

Use this equation to calculate the annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of natural gas received at the custody transfer station using energy-based default emission factors.

$$CO_{2i} = 0.001 \times \sum NG_h \times HHV_h \times EF_h$$

Where:

CO<sub>2i</sub> Annual CO<sub>2</sub> emissions from the complete combustion or oxidation of the natural gas received by the distributor at its custody transfer stations, expressed in tonnes.

NG<sub>h</sub> Annual quantity of natural gas received, excluding any natural gas derived from biomass or gas that does not contain any carbon, at the custody transfer station in period “h”, expressed in Rm<sup>3</sup>.

HHV<sub>h</sub> **Default high heat value contained in**

Table 11-2: Energy Based Default Factors for Natural Gas or a distributor-specific higher heating value determined in accordance with part c of section 11.4, expressed in GJ per Rm<sup>3</sup> or GJ per litre.

EF<sub>h</sub> **Default CO<sub>2</sub> emission factor contained in**

Table 11-2: Energy Based Default Factors for Natural Gas or a distributor-specific CO<sub>2</sub> emission factor determined in accordance with part c of section 11.4, expressed in kg of CO<sub>2</sub> per GJ.

0.001 Conversion factor from kilograms to tonnes.

**(2) Equation 11-10:**

Use this equation to calculate the annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the natural gas received at the custody transfer station using volume-based default emission factors.

$$CO_{2i} = \sum NG_h \times EF$$

Where:

- CO<sub>2i</sub> Annual CO<sub>2</sub> emissions from the complete combustion of the natural gas received by the distributor at its custody transfer stations, expressed in tonnes.
- NG<sub>h</sub> Annual quantity of natural gas received, excluding any natural gas derived from biomass or gas that does not contain any carbon, at the custody transfer station in period “h”, expressed in Rm<sup>3</sup>.
- EF Default CO<sub>2</sub> emission factor contained in Table 11-3: Volume Based Default Factors for Natural Gas or a distributor-specific CO<sub>2</sub> emission factor determined in accordance as described in the Sampling, Analysis, and Measurement Requirements section of this chapter, expressed in tonnes of CO<sub>2</sub> per Rm<sup>3</sup>.

- b) In addition to the requirements in (a) above, each distributor shall calculate the following CO<sub>2</sub> emissions, expressed in tonnes

**(3) Equation 11-11**

Use this equation to calculate the annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of natural gas that is distributed to another distributor “j” or exported out of Nova Scotia.

$$CO_{2j} = NG_j \times EF$$

Where:

- CO<sub>2j</sub> Annual CO<sub>2</sub> emissions from the complete combustion of the natural gas that is distributed to another distributor or exported out of Nova Scotia, expressed in tonnes.
- NG<sub>j</sub> Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, distributed to another distributor “j” or exported out of Nova Scotia, expressed in Rm<sup>3</sup>.
- EF Default CO<sub>2</sub> emission factor contained in Table 11-3: Volume Based Default Factors for Natural Gas or a distributor-specific CO<sub>2</sub> emission factor determined as described in the Sampling, Analysis, and Measurement Requirements section of this chapter, expressed in tonnes of CO<sub>2</sub> per Rm<sup>3</sup>.

#### (4) Equation 11-12

Use this equation to calculate the annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of natural gas, excluding any natural gas derived from biomass, that is distributed to a person required to verify a GHG report, “k”

$$CO_{2k} = NG_k \times EF$$

Where:

- CO<sub>2k</sub> Annual CO<sub>2</sub> emissions that would result from the complete combustion of the natural gas that is distributed to other persons required to report and verify emissions under the Regulation, expressed in tonnes.
- NG<sub>k</sub> Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, distributed to capped participant “k”.
- EF Default CO<sub>2</sub> emission factor contained in Table 11-3: Volume Based Default Factors for Natural Gas or a distributor-specific CO<sub>2</sub> emission factor determined as described in the Sampling, Analysis, and Measurement Requirements section of this chapter, expressed in tonnes of CO<sub>2</sub> per Rm<sup>3</sup>.

#### (5) Equation 11-13

Use this equation to calculate the annual CO<sub>2</sub> emissions that would result from the complete combustion or oxidation of the quantity of natural gas that represents the net change in natural gas stored during the calendar year:

$$CO_{2l} = [Fuel_1 - Fuel_2] \times EF$$

Where:

- CO<sub>2l</sub> Annual CO<sub>2</sub> emissions that would result from the complete combustion of natural gas that represents the net change in natural gas stored within the calendar year, expressed in tonnes.
- Fuel<sub>1</sub> Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, put into storage after the custody transfer station during the calendar year, expressed in Rm<sup>3</sup>.
- Fuel<sub>2</sub> Annual quantity of natural gas, excluding any natural gas derived from biomass or gas that does not contain any carbon, that is taken out of storage after the custody transfer station during the calendar year, expressed in Rm<sup>3</sup>.
- EF Default CO<sub>2</sub> emission factor contained in Table 11-3: Volume Based Default Factors for Natural Gas or a distributor-specific CO<sub>2</sub> emission factor determined as described in the Sampling, Analysis, and Measurement Requirements section of this chapter expressed in tonnes of CO<sub>2</sub> per Rm<sup>3</sup>.

**(6) Equation 11-14**

Use this equation to calculate the total annual CO<sub>2</sub> emissions.

$$CO_{2f} = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2k} - \sum CO_{2l}$$

Calculation of CH<sub>4</sub> and N<sub>2</sub>O emissions from natural gas distribution.

A distributor shall use

- c) **Equation 11-15:** to calculate annual CH<sub>4</sub> emissions and **Equation 11-16:** to calculate annual N<sub>2</sub>O emissions that would result from the complete combustion or oxidation of natural gas received at the custody transfer station, expressed in tonnes.

**Equation 11-15:**

$$CH_4 = CO_{2f} \times EF_{CH4} \times 0.000001 \div EF_h$$

**Equation 11-16:**

$$N_2O = CO_{2f} \times EF_{N2O} \times 0.000001 \div EF_h$$

Where:

- CH<sub>4</sub> Annual CH<sub>4</sub> emissions, expressed in tonnes.  
 N<sub>2</sub>O Annual N<sub>2</sub>O emissions, expressed in tonnes.  
 EF<sub>h</sub> CO<sub>2</sub> emission factor used to calculate CO<sub>2</sub> emissions in as shown in h) of this section, expressed in tonnes of CO<sub>2</sub> per Rm<sup>3</sup>.  
 EF<sub>CH4</sub> Default CH<sub>4</sub> emissions factor contained in Table 4-5 using the value for "Residential, Construction, Commercial/Institutional, Agriculture", expressed in grams of CH<sub>4</sub> per Rm<sup>3</sup>.  
 EF<sub>N2O</sub> Default N<sub>2</sub>O emissions factor contained in Table 4-5 using the value for "Residential, Construction, Commercial/Institutional, Agriculture, expressed in grams of N<sub>2</sub>O per Rm<sup>3</sup>.

**Table 11-2: Energy Based Default Factors for Natural Gas**

Fuel	Default High Heating Value Factor GJ/m <sup>3</sup>	Default CO <sub>2</sub> Emission Factor (kg CO <sub>2</sub> /GJ)
Natural Gas	0.0394	51.16

**Table 11-3: Volume Based Default Factors for Natural Gas**

Fuel	Unit	Default CO <sub>2</sub> Emission Value (tonnes CO <sub>2</sub> /Unit)
Natural Gas	Reference cubic metres (Rm <sup>3</sup> )	0.0020136

## **11.4 Sampling, Analysis, Measurement and Monitoring Requirements**

Sampling, analysis, measurement, and monitoring requirements for all non-natural gas fuels are shown in (a) to (c) below. Sampling, analysis, measurement, and monitoring requirements for natural gas distributors are shown in (d) to (g) below.

For Non-natural gas fuel Suppliers: Petroleum product suppliers

- a. Determination of quantity of petroleum product.
  - (1) The supplier required to determine the quantities of fuels pursuant to this method shall determine those quantities using the following:
    - (i) Appropriate standard methods published by a consensus-based standards organization; or
    - (ii) Where no such methods exist, industry standard practices.
- b. Equipment Calibration.
  - (1) The supplier required to determine quantities of petroleum product pursuant to this method shall calibrate all measurement equipment prior to its first use for the purposes of this method using a standard method published by a consensus-based standards organization or according to the calibration or verification procedures specified by the equipment manufacturer.
  - (2) The supplier required to determine quantities of petroleum product pursuant to this method shall recalibrate equipment mentioned in (1) at the minimum frequency specified by the standard method or by the equipment manufacturer.
  - (3) Sections (1) and (2) above do not apply to any equipment used for financial transactions.
- c. Procedures for determining emissions factors using direct measurements under **Equation 11-6:**
  - (1) A supplier required to determine emissions factors using direct measurements pursuant to **Equation 11-6:** shall collect at least one sample of each fuel using an appropriate standard method published by a consensus-based standards organization for each calendar month of the calendar year in which the fuel is supplied in Nova Scotia.

- (2) A supplier required to determine emissions factors shall ensure the mixing and handling of samples is performed using an appropriate standard method published by a consensus-based standards organization.
- (3) A supplier required to determine density measurements shall use the following for each sample collected under (1).
  - (i) For all non-solid fuels, the supplier shall test for density using an appropriate standard method published by a consensus-based standards organization.
  - (ii) The density value for each fuel shall be generated by a single composite sample or an average of multiple samples.
  - (iii) All measurements of density shall be temperature-adjusted and pressure-adjusted to the reference conditions contained in this method.
- (4) For each sample collected under (1) the supplier required to determine the carbon share measurement shall do the following:
  - (i) Test for carbon share using an appropriate standard method published by a consensus-based standards organization.
  - (ii) If the supplier uses a standard method that involves gas chromatography to determine the per cent mass of each component in a fuel the supplier shall calculate the fuel's carbon share using **Equation 11-7:** below.

**Equation 11-17:**

$$\text{Carbon Share} = \sum (\% \text{Composition}_{i...n} \times \% \text{Mass}_{i...n})$$

Where:

$\% \text{Composition}_{i...n}$  Percent of total mass of each molecular component in the fuel.  
 $\% \text{Mass}_{i...n}$  Percent of total mass that carbon represents in each molecular component of the fuel.

- (i) The carbon share for each fuel shall be generated by a single composite sample or an average of multiple samples.

d. Determination of quantity of natural gas

- (1) The distributor required to determine quantities of natural gas pursuant to this method shall determine those quantities using standard quantification practices used for:
  - (i) Billing purposes in the natural gas industry; or
  - (ii) Non-billing purposes in the natural gas industry.
- (2) If the distributor determines the quantities of natural gas using (d)(1)(ii), the minimum frequency of measurement shall be the same as the one used in the quantification practices under (d)(1)(i).

- (3) The distributor required to determine quantities of natural gas for the purposes of using **Equation 11-9**, **Equation 11-10** or **Equation 11-11** of this method shall use the volume of natural gas measured at the custody transfer meter(s).
  - (4) The distributor referred to in (3) may use measurements or records of deliveries in place of the volume of natural gas measured at the custody transfer meter(s).
  - (5) The distributor required to determine quantities of natural gas for the purposes of using **Equation 11-12** of this method shall measure the volume of natural gas at all customer meter(s) at the facility.
  - (6) The distributor required to determine quantities of natural gas for the purposes of using **Equation 11-13** of this section shall measure natural gas as follows:
    - (i) Fuel<sub>1</sub> shall be measured at the on-system storage injection meters and at the meters measuring natural gas to be liquefied.
    - (ii) Fuel<sub>2</sub> shall be measured at the meters used for measuring on-system storage withdrawals or LNG vaporization injection.
- e. Determination of high heating values (HHV).
- (1) The distributor required to use **Equation 11-9**: shall, when using a distributor-specific HHV, calculate the HHV in accordance with an appropriate standard test published by a consensus-based standards organization using one of the following measurements:
    - (i) If the distributor takes its own HHV measurements in accordance with established business practices, then its own measurements shall be used.
    - (ii) If the distributor does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.
- f. Determination of distributor-specific emission factors.
- (1) A distributor using a distributor-specific emission factor in accordance with this method shall conduct compositional analysis using an appropriate standard method published by a consensus-based standards organization to determine the CO<sub>2</sub> emission factor.
- g. Equipment Calibration (which may also be referred to as Equipment verification).
- (1) A distributor required to determine quantities of natural gas in accordance with this method shall calibrate orifice, nozzle, and venturi flow meters:
    - (i) Prior to its first use for the purposes of this method; and
    - (ii) Using in-situ calibration of the differential pressure (delta-P), total pressure and temperature transmitters.
  - (2) For flow meters used for natural gas, the distributor may follow the requirements under the laws and regulations of Measurement Canada for electricity and gas or as specified by the equipment manufacturer.
  - (3) A distributor required to determine quantities of natural gas pursuant to this method shall recalibrate equipment mentioned in (g)(1) or (g)(2) at the frequency specified by:
    - (i) Any applicable method listed in the Technical Reference Document section of this Guideline;
    - (ii) The most appropriate method published by a consensus-based standards organization;

- (iii) Using methods and requirements in accordance with the requirements under the laws and regulation of Measurement Canada for electricity and gas; or
- (iv) The manufacturer's directions.

## **11.5 Procedures for Estimating Missing Data**

Procedures for estimating missing data for all non-natural gas fuels are described under (a) and (b) below. Procedures for estimating missing data for natural gas fuels are described under (c) below.

a. Determination of quantity.

The supplier shall ensure that whenever the quantity of one or more fuels or types of biomass during any period is not measured the following missing data procedures are used:

- (1) For quantities of a fuel that are purchased or sold, the missing data shall be substituted using the supplier's established procedures for billing purposes.
- (2) For quantities of a fuel that are not purchased or sold but for which the custody is transferred, the missing data shall be substituted using the supplier's established procedures for tracking purposes.

b. Determination of emission factor.

Where any of the procedures in **Equation 11-6:** cannot be followed to develop an emission factor for any reason, the supplier shall use default emission factors shown in **Error! Reference source not found.** for the entire calendar year.

c. Whenever a value for natural gas, HHV or EF is required by this method and is unavailable during a calendar year or part thereof, the distributor shall substitute a value for the missing data in accordance with the following:

- (1) Substitute the missing quantity of natural gas with quantities derived from:
  - (i) The delivering pipeline metered deliveries at the custody transfer station or
  - (ii) Nominations and scheduled delivery quantities.
- (2) Substitute the missing HHV value with:
  - (i) Delivering pipeline measurements;

**The default HHV provided in**

(ii) Table 11-2: Default Factors for Natural Gas; or,

**Where values relating to a distributor-specific emission factor are unavailable, substitute the missing EF value with the value from**

(iii) Table 11-2: Default Factors for Natural Gas or Table 11-3: Volume Based Default Factors for Natural Gas as applicable.

# **12. Cement Production**

## **12.1 Activity Definition**

Cement production consists of each kiln and each in-line kiln/raw mill at any Portland, masonry, pozzolanic, or other hydraulic cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/ raw mills that burn hazardous waste.

## **12.2 Greenhouse Gas Reporting Requirements**

A facility shall provide the following information using standard quantification methods described in this chapter unless the minister has consented to the use of a best alternative quantification method in section 2.2, in an emission report prepared for a calendar year in respect of cement production at a facility:

- a. Annual aggregated emissions of CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O from all sources, in tonnes.
- b. Annual CO<sub>2</sub> process emissions (excluding emissions from fuel combustion) in tonnes.
- c. Report the following information if the process CO<sub>2</sub> emissions are calculated according to the procedures specified in section 11.3(b)(1):
  - (1) Monthly plant specific clinker emission factors (tonnes CO<sub>2</sub>/tonnes clinker).
    - (i) Monthly quantities of clinker produced (tonnes).
    - (ii) Monthly total calcium content of clinker, expressed as calcium oxide (CaO) (weight fraction, tonne CaO/tonne clinker).
    - (iii) Monthly total magnesium content of clinker, expressed as magnesium oxide (MgO) (weight fraction, tonne MgO/tonne clinker).
    - (iv) Monthly non-calcined calcium oxide content of clinker, expressed as CaO (weight fraction, tonne CaO/tonne clinker).
    - (v) Monthly non-calcined magnesium oxide content of clinker, expressed as MgO (weight fraction, tonne MgO/tonne clinker).
    - (vi) Monthly quantity of non-carbonate raw materials entering the kiln (tonnes).
  - (2) Quarterly cement kiln dust (CKD) emission factor (tonne CO<sub>2</sub>/tonne CKD not recycled back to kilns).
    - (i) Quarterly quantity of CKD not recycled back to kilns (tonnes).
    - (ii) Quarterly total calcium oxide content of CKD not recycled to the kilns, (tonne CaO/tonne CKD)
    - (iii) Quarterly non-calcined calcium oxide content of CKD not recycled to the kilns, (tonne CaO/tonne CKD)
    - (iv) Quarterly total magnesium oxide content of CKD not recycled to the kilns, (tonne MgO/tonne CKD)

- (v) Quarterly non-calcined magnesium oxide content of CKD not recycled to the kilns, tonne (MgO/tonne CKD)
- d. Annual CO<sub>2</sub> process emissions from organic carbon oxidation (tonnes) and the following information if the process CO<sub>2</sub> emissions are calculated according to the procedures in 11.3(b)(2):
  - (1) Amount of raw material consumed in the report year (tonnes).
  - (2) Annual organic carbon content of raw material (weight fraction).
- e. Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from fuel combustion in all kilns combined, following the calculation methodology and reporting requirements specified in 11.3(c) (tonnes).
- f. Annual CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methodology and reporting requirements specified in 11.3(c) (tonnes).
- g. **Production Parameter:** Annual clinker production, and quantity of gypsum and limestone added as mineral additives to the clinker at the facility (tonnes).
- h. If a continuous emissions monitor is used to measure CO<sub>2</sub> emissions from the kilns, then the requirements of paragraphs (c) and (d) of this section do not apply for CO<sub>2</sub>. Cement plants that measure CO<sub>2</sub> emissions using CEMS shall report fuel usage by fuel type for kilns.
- i. Number of times missing data procedures were used to determine clinker production, non-calcined calcium oxide and magnesium oxide content of clinker, CKD not recycled, non-calcined calcium oxide and magnesium oxide content of CKD, organic carbon content, and raw material consumption.

## 12.3 Calculation of GHG Emissions

- a. Determine CO<sub>2</sub> emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
  - (1) Calculate the total process and combustion CO<sub>2</sub> emissions from all the kilns using a continuous emissions monitoring system (CEMS) as specified in Calculation Methodology 4 in Section 4.3 and combustion CO<sub>2</sub> emissions from all the kilns using the calculation methodologies specified in paragraph (c) of this section.
  - (2) Calculate the sum of CO<sub>2</sub> process emissions from kilns and CO<sub>2</sub> fuel combustion emissions from kilns using the calculation methodologies specified in paragraphs (b) and (c) in this section.
- b. Process CO<sub>2</sub> Emissions Calculation Methodology. Calculate total CO<sub>2</sub> 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. The following equation should be used to aggregate total process CO<sub>2</sub> emissions:

### Equation 12-1:

$$E_{CO2-P} = E_{CO2-C} + E_{CO2-F}$$

Where:

- $E_{CO2-P}$  Annual process CO<sub>2</sub> emissions, tonnes/year  
 $E_{CO2-C}$  Annual process CO<sub>2</sub> emissions from calcination, tonnes/year  
 $E_{CO2-F}$  Annual process CO<sub>2</sub> emissions from feed oxidation, tonnes/year

- (1) **Calcination Emissions.** Calculate CO<sub>2</sub> process emissions from calcination using **Equation 12-2:** and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

### Equation 12-2:

$$E_{CO2-C} = \sum_{m=1}^{12} [Q_{Cli,m} \times EF_{Cli,m}] + \sum_q^4 [Q_{CKD,q} \times EF_{CKD,q}]$$

Where:

- $E_{CO2-C}$  Annual process CO<sub>2</sub> emissions from calcination, tonnes  
 $Q_{Cli,m}$  Quantity of clinker produced in month  $m$ , tonnes  
 $EF_{Cli,m}$  CO<sub>2</sub> emission factor for clinker in month  $m$ , calculated as specified in paragraph (b)(1)(i) of this section, tonnes CO<sub>2</sub>/tonne of clinker  
 $Q_{CKD,q}$  Quantity of CKD not recycled to kilns in quarter  $q$ , tonnes  
 $EF_{CKD,q}$  CO<sub>2</sub> emission factor for CKD not recycled to the kilns, calculated as specified in paragraph (b)(1)(ii) of this section, tonnes of CO<sub>2</sub>/tonne CKD

- (i) **Clinker Emission Factor.** Calculate a plant-specific clinker emission factor ( $EF_{Cli,m}$ ) 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 12-3:**

### Equation 12-3:

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

Where:

- $EF_{Cli}$  Monthly CO<sub>2</sub> emission factor for clinker, tonne CO<sub>2</sub>/tonne clinker  
 $CaO_{cli}$  Monthly total calcium content of clinker expressed as calcium oxide, tonne CaO/tonne clinker

CaOf	Monthly non-calcined calcium oxide content of clinker <sup>6</sup> , tonne CaO/tonne clinker
MgO <sub>Cl</sub>	Monthly total magnesium content of clinker expressed as magnesium oxide, tonne MgO/tonne clinker
MgOf	Monthly non-calcined magnesium oxide content of clinker <sup>7</sup> , tonne MgO/tonne clinker
0.785	Ratio of molecular weights of CO <sub>2</sub> to CaO
1.092	Ratio of molecular weights of CO <sub>2</sub> to MgO

(ii) **CKD Emission Factor.** If CKD is generated and not recycled back to the kilns, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using **Equation 12-4:**

#### Equation 12-4:

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

Where:

EF <sub>CKD</sub>	Quarterly CO <sub>2</sub> emission factor for CKD not recycled to the kilns, tonne CO <sub>2</sub> /tonne CKD
CaO <sub>CKD</sub>	Quarterly total calcium oxide content of CKD not recycled to the kilns, tonne CaO/tonne CKD
CaOf	Quarterly non-calcined calcium oxide content of CKD <sup>8</sup> not recycled to the kilns, tonne CaO/tonne CKD
MgO <sub>CKD</sub>	Quarterly total magnesium oxide content of CKD <sup>9</sup> not recycled to the kilns, tonne MgO/tonne CKD
MgOf	Quarterly non-calcined magnesium oxide content of CKD not recycled to the kilns, tonne MgO/tonne CKD
0.785	Ratio of molecular weights of CO <sub>2</sub> to CaO
1.092	Ratio of molecular weights of CO <sub>2</sub> to MgO

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<sup>6</sup> The non-calcined calcium oxide content in the clinker is the sum of the CaO content present as a non-carbonated species in the raw materials entering the kiln and the non-transformed CaCO<sub>3</sub> content remaining in the clinker after oxidation, expressed as CaO.

<sup>7</sup> The non-calcined magnesium oxide content in the clinker is the sum of the MgO content present as a non-carbonated species in the raw materials entering the kiln and the non-transformed MgCO<sub>3</sub> content remaining in the clinker after oxidation, expressed as MgO.

<sup>8</sup> The non-calcined calcium oxide content in the dust is the sum of the CaO content present as a non-carbonate species in the raw materials entering the kiln and the non-transformed CaCO<sub>3</sub> content remaining in the kiln dust collected that is not recycled after oxidation, expressed as CaO.

<sup>9</sup> The non-calcined magnesium oxide content in the dust is the sum of the magnesium oxide that enters the kiln as a non-carbonate species and the non-transformed MgCO<sub>3</sub> content remaining in the kiln dust collected that is not recycled after oxidation, expressed as MgO.

- (2) **Organic Carbon Oxidation Emissions.** Calculate CO<sub>2</sub> process emissions from the total organic content in raw materials by using **Equation 12-5:**

**Equation 12-5:**

$$E_{CO_2-RM} = TOC_{RM} \times RM \times 3.664$$

Where:

E <sub>CO<sub>2</sub>-RM</sub>	Annual process CO <sub>2</sub> emissions from raw material oxidation, tonnes
TOC <sub>RM</sub>	Total organic carbon content in raw material (weight fraction), measured using the method in 12.4(b) of this chapter or using a default of 0.002 (0.2%)
RM	Amount of raw material consumed (tonnes/year)
3.664	Ratio of molecular weights of carbon dioxide to carbon

- c. Fuel Combustion Emissions in Kilns/Other Stationary Combustion Sources. Calculate CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from stationary fuel combustion in accordance with the calculation methodologies specified in Section 4. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shutdown, or malfunction may report CO<sub>2</sub> emissions from fossil fuels using Calculation Methodology 1 in Section 4.3. “Pure” means that the biomass-derived fuels account for at least 97 per cent of the total amount of carbon in the fuels burned.

Cement plants that calculate CO<sub>2</sub> emissions from kilns using a continuous emissions monitoring system under 12.3(a)(1) may report:

1. Fuel combustion CO<sub>2</sub> emissions in kilns by subtracting the total emissions calculated using 12.3(a)(1) from the process CO<sub>2</sub> emissions calculated using 12.3(b); or
2. Fuel combustion CO<sub>2</sub> emissions in kilns using Calculation Methodology 1 in Section 4.3 and fuel sampling based on the same plant techniques used for accounting purposes.

## 12.4 Sampling, Analysis and Measurement Requirements

- a. Determine the monthly plant-specific weight fractions of total calcium (as CaO) and total magnesium (as MgO) in clinker using one of the following:
  - (1) The most recent version of ASTM C114 or any of the other applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 3);
  - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

The monitoring shall 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 one of the following:
  - (1) The most recent version of ASTM C114 or any of the other applicable analytical methods listed in the Technical Reference Document section of this Guideline (section 3);
  - (2) The most appropriate method published by a consensus-based standards organization, if such a method exists. If no appropriate method is published by a consensus-based standards organization, use industry standard methods, noting where such methods are used and what methods are used.

The monitoring shall be conducted either 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 a documented analytical method or the appropriate industrial standard practice, or use 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 a documented analytical method or the appropriate industrial standard practice, or use 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 a documented analytical method or the appropriate industrial standard practice, or use 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 a documented analytical method or the appropriate industrial standard practice, or use a value of 0.0.
- g. Determine annually the total organic carbon contents of raw materials using ASTM C114, an equivalent industry method for total organic carbon determination in raw mineral material, or use a default value of 0.002. The analysis shall be conducted on sample material drawn from bulk raw material storage for each category of raw material.
- h. The quantity of clinker produced shall 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 shall verify the accuracy of this factor on a monthly basis.
- i. The quantity of CKD not recycled back to the kiln shall 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) shall be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders or using a material balance.
- k. The quantity of limestone and gypsum blended with the clinker shall be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes.
- l. Equipment used to measure the clinker, limestone and gypsum shall be:
  - (1) calibrated according to the manufacturer's instructions; and
  - (2) maintained to achieve an accuracy of plus or minus 5%.

## 12.5 Procedures for Estimating Missing Data

### Unavailable Analytical Data

- a. Whenever analytical data relating to sampling is unavailable, the facility shall use the methods prescribed in 11.4, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

### Determination of Quantity

- b. Whenever sampling and measurement data required by 11.4 for the calculation of emissions is missing the facility shall ensure that the data is replaced using the following missing data procedures:
  - (1) When the missing data concerns carbon content, calcium oxide content, magnesium oxide content, temperature, pressure or gas concentration, the facility shall:
    - (i) Determine the sampling or measurement rate using **Equation 12-6:**

### Equation 12-6:

$$R = Q_{SAct}/Q_{SRequired}$$

Where:

R	Sampling or measurement rate that was used, expressed as a percentage
$Q_{SAct}$	Quantity of actual samples or measurements obtained by the facility
$Q_{SRequired}$	Quantity of samples or measurements required under section 11.4.

(ii) Replace the missing data as follows:

- (A) If  $R \geq 0.9$ : replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the facility shall use the first available data from after the missing data period;
  - (B) If  $0.75 \leq R < 0.9$ : replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
  - (C) If  $R < 0.75$ : replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (4) When the missing data concerns clinker production, the facility shall use the first data estimated after the period for which the data is missing or use the maximum daily production capacity and multiply it by the number of days in the month;
  - (5) When the missing data concerns raw material consumption, the facility shall use the first data estimated after the period for which the data is missing or use the maximum rate of raw materials entering the kiln and multiply by the number of days in the month;
  - (6) When the missing data concerns the quantity of dust, the quantity of gypsum or the quantity of limestone, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

#### Continuous Emissions Monitor

- c. For all units subject to the requirements of Section 4 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" <sup>(10)</sup> shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

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<sup>(10)</sup> Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7, Available at: <https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromThermalPowerGeneration.pdf>

# **13. Operation of equipment related to the transmission, storage and transportation of natural gas.**

## **13.1 Activity Definition**

- a. Natural gas transmission compression. 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, into storage or at times directly to customers located along the pipeline route. 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 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 LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and reliquefy 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 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 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. Some natural gas distribution systems receive gas from gas batteries rather than from transmission pipelines and typically transport odourized natural gas.

- 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. In some cases natural gas is delivered directly from natural gas transmission pipelines to farms and industrial end users along the pipeline route.

## 13.2 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. CO<sub>2</sub> and CH<sub>4</sub> (and N<sub>2</sub>O, 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 natural gas transmission compression and natural gas transmission pipelines, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
  - (1) Compressor venting (from the following sources):
    - (i) Reciprocating compressors. [12.3(f)]
    - (ii) Centrifugal compressors. [12.3(e)]
    - (iii) Blowdown vent stacks [12.3(c)]
    - (iv) Natural gas pneumatic continuous high-bleed devices. [12.3(a)]
    - (v) Natural gas pneumatic pumps. [12.3(a.1)]
    - (vi) Natural gas pneumatic continuous low-bleed device venting. [12.3(b)]
    - (vii) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. [12.3(b.1)]
    - (viii) Other venting emission sources.\* [12.3(l)]
  - (2) Compressor fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. [12.3(g)] or [12.3(h)], size dependent
  - (3) Compressor station flaring. [12.3(d)]
  - (4) Compressor other fugitive emission sources.\*[12.3(l)]
  - (5) Above grade meters and regulators and associated equipment at custody transfer meter regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. [12.3(g)]
  - (6) Above grade meters and regulators and associated equipment at non-custody transfer meter-regulating stations, including station equipment leaks. [12.3(h)]

- (7) Pipeline flaring. [12.3(d)]
  - (8) Pipeline belowground meters and regulators and valve fugitives. [12.3(h)]
  - (9) Pipeline other fugitive emission sources not covered in (b)(5), (b)(6), (b)(7), (b)(8) or (b)(12) (including, but not limited to, farm taps <=700 kPa, pipe leaks, and customer meter sets).\*, \*\* [12.3(l)]
  - (10) Pipeline other venting emission sources.\*[12.3(l)]
  - (11) Transmission storage tanks. [12.3(m)]
  - (12) Third party line hits. [12.3(c.1)]
- c. For underground natural gas storage, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. [12.3(f)]
    - (ii) Centrifugal compressors. [12.3(e)]
    - (iii) Natural gas pneumatic continuous high-bleed devices. [12.3(a)]
    - (iv) Natural gas pneumatic pumps. [12.3(a.1)]
    - (v) Natural gas pneumatic continuous low-bleed device venting. [12.3(b)]
    - (vi) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. [12.3(b.1)]
    - (vii) Other venting emission sources.\* [12.3(l)]
  - (2) Fugitive equipment leaks from valves, connectors, open ended lines, pressure relief valves and meters. [12.3(g)], [12.3(h)]
  - (3) Flares. [12.3(d)]
  - (4) Other fugitive emission sources.\* [12.3(l)]
- d. For LNG storage, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. [12.3(f)]
    - (ii) Centrifugal compressors. [12.3(e)]
    - (iii) Other venting emission sources.\* [12.3(l)]
  - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. [12.3(g)], [12.3(h)]
  - (3) Flares. [12.3(d)]
  - (4) Other fugitive emission sources.\* [12.3(l)]
- e. LNG import and export equipment, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
- (1) Venting (from the following sources):
    - (i) Reciprocating compressors. [12.3(f)]
    - (ii) Centrifugal compressors. [12.3(e)]
    - (iii) Blowdown vent stacks (including third party line hits). [12.3(c)]
    - (iv) Other venting emission sources.\* [12.3(l)]
  - (2) Fugitive equipment leaks from valves, pump seals, connectors, vapour recovery compressors, and other equipment leak sources. [12.3(g)], [12.3(h)]
  - (3) Flares. [12.3(d)]
  - (4) Other fugitive emission sources.\*[12.3(l)]

- f. For natural gas distribution, report CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions from the following sources:
  - (1) Meters, regulators, and associated equipment at above grade custody transfer metering regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines. [12.3(g)]
  - (2) Meters, regulators, and associated equipment at above grade non custody transfer metering-regulating stations, including fugitive equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open-ended lines. [12.3(h)]
  - (3) Equipment leaks from vaults at below grade metering-regulating stations. [12.3(h)]
  - (4) Meters, regulators, and associated equipment at above grade metering-regulating stations. [12.3(h)]
  - (5) Equipment leaks from vaults at below grade metering-regulating stations [12.3(h)]
  - (6) Pipeline main fugitive equipment leaks. [12.3(h)]
  - (7) Service line fugitive equipment leaks. [12.3(h)]
  - (8) Pipeline flaring. [12.3(d)]
  - (9) Flares. [12.3(d)]
  - (10) Third party line hits [12.3(c.1)]
  - (11) Other fugitive emission sources (including, but not limited to, farm taps, and customer meter sets).\*, \*\* [12.3(l)]
  - (12) Venting (from the following sources):
    - (i) Natural gas pneumatic continuous high-bleed devices. [12.3(a)]
    - (ii) Natural gas pneumatic pumps. [12.3(a.1)]
    - (iii) Natural gas pneumatic continuous low-bleed device venting. [12.3(b)]
    - (iv) Natural gas pneumatic intermittent (low and high) bleed device (including compressor starters) venting. [12.3(b.1)]
    - (v) Other venting emission sources.\* [12.3(l)]
- g. Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each stationary fuel combustion source type combusting field gas or process vent gas [6.3(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 Section 4 quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.
- h. Report CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from each portable equipment combustion source type combusting field gas or process vent gas [6.3(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 Section 4 quantification methods. The reference to process vent gas is not intended to include vent gas that is sellable quality natural gas.
- 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 or emissions information, as appropriate, used in place of Table 13-1 to Table 13-5.
- (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) Count of third party line hits
  - (i) Engineering distribution of number of line hits by volume of gas released by hit
- (8) Total pipeline length.
- (9) 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 Sm<sup>3</sup>/day operated
  - (ii) Desiccant dehydrators:
    - (A) The number of desiccant dehydrators operated.
- (10) For each compressor report the following:
  - (i) Type of compressor whether reciprocating, centrifugal dry seal, or centrifugal wet seal.
  - (ii) Compressor driver capacity in horsepower.
  - (iii) Number of blowdowns per year.
  - (iv) Operating mode(s) during the year (i.e., operating, not operating and pressurized or not operating and depressurized).
  - (v) Number of compressor starts per year.
- (11) For fugitive equipment leaks and population-count/emission-factor sources, using emission factors for estimating emissions in 12.3(g) and (h), report the following:
  - (i) Component count for each source type for which an emission factor is provided in Tables Table 13-1, Table 13-2 or Table 13-3, Table 13-4 or Table 13-5 in this document. Current processing and instrumentation drawings (P&ID) may be used for the source of component counts for all years.
  - (ii) Total counts of leaks found in leak detection surveys by type of leak source for which an emission factor is provided.
- (12) For natural gas distribution, report the following, in addition to other requirements:
  - (i) The number of custody transfer meter-regulating stations.
  - (ii) The number of non-custody transfer meter-regulating 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) The greenhouse gas emissions for the facility in the previous year.

(iv) The purchaser or seller, as appropriate.

\* 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.

\*\* Tubing systems less than one half inch diameter may be quantified using 12.3(g) instead of 12.3(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using 12.3(h). Reporting must occur using the appropriate section of 12.2, dependent upon industry segment and quantification method used.

### 13.3 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. In general, equations are presented at the most basic unit level and emissions must be summed, so that the total population of devices and/or events are included for the reporting facility or organization, as required by regulation. Nomenclature used in the equations is presented in Table 13-7.

- a. Natural gas pneumatic continuous high-bleed device venting. Calculate emissions from a natural gas pneumatic continuous high-bleed flow control device venting using the method specified in paragraph (a)(1) below when the device is metered. Natural gas consumption must be metered for all of the operator's pneumatic high-bleed devices. For the purposes of this reporting requirement, high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m<sup>3</sup>/hr. For unmetered devices the operator must use the method specified in paragraph (a)(2).
  - (1) The operator must calculate vented emissions for metered pneumatic high-bleed devices using the following equation:

### **Equation 13-1**

$$E_s = Q_j$$

Where:

$E_s$  Annual natural gas volumetric emissions for pneumatic high-bleed devices and pneumatic pumps where gas is metered ( $\text{Sm}^3/\text{y}$ ).

$Q_j$  Natural gas consumption for meter  $j$  ( $\text{Sm}^3/\text{y}$ ).

- (2) The operator must calculate vented emissions for unmetered pneumatic high-bleed devices using the following equation:

### **Equation 13-2**

$$E_s = EF_j \times t_j$$

Where:

$E_s$  Annual natural gas volumetric emissions for pneumatic high-bleed devices where gas is unmetered ( $\text{Sm}^3/\text{y}$ ).

$EF_j$  Natural gas-drive pneumatic device (or equivalent device),  $j$ , bleed rate volume in Table 13-6 (data within Table as revised from time to time and provided by the regulator) ( $\text{Sm}^3/\text{h}/\text{device}$ ).

i. For individual pneumatic high-bleed controllers, except as noted in subparagraph 1 below, use the device (or equivalent device)-specific emission factor provided in Table 13-5.

1. The  $EF_j$  parameter may be calculated using **Equation 12-2a**:

### **Equation 12-2a**

$$EF_j = m \times SP_j$$

Where:

$m$  The supply pressure coefficient in Table 13-6.

$SP_j$  The supply pressure (kPa) of controller  $j$ .

ii. For pumps, except as noted in subparagraphs 1 and 2 below, use the pump (or equivalent pump)-specific emission factor provided in Table 13-6.

$t_j$  Total time that the pneumatic device,  $j$ , has been in service the (i.e. the time that gas flows to the device) through the reporting period (h).

- (3) 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. If data for a reasonably similar pump model size and operational characteristics cannot be obtained, use the factor in Table 13-4 for high-bleed pneumatic devices
  - (4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section
  - (5) Provide the total number of continuous high-bleed natural gas pneumatic devices as follows:
    - (i) Facilities must update the total count of continuous high-bleed pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.
- (a.1) Natural gas pneumatic pump venting. Calculate emissions from natural gas-driven pneumatic pump venting using the method specified in paragraph (a)(1) above when the pump is metered. Natural gas consumption must be metered for all of the operator's pneumatic pumps. For unmetered pumps the operator must use the methods preferentially specified in paragraph (a.1)(2). Natural gas-driven pneumatic pumps covered in paragraph (d) (dehydrator vents) of this section do not have to report emissions under paragraph (a.1) of this section.
- (1) The operator must calculate vented emissions for metered pneumatic pumps using **Equation 13-1**.
  - (2) The operator must calculate vented emissions for unmetered pneumatic pumps using **Equation 13-3**.
    - (i) 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. 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.
    - (ii) Maintain a log of the amount of liquid pumped annually from individual pumps.
    - (iii) Calculate the natural gas emissions for each pump using **Equation 13-3**.

### **Equation 13-3**

$$E_s = EF_j \times Q_j$$

Where:

- E<sub>s</sub> Annual natural gas volumetric emissions (Sm<sup>3</sup>/y).
- EF<sub>j</sub> Natural gas-drive pneumatic device (or equivalent device), j, bleed rate volume in Table 13-6 (data within Table as revised from time to time and provided by the regulator) (Sm<sup>3</sup>/h/device).

i. For individual pneumatic high-bleed controllers, except as noted in subparagraph 1 below, use the device (or equivalent device)-specific emission factor provided in Table 13-5.

1. The  $EF_j$  parameter for pumps may be calculated using **Equation 12-3a**<sup>11</sup>:

### Equation 12-3a

$$EF_j = (g \times SP_j) + (n \times DP_j) + (p \times SPM_j)$$

Where:

Bleed Rate<sub>j</sub> The volume of natural gas bled per hour for pneumatic pump (or equivalent pump), j ( $\text{Sm}^3\text{NG}/\text{h}$ ).

G The supply pressure coefficient provided in Table 13-6 (kPa).

SP<sub>j</sub> The fuel supply pressure for pump (or equivalent pump) j.

n The discharge pressure coefficient provided in Table 13-6 (kPa).

DP<sub>j</sub> The discharge pressure of pump (or equivalent pump) j.

p The strokes per minute coefficient provided in Table 13-6.

SPM<sub>j</sub> The strokes per minute of pump (or equivalent pump) j (spm).

2. The  $EF_j$  parameter may be calculated using **Equation 12-3b**:

### Equation 12-3b

$$EF_j = Q_j \times R_j$$

Where:

Q<sub>j</sub> The volume rate of chemical injection for pump, j (L/h).

R<sub>j</sub> The pump specific factor expressed as the volume of gas vented per liter of chemical injected. The factor takes into account fuel supply pressure, piston size, and discharge pressure and is based on the chart published by the pump j manufacturer ( $\text{Sm}^3\text{NG}/\text{L}$ )

Q<sub>j</sub> Volume of liquid pumped annually by pump j (liters/y).

(3) If the device, or equivalent device, is not listed in Table 13-6, use the generic high bleed emission factor for all high bleed controllers and use the generic bleed rate for diaphragm or piston pumps, as appropriate.

(4) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section

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<sup>11</sup> If the pump is operating at less than five strokes per minute, this equation is not applicable and the mean bleed rate or volume of chemical equation should be used instead.

- (5) Provide the total number of natural gas pneumatic pumps as follows:
- Facilities must update the total count of pneumatic pumps and adjust accordingly to reflect any modifications due to changes in equipment.
- b. Natural gas pneumatic continuous low-bleed device venting. Calculate emissions from natural gas pneumatic continuous low-bleed device venting using **Equation 13-4** of this section.

#### **Equation 13-4**

$$E_s = EF_j \times t_j$$

Where:

- $E_s$  Annual natural gas volumetric emissions for pneumatic continuous low-bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  Population emission factor for natural gas-driven pneumatic continuous lowbleed device,  $j$ , as provided in Table 12-4 ( $\text{Sm}^3/\text{h/device}$ ).
- $t_j$  Total time that the pneumatic device,  $j$ , has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).

- Both  $\text{CH}_4$  and  $\text{CO}_2$  volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
  - Provide the total number of continuous low-bleed natural gas pneumatic devices of each type as follows:
    - Facilities must update the total count of continuous low-bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.
- b.1) Natural gas pneumatic intermittent (low and high) bleed device venting. Calculate emissions from natural gas pneumatic intermittent (low and high) bleed device venting as follows.
- The operator must calculate vented emissions for pneumatic intermittent (low and high) bleed devices used to maintain a process condition such as liquid level, pressure, delta pressure or temperature using **Equation 13-5**:

#### **Equation 13-5**

- $E_s$  Annual natural gas volumetric emissions for pneumatic intermittent (low and high) bleed devices ( $\text{Sm}^3/\text{y}$ ).
- $EF_j$  Natural gas-drive pneumatic device (or equivalent device),  $j$ , bleed rate volume in Table 12-6 (data within Table as revised from time to time and provided by the regulator) ( $\text{Sm}^3/\text{h/device}$ ).

- i. For individual intermittent pneumatic devices, except as noted below, use the device (or equivalent device)-specific emission factor provided in Table 13-6.
  - 1. The EF<sub>j</sub> parameter may be calculated using emissions from these devices may be calculated using Equation 12-5a

**Equation 12-5a**

$$EF_j = m \times SP_j$$

Where:

- m The supply pressure coefficient in Table 13-6.
- SP<sub>j</sub> The supply pressure (kPa) of controller j.

- ii. If the device (or equivalent device) is not present in Table 13-6, use the generic intermittent (high or low, as appropriate) bleed emission factor in Table 13-4.
- t<sub>j</sub> Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (h).
- (2) The operator must calculate vented emissions for pneumatic intermittent (high) bleed devices, used to drive compressor starters, using Equation 13-6\*:

**Equation 13-6**

$$E_s = EF_j \times t_j$$

Where:

- E<sub>s</sub> Annual natural gas volumetric emissions for pneumatic intermittent (high) bleed devices (Sm<sup>3</sup>/y).
- EF<sub>j</sub> Emission factor for natural gas-driven pneumatic compressor starter, *j*, as provided by the manufacturer for the operating condition (Sm<sup>3</sup>/min/device). If an emission factor is not available from the manufacturer, an emission factor for a similar compressor starter may be used in its place.
- t<sub>j</sub> Total time that the pneumatic device, *j*, has been in service (i.e. the time that the gas flows to the device) through the reporting period (min).

*Note: The volume of gas per start provided by the manufacturer may be used in place of the EF<sub>j</sub> and t variables.*

- (3) Both CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (j) and (k) of this section.
- (4) Provide the total number of intermittent (low and high) bleed natural gas pneumatic devices as follows:
- (i) Count all devices. Facilities must update the total count of intermittent (low and high) bleed natural gas pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment each year.
- c. Blowdown Vent Stacks. Calculate blowdown vent stack emissions from depressurizing equipment to reduce system pressure for planned or emergency shutdowns or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases) as follows:
- (1) Calculate the total physical volume (including, but not limited to, pipe, 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 physical volume between isolation valves is greater than or equal to 1.42 Sm<sup>3</sup>, retain logs of the number of blowdowns for each equipment system (including, but not limited to pipes, compressors and vessels). Physical volumes smaller than 1.42 m<sup>3</sup> are exempt from reporting under paragraph (c) of this section.
  - (3) Calculate the venting emissions for each equipment type using **Equation 13-7**.

### **Equation 13-7**

$$E_s = V_v \left[ \frac{(273.15 + T_s)(P_{a,1} - P_{a,2})}{(273.15 + T_a)P_s} \right]$$

Where:

- E<sub>s</sub> Natural gas venting volumetric emissions from blowdown of an equipment system (Sm<sup>3</sup>).
- V<sub>v</sub> Total physical volume of blowdown equipment chambers (including, but not limited to, yard piping, pipelines, compressors and vessels) between isolation valves for the equipment system (m<sup>3</sup>).
- T<sub>s</sub> Temperature at standard conditions (°C).
- T<sub>a</sub> Temperature at actual conditions in the equipment system ( C ).
- P<sub>s</sub> Absolute pressure at standard conditions (kPaa).
- P<sub>a,1</sub> Absolute pressure at actual conditions in the equipment system prior to depressurization (kPaa).
- P<sub>a,2</sub> Absolute pressure at actual conditions in the equipment system after depressurization; 0 if equipment is purged using non-GHG gases (kPaa).

- (4) Calculate both CH<sub>4</sub> and CO<sub>2</sub> 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 (k) Flare stacks calculation method rather than (c) Blowdown vent stacks calculation method.
- (c.1) Third party line hits. Calculate fugitive emissions from third party line hits as follows:
- (1) For transmission and gathering systems only. Use company gas release data used for regulatory purposes if available. If this data is not available, then for each dig-in incident (i.e., line hit) which results in gas release  $\geq 1.416 \text{ Sm}^3$ , calculate volumetric flow rate prior to pipeline isolation for both catastrophic pipeline ruptures and pipeline puncture incidents using the appropriate methodology below.<sup>12</sup>
    - (i) For catastrophic pipeline ruptures where the pipeline is severed, use the following methodology:

### **Equation 13-8**

$$Q_s = \frac{3.6 \times 10^6 \times A}{\rho_s} \sqrt{\frac{K \times MW}{1000 \times R \times (273.15 + T_a)}} \times \frac{P_a \times M}{\left(1 + \frac{K-1}{2} M^2\right)^{\frac{K+1}{2(K-1)}}}$$

### **Equation 13-9**

$$M = \sqrt{\frac{2 \left[ \left(\frac{P_a}{P_e}\right)^{\frac{K-1}{K}} - 1 \right]}{K-1}}, \text{ (for } M \leq 1), M=1, \text{ (for all other cases)}$$

Where:

- Q<sub>s</sub> Natural gas venting volumetric flow rate ( $\text{Sm}^3/\text{h}$ ).
- A Cross-sectional flow area of the pipe ( $\text{m}^2$ ,  $A=\pi D^2/4000,000$ )
- D Inside diameter of the pipe (mm).
- K Specific heat ratio of the gas (dimensionless – 1.299 for methane).
- M Mach number of the flow (m/s).
- MW Molecular weight of the gas (kg/mole, 16.043 kg/mole for methane).
- P<sub>e</sub> Pressure at the damage point (local atmospheric pressure, kPa).
- P<sub>a</sub> Pressure inside the pipe at supply (kPa) (usually taken at the point where the damaged main branches off a larger main). The supply pressure values should

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<sup>12</sup> 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). Prepared by Clearstone Engineering Ltd. Calgary, Alberta, September 25, 2007. Chapter7, Third-Party Dig-Ins, page 117.

represent a stable supply pressure; however, it is important to account for the lower pressure which will occur because of the flow of gas from the break.

R Universal gas constant (8.3145 kPam<sup>3</sup>/kmol/K).

T<sub>a</sub> Temperature inside pipe at the supply (°C).

ρ<sub>s</sub> Gas density at standard conditions (kg/m<sup>3</sup>) (0.6785 kg/m<sup>3</sup> for CH<sub>4</sub>).

(ii) For pipeline punctures use the following methodology either individually per puncture or in aggregate (using weighted averages) for all punctures of pipes of a given pressure and pipe type:

### **Equation 13-10**

$$Q_s = \frac{A_e}{\rho_s} \sqrt{\frac{2000 \times K}{K - 1}} P_a \rho_a \left[ \left( \frac{P_{Atm}}{P_a} \right)^{2/K} - \left( \frac{P_{Atm}}{P_a} \right)^{K+1/K} \right]$$

Where:

### **Equation 13-11**

$$\left( \frac{P_{Atm}}{P_a} \right) \geq \left( \frac{P_{Atm}}{P_a} \right)_{choked} = \left( \frac{2}{K + 1} \right)^{\frac{K}{K-1}} = 0.546 \text{ (for methane)}$$

Where:

A<sub>e</sub> Size of the hole in the pipe (as either measured or estimated using engineering estimation techniques) (m<sup>2</sup>).

P<sub>a</sub> Pressure inside the pipe (as either measured or estimated using engineering estimation techniques) at the puncture location (kPa)

ρ<sub>a</sub> Gas density inside the pipe at the puncture location (kg/m<sup>3</sup>).

MW Molecular weight of the natural gas (16.043 for methane).

T<sub>a</sub> Temperature inside the pipe (°C).

(P<sub>ATM</sub>/P<sub>a</sub>)<sub>c</sub> 0.546 - lower limit for choked flow.

(iii) Determine which quantification method to use

(A) If (P<sub>ATM</sub>/P<sub>a</sub>) is  $\geq 0.546$  or the third party line hit is on a distribution pipeline or gathering pipeline, the reporter must use the equations in section (c.1) (ii) above.

(B) If (P<sub>ATM</sub>/P<sub>a</sub>) < 0.546 and the third party line hit is on a transmission main or intermediate pressure line, the reporter must use the equations in section (c.1)(i) above and A must be set to the cross sectional flow area of the pipe.

- (C) When flow is determined through a service tee drill or punch opening the reporter must use an appropriate industry standard quantification method.
- (iv) Calculate volumetric natural gas emissions by multiplying  $Q_s$  for each pipeline rupture and puncture by the total elapsed time from pipeline rupture or puncture until isolation and final bleed-down to atmospheric pressure.
  - (v) Calculate GHG ( $\text{CH}_4$  and  $\text{CO}_2$  emissions) mass emissions using the methodologies in sections (j) and (j) of this section.
- (2) For distribution systems only: Until updated Canadian Energy Partnership for Environmental Innovation methods are published or otherwise made available and accepted, may use emission factors ( $45.32 \text{ m}^3$  natural gas/km-main year) and quantification methods available in the Radian Survey reports (Emission Factor Documentation Technical Memorandum, October 2001. Prepared by URS Corporation for the Canadian Energy Partnership for Environmental Innovation).
- d. Flare stacks. Calculate  $\text{CO}_2$ ,  $\text{CH}_4$ , and  $\text{N}_2\text{O}$  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.
  - (2) If there is a continuous gas composition analyzer on the gas stream to the flare, these compositions must be used in calculating emissions. If there is not a continuous gas composition analyzer on the gas stream to the flare, use the gas compositions for each stream of hydrocarbons going to the flare (must be determined using (j)(1) and (j)(2) of this section).
  - (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 **Equation 13-12**, **Equation 13-13**, **Equation 13-14**, and **Equation 13-15**.

**Equation 13-12:**

$$E_{s,\text{CH}_4}(\text{noncumbusted}) = Q_s \times (1 - \eta) \times Y_{\text{CH}_4}$$

**Equation 13-13:**

$$E_{s,\text{CO}_2}(\text{noncumsted}) = Q_s \times Y_{\text{CO}_2}$$

**Equation 13-14:**

$$E_{s,\text{CO}_2}(\text{combusted}) = \sum_i \eta \times Q_s \times Y_i \times n_i$$

**Equation 13-15:**

$$E_{s,co2}(\text{total}) = E_{s,co2}(\text{combusted}) + E_{s,co2}(\text{noncombusted})$$

Where:

$E_{s,CH_4}$ (noncombusted)	Contribution of annual noncombusted volumetric $CH_4$ emissions from flare stack ( $Sm^3$ ).
$E_{s,CO_2}$ (noncombusted)	Contribution of annual volumetric $CO_2$ emissions from $CO_2$ in the inlet gas passing through the flare noncombusted ( $Sm^3$ ).
$E_{s,CO_2}$ (combusted)	Contribution of annual $CO_2$ emissions from combustion from flare stack under ambient conditions ( $Sm^3$ ).
$Q_s$	Volume of natural gas sent to flare during the year ( $Sm^3$ ).
$\eta$	Fraction of natural gas combusted by flare (default combustion efficiency is 0.98). For gas sent to an unlit flare, $\eta$ is zero.
$Y_{CH_4}$	Mole fraction of $CH_4$ in gas to the flare.
$Y_{CO_2}$	Mole fraction of $CO_2$ in gas to the flare.
$Y_i$	Mole fraction of hydrocarbon constituents $i$ (i.e., methane, ethane, propane, butane, pentanes, hexanes and pentanes plus) in natural gas to the flare.
$n_i$	Number of carbon atoms in the hydrocarbon constituent $i$ (i.e., 1 for methane, 2 for ethane, 3 for propane, 4 for butane, 5 for pentanes, 6 for hexanes and 7 for pentanes plus) in natural gas to the flare.

- (5) Calculate both  $CH_4$  and  $CO_2$  mass emissions from volumetric  $CH_4$  and  $CO_2$  emissions using calculation in paragraph (k) of this section.
- (6) Calculate  $N_2O$  emissions using **Equation 13-16**.

**Equation 13-16**

$$E_{N2O} = Q_s \times HHV \times EF \times 0.001$$

Where:

$E_{N2O}$	Annual $N_2O$ mass emissions from flaring (tonnes/y).
$Q_s$	Volume of gas combusted by the flare in the reporting period ( $Sm^3/y$ ).
HHV	High heat value of the flared gas from paragraph (d)(2).
EF	$N_2O$ emission factor. Use $9.52 \times 10^{-5}$ kg $N_2O/GJ$ .
0.001	Conversion factor from kilograms to tonnes.

- (7) To avoid double-counting, this emissions source excludes any emissions calculated under other emissions sources in 12.3. Where gas to be flared is

manifolded from multiple sources in 12.3 to a common flare, report all flaring emissions under 12.3(d).

- e. Calculate emissions from all centrifugal compressor vents as follows. Dry seal and wet seal centrifugal compressors can enter the following operating modes (1) “operating, pressurized”, (2) “stand-by, pressurized” and (3) “not-operating, depressurized”.
  - (1) The operator must calculate CO<sub>2</sub>, and CH<sub>4</sub>, and N<sub>2</sub>O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents (including wet seal oil degassing) where the aggregate rated power for the sum of compressors at the facility is 186.4 kW or greater using a temporary or permanent flow measurement meter such as, but not limited to, a portable utility grade (bellows) meter, high-flow sampler or a vane anemometer according to methods set forth in 12.4(b).
  - (2) Estimate annual emissions using flow meter measurement using **Equation 13-7**.

### **Equation 13-17**

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Where:

- E<sub>s,i</sub> Annual volumetric emissions of GHG i (either CH<sub>4</sub> or CO<sub>2</sub>) from all compressor venting modes (Sm<sup>3</sup>/y).
- Q<sub>s,m</sub> Measured volumetric gas emissions during operational mode m described in paragraph (e)(4) of this section (Sm<sup>3</sup>/h).
- m The operational mode of a centrifugal compressor.
- t<sub>m</sub> Total time the compressor is in operational mode m during the calendar year (h).
- Y<sub>i</sub> Mole fraction of GHG i in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.
- CF Fraction 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.

(2.1) To ensure that emissions for modes not found during the annual measurement are included in reported estimates, **Equation 13-7** a must be used to calculate total emissions:

### **Equation 12-17a**

$$E_{s,i,c} = E_{s,i} + E_{m,nf}$$

Where:

- $E_{s,i}$  Output of Equation 12-17.
- $E_{m,nf}$  Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used, in order of preference.
- (3) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the  $Q_{s,m}$  variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor. Alternatively, a source-specific emissions factor can be established by measuring the emissions from relevant sources during each operational mode.
  - (4) Conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement. As applicable, measure emissions from (including emissions manifolded to common vents) degassing vents, unit isolation-valve vents, and blowdown-valve vents. If there is a safety risk that cannot be (reasonably) mitigated with measuring emissions from a specific vent line, a request for exemption of measurement that is accompanied by documentation (including photos showing and written description of the issue and measurement options contemplated) must be provided to the regulatory Director who may indicate that an emission factor approach be used instead. Given that there is not a requirement to measure in the winter months, winter safety would not be applicable evidence unless the site were winter access only. Consideration of practices of industry peers would need to be considered.
    - (i) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and wet seal oil degassing vent (if applicable); for wet seal and dry seal compressors.
    - (ii) Standby pressurized mode.
    - (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 the compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance). 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 not operating depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the not operating depressurized mode.
  - (5) Calculate both CH<sub>4</sub> and CO<sub>2</sub> 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 lines must use methods outlined in EPA Subpart W 98.233(o)
- f. Reciprocating compressor venting. Calculate annual CH<sub>4</sub> and CO<sub>2</sub> emissions from all reciprocating compressor vents as follows. Where venting emissions are sent to a common flare, calculate emissions using 12.3(d). A reciprocating compressor's operational modes include "operating, pressurized", "standby, pressurized mode" and "not operating, depressurized".
  - (1) Estimate annual emissions using the flow measurement in (f)(2) or (f)(3) below and **Equation 13-8**.

### **Equation 13-18**

$$E_{s,i} = \sum_m Q_{s,m} \times t_m \times Y_i \times (1 - CF)$$

Where:

- E<sub>s,i</sub> Annual volumetric emissions of GHG *i* (either CH<sub>4</sub> or CO<sub>2</sub>) from all compressor venting modes (Sm<sup>3</sup>/y).
- Q<sub>s,m</sub> Measured volumetric gas emissions during operational mode *m* described in paragraph (f)(4) (Sm<sup>3</sup>/h).
- m* The operational mode of a reciprocating compressor.
- t<sub>m</sub> Total time the compressor is in operational mode *m* during the calendar year (h).
- Y<sub>i</sub> Annual average mole fraction of GHG *i* in the vent gas; use the appropriate gas compositions in paragraph (j)(2) of this section.
- CF Fraction of reciprocating 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.

- (1.2) To ensure that emissions for modes not found during the annual measurement are included in reported estimates, **Equation 12-18a** must be used to calculate total emissions:

### **Equation 12-18a**

$$E_{s,i,c} = E_{s,i} + E_{m,nf}$$

Where:

$E_{s,i}$  Output of **Equation 13-18**.

$E_{m,nf}$  Estimate of emissions for the modes not found during the annual measurement as calculated from emissions for mode not found for the compressor during previous years and prorated for the time in the year for the mode not found. If the mode not found did not occur in previous years, estimates from a similar compressor or manufacturer emission factors may be used, in order of preference.

- (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-flow Sampler according to methods set forth in 12.4(c) and (d).
  - (ii) Use a temporary meter such as a portable utility grade (bellows) meter or 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 12.4(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 12.4(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 12.4(a) to conduct a progressive 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 12.4(b), (c), or (d).
- (4) Conduct an annual measurement for each compressor in the operational 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. If there is a safety risk that cannot be (reasonably) mitigated with measuring emissions from a specific vent line, a request for exemption of measurement that is accompanied by documentation (including photos showing and written description of the issue and measurement options contemplated) must be provided to the regulatory Director who may indicate that an emission factor approach be used instead. Given that there is not a requirement to measure in the winter months, winter safety would

not be applicable evidence unless the site were winter access only. Consideration of practices of industry peers would need to be considered.

- (i) Operating pressurized mode, blowdown vent leakage through the blowdown vent stack and reciprocating rod packing emissions.
  - (ii) Standby pressurized mode.
  - (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 the compressor enters the not operating depressurized mode during normal service (i.e. excluding maintenance). 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 not operating depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the not operating depressurized mode.
- (5) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (j) and (k) of this section.
  - (6) 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.
    - (ii) An engineering estimate approach based on similar equipment specifications and operating conditions or manufacturer's data may be used to determine the Q<sub>s,m</sub> variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year.
- g. Leak detection and leaker emission factors. Existing legislative or regulatory requirements (described in 12.4(a)(1) or progressive sampling methods (described in 12.4(a)(2) must be used to conduct a leak detection survey of fugitive equipment leaks from all sources listed in 12.2(d)(9). This paragraph (g) applies to emissions sources in streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight need to be reported instead under paragraph (l) of this section. \*\*

If fugitive equipment leaks are detected for sources listed in this paragraph, calculate equipment leak emissions per source per reporting facility using Equation 13-19 (for volumetric emission factor [Sm<sup>3</sup>/h/component]) or Equation 13-20 (for mass emission factors [t/h/component]) of this section, as appropriate, for each source with fugitive equipment leaks.

#### **Equation 13-19**

$$E_i = EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

### **Equation 13-20**

$$E_{s,i} = EF_s \times Y_i \times t$$

Where:

- E<sub>s,i</sub> Annual total volumetric emissions of GHG i (either CH<sub>4</sub> or CO<sub>2</sub>), from each fugitive equipment leak source (Sm<sup>3</sup>/y).
  - EF<sub>s</sub> Leaker emission factor for specific sources listed in Table 13-1 through Table 13-5 of this section or facility/company-specific emission factors\* used in place of Table 13-1 to Table 13-5 (Sm<sup>3</sup>/component/year for Equation 13-19 and tonnes/ component/year for Equation 13-20).
  - Y<sub>i</sub> For volumetric emissions in Equation 13-19, use 1 for CH<sub>4</sub> and 1.1 × 10<sup>-2</sup> for CO<sub>2</sub>. For mass emissions in Equation 13-20, use mass fractions of CH<sub>4</sub> and CO<sub>2</sub> from each unit of a distribution or transmission company within a jurisdiction that has similar gas composition or the 2007 Canadian Energy Partnership for Environmental Innovation (CEPEI) Methodology Manual.
  - t 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 last survey during which it was determined to be not leaking, 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<sub>s,i</sub> Density of GHG i (1.861 kg/m<sup>3</sup> for CO<sub>2</sub> and 0.678 kg/m<sup>3</sup> for CH<sub>4</sub> at standard conditions of 15 °C and 1 atmosphere).
  - 0.001 Conversion factor from kilograms to tonnes.
- (1) Natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table 13-1 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 13-2 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 13-3 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 13-4 of this section for fugitive equipment leaks detected from valves; pump seals; connectors; and other.
- (5) Natural gas distribution facilities for above ground meters and regulators at custody transfer meter-regulating stations shall use the appropriate default leaker emission factors listed in Table 13-5 of this section for fugitive equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

*\* component-specific emission factors may equal leak rates quantified, following WCI.354(c) or (d), during leak detection surveys.*

*\*\* tubing systems less than one half inch diameter may be quantified using 12.3(g) instead of 12.3(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using 12.3(h). Reporting must occur using the appropriate section of WCI.352, dependent upon industry segment and quantification method used.*

- h. Population count and emission factors. This paragraph applies to emissions sources listed in 12.2 (b)(2) (where total emissions for a compressor station are less than 10,000 tonnes CO<sub>2</sub>e), b(6), b(8), (c)(2), (d)(2), (e)(2), (f)(2), (f)(3), (f)(4), (f)(5), (f)(6) and (f)(7) on streams with gas containing greater than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight. Emissions sources in streams with gas containing less than 10 percent CH<sub>4</sub> plus CO<sub>2</sub> by weight do not need to be reported. \*\*

Calculate emissions from all sources listed in this paragraph using Equation 13-21 (for volumetric emission factor [m<sup>3</sup>/h/component]) or Equation 13-22 (for mass emission factors [kg/h/component]) of this section, as appropriate.

### **Equation 13-21**

$$E_i = N \times EF_s \times Y_i \times t \times \rho_{s,i} \times 0.001$$

### **Equation 13-22**

$$E_i = N \times EF_s \times X_i \times t \times 0.001$$

Where:

E<sub>i</sub>      Annual total mass emissions of GHG i (CH<sub>4</sub> or CO<sub>2</sub>) from each fugitive source (tonnes/year).

$E_{s,i}$	Annual total volumetric emissions of GHG i ( $\text{CH}_4$ or $\text{CO}_2$ ) from each fugitive source ( $\text{Sm}^3/\text{year}$ ).
N	Total number of this type of emission source at the facility. Component counts for individual facilities must be used. 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. Current processing and instrumentation drawings (P&ID) may be used for the source of component (or major equipment) counts for all years.
$EF_s$	Population emission factor for specific sources listed in Table 13-1 through Table 13-5 of this section ( $\text{Sm}^3/\text{component}/\text{hour}$ for Equation 13-21 and tonnes/component/hour for Equation 13-22). EF for custody transfer meter regulating stations is determined in Equation 13-23. Direction on the use of Table 13-1 through Table 13-5, provided prior to the tables, must be followed and indicates that if facility specific emission factors are available these facility specific emission factors must be used*.
$Y_i$	For volumetric emissions in Equation 13-21, use 1 for $\text{CH}_4$ and $1.1 \times 10^{-2}$ for $\text{CO}_2$ .
$X_i$	For mass emissions in Equation 13-22, use mass fractions of $\text{CH}_4$ and $\text{CO}_2$ 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).
$P_{s,i}$	Density of GHG i (1.861 $\text{kg}/\text{m}^3$ for $\text{CO}_2$ and 0.678 $\text{kg}/\text{m}^3$ for $\text{CH}_4$ at standard conditions 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 13-2 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 13-3 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 13-4 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)(4) of this section.
  - (i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table 13-5 of this section.
  - (ii) Above grade meters and regulators at meter-regulating stations not at custody transfer as listed 12.2(f)(2), must use the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in paragraph

(g)(5) of this section to develop facility emission factors using **Equation 13-23** of this section. The calculated facility emission factor from **Equation 13-23** of this section shall be used in **Equation 13-15** and **Equation 13-16** of this section.

**Equation 13-23**

$$EF_{s,i} = \sum \frac{E_{s,i}}{N \times 8760}$$

Where:

- EF<sub>s,i</sub> Facility emission factor for a meter/regulator run at above grade metering regulating for GHG i (Sm<sup>3</sup>/year).  
E<sub>s,i</sub> Annual volumetric GHG emissions, CO<sub>2</sub> or CH<sub>4</sub> from all equipment leak sources at all above-grade, custody-transfer, metering-regulating stations, from paragraph (g) of this section (Sm<sup>3</sup>).  
N Total number of meter/regulator runs at all custody-transfer, metering regulating stations.  
8760 Conversion to hourly emissions.

(iii) To ensure proper calculation of emissions from buried pipeline-main and service line equipment leaks, Equation 13-21 and Equation 13-22 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 used in place of count and company-specific leak data and CEPEI manual equations is permitted.

\* facility -specific emission factors may equal leak rates quantified, following 12.4(c) or (d), during leak detection surveys or those emission factors calculated for the purposes of 12.7 – Directions for the use of Table 13-1 to Table 13-5.

\*\* tubing systems less than one half inch diameter may be quantified using 12.3(g) instead of 12.3(h) if a leak detection survey captures them. If not covered by a leak detection survey, they must be quantified using 12.3(h). Reporting must occur using the appropriate section of 12.2, dependent upon industry segment and quantification method used.

- i) Volumetric emissions. Calculate volumetric emissions at standard conditions as specified in paragraphs (i)(1) or (2) , with actual pressure and temperature 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 actual temperature and pressure to standard temperature and pressure (15 °C and 1 atmosphere in Canada) using **Equation 13-24** of this section.

### **Equation 13-24**

$$E_s = \frac{E_a \times (273.15 + T_s) \times P_a}{(273.15 + T_a) \times P_s}$$

Where:

$E_s$  Natural gas volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).

$E_a$  Natural gas volumetric emissions at actual conditions ( $\text{m}^3$ ).

$T_s$  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 actual conditions (kPa).

- 2) Calculate GHG volumetric emissions at standard conditions by converting actual temperature and pressure of GHG emissions to standard temperature and pressure using **Equation 13-25** this section.

### **Equation 13-25**

$$E_{s,i} = \frac{E_{a,i} \times (273.15 + T_s) \times P}{(273.15 + T_a) \times P_s}$$

Where:

$E_{s,i}$  GHG i volumetric emissions at standard temperature and pressure (STP) conditions ( $\text{Sm}^3$ ).

$E_{a,i}$  GHG i volumetric emissions at actual conditions ( $\text{m}^3$ ).

$T_s$  Temperature at standard conditions. ( C).

$T_a$  Temperature at actual emission conditions. (oC).

$P_s$  Absolute pressure at standard conditions (kPa).

$P_a$  Absolute pressure at actual conditions (kPa).

- GHG volumetric emissions.** If the GHG volumetric emissions at actual conditions are known, follow the method in (j)(2) to calculate their emissions at standard conditions. If the GHG volumetric emissions are not yet known, then follow the methods below to 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 CH<sub>4</sub> and CO<sub>2</sub> emissions from natural gas emissions using **Equation 13-26**.

### Equation 13-26

$$E_{s,i} = E_s \times Y_i$$

Where:

E<sub>s,i</sub> GHG *i* (CH<sub>4</sub> or CO<sub>2</sub>) volumetric emissions at standard conditions.

E<sub>s</sub> Natural gas volumetric emissions at standard conditions.

Y<sub>i</sub> Mole fraction of GHG *i* in the natural gas.

- 2) For Equation 13-26 of this section, the mole fraction, Y<sub>i</sub>, shall be the annual average mole fraction for each unit of a natural gas distribution, natural gas transmission, LNG storage, LNG import or export, or underground natural gas storage company within a jurisdiction that has similar gas composition as sampled within the current (required if available) or previous (if current data not available) reporting period, using the methods set forth in 12.4(b), and 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 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 tonnes of carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 13-27.

### Equation 13-27

$$E_i = E_{s,i} \times \rho_{s,i} \times GWP_i \times 0.001$$

Where:

E<sub>i</sub> GHG *i* (either CH<sub>4</sub>, CO<sub>2</sub>, or, N<sub>2</sub>O mass emissions (tonnes CO<sub>2</sub>e).

E<sub>s,i</sub> GHG *i* (either CH<sub>4</sub>, CO<sub>2</sub>, or, N<sub>2</sub>O) volumetric emissions (Sm<sup>3</sup>).

ρ<sub>s,i</sub> Density of GHG *i*, (1.861 kg/m<sup>3</sup> for CO<sub>2</sub> and 0.678 kg/m<sup>3</sup> for CH<sub>4</sub> at standard conditions of T<sub>s</sub>=15 C and P<sub>s</sub>=101.325 kPa)

$$= \frac{P_s \times MW_i}{R_u \times (T_s + 273.15)}$$

$GWP_i$	Global warming potential of GHG $i$ (1 for CO <sub>2</sub> and 25 for CH <sub>4</sub> , and 298 for N <sub>2</sub> O).
$MW_i$	Molecular weight for GHG <sub>i</sub> taken from the 12th edition of the Gas Processors Suppliers Association Engineering Data Book (kg/kmole).
$R_u$	Universal gas constant (8.31434 kJ/kmole K)
0.001	Conversion factor from kilograms to tonnes.

- l) Other venting or fugitive emissions. All venting or fugitive emissions not covered by quantification methods in 12.3 must be calculated by methodologies consistent with those presented here, in the 2007 Canadian Energy Partnership for Environmental Innovation Methodology Manual (as amended from time to time), or in other relevant Canadian Gas Association documentation.
- m) Transmission storage tanks. For condensate storage tanks, either water or hydrocarbon, without vapour recovery or thermal control devices in natural gas transmission compression facilities calculate CH<sub>4</sub>, CO<sub>2</sub> and N<sub>2</sub>O (when flared) annual emissions from compressor scrubber dump valve leakage as follows. For 2012, other methodologies may be used to quantify emissions from transmission storage tanks in addition to those outlined below.
  - 1) Monitor the tank vapour vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in 12.4(a)(1) or by directly measuring the tank vent using a flow meter, calibrated bag, or High-flow Sampler according to methods in 12.4(b) through (d) for a duration of 5 minutes. Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in 12.4(a)(4).
  - 2) If the tank vapours are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (m)(2) of this section to quantify annual emissions:
    - i) Use a meter, such as a turbine meter, calibrated bag, or High-flow Sampler to estimate tank vapour volumes according to methods set forth in 12.4(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapour vent stack. If the vent is directly measured for five minutes under paragraph (m)(1) of this section to detect continuous leakage, this serves as the measurement.
    - ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in 12.4(a)(4).
    - iii) Use the appropriate gas composition in paragraph (j) of this section.
  - 3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.
  - 4) Calculate annual emissions from storage tanks to flares as follows:
    - i) Use the storage tank emissions volume and gas composition as determined in paragraphs (m)(1) through (m)(3) of this section.

- ii) Use the calculation methodology of flare stacks in paragraph (d) of this section to determine storage tank emissions sent to a flare.

## **13.4 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 appropriately certified personnel or individuals with demonstrated understanding and experience in the application (and principles related) of the specific sampling, analysis and measurement technique in use.

### a. Leak Detection

- (1) 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. A minimum of 12 months and a maximum of 36 months is allowed between surveys.
- (2) If there is no such legal requirement (as specified in paragraph (a)(1) of this section), 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 12.3(f), (g), and (h), as applicable. Progressive sampling means establishing a statistically valid baseline sample of leaks under normal operating conditions over a 1 year period, with subsequent sampling determined based on random or spot-sampling, modeling, detection 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 is 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.

- (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 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 inspection 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 (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 for operational circumstances provided that sufficient documentation as to the method used, results on tests, and the methods 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 appropriate QA/QC procedures, including measurement methods, maintenance practices, and calibration methods, prior to the first reporting year and in each subsequent reporting year according to the an appropriate standard 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, American Society of Mechanical Engineers (ASME), and North American Energy Standards Board (NAESB). If no appropriate standard exists from the organizations listed above, one from the Canadian Association of Petroleum Producers (CAPP), American Petroleum Institute (API) may be used. 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) Correct the natural gas volumetric emissions to standard conditions using the calculations in 12.3(i).
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in 12.3(j) and (k).
- d. Use a High-flow Sampler to measure emissions within the capacity of the instrument.
- (1) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH<sub>4</sub> by using calibrated gas samples and by following manufacturer's instructions for calibration.
  - (2) A technician following (and competent to follow) manufacturer's instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a High-flow Sampler, positioning the instrument for complete capture of the fugitive equipment leaks without creating backpressure on the source.
  - (3) If the High-flow 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.
  - (4) Estimate CH<sub>4</sub> and CO<sub>2</sub> volumetric and mass emissions from volumetric natural gas emissions using the calculations in 13.3(j) and (k).

### **13.5 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.

## **13.6 Definitions Relevant to Natural Gas Transmission**

Blowdown vent stack emissions mean natural gas and/or CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> from escaping to the atmosphere.

Centrifugal compressor dry seals emissions mean natural gas or CO<sub>2</sub> 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 mean emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO<sub>2</sub>. 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 natural gas or CO<sub>2</sub> by drawing in low pressure natural gas or CO<sub>2</sub> and discharging significantly higher pressure natural gas or CO<sub>2</sub>.

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.

Custody-transfer means the transfer of product from one gas-company to another gas company, excluding transfers between companies who have same parent company.

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.

Engineering estimation, for the purposes of Section 12 and Section 6 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.

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.

Farm taps means pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers.

Field gas means natural gas extracted from a production well prior to its entering the first stage of processing, such as dehydration.

Flare, for the purposes of Section 12, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

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 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 means 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 0.17 standard cubic meters 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.

Meter-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

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/m<sup>3</sup> or less than 40.98 MJ/m<sup>3</sup>, 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 Section 6.1(a)(2), as applicable to natural gas transmission and distribution operations

Pump means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

Pump seals mean 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 mean 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.

Third party line hit means damages to gas pipelines and surface facilities resulting from natural causes or third party incidents. Natural causes include corrosion, abrasion, rock damage, frost heaving or settling. Third party damages may include hits on surface facilities and dig-ins. Specific examples of dig-ins include grader/dozer/scraper excavation, demolition/breakout, general agriculture, driving bars/stakes/posts/anchors, backhoe/trackhoe excavation, ditch shaping, snow removal, landscaping/tree planting, hand excavation, bobcat/loader excavation, saw cutting, cable/pipe plowing, vertical

augering/drilling, trencher excavation, blasting/vibrosis, deep tillage, horizontal augering/boring, and other such anthropogenic ground disturbances.

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 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.

## 13.7 Tables Relevant to Natural Gas Transmission

### Directions for the use of Tables 12-1 to 12-5

- a. for each component listed in the Table 13-1 to Table 13-5, or otherwise required by the quantification method referencing Table 13-1 and Table 13-2:
  - (1) If statistically valid facility-specific emission factors for a component type are available or can be safely or reasonably developed they must be used
  - (2) 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.
  - (3) If statistically valid facility or company-specific emission factors for a specific component type cannot be safely and reasonably developed, estimates in the default Table 13-1 to Table 13-5 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. 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
- c. Any changes from facility-specific factors to company-specific or table factors, or from company-specific factors to the defaults in Table 13-1 to Table 13-5 must be approved by the jurisdiction and substantiated by proof that the new approach is more accurate for the facility or facilities in question

- d. If an emission factor required by the quantification method referencing Table 13-1 to Table 13-5 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).
- e. 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
- f. 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.
- g. Updated emission factors can only be incorporated for reporting purposes at the start of a reporting period and not during a calendar year.
- h. The default emission factors provided in Table 13-1 to Table 13-5 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 13-1: Default Emission Factors for Transmission**

<b>Transmission</b>	<b>Emission Factor (tonnes/hour/component) Direct conversion of EF's in CGA Manual<sup>4</sup> Table 9 (kg to tonnes)</b>
<b>Leaker Emission Factors - All Components, Gas Service</b>	
Connector	4.848E-5
Block valve	1.275E-4
Control valve	8.205E-5
Compressor blowdown valve	5.691E-3
Pressure relief valve	5.177E-4
Orifice meter	2.076E-4
Other meter	3.493E-7
Regulator	1.125E-4
Open-ended line	1.580E-4
<b>Population Emission Factors - Other Components, Gas Service</b>	
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 E-1
Pneumatic Pumps	3.766 E-1

\*: The distribution emission factors in Table 12-5 should be used for equipment in odourized service and the transmission factors in Table 12-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility.

**Table 13-2: Default Methane Emission Factors for Underground Storage**

Underground Storage	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-4 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - Storage Station, Gas Service</b>	
Valve <sup>1</sup>	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
<b>Population Emission Factors - Storage Wellheads, Gas Service</b>	
Connector	2.8 E-4
Valve	2.8 E-3
Pressure relief valve	4.8 E-3
Open-ended line	8.5 E-4
<b>Population Emission Factors - Other Components, Gas Service</b>	
Low-bleed pneumatic device vents	5.07 E-2
High continuous bleed pneumatic device vents	5.69 E-1
Intermittent (low and high) bleed pneumatic device vents	5.69 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 13-3: Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage\***

LNG Storage	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-5 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - LNG Storage Components, LNG Service</b>	
Valve	3.43 E-2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other <sup>1</sup>	5.10 E-2
<b>Population Emission Factors - LNG Storage Compressor, Gas Service</b>	
Vapour Recovery Compressor	1.20 E-1

<sup>1</sup> 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 13-4: Default Methane Emission Factors for LNG Terminals\***

LNG Terminals	Emission Factor (Sm <sup>3</sup> /hour/component) Direct conversion of EF's in EPA Subpart W Table W-6 (scf to Sm <sup>3</sup> )
<b>Leaker Emission Factors - LNG Terminals Components, LNG Service</b>	
Valve	3.43 E -2
Pump seal	1.15 E-1
Connector	9.9 E-3
Other	5.10 E-2
<b>Population Emission Factors - LNG Terminals Compressor, Gas Service</b>	
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 13-5: Default Emission Factors for Distribution**

Distribution	Emission Factor** (tonnes/hour/component) Direct conversion of EF's in CGA Manual <sup>5</sup> Table 9 (kg to tonnes)
<b>Leaker Emission Factors - Above Grade M&amp;R Stations Components, Gas Service</b>	
Connector	0.6875 E-3
Block valve	1.410 E-2
Control valve	7.881 E-2
Pressure relief valve	3.524 E-2
Orifice meter	8.091 E-3
Regulator	2.849 E-2
Open-ended line	1.216 E-1
<b>Population Emission Factors - Below Grade M&amp;R Stations Components, Gas Service<sup>1</sup></b>	
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
<b>Population Emission Factors - Distribution Mains, Gas Service<sup>2*</sup></b>	
Unprotected steel	1.83 E-1
Protected steel	7.22 E-2
Plastic	7.76 E-2
Cast iron <sup>*</sup>	7.836 E-1
<b>Population Emission Factors - Distribution Services, Gas Service<sup>3</sup></b>	
Unprotected steel	7.08 E-2
Protected steel	3.23 E-2
Plastic	1.04 E-2
Copper	2.7 E-2

<sup>1</sup> Emission Factor is in units of "Sm<sup>3</sup>/hour/station"

<sup>2</sup> Emission Factor is in units of "Sm<sup>3</sup>/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 12-5 should be used for equipment in odourized service and the transmission factors in Table 12-1 should be used for equipment in unodourized service, regardless of the actual classification or functionality of the facility

**Table 13-6: Average Manufacturer Bleed Rates for Pneumatic Controllers, Positioner, Transmitters and Transducers**

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m³/h) <sup>4</sup>
Liquid level controller	Bristol Babcock	Series 5453-Model 624-II	Continuous	0.0850
Liquid level controller	Fisher	2100	Continuous	0.0283
Liquid level controller	Fisher	2500	Continuous	1.1893
Liquid level controller	Fisher	2660	Continuous	0.0283
Liquid level controller	Fisher	2680	Continuous	0.0283
Liquid level controller	Fisher	2900	Continuous	0.6513
Liquid level controller	Fisher	L2	Continuous	0.0425
Liquid level controller	Invalco	AE-155	Continuous	1.5008
Liquid level controller	Invalco	CT Series	Continuous	1.1327
Liquid level controller	Norriseal	1001 (A) 'Envirosave'	Intermittent	0.0000
Liquid level controller	Norriseal	1001 (A) snap	Intermittent	0.0057
Liquid level controller	Norriseal	1001 (A) throttle	Intermittent	0.0002
Liquid level controller	Wellmark	2001 (snap)	Intermittent	0.0057
Liquid level controller	Wellmark	2001 (throttling)	Intermittent	0.0002
Positioner	Becker	EFP-2.0	Intermittent	0.0000
Positioner	Becker	HPP-5	Continuous	0.1416
Positioner	Fisher	3582	Continuous	0.4531
Positioner	Fisher	3590	Continuous	0.8495
Positioner	Fisher	3660	Continuous	0.1982
Positioner	Fisher	3661	Continuous	0.2959
Positioner	Fisher	3582i	Continuous	0.5833
Positioner	Fisher	3610J	Continuous	0.4531
Positioner	Fisher	3620J	Continuous	0.7532
Positioner	Fisher	DVC 5000	Continuous	0.2832
Positioner	Fisher	DVC 6000	Continuous	0.3964
Positioner	Fisher	Fieldview Digital	Continuous	0.8920
Positioner	Masoneilan	7400	Continuous	1.0477
Positioner	Masoneilan	4600B Series	Continuous	0.6796
Positioner	Masoneilan	4700B Series	Continuous	0.6796
Positioner	Masoneilan	4700E	Continuous	0.6796
Positioner	Masoneilan	SV	Continuous	0.1133
Positioner	Moore Products	73N-B	Continuous	1.0194
Positioner	Moore Products	750P	Continuous	1.1893
Positioner	PMV	D5 Digital	Continuous	0.0283
Positioner	Sampson	3780 Digital	Continuous	0.0283
Positioner	VCR	VP700 PtoP	Continuous	0.0283
Pressure controller	Ametek	Series 40	Continuous	0.1699
Pressure controller	Becker	HPP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-B-CH	Continuous	0.1416
Pressure controller	Becker	VRP-SB	Intermittent	0.0000
Pressure controller	Becker	VRP-SB Gap Controller	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-CH	Intermittent	0.0000
Pressure controller	Becker	VRP-SB-PID Controller	Intermittent	0.0000

**Table 12-6, Continued**

Description	Manufacturer	Model	Operating Condition	Manufacturer Rate (m <sup>3</sup> /h) <sup>4</sup>
Pressure controller	Bristol Babcock	Series 5453-Model 10F	Continuous	0.0850
Pressure controller	Bristol Babcock	Series 5455-Model 624-III	Continuous	0.0708
Pressure controller	CSV	4150	Continuous	0.6853
Pressure controller	CSV	4160	Continuous	0.6853
Pressure controller	Dyna-Flow	4000	Continuous	0.6853
Pressure controller	Fisher	2506	Continuous	0.6853
Pressure controller	Fisher	2516	Continuous	0.6853
Pressure controller	Fisher	4150	Continuous	0.7362
Pressure controller	Fisher	4160	Continuous	0.7362
Pressure controller	Fisher	4194	Continuous	0.1203
Pressure controller	Fisher	4195	Continuous	0.1203
Pressure controller	Fisher	4660	Continuous	0.1416
Pressure controller	Fisher	4100 (large orifice)	Continuous	1.4158
Pressure controller	Fisher	4100 (small orifice)	Continuous	0.4248
Pressure controller	Fisher	C1	Continuous	0.1472
Pressure controller	Fisher	DVC 6010	Continuous	0.0878
Pressure controller	Foxboro	43AP	Continuous	0.5097
Pressure controller	ITT Barton	338	Continuous	0.1699
Pressure controller	ITT Barton	358	Continuous	0.0510
Pressure controller	ITT Barton	359	Continuous	0.0510
Pressure controller	ITT Barton	335P	Continuous	0.1699
Pressure controller	ITT Barton	335P	Continuous	0.1699
Transducer	Bristol Babcock	9110-00A	Continuous	0.0119
Transducer	Bristol Babcock	Series 502 A/D	Continuous	0.1671
Transducer	Fairchild	TXI 7800	Continuous	0.2407
Transducer	Fisher	546	Continuous	0.8495
Transducer	Fisher	646	Continuous	0.2209
Transducer	Fisher	846	Continuous	0.3398
Transducer	Fisher	i2P-100	Continuous	0.2832
Transmitter	Bristol Babcock	Series 5457-70F	Continuous	0.0850
Transmitter	ITT Barton	273A	Continuous	0.0850
Transmitter	ITT Barton	274A	Continuous	0.0850
Transmitter	ITT Barton	284B	Continuous	0.0850
Transmitter	ITT Barton	285B	Continuous	0.0850

Footnotes and Sources:

<sup>1</sup> Canadian Association of Petroleum Producers. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Module 3, CETAC West, Calgary, AB. 2008 Appendix B converted to metric units.

<sup>2</sup> United States Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. Washington, DC. 2006. Appendix A converted to metric units.

<sup>3</sup> Various manufacturer specification publications.

<sup>4</sup> Factors equal to zero indicate that the device does not vent gas.

**Table 13-7: Nomenclature (Subscripts, Variables and their Descriptions)**

Variable Name	Description
A	Variable – Area
a	Subscript – Actual condition for temperature and pressure
CF	Variable – Control factor (fractional)
D	Variable – Diameter
E	Variable – Greenhouse Gas release rate
e	Subscript – exit point
EF	Variable – Emission factor
GOR	Variable – Gas to oil ratio
GWP	Variable – Global warming potential
HHV	Variable – Higher (gross) heating value
i	Subscript - Chemical compound
j	Subscript - Individual device, equipment, meter or well
K	Variable – Specific heat ratio for gases
k	Subscript - Service type (e.g., fuel gas, process gas, liquid, etc)
L	Variable - Length
l	Subscript - Individual equipment components
M	Variable – Mach number
MW	Variable – Molecular weight
m	Subscript – Operating mode
N	Variable – Count of devices, equipment, meters, wells, events, etc.
n	Variable – Number of carbon atoms in a molecule of a specified substance
P	Variable – Pressure
R	Variable – Universal Gas Constant
s	Subscript – Standard condition for temperature (15 °C) and pressure (101.325 kPa)
t	Variable – Time duration of event
T	Variable – Temperature (°C)
Q	Variable – Volumetric flow rate
V	Variable - Volume
X	Variable - Mass fraction
Y	Variable - Mole fraction
$\rho$	Variable - density
$\eta$	Variable – efficiency (fractional)

# **14. Underground Coal Mining**

## **14.1 Activity Definition**

The underground coal mine activity 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 in 90 days of calendar year.
  - (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 activity 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 activity does not include abandoned or closed mines, surface coal mines, or post-coal mining activities (i.e., storage or transportation of coal).

## **14.2 Greenhouse Gas Reporting Requirements**

The annual emissions data report shall contain the following information:

- a. Quarterly CH<sub>4</sub> destruction at all ventilation and degasification system destruction devices or point of offsite transport (tonnes CH<sub>4</sub>).
- b. Quarterly CH<sub>4</sub> emissions (net) from all ventilation and degasification systems (tonnes CH<sub>4</sub>).
- c. Quarterly CO<sub>2</sub> emissions from onsite destruction of coal mine gas CH<sub>4</sub>, where the gas is not a fuel input for energy generation or use (e.g., flaring) (tonnes CO<sub>2</sub>).

- d. **Production parameter:** Annual coal production (tonnes coal).

### 14.3 Calculation of Greenhouse Gas Emissions

- a. For each ventilation shaft, vent hole, or centralized point into which CH<sub>4</sub> from multiple shafts and/or vent holes are collected, calculate the quarterly CH<sub>4</sub> liberated from the ventilation system using **Equation 14-1** of this section. Measure CH<sub>4</sub> content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in section 13.4.

#### Equation 14-1

$$CH_{4V} = n \times \left( V \times MCF \times \frac{C}{100\%} \times 0.6775 \times \frac{288.71K}{T} \times \frac{P}{1atm} \times 1,440 \right) \times 0.001$$

Where:

CH <sub>4V</sub>	Quarterly CH <sub>4</sub> liberated from a ventilation monitoring point (tonnes CH <sub>4</sub> ).
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”. <ul style="list-style-type: none"> <li>• Moisture correction factor for the measurement period, volumetric basis.</li> <li>• 1 when V and C are measured on a dry basis or if both are measured on a wet basis.</li> <li>• 1 - (f<sub>H2O</sub>)<sub>n</sub> when V is measured on a wet basis and C is measured on a dry basis.</li> <li>• 1/[1-(f<sub>H2O</sub>)] when V is measured on a dry basis and C is measured on a wet basis.</li> </ul>
MCF	
(f <sub>H2O</sub> )	Moisture content of the CH <sub>4</sub> emitted during the measurement period, volumetric basis (cubic meter water per cubic meter emitted gas).
C	Daily CH <sub>4</sub> 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 <sub>4</sub> at 288.71K (15.56 °C) and 1 atm (kg/m <sup>3</sup> ).
288.71K	288.71 Kelvin.
T	Temperature at which flow is measured (K) for the quarter.
P	Pressure at which flow is measured (atm).
1,440	Conversion factor (min/day).

- (1) 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 CH<sub>4</sub> liberated from ventilation systems (CH<sub>4VTotal</sub>) as the sum of the CH<sub>4</sub> from all ventilation monitoring points in the mine, as follows in **Equation 14-2**:

#### **Equation 14-2**

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

Where:

CH <sub>4VTotal</sub>	Total quarterly CH <sub>4</sub> liberated from ventilation systems (tonnes CH <sub>4</sub> ).
CH <sub>4V</sub>	Quarterly CH <sub>4</sub> liberated from each ventilation monitoring point (tonnes CH <sub>4</sub> ).
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 CH<sub>4</sub> from multiple wells and/or vent holes are collected), calculate the weekly CH<sub>4</sub> liberated from the mine using CH<sub>4</sub> measured weekly or more frequently (including by CEMS) according to 13.4(c), CH<sub>4</sub> content, flow rate, temperature, pressure, and moisture content, and **Equation 14-3** of this section.

#### **Equation 14-3**

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

Where:

CH <sub>4D</sub>	Weekly CH <sub>4</sub> liberated from a monitoring point (tonnes CH <sub>4</sub> ).
V <sub>i</sub>	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”

$MCF_i$	<ul style="list-style-type: none"> <li>• Moisture correction factor for the measurement period, volumetric basis.</li> <li>• 1 when <math>V_i</math> and <math>C_i</math> are measured on a dry basis or if both are measured on a wet basis.</li> <li>• <math>1-(f_{H2O})_i</math> when <math>V_i</math> is measured on a wet basis and <math>C_i</math> is measured on a dry basis.</li> <li>• <math>1/[1-(f_{H2O})_i]</math> when <math>V_i</math> is measured on a dry basis and <math>C_i</math> is measured on a wet basis.</li> </ul>
$(f_{H2O})_i$	Moisture content of the $CH_4$ 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 288.71K (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).
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  $CH_4$  liberated from degasification systems for the mine should be determined as the sum of  $CH_4$  liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows in **Equation 14-4**:

#### Equation 14-4

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

Where:

$CH_{4DTotal}$    Quarterly  $CH_4$  liberated from all degasification monitoring points (tonnes  $CH_4$ ).

$\text{CH}_4\text{D}$  Weekly  $\text{CH}_4$  liberated from a degasification monitoring point (tonnes  $\text{CH}_4$ ).  
 $m$  Number of monitoring points.  
 $w$  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  $\text{CH}_4$  destroyed for each destruction device and each point of offsite transport to a destruction device, using **Equation 14-5** of this section. You must measure  $\text{CH}_4$  content and flow rate according to the provisions in section 13.4.

### **Equation 14-5**

$$\text{CH}_4\text{Destroyed} = \text{CH}_4 \times DE$$

Where:

$\text{CH}_4\text{Destroyed}$  Quarterly  $\text{CH}_4$  destroyed (tonnes).  
 $\text{CH}_4$  Quarterly  $\text{CH}_4$  routed to the destruction device or offsite transfer point (tonnes).  
 $DE$  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  $\text{CH}_4$  destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using **Equation 14-6** of this section.

### **Equation 14-6**

$$\text{CH}_4\text{DestroyedTotal} = \sum_{i=1}^d (\text{CH}_4\text{Destroyed})_d$$

Where:

$\text{CH}_4\text{DestroyedTotal}$  Quarterly total  $\text{CH}_4$  destroyed at the mine (tonnes  $\text{CH}_4$ ).  
 $\text{CH}_4\text{Destroyed}$  Quarterly  $\text{CH}_4$  destroyed from each destruction device or offsite transfer point.  
 $d$  Number of onsite destruction devices and points of offsite transport.

Calculate the quarterly measured net  $\text{CH}_4$  emissions to the atmosphere using **Equation 13-7** of this section.

### Equation 14-7

$$CH_{4\text{emitted(}net\text{)}} = CH_{4V\text{Total}} + CH_{4D\text{Total}} - CH_{4\text{DestroyedTotal}}$$

Where:

$CH_{4\text{emitted(}net\text{)}}$	Quarterly CH <sub>4</sub> emissions from the mine (tonnes).
$CH_{4V\text{Total}}$	Quarterly sum of the CH <sub>4</sub> liberated from all mine ventilation monitoring points (CH <sub>4V</sub> ), calculated using <b>Equation 14-2</b> of this section (tonnes).
$CH_{4D\text{Total}}$	Quarterly sum of the CH <sub>4</sub> liberated from all mine degasification monitoring points (CH <sub>4D</sub> ), calculated using <b>Equation 14-4</b> of this section (tonnes).
$CH_{4\text{DestroyedTotal}}$	Quarterly sum of the measured CH <sub>4</sub> destroyed from all mine ventilation and degasification systems, calculated using <b>Equation 14-6</b> of this section (tonnes).

- e. 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 General Stationary Fuel Combustion – Section 4 of this guidance), estimate the CO<sub>2</sub> emissions using **Equation 14-8** of this section.

### Equation 14-8

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

Where:

$CO_2$	Total quarterly CO <sub>2</sub> emissions from CH <sub>4</sub> destruction (tonnes).
$CH_{4\text{Destroyedonsite}}$	Quarterly sum of the CH <sub>4</sub> destroyed, calculated as the sum of CH <sub>4</sub> destroyed for each onsite, non-energy use, as calculated individually in <b>Equation 14-5</b> of this section (tonnes).
44/16	Ratio of molecular weights of CO <sub>2</sub> to CH <sub>4</sub> .

## **14.4 Sampling, Analysis, and Measurement Requirements**

Emissions may be estimated by monitoring as specified under paragraphs (a) through (g).

- a. For CH<sub>4</sub> liberated from ventilation systems, CH<sub>4</sub> 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 is 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<sub>4</sub> liberated at degasification systems, CH<sub>4</sub> 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 is 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 13.4(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 CH<sub>4</sub> destruction, CH<sub>4</sub> 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.

## **14.5 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 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 CH<sub>4</sub> 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.

# 15. Industrial Wastewater

## 15.1 Activity definition

Wastewater treatment can be a source of methane ( $\text{CH}_4$ ) when treated or disposed of anaerobically. It can also be a source of nitrous oxide ( $\text{N}_2\text{O}$ ) emissions. The extent of  $\text{CH}_4$  generation depends primarily on the quantity of degradable organic material in the wastewater, the temperature, and the type of treatment system. The principal factor in determining the  $\text{CH}_4$  generation potential of wastewater is the amount of degradable organic material in the wastewater. Common parameters used to measure the organic component of the wastewater are Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD). Under the same conditions, wastewater with higher COD or BOD concentrations will generally yield more  $\text{CH}_4$  than wastewater with lower COD (or BOD) concentrations.  $\text{N}_2\text{O}$  emissions are associated with the degradation of nitrogen components in the wastewater (e.g., urea, nitrate and protein).

- (a) This activity includes  $\text{CH}_4$  and  $\text{N}_2\text{O}$  emissions from anaerobic treatment at industrial wastewater treatment facilities.

## 15.2 Greenhouse Gas Reporting Requirements

- a. Report annual  $\text{CH}_4$  and  $\text{N}_2\text{O}$  emissions from industrial anaerobic wastewater treatment.

## 15.3 Calculation of Greenhouse Gas Emissions

- b. The facility shall calculate  $\text{CH}_4$  emissions from anaerobic wastewater treatment (such as an anaerobic reactor, digester, or lagoon) using **Equation 15-1** or **Equation 15-2**.

### Equation 15-1

$$\text{CH}_4 = Q \times \text{COD}_{qave} \times B \times \text{MCF} \times 0.001$$

### Equation 15-2

$$\text{CH}_4 = Q \times \text{BOD}_{5qave} \times B \times \text{MCF} \times 0.001$$

Where:

CH <sub>4</sub>	Emission of methane (tonnes/yr).
Q	Volume of wastewater treated (m <sup>3</sup> /yr).
COD <sub>qave</sub>	Average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m <sup>3</sup> ).
BOD <sub>5qave</sub>	Average of quarterly determinations of five-day biochemical oxygen demand of the wastewater (kg/m <sup>3</sup> ).
B	Methane generation capacity (B = 0.25 kg CH <sub>4</sub> /kg COD and 0.06 kg CH <sub>4</sub> /kg BOD <sub>5</sub> ).
MCF	Methane correction factor for anaerobic decay (0-1.0) from Table 15-1.
0.001	Conversion factor from kg to tonnes.

- c. For anaerobic processes from which biogas is recovered and not emitted, the facility shall adjust the CH<sub>4</sub> emissions calculated in paragraph 14.3(a) by the amount of CH<sub>4</sub> collected.
- d. The facility shall calculate N<sub>2</sub>O emissions from wastewater treatment using **Equation 15-3**.

### Equation 15-3

$$N_2O = Q \times N_{qave} \times EF_{N2O} \times 1.571 \times 0.001$$

Where:

N <sub>2</sub> O	Emissions of N <sub>2</sub> O (tonnes/yr).
Q	Volume of wastewater treated (m <sup>3</sup> /yr).
N <sub>qave</sub>	Average of quarterly determinations of N in effluent (kg N/m <sup>3</sup> ).
EF <sub>N2O</sub>	Emission factor for N <sub>2</sub> O from discharged wastewater (0.005 kg N <sub>2</sub> O-N/kg N).
1.571	Conversion factor – kg N <sub>2</sub> O-N to kg N <sub>2</sub> O.
0.001	Conversion factor from kg to tonnes.

## 15.4 Sampling, Analysis, and Measurement Requirements

- (a) The facility shall 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). The facility shall collect and analyze samples for COD or BOD<sub>5</sub> concentration once each calendar week.
- (b) The facility shall measure the flow rate of wastewater entering anaerobic wastewater treatment process once each calendar week. The flow measurement location shall

correspond to the location used to collect samples analyzed for COD or BOD<sub>5</sub> concentration.

- (c) The quarterly nitrogen content of the wastewater.

## 15.5 Procedures for Estimating Missing Data

### Unavailable Analytical Data

- (a) Whenever analytical data relating to sampling is unavailable, the facility shall, using the methods prescribed in 14.4, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

### Determination of Quantity

- (b) Whenever sampling and measurement data required by section 14.4 for the calculation of CH<sub>4</sub> or N<sub>2</sub>O emissions is missing the facility shall ensure that the data is replaced using the following missing data procedures:
- (1) For missing data on the quantity of wastewater treated, the replacement data must be generated from best estimates based on all of the data relating to the process.

## 15.6 Tables Relevant to Industrial Wastewater Treatment

**Table 15-1: Default MCF Values for Industrial Wastewater**

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Sea, river and lake discharge	Untreated, rivers with high organic loading may turn anaerobic, however this is not considered here.	0.1	0 - 0.2
Aerobic treatment plant	Treated, well maintained, some CH <sub>4</sub> may be emitted from settling basins.	0	0 – 0.1
Aerobic treatment plant	Treated, not well maintained, overloaded.	0.3	0.2 – 0.4
Anaerobic digester for sludge	Treated, CH <sub>4</sub> recovery not considered here.	0.8	0.8 – 1.0
Anaerobic reactor	Treated, CH <sub>4</sub> recovery not considered here.	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Treated, depth less than 2 metres.	0.2	0 – 0.3
Anaerobic deep lagoon	Treated, depth more than 2 metres.	0.8	0.8 – 1.0

For CH<sub>4</sub> generation capacity (B) in kg CH<sub>4</sub>/kg COD, use default factor of 0.25 kg CH<sub>4</sub>/kg COD.

The emission factor for N<sub>2</sub>O from discharged wastewater (EF<sub>N2O</sub>) is 0.005 kg N<sub>2</sub>O-N/kg-N.

MCF = methane conversion factor (the fraction of waste treated anaerobically).

COD = chemical oxygen demand (kg COD/m<sup>3</sup>).

# **16. Electricity Importation**

## **16.1 Activity Definitions**

“Balancing authority area” means the metered boundaries of the collection of generation, transmission, and loads of a balancing authority.

“Balancing authority” means an entity that maintains load-interchange-generation balance within a balancing authority area and supports frequency in real time.

“Electricity generating facility” means a facility that generates electricity and includes one or more electricity generating units at the same location.

“Electricity generation unit” is the physically connected equipment that operate together to produce electricity at the same location.

“Electricity importer” means a person to who imports electricity into the province as defined in the QRV Regulation.

“Electricity transaction” means the purchase, sale, import, export or exchange of electric power.

“e-tag” means North American Energy Standards Board (NAESB) energy tag.

“Frequency in real time” means maintaining interconnection frequency at 60 hertz (Hz).

“Load interchange generation balance” means the balance between electricity demand and supply from resources within the Balancing Authority Area, and the flow of electricity into or out of the Balancing Authority Area on tie lines.

“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.

“Metered boundaries” means boundaries between adjacent province or balancing authority areas as defined by tie line meters that record the flow of energy between the province or balancing authority areas.

“Power contract” means an arrangement for the purchase of electricity including but not limited to power purchase agreements and tariff provisions.

“Scheduled” means electricity that is scheduled to flow between the Nova Scotia grid and a neighbouring province or balancing authority area.

“Scheduled quantity” means the final amount listed in the e-tag that is approved by all balancing authority areas on the transmission path specified on the e-tag.

“Specified electricity generator” means an electricity generation unit, facility or new additional production outside of Nova Scotia that supplies specified imported electricity.

“Specified imported electricity” means electricity which:

b. Is subject to a written contract between the electricity generator and the electricity importer; and:

(1) Comes from an electricity generator built after January 1, 2018; or

(2) Is the result of an increase in production from the electricity generator that occurred after January 1, 2018; or

- (3) Was imported from an electricity generator within the framework of a contract entered into before 1 January 2018 that is still in force or has been renewed, or was imported from that electricity generator after the end of the contract; or
- “Unspecified imported electricity” means imported electricity that is not specified imported electricity.
- “Wheeled electricity” is imported electricity that is identified in the e-tag of a transaction that shows Nova Scotian transmission on the transmission path and does not serve load in Nova Scotia.

## **16.2 Greenhouse Gas Reporting Requirements**

- b. The electricity importer shall set out the following information, calculated for the calendar year using standard quantification methods 15.0-15.5, in the report prepared for a calendar year in respect of electricity importation:
- (1) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, calculated using the methods in 15.3 and 15.4.
  - (2) Annual quantity of specified and unspecified imported electricity used in the calculations contained in 15.3 and 15.4, expressed in MWh.
  - (3) The following information for each specified electricity generator from which the electricity importer imports electricity:
    - (i) The facility name;
    - (ii) The facility ID;
    - (iii) If applicable, the electricity generating unit ID.
    - (iv) Annual scheduled quantity of specified imported electricity used in 15.3, expressed in MWh.
    - (v) Annual quantity of specified imported electricity wheeled through Nova Scotia, expressed in MWh.
    - (vi) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, from the specified electricity generator.
  - (4) Report the following information for each province or balancing authority area from which unspecified electricity originated:
    - (i) The name of the province or balancing authority area;
    - (ii) Annual scheduled quantity of unspecified imported electricity used in 15.4, expressed in MWh; and
    - (iii) Annual quantity of unspecified imported electricity wheeled through Nova Scotia, expressed in MWh.
    - (iv) Total annual amount of greenhouse gas emissions in tonnes of CO<sub>2</sub>e, from unspecified electricity generation by province or balancing authority area.

## 16.3 Calculation of Specified Electricity

The electricity importer shall use the following equations, as applicable to calculate the emissions from specified imported electricity. If data is not available or cannot be obtained to calculate the emissions using the methods from section 15.3, the electricity importer may use the calculation methods from section 15.4

- c. Calculation Methodology 1. Use **Equation 15-1** to calculate the total annual emissions of specified imported electricity.

### Equation 15-4

$$E = \sum_{i=1}^n \left( CO2_{ti} \times AF \times \frac{MWh_{imp\_i}}{MWh_{t\_i}} \right)$$

Where:

E	Total annual emissions of specified imported electricity from specified electricity generators that report GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75, the U.S. Energy Information Administration, or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO <sub>2</sub> e.
CO2 <sub>ti</sub>	Total annual emissions from specified electricity generator i during the calendar year, expressed in tonnes CO <sub>2</sub> e as reported to The Climate Registry, U.S.EPA, U.S. Energy Information Administration or Environment Canada and where provided to the person.
AF	Adjustment factor calculated in accordance with Equation 15-6.
MWh <sub>imp_i</sub>	Scheduled quantity of specified imported electricity imported from specified electricity generator i, recorded in all the e-tags from the specified electricity generator i, expressed in MWh. calculated in accordance with Equation 15-4.
MWh <sub>t_i</sub>	Total annual megawatt-hours of net power generated by specified electricity generator i, expressed in MWh.
n	The number of specified electricity generators.

- d. Calculation Methodology 2. Use **Equation 15-5** to calculate the total annual emissions from specified imported electricity where
  - (1) The specified electricity generator from which the specified imported electricity is received has not reported emissions to The Climate Registry, the U.S.EPA using 40 CFR Part 75, U.S. Energy Information Administration or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33:

### Equation 15-5

$$E = \sum_{i=1}^n \sum_{f=1}^m \left( Fuel_{fi} \times HHV_{fi} \times EF_{fi} \times 0.001 \times AF \times \frac{MWh_{impi}}{MWh_{ti}} \right)$$

Where:

E	Total annual emissions from specified imported electricity from specified electricity generators that have NOT reported GHG emissions to the Climate Registry, the U.S.EPA using 40 CFR Part 75, the U.S. Energy Information Administration or to Environment Canada under Section 46 of the Canadian Environmental Protection Act, 1999 S.C. 1999, c. 33 expressed in tonnes CO <sub>2</sub> e.
Fuel <sub>fi</sub>	Total annual mass or volume of fuel “f” combusted by specified electricity generator “i” expressed in tonnes for solid fuel, volume in standard cubic meters for gaseous fuel, and volume in kilolitre for liquid fuel.
HHV <sub>fi</sub>	Higher heating value of fuel “f” consumed for electricity production in GJ per unit of fuel or measured in accordance with section 4.5 for specified electricity generator “i”.
EF <sub>fi</sub>	Fuel-specific default CO <sub>2</sub> e emission factor for fuel “f” from Section 4 (General Stationary Fuel Combustion) expressed in kg CO <sub>2</sub> e/GJ for specified electricity generator “i”.
0.001	Conversion factor from kilograms to tonnes.
AF	Adjustment factor calculated in accordance with Equation 15-6.
MWh <sub>impi</sub>	Scheduled quantity of specified imported electricity from specified electricity generator i, recorded in all the e-tags from specified electricity generator i, expressed in MWh calculated in accordance with Equation 15-4.
MWh <sub>ti</sub>	Total annual megawatt-hours of net power generated by specified electricity generator “i”.
n	The number of specified electricity generators
m	The number of fuels

For the purposes of Equation 15-1 and 15-2, when the electricity comes from a specified nuclear, hydroelectric, sea current, wind, solar or tidal power facility, E shall be deemed as 0 (Zero)

## 16.4 Calculation of Unspecified Electricity

The electricity importer shall use Equation 15-3 to calculate the emissions from unspecified imported electricity from each province or balancing authority area that serves load in Nova Scotia.

### Equation 15-6

$$E = MWh_{imp} \times EFD \times AF$$

Where:

E	Total annual emissions of unspecified imported electricity expressed in tonnes CO <sub>2</sub> e.
MWh <sub>imp</sub>	Annual scheduled quantity of unspecified imported electricity serving load in Nova Scotia, based on the e-tag expressed in MWh calculated in accordance with Equation 15-5.
EFD	The default emission factor for the province or balancing authority area from which the electricity comes, in metric tons of CO <sub>2</sub> per megawatt-hour, which is either — indicated in Table 15-1; — when the electricity comes from a nuclear, hydroelectric, sea current, wind, solar or tidal power generator, a factor of 0;
AF	Adjustment factor calculated in accordance with Equation 15-6.

**Table 15-2: Default greenhouse gas emission factors for Canadian provinces and certain balancing authority areas, in metric tons CO<sub>2</sub> equivalent per megawatt-hour**

Canadian provinces and balancing authority areas	Default emission factor (metric tons GHG/MWh)
Newfoundland and Labrador	0.032
New Brunswick	0.282
Québec	0.001
Ontario	0.041
Manitoba	0.003
New England Independent System Operator (NE-ISO), including all or part of the following states: - Connecticut - Massachusetts - Maine - Rhode Island - Vermont - New Hampshire	0.290

New York Independent System Operator (NY-ISO)	0.236
Pennsylvania Jersey Maryland Interconnection Regional Transmission Organization (PJM-RTO), including all or part of the following states: - North Carolina - Delaware - Indiana - Illinois - Kentucky - Maryland - Michigan - New Jersey - Ohio - Pennsylvania - Tennessee - Virginia - West Virginia - District of Columbia	0.554
Midwest Independent Transmission System Operator (MISO-RTO), including all or part of the following states: - Arkansas - North Dakota - South Dakota - Minnesota - Iowa - Missouri - Wisconsin - Illinois - Michigan - Nebraska - Indiana - Montana - Kentucky - Texas - Louisiana - Mississippi	0.596
Southwest Power Pool (SPP), including all or part of the following states: - Kansas - Oklahoma - Nebraska - New Mexico - Texas - Louisiana - Missouri - Mississippi - Arkansas	0.566

## 16.5 Calculation of Imported Electricity

### Equation 15-7

$$MWh_{imp\_i} = \sum (MWh_{total\_i} - MWh_{wheel\_i})$$

### Equation 15-8

$$MWh_{imp} = \sum \sum (MWh_{total} - MWh_{wheel})$$

Where:

MWh <sub>imp_i</sub>	Annual Scheduled quantity of specified imported electricity imported into Nova Scotia by the electricity importer, expressed in MWh.
MWh <sub>imp</sub>	Annual Scheduled quantity of unspecified imported electricity imported into Nova Scotia by the electricity importer, expressed in MWh.
MWh <sub>Total_i</sub>	Quantity of scheduled specified imported electricity recorded in each e-tag "i" that is imported into Nova Scotia by the electricity importer, expressed in MWh.
MWh <sub>wheel_i</sub>	Scheduled quantity of specified imported electricity recorded in each e-tag "i" that is imported into Nova Scotia by the electricity importer that is wheeled through Nova Scotia, expressed in MWh.
MWh <sub>Total</sub>	Quantity of scheduled unspecified imported electricity recorded in each e-tag that is imported into Nova Scotia by the electricity importer, expressed in MWh..
MWh <sub>wheel</sub>	Scheduled quantity of unspecified imported electricity recorded in each e-tag that is imported into Nova Scotia by the electricity importer that is wheeled through Nova Scotia, expressed in MWh.

## 16.6 Calculation of Adjustment Factor

- c. An electricity importer that imports electricity from a jurisdiction with a carbon price in the calendar year shall calculate the adjustment factor (AF) as follows:

### Equation 15-9

$$AF = \left(1 - \frac{P_{jurisdiction}}{P_{NS}}\right)$$

Where:

AF                    Adjustment factor.  
P<sub>jurisdiction</sub>        Average sale price of emission allowances at auctions held during the calendar year by a jurisdiction where the import is from a member of and offered allowances for sale in an auction carried out by the Regional Greenhouse Gas Initiative or Western Climate Initiative in the calendar year (in Canadian dollars).

Or

The carbon price applied to the electricity in the jurisdiction in which it was generated, established under the applicable federal or provincial legislation. (in Canadian dollars)

P<sub>NS</sub>                Average sale price of emission allowances at auctions held during the calendar year by Nova Scotia (in Canadian dollars).

Or

Before the first auction, the minimum price of emission allowances at an auction established in Nova Scotia's Cap-and-Trade Program Regulations (in Canadian dollars).

- d. If a calculation for AF under paragraph (a) of 15.6 is less than zero, then the value of AF shall be equal to zero.

# **17. Operation of Equipment for an Electricity Transmission or Distribution System**

## **17.1 Activity Definition**

Sulfur hexafluoride ( $\text{SF}_6$ ) and perfluorocarbons (PFCs) 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.

For the purposes of this standard quantification method:

“Automated mass-flow measurement” means the use of mass-flow meters attached to electrical power distribution equipment to directly measure the amount of  $\text{SF}_6$  added to equipment.

“Electricity transmission and distribution” has the same meaning as “operation of equipment for a transmission system or a distribution system (electricity)” in the Regulation.

“Person” means a person that engages in electricity transmission or distribution.

“PFC” means perfluoroethane, perfluoropropane, perfluorobutane, perfluorocyclobutane, perfluoropentane, perfluorohexane.

“Storage containers” includes cylinders, gas carts, and other storage containers, but does not include electrical power distribution equipment.

“Total nameplate capacity” means the full and proper charge of electrical power distribution equipment.

“Weigh-scale measurement” means measuring the  $\text{SF}_6$  or PFC in a storage container before and after its contents are added to electrical power distribution equipment with the difference being equal to the  $\text{SF}_6$  or PFC added to the equipment.

## **17.2 Greenhouse Gas Reporting Requirements**

A person shall set out the following information, calculated for the calendar year using standard quantification methods 16.0 – 16.5, in an emission report prepared for a calendar year in respect of electricity transmission and distribution at a facility:

- (a) The  $\text{SF}_6$  and PFC emissions from electricity transmission and distribution and distribution calculated in accordance with 16.3(a) and (b).

### 17.3 Calculation of SF<sub>6</sub> and PFC Emissions

- a. A person shall use one of the following calculation methodologies to calculate SF<sub>6</sub> emissions
  - (1) Mass Balance Methodology.
    - (i) Calculate the change in inventory of SF<sub>6</sub> in storage using **Equation 16-1**.

#### Equation 16-1

$$\Delta S_{Inv} = S_{Inv-Begin} - S_{Inv-End}$$

Where:

$\Delta S_{Inv}$	Change in inventory of SF <sub>6</sub> in storage expressed in kilograms.
$S_{Inv-Begin}$	Quantity of SF <sub>6</sub> in storage at the beginning of the reporting period expressed in kilograms.
$S_{Inv-End}$	Quantity of SF <sub>6</sub> in storage at the end of the reporting period expressed in kilograms.

- (ii) Calculate the amount of all SF<sub>6</sub> acquired during the year that is contained either in storage containers or in electrical power distribution equipment using **Equation 17-2**.

#### Equation 17-2

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

Where:

$S_{PA}$	Sum of all SF <sub>6</sub> acquired during the year that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms.
$S_{Cyl}$	Quantity of SF <sub>6</sub> in storage containers obtained from producers or distributors expressed in kilograms.
$S_{Equip}$	Quantity of SF <sub>6</sub> stored or contained inside equipment provided by electrical power distribution equipment manufacturers expressed in kilograms.
$S_{Recyc-ret}$	Quantity of SF <sub>6</sub> returned to site after off-site recycling expressed in kilograms.

- (iii) Calculate the sum of all SF<sub>6</sub> transferred out of the facility during the year either in storage containers or in electrical power distribution equipment using **Equation 17-3**.

### Equation 17-3

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

Where:

$S_{Sales}$	Quantity of SF <sub>6</sub> sold or transferred to other facilities including SF <sub>6</sub> that is left in electrical power distribution equipment that is sold expressed in kilograms.
$S_{Returns}$	Quantity of SF <sub>6</sub> returned to suppliers expressed in kilograms.
$S_{Destruct}$	Quantity of SF <sub>6</sub> sent to destruction facilities expressed in kilograms.
$S_{Recyc-off}$	Quantity of SF <sub>6</sub> sent off-site for recycling expressed in kilograms.

- (iv) Calculate the net increase in total nameplate capacity of electrical power distribution equipment that uses SF<sub>6</sub> using **Equation 17-4**.

### Equation 17-4

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

Where:

$\Delta S_{Cap}$	Net increase in total nameplate capacity of electrical power distribution equipment that uses SF <sub>6</sub> expressed in kilograms.
$S_{Cap-new}$	Total nameplate capacity of new electrical power distribution equipment at proper full charge expressed in kilograms.
$S_{Cap-retire}$	Total nameplate capacity of electrical power distribution equipment that has been retired, sold or transferred at proper full charge expressed in kilograms.

- (v) Calculate total emissions for the reporting period using **Equation 17-5**.

### Equation 17-5

$$S = (\Delta S_{Inv} + S_{PA} - S_{SD} - \Delta S_{Cap}) \div 1,000$$

Where:

$S$	Total annual SF <sub>6</sub> emissions expressed in tonnes.
$\Delta S_{Inv}$	Change in inventory of SF <sub>6</sub> in storage expressed in kilograms calculated in accordance with <b>Equation 16-1</b> .
$S_{PA}$	Sum of all SF <sub>6</sub> acquired that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms, calculated in accordance with <b>Equation 17-2</b> .

$S_{SD}$	Sum of all SF <sub>6</sub> transferred out of the facility during the year that is contained either in storage containers or in electrical power distribution equipment expressed in kilograms calculated in accordance with <b>Equation 17-3</b> .
$\Delta S_{Cap}$	Net increase in total nameplate capacity of electrical power distribution equipment using SF <sub>6</sub> expressed in kilograms calculated in accordance with <b>Equation 17-4</b> .
1,000	Factor to convert kilograms to tonnes.

(2) Direct Measurement Methodology.

- (i) SF<sub>6</sub> emissions from the operations phase shall be calculated by directly measuring the mass of SF<sub>6</sub> added to electrical power distribution equipment during the operation phase using automated mass-flow measurement or weigh-scale measurement in accordance with **Equation 17-6**.

**Equation 17-6**

$$S_o = \sum_i^N S_i$$

Where:

- $S_o$  Annual SF<sub>6</sub> emissions during the operation phase expressed in kilograms.
- N Number of SF<sub>6</sub> additions in a given year.
- $S_i$  SF<sub>6</sub> added to electrical power distribution equipment during addition  $i$ , expressed in kilograms.

- (ii) SF<sub>6</sub> emissions from the decommissioning phase shall be calculated by directly measuring the amount of SF<sub>6</sub> collected from any decommissioned electrical power distribution equipment calculated in accordance with **Equation 17-7**.

**Equation 17-7**

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

Where:

- $S_D$  Annual SF<sub>6</sub> emissions during decommissioning phase expressed in kilograms.
- N Number of units of electrical power distribution equipment decommissioned in a given year.

$NC_i$  Nameplate capacity of decommissioned electrical power distribution equipment  $i$ , expressed in kilograms.

$S_i$  SF<sub>6</sub> collected from decommissioned electrical power distribution equipment  $i$ , expressed in kilograms.

(iii) Total annual SF<sub>6</sub> emissions are calculated according to **Equation 17-8**.

### **Equation 17-8**

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

Where:

$S$  Annual SF<sub>6</sub> emissions expressed in tonnes.

$S_o$  Annual SF<sub>6</sub> emissions during operation phase expressed in kilograms.

$S_D$  Annual SF<sub>6</sub> emissions during decommissioning phase expressed in kilograms.

- b. A person shall use the methods in (a) to calculate the emissions from PFCs, substituting PFCs for SF<sub>6</sub> and making all other necessary substitutions in **Equation 16-1** through **Equation 17-8**.

## **17.4 Sampling, Analysis, and Measurement Requirements**

- (a) When using the calculation methodology in 16.3(a)(1), the person shall determine changes in cylinder or container weights and inventories as follows:
- (1) Using scales or load cells with an accuracy of 1 per cent of full scale or better, accounting for the tare weights of the cylinders or other containers; or
  - (2) Using 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 cylinders or other containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards in (c) are met.
- (b) When using the calculation methodology in 16.3(a)(1), a person shall monitor and record cylinder and other container identities and masses as follows:
- (1) Track the identities and masses of cylinders and other containers leaving and entering storage with check-out and check-in sheets and procedures.
  - (2) Measure masses of cylinders and other containers returning to storage immediately before the cylinders or other containers are put back into storage.
- (c) When using the calculation methodologies in 16.3(a)(2) or the corresponding method required by 16.3(b), a person shall measure additions of SF<sub>6</sub> or PFCs during the operation phase using a measuring instrument such as a flowmeter or weigh scale.

- (d) When using the calculation methodologies in 16.3(a)(2) or the corresponding method required by 16.3(b), a person shall calibrate equipment used to measure the mass of SF<sub>6</sub> or PFCs as follows.
  - (1) For automated mass-flow measurement, equipment shall be calibrated according to the calibration procedure specified by manufacturer.
  - (2) For weigh-scale measurement, equipment shall be calibrated every 6 months by weighing objects of pre-determined mass and zeroing the weigh scale accordingly.

## 17.5 Procedures for Estimating Missing Data

Unavailable analytical Data

- a. Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in 16.4, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

Determination of Quantity

- b. Whenever sampling and measurement data required by 16.4 for the calculation of emissions is unavailable the person shall ensure that the data is substituted using the following missing data procedures:
  - (1) Determine the sampling or measurement rate that was used using **Equation 17-9**:

### Equation 17-9

$$R = \frac{QS_{Act}}{QS_{Required}}$$

Where:

R Sampling or measurement rate that was used, expressed as a percentage.

QS<sub>Act</sub> Quantity of actual samples or measurements obtained by the person.

QS<sub>Required</sub> Quantity of samples or measurements required under Section 18.

- (2) Substitute the missing data as follows:
  - (i) If R ≥ 0.9: substitute the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;
  - (ii) If 0.75 ≤ R < 0.9: substitute the missing data with the highest data value sampled or analyzed during the reporting period for which the calculation is required;

- (iii) If  $R < 0.75$ : substitute the missing data with the highest data value sampled or analyzed during the 3 preceding years;
- (3) When the missing data concerns gas quantity, the person shall generate the replacement data from best estimates based on all of the data relating to the processes.
- (4) When the missing data relates to electrical power distribution equipment capacity, the person shall estimate the replacement data on the basis of an equivalent nominal SF<sub>6</sub> and PFC gas capacity, and on repair, replacement and maintenance data for similar pieces of equipment.

# 18. Procedures for Estimating Missing Data

## 18.1 Unavailable Analytical Data

Whenever analytical data relating to sampling is unavailable, the person shall, using the methods prescribed in this Standard, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period.

## 18.2 Determination of Quantity

Whenever sampling and measurement data required in this Standard for the calculation of emissions is missing, the person shall ensure that the data is replaced using the following missing data procedures:

- (1) When the missing data concerns carbon content, temperature, pressure or gas concentration, the person shall:
  - (i) Determine the sampling or measurement rate using the following **Equation 18-1**.

### Equation 18-1:

$$R = \frac{Q_{S\ Act}}{Q_{S\ Required}}$$

Where:

R	= Sampling or measurement rate that was used, expressed as a percentage
$Q_{S\ Act}$	= Quantity of actual samples or measurements obtained by the person
$Q_{S\ Required}$	= Quantity of samples or measurements required as per the Standard

- (ii) Replace the missing data as follows,

- (A) If  $R \geq 0.9$ : replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the period missing data period. If no data is available from before the missing data period, the person shall use the first available data from after the missing data period;

- (B) If  $0.75 \leq R < 0.9$ : replace the missing data by the highest data value sampled or analyzed during the reporting period for which the calculation is made;
  - (C) If  $R < 0.75$ : replace the missing data by the highest data value sampled or analyzed during the 3 preceding years;
- (2) When the missing data concerns gas consumption, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

For units that monitor and report emissions using a CEMS, the missing data backfilling procedures in Environment and Climate Change Canada's, "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7"<sup>(13)</sup> shall be followed for CO<sub>2</sub> concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

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<sup>13</sup> Environment Canada (2012) Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7, Available at: <https://www.ec.gc.ca/Publications/F8C7CED9-FCD0-477B-8E4A-64E0AB3089C7/QuantificationofCarbonDioxideReleasesbyContinuousEmissionMonitoringSystemsfromT>hermalPowerGeneration.pdf