Quantification Methodologies for the Carbon Competitiveness Incentive Regulation and the Specified Gas Reporting Regulation

Alberta Environment and Parks

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Summary of Revisions

Version	Date	Summary of Revisions
1.0	June 2018	First publication of chapters 1, 8, 12, 13, 14, and 17 and Appendix A, B, C, and D.
1.1	November 2018	Revision 1 to chapters 1, 8, 12, 13, 14, and 17 and Appendix A, B, C, and D. • Updates and corrections to emission factors in Chapter 1 (Tables 1-1 to 1-4). • Added technology based emission factors for methane and nitrous oxide in Chapter 1 (Table 1-3). • Updates to the structure of methods and tier classification in Chapter 1 (Figures 1-1 and 1-2). • New methods introduced in Chapter 8 (Section 8.2.5) and Appendix C (Section C.6). • Updates to fuel properties in Appendix B. • Updates to production in Chapter 13 to include ethylene glycol and high value chemicals (HVC). • Updates to Section 17.3 in Chapter 17. • Other minor miscellaneous edits to various chapters.
1.2	November 2019	First publication of chapters 4 and 5.
1.3	January 2020	The following updates were made to chapters 1, 5, 8, 12, 13, 14, and 17: • Minor updates and corrections throughout the chapters. • Clarification on fuel used for flare pilot. • Definition of negligible emissions sources. • Emission factors in chapters 1 and 14. • Quantification methodologies for lime kilns in Kraft pulp mills in chapter 8. • Alberta Gas Processing Index (ABGPI) in chapter 13. • Fuel consumption requirements in chapter 17. • Table 17.3 to provide clarity on sampling frequencies.
1.4	March 2020	Minor corrections to Appendix C.

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Introduction

The Carbon Competitiveness Incentive Regulation (CCIR) and the Specified Gas Reporting Regulation (SGRR) require the use of standard quantification methods for the reporting of greenhouse gas emissions under each respective regulation. The *Quantification Methodologies for the CCIR and SGRR* provides the standard methods for activities that generate greenhouse gas emissions. Some methods prescribed in this document are only applicable to one of the regulations and the reporting of emissions and other parameters such as production and biomass emissions must follow the requirements under the respective regulation. Where quantification methods and emission factors are not prescribed or if deviations from prescribed methods are required, alternative methods may be proposed by the reporter and will be reviewed and approved by the Director on a case-by-case basis. Procedures to request for deviations and/or alternative methods are described in the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* for regulated facilities under CCIR.

For some activities, several methods are outlined to quantify greenhouse gas emissions, which may include mass balances, emission factors, engineering estimates, and/or direct emissions measurements. These methods have been identified as “tiers” of quantification methods. The *Specified Gas Reporting Standard* and the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* prescribes the “tier” method that is required for a facility that is reporting under SGRR and/or CCIR respectively.

The *Quantification Methodologies for the CCIR and SGRR*, the *Specified Gas Reporting Standard*, and the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* will be updated from time to time. Regulated facilities are required to use the most up-to-date version of these documents in the reporting of greenhouse gas emissions under the respective regulations.

Scope and Applicability

The objective of the quantification methodologies is to ensure accuracy and consistency across reporters and sectors regulated under the CCIR and SGRR. The intention is also to align with methods that are prescribed by Environment and Climate Change Canada (ECCC) and other jurisdictions that regulate greenhouse gas emissions such as British Columbia, Ontario, Quebec, and California. Further, methodologies from organizations such as the Western Climate Initiative, Inc. (WCI) and the Intergovernmental Panel on Climate Change (IPCC) are referenced or adopted as appropriate for various activity types and modified to meet the needs of Alberta sectors.

Greenhouse gas emissions covered in these quantification methods include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6), nitrogen trifluoride (NF_3), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). For a complete list of HFCs and PFCs, refer to the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports*.

For some reporting purposes facilities are required to apply the appropriate Global Warming Potential (GWPs) to the greenhouse gas in order to calculate the carbon dioxide equivalent (CO_2e). These GWPs are prescribed in the standards corresponding to the respective regulations.

Activity Type

This *Quantification Methodologies for the CCIR and SGRR* provides quantification methods for the following activities:

Chapter 1: Stationary Fuel Combustion

Chapter 2: Flaring

Chapter 3: Fugitives

Chapter 4: Venting

Chapter 5: On-Site Transportation

Chapter 6: Waste and Digestion

Chapter 7: Wastewater

Chapter 8: Industrial Processes

Chapter 9: HFCs, PFCs, SF_6, NF_3

Chapter 10: Formation CO_2

Chapter 11: Injected, Sent Offsite, Received CO_2

Chapter 12: Imports

Chapter 13: Production

Chapter 14: Carbon Dioxide Emissions from Combustion of Biomass

Chapter 15: Reporting Requirements under CCIR and SGRR

The chapters below provide guidance for reporters:

Chapter 17:	Measuring, Sampling, Analysis and Data Management

The following appendices provide support to the activities presented in the above chapters:

Appendix A:	References
Appendix B:	Fuel Properties
Appendix C:	General Calculation Instructions
Appendix D:	Conversion Factors

Application for Deviation Requests

Facilities that are unable to execute a prescribed method must request a time limited approval to deviate from the prescribed method. The application should include:

- A description of the alternative method to be used
- Evidence that the alternative method would tend to be conservative versus the prescribed method
- A plan for future adoption of the prescribed method

The Director will review the request to deviate and issue a letter indicating whether it is approved. This letter should be kept as record to support verification activities. For further information on this process please consult the *Standard for Completing Greenhouse Gas Compliance and Forecasting Reports* for regulated facilities under CCIR.

Definitions

"AB-CWB Methodology" means the methodology based on CAN-CWB and adapted to Alberta framework.

"Accuracy" means the ability of a measurement instrument to indicate values closely approximating the true value of the quantity measured.

"bbl/cd"" means barrels per calendar day.

"Bias" means any influence on a result that produces an incorrect approximation of the true value of the variable being measured. Bias is the result of a predictable systematic error.

“Biomass” means organic matter consisting of, or recently derived from living organisms.

“Biogenic emissions” are derived from biomass, either through combustion or other processes.

“Calibration” means the process or procedure of adjusting an instrument so that its indication or registration is in satisfactorily close agreement with a reference standard.

“CAN-CWB Methodology” means the calculation methodology described in “The CAN-CWB Methodology for Regulatory Support: Public Report” dated January 2014, prepared by Solomon Associates.

“Carbon content” means the fraction of carbon in the material.

“Consensus Based Standards Organization” means 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, the Gas Processors Suppliers Association (GPSA), the American National Standards Institute (ANSI), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB), International Organization for Standardization (ISO), British Standard Institution, Measurement Canada, or other similar standards organizations.

“Compensation” means the adjustment of the measured value to reference conditions (e.g. pressure compensation).

“Continuous emission monitoring system (CEMS)” means the equipment required to sample, analyze, measure, and provide, by means of monitoring at regular intervals, a record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

“Cogeneration unit” means a fuel combustion device which simultaneously generates electricity and either heat or steam.

“FCC” means Fluid Catalytic Cracker.

“Fuel” means solid, liquid or gaseous combustible material.

“Fuel gas” means typically a mixture of light hydrocarbon and other molecules (e.g. H_2, N_2) in a gaseous state that are consumed in fired heaters. Fuel gas is often a mixture of recovered gaseous molecules from plant operations and purchased natural gas.

“GHGs” means greenhouse gases.

“GWP” means global warming potential.

“HFCs” means hydrofluorocarbons.

"*Higher Heating Value*" or HHV means the amount of heat released by a specified quantity of fuel once it is combusted and the products have returned to the initial temperature of the fuel, which takes into account the latent heat of vaporization of water in the combustion products.

"Influence parameter" means any factor that impacts the performance of the measuring device, hence the uncertainty and accuracy of the measurement. Examples are process temperature, pressure, fluid composition, upstream straight length, etc.

"Inspection" means a visual assessment or mechanical activity (e.g. instrument lead line blow down or orifice plate cleanliness) that does not include comparison or adjustment to a reference standard.

"Instrument Verification" means the process or procedure of comparing an instrument to a reference standard to ensure its indication or registration is in satisfactorily close agreement, without making an adjustment.

"*Landfill Gas"* (LFG) means the mixture of methane and carbon dioxide generated by decomposing organic waste in Solid Waste Disposal Sites.

"*Lower Heating Value*" or LHV means the amount of heat released by combusting a specified quantity of fuel and returning the temperature of the combustion products to 150℃, which assumes the latent heat of vaporization of water in the reaction products is not recovered.

"Meter condition factor" means an estimate of additional uncertainty based on a technical judgment of the physical condition of the meter in lieu of the ability to inspect.

"Metering or measurement system" means a combination of primary, secondary and/or tertiary measurement components necessary to determine the flow rate.

"Municipal waste" is waste collected by municipalities or other local authorities. Typically, MSW includes: household waste, garden (yard) and park waste and commercial/institutional waste.

"NAICS" is the North American Industry Classification System.

"*Negligible emission sources*" are sources with emissions that represent less than 1% of a facility's total regulated emissions (TRE) or output-based allocation (OBA) (CO_2e) and are not to exceed 5,000 tonne of CO_2e for a facility with a TRE less than 1 million tonnes of CO_2e or not to exceed 10,000 tonnes of CO_2e for a facility with TRE equal to or greater than 1 million tonnes of CO_2e under CCIR. Alternative methods may be used to assess the negligibility of these emissions.

"Performance" means the response of a measurement device to influence parameters such as operating conditions, installation effects, and fluid properties.

“Range of uncertainty” means the range or interval within which the true value is expected to lie with a stated degree of confidence.

“Standard Temperature and Pressure” or *“STP conditions"* or *"standard condition"* means conditions at 15.0 degrees Celsius and 1 atmosphere of absolute pressure.

“Uncertainty” means the description of the range of deviation between a measured value and the true value, expressed as a percentage. For example, a device with an accuracy of 2% would have an uncertainty of ±2 %.

“2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines”: 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Intergovernmental Panel on Climate Change National Greenhouse Gas Inventories Program. Available online at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

σ means the standard deviation.

1.0 Quantification Methods for Stationary Fuel Combustion

1.1 Introduction

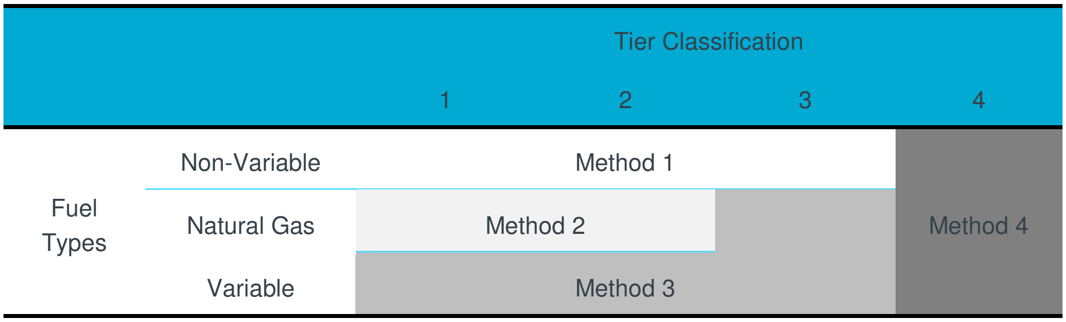
Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of providing useful heat or energy for industrial, commercial, or institutional use. Methods for carbon dioxide (CO_2) emissions from biomass combustion are provided in Chapter 14, while methods for methane (CH_4) and nitrous oxide (N_2O) from biomass combustion are included in this chapter. Stationary fuel combustion sources include, but are not limited to boilers, simple and combined-cycle combustion turbines, engines, emergency generators, portable equipment, process heaters, furnaces and any other combustion devices or system (e.g. blasting for mining purposes). This source category does not include flare emission sources, except for fuel that is combusted for the flare pilot, or waste incineration, which are discussed in Chapter 2 and Chapter 6, respectively.

1.2 Carbon Dioxide

1.2.1 Introduction

For each fuel type combusted, calculate the mass of CO_2 emissions from fuel combustion for the reporting period, using one of the four quantification methodologies specified in this section. Various methods to calculate CO_2 emissions from different fuel types are presented in this section. A facility must use the method that corresponds with the tier classification that is assigned to the facility as illustrated in Figure 1.1. A facility must also apply the sampling and measurement requirements in Chapter 17 that corresponds with the facility's tier classification.

Figure 1-1 Tier classification and methodology mapping



<table>
<tr><th></th><th></th><th colspan="4">Tier Classification</th></tr>
<tr><th></th><th></th><th>1</th><th>2</th><th>3</th><th>4</th></tr>
<tr><td rowspan="3">Fuel Types</td><td>Non-Variable</td><td colspan="3">Method 1</td><td rowspan="3">Method 4</td></tr>
<tr><td>Natural Gas</td><td colspan="2">Method 2</td><td rowspan="2">Method 3</td></tr>
<tr><td>Variable</td><td colspan="2">Method 3</td></tr>
</table>

1.2.2 Method 1 - A fuel-specific default CO_2 emission factor for non-variable fuels

(1) Introduction

This method is used for fuels that are non-variable in composition and based on a default CO_2 emission factor and the quantity of fuel consumed. This method can be used for tiers 1, 2, or 3 as illustrated in Figure 1-1. Non-variable fuels that are acceptable to be used under this methodology include ethane, propane, butane, diesel, and gasoline. For diesel and gasoline that is subject to the Renewable Fuels Standard (RFS), the default CO_2 emission factors take into account the biofuel that is required as part of the fuel composition. Under the RFS, gasoline and diesel must contain 5% and 2% biofuel, respectively. Note the biofuels are included in the chapter for CO_2 from biomass combustion. The quantity of fuel consumed may be measured on a volume or energy basis, which can be provided by a third party supplier (i.e. invoices) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Fuel consumption measured or provided in units of energy must be based on the higher heating value (HHV) of the fuel. Table 1-1 provides the emission factors for these fuels in mass of CO_2 emitted per gigajoules (GJ) or kilolitres (kl).

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 1-1 is used to convert the volume of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Table 1-1 to calculate the CO_2 mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-1a can be used directly to calculate the CO_2 mass emissions based on the appropriate energy based emission factor from Table 1-1.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 1-1a using the fuel quantity in volume basis with the appropriate volume based emission factor from Table 1-1 to calculate the CO_2 mass emissions.

(2) Equations

For a liquid or gaseous fuel, use Equation 1-1 or Equation 1-1a to calculate the CO_2 mass emissions for the reporting period.

$$\boldsymbol{CO_{2,p} = \upsilon_{fuel,p} \times HHV \times EF_{ene}} \qquad \text{Equation 1-1}$$

$$\boldsymbol{CO_{2,p} = \upsilon_{fuel,p} \times EF_{vol}\ or\ ENE_{fuel,p} \times EF_{ene}} \qquad \text{Equation 1-1a}$$

Where:

$CO_{2,\,p}$ = CO_2 mass emissions for the specific fuel type for the reporting period, *p* (tonnes CO_2).

$v_{fuel,\,p}$ = For Equation 1-1 and 1-1a, the volume of fuel combusted in kilolitres (kl) combusted during reporting period, *p,* calculated in accordance with Chapter 17 and Appendix C.

$ENE_{fuel,p}$ = For Equation 1-1a, energy of fuel in gigajoules (GJ) combusted during reporting period, *p*. Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

HHV = Measured or supplied higher heating value in gigajoules per kilolitres (GJ/kl).

EF_{vol}, EF_{ene} = Fuel-specific default CO_2 emission factor, from Table 1-1 in tonnes of CO_2 per volume units (kl) or energy units (GJ).

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

1.2.3 Method 2 - CO_2 emissions from combustion of natural gas

(1) Introduction

This method is adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO_2 mass emissions from natural gas combustion based on the measured HHV. This method can be used for tiers 1 and 2 as illustrated in Figure 1-1. Tier 3 facilities must use Method 3 for natural gas.

Calculate the CO_2 mass emissions for the reporting period based on the natural gas HHV provided by the fuel supplier or measured by the facility using Equation 1-2.

(2) Equation

For marketable natural gas, where the measured HHV is available, but not the carbon content, use Equation 1-2:

$$CO_{2,p} = v_{fuel,p} \times \left(60.554 \times HHV_p - 404.15\right) \times 10^{-6}$$

Equation 1-2

Where:

$CO_{2,\,p}$ = CO_2 mass emissions for the marketable natural gas combusted during the reporting period, p (tonnes CO_2).

$v_{fuel,\,p}$ = Volume of fuel (m^3) at standard conditions combusted during reporting period, p, calculated in accordance with Chapter 17 and Appendix C.

HHV_p = Weighted average measured higher heating value of fuel (MJ/m^3) at standard conditions as defined in Appendix C.

$(60.554 \times HHV_p - 404.15)$ = Empirical equation adapted from ECCC (grams of CO_2 per cubic meter of natural gas) representing relationship between CO_2 and volume of natural gas determined through higher heating value using a discreet set of data collected by ECCC.

10^{-6} = Mass conversion factor (t/g).

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

1.2.4 Method 3 - CO_2 emissions from variable fuels based on the measured fuel carbon content

(1) Introduction

This method is used for variable fuels based on a mass balance approach using the measured fuel carbon content. This method can be used for tiers 1, 2, or 3. Variable fuels are those that have varying composition and require testing for carbon content. All fuels not listed as non-variable fuels are to be considered variable fuels. The quantity of fuel consumed and/or the carbon content may be provided by the third party supplier (i.e. invoices or third party documentation) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C.

For FCC processes, the emissions are considered to be stationary fuel combustion; however, there are no quantification methodologies currently prescribed. Facilities performing these processes may develop their own quantification methodologies or apply existing quantification methodologies until such methodologies are provided in this chapter.

Calculate the CO_2 mass emissions for the reporting period for each fuel based on Equation 1-3a, Equation 1-3b, Equation 1-3c, or Equation 1-3d depending on the type of fuel combusted.

(2) Equations

For gaseous fuels, where fuel consumption is measured in units of volume (m^3), use Equation 1-3a:

$$\boldsymbol{CO_{2,p} = v_{fuel\,(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}$$ Equation 1-3a

For gaseous fuels, where fuel consumption is measured in units of energy (GJ), use Equation 1-3b:

$$\boldsymbol{CO_{2,p} = \frac{ENE_{fuel\,(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV}}$$ Equation 1-3b

Where:

$CO_{2,p}$ = CO_2 mass emissions for the gaseous fuel combusted during the reporting period, *p* (tonnes CO_2).

$v_{fuel(gas),\,p}$ = Volume of fuel (m^3) at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.

$ENE_{fuel(gas),p}$ = Energy of fuel (GJ) at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.

HHV = Weighted average higher heating value of fuel (GJ/m^3) at standard conditions as defined in Appendix C.

$CC_{gas,p}$ = Weighted average carbon content of the gaseous fuel during the reporting period *p*, calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m^3).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Mass conversion factor (t/kg).

For a liquid fuel, where fuel consumption is measured in units of volume (kilolitres), use Equation 1-3c:

$$\boldsymbol{CO_{2,p} = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664} \qquad \text{Equation 1-3c}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions for the liquid fuel during the report period, p (tonnes CO_2).

$v_{fuel(liq),p}$ = Volume of liquid fuel combusted during the reporting period p, calculated in accordance with Chapter 17 and Appendix C (kilolitres).

$CC_{liq,p}$ = Weighted average carbon content of the liquid fuel during the reporting period p, calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of tonnes of carbon per kilolitre of liquid fuel (tonnes C/kl).

3.664 = Ratio of molecular weights, CO_2 to carbon.

For a solid fuel, where fuel consumption is measured in units of mass (tonnes), use Equation 1-3d:

$$\boldsymbol{CO_{2,p} = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664} \qquad \text{Equation 1-3d}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions for the solid fuel during the report period, p

$m_{fuel(sol),p}$ = Mass of solid fuel combusted during the reporting period p, calculated in accordance with Chapter 17 and Appendix C (tonnes).

$CC_{sol,p}$ = Weighted average carbon content of the fuel during the reporting period p, calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of tonnes of carbon per tonnes of solid fuel (tonnes C/tonnes).

3.664 = Ratio of molecular weights, CO_2 to carbon.

(3) Data requirements

- Facilities must ensure that the proper units of fuel consumption, carbon content, and HHV are applied in the equations provided in this section.
- Fuel consumption measured or supplied in units of energy must be based on the HHV of the gaseous fuel.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.
- For coal combustion used for electricity generation, an oxidation factor of 99.48% is applied. This factor may be applied in Equation 1-3d to calculate carbon dioxide emissions. This oxidation factor was derived from a study conducted by ECCC on oxidation factors for coal combustion in Canada.

1.2.5 Method 4 - Continuous emissions monitoring systems

(1) Generality

For tier 4, calculate the CO_2 mass emissions for the reporting period from all fuels combusted in a unit, by using data from a CEMS as specified in (a) through (g). This methodology requires a CO_2 monitor (or O_2 monitor) and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies provided in reference [8] in Appendix A or by another document that supersedes it. Facilities that are assigned a lower tier may choose to apply Method 4 to quantify their CO_2 emissions from fuel combustion.

(a) For a facility that operates CEMS in response to federal, provincial or local regulation (i.e. required by the facility's Alberta Energy Regulator (AER) or Environmental Protection and Enhancement Act (EPEA) approval), use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies required by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or in accordance with reference [8] in Appendix A.
(b) Report CO_2 emissions for the reporting year in tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to tonnes.
(c) An O_2 concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO_2 concentrations. This may be used if the effluent gas stream monitored by the CEMS consists of combustion products (i.e., no process CO_2 emissions or CO_2 emissions from acid gas control are mixed with the

combustion products) and only if 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_2 concentrations.
  (2) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that the calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in reference [8] in Appendix A or Alberta CEMS Code.

(d) If both biomass and fossil fuels (including fuels that are partially biomass) are combusted during the year, determine the biomass CO_2 mass emissions separately, as described in Chapter 14.
(e) For any units using CEMS data, industrial process and stationary combustion CO_2 emissions must be provided separately. Determine the quantities of each type of fossil fuel and biomass fuel consumed for the reporting period, using the fuel sampling approach in Section 17.3 in Chapter 17.
(f) If a facility subject to requirements for continuous monitoring of gaseous emissions chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, select and operate the added devices using appropriate requirements in accordance with reference [8] in Appendix A for the facility, as applicable in Alberta under the Alberta CEMS Code.
(g) If a facility does not have a CEMS and chooses to add one in order to measure CO_2 concentrations, select and operate the CEMS using the appropriate requirements in accordance with reference [8] in Appendix A or equivalent requirements as applicable in Alberta under the Alberta CEMS Code.

(2) Data requirements

No additional data requirements are needed.

1.3 Methane and Nitrous Oxide

1.3.1 Introduction

Calculate the CH_4 and N_2O mass emissions for the reporting period from stationary fuel combustion sources, for each fuel type including biomass fuels, using the methods specified in this section. Figure 1-2 provides additional requirements for facilities based on sector and tier classification.

Figure 1-2 Additional requirements for natural gas emission factors based on sector and tier classification

<table>
<tr><th colspan="2"></th><th colspan="3">Tier Classification</th></tr>
<tr><th colspan="2"></th><th>1</th><th>2</th><th>3</th></tr>
<tr><td rowspan="2">Sectors</td><td>Oil and gas[1]</td><td rowspan="2">Method 1
Sector or technology based emission factors</td><td>Method 1
Technology based emission factors only (Table 1-3)</td><td rowspan="2">Method 2</td></tr>
<tr><td>All other sectors</td><td></td></tr>
</table>

[1] Oil and gas sector includes conventional (NAICS: 211113) and non-conventional (NAICS: 211114) oil and gas facilities.

1.3.2 Method 1- Default CH_4 and N_2O emission factor

(1) Introduction

This method calculates the CH_4 and N_2O mass emissions based on default emission factors that are based in energy or physical units of fuel consumed. CH_4 and N_2O generated from combustion of biomass is included in this section. The quantity of fuel consumed can be provided by a third party supplier (i.e. invoices) or measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Fuel consumption measured or provided in units of energy must be based on the HHV of the fuel. Tables 1-1, 1-2, 1-3, and 1-4 provide the emission factors for these fuels in mass of CH_4 and N_2O emitted per GJ, kilolitres, cubic metres, or tonnes of fuel. For a fuel that is not prescribed an emission factor in these tables, the facility may use an emission factor from an alternative source or perform engineering estimates to quantify these emissions.

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 1-4 is used to convert the volume of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Tables 1-1, 1-2, 1-3, or 1-4 to calculate the CH_4 and N_2O mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-4a can be used directly to calculate the CH_4 and N_2O mass emissions based on the appropriate energy based emission factor from Tables 1-1, 1-2, 1-3, and 1-4.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 1-4a using the fuel quantity in volume basis with the appropriate volume based emission factor from Tables 1-1, 1-2, 1-3, or 1-4 to calculated the CH_4 and N_2O mass emissions.

This method is used for tiers 1, 2, and 3. Figure 1-2 provides additional requirements for natural gas emission factors based on the sector and tier classification for the facility.

(2) Equations

For a solid, liquid and gaseous fuel, use Equation 1-4or Equation 1-4a:

$$\boldsymbol{CH_{4,p} or\ N_2O_p = Fuel_p \times HHV \times EF_{ene}}$$ Equation 1-4

$$\boldsymbol{CH_{4,p} or\ N_2O_p = Fuel_p \times EF_{vol}\ or\ EF_{ene}}$$ Equation 1-4a

Where:

$CH_{4,\boldsymbol{p}}$ or $N_2O_{\boldsymbol{p}}$ = CH_4 or N_2O mass emissions for the specific fuel type for the reporting period, *p,* (tonnes CH_4 or N_2O).

$Fuel_p$ = For Equation 1-4, the quantity of fuel combusted in kilolitres, cubic metres, or tonnes (kl, m^3, tonnes) combusted during reporting period, *p*. For Equation 1-4a, energy of fuel in gigajoules or quantity of fuel in kilolitres, cubic metres, or tonnes (GJ, kl, m^3, or tonnes) combusted during reporting period, *p*. Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

HHV = Measured or supplied higher heating value in gigajoules per kilolitres, cubic metres, or tonnes (GJ/kl, GJ/m^3, or GJ/tonne).

EF_{vol}, EF_{ene} = Fuel-specific default emission factor, from Tables 1-1, 1-2, 1-3, or 1-4 in tonnes of CH_4 or N_2O per energy units (GJ), volume units (kilolitres or cubic metres), or mass units (tonnes).

For facilities that combust biomass for steam generation and the steam generated is measured, use Equation 1-5:

$$\boldsymbol{CH_{4,p}\ or\ N_2O_p = Steam \times B \times EF}$$ Equation 1-5

Where:

$CH_{4,p}$ or N_2O_p	CH_4 and N_2O mass emissions for the specific fuel type for the reporting period, p (tonnes CH_4 or N_2O).
Steam	Total steam generated by biomass fuel or biomass combustion during the reporting period (tonnes steam), in GJ and calculated in accordance with Chapter 17 and Appendix C.
B	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity in GJ per GJ calculated in accordance with Chapter 17.
EF	Fuel-specific default CH_4 and N_2O emission factor, from Table 1-4, in tonnes of CH_4 and N_2O per GJ.

(3) Data requirements

- HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.
- Facilities that use internal combustion engines are required to use technology based emission factors for internal combustion engines to calculate the CH_4 and N_2O emissions from those equipment.

1.3.3 Method 2 – Continuous emissions monitoring systems

(1) Introduction

The CH_4 or N_2O emissions for the reporting period attributable to the combustion of any type of fuel used in stationary combustion units may be calculated using data from CEMS including a gas volumetric flow rate monitor and a CH_4 or N_2O concentration monitor, in accordance with reference [9] in Appendix A or in accordance with the manufacturer's specifications.

1.4 Emission factors

The tables in this section provide the emission factors to be used in the equations outlined in the above sections.

Table 1-1 Default emission factors by fuel type for non-variable fuels

Non-Variable Fuels	HHV (GJ/kl)[1]	CO$_2$ Emission Factor[4]		CH$_4$ Emission Factor[4]		N$_2$O Emission Factor[4]	
		tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel[2]	38.35	2.681	0.0699	-	-	-	-
<19kW	-	-	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 1-3	-	-	-	7.3E-05	1.9E-06	2.0E-05	5.8E-07
>=19kW, Tier 4	-	-	-	7.3E-05	1.9E-06	2.3E-04	5.9E-06
Diesel in Alberta[3]	37.83	2.610	0.06953	see note 5			
Biodiesel[6]	35.16	-	-	see note 5			
Gasoline				-	-	-	-
2-stroke	33.43	2.307	0.069	1.1E-02	3.0E-04	1.3E-05	3.6E-07
4-stroke				5.1E-03	1.5E-04	6.4E-05	1.8E-06
Gasoline in Alberta3	33.24	2.174	0.06540	see note 7			
Butane	28.45	1.747	0.0614	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	17.21	0.986	0.0573	2.4E-05	1.4E-06	1.08E-04	6.3E-06
Propane	25.29	1.515	0.0599	2.4E-05	9.5E-07	1.08E-04	4.3E-06

1. For facilities that are unable to obtain the HHV of their fuel, this column presents the default HHV for the non-variable fuels.
2. Tiers adapted from USEPA requirements.
3. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content.
4. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).
5. Diesel CH4 and N2O emission factors are used.
6. Biodiesel CO2 emission factors are provided in Table 14-1.
7. Gasoline CH4 and N2O emission factors are used.

Table 1-2 Sector based default CH_4 and N_2O emission factors for natural gas

Natural Gas[1]	CH_4 Emission Factor[2]		N_2O Emission Factor[2]	
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ
Electric Utilities	4.9E-07	1.3E-05	4.9E-08	1.3E-06
Industrial	3.7E-08	9.8E-07	3.3E-08	8.7E-07
Oil and Gas Sector and Producer Consumption (Non-marketable)[1]	3.7E-08	9.8E-07	3.5E-08	9.0E-07
Pipelines	1.9E-06	5.0E-05	5.0E-08	1.3E-06
Cement	3.7E-08	9.8E-07	3.4E-08	9.0E-07
Manufacturing Industries	3.7E-08	9.8E-07	3.3E-08	8.7E-07
Residential, Construction, Commercial/Institutional, Agriculture/Other	3.7E-08	9.8E-07	3.5E-08	9.0E-07

1. Marketable gas is considered to be gas that is saleable for consumption.
2. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).

Table 1-3 Technology based default CH_4 and N_2O emission factors for natural gas

Natural Gas	CH_4 Emission Factor		N_2O Emission Factor		Reference[1]
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ	
Boilers/Furnaces/Heaters:					
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07	AP-42 Table 1.4-2
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07	AP-42 Table 1.4-2
Internal Combustion Engine[3]:					
Turbine	1.4E-07	3.7E-06	4.9E-08	1.3E-06	AP-42 Table 3.1-2a
2 stroke lean	2.37E-05	6.23E-04			AP-42 Table 3.2-1
NOx 90-105% Load	-	-	7.77E-07	2.04E-05	AP-42 Table 3.2-1
NOx < 90% Load	-	-	4.75E-07	1.25E-05	AP-42 Table 3.2-1

Natural Gas	CH_4 Emission Factor		N_2O Emission Factor		Reference[1]
	tonne/m^3	tonne/GJ	tonne/m^3	tonne/GJ	
4 stroke lean	2.04E-05	5.37E-04			AP-42 Table 3.2-2
NOx 90-105% Load	-	-	1.00E-06	2.63E-05	AP-42 Table 3.2-2
NOx < 90% Load	-	-	2.07E-07	5.46E-06	AP-42 Table 3.2-2
4 stroke rich	3.76E-06	9.89E-05			AP-42 Table 3.2-3
NOx 90-105% Load	-	-	5.41E-07	1.43E-05	AP-42 Table 3.2-3
NOx < 90% Load	-	-	5.56E-07	1.46E-05	AP-42 Table 3.2-3

1. For emission factors adapted from USEPA AP-42, the default emission factor is based on a natural gas heating value of 1,020 British thermal units per standard cubic feet (Btu/scf).

Table 1-4 Default CH_4 and N_2O emission factors by fuel type

Liquid Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Kerosene				
Electric Utilities	6.0E-06	2.0E-07	3.1E-05	8.3E-07
Industrial	6.0E-06	2.0E-07	3.1E-05	8.3E-07
Producer Consumption[1]	6.0E-06	1.6E-07	3.1E-05	8.2E-07
Forestry, Construction and Commercial/Institution	2.6E-05	7.0E-07	3.1E-05	8.3E-07
Light Fuel Oil				
Electric Utilities[1]	1.8E-04	4.6E-06	3.1E-05	7.99E-07
Industrial	6.0E-06	2.0E-07	3.1E-05	8.0E-07
Producer Consumption[1]	6.0E-06	1.6E-07	3.1E-05	7.99E-07
Forestry, Construction and Commercial /Institution	2.6E-05	6.7E-07	3.1E-05	8.0E-07

Liquid Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Heavy Fuel Oil				
Electric Utilities	3.4E-05	8.0E-07	6.4E-05	1.5E-06
Industrial	1.2E-04	2.8E-06	6.4E-05	1.5E-06
Producer Consumption[2]	1.2E-04	2.8E-06	6.4E-05	1.506E-06
Forestry, Construction and Commercial /Institution	5.7E-05	1.30E-06	6.4E-05	1.5E-06

Solid Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/m^3	tonne/GJ	tonne/m^3	tonne/GJ
Petroleum Coke - Refinery Use	1.2E-04	2.6E-06	2.8E-05	5.9E-07
Petroleum Coke - Upgrader Use	1.2E-04	3.0E-06	2.4E-05	5.9E-07
Coal				
Electric Utilities				
Anthracite	2.0E-05	8.0E-07	3.0E-05	1.0E-06
Canadian Bituminous	2.0E-05	8.0E-07	3.0E-05	1.0E-06
Foreign Bituminous	2.0E-05	7.0E-07	3.0E-05	1.0E-06
Lignite	2.0E-05	1.0E-06	3.0E-05	2.0E-06
Sub-bituminous	2.0E-05	1.0E-06	3.0E-05	2.0E-06
Industry and Heat and Steam Plants				
Anthracite	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Canadian Bituminous	3.0E-05	1.0E-06	2.0E-05	7.0E-07
Foreign Bituminous	3.0E-05	1.0E-06	2.0E-05	7.0E-07

Solid Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ
Lignite	3.0E-05	2.0E-06	2.0E-05	1.0E-06
Sub-bituminous	3.0E-05	2.0E-06	2.0E-05	1.0E-06
Residential, Public Administration				
Anthracite	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Canadian Bituminous	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Foreign Bituminous	4.0E-03	1.0E-04	2.0E-05	7.0E-07
Lignite	4.0E-03	2.0E-04	2.0E-05	1.0E-06
Sub-bituminous	4.0E-03	2.0E-04	2.0E-05	1.0E-06
Coke	3.0E-05	1.0E-06	2.0E-05	7.0E-07

Biomass Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Wood Waste	9.0E-05	5.0E-06	6.0E-05	3.0E-06
Spent Pulping Liquor	2.0E-05	1.0E-06	2.0E-05	3.0E-06
Peat[2]	NA	1.0E-06	NA	1.5E-06

Gaseous Fuels[1]	CH_4 Emission Factor		N_2O Emission Factor	
	tonne/m³	tonne/GJ	tonne/m³	tonne/GJ
Coke Oven Gas	4.0E-08	2.0E-06	4.0E-08	2.0E-06
Still Gas[3,4]	3.1E-08	9.1E-07	2.0E-08	6.0E-07

1. Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (Reference [3] in Appendix A).
2. WCI Table 20-2 or 20-7.
3. Adapted from IPCC (2006) and CIEEDAC (2014).
4. SGA (2000).

4.0 Quantification of Venting Emissions

Venting emissions are from intentional or controlled releases to the atmosphere of a waste gas or liquid stream that contains greenhouse gases (GHGs). Venting emissions are releases by design or operational practice. Routine venting occurs either continuously or intermittently as part of normal operations. Non-routine venting results in intermittent and infrequent emissions and can be planned or unplanned under abnormal operation.

Methane (CH_4) is the predominant specified gas contained in venting emissions but carbon dioxide (CO_2) can also be present in some venting emissions. Nitrous oxide (N_2O) is not typically vented unless a vented process stream contains this substance.

Venting emissions normally exist as part of upstream oil and gas (UOG) production, processing, petroleum refining, oil sands and coal mining and upgrading industries in any facility that uses natural gas (which typically is greater than 90 mol% methane) or process materials containing CH_4 or CO_2. In Alberta, venting occurs predominantly in the UOG facilities. Venting emissions also occur in chemical, coal mining, petrochemical, pipelines and fertilizer industries.

Venting emissions can be collected through vent gas capture systems, and then directed to emissions control systems. The following emissions controls are generally used by industry:

- Gas Conservation – where gas is captured and sold, used as fuel, injected into reservoirs for pressure maintenance or other beneficial purpose.
- Flare Systems – where gas is captured and combusted by thermal oxidization in a flare or incinerator.
- Scrubber Systems – where gas is captured and specific substances of concern (e.g. H_2S) are removed via adsorption or catalytic technologies.

If the vent gases are captured and directed to a fuel system or directed to a stationary fuel combustion unit and/or flare stack, the emissions from these gases should be calculated under stationary fuel combustion or flaring source categories. Destruction efficiencies of flaring are considered under the flaring source categories, and are not to be reflected in the venting CF.

This chapter provides quantification methodologies for venting emissions from potential venting sources in UOG, petroleum refining, petrochemical, fertilizer industries and other industries in Alberta, which may have similar venting sources. Carbon dioxide emissions from industrial process should be quantified according to the methodologies prescribed in the Chapter 8 for industrial process (IP) emissions. Venting emissions due to biological reactions from waste management or wastewater treatment facilities are classified as waste and wastewater emissions. The methodologies for these emissions are prescribed in Chapter 6 for waste and digestion emissions and Chapter 7 for wastewater emissions.

In this chapter, there may be one or more methodologies prescribed for a process that are not tiered and therefore, are considered to be acceptable for use by a facility under any tier classification. As well, facilities are permitted to use a higher tiered method to quantify the facility's emissions where appropriate. In addition, the chapter distinguishes venting emission sources into routine and non-routine for emission quantifications purpose. However, CCIR and SGRR do not require to report routine and non-routine venting emissions separately. Facilities should aggregate total venting emissions for reporting.

For all sources discussed in this chapter, CO_2 that is entrained in produced oil and gas are considered to be formation CO_2. Methodologies in this chapter are given for CH_4 and CO_2, but CO_2 will be reported as formation CO_2 if it meets the definition of formation CO_2. Imported CO_2 and CO_2 from IP are not considered to be formation CO_2. For facilities reporting under CCIR, formation CO_2 emissions must be reported in a separate category; while facilities reporting under SGRR must report venting and formation CO_2 emissions under the venting category.

4.1 General Calculation

4.1.1 Control Factor (CF)

(1) Introduction

When a vent gas capture system is installed, venting emissions may still occur if the capture equipment is not operating or functioning properly due to maintenance or periodic, planned, or unplanned shutdowns, or emissions are not fully captured when the capture system is operating due to capture system inefficiency. A control factor (CF) is introduced in this chapter to reflect the efficiency of any venting capture system operation.

The CF should account for two factors that affect the final venting capture efficiency: collection efficiency of the capture system and any downtime of the capture system. Therefore, CF should be calculated by multiplying the capture system operation percentage of hours when the venting sources are emitting in the report period by collection efficiency (percentage of GHGs that are collected through the capture system), but should not reflect the destruction efficiency of a flare, which is relevant to the flaring source category.

For instance, a control equipment is running 95% of the time when a venting source is emitting and the capture efficiency is 98%, the CF = 95% (running time) * 98% (capture efficiency) = 93.1%. A facility may conduct an engineering assessment to determine the capture efficiency. In cases where the system is fully enclosed, the facility may determine that the capture efficiency is close to 100%.

(2) Equations

The CF for each emission source in the chapter is calculated using Equation 4-1a and should be applied to all venting sources with a gas capture system.

$$CF = \frac{t_{op}}{t_{total}} \times eff_{capture} \qquad \text{Equation 4-1a}$$

Where:

CF	=	Control factor for venting emission source with a capture system in the report period.
t_{op}	=	Total uptime of capture system when the venting source is emitting (hour) in the report period.
t_{total}	=	Total hours of venting (hour) regardless of whether the capture system is operating or not in the report period.
$eff_{capture}$	=	Efficiency of capture system based on manufacturer data or engineering design or assessment.

(3) Data requirements

- Total operating hours of the capture system and total hours of the venting hours of the venting source must be recorded.
- Facilities are required to use manufacturer or design data and/or conduct an engineering assessment to determine the efficiency of the capture system. This may be conducted once for a capture system. If a new capture system is installed or there are changes to an existing capture system, facilities are required to re-evaluate the capture efficiency.
- Documents from manufacturer or engineering design and assessment must be available for inspection or verification, if requested.

4.1.2 General Calculation-Periodic or Continuous Measurement

(1) Introduction

Vent gas streams may be required to be measured or tested through AER Directive 017 or Directive 060 for UOG facilities or other applicable regulations for non-UOG facilities. Continuous direct measurement or periodic testing of individual emission sources is encouraged where possible and where these solutions would result in more accurate reporting of emissions than the methods discussed. The following method is classified as a tier 4 methodology and applies to all venting sources if a tier 4 methodology is not specifically prescribed for a venting source.

(2) Equations

Where periodic or continuous volumetric vent rate or volume is measured for vent streams, calculate GHG emissions using Equation 4-1b.

$$\boldsymbol{GHG} = \sum_{\boldsymbol{i=1}}^{\boldsymbol{n}} \boldsymbol{VR}_{\boldsymbol{v}} \times \boldsymbol{t} \times \boldsymbol{MF}_{\boldsymbol{GHG}} \times \boldsymbol{\rho}_{\boldsymbol{GHG}} \times \mathbf{0.001} \qquad \text{Equation 4-1b}$$

Where:

GHG = CH_4 or CO_2 mass emissions from a venting source (tonnes) or vent gas recovery system outlet venting to atmosphere in the report period.

i = Vent source or vent gas recovery system outlet.

N = Total number of vents or vent gas recovery system outlets venting to the atmosphere in the report period. It is possible a number of vents are connected to one outlet where the measured vent rate may represent the total emissions from multiple vents.

VR_v = Average volumetric vent rate at the vent or outlet of the recovery system (Sm^3/h). If the source or the gas recovery system is equipped with a continuous meter, use the metered volume (Q, Sm^3) in the report period to replace VR*t. If a continuous vent meter is not available, periodic vent rate measurement should measure the representative average vent rate for the report period.

t = Venting time if the measurement is conducted at the vent source or operating time of the recovery system if the measurement is conducted at the outlet of the recovery system during the report period (hours).

MF_{GHG} = Mole fraction of CO_2 or CH_4. Measured at the location where the vent rate is measured; or if the vent rate measurement location has potential safety issue for gas composition sampling, sample at a location where the gas composition is the most representative of the vent gas composition.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions ($\rho CO_2 = 1.861$ kg/sm^3; $\rho CH_4 = 0.6785$ kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

Where periodic or continuous mass vent rate or mass is measured for vent streams, calculate GHG emissions using Equation 4-1c.

$$\boldsymbol{GHG = \sum_{i=1}^{n} VR_{mass,j} \times t \times F_{GHG/mass,j} \times 0.001} \qquad \text{Equation 4-1c}$$

Where:

GHG = CH_4 or CO_2 mass emissions from a venting source (tonnes) in the report period.

i = Vent source or vent gas recovery system outlet.

n = Total number of vents or vent gas recovery system outlets venting to the atmosphere in the report period. It is possible a number of vents are connected to one outlet where the measured vent rate may represent the total emissions from multiple vents.

$VR_{mass,j}$ = Average vent rate at the vent or outlet of the recovery system (kg/h) expressed in mass j. If the source or the gas recovery system is equipped with a continuous meter, use the metered mass (kg) in the report period to replace $VR_{mass,j}$*t. If a continuous vent meter is not available, periodic vent rate measurement should measure the representative average vent rate for the report period.

j = Type of compound that is metered, such as total hydrocarbons (THCs), total volatile organic compounds (VOCs), etc.

t = Venting time if the measurement is conducted at the vent source or operating time of the recovery system if the measurement is conducted at the outlet of the recovery system during the report period (hours).

$F_{GHG/mass,j}$ = Mass fraction of CO_2 or CH_4 to the mass j measured by the meter. Measured at the location where the vent rate is measured.

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

- Periodic vent rate measurement at the outlet of the vent source or at the outlet of the vapor recovery system if appropriate should be conducted under normal process operation. If the measurement frequency is not prescribed for a particular source (as outlined throughout this chapter), quarterly measurements are required at minimum for a facility operating continuously in a year. If the facility does not operate for an entire quarter, the facility is not required to sample in that quarter.

- Facilities should follow meter installation, calibrations, vent rate measurement and vapor composition sampling frequencies required by AER Directives. Non-UOG facilities may use other applicable regulatory requirements or industry best practices for these parameters.

- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

- If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used.

- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Gas compositions must be measured using:
    - An applicable analytical method prescribed by AER Directives for UOG facilities;
    - An analytical method prescribed in Section 17.2.3 of Chapter 17.

4.2 Routine Venting–Produced Gas at UOG Facilities

4.2.1 Introduction

Natural gas produced in conjunction with crude oil or bitumen is referred to as produced gas. Produced gas may be gas dissolved in the oil that ‘flashes’ out upon depressurization or may be a free ‘gas cap’ that was above the oil in the reservoir. Flashing losses are the dominant contributor to produced gas volumes and occur at oil production sites where unstable hydrocarbon liquids (i.e. products that have a vapor pressure greater than the local barometric pressure) are produced into lower pressure vessels (separator) or atmospheric storage tanks. These types of emissions occur at UOG facilities.

Ideally, produced gas is conserved with gathering pipelines or utilized as combustion fuel. However, stranded gas is often flared or vented. If the produced gas is conserved and used as fuel at the site, the emissions should be calculated according to Chapter 1 Stationary Fuel Combustion. If the produced gas is captured and flared, the emissions should be calculated according to Chapter 2 Flaring.

4.2.2 Tier 1-Rule-of-Thumb Method

(1) Introduction

The produced gas volume relates to the hydrocarbon liquid production volume and the Gas in Solution (GIS). The emissions calculated by the following method are based on the rule of thumb GIS estimation in AER Directive 017. This approach is applicable for light-medium oil production. The CO_2 emissions calculated using the equations below are considered to be formation CO_2.

(2) Equations

Calculate GHG emissions using Equation 4-2a.

$$\boldsymbol{GHG = Q_{oil} \times GIS \times \rho_{GHG} \times MF_{GHG/Gas} \times 0.001 \times (1 - CF)} \qquad \text{Equation 4-2a}$$

Where:

GHG = CH_4 or CO_2 mass emissions from produced gas venting (tonnes) in the report period.

Q_{oil} = Total volume of oil produced for the report period, (m^3 oil).

GIS	=	A rule-of-thumb value calculated using Equation 4-2b, which represents the amount of gas dissolved in a volume of hydrocarbon liquid produced (of all API gravities), and is correlated to the amount of pressure drop between the reservoir and the current vessel.
$MF_{GHG/Gas}$	=	Mole fraction of CO_2 or CH_4 in vented gas.
CF	=	Venting control factor (dimensionless). This accounts for collection efficiency of the capture system as well as any downtime of the capture system, calculated using Equation 4-1a. CF is zero if no capture system is installed.
ρ_{GHG}	=	Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3).
0.001	=	Mass conversion factor (tonne/kg).

$$\boldsymbol{GIS = 0.0257 \times \Delta P} \qquad \text{Equation 4-2b}$$

Where:

ΔP	=	Pressure drop between the well reservoir and the vessel (kPa) at well site.
0.0257	=	GIS coefficient (sm^3 gas/sm^3 oil/kPa of pressure drop).

(3) Data requirements

- For this method, facilities are required to follow AER Directive 017 for conventional light-medium oil production measurement and reporting requirements.
- The control technology and operating time in the report period must be documented.

4.2.3 Tiers 2, 3, and 4-AER Directive 017 Measurements and Estimation Methods

(1) Introduction

Produced gas from a well must be determined based on the requirements of AER Directive 017. This may include continuous direct metering or periodic measurement. The GIS should be representative of vented gas volume and production volume during normal process operations. Facilities are expected to select the most representative methodology from Directive 017 to quantify vented emissions.

In cases where all produced gas is vented, the vent gas volume is equal to the produced gas volume.

(2) Equations

Equation 4-2a is used with a measured GIS value, which should be determined according to AER Directive 017.

(3) Data requirements

- The GIS must be determined by applicable tests, procedures and requirements for the equipment outlined in AER Directive 017 for the specific process scenario (i.e. single well battery, multiwell oil proration battery, etc.)
- GIS measurement method and frequency must follow Section 12.2.2 and Table 12.1 in Directive 017 for crude bitumen facilities.
- Oil production must be the oil-produced volume in the corresponding duration when the gas volume is tested.
- Facilities are required to follow AER Directive 017 to calculate production quantities.
- An extended hydrocarbon analysis of the flash gas from the GIS sample may be conducted if the gas composition is changing.

4.3 Routine Venting-Continuous Gas Analyzer Purge

4.3.1 Tiers 1, 2 and 3-Default Vent Rate

(1) Introduction

An online gas analyzer normally draws a continuous stream of sample. It uses some fraction of this stream and then vents both the unused and spent portions to the atmosphere. Depending on the type of analyzer, the used portion of sample may be released unchanged or as a product of combustion. The amount of emissions depends on the sampling rate and the characteristics of the analyzer. The emissions quantification method provided is applicable to tiers 1, 2, and 3.

(2) Equations

Calculate GHG emissions using Equation 4-3.

$$GHG = \sum_{j}^{m} \sum_{i}^{n} Q_{v} \times MF_{GHG} \times \rho_{GHG} \times 0.001 \qquad \text{Equation 4-3}$$

Where:

GHG = CH_4 or CO_2 mass emissions from gas analyzer (tonnes) in the report period.

i = Analyzer identifier.

j = Month identifier.

n = Total number of analyzers used in a month.

m = Total months in the report period.

Q_v = Vented gas volume per analyzer per month (sm^3/analyzer/month) at the standard condition during the report period.

MF_{GHG} = Mole fraction of CO_2 or CH_4 in the vented gas. Using the average gas analysis per analyzer for the report period.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

- The vent rate from the analyzer may be based on manufacturer data or an engineering estimate. If an average vent rate for upstream oil and gas installations is not available, 69.8 m^3 of natural gas/month/analyzer could be used for each analyzer on a natural gas transmission pipeline.
- The facility is required to apply the gas analysis measured by the gas analyzer itself.
- If multiple analysis is done in a month, use an average of the gas compositions.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.

4.4 Routine Venting-Solid Desiccant Dehydrators

4.4.1 Tiers 1, 2 and 3-Physical Volume Depression

(1) Introduction

Desiccant dehydrators are filled with solid desiccants, which absorb water from a gas stream. Solid desiccants employed in the upstream oil & gas industry include silica gel, activated alumina and molecular sieves. Desiccant dehydrators typically feature at least two vessels that operate in a cyclic manner alternating between drying and regeneration. There are various ways to regenerate a dryer, including recycling a portion of the product stream, or some other gas stream. In some cases, a heated gas stream passes through the desiccant to desorb water and is typically recycled back to the wet gas flow so zero venting occurs during normal operation. However, gas can be vented each time the vessel is depressurized for desiccant refilling. The following equation reflects the emissions from the desiccant dehydrator depressurization emissions.

(2) Equations

For each desiccant dehydrator venting event, calculate CH_4 or CO_2 emissions separately and then add the emissions in the report period based on total events using the following equation. The CO_2 emissions calculated using the equations below are considered to be formation CO_2.

The equation is also applicable to any vessel that is depressurized and emptied, either regularly or during shutdowns, for cleaning and maintenance.

$$\boldsymbol{GHG = \sum_{j}^{m}\sum_{i}^{n}\left[\frac{V_{vessel,i} \times P_{\,vessel,i,j} \times T_{a} \times G_{i.j}}{T_{vessel,i,j} \times P_{\,a}} \times MF_{\,GHG/gas,i,j}\right] \times (1 - CF) \times \rho_{\,GHG} \times 0.001} \qquad \text{Equation 4-4}$$

Where:

GHG = CH_4 or CO_2 mass emissions from desiccant dryer venting (tonnes) in the report period.

i = Solid desiccant dehydrator identifier.

j = Venting event identifier.

n = Number of dehydrators having venting events in the report period.

m = Number of venting events in the report period.

$V_{vessel,i}$ = Volume for vessel i, obtained through design or nameplate information, or from engineering estimates.

0.001 = Mass conversion factor (tonne/kg).

$P_{vessel,i,j}$ = Absolute pressure at actual conditions in the equipment system i prior to depressurization (kPaa) at the venting event j.

P_a = Absolute atmospheric pressure (kPaa).

$T_{vessel,i,j}$ = Temperature at actual conditions in the equipment system i prior to depressurization (K) at the venting event j.

T_a = Atmospheric temperature (K).

$G_{,i,j}$ = Fraction of the vessel i that is filled with gas (%, dimensionless) at the venting event j.

$MF_{GHG/Gas,i,j}$ = Mole fraction of CO_2 or CH_4 from the vessel i in vented gas from the event j.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρCO_2 = 1.861 kg/sm^3; ρCH_4 = 0.6785 kg/sm3).

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

- The facility should apply the gas compositions from desiccant dehydrators. If unavailable, the facility may apply typical gas analysis downstream or upstream of the dehydrators that is representative of the vent gas from desiccant dehydrators.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- The facility is required to measure the vessel pressure prior to depressurization and convert to absolute pressure.
- The facility may use the absolute atmospheric pressure (kPaa) at the location of the facility or 101.325 kPaa.

4.5 Routine Venting-Pigging and Purges

4.5.1 Tiers 1, 2 and 3-Physical Volume Depression

(1) Introduction

Pigging operations in the UOG facilities are a routine practice to maintain and ensure proper flow in pipelines. Typical steps in the pigging process are:

- Depressurization (e.g. venting) of the pig launch trap;
- Insertion of the pig into the launch trap;
- Re-pressurization and depressurization of the purge gas. This process may or may not be conducted as part of the pigging operation. If conducted, it may be repeated several times depending on level of service required;
- Re-pressurization of the pipeline to launch the pig;

- Depressurization of (e.g. venting) the receiver trap;
- Removal of the pig from the receiver trap;
- Re-pressurization of the pipeline after removal of pig; and
- Return to normal operation.

(2) Equations

Emissions generated from the pigging operation are from depressurization at the launch and receiver traps and re-pressurization and depressurization of the purge gas, which may not be applicable for smaller operations or may be repeated several times depending on operational needs. It is assumed that the entire volume of the purge gas is vented, unless the purged gas is captured or flared. Calculate the venting emissions based on the number of depressurization and purge events using Equation 4-5a. Equation 4-5a is applicable to isothermal expansion of ideal gas only.

The equation is also applicable to any blow-down and purge equipment undergoing isothermal expansion under ideal gas condition.

$$GHG = \sum_{i=1}^{N} \left[V_{\,v,i} \times \frac{(288.15)\left(P_{\,a,1,i} - P_{a,2,i}\right)}{\left(273.15 + T_{\,a,i}\right) P_s} \times MF_{GHG,i} \right]_i \times \rho_{\,GHG} \times 0.001 \qquad \text{Equation 4-5a}$$

Where:

GHG = CH_4 or CO_2 mass emissions from depressurization and purging events (tonnes) in the report period.

i = Vent event identifier.

N = Number of depressurization or purging events in the report period.

$V_{v,i}$ = Total physical volume of equipment chambers between isolation valves being depressurized. Volume is calculated through measured physical dimensions or engineering estimates using dimensions of components in the process system.

288.15 = Temperature at the standard condition (equivalent to 15 ºC).

$T_{a,i}$ = Initial temperature of gas at actual conditions in the equipment system prior to depressurization or purge (ºC).

P_s = Absolute atmospheric pressure at standard conditions (101.325 kPa).

$P_{a,1,i}$ = Absolute pressure at actual conditions in the equipment system prior to depressurization or purge (kPaa).

$P_{a,2,i}$ = Absolute pressure at actual conditions in the equipment system after depressurization or purge (kpaa). This pressure may be assumed to be the same as the absolute atmospheric pressure (P_s) if this measurement is not taken .

$MF_{GHG,i}$ = Mole fraction of CO_2 or CH_4 in the vented gas at the depressurization or purging event i.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

For non-ideal gas scenarios, Equation 4-5b may be used. Equation 4-5b assumes an initial period when the equipment is isolated and depressurized with no flow into the equipment, followed by a period of purge gas flow through the equipment where the entire volume of the purge gas is vented to atmosphere. Equation 4-5b can also be used if the equipment is not purged with gas prior to repressurization by setting the $\dot{m}_{\mathrm{Purge}}$ or t_{purge} term equal to zero. If the assumptions for Equation 4-5b are not valid, engineering estimates may be used to quantify greenhouse gas emissions from pigging and purge operations.

$$\boldsymbol{GHG = \sum_{i=0}^{n}\left[\left(V_{v} \times \left(\rho_{a,1} - \rho_{a,2}\right) \times F_{GHG/vapor}\right) + \left(\dot{m}_{Purge} \times t_{purge} \times F_{GHG/Purge}\right)\right] \times 0.001} \qquad \text{Equation 4-5b}$$

Where:

GHG = CH_4 or CO_2 mass emissions from pigging and purges (tonnes) in the report period.

i = Vent event identifier.

n = Total number of events in the report period.

$\rho_{a,1}$ = Density of gas in equipment chamber at actual conditions prior to depressurization, as estimated using real gas properties or by suitable equation of state, kg/m^3.

$\rho_{a,2}$ = Density of gas in pigging equipment chamber after depressurization, as estimated using real gas properties or by suitable equation of state, kg/m^3. If the equipment is purged following depressurization, $\boldsymbol{\rho}_{\boldsymbol{a},\mathbf{2}} = 0$.

V_v = Total physical volume of pigging equipment between isolation valves being depressurized. Volume is calculated through measured physical dimensions or engineering estimates using dimensions of components (m^3).

$\dot{m}_{\mathrm{Purge}}$ = Mass flow rate of gas used to purge equipment (kg/s).

t_{purge} = Duration of equipment purge event(s).

$F_{GHG/Vapor}$ = Mass fraction of CH_4 or CO_2 components in vapor during depressurization.

$F_{GHG/purge}$ = Mass fraction of CH_4 or CO_2 components in purge during depressurization.

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

- Actual pressure and temperature before and after each depressurization and purging event should be metered and documented.
- When the purge gas contains greenhouse gas components, the duration and mass flow rate of purge gas used for each purging event should be estimated and documented.
- Facilities are required to use the gas composition in the period closest to when the pigging operation occurred.
- Gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

4.6 Routine Venting-Atmospheric Liquid Storage Tank

4.6.1 Introduction

GHG emissions can occur from atmospheric pressure fixed-roof and floating-roof storage tanks receiving hydrocarbon liquids. Floating roof tanks control vapor spaces by lowering and lifting the tank roof to reduce the vapor accumulation on top of the storage liquid. These tanks are common in various types of facilities that process or store hydrocarbons.

There are typically three types of activities that release emissions from storage tanks:

- Evaporative losses from the storage of hydrocarbons are known as breathing (or standing) losses and are caused by changes in daily temperature or barometric pressure.
- Evaporative losses during tank filling and emptying operations are known as working losses and are caused by the displacement of tank vapors during liquid level changes.
- Flashing losses when pressurized hydrocarbon liquids are delivered from higher-pressure separators to lower-pressure storage tanks.

The main areas where tank flashing losses occur are at:

- Wellhead sites when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Tank batteries when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Compressors stations when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Gas plants when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel; and/or
- When the liquids in the gas lines are “pigged” (physically purged of condensate) and then sent to an atmospheric storage vessel.
- The tank venting is from the vapor space at the top of the tank, which includes mostly volatile hydrocarbons.

These methodologies are not intended for the following types of equipment:

- Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
- Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- Bottoms receivers or sumps;
- Vessels storing wastewater;
- Reactor vessels associated with a manufacturing process unit.

Emissions from these types of equipment are addressed in other chapters of this document.

Quantification methodologies are prescribed in this section to cover petroleum liquids, pure volatile organic liquids, and other types of chemical mixtures. However, not all methods are applicable for all types of liquids. The reporter is required to select the most appropriate method based on the type of tank system and tank contents.

The total venting emissions from tanks should be the sum of all three types of emissions including flashing, breathing, and working losses for the reporting period. Table 4-1 assigns the methodologies to be used based on the applicable tier classifications. A reporter may choose to calculate tank emissions separately for flashing, breathing, and working losses and then aggregate these emissions (Approach 1) or calculate the total emissions (Approach 2).

Figure 4-1 Tier Classification and Methodology Mapping

Tank Total Emissions	Category of Tank Emission	Tier Classification			
		Tier 1	Tier 2	Tier 3	Tier 4
Approach 1	Tank breathing and working losses	Use engineering estimates for facilities other than refineries.	Method 2		Method 7
	Tank flashing losses		Method 3 or 4	Method 5	
Approach 2	Tank total emissions	Method 1 for refineries. Use engineering estimates for facilities other than refineries.	Method 6		

4.6.2 Method 1: Generic Vent Rate

(1) Introduction

The following provides quantification methodologies for CH_4 emissions only from atmospheric pressure storage tanks using a generic vent rate. The equations for Method 1 are only applicable for refineries. Facilities other than refineries cannot use Method 1. Instead, these facilities should quantify CH_4 emissions from tanks using process knowledge and/or engineering estimates.

(2) Equations

For storage tanks other than those that process unstabilized crude oil at refinery facilities including stabilized and intermediate crude oil, calculate total tank CH_4 emissions using Equation 4-6a. Stabilized crude oil is considered to be crude petroleum that has lost an appreciable quantity of its more volatile components due to evaporation and other natural causes during storage and handling.

$$CH_4 = 6.29 \times 10^{-7} \times Q \qquad \text{Equation 4-6a}$$

Where:

CH_4 = Methane emissions from storage tank (tonnes) in the report period.

6.29×10^{-7} = Default emission factor for storage tanks (tonnes CH_4/m^3).

Q = Total quantity of stabilized crude oil and intermediate products received from off site that are processed at the facility in the report period (m^3).

For storage tanks that process unstabilized crude oil at refinery facilities, calculate CH_4 emissions using Equation 4-6b. Unstabilized crude oil means crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

$$CH_4 = \sum_{i}^{n} 0.025703 \times Q_{\ throughput,i} \times \Delta P \times MF_{CH4,i} \times \frac{16.0425}{23.645} \times 0.001 \qquad \text{Equation 4-6b}$$

Where:

CH_4 = Methane emissions from storage tank (tonnes) in the report period.

i = Tank identifier.

n = Number of tanks in the report period.

0.025703 = Correlation equation factor (m^3 gas per m^3 oil per kpaa).

$Q_{throughput,i}$ = Total throughputs of un-stabilized crude oil in the tank i in the report period (m^3).

ΔP = Pressure difference from the previous storage pressure to atmospheric pressure (kpaa).

$MF_{CH4,i}$ = Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4/kg-mole gas); use 0.27 as a default for refineries if measured data are not available.

16 = Molecular weight of methane (kg/kmol).

22.4 = Molar volume conversion factor (m^3/kmol).

0.001 = Conversion factor (tonne/kg).

(3) Data requirements

- Actual pressure at the upstream storage should be metered and documented.
- Facilities are required to use the metered product throughputs if a meter is installed for each storage tank; if metering is not available, facilities may use the throughputs used for accounting purposes.
- Facilities may use the atmospheric pressure at the location of the facility or 101.325 kilopascals for Equation 4-6b.

4.6.3 Method 2: Breathing Loss and Working Loss Using US EPA AP-42 Method

(1) Introduction

US EPA Section 7.1 of AP-42: Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources can be used to calculate GHG emissions from breathing and working losses.

US EPA Section 7.1 of AP-42 applies empirical correlations and fundamental engineering principles to develop emission estimates based on the specific tank physical parameters, operating conditions, geographical location, and weather.

(2) Equations

For breathing and working losses using the US EPA AP-42 methodology, GHG emissions are calculated using Equation 4-7a based on the total VOC emissions using US EPA AP-42 methodology and the mass faction of the specific GHG in the tank vapor.

The CO_2 emissions calculated by Equation 4-7a are considered to be formation CO_2 and should be reported under that category.

$$GHG = \sum_{j=1}^{J}\sum_{i=1}^{I}\left[Mass_{VOC,i,j} \times \left(1 - CF_{i,j}\right) \times F_{GHG/VOC,i,j}\right] \qquad \text{Equation 4-7a}$$

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from storage tank in the report period.

i = Tank identifier.

I = Number of tanks holding products in the report period.

j = Type of product.

J = Number of products in the report period.

$Mass_{VOC,i,j}$ = Total VOC mass emissions calculated using US EPA AP-42 methodology from product j throughputs in tank i in the report period.

CF = Control factor (dimensionless fraction).

$F_{GHG/VOC,i,j}$ = Mass fraction of CH_4 or CO_2 in the vented VOCs for product j in tank i.

(3) Data requirements

- For the mass fraction, the facility may use a measured value, engineering estimate, or default compositions presented in Tables 3-2a to 3-2e in Chapter 3 Fugitives. Tables 3-2a to 3-2e from Chapter 3 have been temporarily provided in this chapter for reference.

Table 3-2a Speciation Profiles (on a moisture-free basis) for Dry and Sweet Gas Production and Processing Facilities.

	Dry Gas						Sweet Gas							
	Gas		Light Liquid		Dehy Off Gas		Gas		Tank Vapors		Light Liquid		Dehy Off Gas	
Component	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	1.7099	2.9153	0.01	0.0050	6.0450	9.3101	0.6793	1.0865	2.9668	2.9436	0.01	0.0050	3.0220	3.5883
CO_2	0.2646	0.7088	0.05	0.0394	3.6656	8.8694	0.5814	1.4610	1.3436	2.0944	0.05	0.0394	6.3865	11.914
H_2S	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C_1	97.291	94.998	0.59	0.1695	87.460	77.143	91.880	84.163	56.421	32.060	0.59	0.1695	68.9410	46.881
C_2	0.7009	1.2828	31.52	16.975	2.8296	4.6780	5.4263	9.3166	15.222	16.212	31.52	16.975	11.4083	14.541
C_3	0.0295	0.0792	21.61	17.067	0	0	1.0490	2.6412	11.630	18.165	21.61	17.067	3.7118	6.9379
i-C_4	0.0012	0.0041	9.60	9.9936	0	0	0.1291	0.4284	2.6504	5.4564	9.60	9.9936	3.2751	8.0689
n-C_4	0.0020	0.0069	10.06	10.473	0	0	0.1949	0.6468	5.5796	11.487	10.06	10.473	3.2751	80.689
i-C_5	0.0006	0.0026	0.83	1.0725	0	0	0.0254	0.1046	1.2562	3.2103	0.83	1.0725	0	0
n-C_5	0.0005	0.0020	0.99	1.2793	0	0	0.0296	0.1219	1.5784	4.0336	0.99	1.2793	0	0
C_6	0.0001	0.0003	5.87	9.0601	0	0	0.0060	0.0295	0.9312	2.8424	5.87	9.0601	0	0
C_{7+}	0.0001	0.0003	18.87	33.866	0	0	0	0	0.4215	1.4960	18.87	33.866	0	0
Mole Wt	16.430	16.430	55.835	55.835	18.189	18.189	17.514	17.514	28.233	28.233	55.835	55.835	23.5920	23.592

1. This table is adapted from Table 24 from Volume 3, Methodology for Greenhouse Gases, CAPP, 2005.

Table 3-2b Speciation Profiles (on a moisture-free basis) for Sour Gas Production and Processing Facilities and for Natural Gas Transmission Facilities.

	Sour Gas				Natural Gas			
	Gas		Tank Vapors		Light Liquid		Gas	
Component	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.6552	1.0140	2.9668	2.9436	0.01	0.0050	0.7791	1.2500
CO_2	0.5608	1.3635	1.3436	2.0944	0.05	0.0394	0.6160	1.5527
H_2S	3.5460	6.6755	0.0000	0.0000	0.00	0.0000	0.0000	0.0000
C_1	88.6210	78.5447	56.4205	32.0598	0.59	0.1695	92.5394	85.0226
C_2	5.2339	8.6947	15.2219	16.2121	31.52	16.9753	4.5125	7.7709
C_3	1.0118	2.4649	11.6300	18.1646	21.61	17.0671	1.0904	2.7538
i-C_4	0.1245	0.3998	2.6504	5.4564	9.60	9.9936	0.1498	0.4985
n-C_4	0.1880	0.6037	5.5796	11.4867	10.06	10.4725	0.2103	0.7000
i-C_5	0.0245	0.0977	1.2562	3.2103	0.83	1.0725	0.0415	0.1716
n-C_5	0.0286	0.1140	1.5784	4.0336	0.99	1.2793	0.0358	0.1478
C_6	0.0058	0.0276	0.9312	2.8424	5.87	9.0601	0.0170	0.0839
C_{7+}	0.0000	0.0000	0.4215	1.4960	18.87	33.8656	0.0084	0.0482
Mole Wt	18.1011	18.1011	28.2333	28.2333	55.8345	55.8345	17.4613	17.4613

1. This table is adapted from Table 25 from Volume 3, Methodology for Greenhouse Gases, CAPP, 2005.

Table 3-2c Speciation Profiles (on a moisture-free basis) for Light/Medium Crude Oil and Primary Heavy Crude Oil Production Facilities.

	Light/Medium Crude Oil						Heavy Crude Oil (Primary)					
	Gas		Tank Vapors		Light Liquid		Gas		Tank Vapors		Light Liquid	
Component	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.619	0.7723	13.9989	8.8642	0.1316	0.0464	0.1817	0.303	6.3477	8.9364	0.1046	0.0353
CO_2	5.243	10.2765	0.3303	0.3286	0.324	0.1794	0.0859	0.225	0.6892	1.5243	0.7665	0.4069
H_2S	0	0	0	0	0	0	0.0001	0.0002	0	0	0	0
C_1	73.2524	52.3386	10.01	3.63	9.7419	1.9668	98.0137	93.6026	87.2337	70.3327	7.6718	1.4844
C_2	11.9708	16.0314	15.7274	10.69	3.6464	1.3798	0.9062	1.6221	2.2616	3.4177	2.7538	0.9987
C_3	5.3198	10.4477	24.1601	24.0821	4.9064	2.7227	0.0408	0.1071	0.1905	0.4222	3.8341	2.0392
i-C_4	0.8778	2.2723	6.6404	8.7244	1.9516	1.4275	0.0564	0.1951	0.1324	0.3868	1.8191	1.2752
n-C_4	1.7027	4.4077	16.6022	21.8126	4.043	2.9572	0.0351	0.1214	0.1137	0.3321	3.5935	2.5191
i-C_5	0.357	1.1472	4.2113	6.8682	3.0507	2.7699	0.0501	0.2152	0.14	0.5076	2.4084	2.0958
n-C_5	0.3802	1.2217	4.5447	7.412	3.6626	3.3255	0.0433	0.186	0.123	0.446	2.7543	2.3968
C_6	0.2446	0.9388	2.9655	5.7767	18.1649	19.6995	0.0927	0.4755	0.3949	1.5132	17.975	18.683
C_{7+}	0.0327	0.1459	0.7997	1.8113	50.3769	63.5253	0.494	2.9467	2.4188	12.1808	56.319	68.0654
Molecular Weight	22.4536	22.4536	44.2399	44.2399	79.4647	79.4647	16.799	16.799	19.8981	19.8981	82.7121	82.9121

1. This table is adapted from Table 26 from Volume 3, Methodology for Greenhouse Gases, CAPP, 2005.

Table 3-2d Speciation Profiles (on a moisture-free basis) Light/Medium Crude Oil and Primary Heavy Crude Oil Production Facilities.

	Sour Crude Oil			
	Sour Solution Natural Gas		Sour Light Liquid	
Component	Mole %	Mass %	Mole %	Mass %
N_2	3.2898	4.0741	0.1081	0.0385
CO_2	3.5298	6.8675	0.3733	0.2089
H_2S	3.2898	4.9558	0.8527	0.3695
C_1	71.7705	50.9011	7.4364	1.5172
C_2	9.0895	12.0828	3.8033	1.4544
C_3	5.3197	10.3703	6.0853	3.4126
i-C_4	0.8010	2.0581	1.9617	1.4500
n-C_4	1.6399	4.2138	5.8751	4.3427
i-C_5	0.3920	1.2503	3.5331	3.2418
n-C_5	0.4100	1.3077	4.6140	4.2336
C_6	0.2490	0.9485	19.9173	21.8257
C_{7+}	0.2190	0.9701	45.4395	57.9049
Molecular Weight	22.6218	22.6218	78.5652	78.5652

1. This table is adapted from Table 27 from Volume 3, Methodology for Greenhouse Gases, CAPP, 2005.

Table 3-2e Speciation Profiles (on a moisture-free basis) for Thermal Conventional Heavy Crude Oil and Cold Bitumen Production.

	Thermal Conventional Heavy Crude Oil						Cold Bitumen			
	Gas		Tank Vapors		Light Liquid		Gas		Tank Vapors / Light Liquid	
Component	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %	Mole %	Mass %
N_2	0.1932	0.1767	3.3516	3.0552	0.1044	0.0353	0.6130	0.6343	0.0000	0.0000
CO_2	2.6094	3.7485	16.1140	23.0772	0.7652	0.4066	28.5280	46.3771	22.0000	41.5226
H_2S	0.0150	0.0167	0.1439	0.1596	0.1744	0.0718	0.2490	0.3134	0.0000	0.0000
C_1	72.9361	38.1942	66.6600	34.8000	7.6584	1.4834	63.9410	37.8919	70.0000	48.1609
C_2	1.9370	1.9012	0.9490	0.9286	2.7490	0.9980	1.2070	1.3407	8.0000	10.3165
C_3	3.0956	4.4558	0.5394	0.7740	3.8274	2.0377	0.9160	1.4921	0.0000	0.0000
i-C_4	1.0807	2.0504	0.1922	0.3635	1.8159	1.2743	0.2640	0.5668	0.0000	0.0000
n-C_4	2.3889	4.5323	0.3678	0.6957	3.5872	2.5173	0.9520	2.0440	0.0000	0.0000
i-C_5	1.9994	4.7088	0.4541	1.0662	2.4042	2.0943	1.3020	3.4700	0.0000	0.0000
n-C_5	2.2733	5.3539	0.5829	1.3686	2.7495	2.3951	1.1310	3.0143	0.0000	0.0000
C_6	5.8086	16.3394	2.1914	6.1454	17.9436	18.6696	0.8970	2.8554	0.0000	0.0000
C_{7}+	5.6628	18.5221	8.4539	27.5661	56.2207	68.0166	0.0000	0.0000	0.0000	0.0000
Molecular Weight	30.6359	30.6359	30.7306	30.7306	82.8268	82.8268	27.0719	27.0719	23.3179	23.3179

1. This table is adapted from Table 28 from Volume 3, Methodology or Greenhouse Gases, CAPP, 2005.

4.6.4 Method 3: Flashing Losses Using the Vazquez and Beggs Correlation

(1) Introduction

The Vazquez and Beggs correlation (VBE) is based on a regression of experimentally determined bubble-point pressures for various crude oil systems. Repeated analyses of various production oils have been compiled into useful references for estimating the Gas in Solution (GIS) that will evolve from saturated oils as they undergo pressure drop. The method provides an approach for calculating flashing emissions when products are delivered from a separator to the first connected atmospheric storage tank when limited input data are available. The VBE correlation is only applicable for crude oils.

VBE calculations can also be performed using the GRI-HAPCalc model, which runs in a Windows format developed by the Gas Research Institute (GRI).

(2) Equations

The VBE estimates the dissolved GIS of a hydrocarbon solution as a function of the separator temperature, pressure, gas specific gravity, and liquid API gravity between the separator and the first storage tank. Flashing losses from a storage tank are estimated using the GIS, liquid throughput from the separator to tank, tank vapor molecular weight, and weight fraction of GHG in the vent gas. The flashing loss should be calculated using Equation 4-7b.

The VBE is accurate to within ±10 percent more than 85 percent of the time when the specific gravity of the oil is in the range of values listed below. The VBE method should not be used to estimate emissions if site operating parameters are outside of these ranges. If the parameters do not fall within the ranges, use Method 4 or 5 for flashing emissions or Method 6 for total tank emissions.

Bubble point pressure, kPa	345 to 36,190
Reservoir temperature, ℃	21 to 146
Solution gas-to-oil ratio at bubble point pressure, sm^3/sm^3	3.5 to 369
Oil specific gravity, °API	16 to 58

$$GHG = C_1 \times \gamma_{gs} \times p^{C2} \times exp\left(\frac{C_3}{\gamma_0 T} - \frac{C_4}{T}\right) \times Q \times VTM \times MF_{GHG} \times MW_{GHG} \times (1 - CF) \times 0.001$$ Equation 4-7b

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from storage tank in the report period.

γ_{gs} = Specific gas gravity corrected at 689.4 kpa or 100 psig with respect to air, calculated by Equation 4-7c.

P = Absolute pressure upstream of the vessel of interest (kPaa).

T = Temperature at upstream of the vessel of interest (K).

γ_o = Specific gravity of the liquid hydrocarbon at final condition of the separator with respect to water, calculated by Equation 4-7d (dimensionless).

C_1 = For γ_o<0.876, 3.204 × 10^{-4}; γ_o ≥0.876, 7.803×10^{-4}.

C_2 = For γ_o<0.876, 1.187; γ_o ≥0.876, 1.0937.

C_3 = For γ_o<0.876, 1,881.24; γ_o ≥0.876, 2,022.19.

C_4 = For γ_o<0.876, 1,748.29; γ_o ≥0.876, 1,879.28.

Q = Throughputs of liquid hydrocarbon in a tank (m^3) for the report period.

MF_{GHG} = CH_4 or CO_2 mole fraction. Measured by the facility or if unavailable, refer to values presented in Tables 3-2a to 3-2e of Chapter 3 Fugitives.

MW_{GHG} = Molecular weight of CH_4 or CO_2 (kg/kmol).

VTM = Volume to mole conversion at standard condition of 101.325 kPa and 15℃; 0.042293 kmol/m^3.

$$\boldsymbol{\gamma_{gs} = \gamma_g\left[1 + \left(\frac{8.365}{\gamma_0} - 7.774\right) \times \frac{(1.8 \times T - 459.7)}{1000} \times \log\left(\frac{p}{790.83}\right)\right]}$$ Equation 4-7c

Where:

γ_g = Specific gravity of a gas in the upstream of a vessel at the actual conditions, calculated by Equation 4-7e (dimensionless).

$$\boldsymbol{\gamma_0 = \frac{141.5}{131.5 + °API}} \qquad \text{Equation 4-7d}$$

Where:

°API = API gravity of product in the separator before the first storage tank.

$$\boldsymbol{\gamma_g = \frac{MW_{sg}}{MW_{air}}} \qquad \text{Equation 4-7e}$$

Where:

MW_{sg} = Molecular weight of solution gas at standard temperature and pressure conditions.

MW_{air} = Molecular weight of air, (28.96 g/mol) at standard temperature and pressure conditions.

(3) Data requirements

- A facility may determine the composition based on process knowledge and/or engineering estimates or use default compositions as presented in Tables 3-2a to 3-2e in Chapter 3.

Method 4: Flashing Losses using Models/Simulations or Engineering Estimation

(1) Introduction

For tanks storing non-crude hydrocarbons, Method 3 may not be appropriate for use. Facilities may use other models, simulations, or engineering estimates to quantify flashing losses when the contents from the separator or non-separator equipment enters an atmospheric pressure storage tank. Various methods are available to estimate flashing losses as listed below.

(2) Methods

- Peng-Robinson Equation of State (for flashing emissions only).
- Process simulators such as HYSIM, HYSYS, WINSIM, PROSIM.
- Engineering estimate based on process or emission specific data.

(3) Data requirements

- Site specific process and operational conditions should be used for modelling, simulations or engineering estimates.
- Facilities are required to document methodologies, supporting data, and assumptions used to calculate the emissions.

4.6.6 Method 5: Flashing Losses Using the Measured GIS Method

(1) Introduction

The GIS should be a measured value reflecting the flashing emissions due to the pressure drop from the up stream separator to the first storage tank. An extended hydrocarbon analysis of the flash gas from the sample should also be conducted to determine the methane concentrations in the tank's flashing emissions.

(2) Equations

The equations for flashing losses are outlined in Section 4.2.3.

(3) Data requirements

The data requirements are outlined in Section 4.2.3.

4.6.7 Method 6: Total Tank Emissions Using Peng-Robinson (PR) Equation of State (EOS)

(1) Introduction

Models based on the Peng-Robinson (PR) Equation of State (EOS) may be used to calculate the total tank emissions including flashing, breathing and working losses from fixed-and floating-roof storage tanks. EOS is a mathematical equation relating thermodynamic variables such as pressure, temperature, and volume of a specific material in thermodynamic equilibrium.

The emissions calculated can represent the total VOCs or specific GHG depending on the parameters used in the calculation.

(2) Equations

If total VOCs are determined from the modelling, calculate the CH_4 or CO_2 emissions using the Equation 4-7a and follow the data requirement in Section 4.5.4 for tank vapor analysis.

If total GHGs are determined from the modelling, calculate the CH_4 or CO_2 emissions using Equation 4-8 based on the uncontrolled CO_2 and CH_4 and apply the control efficiency of the emissions recovery system.

$$GHG = \sum_{j=0}^{J} \sum_{i=0}^{I} \left[Mass_{\ GHG,i,j} \times \left(1 - CF_{\ i,j}\right)\right] \qquad \text{Equation 4-8}$$

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) in the report period.

i = Tank identifier.

I = Number of tanks holding products in the report period.

j = Type of product.

J = Number of products in the report period.

$Mass_{GHG,i,j}$ = CO_2 or CH_4 mass emissions (tonnes) for product i in tank j in the report period. This value is derived from the modelling using the Peng-Robinson Equation of State.

CF = Control factor (dimensionless fraction).

(3) Data requirements

A facility should follow EOS to quantify model input parameters.

4.6.8 Method 7-Tank Vent Measurement

(1) Introduction

Tank vapor vent measurement is not feasible or economical using calibrated bag or a high-flow sampler due to accessibility and safety issues. Measurement technologies avoiding close access to the tank vents may be used for quantification of tank venting emissions such as stationary tracer technology.

If tanks are connected to a vapor recovery unit to capture venting emissions from the storage tanks and then directly vent to atmosphere instead of routing to the flare or product line, the emissions at the outlet of a vapor recovery unit to the atmosphere can be measured. Refer to Section 4.1.2 for sampling requirements and the Equations 4-1b and 4-1c for the calculations.

(2) Equations

Equation 4-9 provides the GHG calculation using the tracer test technology.

$$GHG = \left[RR_{\ tracer} \times \frac{C_{\ GHG}}{C_{\ tracer}} \times \frac{MW_{\ GHG}}{MW_{\ tracer}} \right] \times t\ \times 0.001 \qquad \text{Equation 4-9}$$

Where:

GHG = CO_2 or CH_4 emissions in the report period (tonne).

RR_{tracer} = Release rate of the tracer gas (kg/h).

C_{GHG} = Plume GHG concentrations above background (ppbv) at the fixed position of the downstream of tracer release.

C_{tracer} = Plume concentration of tracer above background (ppbv) at the fixed position of the downstream of tracer release.

MW_{GHG} = Molecular weight of CO_2 or CH_4 (kg/mol).

MW_{tracer} = Molecular weight of tracer (kg/mol).

t = Vent time in the report period.

0.001 = Constant converting kg to tonne.

(3) Data requirements

- Data requirements are prescribed in Section 4.1.2.
- Tracer test should be performed during representative operating conditions for the tanks.
- The tracer test and composition of tank vapor including CH_4 and CO_2 should be measured at least once every 3 years for each storage product. It is acceptable to take one measurement if there are multiple tanks with the same physical parameters (including color, roof configuration, dimensions etc.), operational condition and contains the same product. If there is a product change or operational condition change, a new test and measurement should be conducted for the tank(s).

4.7 Routine Venting-Pneumatic Control Instruments

4.7.1 Introduction

Pneumatic instruments mean automated flow control instruments powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Venting can occur from gas-actuated pneumatic control loops, which can include controllers, transmitters, positioners and transducers. All emissions from static, transient and dynamic control instruments are released to the atmosphere if vent emissions control equipment is not installed. The vent gas from pneumatic control instruments can be collected and recovered and are often piped away in a common vent line or sent to a flare stack with a control system. However, vent emissions may still be released from inefficiencies in the operation of emissions control systems.

4.7.2 Tier 1-Generic Vent Rates

(1) Introduction

Generic emission factors are distinguished by pneumatic instrument type for UOG facilities. For other facilities, emission factors are classified by high bleed and low bleed along with intermittent or continuous bleed. The classification of the pneumatic instruments are described in the following:

- High-bleed pneumatic instruments means 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.

- Low-bleed pneumatic instruments mean 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.
- Intermittent-bleed (high and low) pneumatic are snap-acting or throttling instruments that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

(2) Equations

Calculate GHG emissions using Equation 4-10.

$$GHG = \rho_{GHG} \times 0.001 \times \sum_{i=1}^{n} VR_{i} \times t_{i} \times (1 - CF_{i}) \times MF_{GHG,i} \qquad \text{Equation 4-10}$$

Where:

GHG = CH_4 or CO_2 mass emissions from pneumatic control device venting (tonnes) in the report period.

i = Pneumatic device identifier.

n = Number of pneumatic instruments in the report period.

VR_i = Average vent rate for the device i (m^3/hour/device) at the standard condition in Table 4-1a and 4-1b.

t_i = Operating time of the instrument i in the report period (hours).

CF i = Control factor (dimensionless fraction) for pneumatic device i.

$MF_{GHG.i}$ = Mole fraction of CO_2 or CH_4 in vented gas. Refer to Table 17-3 of Chapter 17 for natural gas composition sampling requirements.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρCO_2 = 1.861 kg/sm^3; ρCH_4 = 0.6785 kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

Table 4-1a Generic Pneumatic Controller Vent Rate Based on Sample-Size Weighted Average Vent Rate for UOG Facilities

Pneumatic Device Type	Average Vent Rate (Sm^3 /hour/device)
Level Controller	0.3508
Positioner	0.2627
Pressure Controller	0.3217
Transducer	0.2335
Generic Pneumatic Device	0.3206

1. This table is adapted from Table ES-2 of Technical report-update of equipment, component and fugitive emission factors for Alberta Upstream Oil and Gas, Clearstone 2018.
2. The vent rate of “generic pneumatic device” includes high and low-bleed instruments that continuously vent.

Table 4-1b Pneumatic Instruments Average Vent Rate for non-UOG

Pneumatic Device Type	Vent Rate Sm^3/hour/device
Low-Bleed Pneumatic Instruments Vents**	0.0388
High Continuous Bleed Pneumatic Instruments Vents*	0.2605
Intermittent high Bleed Pneumatic Instruments Vents*	0.2476
Intermittent low Bleed Pneumatic Instruments Vents**	0.0665

1. This table is adapted from Section 24 of WCI Quantification Method 2013 Addendum to Canadian Harmonization Version which originally comes from the Prasino Final Pneumatic Field Sampling Report (*), or direct conversion of emission factors in 2011 EPA subpart W Table W-3 (**) from scf to sm^3.

(3) Data requirements

- An inventory should be created by field survey or estimated based on the most recent piping and instrumentation drawing (P&ID) or process flow diagrams (PFD) for the facilities.

- The facility should update the inventory whenever there are changes in equipment (replaced, added or decommissioned) at the facility.
- Information regarding the make and model, pneumatic instrument type (positioner, transducer, pressure or level controller), actuation frequency of level controllers should be documented.
- Information regarding pneumatic instrument type (low-bleed, high continuous bleed, intermittent high/low bleed) should be documented for transmission and underground storage and distribution facilities.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.7.3 Tiers 2 and 3-Specific Manufacturer and Model Vent Rate or Calculated Based on Correlation

(1) Introduction

The published venting rates are generated based on the average vent rates for specific pneumatic control device manufacturers and models. The vent rates are further distinguished into high bleed or low bleed and continuous or intermittent operations.

(2) Equations

Equation 4-10 should be used to calculate the GHG vent emissions using the vent rates in Tables 4-2a or 4-2b. However, the average vent rate in Table 4-2a for the specific manufacturer and model of device must be considered first since the data provided in this table were developed based on extensive field surveys of oil gas facilities in Alberta and British Columbia. If a device manufacturer and model are not listed in the Table 4-2a, use the vent rate based on the device's manufacturer vent rate in Table 4-2b.

$$\boldsymbol{VR}_{\boldsymbol{i}} = \boldsymbol{m} \times \boldsymbol{SP}_{\boldsymbol{i}} \qquad \text{Equation 4-11}$$

Where:

VR_i = Average vent rate determined by the manufacturer and model i and operating condition of pneumatic instrument at the standard condition (Sm^3/hour).

m = Supply pressure coefficient in Table 4-2a (m^3/hour/kpa gauge).

SP_i = Supply pressure of controller i to the instrument (kpa gauge).

The vent rate should be calculated using Equation 4-11 and data provided in Table 4-2a for the following scenarios in the preferable order of accuracy:

- Use specific model coefficient in Table 4-2a if the manufacturer, model and operational pressure are available;
- Use a vent rate based on the device manufacturer and model provided in the last column of the Table 4-2a (m^3/hour/device) if the manufacturer and model are available, but the operational pressure is not known; or
- Use generic high bleed and low bleed coefficients from Table 4-2a if operational pressures are available, but the pneumatic manufacturer and model type are not known.

If the manufacturer and model are not available in the Table 4-2a, use the manufacturer vent rate in Table 4-2b. These manufacturer vent rates are based on manufacturer lab testing and may not reflect actual field conditions. The vent rates should be selected as follows:

- If the manufacturer and model are listed in Table 4-2b, a manufacturer-specified emission rate should be selected which best represents the site operating conditions: continuous or intermittent;
- If the manufacturer and model are not listed in Table 4-2b, choose a vent rate in the table that is similar to the model used at the facility based on process knowledge; or
- If a similar manufacturer and model can not be found in Table 4-2b, use the highest emission rate available for the manufacturer of the pneumatic device.

Table 4-2a Pneumatic Device Average Natural Gas Vent Rates Determined From Field Measurements

Pneumatic Device	Manufacturer	Model	Supply Pressure Coefficient (m^3/hour/kpa gauge)	Vent Rate (Sm^3/hour/device)
High bleed pneumatic controller	-	-	0.0012	0.2605
Low bleed Intermittent controller	-	-	0.0012	0.2476
Pressure Controller	CVS	4150	-	0.4209
	Fisher	4150, 4150K, 4150R	0.0019	0.4209
	Fisher	4160	0.0019	0.4209
	Fisher	4660, 4660A	-	0.0151
	Fisher	C1	0.003	0.0649
Level Controller	Fisher	2500, 2500S, 2503	0.0011	0.3967
	Fisher	2680, 2680A	0.0014	0.2679
	Fisher	2900, 2900A, 2901, 2901A	-	0.1447
	Fisher	L2	0.0012	0.2641
	Fisher	L3	0.0011	0.3967

Pneumatic Device	Manufacturer	Model	Supply Pressure Coefficient (m^3/hour/kpa gauge)	Vent Rate (Sm^3/hour/device)
	Fisher[1]	L2 actuating 0-15 mins	-	0.75
	Fisher[1]	L2 actuating >0-15 mins	-	0.19
	Fisher[2]	L2 actuating (improved low vent Relay)	-	0.10
	Murphy	L1100	0.0012	0.2619
	Murphy	L1200, L1200N, L1200DVO	0.0012	0.2619
	Norriseal	1001, 1001A, 1001XL	-	0.193
	Norriseal[2]	EVS	-	0.11
	SOR	1530	-	0.0531
Temperature Controller	Kimray	HT-12	-	0.0351
Positioner	Fisher	FIELDVUE™ DVC 6000	0.0011	0.2649
	Fisher	FIELDVUE™ DVC 6010	0.0011	0.2649
	Fisher	FIELDVUE™ DVC 6020	0.0011	0.2649
	Fisher	FIELDVUE™ DVC 6030	0.0011	0.2649

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[1] The average rate is from Pneumatic Vent Gas Measurement. Prepared by Spartan Controls, Alberta Upstream Petroleum Research (AUPR). 2018.

[2] The average rate is from Level Controller Emission Study DRAFT, Petroleum Technology Alliance of Canada (PTAC). (2018).

Pneumatic Device	Manufacturer	Model	Supply Pressure Coefficient (m^3/hour/kpa gauge)	Vent Rate (Sm^3/hour/device)
Transducer	Fairchild	TXI 7800	0.0009	0.1543
	Fairchild	TXI 7850	0.0009	0.1543
	Fisher	546, 546S	0.0017	0.3547
	Fisher	i2P-100 (1st generation)	0.0009	0.2157

1. This table is adapted from Table 1 of Final Report for Determining Bleed Rates for Pneumatic Instruments in British Columbia, the Prasino group, 2013.
2. “-” means that the coefficient is weak between pressure and vent rate or not available.

Table 4-2b Average Manufacturer Vent Rates for Pneumatic Instruments[1]

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm³/h/device)[2]
Pressure Controllers		
Ametek Series 40	20	0.22
	35	0.22
Bristol Babcock Series 5453-Model 10F	20	0.11
	35	0.11
Bristol Babcock Series 5455-Model 624-III	20	0.07
	35	0.11
Bristol Babcock Series 502 A / D (recording controller)	20	0.22
	35	0.22
Dynaflo 4000LB	20	0.06
	35	0.09
Fisher 4100 Series (Large Orifice)	20	1.83
	35	1.83
Fisher 4194 Series (Differential Pressure)	20	0.13
	35	0.18
Fisher 4195	20	0.13
	35	0.18
Foxboro 43AP	20	0.66
	35	0.66
ITT Barton 338	20	0.22
	35	0.22
ITT Barton 335P	20	0.22
	35	0.22

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm^3/h/device)[2]
Natco CT	20	1.28
	35	1.28
Transducers		
Bristol Babcock Series 9110-00A	20	0.02
	35	0.02
Fisher i2P-100LB	20	0.08
	35	0.11
Fisher 646	20	0.04
	35	0.04
Fisher 846	20	0.04
	35	0.04
Level Controllers		
Dynaflo 5000	20	0
	35	0
Fisher 2660 Series	20	0.04
	35	0.04
Fisher 2100 Series	20	0.04
	35	0.04
Fisher L2sj	20	0.01
	35	0.02
Invalco CT Series	20	0.05
	35	1.46
Wellmark 2001	20	0.01
	35	0.01

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate ($sm^3/h/device$)[2]
Positioners		
Fisher 3582	20	0.51
	35	0.66
Fisher 3661	20	0.32
	35	0.44
Fisher 3590 (Electro-pneumatic)	20	0.88
	35	1.32
Fisher 3582i (Electro-pneumatic)	20	0.63
	35	0.88
Fisher 3620J (Electro-pneumatic)	20	0.66
	35	1.28
Fisher 3660	20	0.22
	35	0.29
Fisher FIELDVUE DVC5000	20	0.37
	35	0.55
Fisher FIELDVUE DVC6200 (standard)	20	0.51
	80	1.79
Fisher FIELDVUE DVC6200 (low bleed)	20	0.08
	80	0.25
Masoneilan SVI Digital	20	0.04
	35	0.04
Moore Products – Model 750P	20	0
	35	1.53
Moore Products – 73 – B PtoP	20	1.32

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm^3/h/device)[2]
	35	0
PMV D5 Digital	20	0.04
	35	0.04
Sampson 3780 Digital	20	0.04
	35	0.04
Siemens PS2	20	0.04
	35	0.04
VRC Model VP7000 PtoP	20	0.04
	35	0.04

1. This table is adapted from the Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices, version 2.0, January 25, 2017 and Alberta Energy Regulator's Manual 015, December 2018.
2. Manufacturer vent rates were multipled by 1.29 to convert volumes from total air to total fuel gas.

(3) Data requirements

- An inventory should be created by field survey or estimated based on the most recent piping and instrumentation drawing (P&ID) or process flow diagrams (PFD) for the facilities.
- The facility should update the inventory whenever there are changes in equipment (replaced, added or decommissioned) at the facility.
- Information regarding manufacturer, model type, and operating conditions (continuous or intermittent) must be collected and documented.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.7.4 Tier 4-Direct Measurement

(1) Introduction

Direct measurements may be conducted periodically or continuously.

Periodic measurement may miss dynamic bleeding events and the facility would have to conduct other measurements to capture dynamic bleeding. Continuous measurements can capture vented emissions in full bleed cycle.

(2) Equations

Equation 4-1b or 4-1c can be used to calculate the vented emissions from direct measurements. The vent rate is based on the actual field measurement of the pneumatic instruments either from periodic or continuous measurements.

(3) Data requirements

- Refer to Section 4.1.2 for data requirements.
- Periodic measurements must be conducted on a quarterly basis at minimum.

- The measurement must capture both the static and dynamic bleed rates for pneumatic instruments.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.8 Routine Venting-Pneumatic Pumps

4.8.1 Introduction

Pneumatic pumps use the force of compressed gases to generate mechanical effects, which drive the pump plunger and inject liquid chemicals such as corrosion inhibitors, de-foamers or anti-foamers, detergents, methanol, and emulsifiers or de-emulsifiers into the pressurized system (pipeline or wells) for specific applications. The expanded supply gas is then vented to atmosphere (or into a collection system) and the cycle repeated.

4.8.2 Tier 1-Default Vent Rates

(1) Introduction

The method uses the generic vent rates for diaphragm and piston pumps. Emission factors for several models are provided as well.

(2) Equations

Calculate CH_4 or CO_2 emissions using Equation 4-10 for pneumatic instruments.

If the pneumatic pump's manufacturer and models are not available, the generic vent rates for pneumatic piston and diaphragm pumps should be used. Several pump models are provided in Table 4-3 (m^3/hour/pump).

Table 4-3 Pneumatic Pump Average Natural Gas Vent Rates Based on Field Measurements

Pneumatic Device	Average Vent Rate (Sm^3/hour/pump)
Generic piston pumps	0.5917
Generic diaphragm pumps	1.0542
Morgan HD312	1.1292
Texsteam 5100	0.9670
Williams P125	0.4098
Williams P250	0.8022
Williams P500	0.6969

1. This table is adapted from Table 11 of the final report for determining bleed rates for pneumatic instruments in British Columbia, the Prasino group, 2013.

(3) Data requirements

- An inventory must be done by field survey once and repeated following any changes to the inventory.
- The facility should update the inventory whenever there are changes in equipment (replaced, added or decommissioned) at the facility.
- Information regarding to the pump types (piston or diaphragm), manufacturer and model types must be collected and documented.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

4.8.3 Tiers 2 and 3-Vent Rate Based on Correlation

(1) Introduction

Pump vent rates are correlated to the pump operational parameters including strokes, supply pressures and injection pressures. When the operational parameters are reliable, the vent rate based on correlation can provide a better representative vent rate for the actual operating conditions.

(2) Equations

Calculate CH_4 or CO_2 emissions using Equation 4-10 for all natural gas driven pneumatic pumps.

Vent rates for pneumatic pumps should be determined using the following two correlation methods.

Correlation Method 1:

If the supply pressure, discharge pressure, and the strokes per minute of the pump are known, the average vent rate of the pneumatic pump can be calculated using the following correlation coefficient for pump models listed in Table 4-4 and using Equation 4-12. The correlation can also be used to estimate the vent rate from unknown pump models using generic coefficient for diaphragm and piston pumps.

If a facility’s pump manufacturer and model are listed in Table 4-4, the corresponding vent rate must be used. Otherwise, use the generic vent rate for piston and diaphragm pumps in Table 4-4.

$$\boldsymbol{VR_i} = (\boldsymbol{g} \times \boldsymbol{SP}) + (\boldsymbol{n} \times \boldsymbol{IP}) + (\boldsymbol{p} \times \boldsymbol{SPM}) \qquad \text{Equation 4-12}$$

Where:

VR_i = Average vent rate for pump i, Sm^3/hr.

g = Supply pressure (SP) coefficient ($m^3/hr/kpag$) for the pump type in Table 4-4.

SP = Supply pressure of the pump (kPag).

n = Injection pressure coefficient (IP) ($m^3/hr/kpag$) for the pump type in Table 4-4.

IP = Injection pressure of the pump (kPag).

p = Strokes per minute coefficient (m^3/hr/kpag) for the pump type in Table 4-4.

SPM = Strokes per minute of the pump (strokes/minute).

Table 4-4: Coefficients for Determining Pneumatic Pump Average Emission Rates

Pump Type	Supply Pressure Coefficient (g) (m^3/hr/kpag)	Injection Pressure Coefficient (n) (m^3/hr/kpag)	Strokes per minute Coefficient (p) (m^3/hr/kpag)
Generic diaphragm pump	0.00202	0.000059	0.0167
Generic piston pump	0.00500	0.000027	0.0091
Morgan HD312	0.00418	0.000034	0.0073
Texsteam 5100	0.00030	0.000034	0.0207
Williams P125	0.00019	0.000024	0.0076
Williams P250	0.00096	0.000042	0.0079
Williams P500	0.00224	-0.000031	0.0046

1. This table is adapted from Table 11 of the final report for determining bleed rates for pneumatic instruments in British Columbia, the Prasino group, 2013.

Correlation Method 2:

Pneumatic pump manufacturers commonly publish charts and graphs in product brochure that can be used to determine the gas consumption for each make and model of pump under a variety of operating conditions. The following method was derived data collected from multiple device manufacturers.

Use Equation 4-13 to calculate GHG emissions and Equation 4-13a to calculate pump vent rate.

$$GHG = \sum_{i=1}^{n} \sum_{j=1}^{m} Q_{C,j} \times VR_j \times (1 - CF) \times MF_{GHG} \times \rho_{GHG} \times 0.001 \qquad \text{Equation 4-13}$$

Where:

GHG = CH4 or CO2 mass emissions (tonnes) from pneumatic pump venting in the report period.

Q C,j = Volume of liquid chemical injected by pump j (litres).

j = Pump type identifier.

i = Number of the pump identifier.

m = Number of pump types.

n = Number of pumps for each type of pump.

CF = Emission control factor (dimensionless).

VR j = Natural gas-driven pneumatic pump, j, venting rate (sm3/liter/pump) determined from the correlation in Equation 4-13a.

MF GHG = Mole fraction of CO2 or CH4 in vented gas.

ρ GHG = Density of CO2 or CH4 at standard conditions (ρCO2 = 1.861 kg/sm3; ρCH4 = 0.6785 kg/sm3).

0.001 = Mass conversion factor (tonne/kg).

$$\boldsymbol{VR_{j} = c \times CIP^{2} + d \times CIP + e} \qquad \text{Equation 4-13a}$$

Where:

VR_j = Natural gas-driven pneumatic pump, j, vent rate per pumping a liter of liquid (Sm^3/liter/pump).

CIP = Chemical injection pressure (pipeline pressure) (kPa gauge).

C = Manufacturer CIP^2 coefficient c provided in Table 4-5.

D = Manufacturer CIP^1 coefficient d provided in Table 4-5.

E = Manufacturer CIP^0 coefficient e provided in Table 4-5.

Table 4-5: Pneumatic Pump Venting Coefficients Derived From Manufacturer Specifications for Selected Models

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP^2 Coeff. (c)	CIP^1 Coeff. (d)	CIP^0 Coeff. (e)
ARO	66610	120 psi supply		0	8.579E-06	7.700E-03
Bruin	BR 5000	0.25	0.5	0	2.448E-05	4.603E+00
Bruin	BR 5000	0.25	1.25	0	9.530E-06	1.848E+00
Bruin	BR 5000	0.375	0.5	0	2.467E-05	2.049E+00
Bruin	BR 5000	0.375	1.25	0	9.615E-06	8.266E-01
Bruin	BR 5000	0.5	0.5	0	2.474E-05	1.133E+00
Bruin	BR 5000	0.5	1.25	0	9.731E-06	4.711E-01
Bruin	BR 5000	0.75	0.5	0	2.480E-05	5.102E-01
Bruin	BR 5000	0.75	1.25	0	9.899E-06	2.042E-01
Bruin	BR 5000	1	0.5	0	2.480E-05	2.868E-01
Bruin	BR 5000	1	1.25	0	9.932E-06	1.150E-01
Bruin	BR 5000	1.25	0.5	0	2.496E-05	1.821E-01
Bruin	BR 5000	1.25	1.25	0	9.923E-06	7.243E-02
Bruin	BR 5000	0.1875	1	0	9.905E-06	2.054E+00
Bruin	BR 5000	0.25	1	0	1.005E-05	1.155E+00
Bruin	BR 5000	0.375	1	0	1.009E-05	5.137E-01
Bruin	BR 5100	0.5	1	0	1.008E-05	2.887E-01
CheckPoint	1250	0.125	0.94	2.360E-10	2.278E-05	1.184E+00
CheckPoint	1250	0.25	0.94	2.224E-10	1.129E-05	2.773E-01
CheckPoint	1250	0.375	0.94	1.255E-10	1.224E-05	1.025E-01

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP^2 Coeff. (c)	CIP^1 Coeff. (d)	CIP^0 Coeff. (e)
CheckPoint	1250	0.5	0.94	-1.266E-12	1.190E-05	7.104E-02
CheckPoint	1500	0.5	1	4.069E-11	2.733E-05	5.143E-01
CheckPoint	1500	0.75	1	1.335E-10	1.945E-05	1.729E-01
CheckPoint	1500	1	1	-9.817E-11	2.083E-05	1.123E-01
CheckPoint	LPX-04	0.25		0	0	3.464E-01
CheckPoint	LPX-08	0.125		0	0	1.409E+00
Linc	84T-10-x1	0.1875	1	0	1.513E-05	3.872E-01
Linc	84T-11-x1	0.25	1	0	1.071E-05	1.646E-01
Linc	84T-11-x2	0.25	1	0	1.190E-05	2.925E-01
Linc	84T-12-x2	0.5	1	0	1.190E-05	7.313E-02
Linc	84T-12-x4	0.5	1	0	1.058E-05	1.300E-01
Linc	84T-14-x4	1	1	0	1.134E-05	3.250E-02
Linc	87TA-11-x1	1	1	0	9.921E-06	8.545E-02
Linc	85T-10	0.25	1	0	1.498E-05	1.648E-01
Linc	85T-11	0.5	1	0	1.512E-05	7.393E-02
Morgan	HD187-3K-TR2		0.5	-3.059E-11	5.192E-05	3.526E-01
Morgan	HD187-TR2		0.5	-1.049E-09	7.424E-05	2.494E-03
Morgan	HD312-3K-TR2		1	-4.013E-25	2.558E-05	1.058E-01
Morgan	HD312-K5-TR2		1	-2.368E-12	2.545E-05	2.546E-01
Morgan	HD312-TR2		1	2.655E-09	2.198E-05	-3.868E-03
SandPiper	G05	0.5		7.635E-09	2.563E-05	6.379E-03

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP^2 Coeff. (c)	CIP^1 Coeff. (d)	CIP^0 Coeff. (e)
SandPiper	SB-1 and SB-25	1		3.226E-08	-1.070E-05	7.688E-03
Texsteam	5002	1	0.5	-1.949E-10	5.935E-05	5.222E+00
Texsteam	5002	0.25	1.25	-2.601E-11	2.817E-05	2.087E+00
Texsteam	5003	0.25	0.5	-1.078E-11	1.399E-05	2.652E+00
Texsteam	5003	0.375	1.25	-1.075E-11	1.398E-05	1.044E+00
Texsteam	5004	0.375	0.5	-4.756E-10	4.049E-05	6.351E-01
Texsteam	5004	0.75	1.25	-2.109E-10	2.697E-05	2.495E-01
Texsteam	5005	0.75	0.5	-1.160E-13	1.303E-05	1.496E+00
Texsteam	5005	0.5	1.25	3.412E-26	1.302E-05	5.985E-01
Texsteam	5006	0.5	0.5	-1.293E-25	1.302E-05	3.741E-01
Texsteam	5006	1	1.25	1.666E-25	1.302E-05	1.496E-01
Texsteam	5007	1	0.5	-7.148E-25	1.302E-05	2.394E-01
Texsteam	5007	1.25	1.25	-1.293E-25	1.302E-05	9.726E-02
Texsteam	5101	1.25	0.33	1.499E-09	6.724E-05	5.467E+00
Texsteam	5101	0.25	1	4.995E-10	2.241E-05	1.822E+00
Texsteam	5103	0.25	0.33	1.202E-11	1.471E-04	2.592E+00
Texsteam	5103	0.375	1	4.007E-12	4.902E-05	8.641E-01
Texsteam	5104	0.375	0.33	-1.076E-09	1.240E-04	9.996E+00
Texsteam	5104	0.1875	1	-3.851E-10	4.208E-05	3.330E+00
Texsteam	5105	0.1875	0.33	5.241E-11	3.741E-05	1.159E+00
Texsteam	5105	0.5	1	1.747E-11	1.247E-05	3.864E-01
Texsteam	9001	30 psi supply		1.475E-08	8.510E-07	3.167E-03

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP^2 Coeff. (c)	CIP^1 Coeff. (d)	CIP^0 Coeff. (e)
Texsteam	9001	50 psi supply		1.102E-08	8.300E-07	4.553E-03
Timberline	2515		1	0	1.176E-05	5.212E-02
Timberline	2522		1	0	1.164E-05	9.879E-02
Timberline	2530		1	0	1.114E-05	1.627E-01
Timberline	5030		1	0	1.100E-05	5.155E-02
Timberline	5040		1	0	1.255E-05	3.346E-02
Western	DFF	0.375	0.875	0	1.636E-05	7.795E-01
Western	DFF	0.625	0.875	0	1.742E-05	3.097E-01
Wilden	P1 Metal	Rubber/PFTE fitted		3.286E-08	-1.261E-05	6.708E-03
Williams	CP125V125	1.25	1	0	0	7.716E-01
Williams	CP250V225	2.25	1	0	0	6.173E-01
Williams	CP250V300	3	1	0	0	1.138E+00
Williams	CP500V225	2.25	1	0	0	1.531E-01
Williams	CP500V300	3	1	0	0	2.822E-01
Williams	CRP1000V4	4	1	0	0	1.224E-01
Williams	CRP1000V6	6	1	0	0	2.472E-01
Williams	CRP1000V8	8	1	0	0	4.360E-01
Williams	CRP500V40	4	1	0	0	4.832E-01
Williams	CRP750V40	4	1	0	0	2.227E-01

1. This table is adapted from Table 31 of AER Manual 15, December 2018.

(3) Data requirements

- An inventory may be completed by field survey or estimated based on the most recent piping and instrumentation drawing (P&ID) or process flow diagrams (PFD) of the facilities annually.
- The facility should update the inventory whenever there are changes to the pneumatic pumps at the facility during the report period.
- Information regarding to manufacturer, model type, plunger diameter, stroke length and inject pressure must be collected and documented.
- The amount of liquids pumped by pump type during the report period must be documented.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.8.4 Tier 4-Direct Measurement

Refer to Section 4.7.4 for the methodology.

4.9 Compressor Seal Venting

4.9.1 Introduction

Packing is used on reciprocating compressors to control leakage around the piston rod on each compression cylinder. Under normal operation, emissions from reciprocating compressor seals (RCS) occur when the process gas in the cylinder head migrates through the piston-rod-packing and into the piston-rod-packing vent and drain, distance piece vent and drain or compressor crankcase vent. The rod packing seal vent rate is a combination of all the potential vent paths along the entire throw, from the crank end to the head end.

Centrifugal compressors are commonly used for gas transmission service and less so for UOG applications. Centrifugal compressors generally require shaft-end seals between the compressor and bearing housings. Centrifugal compressors with wet seals have gas leakage past face-contact oil-lubricated mechanical seals or oil-ring shaft seals. Centrifugal compressors with dry seals operate without oil. Instead, the dry seal features two precision-machined sealing plates with one stationary and the other rotating with the shaft. At high rotation speed, seal gas separates the plates via a pressure dam effect. Due to very close running clearances, leakage rates are relatively low, but increase the likelihood for worn plates.

4.9.2 Tier 1-Population Average Vent Rate

(1) Introduction

This method uses vent rates that were developed based on a field survey of compressors used in Alberta.

Compressor emissions are traditionally attributed to the fugitive emissions category. The updated Directive 060 (2018) requires UOG facilities to report compressor emissions under the venting emission category.

Emission factors for compressor seals typically include both venting and fugitive emissions. For UOG facilities, the fugitive component in the emission factor has been removed as per the updated Directive 060. However for non-UOG facilities, these emission factors still include both emission types.

In order to quantify only the venting emissions for non-UOG facilities, a factor was developed that represents the proportion of venting to fugitive emissions in the emission factor. This factor is based on Table 18 from the Technical Report - Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas (Clearstone Engineering Ltd.).

Table 4-6b provides the emission factors for non-UOG facilities that represents the emissions from venting only based on this factor. Note that emission factors for fugitive emissions are presented in Chapter 3 Fugitives.

(2) Equations

Calculate CH_4 or CO_2 emissions using Equation 4-14 for each compressor seal vent and sum up all compressor seal emissions in the report period.

$$\boldsymbol{GHG = \sum_{i=1}^{I} VR_{i} \times t \times (1 - CF) \times N \times MF_{GHG/Gas,i} \times \rho_{GHG} \times 0.001} \qquad \text{Equation 4-14}$$

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from compressor in the report period.

i = Compressor type identifier.

I = Total types of compressor in the report period.

$VR_{i,}$ = Average vent rate (sm^3/hour/throw or sm^3/hour/source) for compressor i. Refer to values in Table 4-6a for UOG facilities and Table 4-6b for non-UOG facilities.

N = Number of throws for reciprocating compressors or number of compressors for centrifugal compressors for each type of compressor i which are operating in the report period.

t = Total time the compressor i is pressurized in the report period (hours).

CF = Control factor (dimensionless fraction).

$MF_{GHG/Gas,i}$ = Mole fraction of CO_2 or CH_4 in the vented gas for compressor i.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

Table 4-6a Generic Compressor Average Vent Rate for UOG Facilities

Sector	Component Type	Vent Rate	Unit
All	Reciprocating compressor	1.28	sm^3/h/throw
All	Centrifugal wet seal	1.41	sm^3/h/unit
All	Centrifugal dry seal	1.27	sm^3/h/unit

1. This table is adapted from Table 15 of Compressor Seal Vent Rate Evaluation - Centrifugal Compressor Shaft Seals and Reciprocating Compressor Piston Rod Packing Cases, prepared by Accurata Inc. Calgary, AB, July 31, 2018.

Table 4-6b Generic Compressor Average Vent Rate for Non-UOG Facilities

Sector	Services	Vent Rate[1]	Leak Rate Unit
Synthetic Chemical[2] Manufacture Industry	Gas	0.165	kg TOC/h/source
Refinery[3]	Gas	0.460	kg non-methane TOC/h/source
Marketing Terminal[4]	Gas	8.69E-05	kg TOC/h/source
	Liquid	1.27E-04	kg TOC/h/source

1. The vent rate is calculated using the original vent rate that included both fugitive and venting emissions and multiplied by the ratio of vented emissions to total emissions. The ratio is calculated based on Table 18 of Technical Report-Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas, Clearstone Engineering Ltd.
2. [2]Refer to Table 2-1 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.
3. [3]Refer to Table 2-2 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.
4. [4]Refer to Table 2-3 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.

(3) Data requirements

- The amount of pressurized time must be recorded for individual compressors in the report period.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

4.9.3 Tiers 2 and 3-Manufacturer Vent Rate

(1) Introduction

This approach is applicable for compressors if the manufacturer vent rate is available for the same make and model. Facilities that do not have manufacturer vent rates may use the tier 1 methodology.

(2) Equations

Calculate CH_4 and CO_2 emissions using Equation 4-14. The vent rate is provided by the manufacturer based on the same or similar models and operating conditions. If the vent rate is not available for a specific operating condition, use the highest emission rate available for the manufacturer and model.

(3) Data requirements

- Vent rates for the same or similar manufacturer, model and operating conditions provided by the manufacturer should be used.
- The vent rates should be converted to standard conditions.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- The mole fraction is determined using the gas sampling frequencies prescribed in Table 17-3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

4.9.4 Tier 4-Direct Measurement

(1) Introduction

As per AER Directive 060, facilities are required to measure compressor venting starting on January 1, 2020. If a compressor piston-rod packing is replaced on one throw of a reciprocating compressor seal after a test is completed, an average emission rate of 0.16 m^3 vent gas per hour per throw (adapted from AER Manual 15, December 2018) can be used until the next test is completed.

This approach is applicable for compressors that are tied into an open-ended vent line and the vent rate is measured periodically or continuously.

(2) Equations

The vent rate for reciprocating compressors should be calculated for each throw. The vent rate for centrifugal compressors should be calculated for each seal. A facility may measure the total vent rate at the vent line and determine the vent rate per throw or seal. For example, if a compressor has four throws, but only three was operating during the test event, the facility may calculate the vent rate per throw by dividing the total vent rate by three.

If the volumetric flow rate is measured such as using calibrated bag or volumetric meter, calculate the GHG emissions using the Equation 4-14 using the following parameters.

VR_i = Measured gas volumetric vent rate during operating time for compressor i before the vent control equipment per throw (sm^3/h/throw) for reciprocating compressors and per unit for centrifugal compressors.

If the mass rate is measured such as using hi-flow sampling, calculate the GHG emissions using the same equation as Equation 4-14. However, replace the volumetric rate (VRi) for compressor i and GHG gas density (ρ_{GHG}) by mass rate and replace the mole fraction by mass fraction.

MR_i = Measured gas mass vent rate per throw (kg/h/throw) during operating time for compressor i before the vent control equipment for reciprocating compressors and per unit (kg/h/unit) for centrifugal compressors.

$F_{GHG/THC}$ = Mass fraction of CO_2 or CH_4 in the vented gas for compressor i.

(3) Data requirement

- Refer to Section 4.1.2 for data requirements.
- Vent rate should be measured annually at the compressor during normal operating conditions.
- Measure emissions using a high-flow sampler, calibrated bag, or appropriate meter.
- The measurement locations must be representative of all potential vent paths. For instance, for reciprocating compressors, the total vent rate should include all potential vented emissions from the crank end to the head end. These include vented emissions from the

piston-rod packing vent and drain, distance piece vent and drain, and compressor crankcase vent and drain if they are open to atmosphere.

- For any compressor seal that emits vent gas, the seal must be measured at least every 9,000 hours that it is pressurized.
- The volumetric vent rate must be converted to standard conditions.
- If a continuous gas analyzer is available on the outlet gas stream, then the continuous gas analyzer results must be used.
- If a continuous gas analyzer is not present, the facility is required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.10 Glycol Dehydrator Venting

4.10.1 Introduction

Glycol dehydrators are used to remove water from raw natural gas (wet gas) at gas batteries and gas plants. While glycols easily absorb water, they have a tendency to absorb small amounts of hydrocarbons (primarily benzene, hexane and heavier hydrocarbons, with some methane). These impurities can be vented to atmosphere from the flash tank separator or the regenerator overhead. If the dehydrator unit has vapor recovery, emissions must be adjusted by the amount of emissions recovered, by applying a control factor as illustrated in Section 4.1.

4.10.2 Tiers 1, 2 and 3-GHG Based on Simulation Program

(1) Introduction

This method requires the use of simulation programs such as GRI-GLYCalc, Aspen HYSYS or Prosim for quantifying venting emissions from dehydrators. For example, GRI-GLYCalc is primarily intended for estimating benzene, toluene, ethyl benzene and xylene (BTEX) emitted by a glycol dehydrator since significant amounts of this material may be preferentially absorbed by the glycol and released off the flash tank and still column. However, the program can also provide the total volume of vent gas and gas compositions, which provides sufficient information on estimating the amount of methane emissions.

(2) Equations

Using the vent rate and gas composition calculated by the simulation program, Equation 4-10 can be used to calculate the total GHG emissions using the following parameters:

VR = Simulated gas volumetric vent rate for glycol dehydrator i before the vent control equipment (sm^3/h).

t = Dehydrator running time (h) in the report period.

$MF_{GHG/gas}$ = CO_2 or CH_4 mole fraction based on the output of the simulation for glycol dehydrator i (dimensionless).

Typical data inputs for various simulator programs are listed below:

- Wet gas composition and flow rate.
- Glycol circulation rate.
- Temperature and pressure in the absorber column.
- Type of glycol pump (electric or energy exchange).
- Operating pressure of the flash tank (if one is used) and amount of flash gas used by the process (if at all).
- Type of glycol (TEG or DEG).
- Stripping gas (if used).
- Temperature and pressure of flash tank (if present).

(3) Data requirements

- Facilities are required to follow gas sampling frequencies for wet gas analysis prescribed in Table 17-3 of Chapter 17.
- Wet gas flow rate and circulation rate should be metered continuously and documented for a glycol dehydrator.

- At glycol dehydrator sites, if the dry gas water content is routinely measured, use the measured data. Otherwise, design values for dry gas water content or the number of equilibrium stages in the absorber may be used.

4.11 Glycol Refrigeration Venting

(1) Introduction

Dehydration and refrigeration in the oil and gas industry is used to lower the temperature at which hydrates form or to remove water from natural gas streams, or both. It is more common to lower the hydrate temperature by injecting glycol in the gas after separation of free water.

The associated emissions released during the regeneration of glycol are similar to glycol dehydration and uses the same methodology.

(2) Equations

Refer to Section 4.10 for equations.

(3) Data requirements

Refer to Section 4.10 for data requirements.

4.12 Acid Gas Removal (AGR)/Sulphur Recovery Units Venting

4.12.1 Introduction

Sour gas, which is natural gas with high concentrations of acid gas species (H_2S and CO_2), must be treated to reduce the acid gases to a concentration that meets pipeline transportation criteria. Acid Gas Removal (AGR) units remove H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). There are other acid gas removal technologies besides amine units, including the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process, the latter of which involves the use of molecular sieves. These technologies are reported to reduce CH_4 emissions too.

Sour gas processing or sulfur recovery units (SRU) can directly vent the CO_2 removed from the sour gas stream to the atmosphere or capture the CO_2 for other uses, such as enhanced oil recovery. These emissions are considered to be formation CO_2 and should be reported under that category. These emissions are discussed in Chapter 10 Formation CO_2. CH_4 emission estimation methodologies are provided in this chapter.

In closed amine systems, the reboiler vent is directed to the facility flare and emissions should be calculated in accordance with Chapter 2 Flaring.

The following table assigns the methodologies to be used by AGRs and SRUs at the various tiers.

Figure 4-2 Tier Classification and Methodology Mapping

		Tier Classification			
		1	2	3	4
Equipment Types	AGR (amine)	Method 1	Method 2		Direct Measurement as described in Section 4.1.2
	AGR (non-amine) & SRU	Engineering Estimate			

4.12.2 Method 1-Generic CH4 Vent Rate

(1) Introduction

For uncontrolled AGR units with an amine-based system, two CH_4 vent rates were developed as part of the 1996 GRI/EPA CH_4 emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations of a diethanol amine (DEA) unit (Myers, 1996). Methodologies to calculate CO_2 emissions from AGRs are in Chapter 10 Formation CO_2.

A published generic GHG vent rate is not available for SRUs; thus, their GHG emissions should be calculated using process knowledge and/or engineering estimates.

(2) Equations

For each AGR unit that is not connected to a flare or thermal oxidizer, calculate the CH_4 emissions using Equation 4-15.

$$CH_4 = Q_{in} \times VR_{CH4}$$

Equation 4-15

Where:

$CH_{4,p}$ = CH_4 mass emissions (tonnes) from the AGR unit venting in the report period.

$Q_{in,p}$ = Metered total volume natural gas flow into the AGR unit converted to standard condition per Appendix C (10^6 scf or $10^6 m^3$) in the report period.

VR_{CH4} = Methane vent rate for the AGR unit in Table 4-7 (tonnes/10^6scf or tonnes/10^6 m^3).

Table 4-7 Uncontrolled AGR CH_4 Vent Rate

Source	Methane Vent Rate[3], Original Units	Methane Vent Rate[4], Converted to Tonnes Basis
AGR vent	965 scf/10^6 scf treated gas	0.0185 tonnes/10^6 scf treated gas 0.654 tonnes/10^6 m^3 treated gas

1. This table is adapted from Table 5-5 of Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, American Petroleum Institute (API), August 2009.

(3) Data requirements

- The AGR throughputs may be metered or quantified based on accounting procedures.

4.12.3 Method 2-Vent Rate Using Simulation

(1) Introduction

API’s AMINECalc is designed to estimate hydrocarbon emissions from amine based sour gas and natural gas liquid (NGL) sweetening units. The amine system normally consists of a contactor, flash drum and regenerator. The CH_4 and CO_2 emissions can be estimated from total hydrocarbon emissions

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[3] Myers, D.B. Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report, GRI-94/0257.31 and EPA- 600/R-96-080n, Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Based on a DEA unit.

[4] CH4 emission factors converted from scf are based on 60°F and 14.7 psia.

(2) Equations

Calculate CH_4 or CO_2 emissions using Equation 4-10 using the outputs from AMINECalc including the vent rate and gas compositions.

(3) Data requirements

- The AGR throughputs may be metered or quantified based on accounting procedures.

4.13 Hydrocarbon Liquid Loading/Unloading Venting

4.13.1 Introduction

The vapors from cargo tanks can be displaced directly into the atmosphere when petroleum liquid is loaded into those vessels in the absence of any specific controls. If a separation system is installed to control loading losses from the tank vehicles, or to balance or exchange vapors between the tanks and tank vehicles, the loading/unloading losses are greatly reduced. Loading of petroleum products into railcars or tank-trucks occurs at UOG, oil storage tank farms, upgrader and refining facilities.

CH_4 or CO_2 emissions in most petroleum products including stabilized (weathered) crude are negligible. Unstabilized crude oil contains sufficient dissolved gas hydrocarbons (mainly C_1, C_2, C_3 and C_4) that may be released from the oil at separator conditions. Therefore, evaporative emissions associated with loading/unloading is only for unstabilized crude.

4.13.2 Tiers 1, 2 and 3-Algorithm

Method 1: Loading Emissions from Low Vapor Pressure (LVP) Loading

(1) Introduction

Rail tank cars and tank trucks transport low vapor pressure (LVP) products such as crude oil, condensate and pentanes-plus. Emissions due to the displacement of tank vapors (i.e. evaporated product) can occur during the loading of these carriers. The amount of emissions depends on the vapor pressure of the liquid product, recent loading history and method of loading.

(2) Equations

This approach calculates the total vapor emissions and then uses GHG composition in the vapor to calculate specific GHG emissions. Calculate GHG loading emissions for all products loaded in the report period using Equation 4-16.

$$\boldsymbol{GHG = \sum_{j=1}^{n} \frac{0.120 \times SF_{j} \times P_{True,j} \times Q_{j} \times MW_{vapor} \times F_{GHG,vapor}}{(T_{j} + 273.15)} \times 0.001 \times (1 - CF)}$$

Equation 4-16

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from loading loss of product j in the report period.

j = Product type.

n = Types of product loaded.

0.120 = Constant (k kmol/kpa m^3).

Q_j = Volume of the LVP product loaded in the report period (m^3).

MW_{vapor} = Molecular weight of vapor (kg/kmol).

$P_{true,j}$ = True vapor pressure of the loaded LVP product j (kPa) at bulk liquid temp (T_j). Determined by multiplying the vapor pressure (psi) from Equation 4-16a or Equation 4-16b by 6.8948 to convert psi to kpa.

SF_j = Saturation factor for LVP product j from Table 4-8 to account for the effects of the method of loading (dimensionless).

CF = Average emission control factor (dimensionless) for the control system installed, CF is 0 in absence of control system.

T_j = Bulk temperature of the LVP product j loaded (°C).

$F_{GHG,vapor}$ = Mass fraction of CH_4 or CO_2 in vapor evaporated from product j loading.

For crude oils with Reid Vapor Pressures (RVP) of 2 to 15 pounds per square inch (psi), use Equation 4-16a to convert to a true vapor pressure, and then convert the true vapor pressure from psi to kpa for Equation 4-16.

$$\boldsymbol{P_{true,j} = \exp\{[\frac{2799}{(T+459.6)} - 2.227]\log_{10}(RVP) - \frac{7261}{(T+459.6)} + 12.82\}} \qquad \text{Equation 4-16a}$$

Where:

P $_{true,j}$ = True vapor pressure of loaded LVP product j, in pounds per square inch absolute (psia).

T = Bulk temperature of the loaded LVP product j, in degree Fahrenheit (°F).

RVP = Reid Vapor Pressure of liquid j, in psi; sampled for the liquid j or taken from Table 4-9.

For refined products having a RVP value of 1 to 20 psi, use Equation 4-16b to calculate the true vapor pressure from RVP, and then convert true vapor pressure in psi to kpa for Equation 4-16.

$$\begin{aligned} P_{true,j} = \exp\{[0.7553 - \left(\frac{413.0}{T+459.6}\right)] \times (S)^{0.5} \times \log_{10}(RVP) \\ - \left[1.854 - \left(\frac{1042}{T+459.6}\right)\right] \times (S)^{0.5} \\ + \left[\left(\frac{2416}{T+459.6}\right) - 2.013\right]\log_{10}(RVP) - \frac{8742}{(T+459.6)} + 15.64\} \end{aligned} \qquad \text{Equation 4-16b}$$

Where:

P$_{true,j}$ = True vapor pressure of loaded LVP product j, in pounds per square inch absolute (psia).

RVP = Reid Vapor Pressure of liquid j, in psi; sampled for the liquid j or taken from Table 4-9.

S = Slope of the ASTM distillation curve at 10 percent evaporated, in degree Fahrenheit (℉/vol%), refer to Table 4-10.

T = Bulk temperature of the loaded LVP product j, in degree Fahrenheit (◦F).

RVP = Reid Vapor Pressure of liquid j, in psi; sampled for the liquid j or taken from Table 4-9.

Table 4-8: Saturation Factors for Petroleum Liquid Loading Losses

Cargo Carrier	Mode of Operation	Saturation Factor (Dimensionless)
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00

1. Saturation [S] Factors for Calculation of Petroleum Liquid Loading Losses, USEPA AP-42, 5th Edition, Volume 1, Chapter 5: Petroleum Industry.

Table 4-9: Liquid Product Properties for Loading and Unloading Emission Estimates

Liquid Product	Oil Specific Gravity	Reid Vapor Pressure (RVP)		Vapor Molecular Weight
		(kPa)	(psi)	(kg/kmol)
Condensate	0.715	76.6	11.11	28.2
Light/Medium Crude Oil	0.8315	54.8	7.95	44.2
Heavy Crude Oil	0.9153	40.5	5.87	19.9
Thermal Crude Oil	0.9153	40.5	5.87	30.6
Cold Bitumen	0.9182	39.7	5.76	23.3

Table 4-10: ASTM Distillation Slope for Selected Refined Petroleum Stocks

Refined Petroleum Stock	Reid Vapor Pressure		ASTM-D86 Distillation Slope at 10 Volume Percent Evaporated
	(psi)	(kPa)	(°F/vol%)
Aviation gasoline	ND	ND	2.0
Naphtha	2-8	13.8 to 55.2	2.5
Motor gasoline	ND	ND	3.0
Light naphtha	9-14	62.1 to 96.5	3.5

1. This table is adapted from Table 7.1-4 of USEPA AP-42, 5th Edition, Volume 1, Chapter 7: Liquid Storage Tanks.

(3) Data requirements

- The volumes of loading and unloading products should be measured at the facility or documented by third party invoicing or accounting records.
- The GHG content of vented gas from loading and unloading operations should be measured at least once every three years for each product.
- Gas compositions must be measured using:
    - An applicable analytical method prescribed by AER Directives for UOG facilities;
    - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a tank measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

4.14 Oil-Water Separator Venting for Refineries

4.14.1 Introduction

An oil–water separator is a device designed to separate gross amounts of oil and suspended solids from wastewater effluents. The design of the separator is based on the specific gravity difference between the oil and wastewater. Based on that design criterion, most of the suspended solids will settle to the bottom of the separator as a sediment layer, the oil will rise to the top of the separator, and the wastewater will be contained in the middle layer. Air is introduced to increase the floatation of oil in order to enhance oil removal.

4.14.2 Tiers 1, 2 and 3-Generic Vent Rate

(1) Introduction

The generic vent rate is based on non-methane hydrocarbon vent rate (NMHC) from different types of refinery separators. Separators are also used in petrochemical plants, chemical plants, natural gas processing plants and other industrial oil-water separators, which are not covered in this section. Facilities other than refineries should calculate CH_4 emissions from oil-water separators using process knowledge and engineering estimates.

(2) Equations

Calculate CH_4 emissions from oil-water separators at refineries using Equation 4-17.

$$CH_{4} = VR_{sep} \times Q_{water} \times F_{CH4/NMHC} \times (1 - CF) \times 0.001$$ Equation 4-17

Where:

CH_4 = CH_4 mass emissions (tonnes) from oil water separator in the report period.

Q_{water} = Volume of the wastewater treated in the oil water separator in the report period (m^3).

VR_{sep} = NMHC (non-methane hydrocarbon) emission factor (kg/m^3) from Table 4-11.

CF = Control factor of the oil water separator emission control (dimensionless).

$F_{CH4/NMHC}$ = Mass fraction of CH_4 to NMHC. Use either a default factor of 0.6 or species specific conversion factors determined by analysis or estimation.

0.001 = Convert factor from kg to tonnes.

Table 4-11: Vent Rate for Oil/Water Separators

Separator Type	Vent Rate[5] (kg NMHC/m^3 wastewater treatment)
Gravity Type-uncovered	1.11×10^{-1}
Gravity Type-covered	3.30×10^{-3}
Dissolved air flotation type or induced air flotation type - uncovered[6]	4.00×10^{-3}
Dissolved air flotation type or induced air flotation type - covered[6]	1.20×10^{-4}

1. This table is adapted from Table 11-3 of Canada's Proposed Greenhouse Gas Quantification Requirements, ECCC Canada, September 2018.

(3) Data requirements

- Wastewater volume treated in the oil-water separator is documented.
- The mass fraction of methane to NMHC should be measured once per year at minimum where the default is not used. It should also be measured whenever operating conditions, oil content in water, or oil properties change.
- Measurements must be conducted using:
  - An applicable analytical method prescribed by AER Directives for UOG facilities;
  - An applicable method published by a consensus-based standards organization; or
  - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

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[5] Vent rates do not include ethane

[6] Vent rates for these types of separators apply where they are installed as secondary treatment systems

4.15 Produced Water Tank Venting

4.15.1 Introduction

Produced water is water found in the same formation as oil and gas. When the oil and gas flow to the surface, the produced water is brought to the surface with the hydrocarbons. Produced water can also be water that was previously injected into those formations through activities designed to increase oil production from the formations such as water flooding or steam flooding operations. In some situations additional water from other formations adjacent to the hydrocarbon-bearing layers may become part of the produced water that comes to the surface. Flowback water following hydraulic fracturing is often managed in a similar manner as produced water and is often consider as part of the produced water flow stream. Produced water contains some of the chemical characteristics of the formation from which it was produced and associated hydrocarbons. Produced water is also commonly referred to as saltwater.

Common produced water tanks are atmospheric storage tanks that are located at saltwater disposal sites that store produced water in preparation for disposal. Produced water can be stored in tanks located at oil and gas exploration and production activities, to receive liquids from a separator.

Produced water tank emissions occur in a manner similar to crude oil storage tank flashing losses. Methane emissions from produced water tanks are lower than crude tank flashing losses because CH_4 has a stronger affinity for hydrocarbon oil than it does for water. Thus, less CH_4 is dissolved in the water phase. Varying amounts of CH_4 are emitted from the produced water depending on the temperature and pressure in the produced water tanks.

4.15.2 Tiers 1, 2, and 3–Generic Vent Rate

(1) Introduction

CH_4 emissions are estimated by using the vent rate from produced water tanks, produced water volume and vapor control on the produced water tank by using Equation 4-18.

(2) Equations

$$CH_4 = V_{P,water} \times VR_{CH4} \times (1 - CF) \quad \text{Equation 4-18}$$

Where:

CH_4 = CH_4 mass emissions (tonnes) from produced water tank venting in the report period.

$V_{p,water}$ = Volume of produced water (1000 m^3).

CF = Control factor of the produced water tank emission control (dimensionless).

VR_{CH4} = CH_4 vent rate related to separator pressure and salt content of produced water in Table 4-12a and 4-12b.

Table 4-12a: Produced Salt Water Tank Methane Flashing Vent Rate[1]

Separator Pressure (psi)	Produced Water Salt Content	Water Tank Vent Rate (VR_{CH4}) tonnes CH4 /1000 m^3 produced water
50	20%	0.009185
250	20%	0.06200
250	10%	0.09414
250	2%	0.11137
250	Average of 10.7% [1]	0.08917
1000	20%	0.22273
1000	10%	0.33697
1000	2%	0.39896
1000	Average of 10.7% [1]	0.31955

1. This table is adapted from Table 5-10 of Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, American Petroleum Institute (API), August 2009. Average of emissions factors for 20%, 10% and 2% produced water salt content.
2. Average of vent rates at 20%, 10% and 2% salt.

Table 4-12b: Methane Vent Rates from Produced Water from Shallow Gas Wells

Source Information	CH4 Water Tank Vent Rate
Shallow gas well (76 psi or less, 50℃)	0.036 tonnes CH_4/1000 m^3 produced water

1. This table is adapted from Table 5-11 of Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, American Petroleum Institute (API), August 2009.

(3) Data requirements

- Produced water volume and salt content should be measured or calculated based on engineering estimates.

4.16 Non-Routine Venting-Well Tests, Completion, and Workovers

4.16.1 Introduction

Non-routine well tests, completion, and workovers are planned events that result in venting emissions.

4.16.2 Tiers 1, 2 and 3

(1) Introduction

Hydrocarbon venting from well tests, completions and workovers should be quantified as required by AER Directive 040: Pressure and Deliverability Testing Oil and Gas Wells and Directive 059: Well Drilling and Completion Data Filing Requirements.

(2) Equations

For each blowdown event, calculate CH_4 or CO_2 emissions and sum the CH_4 or CO_2 emissions from blowdown events to calculate total emissions in the report period using Equation 4-19.

$$GHG = \sum_{i=1}^{n} Q_{v} \times MF_{GHG} \times \rho_{GHG} \times 0.001 \qquad \text{Equation 4-19}$$

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from well tests, completion and workovers events in the report period.

i = Vent event identifier.

n = Number of events in the report period.

Q_v = Total vented gas volume (m^3) during a well test, completion or workover event.

MF_{GHG} = Mole fraction of CO_2 or CH_4 in vented gas.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions ($\rho_{CO2} = 1.861$ kg/sm^3; $\rho_{CH4} = 0.6785$ kg/sm^3).

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

- The vented gas volume during the event must be quantified according to AER Directive 040 for minimum standards for performing well tests, and AER Directive 059 requirements for drilling, completion, reconditioning, or well abandonment.
- The composition of the vented gas should be measured before a planned event. Gas compositions must be measured using:
  - An applicable analytical method prescribed by AER Directives for UOG facilities;
  - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

4.17 Non-Routine Venting-Process System Blowdown

4.17.1 Introduction

GHG emissions may be vented to atmosphere during blowdown events required for planned or emergency depressurization (e.g., evacuating process systems or emergency shutdown events).

4.17.2 Tiers 1, 2 and 3-Algorithm

(1) Introduction

This quantification method requires an estimation of the volume of the process system that is evacuated and a measurement or estimation of the composition of the evacuated gas.

(2) Equations

For blowdown emissions, calculate CH_4 or CO_2 emissions for each event and sum the CH_4 or CO_2 emissions from blowdown events to calculate total emissions in the report period.

When the operating conditions represent ideal gas conditions (i.e. gas is not expected to condense due to high pressure and low temperature), use Equation 4-5a to calculate the blowdown emissions.

When the operating conditions represent non-ideal gas conditions (i.e. gas is expected to condense due to high pressure and low temperature), use Equation 4-5b to calculate the blowdown emissions.

(3) Data requirements

Refer to Section 4.5 for ideal gas or non-ideal gas data requirements.

4.18 Non-Routine Venting-Gas Well Liquids Unloading

4.18.1 Introduction

Gas well liquid unloading is a procedure, implemented periodically, where liquids that have accumulated in a gas well are removed to surface equipment. The conventional method of liquids unloading is to use the natural reservoir pressure to lift the liquids accumulated in the tubing to the surface. When reservoir pressure declines, plunger lifts can be used to assist with liquids unloading. In both situations, gas will be vented to the atmosphere. The following equation is used for calculating venting emissions for both natural reservoir pressure and plunger lift unloading procedures.

4.18.2 Tiers 1, 2, and 3-Algorithm

(1) Introduction

The algorithm method estimates the vented gas volume based on the physical dimensions of the casing or plunger lift used for a liquids unloading operation.

(2) Equations

For each liquids unloading venting source, calculate CH_4 or CO_2 emissions for each well unloading event and add the total emissions for all unloading events in the report period using Equation 4-20.

$$GHG = \sum_{i=1}^{n} \left[\left(7.854 \times 10^{-5} \times D^{2} \times WD \times \left[\frac{SP}{101.325} \right] \right) + Q_{sfr} \times t_{open} \right]_{i} \times MF_{GHG/Gas} \times \rho_{GHG} \times 0.001 \qquad \text{Equation 4-20}$$

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from gas well liquid unloading venting in the report period.

i = Gas well liquid unloading event identifier.

n = Number of gas well liquid unloading events in report period.

7.854×10^{-5} = (π/4)/(10,000).

D = Production casing diameter of the well (cm).

WD = Well depth (m).

SP = Well shut-in pressure at well head pressure gauge (kPag).

Q_{sfr} = Maximum monthly sales flow rate of the gas well observed over the report period from production records metered at or converted to standard conditions (Sm^3/h).

t_{open} = Hours that the well was left open to the atmosphere during unloading.

101.325 = Standard absolute pressure (kPaa).

$MF_{GHG/Gas}$ = Mole fraction of CO_2 or CH_4 in vented gas.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3)

0.001 = Mass conversion factor (tonne/ kg).

(3) Data requirements

- Document the length of time (hours) that the well is open to atmosphere and well gauge pressure for each event.
- The composition of vented gas should be measured before a planned event or determined based on process knowledge and/or engineering estimates.
- Gas compositions must be measured using:
  - An applicable analytical method prescribed by AER Directives for UOG facilities;
  - An analytical method prescribed in Section 17.2.3 of Chapter 17.

4.18.3 Tier 4-Direct Measurement

(1) Introduction

This method is for wells that have a flow meter 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).

(2) Equations

Calculate emission from well venting for liquids unloading using Equation 4-21.

$$GHG = \sum_{i=1}^{n} [VR_{i} \times t_{total,i} \times (1 - CF)] \times \left[\frac{P}{101.325}\right] \times MF_{GHG/Gas} \times \rho_{GHG} \times 0.001$$

Equation 4-21

Where:

GHG = CH_4 or CO_2 mass emissions (tonnes) from gas well liquid unloading venting in the report period.

i = Well identifier.

n = Number of wells with the same tubing diameter and producing horizon/formation combination as the measured well.

VR_i = The well vent average flow rate of the measured well i venting for the duration of the liquids unloading event under actual conditions (m^3/hour).

$t_{total,i}$ = Cumulative amount of time in hours of venting from the well i (hour).

P = Absolute pressure at the actual conditions that the flow rate is measured at (kPaa).

CF = Control factor (dimensionless fraction).

101.325 = Standard absolute pressure (kPaa).

$MF_{GHG/Gas}$ = Mole fraction of CO_2 or CH_4 in vented gas.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions (ρ_{CO2} = 1.861 kg/sm^3; ρ_{CH4} = 0.6785 kg/sm^3).

0.001 = Mass conversion factor (tonne/ kg).

(3) Data requirements

- Refer to Section 4.1.2 for data requirements.
- A well vent flow rate measurement should be conducted in accordance with Chapter 17.
- Determine the well vent average flow rate as specified in the following:

  - The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field. The flow rates can be measured from one well representing each unique tubing diameter and producing horizon/formation combination in each producing field.
  - This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination.
  - Flow rates should be measured every other calendar year (if there is a change). An average flow rate is then also recalculated every other calendar year (if there is a change) for each reporting field and horizon starting the first calendar year of data collection.

- Gas compositions must be measured using:
  - An applicable analytical method prescribed by AER Directives for UOG facilities;
  - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

4.19 Non-Routine Venting-Engine and Turbine Starts

4.19.1 Tiers 1, 2 and 3-Generic Vent Rate

(1) Introduction

Pneumatic starters are widely used to start reciprocating engines or turbines, which drive natural gas compressors or electric generators. The starting gas volume will vary according to the pressure of the start gas, condition of the engine/turbine, size of the compressor/generator that is being driven, ambient air temperature, oil viscosity, fuel type, and design cranking speed. The generic vent rates are varied by engine/turbine starter, manufacturer, model and supply pressure.

(2) Equations

Venting volumes from engine and turbine starts are calculated using manufacturer vent rates, and the measured start duration and number of starting events. GHG emissions should be calculated using Equation 4-22.

$$\boldsymbol{GHG} = \sum_{\boldsymbol{i=1}}^{\boldsymbol{n}} [\boldsymbol{VR}_{\boldsymbol{i}} \times \boldsymbol{t}_{\boldsymbol{total,i}} \times (\boldsymbol{1} - \boldsymbol{CF})] \times \boldsymbol{MF}_{\boldsymbol{GHG}} \times \boldsymbol{\rho}_{\boldsymbol{GHG}} \times \boldsymbol{0.001} \qquad \text{Equation 4-22}$$

Where:

GHG = CH_4 or CO_2 mass emissions from engine or turbine start events (tonnes) in the report period.

VR = Manufacturer vent rate for the engine or turbine stated in Table 4-13 (m^3 NG/hour).

i = Engine or turbine identifier.

n = Number of engines or turbines.

$t_{total,j}$ = Total time for engine or turbine i starts in the report period calculated using Equation 4-22a (hr).

CF = Control factor (dimensionless fraction).

MF_{GHG} = Mole fraction of CO_2 or CH_4 in vented gas.

ρ_{GHG} = Density of CO_2 or CH_4 at standard conditions ($\rho CO_2 = 1.861$ kg/sm^3; $\rho CH_4 = 0.6785$ kg/sm^3).

0.001 = Conversion factor from kg to tonne.

$$\boldsymbol{t}_{\boldsymbol{total,j}} = \boldsymbol{t}_{\boldsymbol{un,start}} \times \boldsymbol{N}_{\boldsymbol{un.j}} + \boldsymbol{t}_{\boldsymbol{s,start}} \times \boldsymbol{N}_{\boldsymbol{s,j}}$$

Equation 4-22a

Where:

$t_{total,j}$ = Total start duration (hr) for engine or turbine j in the report period.

$t_{un,start}$ = Average duration per unsuccessful engine or turbine start (hr/start).

$N_{un.j}$ = Number of unsuccessful starts.

$T_{s,start}$ = Average duration per successful engine or turbine start (hr/start).

$N_{un.j}$ = Number of successful starts.

(3) Data requirements

- The successful and unsuccessful starts, and their durations should be documented.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- When vendor flow rates are available, which typically assumes compressed air as the working medium, air consumption rates must be multiplied by 1.29 for equivalent natural gas consumption rates (with ±25% typical uncertainty).

Table 4-13: Pneumatic Starter Natural Gas Consumption Rate by Engine/Turbine

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
			Turbines			
Allison	501-KB	Ingersoll Rand	TS799B	1,034	80	4,822
	501-KC	Tech Development	56K (Low Pressure)	345	33	1,954
			56K (Standard Pressure)	621	55	3,288
	570	Ingersoll Rand	TS799G	621	51	3,068
Dresser Clark	DC990	Tech Development	56B (Low Pressure)	345	36	1,954
			56B (Standard Pressure)	1,034	86	5,172
Dresser Rand	DR990	Tech Development	56B (Low Pressure)	345	36	1,954
	DJ50		56B (Standard Pressure)	1,034	86	5,172
Garrett	IE831	Ingersoll Rand	TS999G	621	47	2,849

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
General Electric	LM500 LM1000 LM1600 LM2500 LM5000 LM6000	Tech Development	56G (Low Pressure)	345	33	1,954
			56G (Standard Pressure)	1,034	86	5,172
Pratt & Whitney	GG3/F13 GG4/G14	Ingersoll Rand	TS799B	1,034	80	4,822
	GG3 GG4 FT4 FT8	Tech Development	56A (Low Pressure)	345	33	1,954
			56A (Standard Pressure)	1,034	86	5,172
Rolls Royce	AVON SPEY	Tech Development	56A (Low Pressure)	345	33	1,954
			56A (Standard Pressure)	1,034	86	5,172

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
Solar Turbines	Saturn 20	Ingersoll Rand	TS725	1,551	27	1,644
			TS750	1,034	44	2,652
		Tech Development	56S	1,034	29	1,725
	Centaur 40 Centaur 50 Taurus 60 Taurus 65 Taurus 70	Ingersoll Rand	TS1401-102	1,551	62	3,726
			TS1435	1,551	69	4,164
			TS1450	1,034	91	5,479
		Tech Development	T100C	1,034	64	3,844
	Mars 90 Mars 100	Recommended by Solar Turbines		2,758	127	7,620

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m³/min)	(m³/hour)
			Reciprocating Engines			
Solar Turbines	G3406	Austart	ATS63	1,034	16	964
	G342 G379 G3412	Austart	ATS73	1,034	22	1,293
	G399	Austart	ATS83	1,034	22	1,293
	G3612 G3616	Austart	ATS93	1,034	48	2,871
	G3616	Austart	ATS103	1,034	56	3,353
	G-342	Ingersoll Rand	150BM	1,034	25	1,490
	G3516	Ingersoll Rand	ST599	1,034	45	2,718
			ST950	1,034	47	2,849
	G3616	Ingersoll Rand	ST950	1,034	47	2,849

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
Solar Turbines	G3612 G3616 G-398 G-399	Ingersoll Rand	SS815	1,034	62	3,726
	G3406 G3408 G3408C	Tech Development	T306-I	827	17	1,048
	G3606	Tech Development	T112-V	1,034	54	3,226
	G3608 G3612 G3616 C280		T121-V	621	59	3,520
Cooper Ajax	DPC-140 DPC-180	Austart	ATS73	1,034	22	1,293

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
Cooper Ajax (cont.)	DPC-360 DPC-600	Austart	ATS83	1,034	22	1,293
	DP-125 DP-165 DPC-180 DPC-60	Ingersoll Rand	150BM	1,034	25	1,490
	DPC-280 DPC-230 DPC-250 DPC-325 DPC-360 DPC-600 DPC-800	Tech Development	T112-B	621	57	3,419
			T121-B	1,034	5	298
Cooper Bessemer	GMX GMSC	Austart	ATS93	1,034	48	2,871
			ATS103	1,034	56	3,353

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m³/min)	(m³/hour)
Cooper Superior	10W330 12V-250 GMVA GMVW MVWC GMXF	Ingersoll Rand	ST950	1,034	47	2,849
	GMXE GMXF GMXH	Ingersoll Rand	SS850	1,034	47	2,794
	6G-825 8G-825 8GT	Austart	ATS83	1,034	22	1,293
	12SGT 16SGT	Austart	ATS93	1,034	48	2,871

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
	825 Series 1700 Series 2400 Series	Tech Development	T112-V	1,034	54	3,226
			T121-V	621	59	3,520
Dresser-Rand	512KV PSVG-12	Ingersoll Rand	ST950	1,034	47	2,849
Int Harvester	RD372 RD450	Ingersoll Rand	3BMG	1,034	12	712
Wartsila	34SG	Ingersoll Rand	ST775	1,034	47	2,849
Waukesha	H24L	Austart	ATS73	1,034	22	1,293
	5790 7042 8LAT27G	Austart	ATS83	1,034	22	1,293
	P9390G 12VAT27G 16VAT25G	Austart	ATS93	1,034	48	2,871

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m³/min)	(m³/hour)
	12VAT27G 16VAT25G 16VAT27G	Austart	ATS103	1,034	56	3,353
	145GZ 6GAK 6WAK F1197G F119G H1077G H1077G H24L H867D	Ingersoll Rand	150T	1,034	26	1,556

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
	2895G (SI/L) H24GL (D) 12VAT25GL 16VAT25GL 7042 (SI/L) 8LAT27GL F2895 F3521 L36GL (D) L7040G P9390G	Ingersoll Rand	ST950	1,034	47	2,849
	12VAT25GL F2895 F3521 L36GL (D)	Ingersoll Rand	ST999	1,034	62	3,726

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
	195GL 6BL V1K V1L VRG283 VRG310	Ingersoll Rand	3BMG	1,034	12	712
	140GZ 140HK 6SRK	Ingersoll Rand	5BMG	1,034	11	679
	6SRB	Ingersoll Rand	SS175G	1,034	18	1,096
	F11G (SI) F18GL (D) H24GL (D)	Ingersoll Rand	SS350G	1,034	33	1,973

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
	145GZ 6GAK 6WAK F1197G F119G H1077G H24L	Ingersoll Rand	150BM	1,034	25	1,490
	7044 7042G (SI/L) 8LAT25D 8LAT25GLF2895G (SI) F3521G (SI)	Ingersoll Rand	SS815	1,034	62	3,726
	12VAT27GL 16AT27GL 16VAT25GL P9390G	Ingersoll Rand	SS825	1,034	49	2,959

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate[1]	
					(m^3/min)	(m^3/hour)
	L5788 L5040 L7042G L7044G	Tech Development	T112-B	621	57	3,419
			T121-B	1,034	5	298
	8LAT27G 12VAT25G 12VAT27G 16VAT27G P9390G	Tech Development	T112-V	1,034	54	3,226
			T121-V	621	59	3,520
White	RXC RXLD RXLX TDXC	Ingersoll Rand	5BMG	1,034	11	679

1. This table is adapted from Tables 28 and 29 of AER Manual 015: Estimating Methane Emissions for Reporting to the AER, December 2018.

4.20 Non-Routine Venting-Pressure Relief

(1) Introduction

GHG emissions may be vented to the atmosphere during pressure relief events when the relief system discharges a stream to atmosphere instead of to a flare or vent gas capture system. Quantification of these emissions require an estimation of the relief rate from the process system and a measurement or estimation of the composition of the fluid.

Different methods can be used to calculate GHG emissions from pressure relief depending on a number of factors, including the phase of the fluid being relieved: gas or vapor relief, two-phase relief, or liquid relief. Emissions may be relieved to atmosphere in two-phases (liquid and gas) in installations such as in liquefied gas storage, refrigerant systems, or gas operations at high pressure. When the fluid inside the process equipment is a liquid, GHG emissions may be released if the liquid contains GHG components and will remain a liquid at atmospheric temperature and pressure conditions (e.g. certain refrigerants) but the discharged liquid pool will slowly evaporate. The liquid stream may also contain dissolved or entrained gaseous GHGs like methane which are released when the relief flow is depressurized to atmosphere.

For pressure relief from rupture discs it is often necessary to perform an unsteady-state calculation to determine the quantity released, because unlike with a conventional or pilot operated PSV, the system pressure will decrease after the initial disc rupture as the system loses inventory, which results in a decreasing flow rate over time. The flow rate should be calculated for each second following the disc rupture using pressure data from a facility's process data historian when available, and these values are then added up over the duration of the relief event in order to obtain the total relief quantity. Where accurate relief pressure data is not available, the relief quantity may be estimated by performing a mass balance around the process system to determine the inventory lost during the pressure relief event. This method may also be employed if isolation valves are used to automatically isolate a process system upon activation of a rupture disc device.

Different calculation approaches will be required for gas vented at sonic velocity, known as critical or choked flow, or below that rate. Relief system hydraulic resistance will need to be determined using manufacturer data for unique components, and standard values for common components.

Estimation of GHG emissions from venting of atmospheric and low-pressure storage tanks is not covered in this section. Refer to Section 4.5 for details on how to estimate GHG emissions from storage tanks.

(2) Equations

Calculation methods based on industry best practices should be used for venting emissions from relief systems, such as those detailed in “Sizing, Selection and Installation of Pressure-Relieving Instruments, Part I: Sizing and selection. API Standard 520. 9th ed.”, American Petroleum Institute, July 2014. The following are additional reference documents:

- “Technical Paper No.410 – Metric Edition: Flow of Fluids Through Valves, Fittings, and Pipe” Crane Valves North America. 1999.
- ”Sizing Pressure-Relief Instruments”, Daniel A. Crowl and Scott A. Tipler, Chemical Engineer Progress, October 2013, American Institute of Chemical Engineers.

Other methodologies developed by consensus based standards organizations may also be used. Under CCIR, the selected methodologies must be documented in the facility’s quantification methodologies document (QMD).

(3) Data requirements

- Actual process temperature and pressure conditions should be used when calculating GHG emissions for each pressure relief event. Engineering estimates should be used if process data is unavailable.
- The composition, physical and transport properties of relief fluids should either be directly measured or estimated based on process knowledge and/or engineering estimates.
- Volumes of process equipment should be calculated directly from isometric drawings as well as vessel and equipment detail drawings.

4.21 Other Venting Emission Sources

(1) Introduction

Alternative quantification methods may be used for routine or non-routine vent gas sources that are not covered in the previous sections. This may include vent gas sources that are similar to ones described in this chapter, but operate under different process conditions.

(2) Equations

A facility may select an appropriate methodology based on the facility's tier classification:

Tier 1:

- Vent or emission rates based on manufacturer specifications; or
- Vent or emission rates from publicly available studies that are specific for the device or type of vent source.

Tier 2:

- Engineering estimates based on, but not limited to mass balances, models, process knowledge, and facility specific data.

Tier 3:

- Periodic (non-continuous) measurements of individual emission sources at normal operating conditions.

Tier 4:

- Continuous measurement of individual emission sources using a permanent or portable meter.

(3) Data requirements

- The facility is required to document the method(s) selected for each vent gas source(s) including the relevant methodology parameters and assumptions used. For facilities reporting under CCIR, the documentation of the selected method should be documented in the facility's QMD.

5.0 Quantification Methods for On-Site Transportation

5.1 Introduction

On-site transportation emissions are direct emissions resulting from fuel combustion in machinery and mobile equipment used for on-site transportation of products and materials integral to the production process of a facility and any other form of transportation taking place within the facility boundary.

Examples of on-site transportation include:

- Transportation of raw or intermediate products and materials within the production process such as equipment used at an oil sands operation to mine and/or move materials to subsequent on-site processing;
- Equipment used at above or below ground mining operations to mine and/or move mined materials;
- Equipment used to transport intermediate products or materials to different on-site production processes;
- Equipment used to handle or load final product for transport, including movement or management of inventory prior to final shipment outside of facility boundaries;
- Transportation of by-products or wastes, such as mining overburden or tailings; and
- Motor vehicle usage on site for general transportation purposes (including transport of people) for regulated facilities under the Carbon Competitiveness Incentive Regulation (CCIR).

Quantification methodologies for on-site transportation emissions are similar to those methods prescribed in Chapter 1 Stationary Fuel Combustion and are referenced throughout this chapter.

Under the CCIR, specified gas emissions from the combustion of fuels that are exempted from the carbon levy must be reported in a facility's compliance reports. Emissions that are priced under the carbon levy are subtracted from the facility's total regulated emissions (TRE). Specifically for the period up to May 31, 2019, emissions from unmarked fuels are subtracted from the TRE; while emissions subsequent to this date are included in the TRE. Therefore, facilities are required to report these emissions separately under CCIR (i.e. emissions from unmarked fuels for the period between January 1 to May 31, 2019).

For emissions that are priced under the carbon levy, CCIR regulated facilities may select any method to quantify the emissions from the combustion of unmarked fuels in on-site transportation, regardless of the facility’s tier classification. Facilities may also use alternative methodologies for all emissions from the combustion of unmarked fuels if the emissions are included in the facility's negligible emissions.

5.2 Carbon Dioxide

5.2.1 Introduction

For each fuel type combusted from on-site transportation, calculate the mass of carbon dioxide (CO_2) emissions from fuel combustion for the reporting period, using one of the methodologies specified in this section. A facility must use the method that corresponds with the tier classification that is assigned to the facility as illustrated in Figure 1.1. A facility must also apply the sampling requirements in Chapter 17 that corresponds with the facility's tier classification.

Figure 5-1 Tier Classification and Methodology Mapping for CO_2 Emissions from On-Site Transportation

		Tier Classification			
		1	2	3	4
Fuel Types*	Non-Variable	Method 1			Method 3
	Natural Gas	Method 2			
	Variable	Method 3			

1. A CCIR regulated facility may use any method, regardless of the facility’s tier classification, to quantify emissions that are priced under the carbon levy from the combustion of unmarked fuels for on-site transportation.

5.2.2 Method 1 - A Fuel-Specific Default CO_2 Emission Factor for Non-Variable Fuels

Facilities are required to use Equation 1-1 or Equation 1-1a from Section 1.2.2 of Chapter 1 Stationary Fuel Combustion to calculate the CO_2 emissions from on-site transportation. Facilities are also required to meet the same data requirements as prescribed in Section 1.2.2. Refer to Table 1-1 of Chapter 1 for the emission factors for non-variable fuels.

These emissions do not include CO_2 emissions from biomass combustion. For blended fuels such as gasoline and diesel, a facility may use the "Diesel in Alberta" and/or "Gasoline in Alberta" to account for the minimum biofuel content. Facilities may also apply Method 3 (below) to account for actual biofuel content in diesel and/or gasoline usage for on-site transportation.

5.2.3 Method 2 - CO_2 Emissions from Combustion of Natural Gas

Facilities are required to use Equation 1-2 from Section 1.2.3 of Chapter 1 Stationary Fuel Combustion to calculate the CO_2 emissions from on-site transportation. Facilities are also required to meet the same data requirements as prescribed in Section 1.2.3.

5.2.4 Method 3 - CO_2 Emissions from Variable Fuels Based on the Measured Fuel Carbon Content

Facilities are required to use Equation 1-3c from Section 1.2.4 of Chapter 1 Stationary Fuel Combustion to calculate the CO_2 emissions from on-site transportation using variable fuels. Facilities are also required to meet the same data requirements as prescribed in Section 1.2.4.

5.3 Methane and Nitrous Oxide

5.3.1 Introduction

Calculate the methane (CH_4) and nitrous oxide (N_2O) mass emissions for the reporting period from on-site transportation emissions, for each fuel type including biomass fuels, using the methods specified in this section. Figure 5-2 provides the requirements for facilities based on tier classification.

Figure 5-2 Requirements Based on Tier Classification

	Tier Classification		
	1	2	3
Requirements	Method 1 using emission factors from Table 1-1 (Chapter 1 Stationary Fuel Combustion) and/or Table 5-1	Method 1 using emission factors from Table 5-1	

1. A CCIR regulated facility may use any method, regardless of the facility's tier classification, to quantify emissions that are priced under the carbon levy from the combustion of unmarked fuels for on-site transportation.

5.3.2 Method 1 - Default CH_4 and N_2O Emission Factor

Facilities are required to use Equation 1-4 or Equation 1-4a of Chapter 1 Stationary Fuel Combustion to calculate CH_4 and N_2O emissions from on-site transportation. Facilities are also required to meet the same data requirements as prescribed in Section 1.3.2. Table 1-1 of Chapter 1 and Table 5-1 present the emission factors for various fuels in mass of CH_4 and N_2O emitted per GJ or kilolitres. For a fuel that is not prescribed an emission factor in these tables, the facility may use an emission factor from an alternative source or use an emission factor from a fuel that is similar in characteristics to a fuel that has a prescribed emission factor.

For CH_4 and N_2O emission calculations, the volume of diesel and gasoline used in on-site transportation must include the biofuel content, as these emissions are not considered to be biomass combustion emissions.

Table 5-1 Emission Factors Based on Fuel and Mobile Equipment Type

Type of Fuel and Mobile Equipment	CH_4 Emission Factor (tonnes/kl)	N_2O Emission Factor (tonnes/kl)
Road Transport		
Gasoline Vehicles		
Light-duty Gasoline Vehicles (LDGVs)		
Tier 2	1.4E-04	2.2E-05
Tier 1	2.3E-04	4.7E-04
Tier 0	3.2E-04	6.6E-04
Oxidation Catalyst	5.2E-04	2.0E-04
Non-catalytic Controlled	4.6E-04	2.8E-05
Light-duty Gasoline Trucks (LDGTs)		
Tier 2	1.4E-04	2.2E-05
Tier 1	2.4E-04	5.8E-04
Tier 0	2.1E-04	6.6E-04
Oxidation Catalyst	4.3E-04	2.0E-04
Non-catalytic Controlled	5.6E-04	2.8E-05

Type of Fuel and Mobile Equipment	CH_4 Emission Factor (tonnes/kl)	N_2O Emission Factor (tonnes/kl)
Heavy-duty Gasoline Vehicles (HDGVs)		
Three-way Catalyst	6.8E-05	2.0E-04
Non-catalytic Controlled	2.9E-04	4.7E-05
Uncontrolled	4.9E-04	8.4E-05
Motorcycles		
Non-catalytic Controlled	7.7E-04	4.1E-05
Uncontrolled	2.3E-03	4.8E-05
Diesel Vehicles		
Light-duty Diesel Vehicles (LDDVs)		
Advanced Control	5.1E-05	2.2E-04
Moderate Control	6.8E-05	2.1E-04
Uncontrolled	1.0E-04	1.6E-04
Light-duty Diesel Trucks (LDDTs)		
Advanced Control	6.8E-05	2.2E-04
Moderate Control	6.8E-05	2.1E-04
Uncontrolled	8.5E-05	1.6E-04
Heavy-duty Diesel Vehicles (HDDVs)		
Advanced Control	1.1E-04	1.5E-04
Moderate Control	1.4E-04	8.2E-05
Uncontrolled	1.5E-04	7.5E-05
Natural Gas Vehicles	9.0E-06	6.0E-08
Propane Vehicles	6.4E-04	2.8E-05
Off-road		
Off-road Gasoline 2-stroke	Refer to Table 1-1 in Chapter 1	

Type of Fuel and Mobile Equipment	CH_4 Emission Factor (tonnes/kl)	N_2O Emission Factor (tonnes/kl)
Off-road Gasoline 4-stroke	Stationary Fuel Combustion	
Off-road Diesel <19kW		
Off-road Diesel >=19kW, Tier 1 - 3		
Off-road Diesel >= 19kW, Tier 4		
Off-road Natural Gas	8.8E-06	6.0E-08
Off-road Propane	6.4E-04	8.7E-05
Railways		
Diesel Train	1.5E-04	1.0E-03
Marine		
Gasoline	2.2E-04	6.3E-05
Diesel	2.5E-04	7.2E-05
Light Fuel Oil	2.6E-04	7.3E-05
Heavy Fuel Oil	2.9E-04	8.2E-05
Kerosene	2.5E-04	7.1E-05
Aviation		
Aviation Gasoline	2.2E-03	2.3E-04
Aviation Turbo Fuel	2.9E-05	7.1E-05

1. Unless otherwise indicated, emission factors are adapted from the 2018 National Inventory Report (NIR 2018) Annex

8.0 Quantification of Industrial Process Emissions

8.1 Introduction

Industrial process (IP) emissions are direct emissions of specified gases generated from an industrial process involving chemical or physical reactions other than combustion, and where the primary purpose of the industrial process is not energy production. Emissions from the unavoidable combustion of carbon black in production of carbon black and ethylene in production of ethylene oxide are also included as IP emissions. IP emissions are typically generated from processes in chemical, mineral, and metal production. This chapter is used for the following industrial process sources:

- CO2 from Hydrogen Production;
- CO2 from Calcining Mineral Carbonates;
- CO2 from Carbonate Use;
- CO2 from Ethylene Oxide Production;
- CO2 from Thermal Carbon Black Production;
- CO2 from Carbon Consumption; and
- N2O from Nitric Acid Production.

Facilities that generate industrial process emissions from a source that is not included in this chapter may use a method that is based on facility specific data or engineering estimates. The methodology used to calculate these emissions must be included in the facility's Quantification Methodology Document (QMD) for reporters under the CCIR.

In this chapter, there may be one or more methodologies prescribed for a process that are not tiered and therefore, are considered to be acceptable for use by a facility under any tier classification.

8.2 CO_2 from hydrogen production

8.2.1 Introduction

Hydrogen is produced at bitumen upgraders, petroleum refineries, chemical plants, stand alone facilities and fertilizer plants, where it is needed for purification or synthesis of substances. In Alberta, hydrogen is produced from gaseous hydrocarbon feeds (typically natural gas) through a process of steam-methane reforming (SMR), followed by shift reactions. The primary and secondary reforming reactions produce carbon monoxide (CO) and hydrogen (H_2). Subsequent shift reactions convert CO to CO_2 to produce additional hydrogen. CO_2 is a by-product of the net reaction:

Steam Methane Reforming: $CH_4 + H_2O \rightarrow CO + 3H_2$

Shift Reaction: $CO + H_2O \rightarrow CO_2 + H_2$

Overall Reaction: $CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$

Any CO_2 generated as a by-product of the above reaction is considered an IP emission. However, under the SGRR these by-product CO_2 emissions must be reported as venting emission instead of IP, if the hydrogen production is at a fossil fuel production or processing facility, such as an upgrader or refinery. This is aligned with requirements of Canada's Greenhouse Gas Reporting Program. The CO_2 by-product produced through reaction can be removed by physical adsorption (e.g. Pressure-Swing Adsorption, PSA) or chemical absorption (e.g. amines, potassium carbonate).

Please note that hydrogen can also be generated through the partial oxidation of hydrocarbons to synthesis gas ("syngas" containing CO and H_2). This process can occur as shown in the first equation above (steam-methane reforming) or the same reaction with pure oxygen added, as follows:

Partial Oxidation Reaction: $HCs + H_2O + O_2 \rightarrow xCO + yH_2 + CO_2(trace)$

As above, any CO_2 generated as a by-product of the above reaction are considered an IP emission. Syngas can be combusted as a fuel but the CO_2 generated from syngas combustion are considered stationary fuel combustion emissions and must be reported under that source category.

CO_2 entrained in the feed are not included in the IP CO_2 emissions total; instead these emissions are classified as formation CO_2 and should be reported under a separate category.

Four methods are provided for IP CO_2 emissions from hydrogen production. These methods are acceptable to be used for any tier classification.

8.2.2 Direct feed oxidation method

(1) Introduction

The Direct Feed Oxidation Method is applicable only for hydrogen production situations where there is no PSA unit to remove and recycle impurities (CO_2, CO, CH_4, C_2H_6) for fuel use. This method assumes that all feed carbon is oxidized to CO_2, which is removed by a chemical absorption process. The method calculates gross IP CO_2 from hydrogen production based on the quantity of reactor feed and its composition. Any inert CO_2 contained in the reactor feed does not participate in the steam-methane reforming reaction and, therefore, is not included in the gross IP CO_2 calculation. The calculation assumes 100% oxidation efficiency for the oxidizable carbon in the feed.

(2) Equations

For each hydrogen production unit where there is no PSA unit to remove and recycle impurities for fuel use, calculate IP CO_2 emissions using the following equation:

$$\boldsymbol{CO_{2,p} = \sum_{i=1}^{N} \left(v_{Feed,i} \times EF_{CO2,i} \right) \times 0.001} \qquad \text{Equation 8-1}$$

Where:

$CO_{2,p}$ = IP CO_2 mass emissions in the reporting period, *p* (tonnes CO_2).

i = Measurement period for reactor feed gas analysis.

N = Number of reactor feed gas analysis measurement periods, *i*, in reporting period.

$v_{Feed,i}$ = Volume of reactor feed gas in measurement period i (standard cubic metres, sm^3), calculated in accordance with Chapter 17 and Appendix C.

$EF_{CO2,i}$ = Feed-specific CO_2 emission factor calculated from the measured reactor feed gas composition analysis results for measurement period i ($kgCO_2/sm^3$) as defined by Equation 8-1a.

0.001 = Mass conversion factor (t/kg).

$$EF_{CO2,i} = \sum_{k=1}^{K} \left(MF_{k,i} \times NC_k\right) \times \rho_{CO2} \qquad \text{Equation 8-1a}$$

Where:

$EF_{CO2,i}$ = IP CO_2 emission factor for measurement period i ($kgCO_2/sm^3$).

I = Measurement period for reactor feed gas analysis.

K = Individual carbon-based oxidizable component of reactor feed gas.

K = Number of measured carbon-based, oxidizable components (e.g. hydrocarbons, CO, COS, CS_2) having non-zero molar fractions in feed gas. Note: CO_2 contained in the feed gas is not included.

$MF_{k,i}$ = Mole fraction of carbon-based oxidizable component k in reactor feed gas in measurement period i. Note: The mole fraction of CO_2 contained in the feed gas is not included.

NC_k = Number of carbons contained in carbon-based oxidizable component k in reactor feed gas.

ρ_{CO2} = 1.8613 kg/m^3 at standard conditions (where ρ_{CO2} is determined by the molecular weight of CO_2 divided by the molar volume of ideal gas at standard conditions as defined by Appendix C).

(3) Data requirements

- The volume, temperature, pressure and composition of the reactor feed gas must be measured in accordance with Chapter 17.

- The volume of the reactor feed gas must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.3 CO_2 Mass balance method

(1) Introduction

The CO_2 Mass Balance Method is typically used in hydrogen production situations where there is a PSA unit that purifies a raw hydrogen stream by removing all non-hydrogen contaminants produced in the SMR and shift reactions or where partial oxidation is used for hydrogen generation. The PSA Purge Gas stream containing CO_2, CO, CH_4, C_2H_6, and some waste H_2 is typically recovered and used as a low-HHV fuel gas in the combustion side of the Reformer Furnace. The method recognizes the following assumptions:

- CO_2 contained in reaction or imported feed is not counted in the IP CO_2 calculation.

(2) Equations

For each hydrogen production unit, calculate IP CO_2 emissions using Equation 8-2:

$$\boldsymbol{CO_2 = CO_2 \ in \ Raw \ Unpurified \ H_2 \ stream \ - CO_2 \ in \ feed}$$

$$\boldsymbol{CO_{2,p} = \left[\sum_{i=1}^{N} \left(v_{RawU\ H2,i} \times MF_{CO2\ RawU\ H2,i} - v_{Feed,i} \times MF_{CO2,Feed,i} \right) \times \rho_{CO2} \right] \times 0.001}$$

Equation 8-2

Where:

$CO_{2,p}$ = IP CO_2 mass emissions in the reporting period, *p* (tonnes CO_2)

i = Measurement period for IP CO_2.

N = Number of IP CO_2 measurement periods i in the reporting period.

$v_{RawU\ H2,i}$ = Volume of raw unpurified H_2 stream in measurement period *i* (sm^3).

$v_{Feed,i}$ = Volume of reactor feed gas in measurement period *i* (sm^3).

$MF_{CO2,Feed,i}$ = CO_2 mole fraction in reactor feed gas ($kmol_{CO2}/kmol_{Feed}$).

$MF_{CO2,RawU\ H2,i}$ = CO_2 mole fraction in raw unpurified hydrogen stream ($kmol_{CO2}/kmol_{RawH2}$).

ρ_{CO2} = 1.8613 kg/m^3 at standard conditions as defined in Appendix C.

0.001 = Mass conversion factor (t/kg).

(3) Data requirements

- The volume, temperature, pressure and composition of the reactor feed gas must be measured in accordance with Chapter 17.
- The volume, temperature, pressure and composition of the raw unpurified hydrogen streams (i.e. before PSA) must be measured in the same frequency as the reactor feed gas.
- The volume of the reactor feed gas and raw unpurified hydrogen stream must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.4 Hydrogen feed calculation method

(1) Introduction

The Hydrogen Feed Calculation Method is an alternative method that back-calculates the quantity of eligible gas feed based on the measured mass of hydrogen generated. This method eliminates the need to measure intermediate, recycled, and wasted streams and their composition by focusing on the stoichiometric feed-to-hydrogen molar ratios for each oxidizable component of the feed gas. The method recognizes the following assumptions:

- CO_2 contained in reaction feed is not counted in the IP CO_2 calculation; and
- All hydrogen is generated through full oxidation of carbon contained in hydrocarbons.

(2) Equations

For each hydrogen production unit, calculate IP CO_2 emissions using the following equation:

$$CO_{2,p} = \sum_{i=1}^{N} \left(\frac{v_{H2,i}}{\sum_{k=1}^{K} \left(SR_{H2/CO2,k} \times MF_{k,i} \right)} \right) \times \rho_{CO2} \times 0.001 \qquad \text{Equation 8-3}$$

Where:

$CO_{2,p}$ = IP CO_2 mass emissions in the reporting period, p (tonnes CO_2).

i = Measurement period for reactor feed gas analysis.

N = Number of reactor feed gas analysis measurement periods i in reporting period.

k = Carbon-based oxidizable components.

K = Number of carbon-based oxidizable components.

$v_{H2,i}$ = Volume of hydrogen produced in measurement period i (sm^3) at standard conditions as defined in Appendix C.

$SR_{H2/CO2,k}$ = Stoichiometric hydrogen-to-CO_2 molar ratio for carbon-based oxidizable component k (CO, CH_4, C_2H_6, etc.) in reactor feed gas, as listed in Table 8-1;

$MF_{k,i}$ = Mole fraction of carbon-based oxidizable component k (e.g. CO, hydrocarbons) in the reactor feed gas in measurement period i. Note: CO_2 and other inert components contained in the reactor feed gas are not included.

ρ_{CO2} = 1.8613 kg/m^3 at standard conditions as defined in Appendix C.

0.001 = Mass conversion factor (t/kg).

Table 8-1 Stoichiometric Molar Ratios of Hydrogen to CO_2

Feed Component	Overall Reaction Equation	SR: H_2/CO_2 Molar Ratio (mol H_2/mol CO_2)
Methane	$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2$	4/1 = 4.000
Ethylene	$C_2H_4 + 4H_2O \rightarrow 2CO_2 + 6H_2$	6/2 = 3.000
Ethane	$C_2H_6 + 4H_2O \rightarrow 2CO_2 + 7H_2$	7/2 = 3.500
Propylene	$C_3H_6 + 6H_2O \rightarrow 3CO_2 + 9H_2$	9/3 = 3.000

Feed Component	Overall Reaction Equation	SR: H_2/CO_2 Molar Ratio (mol H_2/mol CO_2)
Propane	$C_3H_8 + 6H_2O \rightarrow 3CO_2 + 10H_2$	10/3 = 3.333
Butylenes	$C_4H_8 + 8H_2O \rightarrow 4CO_2 + 12H_2$	12/4 = 3.000
Butanes	$C_4H_{10} + 8H_2O \rightarrow 4CO_2 + 13H_2$	13/4 = 3.250
Pentenes	$C_5H_{10} + 10H_2O \rightarrow 5CO_2 + 15H_2$	15/5 = 3.000
Pentanes	$C_5H_{12} + 10H_2O \rightarrow 5CO_2 + 16H_2$	16/5 = 3.200
Hexanes	$C_6H_{14} + 12H_2O \rightarrow 6CO_2 + 19H_2$	19/6 = 3.167
Heptanes	$C_7H_{16} + 14H_2O \rightarrow 7CO_2 + 22H_2$	22/7 = 3.143
Carbon Monoxide	$CO + H_2O \rightarrow CO_2 + H_2$	1/1 = 1.000

(3) Data requirements

- The composition of the reactor feed gas must be measured in accordance with Chapter 17 and Appendix C.
- The volume, temperature, pressure and composition of the hydrogen product stream must be measured in the same frequency as the reactor feed gas.
- The volume of the hydrogen product stream must be adjusted to the volume at standard conditions as defined in Appendix C.

8.2.5 IP CO_2 Emissions from Mass Balance

(1) Introduction

Industrial process CO_2 emissions from hydrogen production can be determined by a mass balance approach if the facility's fuel and feed metering system is integrated and the total fuel and feed consumption can be accurately determined (e.g., third party custody meter). Provided that the facility uses the required methodologies prescribed in Chapter 1 Stationary Fuel Combustion to quantify the CO_2 emissions from fuel combustion, a mass balance approach can be used to quantify the IP CO_2 emissions, which assumes that all carbon that is not combusted would be emitted as IP CO_2. Similar to above methods, CO_2 entrained in the fuel or feed is not included in the IP CO_2 emissions.

(2) Equations

For gaseous fuels and feedstocks, where fuel consumption is measured in units of volume (m^3), use Equation 8-4a:

$$\boldsymbol{CO_{2,p} = (v_{total,p} - v_{SFC,p}) \times CC_{gas,p} \times 3.664 \times 0.001} \qquad \text{Equation 8-4a}$$

For gaseous fuels and feedstocks, where fuel consumption is measured in units of energy (GJ), use Equation 8-4b:

$$\boldsymbol{CO_{2,p} = \frac{ENE_{total,p} - ENE_{SFC,p}}{HHV} \times CC_{gas,p} \times 3.664 \times 0.001} \qquad \text{Equation 8-4b}$$

Where:

$CO_{2,p}$ = IP CO_2 mass emissions in the reporting period, *p* (tonnes CO_2).

$v_{total,p}$ = Total volume of feed and fuel supplied to the facility in the reporting period, *p* (sm^3) calculated in accordance with Chapter 17 and Appendix C.

$v_{SFC,p}$ = Total volume of fuel that is combusted by the facility in the reporting period, *p* (sm^3) calculated in accordance with Chapter 17 and Appendix C.

$CC_{gas,p}$ = Weighted average carbon content of the gaseous fuel during the reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C; however CO_2 contained in the feed gas is not included. CC_p is in the units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m^3).

$ENE_{total,p}$ = Total energy of the total fuel and feed (GJ) supplied to the facility at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.

$ENE_{SFC,p}$ = Total energy of the fuel combusted (GJ) by the facility at standard conditions combusted during reporting period, *p*, calculated in accordance with Chapter 17 and Appendix C.

HHV = Weighted average higher heating value of fuel (GJ/m^3) at standard conditions as

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Mass conversion factor (t/kg).

8.2.6 CO_2 Consumption in urea production

(1) Introduction

Urea production is often performed in conjunction with ammonia production in fertilizer plants and a methodology is included here though this is not necessarily an IP quantity. While steam methane reforming is required and generates CO_2 as IP emissions when producing ammonia, CO_2 is consumed in the urea production process as shown in the following chemical reaction:

$$\mathrm{2NH_3 + CO_2 \rightarrow H_2N - CO - NH_2 + H_2O}$$

(2) Equations

The CO_2 emissions consumed in the urea production process must be included in the total regulated emissions reported under the Carbon Competitiveness Incentive Regulation in accordance with Equation 8-5:

$$\boldsymbol{CO_{2,Urea,p} = m_{Urea} \times \frac{MW_{CO2}}{MW_{Urea}} \times 0.001}$$

Equation 8-5

Where:

$CO_{2,\ Urea,p}$ = CO_2 consumed in urea production in reporting period, *p* (tonnes CO_2).

m_{Urea} = Mass of urea produced during reporting period (kg).

MW_{Urea} = Molecular weight of urea (kg/kmol) (60.06 kg/kmol).

MW_{CO2} = Molecular weight of CO_2 (kg/kmol) (44.01 kg/kmol).

0.001 = Mass conversion factor (t/kg).

(3) Data requirements

Urea production must be measured based on measurement systems used for accounting purposes.

8.2.7 Reporting of waste hydrogen

(1) Introduction

Generated hydrogen that is not used or exported is considered to be waste hydrogen. Waste hydrogen may be vented, flared, or combusted. The method described below is an optional method for calculating waste hydrogen. Other site specific methods of estimating waste hydrogen are also acceptable.

(2) Equations

The equation used to calculate the waste hydrogen is provided by Equation 8-6.

$$\boldsymbol{H_{2,Waste,p} = \sum_{i=1}^{N}\left[\left(m_{H2,Gen,i} + m_{H2,Imp,i}\right) - \left(m_{H2,Exp,i} + m_{H2,Use,i}\right)\right]} \qquad \text{Equation 8-6}$$

Where:

$H_{2,Waste,p}$ = Waste H_2 generated in the reporting period, *p* (tonnes H_2).

i = Measurement period for H_2.

N = Number of H_2 measurement periods, i, in the reporting period.

$m_{H2,Gen,i}$ = Mass of H_2 generated during period i (tonnes).

$m_{H2,Imp,i}$ = Mass of H_2 imported during period i (tonnes).

$m_{H2,Exp,i}$ = Mass of H_2 exported during period i (tonnes).

$m_{H2,Use,i}$ = Mass of H_2 used during period i (tonnes).

A waste hydrogen stream may contain other components such as hydrocarbons and inerts. For the purpose of reporting, only the mass of the hydrogen component is reported. For each of the hydrogen streams (i.e. imported, exported, generated, used, and waste), the mass of the hydrogen component is calculated in accordance with Equation 8-7.

$$\boldsymbol{H_{2,j} = \sum_{i=1}^{N}\left[v_{H2,j} \times MF_{H2,j} \times \rho_{H2}\right] \times 0.001} \qquad \text{Equation 8-7}$$

Where:

$H_{2,j}$ = Hydrogen mass for hydrogen stream j in the reporting period (tonnes H_2).

j = Hydrogen stream.

i = Measurement period for hydrogen.

N = Number of H_2 measurement periods, i, in the reporting period.

$v_{H2,\mathbf{j}}$ = Volume of hydrogen stream j (sm^3 at standard conditions as defined in Appendix

$MF_{H2,j}$ = Mole fraction of hydrogen in stream j ($kmolH_2/kmol$).

ρ_{H2} = 0.08526 kg/m^3, standard density of hydrogen at standard conditions as defined in Appendix C (kg/sm^3).

0.001 = Mass conversion factor (t/kg).

(3) Data requirements

There are no additional data requirements needed.

8.3 CO_2 from calcining carbonates (minerals)

(1) Introduction

Calcining of carbonates into oxides occurs at high temperatures in cement, lime (CaO), and magnesia (MgO) kilns. The most common carbonate feeds used in these facilities are calcium carbonate ($CaCO_3$; Limestone) and magnesium carbonate ($MgCO_3$). Lime kilns can operate at merchant lime facilities and Kraft pulp mills. The primary reaction equations for calcining of carbonates are:

Calcium Carbonate: $CaCO_3 + \text{heat} \rightarrow CaO + CO_2$

Magnesium Carbonate: $MgCO_3 + \text{heat} \rightarrow MgO + CO_2$

This section is adapted from the guidance provided by the World Business Council for Sustainable Development (WBCSD) Cement CO_2 Protocol (2001) and the Western Climate Initiative (WCI). One generic method is provided to cover cement, lime, and magnesia kilns. The contribution from each type of carbonate is accounted for by a composite CO_2 emission factor. The IP CO_2 emissions from calcination include only the CO_2 generated in the calcining reaction. Any CO_2 generated through the combustion of organic carbon contained in kiln feed materials creates useful energy and must be calculated using Equation 8-9 and reported under the Stationary Fuel Combustion source category.

The IP CO_2 emissions are calculated as the sum of CO_2 emitted from calcination producing the primary product, P, and the CO_2 emitted from calcination producing any waste product from the kiln. The primary product, P, may be clinker for cement production, quicklime for lime production, or magnesia for magnesia production. If multiple product grades are produced in one kiln, they must be weight-averaged into one primary product or their CO_2 calculated separately. The waste product, W, may be cement kiln dust (CKD) for cement production, lime kiln dust (LKD) for lime production, or magnesia kiln dust (MKD) for magnesia production. The waste product, W, is a final product from the kiln that is not recycled back to the feed. If multiple waste products are produced, they must be weight-averaged into one waste product or their CO_2 calculated separately.

(2) Equations

For each kiln, calculate IP CO_2 emissions from calcination using the following equation:

$$\boldsymbol{CO_{2-IP,p}} = \sum_{i=1}^{I}\left(\boldsymbol{m_{P,i}} \times \boldsymbol{EF_{P,i}}\right) + \sum_{j=1}^{N}\left(\boldsymbol{m_{W,j}} \times \boldsymbol{EF_{W,j}}\right) \qquad \text{Equation 8-8}$$

Where:

$CO_{2\text{-}IP,p}$ = IP CO_2 mass emissions from calcination of carbonates in reporting period, p (tonnes CO_2).

i = Measurement period i for CaO and MgO in primary product.

I = Number of periods per reporting period for which measurement is required of CaO and MgO in primary product.

j = Measurement period j for CaO and MgO in waste product.

N = Number of periods per reporting period for which measurement is required of CaO and MgO in waste product.

P = Primary kiln product.

W = Waste kiln material.

$m_{P,i}$ = Mass of primary kiln product P in measurement period i (tonnes).

$EF_{P,i}$ = CO_2 emission factor for primary kiln product P in measurement period i (tonnes CO_2 per tonne P), as defined in Equation 8-8a.

$m_{W,j}$ = Mass of waste kiln material W in measurement period j.

$EF_{W,j}$ = CO_2 emission factor for waste kiln material W in measurement period j (tonnes CO_2 per tonne W), as defined in Equation 8-8b.

The kiln-specific CO_2 emission factors ($EF_{P,i}$, $EF_{W,j}$) are calculated based on the total oxide content (e.g. CaO, MgO) of the product or waste, less any oxide in that product or waste that would have been originally present in the feed materials before calcination. These latter oxides are called “non-calcined” oxides and may be present in fly ash or alternative fuels or raw materials (AFR).

$$\boldsymbol{EF_{P,i}} = \left(\boldsymbol{CaO_{P,i}} - \boldsymbol{CaO_{FP,i}}\right) \times \mathbf{0.785} + \left(\boldsymbol{MgO_{P,i}} - \boldsymbol{MgO_{FP,i}}\right) \times \mathbf{1.092}$$

Equation 8-8a

Where:

$EF_{P,i}$ = CO_2 emission factor for primary kiln product P in measurement period i (tonnes CO_2 per tonne P).

$CaO_{P,i}$ = Total calcium oxide content of primary product P in measurement period i (tonnes CaO per tonne P).

$CaO_{FP,i}$ = Non-calcined calcium oxide content of primary product P in measurement period i (tonnes CaO per tonne P), calculated as: fraction of feed calcium oxide mass allocated to P/mass of P.

$MgO_{P,i}$ = Total magnesium oxide content of primary product P in measurement period i (tonnes MgO per tonne P).

$MgO_{FP,i}$ = Non-calcined magnesium oxide content of primary product P in measurement period i (tonnes MgO per tonne P), calculated as: fraction of feed magnesium oxide mass allocated to P/mass of P;

0.785 = Ratio of molecular weight of CO_2 to CaO (44.01/56.1).

1.092 = Ratio of molecular weights of CO_2 to MgO (44.01/40.3).

$$\boldsymbol{EF_{W,j}} = \left(\boldsymbol{CaO_{W,j}} - \boldsymbol{CaO_{FW,j}}\right) \times \mathbf{0.785} + \left(\boldsymbol{MgO_{W,j}} - \boldsymbol{MgO_{FW,j}}\right) \times \mathbf{1.09} \qquad \text{Equation 8-8b}$$

Where:

$EF_{W,j}$ = CO_2 emission factor for waste kiln material W in measurement period j (tonnes CO_2 per tonne W).

$CaO_{W,j}$ = Total calcium oxide content of waste kiln material W in measurement period j (tonnes CaO per tonne W).

$CaO_{FW,j}$ = Non-calcined calcium oxide content of waste kiln material W in measurement period j (tonnes CaO per tonne W), calculated as: fraction of feed calcium oxide mass allocated to W/mass of W.

$MgO_{W,j}$ = Total magnesium oxide content of waste kiln material W in measurement period j (tonnes MgO per tonne W).

$MgO_{FW,j}$ = Non-calcined magnesium oxide content of waste kiln material W in measurement period j (tonnes MgO per tonne W), calculated as: fraction of feed magnesium oxide mass allocated to W/mass of W; magnesium oxide mass allocated to P/mass of P;

0.785 = Ratio of molecular weight of CO_2 to CaO (44.01/56.1).

1.092 = Ratio of molecular weights of CO_2 to MgO (44.01/40.3).

The CO_2 emissions from oxidation of total organic carbon in feed are calculated based on the carbon content of the feed.

$$\boldsymbol{CO_{2,p} = m \times TOC \times 3.664} \qquad \text{Equation 8-9}$$

Where:

$CO_{2,p}$ = Fuel combustion CO_2 mass emissions from oxidation of feed organic carbon in the reporting period, *p* (tonnes CO_2).

m = Mass of kiln feed materials (tonnes) in reporting period.

TOC = Total organic carbon content in kiln feed materials (mass fraction); Default TOC = 0.002 (0.2%);

3.664 = Ratio of molecular weights, CO_2 to carbon.

(3) Data requirements

- The mass of all feeds and products must be determined monthly from measurement systems used for accounting purposes for each lime type and each calcined by products/waste type.
- Chemical composition of CaO and MgO contents of each lime type and each calcined byproduct/waste type must be determined during the same month as the production data.
- The CaO and MgO content of feed and products must be determined once per month based on composite samples.
- The CaO and MgO content of waste materials must be determined once per quarter.

- The CaO and MgO content of any material must be determined using: ASTM C25 - Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime; or the most appropriate industry standard method published by a consensus-based standards organization to determine CaO and MgO content. The reporter should explain the method used while reporting.
- The Total Organic Carbon contained in kiln feeds (TOCF) that is oxidized to CO_2 should be measured once per year, using ASTM C114 or an industry standard method. However, a default TOCF factor of 0.002 (0.2%) can be used.

8.3.2 Lime kilns - Kraft pulp mills

(1) Introduction

Similar to cement, lime, and magnesia kilns, lime kilns are used at Kraft pulp and paper mills. The emissions generated from these kilns include both industrial process emissions and biomass CO_2 emissions. The carbonates in the calcination process, such as sodium carbonate or calcium carbonate, may be derived from mineral or biomass sources. CO_2 emissions that are generated from the calcination of a biomass-based carbonate materials are classifed as biomass CO_2 emissions.

For kilns operating in Kraft pulp mills, the method prescribed to quantify the industrial process emissions only requires the mass of the starting carbonate material that is mineral based. The method assumes a default fraction of carbonate reacted of 1.0 (complete reaction). Since the measurement of unreacted or uncalcined fraction cannot be differentiated between biomass and mineral-based carbonates, this is not a requirement for this method.

(2) Equations

For any carbonate used, calculate IP CO_2 emissions using the following equation:

$$\boldsymbol{CO_{2,p} = \sum_{i=1}^{N} (m_i \times EF_i \times F_i)} \qquad \text{Equation 8-10}$$

Where:

$CO_{2,p}$ = IP CO_2 mass emissions from consumption of carbonates in the reporting period, *p* (tonnes CO_2).

i = Carbonate types.

N = Number of carbonate types.

m_i = Mass of carbonate type i consumed that is mineral based (tonnes) in the reporting period.

EF_i = Emission factor for carbonate type i (tonne CO_2/tonne carbonate consumed), from Table 8-2. If an emission factor is not available in Table 8-2 for a carbonate that is used at the facility, the facility may develop an emission factor based on stoichiometry for the specific carbonate.

F_i = Fraction reacted for each carbonate type i (mass fraction). A default value of 1.0 (complete reaction) is assumed. Alternatively, fraction reacted can be determined by analyzing input and output materials.

(3) Data requirements

- The mass of carbonate consumed shall be determined for the reporting period using the same plant processes used for accounting purposes including purchase records, adjusted for inventory, or direct measurements.
- The mass of carbonates excludes biomass-based carbonates.

8.4 CO_2 from use of carbonates

8.4.1 Introduction

CO_2 can be generated when carbonates participate in some chemical reactions. Flue gas desulphurization, pH control of wastewater, acid leaching of ores containing carbonates, and use of carbonates in metal fluxing are some examples of CO_2 generated from carbonate reactions.

8.4.2 Tier 1 - Carbonate consumption method

(1) Introduction

This simplified method is the same as the method prescribed for lime kilns operating in Kraft pulp mills. The method assumes a default fraction of carbonate reacted of 1.0 (complete reaction). Measurement of fraction reacted by carbonated analysis is optional.

(2) Equations

Use Equation 8-10 to calculate the IP CO_2 emissions.

(3) Data requirements

The mass of carbonate consumed shall be determined for the reporting period using the same plant processes used for accounting purposes including purchase records, adjusted for inventory, or direct measurements.

8.4.3 Tier 2 - Place marker

8.4.4 Tier 3 - Carbonate mass balance method

(1) Introduction

The carbonate mass balance method requires the measurement of the carbonate content in both the input material reacted and the output material produced by reaction.

(2) Equations

For any carbonate used, calculate IP CO_2 emissions for the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^{N} (m_{in} - m_{out}) \times EF_i \qquad \text{Equation 8-11}$$

Where:

$CO_{2,p}$ = IP CO_2 mass emissions from consumption of carbonates (tonnes CO_2) in reporting period, *p* (tonnes CO_2).

i = Carbonate type.

N = Number of input carbonate types.

m_{in} = Mass of input carbonate type i (tonnes) in the reporting period.

EF_i = Emission factor for carbonate type i (tonnes CO_2/tonne carbonate), from Table 8-2.

m_{out} = Mass of output carbonate type i (tonnes) in the reporting period.

(3) Data requirements

The mass of carbonate inputs and outputs must be determined for the reporting period from measurements using the same plant processes used for accounting purposes including purchase records, adjusted for inventory, or direct measurements.

Table 8-2 Default Carbonate CO_2 Emission Factors

Mineral Name	Formula	CO_2 Emission Factor (tonnes CO_2/tonnes Carbonate)
Limestone	$CaCO_3$	0.43971
Magnesite	$MgCO_3$	0.52197
Dolomite	$CaMg(CO_3)_2$	0.47732
Siderite	$FeCO_3$	0.37987
Ankerite	$Ca(Fe,Mg,Mn)(CO_3)_2$	0.47572
Rhodochrosite	$MnCO_3$	0.38286
Sodium Carbonate/Soda Ash	Na_2CO_3	0.41492
Others		Facility specific emission factor to be determined through analysis or supplier information.

8.4.5 Tier 4- Measured CO_2 emission factor method

(1) Introduction

CO_2 from use of carbonates can be estimated based on a facility-specific CO_2 emission factor measured by an annual stack gas test. This method is only applicable when no other sources of CO_2 contribute to the CO_2 in the stack gas from the reaction. CO_2 emissions in the reporting period are calculated by multiplying the activity level of the CO_2 generation process in the reporting period by the measured CO_2 emission factor. Activity level data may be based on:

- Mass of carbonates consumed; or
- Any applicable substance participating in the reaction where CO_2 is released.

One example application of this method is the calculation of CO_2 emissions from the acid leaching of different types of ore containing carbonates.

(2) Equations

For an eligible source of CO_2 from use of carbonates, calculate IP CO_2 emissions in the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^{N}(m_i \times EF_i) \qquad \text{Equation 8-12}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions from consumption of carbonates in the reporting period, *p* (tonnes CO_2).

i = Carbonate-containing material.

N = Number of different carbonate-containing materials.

m_i = Mass of carbonate-containing material of type i consumed (tonnes carbonate) in reporting period.

EF_i = CO_2 emission factor for carbonate-containing material of type i (tonnes CO_2/tonne carbonate), as determined by Equation 8-13.

$$EF_i = \frac{ME_{CO2}}{AL} \qquad \text{Equation 8-13}$$

Where:

ME_{CO2} = CO_2 mass emission rate (tonnes CO_2/hour), where this value is determined from stack testing;

AL = Activity level mass rate of carbonate-containing material of type i (tonnes carbonate/hour) during stack test.

(3) Data requirements

- The activity level used in Equation 8-133 must be determined from measurement systems used for accounting purposes for the period that the stack tests are conducted.
- Stack tests to determine EF_j must be conducted at least once per year for each different type of carbonate used or ore treated. A minimum of three test runs for each stack test and hourly

measurement of activity level are required during the stack test and the results averaged. CO_2 concentrations must be measured by one of the following tests:

  - U.S. EPA Method 320 (40 CFR Part 63, Appendix A), U.S. EPA Method 3A, or any method equivalent to these;
  - ASTM D6348;
  - Any equivalent method published by Environment and Climate Change Canada or Provinces.

- Stack test report containing the measurements used to determine the concentration and mass emission rate of the CO_2 is required to be submitted.

8.5 CO_2 from ethylene oxide production

(1) Introduction

Ethylene oxide ("EO", C_2H_4O) is a reactive chemical that is used mostly as a chemical intermediate to make ethylene glycol (EG) at integrated facilities. Ethylene glycol ("EG", $C_2H_4(OH)_2$) is an organic chemical widely used as an automotive antifreeze and a precursor to polymers such as polyester (for fabrics) and polyethylene terephthalate (PET, for plastic bottles). Ethylene oxide is made by the catalytic "partial" oxidation of ethylene with air or pure oxygen. CO_2 and water are formed as by-products since a fraction of the ethylene is completely oxidized in the reaction process. Approximately 80% of ethylene feed is converted to ethylene oxide and 20% to carbon dioxide and water in two parallel reactions. The by-product CO_2 generated is separated and vented, if not captured for use. All by-product CO_2 is considered as an IP emission.

Ethylene Oxide Production: $C_2H_4 + \frac{1}{2}O_2 \rightarrow C_2H_4O + \text{heat}$ (~80% C_2H_4 converted)

Ethylene Full Oxidation: $C_2H_4 + 3O_2 \rightarrow 2CO_2 + 2H_2O + \text{heat}$ (~20% C_2H_4 converted)

(2) Equations

For each ethylene oxide production train, calculate IP CO_2 emissions using the following equation

$$\boldsymbol{CO_{2,p}} = \left(\sum_{i=1}^{N} \left[\boldsymbol{m_{C2H4\,feed,i}} - \boldsymbol{m_{C2H4\,loss,i}} - \left(\boldsymbol{m_{EO,i}} \times \frac{28.05}{44.05}\right) \right] / \mathbf{28.05} \right) \times \mathbf{2} \times \mathbf{44.01} \qquad \text{Equation 8-14}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions from ethylene full oxidation in reporting period, *p* (tonnes CO_2).

i = Measurement period.

N = Number of measurement periods in reporting period.

$m_{C2H4\ feed,i}$ = Mass of ethylene (C_2H_4) feed for reaction in measurement period i (tonne).

$m_{C2H4\ loss,i}$ = Mass of ethylene (C_2H_4) carried out in the waste gas in measurement period i (tonnes); calculated by Equation 8-14a.

$m_{EO,\ i}$ = Mass EO produced in period i (tonne), calculated from production of monoethylene glycol (MEG), diethylene glycol (DEG), and/or

2 = Number of moles of carbon in C_2H_4.

44.01 = Molecular weight of CO_2 (kg/kmol).

28.05 = Molecular weight of C_2H_4 (kg/kmol).

44.05 = Molecular weight of ethylene oxide (C_2H_4O) (kg/kmol).

$$\boldsymbol{m_{C2H4,loss} = Q_{vent} \times C_{C2H4}/1000} \qquad \text{Equation 8-14a}$$

Where:

Q_{vent} = Vent gas flow rate in the reporting period (m^3).

$C_{C2H4\ loss,i}$ = Concentration of the ethylene (kg/m^3) in the vent gas based on measurements.

$$\boldsymbol{m_{EO,p,i} = m_{MEG} \times 0.710 + m_{DEG} \times 0.830 + m_{TEG} \times 0.880 + m_{HG} \times a + m_{GW} \times b} \qquad \text{Equation 8-14b}$$

Where:

m_{MEG} = Mass of monoethylene glycol production.

0.710 = Ethylene oxide equivalency of monoethylene glycol production.

m_{DEG} = Mass of diethylene glycol production.

0.830 = Ethylene oxide equivalency of diethylene glycol production.

m_{TEG} = Mass of triethylene glycol production.

0.880 = Ethylene oxide equivalency of triethylene glycol production.

m_{HG} = Mass of heavy glycol if applicable.

a = Ethylene oxide equivalency of heavy glycol based on site specific heavy glycol composition.

m_{GW} = Mass of glycol water if applicable.

b = Ethylene oxide equivalency of heavy glycol based on site specific glycol water composition of glycol water.

(3) Data requirements

- The mass of ethylene reacted, mass of ethylene loss and ethylene oxide production are required for the calculation.
- The monthly mass of ethylene oxide should be calculated from the monthly production of all the products: MEG, DEG, TEG, heavy glycol and glycol water, if applicable.
- The quantities of ethylene feed must be based on purchase and accounting records or direct measurements.
- Ethylene content in waste or vent stream should be measured and recorded monthly at minimum.

8.6 CO_2 from use of carbon as reductant

(1) Introduction

CO_2 can be generated when carbon is used directly as a chemical reductant to reduce oxide ores to metals in smelting operations. The consumption of carbon electrodes is a special example of carbon used for metals production.

(2) Equation

For any carbon used in a chemical reaction, calculate IP CO_2 emissions using the following equation:

$$\boldsymbol{CO_{2,p} = m_c \times 3.664} \qquad \text{Equation 8-15}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions from consumption of carbon in reporting period, *p* (tonnes CO_2).

m_C = Mass of carbon consumed (tonnes) in the reporting period. For impure forms of carbon, this quantity is calculated as material mass times carbon content (e.g. 1,000 tonnes x 98.6% C = 986 tonnes C).

3.664 = Ratio of molecular weights, CO_2 to carbon.

(3) Data requirements

- The mass of carbon used is quantified from purchase records, adjusted for inventory, or direct measurement.
- The carbon content of material consumed is based on sampling and chemical analysis using a suitable industry standard method.

8.7 N_2O from nitric acid production

8.7.1 Introduction

Nitric acid (HNO_3; NA) is produced by the oxidation of anhydrous ammonia (NH_3) followed by the absorption of nitrogen oxides (NO, NO_2, N_2O) by water (H_2O). Nitric acid is produced as a 60% solution from the absorber tower. The NOx absorber tail gas contains unabsorbed nitrogen oxides (NO, NO_2, N_2O), which must be controlled prior to release. NOx abatement systems, such as Non-Selective Catalytic Reduction (NSCR) systems, are used to reduce NO, NO_2, and N_2O emissions from NOx absorber tail gas. Nitrous oxide (N_2O) is present in very small concentrations as a by-product of the oxidation reaction and some of this N_2O is emitted in the absorber tail gas as an IP emission.

8.7.2 Tier 1 - Method 1: N_2O Emission factor method for systems with abatement downtime

(1) Introduction

The N_2O Emission Factor Method is used for nitric acid trains that do **not** measure N_2O emissions directly using a CEMS and had abatement downtime when the NOx abatement system was bypassed for a certain period of time during the reporting period. This method requires an annual measurement of N_2O concentration in the NOx Absorber tail gas stream (before the NOx abatement system) and N_2O concentration in the final stack gas stream (after the NOx abatement system).

(2) Equations

For each nitric acid train, calculate IP N_2O emissions using the following equation:

$$N_2O_p = m_{PNA} \times EF_{N2O,NAO} \times \left(1 - \left(DF_{N2O} \times AF_{N2O}\right)\right) \times 0.001 \quad \text{Equation 8-16}$$

Where:

N_2O_p = N_2O mass emissions from nitric acid production in reporting period, *p* (tonnes N_2O).

m_{PNA} = Production mass of nitric acid (100% basis), (tonnes nitric acid product) in reporting period.

DF_{N2O} = Average destruction efficiency of NOx abatement system (%), determined by either:

1) Manufacturer's specifications;
2) Documented engineering estimates based on process knowledge; or
3) Calculated using the direct measurement as shown in Equation 8-16a if the test personal can safely access the upstream of the NOx abatement system.

$EF_{N2O,NAO}$ = Average N_2O emission factor for NOx Absorber Outlet (NAO) (kg N_2O per tonne nitric acid), as defined in Equation 8-16b.

AF_{N2O} = NOx abatement system operating fraction (%) in the reporting period, as defined in Equation 8-16c.

0.001 = Mass conversion factor (t/kg).

The average destruction efficiency can be calculated using the following equation:

$$DF_{N2O} = \frac{(C_{N2O,NAO} \times Q_{N2O,NAO} - C_{N2O,NAS} \times Q_{N2O,NAS})}{C_{N2O,NAO} \times Q_{N2O,NAO}} \times \mathbf{100\%} \qquad \text{Equation 8-16a}$$

Where:

DF_{N2O} = Average abatement system destruction efficiency (%) in reporting period.

$C_{N2O,NAO}$ = N_2O concentration (ppmv) from the NOx Absorber Outlet (NAO).

$Q_{N2O,NAO}$ = Flow rates (m^3/h)from the NOx Absorber Outlet (NAO).

$C_{N2O,NAS}$ = N_2O concentration (ppmv) from the Nitric Acid Stack (NAS).

$Q_{N2O,NAS}$ = Flow rates (m^3/h) from the Nitric Acid Stack (NAS).

The train-specific average N_2O emission factor is calculated based on direct measurement of N_2O concentration in the NOx Absorber outlet (NAO).

$$\boldsymbol{EF_{N2O,NAO}} = \frac{\sum_{i=1}^{N} \frac{\boldsymbol{Q_{NAO,i}} \times \boldsymbol{C_{N2O,NAO,i}}}{\boldsymbol{PR_{NA,i}}} \times \mathbf{1.861} \times \mathbf{10^{-6}}}{\boldsymbol{N}} \qquad \text{Equation 8-16b}$$

Where:

$EF_{N2O,NAO}$ = Average N_2O emission factor for NOx Absorber Outlet (kg N_2O per tonne nitric

i = Test runs.

N = Number of N_2O measurement test runs during stack test.

$Q_{NAO,i}$ = Volumetric flow rate of effluent gas at NOx Absorber Outlet during test run i (sm^3/h) at 15℃ & 1 atm.

$C_{N2O,NAO,i}$ = Measured N_2O concentration at NOx Absorber Outlet in test run i (ppmv N_2O)

$PR_{NA,i}$ = Measured nitric acid production rate during test run i (tonnes nitric acid per hour).

$1.861x10^{-6}$ = N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at 15℃ & 1 atm).

The NOx abatement operating fraction (AF_{N2O}) is a measure of the fraction of total nitric acid production where N_2O emissions are controlled by an operating NOx abatement system. This factor corrects the N_2O equation for any periods during the year when the N_2O destruction by the NOx abatement system is not applied. For operations having 100% NOx abatement uptime, the default AF_{N2O} = 1.0.

$$AF_{N2O} = \frac{PR_{NA,Abate}}{PR_{NA,Total}}$$ Equation 8-16c

Where:

AF_{N2O} = NOx abatement system operating fraction (%) in the reporting period.

$PR_{NA,Abate}$ = Nitric acid production when NOx abatement system is operating (tonnes nitric acid) in the reporting period.

$PR_{NA,Total}$ = Total nitric acid production (tonnes nitric acid) in the reporting period.

(3) Data requirements

- The nitric acid production for the reporting period and the monthly nitric acid production when the N_2O abatement system is operating must be determined from measurement systems used for accounting purposes.

- Stack tests to determine $EF_{N2O,NAO}$ must be conducted at least once per year. A minimum of three test runs for each stack test and hourly measurement of nitric acid production are required during the stack test and the results averaged. N_2O concentrations must be measured by one of the following tests:

  - ○ U.S. EPA Method 320 (40 CFR Part 63, Appendix A) or any method equivalent to this;
  - ○ ASTM D6348;
  - ○ Any equivalent method published by Environment and Climate Change Canada or Provinces.

- Conduct the performance tests for determining the $EF_{N2O,NAO}$ when nitric acid production process has changed or abatement equipment is installed.

- The NOx abatement system destruction efficiency is determined by direct measurement, tests must occur at least once every three years, using the same N_2O concentration methods outlined above.

- For the calculation of AF_{N2O}, the operating time of the NOx abatement system during the reporting period must be determined hourly.

8.7.3 Tier 2 - Method 2: N_2O emission factor method for direct stack test

(1) Introduction

The N_2O Emission Factor Method is used for nitric acid production where NOx abatement systems are integrated within the operating process and cannot be bypassed. A site specific emission factor is developed based on N_2O emissions by stack testing on the final Nitric Acid Stack (NAS) and production rate during the stack test.

(2) Equations

$$\boldsymbol{N_2O_p = m_{PNA} \times EF_{N2O,NAS} \times 0.001}$$

Equation 8-17

Where:

N_2O_p = N_2O mass emissions from nitric acid production in the reporting period, *p* (tonnes N_2O).

m_{PNA} = Production mass of nitric acid (100% basis) (tonnes nitric acid product) in reporting period.

$EF_{N2O,NAS}$ = Average N_2O emission factor (kg N_2O per tonne nitric acid) for the final Nitric Acid Stack (NAS) based on the direct stack testing of the final N_2O emission stack and calculated in Equation 8-17a.

0.001 = Mass conversion factor: tonnes per kg.

$$\boldsymbol{EF_{N2O,NAS} = \frac{\sum_{i=1}^{N} \frac{Q_{NAS,i} \times C_{N2O,NAS,i}}{PR_{NA,i}} \times 1.861 \times 10^{-6}}{N}} \qquad \text{Equation 8-17a}$$

Where:

$EF_{N2O,NAS}$ = Average N_2O emission factor based on final Nitric Acid Stack (NAS) (kg N_2O per tonne nitric acid) in the reporting period.

i = Test runs.

N = Number of N_2O measurement test runs during stack test;

$Q_{NAS,i}$ = Volumetric flow rate of effluent gas at final NAS during test run i (sm^3/h) at 15℃ & 1 atm.

$C_{N2O,NAS,i}$ = Measured N_2O concentration at NAS in test run i (ppmv N_2O);

$PR_{NA,i}$ = Measured nitric acid production rate during test run i (tonnes nitric acid per hour).

$1.861x10^{-6}$ = N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at 15℃ & 1 atm).

(3) Data requirements

- The nitric acid production for reporting period and the monthly nitric acid production when the N_2O abatement system is operating must be determined from measurement systems used for accounting purposes.
- Stack tests to determine $EF_{N2O,NAS}$ must be conducted at least once per year. A minimum of three test runs for each stack test and hourly measurement of nitric acid production are required during the stack test and the results averaged.

- The performance test for determining the $EF_{N2O,NAS}$ must be conducted when nitric acid production process has changed including abatement equipment installation.

8.7.4 Tier 3 - CEMS Method

(1) Introduction

The CEMS Method is a continuous direct measurement of stack flow and N_2O concentrations, which is used to determine the mass flow of N_2O emissions in the stack.

(2) Equation

For each nitric acid production train, calculate N_2O emissions from a CEMS in the reporting period using the following equation. Add N_2O emissions calculated from each train to calculate the total N_2O emissions.

$$\boldsymbol{N_2O_p} = \sum_{t=1}^{T}\left[\boldsymbol{Vel_{s,t}} \times \boldsymbol{Area_s} \times \boldsymbol{C_{N2O,t}} \times \left(\frac{P_{act,t}\times 288.15}{101.325\times T_{act,t}}\right)\right] \times \frac{MW_{N2O}}{23.645} \times \mathbf{0.001} \qquad \text{Equation 8-18}$$

Where:

$N_2O,_p$ = N_2O mass emissions from nitric acid production in reporting period, *p* (tonnes N_2O).

t = CEMS data reporting interval (hour).

T = Number of CEMS data reporting intervals in reporting period (T= 8,760 hours for a non-leap year annual reporting period).

Vel_s = Stack gas velocity (m/h), measured by continuous ultrasonic flow meter.

$Area_s$ = Stack cross-sectional area (m^2).

$C_{N2O,\ t}$ = N_2O concentration (wet basis) of stack gas ($kmol_{N2O}/kmol_{GAS}$), measured by in-situ gas analyzer; (If analyzer provides N_2O concentration in ppmv, then $C_{N2O,\ t}$ = ppmv × 10^{-6}).

MW_{N2O} = Molecular weight of N_2O = 44.01 kg/kmol.

P_{act} = Measured actual pressure of stack gas volume (kPa).

T_{act} = Measured actual temperature of stack gas volume (K).

288.15 = Standard temperature (K).

101.325 = Standard pressure (kPa).

23.645 = Standard molar volume at standard conditions as defined in Appendix C.

0.001 = Mass conversion factor: tonnes per kg.

(3) Data requirements

- Measure N_2O concentration continuously using an in-situ gas analyzer, based on one of the following test methods:
  - U.S. EPA Method 320 (40 CFR Part 63, Appendix A) or any method equivalent to this using Fourier Transform Infrared (FTIR) Spectroscopy;
  - ASTM D6348;
  - Any equivalent method published by Environment and Climate Change Canada or Provinces.
- Measure stack gas temperature and pressure continuously using stack instruments.

8.8 CO_2 from thermal carbon black production

(1) Introduction

The production of thermal carbon black is resulted from the thermal cracking of natural gas based on the following theoretical chemical reaction, where the natural gas is assumed to be primarily methane:

Theoretical Chemical Reaction: $CH_4 = 2H_2 + C$

The off-gas that is generated from this process typically consists of hydrogen, uncracked hydrocarbons, and other smaller constituents. This off-gas may be captured and used as a supplemental fuel to generate energy for the thermal cracking process. The CO_2 emissions generated from the combustion of the off-gas are considered to be stationary fuel combustion emissions. The calculation methodologies for these emissions are prescribed in Chapter 1 of the Quantification Methodologies document.

In addition to offgas combustion, there is combustion of residual carbon that remains in the reactor that can not be extracted as product. The emissions from the combustion of the residual carbon is considered to be IP as the combustion is unavoidable in the chemical production of carbon black.

(2) Equations

The CO_2 emissions from the combustion of the residual carbon are determined using Equation 8-19. Equation 8-19a provides the equation to calculate the mass of carbon in the gaseous feedstock and offgas.

$$\boldsymbol{CO_{2,p} = \left(m_{C,Feed,p} - m_{C,Product,p} - m_{C,Offgas,p}\right) \times 3.664} \qquad \text{Equation 8-19}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions from the combustion of residual carbon in the thermal carbon black production process during the reporting period, *p* (tonnes CO_2).

$m_{C, Feed, p}$ = Mass of carbon in the feedstock consumed in the reporting period, *p* (tonnes C).

$m_{C, Product,p}$ = Mass of carbon in the product produced in the reporting period, *p* (tonnes C).

$m_{C, Offgas,p}$ = Mass of carbon in the offgas consumed in the reporting period, *p* (tonnes C).

3.664 = Ratio of molecular weights, CO_2 to carbon.

$$\boldsymbol{m_{C,Feed,p}\, or\, m_{C,Offgas,p} = v_{fuel(gas)} \times CC_{gas,p} \times 0.001} \qquad \text{Equation 8-19a}$$

Where:

$m_{C,Feed,p}$ or $m_{C,Offgas,p}$ = Mass of carbon in the gaseous feedstock or offgas used during the reporting period, *p* (tonnes C).

$v_{fuel\ (gas),p}$ = Volume of the gaseous feedstock or offgas (m^3) during the reporting period, *p*, at standard conditions as defined in Appendix C.

$CC_{gas,p}$ = Weighted average carbon content of the gaseous feedstock or offgas during the reporting period *p*, calculated in accordance with Chapter 17 and Appendix C. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m^3).

0.001 = Mass conversion factor (t/kg).

(3) Data requirements

- Facilities must ensure that the proper units of feedstock and offgas consumption and carbon content are applied in Equation 8-19a.
- Volume measurements must be adjusted to standard conditions as defined in Appendix C.
- Mass of carbon in the product must be based on the facility's production accounting methods used for the sale of product.

12.0 Quantification of Imports

12.1 Introduction

Imports are considered to be useful thermal energy, electricity and/or hydrogen that are brought into the facility from another facility for consumption in production activities and/or facility operations. Imports do not include quantities of thermal energy, electricity, and/or hydrogen that are generated and consumed within the facility boundaries. Generation and export of these parameters are quantified in a similar manner but are reported as a product, as described in Chapter 13.

There is considerable variation in the consumption of imported and onsite generated electricity, heat, and hydrogen in Alberta facilities, leading to variation in their direct emissions despite otherwise comparable activity. Data on these imports allows these differences to be taken into account when facility performance is compared over time, and across facilities. While other imports also play a role in facility emissions variations, electricity, heat, and hydrogen imports explain many significant emissions performance differences observed. The quantification of these imports should be supported by documents such as invoices or third party documentation, whenever possible, because they represent the shared position of both parties (producer and importer) involved in these imports.

The reporting of imported quantities should be consistent with the overall facility boundaries used for emissions and production reporting. For example, the inclusion of camps, roads, and construction equipment must be consistent with facility boundary definitions.

12.2 Imported Useful Thermal Energy

Imported useful thermal energy refers to energy in any form transferred from a facility producing industrial heat to another facility or residual thermal energy returning to a facility producing industrial heat from a regulated facility or registered offset project, including heat transfer fluids, steam, and hot water. Imported useful thermal energy is to be reported based on third party invoices of total heat imported, if available. If third party invoices of total heat imported are not available then total heat imported is to be calculated in accordance to Chapter 13.11.

The total heat imported is to be reported as follows:

$Heat_{imported}$ = Amount of useful thermal energy imported to the facility, reported in GJ.

12.3 Imported Electricity

Imported electricity refers to electricity generated outside the facility and delivered to the facility from the grid or directly from electricity suppliers. Imported electricity is to be reported based on third party invoices of total imported electricity if available. If third party invoices of imported electricity are not available then total imported electricity is to be calculated in accordance to Chapter 13.6.

The total electricity imported is to be reported as follows:

$E_{imported}$ = Amount of electricity imported to the facility in MWh.

12.4 Imported Hydrogen

Imported hydrogen refers to hydrogen manufactured outside the facility and delivered to the facility. Imported hydrogen is to be reported where hydrogen is greater than 5% of the gas stream by volume. Imported hydrogen is to be reported based on third party invoices of total imported hydrogen if available. If third party invoices of imported hydrogen are not available then total imported hydrogen is to be calculated in accordance to Chapter 13.10.

The hydrogen imported is to be reported as follows:

$H_{imported}$ = Amount of imported hydrogen in tonnes.

As the imported hydrogen stream may contain other constituents (i.e. hydrocarbons, etc.), only the mass of the hydrogen component is reported.

13.0 Quantification of Production

13.1 Introduction

Product data quantification and reporting procedures differ by product. For most product data, reporting is based on production quantities of the finished products. Reporters may use two methodologies for reporting production quantities of finished product data: i) production data and ii) sales data with an inventory adjustment. These two methodologies are considered equivalent. The following table provides the production units that must be reported for each sector.

The quantification of the reported production must be based on direct measurements or a method that is used for accounting records and/or sales records with third parties, except when the production is based on specific references or approaches (e.g. refining, in-situ, and mining oil sands sectors).

Specific products covered in this chapter are those for which established benchmarks have been developed under the *Carbon Competitiveness Incentive Regulation* (CCIR). Definitions of these products are provided in Schedule 2 of the CCIR. This section covers the quantification of production where the definition of what qualifies as a product is covered in the CCIR.

Table 13-1 Products and Production Units

Product	Description/Unit
Ammonia	Tonnes of ammonia (tonnes)
Ammonium Nitrate	Tonnes of ammonium nitrate (tonnes)
Bituminous Coal	Tonnes of clean coal (tonnes)
Cement	Tonnes of clinker, mineral additives (gypsum and limestone) and Supplementary Cementitious Materials added to the clinker produced (tonnes)
Electricity	Megawatt hours (MWh)
Ethylene Glycol	Tonnes of ethylene glycol (tonnes)
Hardwood Kraft Pulp	Air Dried Metric tonnes (ADMt)
High Value Chemicals (HVC)	Tonnes of HVC (tonnes)
Hydrogen	Tonnes of hydrogen (tonnes)

Product	Description/Unit
Industrial Heat	Gigajoules (GJ)
Oil Sands In Situ Oil Bitumen	Cubic meter of bitumen (m3)
Oil Sands Mining Bitumen	Cubic meter of bitumen (m3)
Refining	Alberta Complexity-Weighted Barrel Thousands of barrels (thousand bbl)
Softwood Kraft Pulp	Air Dried Metric tonnes (ADMt)
Natural Gas	Alberta Gas Processing Index

13.2 Ammonia

Ammonia means a compound that is composed of nitrogen and hydrogen with a chemical formula of NH_3 that is typically produced by steam hydrocarbon reforming.

Ammonia production should be reported in tonnes of ammonia. The purity grade of the reported amount should be at least a 99% of ammonia by mass. Production should be measured by mass or by volume at standard conditions as defined in Appendix C.

13.3 Ammonium Nitrate

Ammonium Nitrate is a soluble crystalline solid that can be sold in solid or liquid form, composed of nitrogen and hydrogen with a chemical formula of NH_4NO_3 that is typically produced by the reaction of ammonia with nitric acid.

Ammonium Nitrate production should be measured and reported in tonnes of ammonium nitrate. The purity grade of the reported amount should be at least a 99% of Ammonium Nitrate.

13.4 Bituminous Coal

Bituminous Coal is a moist, mineral-matter free coal which is recovered or obtained from a coal mine located in the Mountain or Foothills regions of Alberta.

Clean Coal means coal which is processed to give a clean, uniform product for sale. In general, a clean coal product would meet product specifications with negotiated maximum and minimum values for ash, volatiles, fixed carbon, sulphur, total moisture, and free swelling index.

Bituminous coal production is to be reported in tonnes of clean coal as delivered.

13.5 Cement

Cement is a fine powered material that consists of a mixture of clinker, gypsum, limestone, and supplementary cementitious materials.

Cement production shall be measured and reported in tonnes after final blending. Cement production is the total mass of clinker produced in tonnes, including mineral and other additives (gypsum, limestone and supplementary cementitious materials).

13.6 Electricity

Electricity means electricity that is exported from the facility. Report electricity production as the total electricity either sold to the end user directly or transmitted to the Alberta Electric System Operator (AESO) controlled grid or an Industrial System (ISD). Electricity transactions (the purchase, sale, import or export of electric power) must be quantified in accordance with the AESO ISO definition for “metered energy” (ISO rule (2010-07-23)). Metered energy means the quantity of electric energy transferred to a point of delivery or from a point of supply, in MWh, reflected by the relevant metering equipment during a particular period of time.

13.7 Ethylene Glycol

As defined by CCIR.

13.8 Hardwood Kraft Pulp

Hardwood Kraft Pulp means wood pulp processed from hardwood species (typically Aspen, Balsam Poplar, or White Birch) by a sulphate chemical process using cooking liquor. Annual Hardwood Kraft Pulp production should be reported in ADMt (Air Dry Metric Tonnes - 10% moisture by mass). Actual mass and moisture content should be measured by bale with measured mass corrected back to a 10% moisture basis.

13.9 High Value Chemicals

As defined by CCIR.

13.10 Hydrogen

Hydrogen is a colorless elemental gas represented by the chemical formula H_2 and is typically produced by, steam methane reforming or hydrocarbon fractionation. Annual production of hydrogen is based on direct measurements, accounting records or sales records with third parties. As the hydrogen product stream may contain other constituents (i.e. hydrocarbons, etc.), only the mass of the hydrogen component is reported.

13.11 Industrial Heat

Industrial heat is quantified as the total heat sold to a third party. Returned boiler feed water or low pressure steam energy is not subtracted as this is to be separately reported as imported heat. Annual production of Industrial Heat is based on sales records with third parties, or calculated in accordance with Chapter 17, Tier 3 and Appendix C.

13.12 Oil Sands In Situ Bitumen

Oil sands in situ bitumen shall be reported consistent with the methodology required by Directive 042: Measurement, Accounting, and Reporting Plan (MARP) Requirement for Thermal Bitumen Schemes and used for the Statistical Report 53 (ST-53) published by the Alberta Energy Regulator in cubic meters.

13.13 Oil Sands Mining Bitumen

Oil sands mining bitumen shall be reported as the total mined crude bitumen production corrected for inventory changes consistent with the methodology used for the Statistical Report 39 (ST-39) published by the Alberta Energy Regulator in cubic meters.

13.14 Refining

13.14.1 Introduction

Refining means any manufacturing or industrial process that occurs at a refinery at which crude oil or bitumen is processed or refined into a transportation fuel.

Complexity Weighted Barrel or CWB is a metric created by Solomon Associates to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The Canadian version of the methodology (CAN-CWB) is outlined in *The CAN-CWB Methodology for Regulatory Support: Public Report, January 2014* (CAN-CWB Methodology).

Alberta has adapted the CAN-CWB to the regulatory and technical requirements in the province introducing the Alberta Complexity Weighed Barrel (AB-CWB) for use as production metric for the refining sector in the province.

13.14.2 Calculations

The AB-CWB methodology is based on three components from the CAN-CWB: the Process CWB, the CWB credit for off-sites and non-energy utilities and the CWB credit for non-crude sensible heat. The CWB adjustments for sales and exports of steam and electricity are not applied in the AB-CWB calculation, since this is already addressed in the CCIR framework which provides allocations for these exports.

The steps for determining the refining production in units of AB-CWB are described below:

13.14.3 Alberta Process CWB

The calculation of the CWB process component is defined as per CAN-CWB methodology and is provided as Equation 13.14-17, with the following two exceptions:

- The CWB Factor for all types of hydrogen production is set to 5.7, independent of the technology and/or feedstock used for hydrogen production.
- The fluid catalytic cracking (FCC) Coke on Catalyst (vol. %) factor is estimated based on the Grace-Davison method described below through equations 13.14 to 13.14-16. The FCC coke on Catalyst (vol. %) factor is then used to calculate the process CWB factor for the FCC unit per CAN-CWB Methodology.

$$\boldsymbol{FCC\ Coke\ on\ Catalyst\ vol\%\ factor_y = Coke\ Yield_y \times \frac{350}{342.17} \times Specific\ Gravity}$$

Equation 13.14-1

Where:

FCC Coke on Catalyst vol% factor = Required input parameter in process CWB

y = Reporting period

Coke Yield = Weight percent of Fresh Feed as calculated below (unitless)

Specific Gravity = As calculated below (unitless)

350/342.17 = Solomon conversion (lb/bbl over lb/bbl)

$$\boldsymbol{Specific\ Gravity = \frac{141.5}{API\ Gravity + 131.5}}$$

Equation 13.14-2

Where:

API Gravity = As measured for combined FCC feed or aggregate of all equivalent FCC feed streams

$$\boldsymbol{Coke\ Yield = 100 \times \frac{Total\ Coke}{FF\ Rate}}$$ Equation 13.14-3

Where:

Total Coke = As calculated below (lb/hr)

FF Rate = Fresh feed rate as calculated below (lb/hr)

$$\boldsymbol{Total\ Coke = Carbon\ Regen\ Burn\ Rate + Hydrogen\ Regen\ Burn\ Rate + Sulpher\ Regen\ Burn\ Rate + Nitrogen\ Regen\ Burn\ Rate}$$

Equation 13.14-4

Where:

Carbon Regen Burn Rate = As calculated below (lb/hr)

Hydrogen Regen Burn Rate = As calculated below (lb/hr)

Sulphur Regen Burn Rate = As calculated below (lb/hr)

Nitrogen Regen Burn Rate = As calculated below (lb/hr)

$$\boldsymbol{Carbon\ Regen\ Burn\ Rate = Molecular\ Wt\ C * (CO\ rate\ in\ flue\ gas + CO2\ rate\ in\ flue\ gas)}$$ Equation 13.14-5

Where:

Molecular Wt C = 12.0107

CO rate in flue gas = As calculated below as component rate (lb/hr)

CO2 rate in flue gas = As calculated below as component rate (lb/hr)

$$\boldsymbol{Hydrogen\ Regen\ Burn\ Rate = Molecular\ Wt\ H2 * H2O\ rate\ in\ flue\ gas}$$

Equation 13.14-6

Where:

Molecular Wt H2 = 2.01588

H20 rate in flue gas = As calculated below (lb-mole/hr)

$$\textbf{Sulpher Regen Burn Rate} = \textbf{Molecular Wt S} * (\textbf{SO2 rate in flue gas} + \textbf{SO3 rate in flue gas})$$

Equation 13.14-7

Where:

Molecular Wt S = 32.065

SO2 rate in flue gas = As calculated below as component rate (lb-mole/hr)

SO3 rate in flue gas = As calculated below as component rate (lb-mole/hr)

$$\textbf{Nitrogen Regen Burn Rate} = \textbf{Molecular Wt S} * (\textbf{NO rate in flue gas} + \textbf{NO2 rate in flue gas})$$

Equation 13.14-8

Where:

Molecular Wt S = 14.0067

NO rate in flue gas = As calculated below as component rate (lb-mole/hr)

NO2 rate in flue gas = As calculated below as component rate (lb-mole/hr)

$$\textbf{Component Mol Rate in Flue Gas} = \textbf{Component mole}\ \% \times \textbf{Dry Flue Gas Mol Rate}/\mathbf{100}$$

Equation 13.14-9

Where:

Component Rate in Flue Gas = Applies to CO, CO2, SO2, SO3, NO, NO2, O2

Component mole % = Measured mole % of component in flue gas (unitless)

Dry Flue Gas Mol Rate = As calculated below (lb-mole/hr)

$$\textbf{H2O mol rate in flue gas} = \frac{\textbf{2 mole H2}}{\textbf{mole O2}} \times [\mathbf{0.20947} \times \textbf{dry air mol rate} + \textbf{O2 purity} \times \textbf{O2 mol rate enriched} - \mathbf{0.5} \times \textbf{CO mol rate in flue gas} - \textbf{CO2 mol rate in flue gas} - \textbf{SO2 mol rate in flue gas} - \mathbf{1.5} \times \textbf{SO3 mol rate in flue gas} - \mathbf{0.5} \times \textbf{NO mol rate in flue gas} - \textbf{NO2 mol rate in flue gas} - \textbf{O2 mol rate in flue gas}]$$

Equation 13.14-10

Where:

0.20947 = Fraction of O2 in air (unitless)

Blower Dry Rate = As calculated below (lb-mole/hr)

O2 purity = Mole fraction O2 in O2 enriched gas (unitless)

O2 mol rate enriched = Rate of enriched gas use as calculated below (lb-mole/hr)

CO mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

CO2 mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

SO2 mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

SO3 mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

NO mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

NO2 mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

O2 mol rate in flue gas = As calculated above as component rate (lb-mole/hr)

$$\boldsymbol{Blower\ Dry\ Rate = Dry\ Air\ Rate \times \frac{60}{379.482}}$$

Equation 13.14-11

Where:

60 = (minutes/hour)

Blower Dry Volume = As calculated below (SCF/minute)

379.482 = Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)

$$\boldsymbol{Dry\ Flue\ Gas\ Rate = \frac{(0.78084+0.00934)\times Dry\ air\ mol\ rate + O2\ Purity \times O2\ Mol\ rate\ enriched}{Regen\ Flue\ Gas\ N2+AR\ mol\ rate}}$$

Equation 13.14-12

Where:

0.78984 = Mole fraction Nitrogen in air (unitless)

0.00934 = Mole fraction Argon in Air (unitless)

Dry air mol rate = As calculated below (lb-mole/hr)

O2 Purity = Mole fraction O2 in O2 enriched gas (unitless)

O2 mol rate enriched = As calculated below (lb-mole/hr)

Regen Flue Gas N2+AR mol rate = 1 – sum of mole fraction of CO, CO2, SO2, SO3, NO, NO2, O2 in flue gas (unitless)

$$\boldsymbol{O2\ mol\ rate\ enriched = O2\ volume\ enriched\ rate \times \frac{60}{379.482}} \qquad \text{Equation 13.14-13}$$

Where:

60 = (minutes/hour)

O2 volume enriched rate = As measured (SCF/minute)

379.482 = Molar volume ideal gas at 1 atm, 60 deg F (SCF/lb-mole)

$$\boldsymbol{Dry\ Air\ Rate = Blower\ Wet\ Rate \times (1 - Water\ content\ in\ air)}$$

Equation 13.14-14

Where:

Wet Air Rate = Measured volume (SCF/minute). This may represent each source of air. Total air input must be captured if resulted from multiple blowers.

Water content in air = As calculated below

$$\boldsymbol{Water\ content\ in\ Air = \frac{Saturated\ Water\ Vapour\ Pressure}{Atmospheric\ Pressure} \times \frac{Relative\ Humidity}{100}}$$

$$\boldsymbol{= \frac{6.1121 \times e^{(17.67 \times T/(243.5+T)}}{Atmospheric\ Pressure} \times \frac{Relative\ Humidity}{100}} \qquad \text{Equation 13.14-15}$$

Where:

Saturated Water Vapour Pressure = Based on Bolton Equation (mbar)

T = Measured ambient temperature (deg C)

Atmospheric Pressure = Measured (mbar)

Relative Humidity = Measured (unitless)

$$\boldsymbol{FF\ Rate = FF\ Volume \times \frac{349.776}{24} \times \frac{141.5}{131.5 + API\ Gravity}} \qquad \text{Equation 13.14-16}$$

Where:

FF Volume = Measured fresh feed volume (B/D)

349.776 = Water density at 60 F and 1 atm (lb/B)

API Gravity = Measured API Gravity of fresh feed (unitless)

24 = time conversion (hr/D)

$$\boldsymbol{CWB_{pro} = \sum_{u=1}^{U} Daily\ Throughput\ Barrel_u \times CWB\ Factor_u} \qquad \text{Equation 13.14-17}$$

Where:

CWB_{pro} [bbl/cd] = Alberta Process CWB as per CAN-CWB and section 13.14.3

u = Units in the refinery boundaries as per CAN-CWB

U = Total number of units in the refinery boundaries as per CAN-CWB

Daily Throughput $Barrel_u$ = Throughput for unit *u* as defined in CAN-CWB in bbl/cd

CWB $Factor_u$ = CWB factor for unit u as defined in CAN-CWB except for Hydrogen Production Unit.

13.14.4 Offsites and non-energy utilities CWB

The CWB credit for offsites and non-energy utilities (CWB_{off}) is calculated based on Process CWB and Total Input Barrels. Total Input Barrels are defined as all raw material inputs to the refinery less transfers of raw materials from the refinery. As per Solomon Associates raw materials include:

- Crude oil to be distilled and otherwise processed by the refinery.
- Natural gas liquids and intermediate hydrocarbon materials that are processed by the refinery, typically downstream from atmospheric crude distillation.
- Blending components and additives that are blended by the refinery into its final products.

In determining Total Input Barrels all liquids should be measured in barrels at standard conditions while gasses including hydrogen, natural gas, fuel gas, ethane, ethylene, and coke should be expressed in Fuel Oil Equivalent Barrels where one Fuel Oil Equivalent Barrel is 6.05 million Btu based on lower heating value.

13.14.5 Non-crude input barrels

The CWB credit for non-crude sensible heat (CWB_{non}) is calculated based on the non-crude input barrels. Non-crude input barrels includes the total input raw material processed by the refinery other than crude or other materials entering the atmospheric distillation unit. As per Solomon Associates they potentially include:

- Hydrogen and hydrogen-rich gas
- Natural gas for hydrogen plant feed
- Butane, isobutane, and mixed butanes
- Natural gas liquids
- Naphtha
- Toluene
- Light cycle oil
- Sour kerosene
- Sour diesel
- Slop oil
- Atmospheric gas oil
- Coker gas oil
- Heavy/vacuum gas oil
- Vacuum residuum
- Residual fuel oil
- Atmospheric reduced crude oil and similar raw materials

All liquids should be measured in barrels at 60 F and 1 atm while gasses including hydrogen, natural gas, fuel gas, ethane, ethylene and coke should be expressed in Fuel Oil Equivalent Barrels where one Fuel Oil Equivalent Barrel is 6.05 million Btu based on lower heating value.

Blending raw materials which are not processed at the refinery are also not included. As per Solomon Associates these may include the following types of material:

- • Product additives
- • Motor gasoline products and blendstocks, including but not limited to the following:
    - – Ethanol, ETBE, MTBE, and other oxygenates
    - – Butanes, pentanes, hexanes, isooctane, isooctane, mixed aromatics, benzene, toluene, mixed xylenes, in addition to other specific hydrocarbons and hydrocarbon mixtures that are suitable for gasoline blending
    - – Alkylate, cat poly gasoline, coker gasoline, and reformate
    - – Motor gasoline product that is purchased for blending by the refinery
- • Kerosene products and blendstocks
- • Diesel products and blendstocks including, but not limited to, the following:
    - – Vegetable oil
    - – Biodiesel
    - – Diesel product for blending that is purchased for blending by the refinery

13.14.6 Refinery production measured in units of AB-CWB

The refinery production, measured in units of AB-CWB (AB-CWB in thousands of barrels per calendar year) is calculated using equation 13.14-18 below:

$$\boldsymbol{Refinery\ Production_y = \frac{(CWB_{pro}+CWB_{off}+CWB_{non})\times Days}{1000}}$$

Equation 13.14-18

Where:

Refinery Production $_y$ = AB-CWB Production of the refinery for year y, in thousand bbl/y

y = Reporting year

CWB_{pro} [bbl/cd] = As per equation 13.14-17 for the reporting year

CWB_{off} [bbl/cd] = 0.327 × Total Input Barrels + 0.0085 × CWB_{pro}

CWB_{non} [bbl/cd] = 0.44 × Non-Crude Input Barrels

Days = Days in the reporting year

The equation above includes the conversion from barrels per calendar day (as defined in the CAN-CWB method) to thousands of barrels per calendar year, which is the unit used in the AB-CWB.

13.15 Softwood Kraft Pulp

Softwood Kraft Pulp means wood pulp processed from softwood species (typically White Spruce, Black Spruce, or Lodgepole Pine) by a sulphate chemical process using cooking liquor. Annual Softwood Kraft Pulp production should be reported in ADMt (Air Dry Metric Tonnes - 10% moisture by mass). Actual mass and moisture content should be measured by bale with measured mass corrected back to a 10% moisture basis.

13.16 Alberta Gas Processing Index

For the natural gas processing sector, the benchmkark was developed based on a modular approach. This approach accounts for differences in the configuration and complexity of Alberta's natural gas processing facilities. The following section provides the quantification methodologies for natural gas process facilities:

13.16.1 Glossary of Terms

Natural gas processing is a complex process that consists of operations involving separation of impurities and various non-methane hydrocarbons and fluids from the raw natural gas to produce a pipeline quality dry natural gas. The process is also used to recover natural gas liquids (condensate, natural gasoline and liquefied petroleum gas) or other substances such as sulfur.

A **"Gas Processing Module"** is one or more grouped operations in the gas processing facility that can be defined and separated from others.

Spec Product (SP) means ethane, propane, butanes or pentanes plus that have been processed (fractionated) to a condition where they meet purchaser specifications for product quality. For condensate (reported in Petrinex as PROC C5-SP), also includes condensate production that is not further processed at the gas plant.

Petrinex is Canada’s upstream, midstream and downstream petroleum industry tool used for reporting information required for the assessment, levy, and collection of crown royalties for the provinces of Alberta and Saskatchewan.

Sulphur is an element produced as a by-product from the sour gas processing. It can be extracted and/or stored in a prill, slate, block, or molten form.

Natural Gas Processing products in this document are defined by *Oil And Gas Conservation Act (*2017), Province Of Alberta, such as:

- **Ethane (C2)** means a mixture mainly of ethane that ordinarily may contain some methane or propane
- **Propane (C3)** means a mixture mainly of propane that ordinarily may contain some ethane or butanes
- **Butanes (C4)** means a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus
- **Natural Gas Liquid (NGL)** means propane, butanes or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate;
- **Pentanes plus (C5+)** means a mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some
- **Condensate** means a mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated.

13.16.2 Unit Modules Description

Inlet Gas Compression

Inlet gas compression is a process that involves pressurizing/compressing inlet natural gas when gas processing at the facility requires pressure higher than the pressure in the delivering pipeline.

The inlet gas throughput (E3m3) includes only the volume of the facility inlet gas that requires compression before the gas enters the first processing module which operates at the facility's working pressure. Module throughputs include inlet gas volumes through both gas-fired and electric-drive compressors.

Any re-compression that exists within a processing unit has been included in the benchmarking for that particular unit and is not included in this module.

Dehydration

Dehydration of natural gas is a process that involves extraction of water vapor from the gas to a specified maximum limit for residual water content. The most common dehydration processes include, but not limited to, absorption with glycol and adsorption with dry desiccant. Glycol dehydrating agents include diethylene glycol (DEG) and triethylene glycol (TEG). The most common desiccants include activated alumina or a granular silica gel material.

The gas throughput volume (E3m3) reflects the total natural gas requiring dehydration. This includes the volume of natural gas through a stand-alone glycol dehydration process and/or the volume of natural gas processed through a molecular sieve dehydrator.

Gas Sweetening

Gas sweetening is a process involving removal of the CO2 and H2S from the raw gas to meet the CO2 and H2S sales gas specifications. Gas sweetening agents may include, but are not limited to primary, secondary, and tertiary amines and/or chemical compounds such as Selexol, Fluor, Purisol, and Sulfinol. A “Merox” process may also be used to remove CO2 and H2S from the raw gas stream.

The amine/gas sweetening throughput includes the total inlet gas volume in E3m3 through the process.

Total Refrigeration

Refrigeration in natural gas treating is a process and/or series of processes that involve separation of natural gas liquids (NGL) from the raw natural gas. Typical individual processes include refrigeration, shallow cut, deep cut and lean oil systems. Refrigeration is also used to meet the hydrocarbon dew point, as well as the water dew point specification for residue or sales gas.

The refrigeration process primarily incorporates the two major methods: absorption and cryogenic expander processes. An absorbing lean oil with high affinity for NGLs is used in the absorption method. The turbo-expander and the Joule-Thomson expansion processes are used in the cryogenic expander method.

The total gas throughput volume (E3m3) in the refrigeration module is determined based on the configuration of refrigeration processes within a facility and is based on three scenarios, as follows:

1. When only one refrigeration process exists within a facility, the total gas throughput volume (E3m3) through this individual refrigeration processing module should be used.
2. When multiple refrigeration processes are run in series, the maximum throughput gas volume (E3m3) through any individual refrigeration processing module should be used.

3. When the refrigeration processes are run in parallel, the total throughput gas volume (E3m3) must be calculated based on the sum of throughput for each individual refrigeration processing module operating in parallel.

Fractionation

Fractionation is a process that involves further separation of the NGLs removed from the natural gas and/or NGLs brought onsite from a Third-Party contractor(s) for further processing/fractionation. Fractionation is based on the different boiling points of different hydrocarbons in the NGL stream. The fractionation process is broken down into steps in the following processing order:

1. Deethanizer - removal of spec product ethane (C2-SP);
2. Depropanizer – removal of spec product propane (C3-SP); and
3. Debutanizer – removal of spec product butanes (normal- and iso- C4-SP), leaving the pentanes and heavier hydrocarbons in the spec product pentane (C5-SP) and/or NGL streams.

Deethanizer, Depropanizer and Debutanizer are referred as the “Fractionation processing module”.

The production from the fractionation module includes the total production of specification (SP) ethane, propane, butane, and pentane products reported in Petrinex in m3 and converted to cubic metres of oil equivalent (m3OE).

Only the portion of C5 plus that goes through the fractionation module, reported as FRAC in Petrinex, should be included here.

When pipeline specification ethane is produced in a Deep Cut Refrigeration process or in the Ethane Extraction processing module at a straddle plant, it should not be included in the fractionation production.

The total fractionation production should include specification products from both: Gas Processing (reported as PROC in Petrinex excluding PROC Pentane-SP) and Fractionation Processing (reported as FRAC in Petrinex).

Stabilization

Condensate stabilization is a process that involves a separation of the very light hydrocarbon gases, e.g. methane and ethane, from the heavier hydrocarbon components so that a vapor phase is not produced upon flashing the liquid into atmospheric storage tanks. Stabilization of the condensate/pentanes+ is usually accomplished through flash vaporization.

The production from the stabilization module includes the total production of Pentane-SP reported in Petrinex as PROC Pentane-SP in m3 and converted to cubic metres of oil equivalent (m3OE). This should not include C5-SP produced in the fractionation module that is reported in Petrinex as FRAC C5-SP.

Sales Compression

Sales gas compression involves pressurizing/compressing pipeline specification sales natural gas to a pressure required for the natural gas transmission and distribution system.

The sales gas throughput (E3m3) includes only the volume of the sales gas leaving the facility where the processing module operating pressure requires further compression prior to delivery to the natural gas transmission and distribution system.

Any re-compression that exists within a processing unit has been included in the benchmarking for that particular unit and is not included in this module.

Module throughputs include sales gas volume delivered to a natural gas transmission line through both gas-fired and electric-drive compressors.

Sulphur Plant

Sulphur recovery is a process of recovering elemental sulfur from acid gas streams containing hydrogen sulfide.

Hydrogen sulfide is a by-product of the sour natural gas processing. The “Claus Process” is the most common method used is the recovery of elemental sulfur. The “Claus” technology consists of a thermal stage (combustion chamber, waste heat boiler) and two or three catalytic reaction stages (reheater, reactor and condenser). The sulfur produced in the thermal stage is condensed in the waste heat boiler or the condenser. The remaining un-combusted hydrogen sulfide undergoes the “Claus” catalytic reaction to form elemental sulfur. Alumina or titanium dioxide are the most commonly used catalysts.

The sulphur plant production includes the sulphur production reported in Petrinex in tonnes of sulphur.

Ethane Extraction

Ethane extraction is a process of removing ethane (including natural gas liquids) from marketable natural gas. Facilities that utilize this process are also referred as straddle plants.

The most common ethane extraction process is a cryogenic process. The cryogenic process consists of lowering the temperature of the gas stream, often with the use of a turbo expander process. The natural gas stream is cooled by using external refrigerants, followed by an expansion turbine, which rapidly expands the chilled gases. This causes the natural gas temperature to drop significantly and rapidly, thus condensing ethane and other hydrocarbons. Methane will remain in a gaseous form.

For straddle plants, the greenhouse gas emissions associated with dehydration, amine sweetening and refrigeration processing are embedded within the ethane extraction plant so a single ethane extraction processing module includes all three processes.

The ethane production includes the volume of ethane production (C2-SP) in E3m3 reported in Petrinex and converted to cubic metres of oil equivalent (m3OE).

Acid Gas Injection

Acid gas injection is a process of injecting or disposing of the acid gas stream into a deep geological formation. The two following steps are associated with the acid gas injection process, after sulfur and carbon dioxide compounds are removed from the acid gas through an amine gas treatment process:

1. The gas is transported through pipelines to a suitable place where it can be injected; and
2. The gas is forced into an injection well.

The acid gas injection throughput includes the total injected volume of acid gas (E3m3) reported in Petrinex or measured at the facility.

Cavern Storage

Cavern storage is the storage of liquid hydrocarbon products in depleted salt caverns. This does not include the storage of processed natural gas. The process of “displacement” is used to move the product in and out of the cavern. Displacement uses brine to force product out of the cavern. Since the brine is heavier than the hydrocarbons and sits below the product in the cavern, brine can be pumped into the cavern through a pipe close to the bottom of the cavern to force the product out through a pipe at the top of the cavern. As product is injected into the cavern, the brine is removed from the bottom of the cavern. To make the displacement system work, most of storage facilities maintain a large brine pond on the surface to move product in and out of the cavern. The volume of the brine pond usually equals that of the volume of the cavern.

The cavern storage production includes the total volume of all liquefied gas product(s), i.e. ethane, propane, butane and associated mixtures reported in m3 injected into the cavern(s).

Note: At this time, due to the small sample size, cavern storage allocations will be assigned on a per facility basis.

CO2 Plant

The CO2 plant refers to a process involving the removal of CO2 from the gas stream, including CO2 purification and/or liquefaction. The cryogenic technology is the most common and efficient technology used in this process.

The CO2 plant processing module throughput includes the total CO2 gas volume (E3m3) produced through the CO2 removal process as measured by facility meters or scales.

Flaring, Venting, Fugitives, Other

The "Flaring, Venting, Fugitives, Other" module includes all GHG emissions sources that are not used for the purpose of gas or liquids processing at a regulated facility.

This module includes, but is not limited to, flare and incinerator stacks, venting (other than formation CO2), facility fugitive emissions, residue gas for straddle plants, diesel emergency generators, fire water pumps and other minor (<100 tonnes CO2e) emission sources.

The "Flaring, Venting, Fugitives, Other" throughput is taken as the total annual facility production reported in Petrinex, converted to m3OE.

To further illustrate the concept of the natural gas processing modules, refer to Appendix E for an overview of the modules followed by some typical natural gas plant configurations.

Average module intensities represented by weighting factors for Alberta Gas Processing Index are also provided in the Appendix.

13.16.3 Production and Throughput Quantification Methods

The intent of this guidance is to align, to the extent possible, the requirements of the Quantification Methodologies for the Carbon Competitiveness Incentive Regulation and the Specified Gas Reporting Regulation and the Alberta Energy Regulator's Directive 007: Volumetric and Infrastructure Requirements. Both documents require production and throughput to be reported at standard temperature and pressure conditions of 288.15 K and 101.325 kPa. No new production metering requirements apply for the 2018 compliance year. Methods used should be documented in the facility's Quantification Methodology Document.

Alberta Environment and Parks recognizes that quantification of modular throughputs and production will require flexibility for 2019 as facilities adapt to the new reporting requirements with existing infrastructure. Accordingly, this section sets out a hierarchy of methods for measuring throughputs and production.

Configuration	Method
Module throughput or production is not metered	Method 1
Module throughput or production is metered	Method 2

Method 1: Where a facility does not have a meter(s) for a given module's throughput or production, it is acceptable to calculate with a material balance from other measured parameters if:

- The approach is documented in the facility's Quantification Methodology Document.
- The approach is the most accurate one readily available.
- The more conservative approach is used when two equally accurate approaches are available.

Method 2: Where a facility has a meter(s) installed for a given module's throughput or production, the metered value shall be used. Where a module's metered throughput or production value differs from an analogous value reported in Petrinex suggested by this guidance document, the facility shall include an explanation for the difference in its Quantification Methodology Document.

When a processing module's throughput or production directly obtained through either Method 1 or Method 2 is more representative than the Petrinex reported value or such throughput or production is not being reported to Petrinex, use the values directly obtained through Method 1 or Method 2 instead and include a description of the difference in the Quantification Methodology Document.

Table 13.16 Alberta Gas Processing Index Weighting Factors

Module		Stream		Weighting Factor	
		Type	Unit	Value	Unit
1	Inlet Compression	throughput	e^3m^3	0.03304	t_{CO2e} / e^3m^3
2	Dehydration	throughput	e^3m^3	0.00247	t_{CO2e} / e^3m^3
3	Gas Sweetening	throughput	e^3m^3	0.03040	t_{CO2e} / e^3m^3
4	Total Refrigeration	throughput	e^3m^3	0.01835	t_{CO2e} / e^3m^3

Module		Stream		Weighting Factor	
		Type	Unit	Value	Unit
5	Fractionation	production	m^3_{OE}	0.04141	t_{CO2e} / m^3_{OE}
6	Stabilization	production	m^3_{OE}	0.05537	t_{CO2e} / m^3_{OE}
7	Sales Compression	throughput	e^3m^3	0.02135	t_{CO2e} / e^3m^3
8	Sulphur Plant	production	$t_{Sulphur}$	0.4249	t_{CO2e} / $t_{Sulphur}$
9	Acid Gas Injection	throughput	$e^3m^3_{Acid\ Gas}$	0.3960	t_{CO2e} / $e^3m^3_{Acid\ Gas}$
10	Ethane Extraction	production	m^3_{OE}	0.1251	t_{CO2e} / m^3_{OE}
12	CO_2 Plant	throughput	$e^3m^3_{CO2}$	0.1881	t_{CO2e} / $e^3m^3_{CO2}$
13	Flaring, Venting, Fugitives	production	m^3_{OE}	0.004452	t_{CO2e} / m^3_{OE}

For additional information on the Alberta Gas Processing Index, refer to the following appendices:

E.1 – Overview of Natural Gas Processing Modules

E.2 – Simplified Flow Diagram of a Typical Natural Gas processing Plant

E.3 – Simplified Flow Diagram of a Typical Natural Gas processing Plant (Dehydration within Refrigeration)

E.4 – Simplified Flow Diagram of a Typical Natural Gas Straddle Plant

E.5 – Simplified Flow Diagram of a Typical Natural Gas Straddle Plant (without Fractionation)

E.6 – Oil Equivalent Conversion Factors

14.0 Quantification Methods for Carbon Dioxide from Combustion of Biomass

14.1 Introduction

This chapter presents the methodologies for CO_2 emissions from the combustion of biomass, while CH_4 and N_2O emissions from the combustion of biomass are considered to be stationary fuel combustion and are covered in Chapter 1.

14.2 Tier 1 - A fuel-specific default CO_2 emission factor

(1) Introduction

This method is used for biomass fuels based on a default CO_2 emission factor and the quantity of fuel consumed. The quantity of biomass consumed may be in energy or physical unit basis, which is measured by the facility using the methods prescribed in Chapter 17 and Appendix C. Biomass consumption measured or provided in units of energy must be based on the HHV of the fuel. Table 14-1 provides the emission factors for biomass fuels in mass of CO_2 emitted per gigajoules (GJ), tonnes or kilolitres (kl).

For facilities that have the HHV of the fuel, measured or supplied by the third party supplier, Equation 14-1 is used to convert the volume or mass of the fuel to the energy of the fuel based on the HHV and then multiplied by the appropriate energy based emission factor from Table 14-1 to calculate the CO_2 mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 14-1a can be used directly to calculate the CO_2 mass emissions based on the appropriate energy based emission factor from Table 14-1.

Facilities must use measured or supplied HHVs to determine the fuel consumption if this data is available; however in cases where a facility is unable to obtain this information, a facility may apply Equation 14-1a using the fuel quantity in mass/volume basis with the appropriate mass/volume based emission factor from Table 14-1 to calculated the CO_2 mass emissions.

Calculate the CO_2 mass emissions for the reporting period for each type of biomass by substituting a fuel-specific default CO_2 emission, a measured or supplied HHV and the fuel consumption for the reporting period into Equation 14-1 or Equation 14-1a.

(2) Equations

For a biomass fuel, use Equation 14-1 or Equation 14-1a to calculate the CO_2 mass emissions for the reporting period.

$$CO_{2,p} = Fuel_p \times HHV \times EF_{ene} \quad \text{Equation 14-1}$$

$$CO_{2,p} = Fuel_p \times EF_{vol} \text{ or } EF_{ene} \quad \text{Equation 14-1a}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions for the biomass fuel for the reporting period, *p* (tonnes CO_2).

$Fuel_p$ = For Equation 14-1, the mass/volume of fuel combusted in tonnes or kilolitres (tonnes or kl). For Equation 14-1a, energy units of fuel in gigajoules or physical units of fuel in tonnes or kilolitres (GJ, tonnes, or kl). Fuel quantities must be calculated in accordance with Chapter 17 and Appendix C.

HHV = Measured or supplied higher heating value in gigajoules per tonne or kilolitres (GJ/tonne or GJ/kl).

EF_{vol}, EF_{ene} = Fuel-specific default CO_2 emission factor, from Table 14-1 in tonnes of CO_2 per energy units (GJ) or physical units (tonnes or kl).

(3) Data requirements

HHV is provided by the third party fuel supplier or measured by the facility in accordance with Chapter 17 and Appendix C.

14.3 Tier 2 - Place marker.

14.4 Tier 3 - Measurement of fuel carbon content

(1) Introduction

Calculate the CO_2 mass emissions from biomass combustion by using the measured fuel carbon content using Equation 14-3a, Equation 14-3b, Equation 14-3c, or Equation 14-3d. For steam generation from biomass combustion, CO_2 mass emissions may be calculated using Equation 14-3e.

(2) Equations

For gaseous biofuels, where fuel consumption is measured in units of volume (m^3), use Equation 14-3a:

$$\boldsymbol{CO_{2,p} = v_{fuel(gas),p} \times CC_{gas,p} \times\ 3.664 \times 0.001} \qquad \text{Equation 14-3a}$$

For gaseous biofuels, where fuel consumption is measured in units of energy (GJ), used Equation 14-3b:

$$\boldsymbol{CO_{2,p} = \frac{ENE_{fuel(gas)p} \times CC_{gas,p} \times\ 3.664 \times 0.001}{HHV}} \qquad \text{Equation 14-3b}$$

Where:

$CO_{2,p}$ = CO_2 mass emissions for the gaseous biofuel combusted during the reporting period, p (tonnes CO_2).

$v_{fuel(gas),p}$ = Volume of fuel (m^3) at standard conditions combusted during reporting period, p, calculated in accordance with Chapter 17 and Appendix C.

$ENE_{fuel(gas),p}$ = Energy of fuel (GJ) at standard conditions combusted during reporting period, p, calculated in accordance with Chapter 17 and Appendix C.

HHV = Weighted average higher heating value of biofuel (GJ/m^3).

$CC_{gas,p}$ = Weighted average carbon content of the gaseous biofuel during the reporting period p, calculated in accordance with Chapter 17 and Appendix C. CC_p is expressed in units of kilogram of carbon per standard cubic metre of gaseous fuel ($kg\ C/m^3$).

3.664 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Mass conversion factor (t/kg).

For liquid biofuels, where fuel consumption is measured in units of volume (kl), use Equation 14-3c:

$$\boldsymbol{CO_{2,p} = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664} \qquad \text{Equation 14-3c}$$

Where:

$CO_{2,p}$	CO_2 mass emissions for the liquid biofuels during the report period, p (tonnes CO_2).
$v_{fuel(liq),p}$	Volume of liquid biofuel combusted during the reporting period p, calculated in accordance with Chapter 17 and Appendix C (kl).
$CC_{liq,p}$	Weighted average carbon content of the liquid biofuel during the reporting period
3.664	Ratio of molecular weights, CO_2 to carbon.

For solid biomass fuels, where fuel consumption is measured in units of mass (tonnes), use Equation 14-3d:

$$CO_{2,p} = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664 \qquad \text{Equation 14-3d}$$

Where:

$CO_{2,p}$	CO_2 mass emissions for the biomass fuel during the report period, p (tonnes CO_2)
$m_{fuel(sol),p}$	Mass of biomass fuel combusted during the reporting period p, calculated in accordance with Chapter 17 and Appendix C (tonnes).
$CC_{sol,p}$	Weighted average carbon content of the fuel during the reporting period p, calculated in accordance with Chapter 17 and Appendix C. CC_p is expressed in units of tonnes of carbon per tonnes of solid fuel (tonnes C/tonnes).
3.664	Ratio of molecular weights, CO_2 to carbon.

For biomass combustion used to generate steam, use Equation 14-3e:

$$CO_{2,p} = Steam \times B \times EF \qquad \text{Equation 14-3e}$$

Where:

$CO_{2,p}$	CO_2 mass emissions for the biomass fuel for the reporting period, *p*, (tonnes CO_2).
Steam	Total steam generated by biomass fuel or biomass combustion during the reporting year (tonnes steam), in GJ and calculated in accordance with Chapter 17 and Appendix C.
B	Ratio of the boiler's design rated heat input capacity to its design rated steam output capacity in GJ per GJ provided by the manufacturer or calculated in
EF	Measured emission factor for biomass solid fuel from a methodology approved by the director, in tonnes of CO_2 per GJ.

(3) Data requirements

No additional requirements are needed.

14.5 Tier 4 Continuous emissions monitoring systems

(1) Generality

Calculate the CO_2 mass emissions for the reporting period from all fuels combusted in a unit, by using data from CEMS as specified in (a) though (g). This methodology requires a CO_2 monitor and a flow monitoring subsystem, except as otherwise provided in paragraph (c). CEMS shall use methodologies in accordance with reference [8] in Appendix A or by other document that supersedes it.

(a) For a facility that operates CEMS in response to federal, provincial or local regulation (i.e. required by the facility's Alberta Energy Regulator (AER) or Environmental Protection and Enhancement Act (EPEA) approval), use CO_2 or oxygen (O_2) concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided by the applicable regulatory requirements (i.e. facility's AER or EPEA approval) or in accordance with reference [8] in Appendix A.

(b) Report CO_2 emissions for the reporting period in tonnes based on the sum of hourly CO_2 mass emissions over the reporting period.

(c) An O_2 concentration monitor may be used in lieu of a CO_2 concentration monitor in a CEMS install before January 1, 2012, to determine the hourly CO_2 concentrations, if the effluent gas stream monitored by the CEMS consists of 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.

(i) If the operator of a facility that combusts biomass fuels uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that the calculated CO_2 concentrations, when compared to measured CO_2 concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in reference [8] in Appendix A or Alberta CEMS Code.

(d) If both biomass and fossil fuels (including fuels that are partially biomass) are combusted during the reporting period, determine the biogenic CO_2 mass emissions separately, as described in Section 14.4 (2).

(e) For any units using CEMS data, industrial process and stationary combustion CO_2 emissions must be provided separately. Determine the quantities of each type of fossil fuel and biomass consumed during the reporting period, using the fuel sampling approach in Table 17.3 of Chapter 17.

(f) If a facility subject to requirements for continuous monitoring of gaseous emissions chooses to add devices to an existing CEMS for the purpose of measuring CO_2 concentrations or flue gas flow, select and operate the added devices using appropriate requirements in accordance with reference [8] in Appendix A for the facility, as applicable in Alberta under the Alberta CEMS Code.

(g) If a facility does not have a CEMS and chooses to add one in order to measure CO_2 concentrations, select and operate the CEMS using the appropriate requirements in accordance with reference [8] in Appendix A or equivalent requirements as applicable in Alberta under the Alberta CEMS Code.

(2) CO_2 emissions from combustion of mixture of biomass, or biomass fuels and fossil fuels

Use the procedures in this section to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels, including combustion of waste-derived fuels that are partially biomass.

(a) If a CEMS is not used to measure CO_2 and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Tier 1, 2 or 3, as applicable, to calculate the biogenic CO_2 mass emissions for the reporting period 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 the best available information to determine the mass of biomass fuels and document the procedure.

(b) If a CEMS is used to measure CO_2 (or O_2 as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels, use Tier 1, 2 or 3, as appropriate in Chapter 1, to calculate the CO_2 mass emissions for the reporting period from the combustion of fossil fuels. Calculate biomass fuel emissions by subtracting the fossil fuel-related emissions from the total CO_2 emissions determined from the CEMS based methodology.

(c) If combusted fuels or fuel mixtures contain a biomass fraction that is unknown or cannot be documented (e.g., wood waste and tire-derived fuel, etc.), or biomass fuels with no CO_2 emission factor provided in Table 14-1 use the following to estimate biogenic CO_2 emissions:

    (i) Tier 1, 2, 3 or 4 to calculate the total CO_2 mass emissions for the reporting period, as applicable.
    (3) Determine the biogenic portion of the CO_2 emissions using ASTM D6866-16 “Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis”. This procedure is not required for fuels containing less than 5% biomass by weight or for waste-derived fuels that are less than 30% by weight of total fuels combusted in the year for which emissions are being reported, except, if a facility wishes to report a biomass fuel fraction of CO_2 emissions.
    (4) Conduct analysis of representative fuel or exhaust gas samples at least every three months, using ASTM D6866-16. Collect the exhaust gas samples over a minimum of 24 consecutive hours following the standard practice specified by ASTM D7459-08(2016) “Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources.”
    (5) Allocate total CO_2 emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed annually for which emissions are being reported.
    (6) If there is a common fuel source for multiple units at the facility, ASTM D6866-16 analysis may be conducted for only one of the unit sharing the common fuel source.

(d) If Equation 14-1 or 14-1a is selected to calculate the biogenic mass emissions for the reporting period for wood, wood waste, or other solid biomass-derived fuel, Equation 14-4 may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified according to Chapter 17 and Appendix C. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented.

$$\boldsymbol{Fuel_i = \frac{[H \times Steam] - (HI)_{nb} \times (Eff)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}}} \qquad \text{Equation 14-4}$$

Where:

$Fuel_i$ = Quantity of biomass consumed during the measurement period i (tonnes/year or tonnes/month, as applicable) calculated in accordance with Section 17.

H = Average enthalpy increase of the boiler steam through the boiler for the

Steam = Total boiler steam production for the measurement period (tonne/month or tonne/year, as applicable) calculated in accordance with Chapter 17.

$(HI)_{nb}$ = Heat input from co-fired fossil fuel and non-biomass-derived fuels for the

$(HHV)_{bio}$ = Default or measured higher heating value of the biomass fuel (GJ/tonne)

$(Eff)_{bio}$ = Efficiency of biomass-to-energy conversion for boiler, expressed as a decimal fraction and calculated in accordance with Chapter 17.

$(Eff)_{nb}$ = Efficiency of fossil fuel and non-biomass derived fuel to energy conversion for boiler, expressed as a decimal fraction.

(3) Data requirements

No additional data requirement are needed.

14.6 Emission Factors

Table 14-1 Default emission factors for biomass fuels

Biomass Fuel	HHV (GJ/kl)	CO_2 Emission Factor		Reference
		tonne/kl	tonne/GJ	
Ethanol	23.42	1.508	0.0644	ECCC Table 2-2
Biodiesel	35.16	2.472	0.0703	ECCC Table 2-2
	HHV (GJ/tonne)	tonne/tonne	tonne/GJ	Reference
Wood Fuel / Wood Waste	18.0	0.840	0.0467	ECCC Table 2-3
Spent Pulping Liquor	14.0	0.891	0.0636	ECCC Table 2-3

17.0 Measurement, Sampling, Analysis and Data Management Requirements

17.1 Introduction

The methodologies prescribed in this chapter are intended to be aligned with methods that are prescribed under Environment and Climate Change Canada (ECCC) and other jurisdictions that regulate greenhouse gas emissions such as British Columbia, Ontario, Quebec, and California. Further, methodologies from organizations such as the Western Climate Initiative, Inc. (WCI), United States Environmental Protection Agency (USEPA), and the Intergovernmental Panel on Climate Change (IPCC) are referenced or adopted as appropriate for various activity types and modified to meet the needs of Alberta sectors.

17.2 Fuel consumption

17.2.1 Fuel consumption measurement requirements

Facilities may determine fuel consumption on the basis of direct measurement, fuel purchase records, or sales invoices measuring any stock change. Equation 17-1 is used to quantify fuel consumption.

$$\boldsymbol{Fuel} = \boldsymbol{Fuel_p} - \boldsymbol{Fuel_s} + \boldsymbol{Fuel_{ii}} - \boldsymbol{Fuel_{ei}} \qquad \text{Equation 17-1}$$

Where:

$Fuel$ = amount of fuel used by the facility in the reporting year

$Fuel_p$ = amount of fuel purchased in the reporting year

$Fuel_s$ = amount of fuel sold in the reporting year

$Fuel_{ii}$ = initial amount of fuel in the inventories

$Fuel_{ei}$ = ending amount of fuel in the inventories

(a) Facilities may quantify liquid fuels consumed at the facility based on third party invoices for the reporting period without accounting for the initial and ending fuel quantities in the inventories for the reporting period provided that:

    (i) the liquid fuels are stored in a storage tank with a volume of 120,000 litres or less; and

    (ii) the method to calculate these emissions are consistent from year to year.

(b) For solid fuels such as coal and coke, the facility must use direct measurements taken at a location in the fuel handling system that is representative of the fuel consumed for the reporting period. Measurement devices such as a weightometer may be used for direct measurements.

(c) For liquid fuels, the facility must use direct tank level measurements, volumetric or mass flow meters, and/or third party invoices. Tank level measurements may be used in combination with third party invoices to determine liquid fuel consumption.

(d) For gaseous fuels, the facility must used direct measurements such as gas flow metering and/or third party invoices or custody metering that is representative of the fuel consumed for the reporting period.

(e) Fuel that is used as feedstock in industrial processes involving chemical or physical reactions other than combustion may utilize the same monitoring requirements as for fuel combustion. This includes gaseous fuels (i.e. natural gas) that are used in steam methane reforming processes.

(f) Fuel consumption may be estimated per the following:

    (i) For Tier 1 classification, facilities may estimate fuel consumption from combustion equipment or mobile equipment based on the methodology outlined in Section C.6 of Appendix C.

    (ii) For Tiers 2 and 3, Section C.6 of Appendix C can be used to estimate fuel use from negligible sources; otherwise Equation 17-1 must be used.

    (iii) For Tiers 2 and 3, Section C.7 of Appendix C can be used to allocate fuel use for individual equipment if the total fuel use can be measured or quantified, but the fuel use for individual equipment cannot.

(g) 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), API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”, or an alternative method that is appropriate based on a method published by a consensus-based standards organization.

(h) Fuel that is used as feed in industrial processes involving chemical or physical reactions other than combustion may utilize the same monitoring requirements as for fuel combustion.

This includes gaseous fuels (i.e. natural gas) that are used in steam methane reforming processes.

17.2.2 Calibration

(a) 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. 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 consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. For flow meters used for natural gas, the facility may follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada, or other regulations or standards for electricity and gas, as applicable for the facility.

(b) Scales and other instruments used for measuring solid and liquid fuels or industrial feedstocks shall be calibrated, at the lesser of, once a year or at the minimum frequency specified by the manufacturer.

17.2.3 Fuel properties

(1) Density

(a) Facilities using Tiers 1 or 2 for CO_2 emissions may use the default density values for fuel oil provided in Table B-3 in Appendix B, in lieu of using the ASTM method in paragraph (d) of Section 17.2.1.

(b) For Tier 3, 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), API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”, or an alternative method that is appropriate based on a method published by a consensus-based standards organization.

(2) Fuel heat content

Fuel heat content sampling and analysis shall be as follows:

(a) For fuel heat content monitoring of natural gas, the facilities may

(i) Follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada, or other regulations or standards for electricity and gas, as applicable for the facility;

(ii) Use on-line instrumentation that determines heating value accurate to within ±0.5 per cent and if such instrumentation provides only low heat value, the facility shall convert the value to HHV using Equation 17-2 in accordance with the following:

1. The conversion factor (CF) for LHV to HHV, shall be determined as a fuel-specific average CF using the following:

(a) Concurrent LHV and HHV measurements determined by on-line instrumentation or laboratory analysis as part of the monthly carbon content determination; or
(b) The HHV/LHV ratio obtained from the laboratory analysis of the monthly samples

$$\boldsymbol{HHV} = \boldsymbol{LHV} \times \boldsymbol{CF} \qquad \text{Equation 17-2}$$

Where:

HHV = Fuel or fuel mixture higher heat value

LHV = Fuel or fuel mixture lower heat value

CF = Conversion factor

(b) For gases, use the most appropriate method published by a consensus-based standards organization, if such a method exists or a method required by the facility's AER or EPEA approval. Specific test procedures may 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.”

(c) For middle distillates and oil, or liquid waste-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may 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.

(d) For solid biomass-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may 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.

(e) For waste-derived fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may include ASTM D5865 and ASTM D5468 “Standard Test Method for Gross Calorific and Ash Value of Waste Materials.”

(f) For black liquor, use Technical Association of the Pulp and Paper Industry (TAPPI) T684 om-15 - Gross High Heating Value of Black Liquor or equivalent method.

17.2.4 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, online calibrated analyzers or determined by the operator, using an applicable analytical method listed below. For carbon content monitoring of natural gas, the facility may follow the requirements prescribed by Alberta Energy Regulator, Measurement Canada or other regulations or standards for electricity and gas, as applicable for the facility.

Appendix B: Fuel Properties and Appendix C: General Calculation Instructions provide guidance for the use of fuel properties and calculation of carbon content and carbon content uncertainties.

(1) Solid fuel

For coal and coke, solid biomass fuels, and waste-derived fuels, and any other solid fuel use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may 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. Operators of coal fired electricity generators are expected to apply additional quality control procedures to ensure accuracy of measured fuel carbon content.

(2) Liquid fuel

For liquid fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may 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) Gaseous fuel

For gaseous fuels, use the most appropriate method published by a consensus-based standards organization or a method required by the facility's AER or EPEA approval. Specific test procedures may 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.

17.3 Equipment, fuel and properties sampling frequency

17.3.1 Introduction

The facility is required to obtain fuel samples pursuant to this standard quantification method by conducting fuel sampling or obtaining fuel sampling results from the fuel supplier in accordance with the following rules:

(a) Fuel samples shall be taken at a location in the fuel handling system that provides a representative sample of the fuel combusted or consumed.
(b) Fuel samples shall be obtained and analysis performed at the minimum frequencies prescribed in Table 17-3.
(c) In the event that more than one sampling frequency criteria is applicable to a fuel type, the higher sampling frequency shall be applied.
(d) If a facility is sampling at a higher frequency than prescribed in Table 17.3, the facility must ensure that the analysis used is representative and unbiased.
(e) Facilities must apply the sampling frequencies prescribed in Table 17-3 for the quantification of the fuel consumed where applicable.
(f) Samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
(g) Fuel that is used as feed in industrial processes involving chemical or physical reactions other than combustion may utilize the same monitoring requirements as for fuel combustion.

This includes gaseous fuels (i.e. natural gas) that are used in steam methane reforming processes.

(h) In the event that more than one sampling frequency criteria is applicable to a fuel type, the higher sampling frequency shall be applied.

Table 17-3 Summary of Minimum Required Sampling/Monitoring Frequency for Fuels or Feed Gases

Type of Fuel	Tier 1	Tier 2	Tier 3
Purchased gasoline, and diesel,	No sampling required	No sampling required	No sampling required
Ethane, propane, and butane	No sampling required	No sampling required	No sampling required
Fuel received by batches	No sampling required	Six times a year	By shipment
Marketable natural gas (including natural gas feed used for industrial processes)	No sampling required	Six times a year	Monthly
Non-marketable liquid or gaseous fuels such as purge gas co-produced at an oil and gas production or petrochemical facility.	No sampling required	Quarterly	Monthly
Gases derived from biomass and biogas	No sampling required	Quarterly	Quarterly
Refinery fuel gas	No sampling required	Every two weeks	Daily (online instrumentation in place) Weekly (online instrumentation not in place)
Feedgases which result in industrial process emissions.	No sampling required	Every two weeks	Daily (online instrumentation in place) Weekly (online instrumentation not in place)
Coal / Coke	No Sampling required	Monthly	Once for each new fuel shipment or delivery.

Type of Fuel	Tier 1	Tier 2	Tier 3
			As often as necessary to capture variations in carbon content and heat value to ensure a representative annual composition, but no less than weekly.
Solid fuels other than coal and coke	No sampling required	No sampling required	Monthly
Heat/Steam including industrial heat exported as a product (steam flow rate, steam discharge temperature and pressure)	Weekly	Daily	Hourly
Boiler efficiency (by fuel)	Manufacturer Specification	Every five years or during boiler planned maintenance based on manufacturer specification, whichever is lower	Every five years or during boiler planned maintenance based on manufacturer specification, whichever is lower

Notes: Weekly/monthly samples means the composition of several samples uniformly distributed over the period of the reported time.

17.4 Data analysis and data management

17.4.1 Fuel reconciliation

When the fuel usage for the reporting of emissions is taken from an internal meter, reconciliations should be developed, where applicable, to ensure that internal meters are accurate. The frequency required for reconciliation should follow the same frequencies prescribed in Table 17-3. It is noted that facilities can only conduct a reconciliation process if there are reference meters that can be used. For example, a facility may measure fuel consumption based on internal metering and also receives third party documentation for the amount of fuel consumed, which would allow a facility to conduct a reconciliation process.

$$\boldsymbol{Reconciled\ Fuel_{i,j}} = \boldsymbol{Non\ Adjusted\ Fuel_{i,j}} \times (\mathbf{1} + \frac{\Delta}{\boldsymbol{Non-Adjusted\ Fuel_i}}) \qquad \text{Equation 17-3}$$

$$\Delta = Reference\ Fuel_i - Non\ Adjusted\ Fuel_i \qquad \text{Equation 17-4}$$

$$Non\ Adjusted\ Fuel_i = \sum_{j=1}^{n} Non\ Adjusted\ Fuel_{i,j} \qquad \text{Equation 17-5}$$

Where:

Reconciled $\text{Fuel}_{i,\ j}$ = Amount of reconciled stream j for the fuel i at standard conditions as defined in Appendix C.

Non-Adjusted Fuel_{i} = Amount of unreconciled fuel i at standard conditions. These are

Non-Adjusted $\text{Fuel}_{i,\ j}$ = Amount of unreconciled stream j for the fuel i in standard conditions as defined in Appendix C.

Reference Fuel_{i} = Reference amount of fuel i used for reconciliation of the

Δ = Amount of fuel to be adjusted.

17.4.2 Procedures for estimating missing data

The following method for estimating missing data was adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements, December 2017.

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

(a) Whenever analytical data relating to sampling is unavailable, the facility shall, using the methods prescribed in Section 17.3, re-analyze the original sample, a backup sample or a replacement sample for the same measurement and sampling period; if this is not physically possible, the operator should follow the missing data approach.

(b) Whenever sampling and measurement data required by Tier 1, 2, 3 or 4 for the calculation of emissions is missing the facility shall ensure that the data is replaced using the following missing data procedures:

   (i) When the missing data concerns high heat value, carbon content, molecular mass, CO_2 concentration, water content or any other data sampled, the facility shall:

1. Determine the sampling or measurement rate using Equation 17-6:

$$R = \frac{Q_{S\,Ac}}{Q_{S\,Required}}$$ Equation 17-6

Where:

R	=	Sampling or measurement rate that was used, expressed as a percentage
$Q_{S\,Ac}$	=	Quantity of actual samples or measurements obtained by the facility
$Q_{S\,Required}$	=	Quantity of samples or measurements required under Section 17.3

2. 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 $0.75 \leq R < 0.9$ and data directly effects estimated emissions: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
   (c) If $0.75 \leq R < 0.9$ and data inversely effects estimated emissions: replace the missing data by the lowest data value sampled or analyzed during the calendar year for which the calculation is made.
   (d) If $R < 0.75$ and data directly effects estimated emissions: replace the missing data by the highest data value sampled or analyzed during the 3 preceding years or the maximum number of years of operation (if less than 3 years).
   (e) If $R < 0.75$ and data inversely effects estimated emissions: replace the missing data by the lowest data value sampled or analyzed during the 3 preceding years or the maximum number of years of operation (if less than 3 years).

(ii) When the missing data concerns stack gas flow rate, fuel consumption or the quantity of sorbent used, the replacement data shall be generated from best estimates based on all of the data relating to the processes.

(c) A facility that uses CEMS shall determine the replacement data using the procedure in accordance with reference [8] in Appendix A or the following method:

  (iii) When the missing data is data measured by the CEMS:

    1. Determine the sampling or measurement rate using Equation 17-6
    2. Replace the missing data as follows:

        a. If R ≥ 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 ≤ R < 0.9: replace the missing data by the highest data value sampled or analyzed during the calendar year 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 or the maximum number of years of operation (if less than 3 years).

(d) For missing data associated with the quantification of production items, the facility must utilized the best available data to assess the quantities during the missing period. This may include the use of engineering estimates (i.e. operating hours and equipment specifications). For further guidance, facilities may contact the director.

APPENDIX A: References

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12. API Technical Report. Carbon Content, Sampling, & Calculation. Final Draft, August 27, 2012
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APPENDIX B: Fuel Properties

Table B-1. Table of physical properties for hydrocarbons and other compounds[1]

Component	Chemical Formula	HHV [GJ/e^{3}m^3]	Carbon [atoms]	Molar Mass [t/t-mol]
Hydrogen	H_2	12.102	0	2.0159
Oxygen	O_2	0.000	0	31.9988
Helium	He	0.000	0	4.0026
Nitrogen	N_2	0.000	0	28.0134
Hydrogen Sulphide	H_2S	23.784	0	34.0809
Carbon dioxide	CO_2	0.000	1	44.0095
Carbon monoxide	CO	11.964	1	28.0100
Methane	CH_4	37.708	1	16.0425
Ethane	C_2H_6	66.065	2	30.0690
Propane	C_3H_8	93.936	3	44.0956
Isobutane	C_4H_{10}	121.406	4	58.1222
n-Butane	C_4H_{10}	121.794	4	58.1222
Isopentane	C_5H_{12}	149.363	5	72.1488
n-Pentane	C_5H_{12}	149.656	5	72.1488
Hexane	C_6H_{14}	177.550	6	86.1754
Heptane	C_7H_{16}	205.424	7	100.2019
Octane	C_8H_{18}	233.284	8	114.2285
Nonane	C_9H_{20}	261.191	9	128.2551
Decane	$C_{10}H_{22}$	289.067	10	142.2817
Acetylene	C_2H_2	55.038	2	26.0373
Ethylene	C_2H_4	59.724	2	28.0532
Propylene	C_3H_6	86.099	3	42.0797
Hexene	C_6H_{12}	174.068	6	84.1595
Benzene	C_6H_6	139.689	6	78.1118
Toluene	C_7H_8	167.056	7	92.1384
Heptane	C_7H_{16}	205.424	7	95.00
o-Xylene	C_8H_{10}	194.484	8	106.1650
m-Xylene	C_8H_{10}	194.413	8	106.1650
p-Xylene	C_8H_{10}	194.444	8	106.1650

1. GPSA Engineering Handbook Section 23 - Physical Properties

Table B-2. Table of properties of gases

Component	Description	Value	Units
MVC	Standard Molar Volume for a gas at standard conditions (as defined in Appendix C)	23.645	m^3/kmol
MWC	Molecular Weight of Carbon	12.01	t/t-mol

Table B-3. Fuel oil default density value

Fuel Oil	No. 1	No. 2	No. 6
Density (kg/L)	0.81	0.86	0.97

APPENDIX C: General Calculation Instructions

C.1 Weighted average carbon content

Use Equation C.1-1 to calculate the weighted average carbon content of the fuel, if the measured carbon content is used to calculate CO_2 emissions. The units of measure for carbon content for gaseous, liquid, and solid fuels are as follows:

Carbon Content Units of Measure:

- Gaseous Fuels: kilograms of carbon per cubic metre of fuel (kg C/m^3)
- Liquid Fuels: tonnes of carbon per kilolitre of fuel (tonnes C/kl)
- Solid Fuels: tonnes of carbon per tonne of fuel

To apply the carbon content in the equations outlined for various quantification methods, the facility must ensure that the correct units are applied in the equation. Equation C.1-1a provides a common conversion from mole fraction to mass fraction for gaseous fuels.

$$CC_p = \frac{\sum_{i=1}^{N} CC_i \times Fuel_i}{\sum_{i=1}^{N} Fuel_i} \qquad \text{Equation C.1-1}$$

Where:

CC_p = Weighted average carbon content of the fuel during the reporting period, p.

CC_i = Carbon content of the fuel for sampling period i.

$Fuel_i$ = Quantity of fuel combusted during sampling period i, in accordance with Chapter 17:

  - Cubic metres (m^3) for gaseous fuels.
  - Kilolitres (kl) for liquid fuels.
  - Tonnes for solid fuels

N = Number of measurement periods in the reporting period, in accordance with Chapter 17.

For gaseous fuels, where carbon content is measured in mole fraction, Equation C.1-1a is used to convert the mole fraction to kilogram of carbon per cubic metre of fuel:

$$\boldsymbol{CC_i = \sum_{j=1}^{c}(MF_j \times NC_j) \times \frac{12.01}{MVC}} \qquad \text{Equation C.1-1a}$$

Where:

CC_i = Carbon content of the gaseous fuel i (kg of C/m^3).

MF_j = Normalized mole fraction of component j, where, in cases the sum of the mole fractions of components may not add up to 1 because smaller components are excluded from the analysis or are not measurable, facilities must normalize the mole fractions of the measured components in order for the sum of the mole fractions to equal 1.

NC_j = Number of carbons in component j.

c = Number of components.

MVC = Standard molar volume conversion at standard molar volume as defined in Appendix B, Table B-2 (23.645 m^3/kmol).

12.01 = Molecular weight of carbon (kg/kmol)

C.2 Average carbon content expanded uncertainty (95% confidence level)

The 95 % confidence level carbon content uncertainty for the period that the average sample data is used can be calculated from the following Equation C.2-1

$$\boldsymbol{Period\ CC_{95\%\ Uncertainty} = \pm \frac{k_{95\%} \times \sigma}{\sqrt{n}}} \qquad \text{Equation C.2-1}$$

Where:

Period $CC_{95\%\ Uncertainty}$ = Period carbon content 95% confidence uncertainty.

$k_{95\%}$ = 95% confidence coverage factor; for the purpose of this assessment is taken as 2.00 (normal distribution with infinite degrees of freedom)

σ = Carbon content standard deviation of the samples.

n = Number of samples.

This calculation instruction is to be used if the Director requests the calculation and reporting of the carbon content uncertainty.

C.3 Fuel gas molecular weight estimation

If the molecular weight (MW) of the fuel gas is not measured, the molecular weight of the fuel gas should be calculated by the summation of the mole fraction of each fuel gas component multiplied by its respective molecular weight, as shown in the following equation.

$$\boldsymbol{MW = \sum x_i MW_i} \qquad \text{Equation C.3-1}$$

Where:

MW = Molecular weight of fuel gas (kg/kmol)

x_i = Normalized mole fraction of component i, where, in cases the sum of the mole fractions of components may not add up to 1 because smaller components are excluded from the analysis or are not measurable, facilities must normalize the mole fractions of the measured components in order for the sum of the mole fractions to equal 1. The mole fractions of the gas components should be obtained from gas analyses of the fuel stream.

MW_i = Molecular weight of component (kg/kmol), using Table B-1, Appendix B.

C.4 Standard temperature and pressure or standard conditions

In the document, standard conditions for pressure and temperature is 101.325 kPa (1 atm) and 15ºC (288.15K), respectively. If the gas volume is metered or recorded at different conditions, the following equation should be used to convert gas volumes to standard gas volumes.

$$\boldsymbol{v_s = 2.8438 \times \frac{P \times v}{T}} \qquad \text{Equation C.4-1}$$

Where:

v_s = Gas volume at standard conditions.

P = Pressure under which the gas volume is metered or recorded (kPa).

T = Temperature under which the gas volume is metered or recorded, in Kelvin degrees.

v = Gas volume at the metered or recorded conditions.

2.8438 = Constant for converting gas volumes to the standard condition (K/kPa).

C.5 Heating value

The heating value of a fuel is the amount of heat produced by the complete combustion of a unit quantity of fuel. The higher heating value of the fuel gas are calculated by summing the products of the mole fraction and the heating value of each fuel gas component, as shown in the following equations:

$$\boldsymbol{HHV = \sum_{i}^{N} x_i HHV_i} \qquad \text{Equation C.5-1}$$

Where:

HHV = Higher heating value of fuel gas (GJ/m^3).

x_i = Normalized mole fraction of component i, where, in cases the sum of the mole fractions of components may not add up to 1 because smaller components are excluded from the analysis or are not measurable, facilities must normalize the mole fractions of the measured components in order for the sum of the mole fractions to equal 1. The mole fractions of the gas components should be obtained from gas analyses of the fuel stream.

HHV_i = Higher heating value of component i, using Table B-1, Appendix B.

The weighted average higher heating value of the fuel shall be calculated using Equation C.5-2.

$$\boldsymbol{HHV_p = \frac{\sum_{i=1}^{N} HHV_i \times Fuel_i}{\sum_{i=1}^{N} Fuel_i}} \qquad \text{Equation C.5-2}$$

Where:

HHV_p = Weighted average higher heating value of the fuel for the reporting period.

$Fuel_i$ = Mass or volume of the fuel combusted during measurement period i, in accordance with Chapter 17.

N = Number of measurement periods in the period, in accordance with Chapter 17.

HHV_i = Higher heating value of the fuel, for measurement period i, in accordance with Chapter 17.

C.6 Fuel consumption estimation

Facilities may estimate fuel consumption for combustion equipment based on equipment specifications and operating hours using Equation C.6-1 or C.6-2.

$$v_{fuel,j,p} = \sum_{j=1}^{N} \frac{P_{rated\,j}}{n_j} \times \frac{LF_j}{HHV_j} \times OH_j \times 0.0036 \qquad \text{Equation C.6-1}$$

$$v_{fuel,j,p} = \sum_{j=1}^{N} \left(OH_j \times HP_j \times LF_j \times BSFC_j \right) \times 10^{-3} \qquad \text{Equation C.6-2}$$

Where:

$v_{fuel,j,p}$ = Estimated fuel consumption from combustion equipment for a specific fuel type for the reporting period, *p* (m^3).

j = Equipment type.

$P_{rated\ j}$ = Maximum rated power for equipment j (kW).

LF_j = Load factor for each type of equipment j (dimensionless; ranges between 0 and 1).

OH_j = Operating hours for equipment j (hours/reporting period).

n_j = Thermal efficiency for equipment j.

HHV_j = Higher heating value of the fuel combusted by equipment j (GJ/m^3).

N = Number of equipment types using the same fuel.

HP_j = Rated horsepower for equipment j (horsepower).

$BSFC_j$ = Brake-specific fuel consumption for equipment j in litres per horsepower-hour (l/hp-h).

0.0036 = Conversion factor for kWh to GJ.

10^{-3} = Conversion factor for litres to cubic metres.

Table C-1. Typical input heat rates and thermal efficiencies (based on the net heating value of the fuel) for different types and sizes of natural gas-fueled equipment [13].

Source Type	Maximum Rated Power Output (kW)	Maximum Rated Power Output (HP)	Input Heat Rate (kJ/kWh)	Thermal Efficiency (percent)
Reciprocating Engines	<325	<435	12 857	28
	325 to 600	435 to 805	11 250	32
	600 to 2250	805 to 3017	10 000	35
	>2250	>3017	9 474	38
Turbine Engines	All	All	10 909	33
Industrial and Commercial Heaters and Boilers	<375 (Natural Draft)	<503 (Natural Draft)	4 736	76
	<375 (Forced Draft)	<503 (Natural Draft)	4 500	80
	≥375	≥503	4 500	80
Residential Water Heaters	All	All	7 500	48
Residential Furnaces	All	All	5 143	70
Catalytic Heaters	Vented Outdoors	Vented Outdoors	4 500	80
	Vented Indoors	Vented Indoors	3 600	100
Thermoelectric Generators	All	All	100 000	3.6

Table C-2. Estimated load factors for combustion devices during actual running/firing periods

Source Type	Load Factor (Fraction of Maximum Rated Power Output)
Reciprocating Engines	0.75
Turbine Engines	0.90
Industrial and Commercial Heaters and Boilers	1.0
Residential Water Heaters	1.0
Residential Furnaces	1.0
Catalytic Heaters	1.0
Thermoelectric Generators	1.0

C.7 Proration of total measured fuel usage to individual devices

In a situation that a site has only one fuel meter, and information is available on the number, types and sizes of combustion equipment at the site. In these cases, calculations are performed to estimate the theoretical amount of fuel use by each device and the results are then used to develop factors for prorating the actual reported fuel use.

$$\boldsymbol{fuel_{actual,i}} = \boldsymbol{fuel_{theoretical,i}} \times \frac{(\boldsymbol{fuel_{measurement}} - \sum \boldsymbol{fuel_{theoretical,non-com}})}{\sum \boldsymbol{fuel_{theoretical,com}}} \qquad \text{Equation C.7-1}$$

Where:

$fuel_{actual, i}$ = Actual volume of fuel combusted for equipment i in a certain time period.

$fuel_{theoretical\ i}$ = Theoretical volume of fuel combusted for equipment i (calculated using C.6) in a certain time period

$fuel_{measurement}$ = Total volume of fuel consumption metered in a certain time period for all combustion and non-combustion devices.

$\sum fuel_{theoretical,non-com}$ = Calculated/theoretical fuel gas consumption by all non-combustion devices at the site in a certain time period.

$\sum fuel_{theoretical,com}$ = Sum of the calculated/theoretical fuel gas usage by each combustion device at the site in a certain time period.

C.8 Quantification of fuel consumption based on carbon mass balance

A facility may use a mass balance approach to determine the amount of fuel consumed or combusted for a source such as stationary fuel combustion, flaring or industrial process emissions if the total facility consumption of a fuel can be accurately determined by a custody meter (e.g. third party meter) and the fuel consumption of all other sources are quantified and reported. For example, if a facility consumes natural gas for combustion and as feed for an industrial process, the facility may use a mass balance approach to calculate the natural gas consumed for stationary fuel combustion or feed if the total facility fuel consumption and fuel quantity for one of these sources are known. The mass balance approach may only be used if there is only one source with an unknown fuel quantity. The facility may not use this methodology to calculate emissions for venting or fugitive sources.

$$\boldsymbol{Fuel_{source} = Fuel_{facility\ total} - \sum_i^N Fuel_{known\ source,i}} \qquad \text{Equation C.8-1}$$

Where:

$Fuel_{source}$ = Fuel quantity determined for the source of interest (GJ or m^3).

$Fuel_{facility\ total}$ = Total fuel consumed by the facility (GJ or m^3).

$Fuel_{known\ source,i}$ = Fuel consumed by a source that is quantified and reported (GJ or m^3).

N = Number of sources.

C.9 Variables

When a variable is used in a calculation, fuel weighted averages should be calculated as per Equation C.9-1.

$$\boldsymbol{Variable_p = \frac{\sum_{i=1}^N Fuel_i \times Variable_i}{\sum_{i=1}^n Fuel_i}} \qquad \text{Equation C.9-1}$$

Where:

$Variable_p$ = Weighted value of any variable for a reporting period.

$Variable_i$ = Value of any variable in a measurement period i.

$Fuel_i$ = Value of the fuel used in a measurement period i.

i = A measurement period where the variables are collected.

N = Number of measurement periods in a reporting period.

C.10 Allocation of electricity generated from multiple energy suppliers

Use Equation C.10-1 to calculate the allocation of electricity from different suppliers.

$$Electricity_i = Produced\ \ Electricity \times \frac{Heat_i}{\sum_{j=1}^{N} Heat_j} \qquad \text{Equation C.10-1}$$

Where:

$Electricity_i$ = Electricity allocated to supplier i

Produced Electricity = net electricity produced

$Heat_i$ = net heat provided by supplier i

j = each supplier

N = amount of suppliers

C.11 Oxidation factor

As recommended by the Intergovernmental Panel on Climate Change (IPCC), the oxidation factor in the combustion of any fuel including flared fuels, but excluding coal used for electricity generation assumes 100% combustion (i.e. 100% conversion of carbon to carbon dioxide). The methane emissions from fuel combustion assumes a fraction of the fuel that is not combusted. These emissions are conservatively included in the total emissions generated from fuel combustion. For coal combustion used for electricity generation, an oxidation factor of 99.48% is applied. This oxidation factor was derived from a study conducted by ECCC on oxidation factors for coal combustion in Canada.

C.12 Rounding of final reported values

Final reported values should be rounded to the significant digits required in the compliance or reporting form. Data and intermediate values used in the calculations shall not be rounded.

APPENDIX D: Conversion Factors

Table D-1. Prefixes

Metric	Meaning
pico (p)	10^{-12}
angstron (A)	10^{-10}
nano (n)	10^{-9}
micro (µ)	10^{-6}
mili (m)	10^{-3}
deca (da)	10^{1}
kilo (k)	10^{3}
mega (M)	10^{6}
giga (G)	10^{9}
tetra (T)	10^{12}
peta (P)	10^{15}
exa (E)	10^{18}
zetta (Z)	10^{21}

Table D-2. Mass Conversion

Source unit	Factor	Final Unit
1 kg	2.205	lb
1 lb	453.6	g
1 lb	16	oz
1 metric tonne	2,205	lb
1 US short ton	2,000	lb
1 UK long ton	2,239	lb

Table D-3. Volume Conversion

Source unit	Factor	Final Unit
1 l	0.264	gal
1 gal	3.785	l
1 m^3	35.3	ft^3
1 ft^3	28.32	l
1 ft^3	7.482	gal
1 bbl	42	gal
1 bbl	158.9	l
1 bbl	5.6	ft^3

Table D-4. Temperature Conversion

Source unit	Factor
ºF	9 / 5 * ºC +32
ºC	(ºF – 32) * 5 / 9
ºK	ºC + 273.15
ºR	ºF +459.67

Table D-5. Pressure Conversion

Source unit	Factor	Final Unit
1 MPa	0.1	bar
1 MPa	9.87	atm
1 MPa	145	psi
1 atm	1.0132	bar
1 atm	780	mmHg
1 atm	14.696	psi

Table D-6. Distance Conversion

Source unit	Factor	Final Unit
1 cm	0.3937	in
1 m	3.281	ft
1 m	1.094	yd
1 km	0.62137	mi
1 mi	1.609	km

Table D-7. Energy Conversion

Source unit	Factor	Final Unit
1 J	1	Nm
1 J	0.239l	cal
1 J	0.74	ft-lb
1 J	0.0009478	Btu
1 Cal	1	kcal
1 Cal	1 4.187	kJ
1 Cal	3.968	Btu
1 Btu	1,055.056	J
1 Btu	0.252l	kcal
1 kWh	3.6	MJ
1 kWh	3,412	Btu
1 mmBtu	1.055	GJ

APPENDIX E: Alberta Gas Processing Index

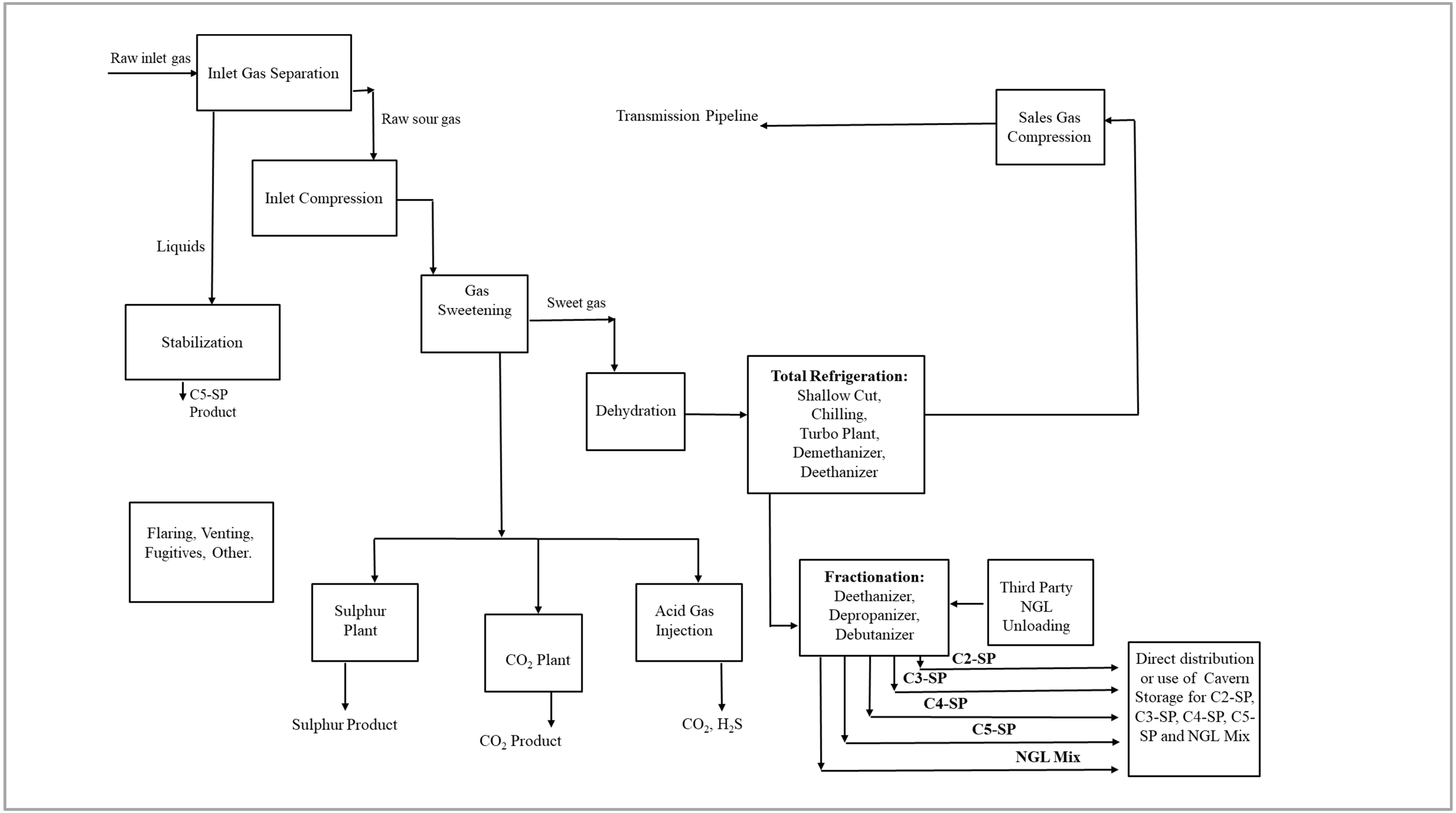
E.1 - Overview of Natural Gas Processing Modules

Process Unit (Module)	Inlet	Outlet	Typical Equipment	Stream Measured	Unit of Measure [1]
Inlet Compression	Inlet Gas to compression	Compressed Inlet Gas to Processes	Reciprocating engines, centrifugal compressors.	Only volume of the inlet gas requiring compression at the facility's point of entry.	E^3m^3
Dehydration	Gas to the dehydrator(s)	Dry gas from the dehydrator(s)	Heaters, boilers, heat exchangers, molecular sieves	All inlet gas volume requiring dehydration.	E^3m^3
Gas/Amine Sweetening	Sour/Sweet Gas to Gas/Amine Sweetening	Sweet Gas from Gas/Amine Sweetening with a separate acid gas	Heaters, boilers, amine sweetening unit(s), heat exchangers.	Total inlet gas volume through the gas/amine sweetening process.	E^3m^3
Total Refrigeration	Sweet gas to Refrigeration	Sales Gas, Natural Gas Liquids ("NGLs") and specification ethane depending in refrigeration process	Heaters, Lean Oil System, Turbo-Expander, Cryogenic Expander.	The total gas in the refrigeration module is determined based on the configuration of refrigeration processes within a facility and is based on three (3) scenarios, as follows: 1. When only one refrigeration process exists within a facility, the total gas volume through this individual refrigeration processing module should be used. 2. When multiple refrigeration processes are run in series, the maximum gas volume through any individual refrigeration processing module should be used. 3. When the refrigeration processes are run in parallel, the total gas volume must be calculated based on the sum of each parallel individual refrigeration processing module.	E^3m^3
Fractionation	Natural Gas Liquids ("NGLs")	Specification Ethane, Propane, Butane, and Pentane Products, and/or NGLs	Heaters, Reboilers, Deethanizer, Depropanizer, Debutanizer, heat exchangers.	The production from the fractionation module includes the total production of specification (SP) ethane, propane, butane, and pentane products reported in Petrinex in m^3 and converted to cubic metres of oil equivalent (m^3OE). Only portion of C5 plus that goes through the fractionation module, reported as FRAC in Petrinex, should be included here. When pipeline specification ethane is produced in a Deep Cut Refrigeration process or in the Ethane Extraction processing module at a straddle plant, it should not be included in the fractionation production. The total fractionation production should include specification products from both: Gas Processing (reported as PROC in Petrinex excluding PROC Pentane-SP) and Fractionation Processing (reported as FRAC in Petrinex).	m^3OE
Stabilization	Inlet Gas	C5-SP Product	Heaters, boilers.	Total production of C5-SP reported in Petrinex as PROC C5-SP. This should not include C5-SP produced in the fractionation module that is reported in Petrinex as FRAC C5-SP.	m^3OE
Sales Compression	Sales Gas to Compression	Sales Gas to Transmission System	Reciprocating engines, centrifugal compressors.	Only volume of the sales gas requiring compression at the Facility's exit point.	E^3m^3
Sulphur Plant	Sour Gas	Sulphur Product	Boilers, heaters, heat exchangers.	Sulphur production reported in Petrinex.	tonnes sulphur
Acid Gas Injection	Acid Gas to Underground Injection	Acid Gas Injected Underground	Reciprocating engines, centrifugal compressors.	Volume of acid gas injected underground, either reported in Petrinex, or obtained directly from the facility.	E^3m^3
Ethane Extraction	Marketable Gas	Sales Gas, Specification Ethane and NGLs	Heaters, boilers, Turbo-Expander, Cryogenic Expander	Ethane production reported in Petrinex.	m^3OE

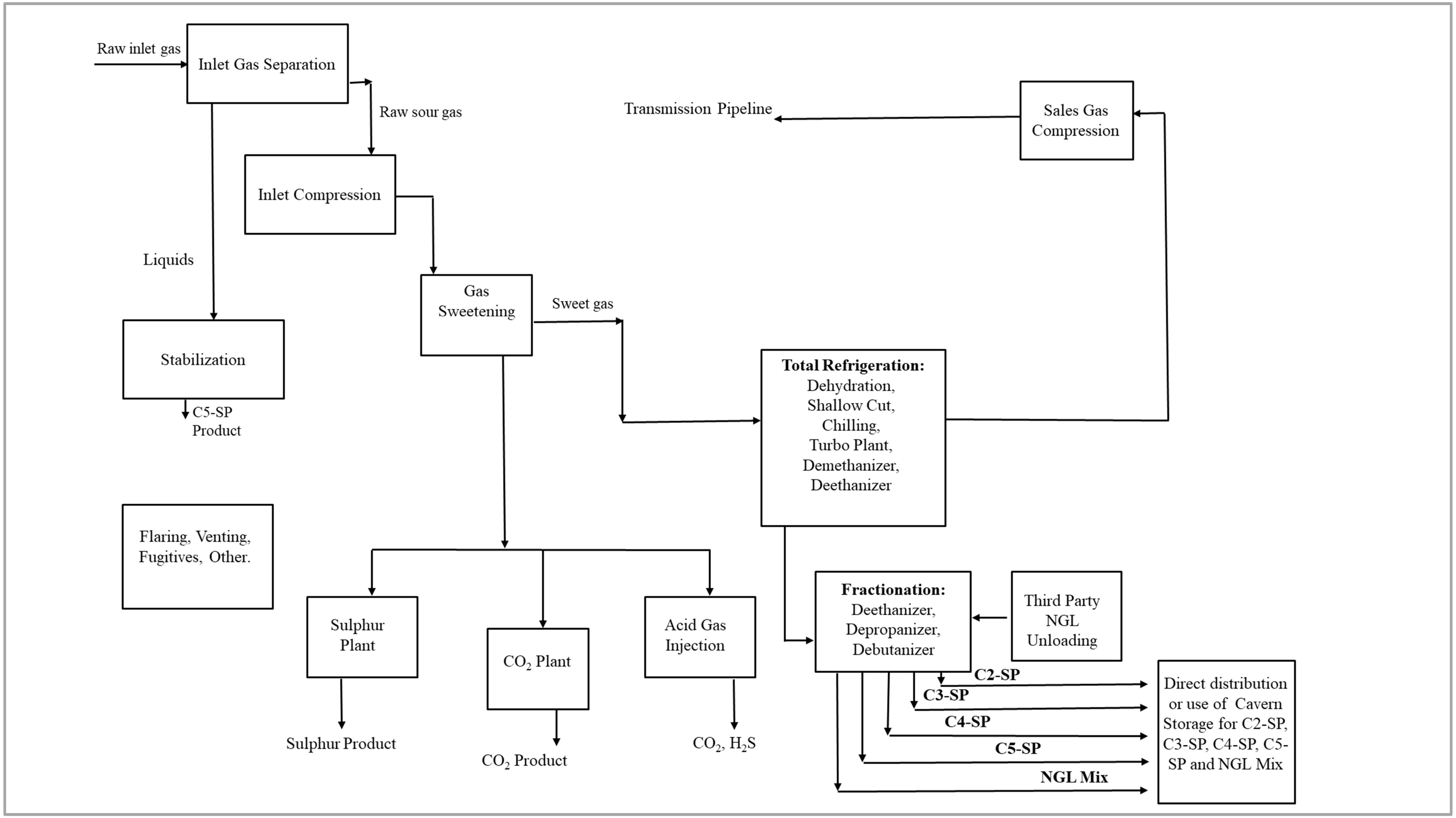
Process Unit (Module)	Inlet	Outlet	Typical Equipment	Stream Measured	Unit of Measure 1
Cavern Storage	Liquefied Gas products, i.e. Ethane, Propane, Butane and associated mixtures	Liquefied Gas products, i.e. Ethane, Propane, Butane and associated mixtures stored in Cavern	Reciprocating engines, centrifugal compressors.	Total volume of the liquefied gas product(s) injected into the cavern(s).	m^3
CO_2 Plant	Acid Gas from Amine Sweetening to the CO_2 Plant	Gaseous or Liquid CO_2 Product	Cryogenic technology equipment involving the removal of CO_2 from the gas stream, including CO_2 purification and/or liquefaction.	Total CO_2 gas volume from the amine sweetening through the CO_2 removal and purification process.	E^3m^3
Flaring, Venting, Fugitives, Other	Various Natural Gas Streams throughout Process Units/Modules	Various Natural Gas Streams throughout Process Units/Modules	Flare and Incinerator stacks, venting, facility fugitive, residue gas for straddle plants, diesel emergency generators, fire water pumps and some other emission sources.	Total annual facility production reported in Petrinex.	m^3OE

1. All volumetric units should match standard conditions as defined in Petrinex. Standard conditions for calculating and reporting gas and liquid volumes are 101.325 kPa (absolute) and 15°C. Monthly gas volumes are reported in units of 10^3 m^3 . The units for Cavern Storage (m^3) will be subject of a further review.

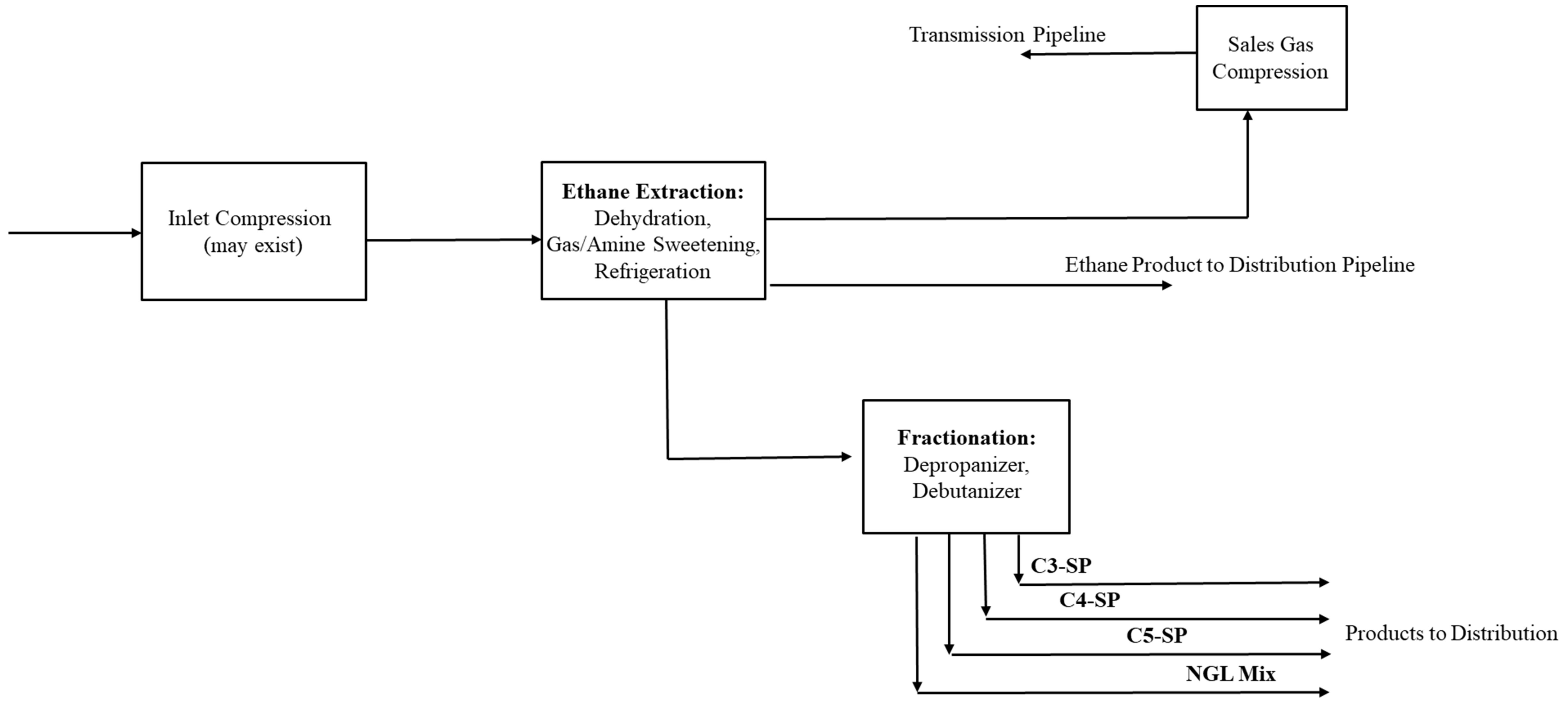
E.2 – Simplified Flow Diagram of a Typical Natural Gas processing Plant



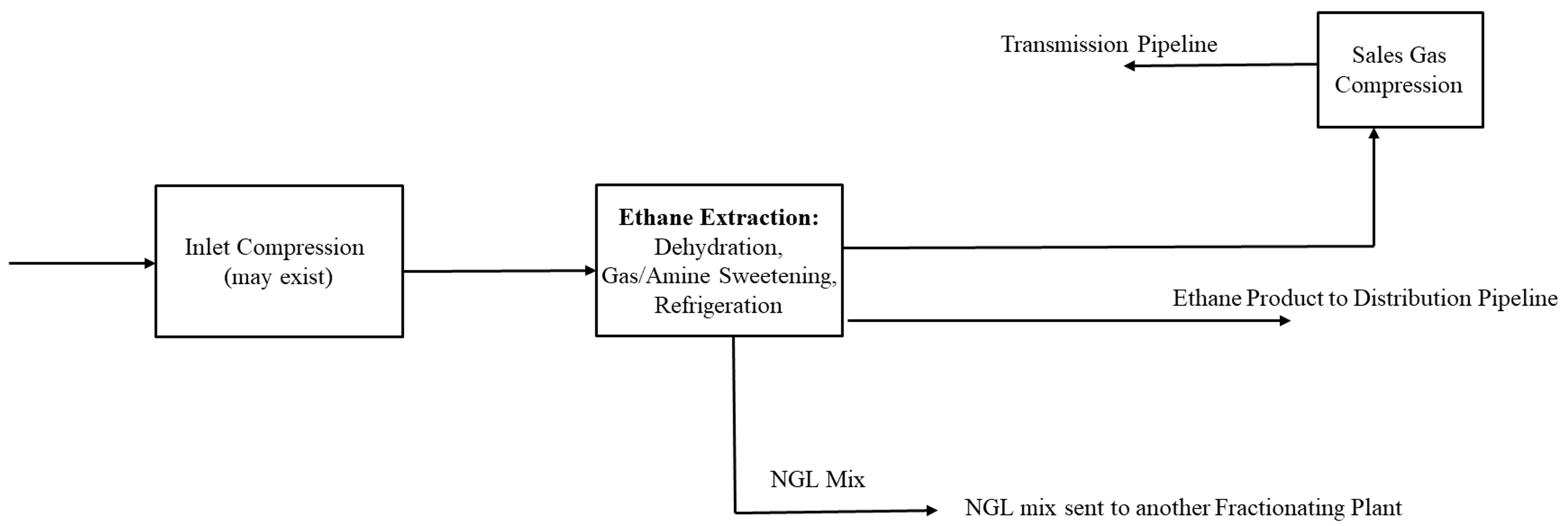
E.3 – Simplified Flow Diagram of a Typical Natural Gas processing Plant (Dehydration within Refrigeration)



E.4 – Simplified Flow Diagram of a Typical Natural Gas Straddle Plant



E.5 – Simplified Flow Diagram of a Typical Natural Gas Straddle Plant (without Fractionation)



E.6 – Oil Equivalent (OE) Conversion Factors

Product Code	Product	Units	Conversion Factors to m^3 OE	
			Gas at standard conditions (101.325 kPa, 288.15 K)	Liquid at 288.15 K
OIL	Lite Oil	m^3	-	1.00
GAS	Gas	e^3m^3	0.971	-
C1MX	Methane Mix	e^3m^3	0.971	-
LITEMX	Lit Mix	e^3m^3	0.971	-
C2SP	Ethane Spec	m^3	0.0017	0.48
C2MX	Ethane Mix	m^3	0.0017	0.48
C3SP	Propane Spec	m^3	0.0024	0.66
C3MX	Propane Mix	m^3	0.0024	0.66
NGL	Natural Gas Liquids	m^3	-	0.71
IC4MX	Iso-Butane Mix	m^3	0.0032	0.72
IC4SP	Iso-Butane Spec	m^3	0.0032	0.72
C4SP	Butane Spec	m^3	0.0032	0.75
C4MX	Butane Mix	m^3	0.0032	0.75
NC4MX	Normal Butane Mix	m^3	0.0032	0.75
NC4SP	Normal Butane Spec	m^3	0.0032	0.75
IC5MX	Iso-Pentane Mix	m^3	-	0.79
IC5SP	Iso-Pentane Spec	m^3	-	0.79
C5MX	Pentane Mix	m^3	-	0.80
C5SP	Pentane Spec	m^3	-	0.80
NC5MX	Normal Pentane Mix	m^3	-	0.80
NC5SP	Normal Pentane Spec	m^3	-	0.80
COND	Condensate	m^3	-	0.86
C5+	Pentane Plus	m^3	-	0.86

1. Conversion factors derived from Higher Heating Values based on 38.5 GJ/m^3 higher heating value of light crude oil
2. HHVs Sources: CAPP, “Calculating Greenhouse Gas Emissions”, 2003; GPSA, “Engineering Data Book”, 1998; AER, “ST98: Alberta's Energy Reserves and Supply/Demand Outlook”, 2018, EPA, “AP-42: Compilation of Air Emissions Factors”, 20