



Alberta greenhouse gas quantification methodologies

Technology innovation and
emissions reduction regulation

Version 2.3

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Alberta Greenhouse Gas Quantification Methodologies (AQM) | Alberta Environment and Protected Areas

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Summary of Revisions

Version	Date	Summary of Revisions
1.0 (CCIR)	June 2018	First publication of chapters 1, 8, 12, 13, 14, and 17 and Appendix A, B, C, and D.
1.1 (CCIR)	November 2018	<ul style="list-style-type: none"> 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 (CCIR)	November 2019	First publication of chapters 4 and 5.
1.3 (CCIR)	January 2020	<p>The following updates were made to chapters 1, 5, 8, 12, 13, 14, and 17:</p> <ul style="list-style-type: none"> Minor updates and corrections throughout the chapters. Clarification on fuel used for flare pilot. Updated emission factors to correct significant digits and align with the federal Greenhouse Gas Reporting Program, where appropriate; 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 (CCIR)	March 2020	Minor corrections to Appendix C.
2.0 (TIER)	October 2020	Final publication of Chapter 15 Aggregate Facilities

Version	Date	Summary of Revisions
2.1 (TIER)	March 2021	<p>Publication of finalized Chapters 1, 5, 8, 12 to 17 and Appendices A, B, C, and D. The following updates have been made since the previous publication under CCIR and stakeholder comments on the draft AQM:</p> <ul style="list-style-type: none"> • Updated classifications of methodologies from "tier" to "level"; • Updated definition of "negligible emissions sources"; • Updated definition of stationary fuel combustion emissions to exclude combustion of flare pilot in Chapter 1. Flare pilot emissions are classified as flaring emissions; • Addition of mass balance methodology in Chapter 1; • Updated Chapter 5 to remove guidance for the treatment of levied and non-levied fuels and removed method for natural gas combustion for on-site transportation; • Updated headings for Chapter 6 Solid Waste and Chapter 7 Wastewater and Digestion in "Activity Type" section; • Removed methodology to calculate industrial process emissions from thermal carbon black production in Chapter 8; • Chapter 10 Formation CO₂ is removed from the list of chapters that will be developed and published. Instead, the reporting of formation CO₂ will no longer be required to be segregated from the source that it is being emitted from. Chapter 1 Stationary Fuel Combustion and Chapter 4 Venting has been updated to provide specific guidance on the treatment of formation CO₂; • Updated AB-CWB quantification methodologies in Chapter 13; • Minor clarification provided to ABGPI section in Chapter 13; • Updated the CWB section to remove equations for FCC coke on catalyst in Chapter 13. • Minor updates and updated Equations 15-11 and 15-12 in Chapter 15 Aggregate Facilities; • Addition of Chapter 16 Cogeneration Benchmark Calculation; • Updated Chapter 17 to provide further clarity on requirements, sampling frequencies, missing data procedures, and weighted averages for fuels and other reported parameters; and • Provided clarification to the weighted average calculation in Appendix C.1 and updated methodology in Appendix C.6.
2.2	December 2021	<ul style="list-style-type: none"> • Finalized Chapter 2 Flaring. • Corrected emission factor for spent pulping liquor in Table 1-6 of Chapter 1 Stationary Fuel Combustion. • Updated equation 1-5b used for quantifying emissions from the combustion of solid biomass. • Updated Tables 13-2 and 13-3 for complexity weighted barrel (CWB) factors in Chapter 13 Production.

Version	Date	Summary of Revisions
		<ul style="list-style-type: none"> Updated definition of ammonia in Chapter 13 Production. Updated data requirements for equation 14-4 in Chapter 14 Biomass CO₂ to provide HHV for solid biomass. Added approach to use default boiler efficiencies in Chapter 17 Measurement, Analysis, Sampling, and Data Collection.
2.3	September 2023	<ul style="list-style-type: none"> Updated emission factors in Table 2-4 in Chapter 2 Flaring. Updated Chapter 15 Aggregate Facilities to include quantification methodologies for flaring emissions.

Introduction

The Technology Innovation and Emissions Reduction Regulation (TIER) and the Specified Gas Reporting Regulation (SGRR) require the use of mandatory quantification methodologies for greenhouse gas emissions, production and other parameters reported under each regulation.

Quantification methodologies in the Alberta Greenhouse Gas Quantification Methodologies (AQM) are classified by levels (i.e. levels 0, 1, 2, 3, 3A, or 4). In general, the stringencies of quantification methodologies increases as the level classifications increases. For example, methodologies classified as level 1 are the lowest in stringency; while level 4 methodologies are typically highest in stringency. For some sources or parameters, there is only one methodology prescribed and therefore, would be acceptable to use under any level classification. There may also be methodologies prescribed in the AQM that are acceptable under multiple levels.

Under TIER, the Standard for Developing Benchmarks and/or Standard for Completing Greenhouse Gas Compliance and Forecasting Reports prescribe the level of quantification methodologies required. While under SGRR, the Standard for Specified Gas Reporting prescribes the level of quantification methodologies required. Where quantification methods and emission factors are not provided in this document, a facility may use facility-specific quantification methods or emission factors.

The AQM will be updated from time to time.

Scope and Applicability

The objective of prescribed quantification methodologies is to ensure accuracy and consistency across all facilities and sectors regulated under TIER and SGRR. Where possible, the quantification methodologies in this document align with Environment and Climate Change Canada (ECCC)'s federal Greenhouse Gas Reporting Program (GHGRP).

Types of greenhouse gases covered in this document include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), sulphur hexafluoride (SF₆), nitrogen trifluoride (NF₃), 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.

Global Warming Potential (GWPs) for the greenhouse gases are applied to calculate the carbon dioxide equivalent (CO₂e). GWPs are prescribed in the standards for the respective regulations.

Activity Type

The AQM provides quantification methodologies 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:	Solid Waste
Chapter 7:	Wastewater and Digestion
Chapter 8:	Industrial Processes
Chapter 9:	HFCs, PFCs, SF ₆ , NF ₃
Chapter 10:	Place marker

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:	Aggregate Facilities
Chapter 16:	Cogeneration Benchmark Calculation
Chapter 17:	Measurements, Sampling, Analysis and Data Management

Appendix A:	References
Appendix B:	Fuel Properties
Appendix C:	General Calculation Instructions
Appendix D:	Conversion Factors
Appendix E:	Additional Information for the Alberta Gas Processing Index

Application for Deviation Requests

If a facility is unable to meet the mandatory requirements, a facility may submit to the director a deviation request with a proposal for alternative methods. The request will be reviewed and approved by the director on a case-by-case basis. If accepted, the deviation requests are approved on a time-limited bases. The standards for the respective regulations provide procedures for the submission of a deviation request.

In addition to any requirements prescribed by a standard, the application should include the following at minimum:

- 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

If accepted, an approval letter will be provided to the applicant and should be kept as a record to support verification activities.

Definitions

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

“AQM” means the Alberta Greenhouse Gas Quantification Methodologies.

“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.

“ECCC” means Environment and Climate Change Canada.

“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. H₂, N₂) 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°C, 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.

“NAICS” is the North American Industry Classification System.

“Negligible emission sources” are sources with combined carbon dioxide equivalent (CO_{2e}) emissions that represent less than 1% of a facility's total regulated emissions (TRE) or allowable emissions (AE) and do not exceed 10,000 tonnes of CO_{2e} for a facility under TIER. Alternative methodologies 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.



Chapter 1

Stationary fuel combustion

Alberta greenhouse gas
quantification methodologies

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1. 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. Stationary fuel combustion sources include, but are not limited to boilers, simple and combined-cycle combustion turbines, engines, emergency generators, portable equipment, process and space heaters, furnaces and any other combustion devices or system (e.g. blasting for mining purposes and drilling and completion activities). For the treatment of levied fuels, refer to the Technology Innovation and Emissions Reduction Regulation (TIER) and respective standards.

Methodologies for carbon dioxide (CO₂) emissions from biomass combustion are provided in Chapter 14, while methodologies for methane (CH₄) and nitrous oxide (N₂O) from biomass combustion are classified as stationary fuel combustion and are included in this chapter.

CO₂ that is entrained in fuels used in stationary combustion are reported under the stationary fuel combustion category. Note that the "formation CO₂" emissions category has been removed for TIER reporting.

Stationary fuel combustion does not include flare emission sources or waste incineration, which will be discussed in Chapter 2 and Chapter 6, respectively. Note that fuel combusted for the flare pilot is classified as a flare emission source.

1.2. Carbon Dioxide

1.2.1. Introduction

For each fuel type combusted, the mass of CO₂ emissions from fuel combustion for the reporting period may be calculated using one of four quantification methodologies specified in this section. A facility must use a methodology that corresponds with the level 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 level classification.

FIGURE 1-1: LEVEL CLASSIFICATION FOR QUANTIFICATION METHODOLOGIES FOR CO₂ EMISSIONS FROM STATIONARY FUEL COMBUSTION

		Level Classification			
		Level 1	Level 2	Level 3	Level 3A ¹
Fuel Types	Non-Variable	Method 1-1			Method 1-5
	Natural Gas	Method 1-2		Method 1-3 or Method 1-4	Method 1-5
	Variable	Method 1-3 or Method 1-4			Method 1-5

1. Level 3A methods can only be used if the facility is unable to apply a level 3 method.

1.2.2. Method 1-1 - A fuel-specific default CO₂ 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 CO₂ emission factor and the quantity of fuel consumed. This method can be used for levels 1, 2, or 3 as illustrated in Figure 1-1. Non-variable fuels include ethane, propane, butane, diesel, and gasoline.

For diesel and gasoline that is subject to the Renewable Fuels Standard (RFS) Regulation, the default CO₂ emission factors take into account the biofuel that is required as part of the fuel composition. Under the RFS, gasoline and diesel must contain an average of 5% and 2% biofuel, respectively. Note the biofuels are included in the chapter for CO₂ from biomass combustion. For facilities that have the composition of the biofuel content in the gasoline or diesel consumed, the facility may calculate the stationary fuel combustion and biomass CO₂ emissions based on actual composition instead of using the Alberta diesel and gasoline emission factors.

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 CO₂ 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 CO₂ mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-1a can be used directly to calculate the CO₂ 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 CO₂ mass emissions.

(2) Equations

For a liquid or gaseous fuel, use Equation 1-1 or Equation 1-1a to calculate the CO₂ mass emissions for the reporting period.

$$CO_{2,p} = v_{fuel,p} \times HHV \times EF_{ene} \quad \text{Equation 1-1}$$

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

Where:

CO _{2, p}	=	CO ₂ mass emissions for the specific fuel type for the reporting period, <i>p</i> (tonnes CO ₂).
V _{fuel, p}	=	For Equation 1-1 and Equation 1-1a, the volume of fuel combusted in kilolitres (kl) combusted during reporting period, <i>p</i> , 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, <i>p</i> . 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 1-2 - CO₂ emissions from combustion of natural gas

(1) Introduction

This method is adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO₂ mass emissions from natural gas combustion based on the measured HHV. This method can be used for levels 1 and 2 as illustrated in Figure 1-1. Level 3 facilities must use Method 1-3 for natural gas.

Calculate the CO₂ 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 natural gas, where the measured HHV is available, but not the carbon content, use Equation 1-2:

$$CO_{2,p} = v_{fuel,p} \times (60.554 \times HHV_p - 404.15) \times 10^{-6} \quad \text{Equation 1-2}$$

Where:

$CO_{2,p}$	=	CO_2 mass emissions for the 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 discrete 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 1-3 - CO_2 emissions from variable fuels based on the measured fuel carbon content

(1) Introduction

This method is used for variable fuels and is conservatively based on the complete oxidation of the measured carbon content in the fuel. 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 fluid catalytic cracking (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 prescribed.

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:

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

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

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

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.

$CC_{\text{gas}, p}$	=	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:

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

Where:

$CO_{2, p}$	=	CO_2 mass emissions for the liquid fuel during the reporting period, p (tonnes CO_2).
$v_{\text{fuel}(\text{liq}), p}$	=	Volume of liquid fuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (kilolitres).
$CC_{\text{liq}, p}$	=	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:

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

Where:

$CO_{2, p}$	=	CO_2 mass emissions for the solid fuel during the reporting period, p (tonnes CO_2).
$m_{\text{fuel}(\text{sol}), p}$	=	Mass of solid fuel combusted during the reporting period p , calculated in accordance with Chapter 17 and Appendix C (tonnes).
$CC_{\text{sol}, p}$	=	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 1-4 – Carbon mass balance method

(1) Introduction

This is a mass balance method that may be used to quantify carbon dioxide emissions from stationary fuel combustion, industrial process or flaring sources. For flaring sources, it would only include pilot or assist gas and not waste gas. For this method, the facility must be able to demonstrate that the fuel/feed supplied is consumed only by the sources within the mass balance. This method can only be used if there is one source with unknown quantity of fuel and emissions.

(2) Equations

Use Equation 1-4a to calculate the mass of carbon from the unknown source of emissions:

$$CM_{source,i,p} = CM_{facility,p} - \sum_n^N CM_{known\ source,n,p} \quad \text{Equation 1-4a}$$

Where:

- $CM_{source,i,p}$ = Mass of carbon for source i. Source i may be a stationary fuel combustion source, industrial process source, or flaring source (from pilot and assist gas only) (tonnes C) for the reporting period, p . Note that there can only be one unknown source in this equation.
- $CM_{facility,p}$ = Total mass of carbon in the fuel or feed supplied to the facility (tonnes C) for the sources in the mass balance for the reporting period, p .
- $CM_{known\ source,n,p}$ = Mass of carbon consumed by source, n . The mass of carbon for source n is quantified using another level 3 method prescribed in the AQM, for the reporting period, p .
- N = Number of known sources.

Equation 1-4b is used to calculate the mass of carbon in the fuel or feed supplied to the facility or to a known source for the reporting period.

$$CM_{facility,p} = v_{fuel,facility,p} \times CC_{gas,facility,p} \times 0.001 \quad \text{or}$$
$$CM_{known\ source,n,p} = v_{fuel,known\ source,n,p} \times CC_{gas,known\ source,n,p} \times 0.001 \quad \text{Equation 1-4b}$$

Where

- $v_{fuel, facility\ or\ known\ source,n,p}$ = Volume of gaseous fuel or feed (m^3) supplied to the facility or a known source, n , at standard conditions combusted during reporting period, p , calculated in accordance with Chapter 17 and Appendix C.
- $CC_{gas, facility,p\ or\ known\ source,n,p}$ = Weighted average carbon content of the gaseous fuel supplied to the facility or a known source during the reporting period p , calculated in accordance with Chapter 17 and Appendix C. The carbon content 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).

Use Equation 1-4c to calculate the carbon dioxide from the unknown source of emissions:

$$CO_{2,p} = CM_{source,i,p} \times 3.664 \quad \text{Equation 1-4c}$$

Where:

- $CO_{2,p}$ = CO_2 mass emissions for source n during the reporting period, p (tonnes CO_2).
- 3.664 = Ratio of molecular weights, CO_2 to carbon.

(3) Data requirements

- The total amount of fuel or feed supplied to a facility must be quantified based on a custody meter(s) (e.g. third party meters);
- The method may only be used to quantify stationary fuel combustion emissions, industrial process emissions, and flaring emissions from pilot fuel combustion.
- This method may only be used if there is one unknown source of emissions (stationary fuel combustion, industrial process or flaring emissions) in the mass balance.

- The emissions of the known sources must be calculated based on a level 3 quantification methodology prescribed in the AQM.
- This method may only be used for gaseous fuels and feeds.

1.2.6. Method 1-5 - Continuous emissions monitoring systems

(1) Generality

Calculate the CO₂ 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 CO₂ monitor (or O₂ 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.

- 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 CO₂ or O₂ concentrations and flue gas flow measurements to determine hourly CO₂ 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.
- Report CO₂ emissions for the reporting year in tonnes based on the sum of hourly CO₂ mass emissions over the year, converted to tonnes.
- An O₂ concentration monitor may be used in lieu of a CO₂ concentration monitor in a CEMS installed before January 1, 2012, to determine the hourly CO₂ concentrations. This may be used if the effluent gas stream monitored by the CEMS consists of combustion products (i.e., no process CO₂ emissions or CO₂ 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.
 - 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 O₂ concentrations.
 - If the operator of a facility that combusts biomass fuels uses O₂ concentrations to calculate CO₂ concentrations, annual source testing must demonstrate that the calculated CO₂ concentrations, when compared to measured CO₂ concentrations, meet the Relative Accuracy Test Audit (RATA) requirements in reference [8] in Appendix A or Alberta CEMS Code.
- If both biomass and fossil fuels (including fuels that are partially biomass) are combusted during the year, determine the biomass CO₂ mass emissions separately, as described in Chapter 14.
- For any units using CEMS data, industrial process and stationary combustion CO₂ 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.
- 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 CO₂ 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.
- If a facility does not have a CEMS and chooses to add one in order to measure CO₂ 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 CH₄ and N₂O mass emissions for the reporting period from stationary fuel combustion sources, for each fuel type including biomass fuels, using Method 1-6 or Method 1-7.

1.3.2. Method 1-6- Default CH₄ and N₂O emission factor

(1) Introduction

This method calculates the CH₄ and N₂O mass emissions based on default emission factors that are based in energy or physical units of fuel consumed. CH₄ and N₂O 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 to 1-7 provide the emission factors for these fuels in mass of CH₄ and N₂O 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 1-5 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 to 1-7 to calculate the CH₄ and N₂O mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 1-5a can be used directly to calculate the CH₄ and N₂O mass emissions based on the appropriate energy based emission factor from Tables 1-1 to 1-7.

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 1-5a using the fuel quantity in volume basis with the appropriate volume based emission factor from Tables 1-1 to 1-7 to calculate the CH₄ and N₂O mass emissions.

(2) Equations

For a solid, liquid and gaseous fuel, use Equation 1-5 or Equation 1-5a:

$$CH_{4,p} \text{ or } N_{2O,p} = Fuel_p \times HHV \times EF_{ene} \quad \text{Equation 1-5}$$

$$CH_{4,p} \text{ or } N_{2O,p} = Fuel_p \times (EF_{vol} \text{ or } EF_{ene}) \quad \text{Equation 1-5a}$$

Where:

CH _{4,p} or N _{2O,p}	=	CH ₄ or N ₂ O mass emissions for the specific fuel type for the reporting period, <i>p</i> , (tonnes CH ₄ or N ₂ O).
Fuel _p	=	For Equation 1-5, the quantity of fuel combusted in kilolitres, cubic metres, or tonnes (kl, m ³ , tonnes) combusted during reporting period, <i>p</i> . For Equation 1-5a, 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, <i>p</i> . 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 to 1-7 in tonnes of CH ₄ or N ₂ O per energy units (GJ), volume units (kilolitres or cubic metres), or mass units (tonnes).

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

$$CH_{4,p} \text{ or } N_{2O,p} = Fuel_i \times EF \quad \text{Equation 1-5b}$$

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).
$Fuel_i$	Calculated per Equation 14-4 in Chapter 14 (tonnes).
EF	Fuel-specific default CH_4 and N_2O emission factor, from Tables 1-6, in tonnes of CH_4 and N_2O per tonnes.

(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 may use sector or technology based emission factors to calculate CH_4 and N_2O emissions.
- If a facility has the HHV for the fuel, the energy based emission factor (tonnes of emissions per gigajoules) must be used to calculate the CH_4 and N_2O emissions. Otherwise, the facility may use the volume based emission factors (tonnes of emissions per cubic metre).

1.3.3. Method 1-7 – 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 continuous emissions monitoring system (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 Fuel	CO ₂ Emission Factor ¹		CH ₄ Emission Factor ¹		N ₂ O Emission Factor ¹	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel						
All industry	2.681	0.0699	7.8E-05	2.0E-06	2E-05	5.8E-07
Upgraders	2.681	0.0699	7.8E-05	2.0E-06	2E-05	5.8E-07
Diesel in Alberta ²	2.610	0.06953	see note 3			
Biodiesel						
All industry	see note 4		7.8E-05	2.2E-06	2E-05	6.3E-07
Upgraders			7.8E-05	2.2E-06	2E-05	6.3E-07
Gasoline	2.307	0.0690	1E-04	3.0E-06	2E-05	6E-07
Gasoline in Alberta ²	2.174	0.06540	see note 5			
Ethanol	See note 4		1E-04	4.3E-06	2E-05	8.5E-07
Butane	1.747	0.0614	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	0.986	0.0573	2.4E-05	1.4E-06	1.08E-04	6.3E-06
Propane	1.515	0.0599	2.4E-05	9.5E-07	1.08E-04	4.3E-06

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content. If the actual biofuel composition is known, a facility may use the gasoline or diesel CO₂ emission factor for the non-biofuel component and the CO₂ emission factor prescribed in Chapter 14 for the biofuel component.
3. Diesel CH₄ and N₂O emission factors are used.
4. CO₂ emission factors are provided in Table 14-1 in Chapter 14. CO₂ emissions from biodiesel and ethanol should be reported under the biomass emissions.
5. Gasoline CH₄ and N₂O emission factors are used.

TABLE 1-2: SECTOR BASED DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR NATURAL GAS

Natural Gas	CH ₄ Emission Factor ¹		N ₂ O Emission Factor ¹	
	tonne/m ³	tonne/GJ	tonne/m ³	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)	6.4E-06	1.40E-04	6E-08	1.3E-06
Pipelines	1.9E-06	5.0E-05	5E-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	9.2E-07

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.

TABLE 1-3: TECHNOLOGY BASED DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR NATURAL GAS

Natural Gas	CH ₄ Emission Factor ¹		N ₂ O Emission Factor ²	
	tonne/m ³	tonne/GJ ³	tonne/m ³	tonne/GJ ³
Boilers/Furnaces/Heaters				
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07
Internal Combustion Engine				
Turbine	1.4E-07	3.7E-06	5E-08	1E-06
2 stroke lean ⁴	2.37E-05	6.23E-04	-	-
NOx 90-105% Load	-	-	7.77E-07	2.04E-05
NOx < 90% Load	-	-	4.75E-07	1.25E-05
4 stroke lean ⁴	2.04E-05	5.37E-04	-	-
NOx 90-105% Load	-	-	1.00E-06	2.63E-05
NOx < 90% Load	-	-	2.07E-07	5.46E-06
4 stroke rich ⁴	3.76E-06	9.89E-05	-	-
NOx 90-105% Load	-	-	5.41E-07	1.43E-05
NOx < 90% Load	-	-	5.56E-07	1.46E-05

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) for the volume based emission factor.
2. Emission factors are adapted from USEPA AP-42 Chapters 1 and 3.
3. The energy-based emission factor should be used if the fuel consumption on an energy basis is available. The volume-based emission factor should only be used if the higher heating value or energy of the fuel is not available.
4. The N₂O emission factor is based on 1.5% of the NOx emission factor, as provided in AP-42.

TABLE 1-4: DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR LIQUID FUELS

Liquid Fuels ¹	CH ₄ Emission Factor ¹		N ₂ O Emission Factor ¹	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Kerosene				
Electric Utilities	6E-06	1.6E-07	3.1E-05	8.3E-07
Industrial	6E-06	1.6E-07	3.1E-05	8.3E-07
Producer Consumption ²	6E-06	1.6E-07	3.1E-05	8.3E-07
Forestry, Construction and Commercial/Institution	2.6E-05	7.0E-07	3.1E-05	8.3E-07
Light Fuel Oil				
Electric Utilities	1.8E-04	4.6E-06	3.1E-05	8.0E-07
Industrial	6E-06	1.5E-07	3.1E-05	8.0E-07
Producer Consumption ²	6E-06	1.5E-07	3.1E-05	8.0E-07
Forestry, Construction and Commercial /Institution	2.6E-05	6.7E-07	3.1E-05	8.0E-07
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	1.5E-06
Forestry, Construction and Commercial /Institution	5.7E-05	1.3E-06	6.4E-05	1.5E-06

1. Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. WCI Table 20-2 or 20-7.

TABLE 1-5: DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR SOLID FUELS

Solid Fuels ¹	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Petroleum Coke ²				
Upgrader	1.2E-04	3.0E-06	2.4E-05	5.9E-07
Refinery and Others	1.2E-04	2.6E-06	2.75E-05	5.93E-07
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Coal				
Electric Utilities				
Anthracite	2.2E-05	7.9E-07	3.2E-05	1.2E-06
Canadian Bituminous	2.2E-05	7.8E-07	3.2E-05	1.1E-06
Foreign Bituminous	2.2E-05	7.4E-07	3.2E-05	1.1E-06
Lignite	2.2E-05	1.4E-06	3.2E-05	2.0E-06
Sub-bituminous	2.2E-05	1.1E-06	3.2E-05	1.7E-06
Industry and Heat and Steam Plants				
Anthracite	3E-05	1.1E-06	2E-05	7.2E-07
Canadian Bituminous	3E-05	1.1E-06	2E-05	7.0E-07
Foreign Bituminous	3E-05	1.0E-06	2E-05	6.7E-07
Lignite	3E-05	1.9E-06	2E-05	1.2E-06
Sub-bituminous	3E-05	1.6E-06	2E-05	1.1E-06
Residential, Public Administration				
Anthracite	4E-03	1.00E-04	2E-05	7.2E-07
Canadian Bituminous	4E-03	1.00E-04	2E-05	7.0E-07
Foreign Bituminous	4E-03	1.00E-04	2E-05	6.7E-07
Lignite	4E-03	2.00E-04	2E-05	1.2E-06
Sub-bituminous	4E-03	2.00E-04	2E-05	1.1E-06
Coke ³	3E-05	1.0E-06	2E-05	6.9E-07
Industrial Waste Fuel (used by cement facilities)	-	3E-05	-	4E-06

1. Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. Petroleum coke refers to a type of coke that is derived from petroleum processing.
3. Coke is typically derived from the processing of coal and does not include petroleum coke.

TABLE 1-6: DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR BIOMASS FUELS

Biomass Fuels ¹	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/tonne	tonne/GJ	tonne/tonne	tonne/GJ
Wood Waste	1.0E-04	4.74E-06	7E-05	3.25E-06
Spent Pulping Liquor	2.9E-05	2.09E-06	5E-06	3.8E-07

1. Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.

TABLE 1-7: DEFAULT CH₄ AND N₂O EMISSION FACTORS FOR GASEOUS FUELS

Gaseous Fuels ¹	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Coke Oven Gas	3.7E-08	1.9E-06	3.5E-08	1.8E-06
Still Gas	3.1E-08	9.1E-07	2E-08	6E-07

1. Unless specified otherwise, emission factors are adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.



Chapter 2

Flaring

Alberta greenhouse gas
quantification methodologies

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2. Flaring

2.1. Introduction

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced at the facility, used for routine, non-routine or emergency disposal of a hazardous waste stream, where the main purpose is not energy production. There are a variety of flare and incineration technologies including flare pits, ground flares, flare stacks, enclosed flares and incinerators and combustors. Methodologies for flaring/incineration of liquid fuel streams are not presented in this chapter.

Typical gases that are flared or incinerated include, but are not limited to waste petroleum gas, refinery or still gas, purge gas, pilot or assistance gas, and biogas. Flaring or incineration commonly occurs at the following types of operations:

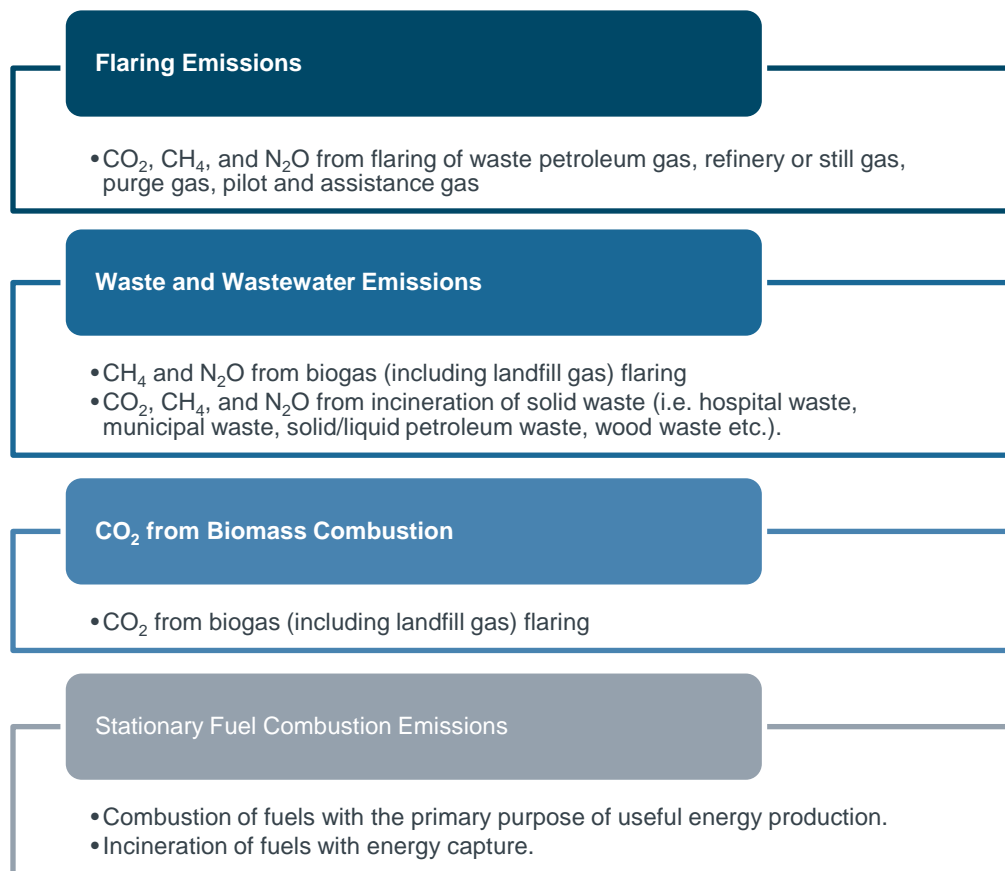
- well testing;
- natural gas gathering system;
- processing plant operations;
- crude oil production;
- pipeline operations;
- petroleum refining;
- chemical fertilizer production and steel production; and
- waste gases generated by sewage digesters.

Emissions from flaring may fit into more than one source category. Figure 2-1 provides clarification on the emission source categories under the Technology Innovation and Emissions Reduction Regulation (TIER) and Specified Gas Reporting Regulation (SGRR).

Note that carbon dioxide (CO₂) that is entrained in the fuel (or previously referred to as formation CO₂) is reported as an emission in the respective categories that the fuel is consumed in. For example, if there is entrained CO₂ within a fuel that is combusted or flared, it would be included in the CO₂ that is emitted in the stationary fuel combustion or flaring categories, respectively. Similarly, if there is entrained CO₂ in a fuel that is vented or released as a fugitive, it would be reported as CO₂ emissions in the venting or fugitive emissions category, respectively.

Quantification methodologies are presented in this chapter for some emissions presented in Figure 2-1 even though some of these are not classified as flaring emissions. The reporter is responsible for ensuring that the emissions are reported under the correct source category.

FIGURE 2-1: CLARIFICATION ON FLARING AND OTHER EMISSIONS CATEGORIES



2.2. Flare Combustion Efficiency

The flare combustion efficiency is defined as the mole or volume fraction of combustible carbon in the flare gas that is converted to CO₂ during the flaring process, which can be expressed as a percentage of carbon combusted or oxidized.

For the quantification of flaring emissions, the following flare combustion efficiencies were adopted from flare efficiency and thermal oxidizer studies conducted and published by the USEPA:

- 98.0% flare combustion efficiency for unassisted flares. These flares are typically found in remote oil and gas production operations;
- 99.5% flare combustion efficiency for properly-operated, highly-turbulent, air- or steam-assisted flares. These flares are typically found in gas plants, upgraders, petroleum refineries, and chemical plants; and
- 100.0% flare combustion efficiency for incinerators, oxidizers, or other “external combustion” units that operate like boilers. As a conservative approach, methane emissions based on emission factors are still applied.

A facility must select a quantification methodology in this chapter that corresponds with the level classification assigned to the facility in the Standard for Completing Greenhouse Compliance and Forecasting Reports for reporting under TIER or the Specified Gas Reporting Standard for reporting under SGRR.

Sampling and measurement frequencies are prescribed in the quantification methodologies presented in this chapter.

2.3. Carbon Dioxide and Methane

2.3.1. Introduction

Carbon dioxide emissions from flares are generated from the oxidization of carbon in the flare gas and from any carbon dioxide entrained in the flare gas. Methane in the flare gas that is un-oxidized is released as methane emissions.

For each flare type, the mass of CO₂ and CH₄ emissions for the reporting period may be calculated using one of three quantification methodologies as illustrated in Table 2-1.

Table 2-1 provides the level classifications for three possible flaring scenarios. The first two flaring scenarios are adapted from Alberta Energy Regulator's (AER's) Directive 60. The descriptions of these scenarios apply to all sectors where flaring occurs.

- Routine flaring is considered to be continuous or intermittent flaring that occurs on a regular basis during normal facility operations.
- Non-routine flaring is considered to be intermittent and/or infrequent flaring and incineration. This includes any planned flaring events that occur during maintenance activities or startups/shutdowns of process operations. Non-routine flaring also includes emergency or unplanned flaring events due to emergency or upset process conditions.
- Where total flaring emissions from all flaring sources representing less than 1% of a facility's total direct emissions the facility may apply any method prescribed in this chapter or an alternative method that is conservative, as indicated in Table 2-1. These emissions do not count towards the facility's negligible emission sources or negligible emission total under TIER.

TABLE 2-1: LEVEL CLASSIFICATION FOR QUANTIFICATION METHODOLOGIES FOR CO₂ AND CH₄ EMISSIONS FROM FLARING

Flaring Scenarios	Level Classification		
	1	2	3
Routine flaring ¹	Method 2-1	Method 2-2 or Method 2-3	
Non-routine flaring ¹	Method 2-1 or Method 2-2		
Flaring emissions represent less than 1% of facility's total emissions ²	Any method prescribed in this chapter or alternative method that is conservative		

1. Definitions of routine and non-routine flaring is adapted from AER Directive 60.

2. The facility should document methodologies used in the facility's Quantification Methodologies Document (QMD).

2.3.2. Method 2-1: Default Emission Factor Method

(1) Introduction

The Default Emission Factor Method is based on default CO₂ and CH₄ emission factors which were developed for different fuel gas types (lean to rich condensate), non-variable fuels (ethane, propane and butane), and other process gas or waste gases. The default emission factors are provided for the three flare combustion efficiencies provided in Section 2.2.

This method provides default emission factors for facilities that do not have gas analysis, but have knowledge of the flare gas properties such as the higher heating value (HHV), or whether it is rich or lean gas being sent to flare stack. Facilities are required to select emission factors from Tables 2-2 or 2-3 that would be the most representative of the flare gas. If the HHV of the flare gas falls between two HHVs in the tables, the facility is required to choose the emission factor with the higher HHV.

Methane emission factors are provided in Table 2-3 representing the un-combusted CH₄ in the flare gas based on the flare combustion efficiency. For incineration, methane emissions are conservatively added even though the flare combustion efficiency was assumed to be 100%.

Methane emission factors for different fuel gases are based on the industrial sector emission factor from Environment and Climate Change Canada (ECCC's) Greenhouse Gas Reporting Program (GHGRP). This emission factor was adjusted by the HHV of the various default gas types.

(2) Equations

For each flare source, use Equation 2-1a or Equation 2-1b to calculate the CO₂ and CH₄ mass emissions.

$$GHG = \sum_{F=1}^N V_{FL,F} \times EF_{vol,F} \times 10^{-6} \quad \text{Equation 2-1a}$$

$$GHG = \sum_{F=1}^N ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6} \quad \text{Equation 2-1b}$$

Where:

GHG	=	CO ₂ or CH ₄ mass emissions from flaring (tonnes) for the reporting period.
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
V _{FL,F}	=	Volume of the flare gas stream, F, at a flare source (standard cubic meters, sm ³) at standard conditions for the reporting period.
ENE _{FL,F}	=	Energy of the of the flare gas stream, F, at a flare source (MJ) for the reporting period.
EF _{vol,F}	=	Default CO ₂ or CH ₄ emission factor, selected from Table 2-2 or Table 2-3 (g/m ³).
EF _{ENE,F}	=	Default CO ₂ or CH ₄ emission factor, selected from Table 2-2 or Table 2-3 (g/MJ).
10 ⁻⁶	=	Mass conversion factor (tonne/g).

TABLE 2-2: DEFAULT CO₂ FLARING EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	Carbon Dioxide Emission Factors						
	High Heating Value (MJ/m³)	Open Flares				Incinerators	
		Unassisted		Assisted			
		98.0% Efficiency		99.5% Efficiency		100% Efficiency	
		(g/m³)	(g/MJ)	(g/m³)	(g/MJ)	(g/m³)	(g/MJ)
Fuel Gas Types							
Sales gas	38.02	1,853	48.75	1,882	49.49	1,891	49.74
Lean gas	40.39	2,006	49.68	2,037	50.44	2,047	50.69
Medium-rich gas	42.48	2,141	50.41	2,174	51.18	2,185	51.44
Rich gas	44.77	2,280	50.93	2,315	51.70	2,327	51.96
Process Fuel Gas Types							
HHV >50 MJ/m³	50.42	2,645	52.46	2,685	53.26	2,699	53.53
Still gas (Upgrading)	34.02	2,097	61.65	2,129	62.59	2,140	62.90
Still gas (Refinery & others)	34.02	2,081	61.16	2,112	62.09	2,123	62.40
Non-Variable Gas Types							
100% Methane (C1)	37.708	1,824	48.37	1,852	49.11	1,861	49.36
100% Ethane (C2)	66.065	3,648	55.22	3,704	56.07	3,723	56.35
100% Propane (C3)	93.936	5,472	58.25	5,556	59.15	5,584	59.44
100% Butane (C4)	121.600	7,296	60.00	7,408	60.92	7,445	61.23
Landfill Gas							
Flaring of landfill gas ⁶	18.85	1,843	97.73	1,857	98.47	1,861	98.72

1. Flare combustion efficiencies have been applied in the emission factor.
2. Molecular weights and HHVs are from Gas Processors Association 2145-09.
3. Default gas compositions used in the development of the emission factors are:
 - Sales gas - 98% CH₄, 1% C₂H₆, 0.3% C₃H₈, 0.1% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Lean gas - 92% CH₄, 5% C₂H₆, 1.9% C₃H₈, 0.5% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Medium gas - 86% CH₄, 10% C₂H₆, 2.5% C₃H₈, 0.9% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Rich gas - 80% CH₄, 15% C₂H₆, 5% C₃H₈
 - Landfill gas - 50% CH₄, 50% CO₂
 - Gas with HHV > 50 MJ/m³ - 70% CH₄, 20% C₂H₆, 10% C₃H₈
4. Still gas emission factors are based on Canada's Greenhouse Gas Quantification Requirements, ECCC GHGRP, December 2019.
5. CO₂ emissions for fuel gases and still gases from entrained CO₂ in the flare gas are included in the CO₂ emission factors.
6. These are considered to be biomass CO₂ and should be reported under the biomass CO₂ category.

TABLE 2-3: DEFAULT CH₄ FLARING EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	Methane Emission Factors						
	High Heating Value (MJ/m³)	Open Flares		Open Flares		Incinerators	
		Unassisted		Assisted			
		(98.0% Efficiency)		(99.5% Efficiency)		(100% Efficiency)	
		(g/m³)	(g/MJ)	(g/m³)	(g/MJ)	(g/m³)	(g/MJ)
Natural Gas Type							
Sales gas	38.02	13.27	0.35	3.32	0.09	0.037	0.0010
Lean gas	40.39	12.46	0.31	3.11	0.08	0.040	0.0010
Medium-rich gas	42.48	11.65	0.27	2.91	0.07	0.042	0.0010
Rich gas	44.77	10.83	0.24	2.71	0.06	0.044	0.0010
Rich gas with HHV >50 MJ/m³	50.42	8.80	0.17	2.20	0.04	0.044	0.00087
Still gas (Upgrading)	34.02	31	0.91	7.75	0.23	0.033	0.001
Still gas (Refinery & others)	34.02	31	0.91	7.75	0.23	0.033	0.001
Non-Variable Gas Types							
100% Methane	37.708	13.54	0.36	3.39	0.09	0.037	0.001
100% Ethane (C2)	66.065	0.00	0.00	0.00	0.00	0.00	0.00
100% Propane (C3)	93.936	0.00	0.00	0.00	0.00	0.00	0.00
100% Butane (C4)	121.600	0.00	0.00	0.00	0.00	0.00	0.00
Landfill Gas							
Landfill gas (50% methane) ⁷	18.85	6.77	0.36	1.69	0.09	0.018	0.0010

1. Flare combustion efficiencies have been applied in the emission factor.
2. Methane emission factors for flaring of fuel gases and non-variable gases using incinerator technology are based on Canada's Greenhouse Gas Quantification Requirements, ECCC GHGRP, December 2019 and are adjusted by HHV of the different fuel types.
3. Molecular weights and HHVs are from Gas Processors Association 2145-09.
4. Default gas compositions used in the development of the emission factors are:
 - Sales gas - 98% CH₄, 1% C₂H₆, 0.3% C₃H₈, 0.1% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Lean gas - 92% CH₄, 5% C₂H₆, 1.9% C₃H₈, 0.5% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Medium gas - 86% CH₄, 10% C₂H₆, 2.5% C₃H₈, 0.9% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Rich gas - 80% CH₄, 15% C₂H₆, 5% C₃H₈
 - Landfill gas - 50% CH₄, 50% CO₂
 - Gas with HHV > 50 MJ/m³ - 70% CH₄, 20% C₂H₆, 10% C₃H₈
5. Still gas emission factors are based on Canada's Greenhouse Gas Quantification Requirements, ECCC GHGRP, December 2019.
6. CO₂ emissions for fuel gases and still gases from entrained CO₂ in the flare gas are included in the CO₂ emission factors.
7. Landfill gas is assumed to be composed of 50% of methane and 50% of carbon dioxide by volume.

(3) Data requirements

- For facilities that are subject to the expansion requirements prescribed by ECCC's GHGRP, the facility should use Method 2-2 or Method 2-3 with measurement frequencies prescribed by ECCC's GHGRP.

For all other facilities:

- The volume or energy of the flare gas may be estimated using engineering estimates, fuel mass balance, manufacturer specifications, and operating time.
- If the facility has measured quantities (in volume or energy basis) of the flare gas, the facility is required to use the measured quantity instead of an estimated quantity.
- If the flare gas volume is not measured, but the flare gas is from a venting source that is captured and sent to flaring, the facility may use a quantification methodology that is described in Chapter 4 Venting to calculate the volume of the flare gas. The facility would select a quantification methodology that is at the required level classification for the facility.
 - When a volumetric venting rate (VR) is a parameter in the venting emissions calculation equations, calculate the flare gas volume by applying $VR \times \text{total venting time (t)} \times \text{control factor (CF)}$.
 - When a volumetric VR is not a parameter in the venting emission calculation equations, use the same approach of venting rate or venting volume estimation as in the equations, calculate the flare gas volume by applying $VR \times t \times CF$ or $Q_{\text{vent}} \times CF$.
 - When a mass VR is a parameter in the venting emissions calculation equations, convert the mass VR first using an appropriate density of the vented gas, then calculate the flare gas volume by applying $VR \times t \times CF$.
- Based on the facility's knowledge of the flare gas composition and flare technology, select the flare gas type that would best align with the flare gas consumed and the appropriate emission factor from Tables 2-2 or 2-3. For flare gases that are aligned with the fuel gas types, if the HHV of the flare gas falls between two HHVs in the tables, the facility is required to select the emission factor with a higher HHV.
- The facility may apply measured gas compositions consistent with Table 17-1 of the AQM if gas analysis is conducted on the site.

2.3.3. Method 2-2 – Multiple Flare Gas Stream Method

(1) Introduction

This method uses estimated and measured gas volumes and compositions of flare gases to calculate CO₂ and CH₄ emissions. This is applicable for multiple flare gas streams that are combined and flared as a single flare gas source.

This method may be used for non-routine flaring where measurements of flare gas volumes and/or gas compositions is not operationally possible. This may include waste gases generated from abnormal operating conditions, start-up or shutdown operations, or process malfunctions. Unmeasured volumes or compositions of flare gas may be calculated based on engineering estimates, fuel mass balance method, manufacturer's specified flow rates, and operating times.

Facilities may have measured volumes and compositions of gases that are routinely flared such as assistant gas, pilot gas, or purge gas streams. These flare gas streams may be equipped with online analyzers.

(2) Equations

For each flare source, use Equation 2-2 and 2-2a to calculate the total CO₂ mass emissions from the flaring of multiple flare gas streams that are combined.

$$CO_{2,flaring} = \sum_{F=1}^N \frac{V_{FL,F}}{MVC} \times (CC_F \times CE_{FL} + MF_{CO_2}) \times MW_{CO_2} \times 0.001 \quad \text{Equation 2-2}$$

$$CC_F = \sum_{i=1}^I MF_{i,F} \times NC_{i,F} \quad \text{Equation 2-2a}$$

Where:

$CO_{2, \text{flaring}}$	=	Total CO_2 mass emissions from a flare source including entrained CO_2 for the reporting period (tonnes).
N	=	Total number of flare gas streams.
F	=	Flare gas stream.
$V_{FL,F}$	=	Measured or estimated volume of the flare gas stream, F , (sm^3) at standard conditions for the reporting period.
MVC	=	Standard molar volume conversion at standard molar volume as defined in Appendix B, Table B-2 (23.645 $m^3/kmol$).
CC_F	=	Average carbon content for flare gas stream, F , ($kmol_{\text{carbon}}/kmol_{\text{flare gas, F}}$) for the reporting period. This excludes carbon from entrained CO_2 in the flare gas.
MF_{F,CO_2}	=	CO_2 mole fraction in flare gas stream, F .
MW_{CO_2}	=	Molecular weight of CO_2 ($kg/kmol$), as provided in Appendix B.
0.001	=	Mass conversion factor (tonne/kg).
I	=	Total number of components in the flare gas stream, F .
i	=	Type of component.
CE_{FL}	=	Flare combustion efficiency (%).
$MF_{i,F}$	=	Normalized mole fraction of component, i , based on the estimated or measured weighted average flare gas composition in the flare gas stream, F , ($kmol\ i/kmol_{\text{flare gas}}$) for the reporting period.
$NC_{i,F}$	=	Number of carbons in component, i , in the flare gas stream, F .

For methane emissions, use Equation 2-4 to calculate uncombusted methane from the flare gas:

$$CH_{4, \text{flaring}} = \sum_{F=1}^n [V_{FL,F} \times MF_{CH_4,F}] \times (1 - CE_{FL}) \times \frac{CH_4}{MVC} \times 0.001 \quad \text{Equation 2-4}$$

Where:

$CH_{4, \text{flaring}}$	=	Total CH_4 mass emissions from a flare source for the reporting period (tonnes);
$V_{FL,F}$	=	Measured or estimated volume of flare gas stream, F , (sm^3) at standard conditions for the reporting period.
$MF_{CH_4,F}$	=	Normalized mole fraction of CH_4 in estimated or measured average flare gas composition for flare gas stream, F ($kmol_{CH_4}/kmol_{GAS}$) for the reporting period.
n	=	Number of flare gas streams.
F	=	Flare gas stream.
CE_{FL}	=	Flare combustion efficiency (%).
CH_4	=	Molecular weight of CH_4 ($kg/kmol$), as provided in Appendix B.

MVC	=	Standard molar volume conversion at standard conditions as provided in Appendix B, Table B-2 (23.645 m ³ /kmol).
0.001	=	Mass conversion factor (tonne/kg).

(3) Data requirements

- For facilities subject to the expansion requirements prescribed by ECCC's GHGRP, the facility should follow measurement frequencies prescribed by ECCC's GHGRP.
- For a flare gas stream that is measured, if there is an online continuous flow measurement device or a continuous gas composition analyzer, the measured flow volumes and gas composition must be used to calculate emissions for the flare gas stream.
- For routine flaring, the following requirements apply:
 - The facility must have measured volumes and gas compositional analysis for a minimum of 60% by volume of the total flare gas stream. Note that for non-variable fuels such as propane and butane, the default gas compositions may be used. The volume and gas composition of the remaining unmeasured flare gas streams may be estimated using engineering estimates, a mass balance, or manufacturer specifications.
 - The volume and gas composition measurements must be taken daily if there is online instrumentation (i.e. flow meter and gas analyzer) or weekly if no online instrumentation is available.
 - A weighted gas composition must be used in calculating emissions and is based on the maximum sampling frequency that the facility is conducting. If the sampling frequency is higher than the prescribed frequency, the facility must apply the higher frequency in the weighted average.
 - For pilot or assistance gas used for flaring where the fuel type is known (i.e. propane, butane, sales gas, etc.), the facility may apply measured gas compositions consistent with the sampling or measurement frequencies outlined in Table 17-1 of the AQM, or the default gas composition of the fuel type listed in Table 2-2.
 - The volume or gas composition of the flare pilot or assistance gas may be calculated using a mass balance approach as described in Method 1-4 in Section 1.2.5 in Chapter 1.
 - For a flare gas stream where the volume is not measured, but the flare gas stream is from a controlled venting emission source, the venting volume may be quantified using quantification methodologies provided in Chapter 4 Venting. Refer to the data requirements in Section 2.3.2 (Method 2-1). The volume quantified using methods in Chapter 4 may be included in the 60% measured volume and gas composition requirement as indicated above.
 - Flare gas volume and composition must be measured using:
 - A analytical methods required by AER Directives and other applicable regulatory requirement; or
 - The most appropriate method published by a consensus-based standards organization.
 - If flare gas volumes and/or gas composition measurements are missing in a reporting period, the missing data procedures outlined in Section 17.5.2 of Chapter 17 should be followed.
- For non-routine flaring, the volume and gas composition of the flare gas may be estimated using engineering estimates, fuel mass balance, manufacturer specifications, and operating time.
- The facility must select a default flare combustion efficiency that best represents the flare technology that is applied at the facility. The selection must be supported by manufacturer specification or test data. The default flare combustion efficiencies are described in Section 2.2.
- If the sum of the mole fractions of components do not add up to 1.000 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 1.000.

2.3.4. Method 2-3 - Combined Flare Gas Stream Method

(1) Introduction

This method requires measured volumes and gas compositions of the flare gas at the point before flaring or incineration. There may be a single flare gas stream or multiple flare gas streams that are combined before being flared at a single point, excluding fuel that used for the flare pilot. The measurements are taken at a point where the flare gas streams have been combined before flaring. This method may be applied for routine flaring operations.

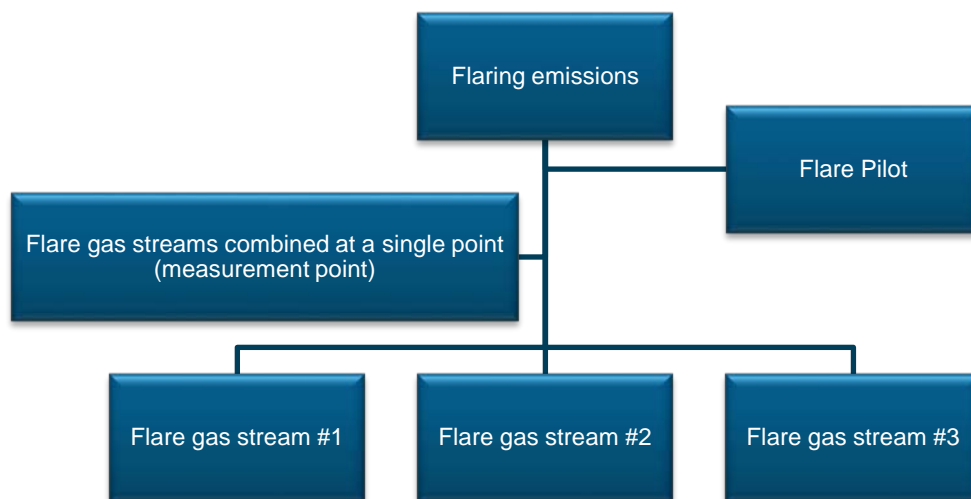


FIGURE 2-2: COMBINED FUEL GAS STREAMS

(2) Equations

For each flare, calculate the CO₂ and CH₄ mass emissions for the reporting period by applying the measured flare gas volume and carbon content using Equation 2-5 and Equation 2-6, respectively.

$$CO_2 = \left(\frac{V_{total}}{MVC} \times (CC_F \times CE_{FL} + MF_{CO_2,F}) + \frac{V_{pilot}}{MVC} \times (CC_P \times CE_{FL} + MF_{CO_2,P}) \right) \times MW_{CO_2} \times 0.001 \quad \text{Equation 2-5}$$

$$CH_4 = (V_{total} \times MF_{CH_4,F} + V_{pilot} \times MF_{CH_4,P}) \times (1 - CE_{FL}) \times \frac{MW_{CH_4}}{MVC} \times 0.001 \quad \text{Equation 2-6}$$

Where:

CO ₂	=	Total CO ₂ mass emissions from a flare source including entrained CO ₂ for the reporting period (tonnes).
CH ₄	=	Total CH ₄ mass emissions from a flare source for the reporting period (tonnes).
V _{total}	=	Total volume of flare gas, excluding the pilot gas, at a flare source (sm ³) at standard conditions for the reporting period.
V _{pilot}	=	Total volume of the pilot gas (sm ³) at standard conditions for the reporting period.
CC _F	=	Weighted average carbon content of the combined flare gas, excluding the pilot gas, (mol of carbons/mol of flare gas) by using Equation 2-2a. This excludes carbon from entrained CO ₂ in the flare gas.
CC _P	=	Weighted average carbon content of the pilot gas (mol of carbons/mol of flare pilot gas) by using Equation 2-2a. This excludes carbon from entrained CO ₂ in the pilot gas.

MVC	=	Standard molar volume conversion at standard conditions as defined in Appendix B, Table B-2 (23.645 m ³ /kmol).
MF _{CO₂,F}		Weighted average mole fraction of CO ₂ in the combined flare gas at a flare source in the reporting period (kmol _C /kmol _{GAS}).
MF _{CO₂,P}		Weighted average mole fraction of CO ₂ in the pilot gas at a flare source in the reporting period (kmol _{CH₄} /kmol _{GAS}).
MF _{CH₄, F}	=	Weighted average mole fraction of CH ₄ in the combined flare gas at a flare source in the reporting period (kmol _{CH₄} /kmol _{GAS}).
MF _{CH₄, P}	=	Weighted average mole fraction of CH ₄ in the pilot gas at a flare source in the reporting period (kmol _{CH₄} /kmol _{GAS}).
CE _{FL}	=	Flaring combustion efficiency (%).
MW _{CO₂}	=	Molecular weight of CO ₂ (kg/kmol), as provided in Appendix B
MW _{CH₄}	=	Molecular weight of CH ₄ (kg/kmol), as provided in Appendix B.
0.001	=	Mass conversion factor (tonne/kg).

(3) Data requirements

- For facilities subject to the expansion requirements prescribed by ECCC's GHGRP, the facility should follow measurement frequencies prescribed by ECCC's GHGRP.
- The flare gas must be measured at a point after the flare gas streams are combined and before flaring. The combined flare gas excludes the fuel that is used for the flare pilot. The measured flow volumes and gas composition must be used to calculate emissions from the flare source.
- For pilot or assistance gas used for flaring where the fuel type is known (i.e. propane, butane, sales gas, etc.), the facility may apply measured gas compositions consistent with the sampling or measurement frequencies outlined in Table 17-1 of the AQM, or the default gas composition of the fuel type listed in Table 2-2.
- The volume and gas composition measurements must be taken daily if there is online instrumentation (i.e. flow meter and gas analyzer) or weekly if no online instrumentation is available.
- A weighted gas composition must be used in calculating emissions and is based on the minimum frequency of measurements that the facility is conducting.
- If flare gas volumes and/or gas composition measurements are missing in a reporting period, the missing data procedures outlined in Section 17.5.2 of Chapter 17 should be followed.
- The facility must select a default flare combustion efficiency that best represents the flare technology that is applied at the facility. The selection must be supported by manufacturer specification or test data. The default flare combustion efficiencies are described in Section 2.2.
- Flare gas volume and composition must be measured using:
 - A analytical methods required by AER Directives and other applicable regulatory requirement; or
 - The most appropriate method published by a consensus-based standards organization.

2.4. Nitrous Oxide

2.4.1. Introduction

For all flare types, the mass of N₂O emissions for the reporting period is calculated using a default emission factor methodology.

2.4.2. Method 2-4: Default Emission Factor Method

(1) Introduction

Default N₂O emission factors are assumed to be independent of the flare combustion efficiencies and dependant on flare gas type.

(2) Equations

For each flare source, calculate the N₂O mass emissions using Equation 2-7a or Equation 2-7b.

$$N_2O = \sum_{F=1}^N V_{FL,F} \times EF_{vol,F} \times 10^{-6} \quad \text{Equation 2-7a}$$

$$N_2O = \sum_{F=1}^N ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6} \quad \text{Equation 2-7b}$$

Where:

N ₂ O	=	N ₂ O mass emissions from a flare source for the reporting period (tonnes of N ₂ O).
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
V _{FL,F}	=	Volume of the flare gas stream, F, at a flare source (sm ³) at standard conditions for the reporting period. Volumes for pure fuel types such as ethane, propane and butane are measured in gas phase.
ENE _{FL,F}	=	Energy of the flare gas stream, F, at a flare source (MJ) for the reporting period.
EF _{vol,F}	=	Default N ₂ O emission factor, selected from Table 2-4 (g/m ³).
EF _{ENE,F}	=	Default N ₂ O emission factor, selected from Table 2-4 (g/MJ).

TABLE 2-4: DEFAULT N₂O EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	HHV	N ₂ O	
	MJ/m ³	(g/m ³)	(g/MJ)
Hydrocarbon gas (sales gas, lean to rich gas) ¹	38.02	0.033	0.00087
Field gas or process vent gas ²	45.79	0.0044	0.0000952
100% Ethane (C ₂) ³	66.065	0.033	0.00050
100% Propane (C ₃) ³	93.936	0.033	0.00035
100% Butane (C ₄) ³	121.600	0.033	0.00027
Still gas ⁴	34.02	0.02	0.0006
Landfill gas ⁴	18.85	0.0064	0.00034

1. Natural gas combustion emission factor for the industrial sector adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (December 2019).
2. Emission factors are adapted from the Western Climate Initiative (WCI) Final Essential Requirements of Mandatory Reporting 2011 Amendment.
3. Natural gas combustion emission factor for the industrial sector adapted from ECCC Canada's Greenhouse Gas Quantification Requirements (December 2019) and adjusted by the HHV of the fuel for an energy-based emission factor.
4. Emission factors adapted from Canada's National Inventory Report (NIR) 2016.

(3) Data requirements

- For facilities subject to the expansion requirements prescribed by ECCC's GHGRP, the facility should apply measurement frequencies prescribed by ECCC's GHGRP.
- For all other facilities:
 - Based on the facility's knowledge of the flare gas composition and flare technology, select the fuel gas type that would best align with the flare gas and the appropriate emission factor from Tables 2-2 or 2-3. Alternatively, if the HHV is available for the flare gas and the HHV of the flare gas falls between two HHVs in the tables, choose the emission factor with the higher HHV.
 - For non-routine flaring and facilities using level 1 methodologies, the volume or energy of the flare gas may be estimated using engineering estimates, fuel mass balance, manufacturer specifications, and operating time.
 - For routine flaring and facilities using levels 2 and 3 methodologies, the volume must be taken daily if there is online instrumentation or weekly if no online instrumentation is available.
 - For a flare gas stream where the volume is not measured, but the flare gas is from a controlled venting emission source, the venting volume may be quantified using quantification methodologies provided in Chapter 4 Venting. Refer to the data requirements in Section 2.3.2 (Method 2-1).



Chapter 4

Venting

Alberta greenhouse gas
quantification methodologies

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4. 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 (CH₄) is the predominant specified gas contained in venting emissions but carbon dioxide (CO₂) can also be present in some venting emissions. Nitrous oxide (N₂O) is not typically vented unless a vented process stream contains this substance.

This chapter provides methodologies for CH₄ and CO₂. For facilities reporting under the Technology Innovation and Emissions Reduction Regulation (TIER), venting emissions from entrained CO₂ in produced oil and gas are reported under the venting emissions category. Note that the "formation CO₂" emissions category has been removed for TIER reporting.

Quantification methodologies for CO₂ emissions from the sources below are not provided in this chapter. Facilities may select an appropriate method from an industry accepted standard developed by an organization such as Western Climate Initiative (WCI), American Petroleum Institute (API), United States Environmental Protection Agency (USEPA), Intergovernmental Panel on Climate Change (IPCC), Canadian Association of Petroleum Producers (CAPP), and ECCC to quantify and report these emissions.

- Acid Gas Removal (AGR)
- Sulphur Recovery Units (SRU)
- Acid Gas Scrubbing
- Fractionation or Other Gas Separation Processes

In this chapter, quantification methodologies are specified for either conventional upstream oil and gas (UOG) or other facilities (non-UOG). Venting emissions exist in UOG and non-UOG facilities. In Alberta, venting occurs predominantly in UOG facilities.

UOG facilities include:

- Batteries,
- compressor stations,
- gas gathering stations, and gas plants,
- other crude oil and gas (UOG) exploration, production, processing and storage facilities.

Non-UOG facilities include, but are not limited to:

- Oil sands in situ extraction, mining, upgrading and transmission;
- Petroleum refinery and petroleum product distribution; and
- Coal mining, petrochemical, chemical manufacturing and fertilizer industries that use natural gas (typically greater than 90 mol% CH₄) or process materials containing CH₄ or CO₂.

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. H₂S) 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 assigned a level and therefore, are considered to be acceptable for use by a facility under any level classification. As well, facilities are permitted to use a higher levelled 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, the TIER and Specified Gas Reporting Regulation (SGRR) do not require reporting of routine and non-routine venting emissions separately. Facilities should aggregate total venting emissions for reporting.

4.1. General Calculations

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.

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

Where:

CF	=	Control factor for venting emission source with a capture system in the reporting 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.

(2) Equations

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

$$GHG = \sum_{i=1}^n VR_v \times t \times MF_{GHG} \times \rho_{GHG} \times 0.001 \quad \text{Equation 4-1b}$$

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 reporting 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 (ρ _{CO₂} = 1.861 kg/sm ³ ; ρ _{CH₄} = 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.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from a venting source (tonnes) in the reporting 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) and total volatile organic compounds (VOCs).
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 17.1 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 17.3 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. Level 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.

(2) Equations

Calculate GHG emissions using Equation 4-2a.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from produced gas venting (tonnes) in the reporting 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 ($\rho_{CO_2} = 1.861 \text{ kg/sm}^3$; $\rho_{CH_4} = 0.6785 \text{ kg/sm}^3$).
0.001	=	Mass conversion factor (tonne/kg).

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

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. Level 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. Levels 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 levels 1, 2, and 3.

(2) Equations

Calculate GHG emissions using Equation 4-3.

$$GHG = \sum_j^m \sum_l^n Q_v \times MF_{GHG} \times \rho_{GHG} \times 0.001 \quad \text{Equation 4-3}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from gas analyzer (tonnes) in the reporting 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 m³ 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. Levels 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 CH₄ or CO₂ emissions separately and then add the emissions in the report period based on total events using the following equation.

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

$$GHG = \sum_j^m \sum_i^n \left[\frac{V_{vessel,i} \times P_{vessel,i,j} \times T_a \times G_{i,j}}{T_{vessel,i,j} \times P_a} \times MF_{GHG/gas,i,j} \right] \times (1 - CF) \times \rho_{GHG} \times 0.001 \quad \text{Equation 4-4}$$

Where:

- GHG = CH₄ or CO₂ mass emissions from desiccant dryer venting (tonnes) in the reporting 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 ($\rho_{CO_2} = 1.861 \text{ kg/sm}^3$; $\rho_{CH_4} = 0.6785 \text{ kg/sm}^3$).
- 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 17.3 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. Levels 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.

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

Where:

- GHG = CH_4 or CO_2 mass emissions from depressurization and purging events (tonnes) in the reporting 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 °C).
$T_{a,i}$	=	Initial temperature of gas at actual conditions in the equipment system prior to depressurization or purge (°C).
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 ($\rho_{CO_2} = 1.861 \text{ kg/sm}^3$; $\rho_{CH_4} = 0.6785 \text{ kg/sm}^3$).
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}_{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.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from pigging and purges (tonnes) in the reporting 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, $\rho_{a,2} = 0$.
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}_{purge}	=	Mass flow rate of gas used to purge equipment (kg/s).

t_{purge}	=	Duration of equipment purge event(s).
$F_{\text{GHG/Vapor}}$	=	Mass fraction of CH ₄ or CO ₂ components in vapor during depressurization.
$F_{\text{GHG/purge}}$	=	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 17.3 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. Figure 4-1 assigns the methodologies to be used based on the applicable level 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: QUANTIFICATION METHODOLOGY LEVELS FOR EMISSIONS FROM VENTING

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

4.6.2. Method 4-1 - Generic vent rate

(1) Introduction

The following provides quantification methodologies for CH₄ emissions only from atmospheric pressure storage tanks using a generic vent rate. The equations for Method 4-1 are only applicable for refineries. Facilities other than refineries cannot use Method 4-1. Instead, these facilities should quantify CH₄ 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 CH₄ 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.

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

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 CH₄ 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.

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

Where:

CH ₄	=	Methane emissions from storage tank (tonnes) in the reporting period.
I	=	Tank identifier.
N	=	Number of tanks in the reporting 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 4-2 - 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 fraction of the specific GHG in the tank vapor.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from storage tank in the reporting period.
I	=	Tank identifier.
I	=	Number of tanks holding products in the report period.
J	=	Type of product.
J	=	Number of products in the reporting 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

Component	Dry Gas						Gas		Sweet Gas					
	Gas		Light Liquid		Dehy Off Gas				Tank Vapors		Light Liquid		Dehy Off Gas	
	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 ₂ S	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C1	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
C2	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
C3	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-C4	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-C4	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-C5	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-C5	0.0005	0.0020	0.99	1.2793	0	0	0.0296	0.1219	1.5784	4.0336	0.99	1.2793	0	0
C6	0.0001	0.0003	5.87	9.0601	0	0	0.0060	0.0295	0.9312	2.8424	5.87	9.0601	0	0
C7+	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

Component	Sour Gas				Natural Gas			
	Gas		Tank Vapors		Light Liquid		Gas	
	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 ₂ S	3.5460	6.6755	0.0000	0.0000	0.00	0.0000	0.0000	0.0000
C1	88.6210	78.5447	56.4205	32.0598	0.59	0.1695	92.5394	85.0226
C2	5.2339	8.6947	15.2219	16.2121	31.52	16.9753	4.5125	7.7709
C3	1.0118	2.4649	11.6300	18.1646	21.61	17.0671	1.0904	2.7538
i-C4	0.1245	0.3998	2.6504	5.4564	9.60	9.9936	0.1498	0.4985
n-C4	0.1880	0.6037	5.5796	11.4867	10.06	10.4725	0.2103	0.7000
i-C5	0.0245	0.0977	1.2562	3.2103	0.83	1.0725	0.0415	0.1716
n-C5	0.0286	0.1140	1.5784	4.0336	0.99	1.2793	0.0358	0.1478
C6	0.0058	0.0276	0.9312	2.8424	5.87	9.0601	0.0170	0.0839
C7+	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

Component	Light/Medium Crude Oil						Heavy Crude Oil (Primary)					
	Gas		Tank Vapors		Light Liquid		Gas		Tank Vapors		Light Liquid	
	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 ₂ S	0	0	0	0	0	0	0.0001	0.0002	0	0	0	0
C1	73.2524	52.3386	10.01	3.63	9.7419	1.9668	98.0137	93.6026	87.2337	70.3327	7.6718	1.4844
C2	11.9708	16.0314	15.7274	10.69	3.6464	1.3798	0.9062	1.6221	2.2616	3.4177	2.7538	0.9987
C3	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-C4	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-C4	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-C5	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-C5	0.3802	1.2217	4.5447	7.412	3.6626	3.3255	0.0433	0.186	0.123	0.446	2.7543	2.3968
C6	0.2446	0.9388	2.9655	5.7767	18.1649	19.6995	0.0927	0.4755	0.3949	1.5132	17.975	18.683
C7+	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

Component	Sour Crude Oil			
	Sour Solution Natural Gas		Sour Light Liquid	
	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 ₂ S	3.2898	4.9558	0.8527	0.3695
C1	71.7705	50.9011	7.4364	1.5172
C2	9.0895	12.0828	3.8033	1.4544
C3	5.3197	10.3703	6.0853	3.4126
i-C4	0.8010	2.0581	1.9617	1.4500
n-C4	1.6399	4.2138	5.8751	4.3427
i-C5	0.3920	1.2503	3.5331	3.2418
n-C5	0.4100	1.3077	4.6140	4.2336
C6	0.2490	0.9485	19.9173	21.8257
C7+	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.

Component	Thermal Conventional Heavy Crude Oil						Cold Bitumen			
	Gas		Tank Vapors		Light Liquid		Gas		Tank Vapors / Light Liquid	
	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 ₂ S	0.0150	0.0167	0.1439	0.1596	0.1744	0.0718	0.2490	0.3134	0.0000	0.0000
C1	72.9361	38.1942	66.6600	34.8000	7.6584	1.4834	63.9410	37.8919	70.0000	48.1609
C2	1.9370	1.9012	0.9490	0.9286	2.7490	0.9980	1.2070	1.3407	8.0000	10.3165
C3	3.0956	4.4558	0.5394	0.7740	3.8274	2.0377	0.9160	1.4921	0.0000	0.0000
i-C4	1.0807	2.0504	0.1922	0.3635	1.8159	1.2743	0.2640	0.5668	0.0000	0.0000
n-C4	2.3889	4.5323	0.3678	0.6957	3.5872	2.5173	0.9520	2.0440	0.0000	0.0000
i-C5	1.9994	4.7088	0.4541	1.0662	2.4042	2.0943	1.3020	3.4700	0.0000	0.0000
n-C5	2.2733	5.3539	0.5829	1.3686	2.7495	2.3951	1.1310	3.0143	0.0000	0.0000
C6	5.8086	16.3394	2.1914	6.1454	17.9436	18.6696	0.8970	2.8554	0.0000	0.0000
C7+	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 of Greenhouse Gases, CAPP, 2005.

4.6.4. Method 4-3 - 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 4-4 or Method 4-5 for flashing emissions or Method 4-6 for total tank emissions.

Bubble point pressure, kPa	345 to 36,190
Reservoir temperature, °C	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

$$GHG = C_1 \times \gamma_{gs} \times p^{C_2} \times \exp\left(\frac{C_3}{\gamma_o T} - \frac{C_4}{T}\right) \times Q \times VTM \times MF_{GHG} \times MW_{GHG} \times (1 - CF) \times 0.001 \quad \text{Equation 4-7b}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from storage tank in the reporting 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 (kPa).
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 $\gamma_o < 0.876$, 3.204×10^{-4} ; $\gamma_o \geq 0.876$, 7.803×10^{-4} .
C_2	=	For $\gamma_o < 0.876$, 1.187; $\gamma_o \geq 0.876$, 1.0937.
C_3	=	For $\gamma_o < 0.876$, 1,881.24; $\gamma_o \geq 0.876$, 2,022.19.
C_4	=	For $\gamma_o < 0.876$, 1,748.29; $\gamma_o \geq 0.876$, 1,879.28.
Q	=	Throughputs of liquid hydrocarbon in a tank (m^3) for the reporting 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 CH₄ or CO₂ (kg/kmol).

VTM = Volume to mole conversion at standard condition of 101.325 kPa and 15°C; 0.042293 kmol/m³.

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

Where:

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

$$\gamma_0 = \frac{141.5}{131.5 + ^\circ API} \quad \text{Equation 4-7d}$$

Where:

$^\circ API$ = API gravity of product in the separator before the first storage tank.

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

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.

4.6.5. Method 4-4 - Flashing losses using models/simulations or engineering estimation

(1) Introduction

For tanks storing non-crude hydrocarbons, Method 4-3 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 4-5 - Flashing losses using the Gas in Solution method

(1) Introduction

The Gas in Solution (GIS) should be a measured value reflecting the flashing emissions due to the pressure drop from the upstream 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 4-6 - 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 CH₄ or CO₂ emissions using the Equation 4-7a and follow the data requirement in Section 4.6.4 for tank vapor analysis.

If total GHGs are determined from the modelling, calculate the CH₄ or CO₂ emissions using Equation 4-8 based on the uncontrolled CO₂ and CH₄ and apply the control efficiency of the emissions recovery system.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) in the reporting period.
i	=	Tank identifier.
I	=	Number of tanks holding products in the reporting period.
j	=	Type of product.
J	=	Number of products in the reporting 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 4-7 - 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 Equation 4-1b and Equation 4-1c for the calculations.

(2) Equations

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

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

Where:

GHG	=	CO ₂ or CH ₄ emissions in the reporting 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 reporting 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 CH₄ and CO₂ 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. Level 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.

$$GHG = \rho_{GHG} \times 0.001 \times \sum_{i=1}^n VR_i \times t_i \times (1 - CF_i) \times MF_{GHG,i} \quad \text{Equation 4-10}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from pneumatic control device venting (tonnes) in the reporting period.
i	=	Pneumatic device identifier.
n	=	Number of pneumatic instruments in the reporting period.
VR _i	=	Average vent rate for the device i (m ³ /hour/device) at the standard condition in Table 4-1a and Table 4-1b.
t _i	=	Operating time of the instrument i in the reporting 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 17-1 of Chapter 17 for natural gas composition sampling requirements.
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 4-1A: 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 FACILITIES

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 sm³.

(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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.7.3. Levels 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 Table 4-2a or Table 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.

$$VR_i = m \times SP_i \quad \text{Equation 4-11}$$

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 ($\text{m}^3/\text{hour}/\text{kpa gauge}$).
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 ($\text{m}^3/\text{hour}/\text{device}$) 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
	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	FIELDVUETM DVC 6000	0.0011	0.2649

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	Fisher	FIELDVUETM DVC 6010	0.0011	0.2649
	Fisher	FIELDVUETM DVC 6020	0.0011	0.2649
	Fisher	FIELDVUETM DVC 6030	0.0011	0.2649
	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 INSTRUMENTS¹

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm ³ /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
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

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm ³ /h/device) ²
	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
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
	35	0
PMV D5 Digital	20	0.04
	35	0.04

Controller Model	Supply Pressure (psi)	Manufacturer Vent Rate (sm ³ /h/device) ²
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 multiplied 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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.7.4. Level 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 Equation 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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 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. Level 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 CH₄ or CO₂ 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 (m³/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 17.1 of Chapter 17.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.

4.8.3. Levels 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 CH₄ or CO₂ 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.

$$VR_i = (g \times SP) + (n \times IP) + (p \times SPM)$$

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.

$$GHG = \sum_{i=1}^n \sum_{j=1}^m Q_{c,j} \times VR_j \times (1 - CF) \times MF_{GHG} \times \rho_{GHG} \times 0.001$$

Equation 4-13

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from pneumatic pump venting in the reporting 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 (sm ³ /liter/pump) determined from the correlation in Equation 4-13a.
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 (ρCO ₂ = 1.861 kg/sm ³ ; ρCH ₄ = 0.6785 kg/sm ³).
0.001	=	Mass conversion factor (tonne/kg).

$$VR_j = c \times CIP^2 + d \times CIP + e \quad \text{Equation 4-13a}$$

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.)	CIP2 Coeff. (c)	CIP1 Coeff. (d)	CIP0 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

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP2 Coeff. (c)	CIP1 Coeff. (d)	CIP0 Coeff. (e)
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
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
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

Manufacturer	Model	Plunger Diameter (in.)	Stroke length (in.)	CIP2 Coeff. (c)	CIP1 Coeff. (d)	CIP0 Coeff. (e)
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
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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.8.4. Level 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. Level 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 CH₄ or CO₂ emissions using Equation 4-14a or Equation 4-14b for each compressor seal vent and sum up all compressor seal emissions in the report period.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from compressor in the reporting period.
i	=	Compressor type identifier.
I	=	Total types of compressor in the reporting 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 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 reporting period.
t	=	Total time the compressor i is pressurized in the reporting 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.

$$GHG = \sum_{i=1}^I MR_i \times t \times (1 - CF) \times N \times F_i \times 0.001 \quad \text{Equation 4-14b}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from a compressor in the reporting period.
i	=	Compressor type identifier (reciprocating or centrifugal compressor).
I	=	Total number of compressor types in the reporting period.
MR _i	=	Average mass vent rate (kg/hour/throw or kg/hour/source) for compressor i. Refer to Table 4-6b.
N	=	Total number of throws for reciprocating compressors or total number of compressors for centrifugal compressors for each type of compressor I, which are operating in the reporting period.
T	=	Total time the compressor i is pressurized in the reporting period (hours).

- CF = Control factor (dimensionless fraction).
- Fi = Mass fraction of CO₂ or CH₄ in the vented TOC or non-methane TOC for compressor i.
- 0.001 = Mass conversion factor (tonne/kg).

TABLE 4-6B: GENERIC COMPRESSOR AVERAGE VENT RATE FOR NON-UOG FACILITIES

Sector	Services	Vent Rate ¹	Leak Rate Unit
Synthetic Chemical ² Manufacturer 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. Refer to Table 2-1 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.
3. Refer to Table 2-2 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.
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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.

4.9.3. Levels 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 level 1 methodology.

(2) Equations

Calculate CH₄ and CO₂ emissions using Equation 4-14a. 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 17-1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 of Chapter 17.

4.9.4. Level 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 m³ 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 (sm³/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 (VR_i) 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 CO₂ or CH₄ 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 17.1 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 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. Levels 1, 2 and 3 - GHG based on simulation

(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 reporting 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 17-1 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 Treatment

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 level that is acceptable for processing in a refinery or gas plant or meets pipeline transmission criteria. The acid gas removed also reduces the amount of sulfur compounds released to the atmosphere.

Generally, acid gas treatments use the following technologies:

- Acid Gas Removal (AGR)
- Sulphur Recovery Unit (SRU)
- Acid Gas Scrubbing

AGR removes H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). Besides amine units, other technologies use molecular sieves such as the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process.

Sour gas processing or sulfur recovery and control systems can directly vent the CO_2 removed from the sour gas stream to the atmosphere. These technologies are reported to reduce CH_4 emissions too. If CO_2 is captured from the sour gas recovery and control system, it is no longer vented to the atmosphere.

For CO_2 emissions from acid gas treatment, refer to Section 4.12.2. For CH_4 emissions, the following table assigns the methodologies to be used by AGRs and SRUs at various level classifications.

FIGURE 4-2: LEVEL CLASSIFICATION FOR EMISSIONS FROM AGR (AMINE) AND AGR (NON-AMINE) AND SRU PROCESSES

		Level Classification			
		Level 1	Level 2	Level 3	Level 4
Equipment Types	AGR (amine)	Method 4-8	Method 4-9		Direct Measurement as described in Section 4.1.2
	AGR (non-amine) & SRU	Engineering Estimate			

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

4.12.2. CO₂ emissions from acid gas treatment

Facilities may select an appropriate quantification methodology for acid gas removal, sulphur recovery and acid gas scrubbing processes from industry accepted standards from organizations such as, but not limited to WCI, API, USEPA, IPCC, CAPP, and ECCC.

4.12.3. Method 4-8 - Generic CH₄ vent rate

(1) Introduction

For uncontrolled AGR units with an amine-based system, two CH₄ vent rates were developed as part of the 1996 GRI/EPA CH₄ emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations of a diethanol amine (DEA) unit (Myers, 1996).

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 CH₄ emissions using Equation 4-15.

$$CH_4 = Q_{in} \times VR_{CH_4} \quad \text{Equation 4-15}$$

Where:

- CH_{4,p} = CH₄ mass emissions (tonnes) from the AGR unit venting in the reporting period.
- Q_{in,p} = Metered total volume natural gas flow into the AGR unit converted to standard condition per Appendix C (10⁶ scf or 10⁶ m³) in the reporting period.
- VR_{CH₄} = Methane vent rate for the AGR unit in Table 4-7 (tonnes/10⁶ scf or tonnes/10⁶ m³).

TABLE 4-7: UNCONTROLLED AGR CH₄ VENT RATE

Source	Methane Vent Rate ² , Original Units	Methane Vent Rate ³ , 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.
2. 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.
3. CH₄ emission factors converted from scf are based on 60°F and 14.7 psia.

(3) Data requirements

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

4.12.4. Method 4-9 - 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 CH₄ and CO₂ emissions can be estimated from total hydrocarbon emissions.

(2) Equations

Calculate CH₄ or CO₂ 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.

CH₄ or CO₂ emissions in most petroleum products including stabilized (weathered) crude are negligible. Unstabilized crude oil contains sufficient dissolved gas hydrocarbons (mainly C1, C2, C3 and C4) 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. Levels 1, 2 and 3 - 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 reporting period using Equation 4-16.

$$GHG = \sum_{j=1}^n \frac{0.120 \times SF_j \times P_{True,j} \times Q_j \times MW_{vapor} \times F_{GHG,vapor}}{(T_j + 273.15)} \times 0.001 \times (1 - CF) \quad \text{Equation 4-16}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from loading loss of product j in the reporting 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 reporting 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 _i). 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.

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

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.

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

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 (°F/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 17.3 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. Levels 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 CH₄ emissions from oil-water separators using process knowledge and engineering estimates.

(2) Equations

Calculate CH₄ emissions from oil-water separators at refineries using Equation 4-17.

$$CH_4 = VR_{sep} \times Q_{water} \times F_{CH_4/NMHC} \times (1 - CF) \times 0.001 \quad \text{Equation 4-17}$$

Where:

CH ₄	=	CH ₄ mass emissions (tonnes) from oil water separator in the reporting period.
Q _{water}	=	Volume of the wastewater treated in the oil water separator in the reporting 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 ³ (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 ⁴	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

³ Vent rates do not include ethane

⁴ Vent rates for these types of separators apply where they are installed as secondary treatment systems

- An analytical method prescribed in Section 17.3 of Chapter 17.

- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

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 considered 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 CH₄ has a stronger affinity for hydrocarbon oil than it does for water. Thus, less CH₄ is dissolved in the water phase. Varying amounts of CH₄ are emitted from the produced water depending on the temperature and pressure in the produced water tanks.

4.15.2. Levels 1, 2, and 3 - Generic vent rate

(1) Introduction

CH₄ 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

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

Where:

CH₄ = CH₄ mass emissions (tonnes) from produced water tank venting in the reporting period.

V_{p,water} = Volume of produced water (1000 m³).

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

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

TABLE 4-12A : PRODUCED SALT WATER TANK METHANE FLASHING VENT RATE¹

Separator Pressure (psi)	Produced Water Salt Content	Water Tank Vent Rate (VR CH ₄) tonnes CH ₄ /1000 m ³ produced water
50	20%	0.009185
250	20%	0.06200
250	10%	0.09414
250	2%	0.11137

Separator Pressure (psi)	Produced Water Salt Content	Water Tank Vent Rate (VR CH ₄) tonnes CH ₄ /1000 m ³ produced water
250	Average of 10.7% ²	0.08917
1000	20%	0.22273
1000	10%	0.33697
1000	2%	0.39896
1000	Average of 10.7% ²	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	CH ₄ Water Tank Vent Rate
Shallow gas well (76 psi or less, 50°C)	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. Levels 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 CH₄ or CO₂ emissions and sum the CH₄ or CO₂ emissions from blowdown events to calculate total emissions in the report period using Equation 4-19.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from well tests, completion and workovers events in the reporting period.
i	=	Vent event identifier.
n	=	Number of events in the reporting 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 ($\rho_{CO_2} = 1.861 \text{ kg/sm}^3$; $\rho_{CH_4} = 0.6785 \text{ kg/sm}^3$).
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 17.3 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. Levels 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 CH₄ or CO₂ emissions for each event and sum the CH₄ or CO₂ 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. Levels 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 CH₄ or CO₂ emissions for each well unloading event and add the total emissions for all unloading events in the report period using Equation 4-20.

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

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from gas well liquid unloading venting in the reporting period.
i	=	Gas well liquid unloading event identifier.
n	=	Number of gas well liquid unloading events in reporting 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 17.3 of Chapter 17.

4.18.3. Level 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.

$$GHG = \sum_{i=1}^n [VR_i \times t_{total,i} \times (1 - CF)] \times \left[\frac{P}{101.325} \right] \times MF_{GHG/Gas} \times \rho_{GHG} \times 0.001 \quad \text{Equation 4-21}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions (tonnes) from gas well liquid unloading venting in the reporting 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 17.3 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. Levels 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.

$$GHG = \sum_{i=1}^n [VR_i \times t_{total,i} \times (1 - CF)] \times MF_{GHG} \times \rho_{GHG} \times 0.001 \quad \text{Equation 4-22}$$

Where:

GHG	=	CH ₄ or CO ₂ mass emissions from engine or turbine start events (tonnes) in the reporting 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 reporting 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 (ρ _{CO₂} = 1.861 kg/sm ³ ; ρ _{CH₄} = 0.6785 kg/sm ³).
0.001	=	Conversion factor from kg to tonne.

$$t_{total,j} = t_{un,start} \times N_{un,j} + t_{s,start} \times N_{s,j} \quad \text{Equation 4-22a}$$

Where:

t _{total,j}	=	Total start duration (hr) for engine or turbine j in the reporting 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 17.1 of Chapter 17.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.3 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 $\pm 25\%$ 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	
					(m³/min)	(m³/hour)
Turbines						
Allison	501-KB 501-KC	Ingersoll Rand	TS799B	1,034	80	4,822
		Tech Development	56K (Low Pressure)	345	33	1,954
			56K (Standard Pressure)	621	55	3,288
		570	Ingersoll Rand	TS799G	621	51
Dresser Clark	DC990	Tech Development	56B (Low Pressure)	345	36	1,954
			56B (Standard Pressure)	1,034	86	5,172
Dresser Rand	DR990 DJ50	Tech Development	56B (Low Pressure)	345	36	1,954
			56B (Standard Pressure)	1,034	86	5,172
Garrett	IE831	Ingersoll Rand	TS999G	621	47	2,849
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
Solar Turbines	Saturn 20	Ingersoll Rand	TS725	1,551	27	1,644
			TS750	1,034	44	2,652

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate ¹	
					(m ³ /min)	(m ³ /hour)
		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

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
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

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate ¹	
					(m ³ /min)	(m ³ /hour)
	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
	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
Cooper Ajax (cont.)	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
	10W330 12V-250 GMVA GMVW MVWC GMXF	Ingersoll Rand	ST950	1,034	47	2,849
	GMXE GMXF	Ingersoll Rand	SS850	1,034	47	2,794

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate ¹	
					(m ³ /min)	(m ³ /hour)
	GMXH					
Cooper Superior	6G-825 8G-825 8GT	Austart	ATS83	1,034	22	1,293
	12SGT 16SGT	Austart	ATS93	1,034	48	2,871
	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
	12VAT27G 16VAT25G 16VAT27G	Austart	ATS103	1,034	56	3,353
	145GZ 6GAK 6WAK F1197G	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)
	F119G H1077G H1077G H24L H867D					
	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
	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)	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)
	F18GL (D) H24GL (D)					
	145GZ 6GAK 6WAK F1197G F119G H1077G H24L	Ingersoll Rand	150BM	1,034	25	1,490
	7044 7042G (SI/L) 8LAT25D 8LAT25GLF289 5G (SI) F3521G (SI)	Ingersoll Rand	SS815	1,034	62	3,726
	12VAT27GL 16AT27GL 16VAT25GL P9390G	Ingersoll Rand	SS825	1,034	49	2,959
	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	Ingersoll Rand	5BMG	1,034	11	679

Engine/Turbine		Pneumatic Starter				
Manufacturer	Model	Manufacturer	Model	Supply Pressure (kPag)	Max. Natural Gas Consumption Rate ¹	
					(m ³ /min)	(m ³ /hour)
	TDXC					

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. Cowl 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 TIER, 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 level classification:

Level 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.

Level 2:

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

Level 3:

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

Level 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 TIER, the documentation of the selected method should be documented in the facility's QMD.



Chapter 5

On-site transportation

Alberta greenhouse gas
quantification methodologies



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5. 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.

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.

5.2. Carbon Dioxide

5.2.1. Introduction

For each fuel type combusted from on-site transportation, calculate the mass of carbon dioxide (CO₂) 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 level classification that is assigned to the facility as illustrated in Figure 5-1. A facility must also apply the sampling requirements in Chapter 17 that corresponds with the facility's level classification.

FIGURE 5-1: LEVEL CLASSIFICATION FOR QUANTIFICATION METHODOLOGIES FOR CO₂ EMISSIONS FROM ON-SITE TRANSPORTATION

		Level Classification		
		Level 1	Level 2	Level 3
Fuel Types*	Non-Variable	Method 5-1		
	Variable	Method 5-2		

5.2.2. Method 5-1 - A Fuel-specific default CO₂ 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 CO₂ 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 CO₂ 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" emission factors to account for the minimum biofuel content. For facilities that have the composition of the biofuel content in the gasoline or diesel consumed, facilities may apply Method 5-3 (below) to account for actual biofuel content in diesel and/or gasoline usage for on-site transportation. Carbon dioxide from the combustion of biofuel is considered to be biomass CO₂.

5.2.3. Method 5-2 - CO₂ 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 CO₂ 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 (CH₄) and nitrous oxide (N₂O) 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

5.3.2. Method 5-3 - Default CH₄ and N₂O emission factors

Facilities are required to use Equation 1-5a of Chapter 1 Stationary Fuel Combustion to calculate CH₄ and N₂O emissions from on-site transportation. Facilities are also required to meet the same data requirements as prescribed in Section 1.3.2. Table 5-1 present the emission factors for various fuels in mass of CH₄ and N₂O 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 CH₄ and N₂O 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 ₂ O Emission Factor (tonnes/kl)
Gasoline Road Transport 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
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
Gasoline or Ethanol Off-Road Engine Type		
Onsite Transportation, 2-stroke	1.06E-02	1.3E-05
Onsite Transportation, 4-stroke	5.08E-03	6.4E-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
Diesel or Bio-Diesel Off-Road Engine Types		

Type of Fuel and Mobile Equipment	CH ₄ Emission Factor (tonnes/kl)	N ₂ O Emission Factor (tonnes/kl)
<19kW	7.3E-05	2E-05
>=19kW, Tier 1-3	7.3E-05	2E-05
>=19kW, Tier 4	7.3E-05	2.3E-04
Natural Gas Vehicles	9E-06	6E-08
Off-road Natural Gas	9E-06	6E-08
Propane Vehicles	6.4E-04	8.7E-05
Off-road Propane	6.4E-04	8.7E-05
Railways		
Diesel Train	1.5E-04	1E-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).



Chapter 8

Industrial processes

Alberta greenhouse gas
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8. 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 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 TIER.

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

8.2. CO₂ 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 (H₂). Subsequent shift reactions convert CO to CO₂ to produce additional hydrogen. CO₂ is a by-product of the net reaction:

Steam Methane Reforming: • $\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3\text{H}_2$

Shift Reaction: • $\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$

Overall Reaction: • $\text{CH}_4 + 2\text{H}_2\text{O} \rightarrow \text{CO}_2 + 4\text{H}_2$

Any CO₂ generated as a by-product of the above reaction is considered an IP emission. However, under the SGRR these by-product CO₂ 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 CO₂ 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 H₂). 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: $\text{HCs} + \text{H}_2\text{O} + \text{O}_2 \rightarrow x\text{CO} + y\text{H}_2 + \text{CO}_2 \text{ (trace)}$

As above, any CO₂ generated as a by-product of the above reaction are considered an IP emission. Syngas can be combusted as a fuel but the CO₂ generated from syngas combustion are considered stationary fuel combustion emissions and must be reported under that source category.

CO₂ entrained in the feed are not included in the IP CO₂ emissions total; instead these emissions are classified as formation CO₂ and should be reported under a separate category.

Four methods are provided for IP CO₂ emissions from hydrogen production. These methods are acceptable to be used for any level 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 (CO₂, CO, CH₄, C₂H₆) for fuel use. This method assumes that all feed carbon is oxidized to CO₂, which is removed by a chemical absorption process. The method calculates gross IP CO₂ from hydrogen production based on the quantity of reactor feed and its composition. Any inert CO₂ contained in the reactor feed does not participate in the steam-methane reforming reaction and, therefore, is not included in the gross IP CO₂ 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 CO₂ emissions using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (v_{Feed,i} \times EF_{CO_2,i}) \times 0.001 \quad \text{Equation 8-1}$$

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 (kg CO ₂ /sm ³) as defined by Equation 8-1a.
0.001	=	Mass conversion factor (t/kg).

$$EF_{CO_2,i} = \sum_{k=1}^K (MF_{k,i} \times NC_k) \times \rho_{CO_2} \quad \text{Equation 8-1a}$$

Where:

EF _{CO₂,i}	=	IP CO ₂ emission factor for measurement period i (kg CO 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_{CO_2}	=	1.8613 kg/m ³ at standard conditions (where ρ_{CO_2} 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. CO₂ mass balance method

(1) Introduction

This 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 CO₂, CO, CH₄, C₂H₆, and some waste H₂ 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:

CO₂ contained in reaction or imported feed is not counted in the IP CO₂ calculation.

(2) Equations

For each hydrogen production unit, calculate IP CO₂ emissions using Equation 8-2:

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

$$CO_{2,p} = \left[\sum_{i=1}^N (v_{RawU\ H_2,i} \times MF_{CO_2\ RawU\ H_2,i} - v_{Feed,i} \times MF_{CO_2,Feed,i}) \times \rho_{CO_2} \right] \times 0.001 \quad \text{Equation 8-2}$$

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.
$v_{RawU\ H_2,i}$	=	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).
$MF_{CO_2,Feed,i}$	=	CO ₂ mole fraction in reactor feed gas (kmol _{CO₂} /kmol _{Feed}).
$MF_{CO_2,RawU\ H_2,i}$	=	CO ₂ mole fraction in raw unpurified hydrogen stream (kmol _{CO₂} /kmol _{RawH₂}).
ρ_{CO_2}	=	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:

CO₂ contained in reaction feed is not counted in the IP CO₂ calculation; and

All hydrogen is generated through full oxidation of carbon contained in hydrocarbons.

(2) Equations

For each hydrogen production unit, calculate IP CO₂ emissions using the following equation:

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

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 ₂ H 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 CO₂

Feed Component	Overall Reaction Equation	SR: H ₂ /CO ₂ Molar Ratio (molH ₂ / molCO ₂)
Methane	$\text{CH}_4 + 2\text{H}_2\text{O} \rightarrow \text{CO}_2 + 4\text{H}_2$	4/1 = 4.000
Ethylene	$\text{C}_2\text{H}_4 + 4\text{H}_2\text{O} \rightarrow 2\text{CO}_2 + 6\text{H}_2$	6/2 = 3.000
Ethane	$\text{C}_2\text{H}_6 + 4\text{H}_2\text{O} \rightarrow 2\text{CO}_2 + 7\text{H}_2$	7/2 = 3.500
Propylene	$\text{C}_3\text{H}_6 + 6\text{H}_2\text{O} \rightarrow 3\text{CO}_2 + 9\text{H}_2$	9/3 = 3.000
Propane	$\text{C}_3\text{H}_8 + 6\text{H}_2\text{O} \rightarrow 3\text{CO}_2 + 10\text{H}_2$	10/3 = 3.333
Butylenes	$\text{C}_4\text{H}_8 + 8\text{H}_2\text{O} \rightarrow 4\text{CO}_2 + 12\text{H}_2$	12/4 = 3.000
Butanes	$\text{C}_4\text{H}_{10} + 8\text{H}_2\text{O} \rightarrow 4\text{CO}_2 + 13\text{H}_2$	13/4 = 3.250
Pentenenes	$\text{C}_5\text{H}_{10} + 10\text{H}_2\text{O} \rightarrow 5\text{CO}_2 + 15\text{H}_2$	15/5 = 3.000
Pentanes	$\text{C}_5\text{H}_{12} + 10\text{H}_2\text{O} \rightarrow 5\text{CO}_2 + 16\text{H}_2$	16/5 = 3.200
Hexanes	$\text{C}_6\text{H}_{14} + 12\text{H}_2\text{O} \rightarrow 6\text{CO}_2 + 19\text{H}_2$	19/6 = 3.167
Heptanes	$\text{C}_7\text{H}_{16} + 14\text{H}_2\text{O} \rightarrow 7\text{CO}_2 + 22\text{H}_2$	22/7 = 3.143
Carbon Monoxide	$\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$	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. Industrial process CO₂ emissions from mass balance**(1) Introduction**

Industrial process CO₂ 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). This method may be used if the facility uses level 3 quantification methodologies prescribed in Chapter 1 Stationary Fuel Combustion to quantify the CO₂ emissions from fuel combustion. This mass balance method assumes that all of the carbon in the feed or fuels supplied to the facility would be emitted as stationary fuel combustion emissions or industrial process emissions. CO₂ entrained in the fuel or feed is not included in the IP CO₂ emissions.

A facility may also use Method 1-4 prescribed in Chapter 1 to calculate the industrial process emissions based on a mass balance approach.

(2) Equations

For gaseous fuels and feedstocks, where fuel consumption is measured in units of volume (m³), use Equation 8-4a:

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

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

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

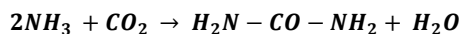
Where:

$CO_{2,p}$	=	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 defined in Appendix C.
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:



(2) Equations

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

$$CO_{2,Urea,p} = m_{Urea} \times \frac{MW_{CO_2}}{MW_{Urea}} \times 0.001 \quad \text{Equation 8-5}$$

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_{CO_2}	=	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.

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

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.

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

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.
$v_{H2,j}$	=	Volume of hydrogen stream j (sm^3 at standard conditions as defined in Appendix C).
$MF_{H2,j}$	=	Mole fraction of hydrogen in stream j ($\text{kmol}_{H2}/\text{kmol}$).
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. CO₂ 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 (CaCO₃; Limestone) and magnesium carbonate (MgCO₃). Lime kilns can operate at merchant lime facilities and Kraft pulp mills. The primary reaction equations for calcining of carbonates are:



This section is adapted from the guidance provided by the World Business Council for Sustainable Development (WBCSD) Cement CO₂ 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 CO₂ emission factor. The IP CO₂ emissions from calcination include only the CO₂ generated in the calcining reaction. Any CO₂ 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 CO₂ emissions are calculated as the sum of CO₂ emitted from calcination producing the primary product, P, and the CO₂ 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 CO₂ 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 CO₂ calculated separately.

(2) Equations

For each kiln, calculate IP CO₂ emissions from calcination using the following equation:

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

Where:

CO _{2-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 CO₂ emission factors (EFP,i, EFW,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).

$$EF_{P,i} = (CaO_{P,i} - CaO_{FP,i}) \times 0.785 + (MgO_{P,i} - MgO_{FP,i}) \times 1.092 \quad \text{Equation 8-8a}$$

Where:

EFP,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).

$$EF_{W,j} = (CaO_{W,j} - CaO_{FW,j}) \times 0.785 + (MgO_{W,j} - MgO_{FW,j}) \times 1.09 \quad \text{Equation 8-8b}$$

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 CO₂ emissions from oxidation of total organic carbon in feed are calculated based on the carbon content of the feed.

$$CO_{2,p} = m \times TOC \times 3.664 \quad \text{Equation 8-9}$$

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.

8.3.1. Lime kilns - Kraft pulp mills

(1) Introduction

Similar to cement, lime, and magnesita 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 classified 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:

$$CO_{2,p} = \sum_{i=1}^N (m_i \times EF_i \times F_i) \quad \text{Equation 8-10}$$

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. CO₂ from use of carbonates

8.4.1. Introduction

CO₂ 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 CO₂ generated from carbonate reactions.

8.4.2. Level 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 CO₂ 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. Level 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 CO₂ emissions for the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (m_{in} - m_{out}) \times EF_i \quad \text{Equation 8-11}$$

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 CO₂ 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 ₂ CO ₃	0.41492
Others		Facility specific emission factor to be determined through analysis or supplier information.

8.4.4. Level 4- Measured CO₂ emission factor method

(1) Introduction

CO₂ from use of carbonates can be estimated based on a facility-specific CO₂ emission factor measured by an annual stack gas test. This method is only applicable when no other sources of CO₂ contribute to the CO₂ in the stack gas from the reaction. CO₂ emissions in the reporting period are calculated by multiplying the activity level of the CO₂ generation process in the reporting period by the measured CO₂ emission factor. Activity level data may be based on:

- Mass of carbonates consumed; or
- Any applicable substance participating in the reaction where CO₂ is released.

One example application of this method is the calculation of CO₂ emissions from the acid leaching of different types of ore containing carbonates.

(2) Equations

For an eligible source of CO₂ from use of carbonates, calculate IP CO₂ emissions in the reporting period using the following equation:

$$CO_{2,p} = \sum_{i=1}^N (m_i \times EF_i) \quad \text{Equation 8-12}$$

Where:

- CO_{2,p} = CO₂ mass emissions from consumption of carbonates in the reporting period, p (tonnes CO₂).
- 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 = CO₂ emission factor for carbonate-containing material of type i (tonnes CO₂/tonne carbonate), as determined by Equation 8-13.

$$EF_i = \frac{ME_{CO_2}}{AL} \quad \text{Equation 8-13}$$

Where:

ME CO₂ = CO₂ mass emission rate (tonnes CO₂/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 8-13 must be determined from measurement systems used for accounting purposes for the period that the stack tests are conducted.
- Stack tests to determine EF_i 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. CO₂ 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 CO₂ is required to be submitted.

8.5. CO₂ from ethylene oxide production

(1) Introduction

Ethylene oxide ("EO", C₂H₄O) is a reactive chemical that is used mostly as a chemical intermediate to make ethylene glycol (EG) at integrated facilities. Ethylene glycol ("EG", C₂H₄(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. CO₂ 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 CO₂ generated is separated and vented, if not captured for use. All by-product CO₂ is considered as an IP emission.

Ethylene Oxide Production: C₂H₄ + ½O₂ → C₂H₄O + heat (~80% C₂H₄ converted)

Ethylene Full Oxidation: C₂H₄ + 3O₂ → 2CO₂ + 2H₂O + heat (~20% C₂H₄ converted)

(2) Equations

For each ethylene oxide production train, calculate IP CO₂ emissions using the following equation

$$CO_{2,p} = \left(\sum_{i=1}^N \left[m_{C_2H_4 \text{ feed},i} - m_{C_2H_4 \text{ loss},i} - \left(m_{EO,i} \times \frac{28.05}{44.05} \right) \right] / 28.05 \right) \times 2 \times 44.01 \quad \text{Equation 8-14}$$

Where:

CO_{2,p} = CO₂ mass emissions from ethylene full oxidation in reporting period, p (tonnes CO₂).

i = Measurement period.

N = Number of measurement periods in reporting period.

m_{C₂H₄ feed,i} = Mass of ethylene (C₂H₄) feed for reaction in measurement period i (tonne).

$m_{C_2H_4, loss, i}$	=	Mass of ethylene (C ₂ H 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 ₂ H ₄ .
44.01	=	Molecular weight of CO ₂ (kg/kmol).
28.05	=	Molecular weight of C ₂ H ₄ (kg/kmol).
44.05	=	Molecular weight of ethylene oxide (C ₂ H ₄ O) (kg/kmol).

$$m_{C_2H_4, loss} = Q_{vent} \times C_{C_2H_4} / 1000 \quad \text{Equation 8-14a}$$

Where:

Q_{vent}	=	Vent gas flow rate in the reporting period (m ³).
$C_{C_2H_4, loss, i}$	=	Concentration of the ethylene (kg/m ³) in the vent gas based on measurements.

$$m_{EO, p, i} = m_{MEG} \times 0.710 + m_{DEG} \times 0.830 + m_{TEG} \times 0.880 + m_{HG} \times a + m_{GW} \times b \quad \text{Equation 8-14b}$$

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. CO₂ from use of carbon as reductant

(1) Introduction

CO₂ 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 CO₂ emissions using the following equation:

$$CO_{2,p} = m_c \times 3.664 \quad \text{Equation 8-15}$$

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. N₂O from nitric acid production

8.7.1. Introduction

Nitric acid (HNO₃; NA) is produced by the oxidation of anhydrous ammonia (NH₃) followed by the absorption of nitrogen oxides (NO, NO₂, N₂O) by water (H₂O). Nitric acid is produced as a 60% solution from the absorber tower. The NO_x absorber tail gas contains unabsorbed nitrogen oxides (NO, NO₂, N₂O), which must be controlled prior to release. NO_x abatement systems, such as Non-Selective Catalytic Reduction (NSCR) systems, are used to reduce NO, NO₂, and N₂O emissions from NO_x absorber tail gas. Nitrous oxide (N₂O) is present in very small concentrations as a by-product of the oxidation reaction and some of this N₂O is emitted in the absorber tail gas as an IP emission.

8.7.2. Level 1 - Method 8-1: N₂O emission factor method for systems with abatement downtime

(1) Introduction

The N₂O Emission Factor Method is used for nitric acid trains that do not measure N₂O emissions directly using a CEMS and had abatement downtime when the NO_x abatement system was bypassed for a certain period of time during the reporting period. This method requires an annual measurement of N₂O concentration in the NO_x Absorber tail gas stream (before the NO_x abatement system) and N₂O concentration in the final stack gas stream (after the NO_x abatement system).

(2) Equations

For each nitric acid train, calculate IP N₂O emissions using the following equation:

$$N_2O_p = m_{PNA} \times EF_{N2O,NAO} \times (1 - (DF_{N2O} \times AF_{N2O})) \times 0.001 \quad \text{Equation 8-16}$$

Where:

N_2O_p	=	N_2O mass emissions from nitric acid production in reporting period, p (tonnes N_2O).
mp_{NA}	=	Production mass of nitric acid (100% basis), (tonnes nitric acid product) in reporting period.
DF_{N_2O}	=	Average destruction efficiency of NO_x abatement system (%), determined by either: <ul style="list-style-type: none"> • Manufacturer's specifications; • Documented engineering estimates based on process knowledge; or • Calculated using the direct measurement as shown in Equation 8-16a if the test personal can safely access the upstream of the NO_x abatement system.
$EF_{N_2O,NAO}$	=	Average N_2O emission factor for NO_x Absorber Outlet (NAO) (kg N_2O per tonne nitric acid), as defined in Equation 8-16b.
AF_{N_2O}	=	NO_x 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:

$$DF_{N_2O} = \frac{(C_{N_2O,NAO} \times Q_{N_2O,NAO} - C_{N_2O,NAS} \times Q_{N_2O,NAS})}{C_{N_2O,NAO} \times Q_{N_2O,NAO}} \times 100\% \quad \text{Equation 8-16a}$$

Where:

DF_{N_2O}	=	Average abatement system destruction efficiency (%) in reporting period.
$C_{N_2O,NAO}$	=	N_2O concentration (ppmv) from the NO_x Absorber Outlet (NAO).
$Q_{N_2O,NAO}$	=	Flow rates (m^3/h) from the NO_x Absorber Outlet (NAO).
$C_{N_2O,NAS}$	=	N_2O concentration (ppmv) from the Nitric Acid Stack (NAS).
$Q_{N_2O,NAS}$	=	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 NO_x Absorber outlet (NAO).

$$EF_{N_2O,NAO} = \frac{\sum_{i=1}^N \frac{Q_{NAO,i} \times C_{N_2O,NAO,i}}{PR_{NA,i}} \times 1.861 \times 10^{-6}}{N} \quad \text{Equation 8-16b}$$

Where:

$EF_{N_2O,NAO}$	=	Average N_2O emission factor for NO_x 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 NO_x Absorber Outlet during test run i (sm^3/h) at 15°C & 1 atm.
$C_{N_2O,NAO,i}$	=	Measured N_2O concentration at NO_x 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).
1.861×10^{-6}	=	N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at 15°C & 1 atm).

The NOx abatement operating fraction (AF N₂O) is a measure of the fraction of total nitric acid production where N₂O emissions are controlled by an operating NOx abatement system. This factor corrects the N₂O equation for any periods during the year when the N₂O destruction by the NOx abatement system is not applied. For operations having 100% NOx abatement uptime, the default AF_{N₂O} = 1.0.

$$AF_{N_2O} = \frac{PR_{NA,Abate}}{PR_{NA,Total}} \quad \text{Equation 8-16c}$$

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 N₂O 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. N₂O 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 N₂O 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. Level 2 - Method 8-2: N₂O emission factor method for direct stack test

(1) Introduction

The N₂O 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 N₂O emissions by stack testing on the final Nitric Acid Stack (NAS) and production rate during the stack test.

(2) Equations

$$N_2O_p = m_{PNA} \times EF_{N_2O,NAS} \times 0.001 \quad \text{Equation 8-17}$$

Where:

N ₂ O _p	=	N ₂ O mass emissions from nitric acid production in the reporting period, p (tonnes N ₂ O).
m _{PNA}	=	Production mass of nitric acid (100% basis) (tonnes nitric acid product) in reporting period.
EF _{N₂O,NAS}	=	Average N ₂ O emission factor (kg N ₂ O per tonne nitric acid) for the final Nitric Acid Stack (NAS) based on the direct stack testing of the final N ₂ O emission stack and calculated in Equation 8-17a.

0.001 = Mass conversion factor: tonnes per kg.

$$EF_{N_2O,NAS} = \frac{\sum_{i=1}^N \frac{Q_{NAS,i} \times C_{N_2O,NAS,i}}{PR_{NA,i}} \times 1.861 \times 10^{-6}}{N} \quad \text{Equation 8-17a}$$

Where:

- $EF_{N_2O,NAS}$ = 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 $15^\circ C$ & 1 atm.
- $C_{N_2O,NAS,i}$ = 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).
- 1.861×10^{-6} = N_2O Density conversion factor ($kg/sm^3 \cdot ppmv^{-1}$; at $15^\circ C$ & 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 $EF_{N_2O,NAS}$ 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 $EF_{N_2O,NAS}$ must be conducted when nitric acid production process has changed including abatement equipment installation.

8.7.4. Level 3 - Continuous emissions monitoring systems

(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.

$$N_2O_p = \sum_{t=1}^T \left[Vel_{s,t} \times Area_s \times C_{N_2O,t} \times \left(\frac{P_{act,t} \times 288.15}{101.325 \times T_{act,t}} \right) \right] \times \frac{MW_{N_2O}}{23.645} \times 0.001 \quad \text{Equation 8-18}$$

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).
- $Vel_{s,t}$ = Stack gas velocity (m/h), measured by continuous ultrasonic flow meter.
- $Area_s$ = Stack cross-sectional area (m^2).
- $C_{N_2O,t}$ = N_2O concentration (wet basis) of stack gas ($kmol_{N_2O}/kmol_{GAS}$), measured by in-situ gas analyzer; (If analyzer provides N_2O concentration in ppmv, then $C_{N_2O,t} = ppmv \times 10^{-6}$).
- MW_{N_2O} = 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.



Chapter 12

Imports

Alberta greenhouse gas
quantification methodologies



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12. 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.

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.

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.

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.



Chapter 13

Production

Alberta greenhouse gas
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13. 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 high performance benchmarks (HPB) have been developed under TIER. Definitions of these products are provided in Schedule 2 of the TIER. This section covers the quantification of production where the definition of what qualifies as a product is covered in the TIER.

TABLE 13-1: PRODUCTS AND PRODUCTION UNITS

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)
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 gross ammonia produced. 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 TIER.

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 TIER.

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, Level 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 and Upgrading

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 TIER 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 for purpose hydrogen production is set to 0, independent of the technology and/or feedstock used for hydrogen production. Useful hydrogen produced is treated as its own product.

The Fluid Catalytic Cracking (FCC) Coke on Catalyst (vol. %) factor is estimated based on the Grace-Davison method. The department can provide a calculation workbook for a facility's use upon request.

$$CWB_{pro} = \sum_{u=1}^U \text{Daily Throughput Barrel}_u \times CWB \text{ Factor}_u \quad \text{Equation 13.14-17}$$

Where:

CWB_{pro} [bbl/cd]	=	Alberta Process CWB as per CAN-CWB
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 in bbl/cd. Refer to Table 13.2 for refining process and Table 13.3 for upgrading process.
CWB Factor _{u}	=	CWB factor for unit u except for Hydrogen Production Units. Refer to Table 13.2 for refining process and Table 13.3 for upgrading process.

TABLE 13-2: REFINING PROCESS UNITS AND CWB FACTORS

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
Alkylation	Alkylation with Hydrofluoric Acid	5.00	C5+ Alkylate	bbl/cd	Olefins, Isobutane	Alkylate, Normal Butane, Isobutane, Propane	Feed Drums, Acid Contactor, Acid Recovery, Acid Regeneration, Depropanizer, Debutanizer, Deisobutanizer, Refrigeration System
	Alkylation with Sulfuric Acid						
	Dimersol		C5+ Product	bbl/cd	Propane/ Propylene	Dimate (Nonene), LPG	Reactors, Catalyst Removal, Stabilizer, Fractionator
	Polymerization of C3 Olefin Feed				Propane/ Propylene	LPG, Polymer Naphtha, Low-Boiling Paraffins	Reactors, Product Fractionator
	Polymerization of C3/C4 Feed				Mixed C3 & C4 Olefins & Paraffins	LPG, Polymer Naphtha, Low-Boiling Paraffins	Reactors, Product Fractionator
Ammonia Recovery Unit	Ammonia Recovery Unit	453.00	Product	short tons/cd	Sour Water Stripper Overhead	Ammonia, Treated Water	Adsorber, Stripper, Fractionator
Aromatics Production	Aromatic Solvent Extraction: Extraction Distillation	3.30	Feed	bbl/cd	C6-C8 Aromatic Rich Stream from Reformate or Pyrolysis Gasoline	High Purity Aromatic Stream	Extractor, Raffinate Wash, Stripper, Recovery Column, Solvent Regenerator, Water Stripper, Clay Treaters
	Aromatic Solvent Extraction: Liquid/Liquid Extraction				C6-C8 Aromatic Rich Stream from Reformate or Pyrolysis Gasoline	High Purity Aromatic Stream	Extractor, Raffinate Wash, Stripper, Recovery Column, Solvent Regenerator, Water Stripper, Clay Treaters
	Aromatic Solvent Extraction: Liquid/Liquid Extraction w/ Extraction Distillation				C6-C8 Aromatic Rich Stream from Reformate or Pyrolysis Gasoline	High Purity Aromatic Stream	Extractor, Raffinate Wash, Stripper, Recovery Column, Solvent Regenerator, Water Stripper, Clay Treaters
	Benzene Column				Mixed C6+ Aromatics from extraction process	Benzene (95+), C7+ Aromatics	Fractionating Column
	Heavy Aromatics Column				Mixed C9+ Aromatics	C9+ Aromatics, C10+ Aromatics	Fractionating Column
	Toluene Column				Mixed C7+ Aromatics from extraction process	Toluene, C8+ Aromatics	Fractionating Column
	Xylene Rerun Column				Mixed C8+ Aromatics	Mixed Xylenes, C9+ Aromatics	Fractionating Column
Asphalt Production	Asphalt Production	2.70	Total Asphalt Production	bbl/cd	Short Resid	Fuel Gas, Asphalt	Steam Generation, Oxidizer, Air Blower, Incinerator
Atmospheric Crude Distillation	Mild Crude Unit	1.00	Feed	bbl/cd	Crude Oil, Condensate, Commingled Liquids	Fuel Gas, Propane, Mixed Butanes, Light & Heavy Naphtha, Kerosene, Diesel, Atmospheric Gas Oil, Atmospheric Residue	Heaters, Preflash Tower, Outboard Flash Tower, Desalters, Crude Distillation Column, Sidestream, Stripper Columns, Pumparound Circuits, Merox, Treating, Saturate Gas Plant (including Gas Compression, Absorber, Stripper, Deethanizer, Depropanizer, Debutanizer, Naphtha Splitter, Sour Water Stripper)
	Standard Crude Unit						

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
C4 Isomerization	C4 Isomerization	1.25	Feed	bbbl/cd	Normal Paraffins, Hydrogen	Mixed Isoparaffins & Normal Paraffins	Once through operation with no feed preparation or internal recycle or unconverted product. Heater, Reactor, Stabilizer, Hydrogen Recycle
C5/C6 Isomerization	C5/C6 Isomerization	1.80	Feed	bbbl/cd	Normal Paraffins, Hydrogen	Mixed Isoparaffins & Normal Paraffins	Once through operation with no feed preparation or internal recycle or unconverted product. Heater, Reactor, Stabilizer, Hydrogen Recycle
Catalytic Cracking	Fluid Catalytic Cracking (Feed ConCarbon <2.25 wt %)	1.150 +1.041 * FCC Coke on Catalyst vol %	Feed	bbbl/cd	Vacuum Gas Oil, Atmospheric Resid	Fuel Gas, C3s, C4s, Gasoline, Cycle Oils, Decant Oil	Feed Preheater, Reactor, Fractionator, Regenerator, CO Boiler, Waste Heat Steam Generator, Tertiary Flue Gas Separator, Electrostatic Precipitators, Catalyst Hoppers.
	Mild Residual (Feed ConCarbon 2.25–3.5 wt %)	0.6593 +1.1075 * FCC Coke on Catalyst vol %	Feed	bbbl/cd			
	Residual Catalytic Cracking (Includes two-stage regeneration; Feed ConCarbon ≥3.5 wt %)	1.1765 * FCC Coke on Catalyst vol %	Feed	bbbl/cd			
	Houdry Catalytic Cracking	4.65	Feed	bbbl/cd			
	Thermoform Catalytic Cracking	4.65	Feed	bbbl/cd			
Catalytic Reformer and AROMAX	Continuous Regeneration	3.50	Feed	bbbl/cd	Naphtha	Fuel Gas, Butanes, Reformate, Hydrogen	Heater, Reactors, Regenerators, Debutanizer, Light Ends Processing, Hydrogen Compression, Recycle System
	Cyclic						
	Semi-Regenerative						
	AROMAX						
CO2 Liquefaction	CO2 Liquefaction	-160.00	Product CO2	short tons/cd	Gaseous CO2	Liquid CO2	Multi-Stage Compression, Dehydrators, Stripper
Coke Calciner	Horizontal Axis Rotary Kiln	96.00	Product	short tons/cd	Green Petroleum Coke	Calcined Coke	Combustion Chamber, Horizontal Rotary Kiln, Electrostatic Precipitator, or other air pollution control equipment (Coke Handling & Storage Equipment reported separately. Report Waste Heat Recovery under Fired Boilers - Solid)
	Vertical Axis Hearth		Product	short tons/cd	Green Petroleum Coke	Calcined Coke	Combustion Chamber, Vertical Rotary Kiln, Electrostatic Precipitator, or other air pollution control equipment (Coke Handling & Storage Equipment reported

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
							separately. Report Waste Heat Recovery under Fired Boilers - Solid)
Coking	Delayed Coking	2.55	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oil, Coke	Reactor, Coke Handling, Coke Burner, Fractionator, Light Ends Processing, Waste Heat Steam Generation, CO Boiler
	Flexicoker	23.60	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oil, Low BTU Gas	Reactor, Coke Burner, Gasifier, Fractionator, Light Ends Processing, Waste Heat Steam Generation
	Fluid Coking	10.30	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oil, Coke	Reactor, Coke Handling, Coke Burner, Fractionator, Light Ends Processing, Waste Heat Steam Generation, CO Boiler
Cracking Feed or Vacuum Gas Oil Desulfurization	Cracking Feed Or Vacuum Gas Oil Hydrodesulphurization	1.00	Feed	bbl/cd	Vacuum Gas Oil/Cracking Feed, Hydrogen	Fuel Gas, Distillate, Vacuum Gas Oil/Cracking Feed	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	Cracking Feed Or Vacuum Gas Oil Hydrodesulphurization and Hydrodenitrification				Vacuum Gas Oil/Cracking Feed, Hydrogen	Fuel Gas, Distillate, Vacuum Gas Oil/Cracking Feed	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
Cryogenic LPG Recovery	Cryogenic LPG Recovery	0.25	Feed	k scf/cd	Refinery Gas Streams	C3s, C4s, Other Gases	Refrigeration, Drier, Compressor, Absorber Stripper, Fractionation
Cumene production	Cumene production	5.00	Cumene Product	bbl/cd	Propylene, Benzene	Propane, Cumene, Heavy Aromatics	Reactor, Hot Oil or Stream Heater, Flash Towers, Benzene Recovery Column, Clay Treater, Fractionator
Cyclohexane production	Cyclohexane production	2.80	Cyclohexane Product	bbl/cd	Benzene, Hydrogen	Cyclohexane	Reactor, Separators, Stabilizer, Steam Generator, Recycle Compressor, Makeup Compressor
Desalination	Desalination	32.70	Product Water	k gallon/cd	Sea or Contaminated Water	Potable Water, Brine	Heater, Boilers, Fractionation
Distillate Desulfurization & Treating	Aromatic Saturation of Distillates	0.90	Feed	bbl/cd	Low Sulfur Distillate, Hydrogen	Low Olefins Distillate	Heater, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	Conventional Distillate Hydrotreating				Distillate/Light Gasoil, Hydrogen	Low Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	High Severity Distillate Hydrotreating				Distillate/Light Gasoil, Hydrogen	Low Gas, Low Sulfur Distillate/ Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	Mid Distillate Dewaxing				Distillate/Light Gasoil, Hydrogen	Low Gas, Low Wax Content Distillate/ Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	S-Zorb Process				Distillate, Gasoil	Low Sulfur Distillate/ Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Ultra-High Severity Distillate Hydrotreating				Distillate/Light Gasoil, Hydrogen	Low Gas, Low Sulfur Distillate/ Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System
Ethylbenzene	Ethylbenzene - Distillation	1.60	Feed	bbl/cd	Mixed C8 Stream	Ethylbenzene, Mixed C8 Stream	Fractionator, Heat Exchange
	Ethylbenzene - Manufacture		Ethylbenzene Product	bbl/cd	Benzene, Ethylene or Refinery Off-Gas Containing Ethylene	Ethylbenzene	Reactor, Heater, Benzene Recycle Column, Fractionator, Recycle Compressor, Makeup Compressor
Flare Gas Recovery	Flare Gas Recovery	0.13	Feed	k scf/cd	Waste Gases, Steam	Compressed Gases	Compressor, Separator
Flue Gas Desulfurizing	Flue Gas Desulfurizing	0.02	Feed	k scf/cd	Flue Gas with Contaminants	Clean Flue Gas	Contactors, Catalyst/Reagent Regeneration, Scrubbing Circulation, Solids Handling
Fuel Gas Sales Treating & Compression	Fuel Gas Sales Treating & Compression	2.52	Horsepower	hp	Raw Fuel Gas	High-Pressure Sweet Fuel Gas	H ₂ S Absorber, Compressor, Miscellaneous Purification
Fuel Solvent Deasphalting	Conventional Solvent	2.80	Feed	bbl/cd	Resid, Solvent	Deasphalted Oil, Asphalt	Heater plus Contactors & Separators or Extraction Column & Strippers, Solvent Recovery
	Supercritical Solvent						Heater plus Contactors & Separators or Extraction Column & Strippers, Solvent Recovery
Gasoline/Naphtha Desulfurization & Treating	Pyrolysis Gasoline/Naphtha Desulfurization	0.91	Feed	bbl/cd	Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low sulfur Pyrolysis gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Benzene Saturation				Naphtha/Gasoline, Hydrogen	Low Benzene Content Naphtha/Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Conventional Naphtha Hydrotreating				Naphtha/Gasoline, Hydrogen	Fuel Gas, Low sulfur naphtha, gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Desulfurization of C4-C6 Feeds				C4-C6, Hydrogen	Fuel Gas, Low sulfur C4-C6	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Diolefin to Olefin Saturation of Gasoline				Light Naphtha, Hydrogen	Treated light naphtha	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	FCC Gasoline Hydrotreating with Minimal Octane Loss				Heavy FCC Naphtha/Gasoline, Hydrogen	Fuel Gas, Low sulfur heavy FCC gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Olefinic Alkylation of Thiophenic Sulfur				Full range FCC Naphtha/Gasoline	Low sulfur FCC gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Reactor for Selective Hydrotreating				Light FCC Naphtha/Gasoline	Low sulfur light FCC gasoline	Reactors
	Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization				Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low sulfur, low olefin Pyrolysis gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization				Pyrolysis Naphtha/Gasoline, Hydrogen	Fuel Gas, Low olefin Pyrolysis gasoline	Heater, Guard Bed, Reactor, Separators, Fractionators, Hydrogen Compression, Recycle System
	S-Zorb Process				Full range FCC Naphtha/Gasoline	Low sulfur FCC gasoline	Heater, Reactor, Recycle Compressor, Exchangers, Separators, Stabilizer, Sorbent Regenerator
H-Oil	H-Oil	4.40	Feed	bbl/cd	Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid.	Heater, Reactors, Regenerator, CO Boiler, Hydrogen Compression, Scrubbing & Recycle, Catalyst Hoppers, Atmospheric & Vacuum Fractionation
Hydrogen Generation	Steam Methane Reforming	0.00	Product	k scf/cd	Fuel Oil, Naphtha, Natural Gas	Hydrogen, Carbon Dioxide	Desulfurizer, Heaters, Reformer or Partial Oxidizer, Shift Converter, Methanation, CO2 Rejection, Hydrogen Compression
	Steam Naphtha Reforming	0.00	Product	k scf/cd			
	Partial Oxidation	0.00	Product	k scf/cd			
Hydrodealkylation	Hydrodealkylation	2.50	Feed	bbl/cd	Toluene, Heavy Alkylbenzenes, Hydrogen	Mixed Benzene & Heavy Aromatics	Heater, Reactors, Separator, Stripper, Clay Treaters, Fractionators, Hydrogen Compression
ISOSIV	ISOSIV	1.80	Feed	bbl/cd	Mixed C5/C6 Paraffins	Isoparaffins, Normal Paraffins	Heater, Reactor, Stabilizer, Hydrogen Recycle
Kerosene Desulfurization & Treating	Aromatic Saturation of Kerosene	0.75	Feed	bbl/cd	Kerosene, Hydrogen	Fuel Gas, Low sulfur Kerosene	Heater, Reactors, Separator, Stripper/Stabilizer, Hydrogen Compression, Recycle System
	Conventional Hydrotreating of Kerosene/Jet Fuel						Heater, Guard Bed, Reactors, Separator, Fractionator, Hydrogen Compression, Recycle System
	High Severity Hydrotreating of Kerosene/Jet Fuel						Heater, Guard Bed, Reactors, Separator, Stripper/Stabilizer, Hydrogen Compression, Recycle System
LC-Fining and Hycon	LC-Fining and Hycon	4.40	Feed	bbl/cd	Atmospheric or Vacuum Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid.	Heater, Reactors, Hydrogen Compression, Scrubbing & Recycle, Atmospheric & Vacuum Fractionation
Lubricant	Catalytic Wax Isomerization and Dewaxing	1.60	Feed	bbl/cd		Dewaxed Oils, Lights Ends, Distillates	Heater, Reactors, Hydrogen Recycle and Make-up Compression, HP Separator, LP

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Selective Wax Cracking				Extracted Gas Oil, Hydrocrackates, Vacuum Distillates		Separator, Recycle Gas Treater, Atmospheric Product Fractionation and/or Stripping. Additionally, and Iso-Dewaxer includes a Hydrofinishing Reactor and Product Stripper
	Deoiling Solvent is Chlorocarbon	11.80	Product	bbl/cd	Slack Wax	Refined (Hard) Wax, Foots Oil/Soft Wax	Refrigeration, Rotary Filter, Solvent Recovery
	Deoiling Solvent is MEK/MIBK						
	Deoiling Solvent is MEK/Toluene						
	Deoiling Solvent is propane						
	Dewaxing Solvent is Chlorocarbon	4.55	Feed	bbl/cd	Extracted Gas Oil, Hydrocrackates, Vacuum Distillates	Dewaxed Oils, Slack Wax, Scale Wax	Solvent/Oil Refrigeration, Scraped Surface Coolers/Chillers, Filter Deed Drum, Crystallizer, Rotary Filters, Solvent Recovery, Solvent Dehydration, Solvent Splitter
	Dewaxing Solvent is MEK/MIBK						
	Dewaxing Solvent is MEK/Toluene						
	Dewaxing Solvent is propane						
	Lube Hydrocracker with Multi-Fraction Distillation	1.15	Feed	bbl/cd	Raffinate or Dewaxed Oil	Base Oil Feedstock, Dewaxed Oils, Fuel Gas	Heater, Reactors, Fractionation, Hydrogen Recycle and Make-up Compression, Atmospheric Product Fractionation and/or Stripping.
	Lube Hydrocracker with Vacuum Stripper						
	Lube Hydrotreating with Vacuum Stripper						
	Hydrofinishing with Vacuum Stripper	2.50	Feed	bbl/cd	Vacuum Gas Oil	Base Oil Feedstock, C3 to 650 F+ Clean Products, Fuel Gas	Heater, Reactors, Product Fractionation, Hydrogen Recycle and Make-up Compression, Hydrogen Scrubbing and Recycle, Atmospheric and Vacuum Distillation Columns
	Hydrotreating with multi-fraction distillation						
	Extraction Solvent is Duo-Sol	2.20	Feed	bbl/cd	Vacuum Gas Oil, Deasphalted Oil, Vacuum Tower, Bottoms	Raffinates, Extracts	Heater, Extraction Tower, Raffinate and Extract Solvent Recovery
	Extraction Solvent is Furfural						
	Extraction Solvent is NMP						
	Extraction Solvent is Phenol						
	Extraction Solvent is SO ₂						
	Wax hydrofinishing with Vacuum Stripper	1.15	Feed	bbl/cd	Refined Wax, Slack Wax, Scale Wax	HF Refined Wax, HF Scale Wax, HF Slack Wax	Heater, Reactors, Separator, Fractionation, Hydrogen Recycle and Make-up Compression,
	Wax hydrotreating with Multi-Fraction Distillation						
	Wax hydrotreating with Vacuum Stripper						

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
Methanol Synthesis	Methanol Synthesis	-36.00	Product	bbl/cd	Hydrogen & CO	Methanol	POX Reactor, Scrubber, Soot Recovery, Gas Cleanup & Sulfur Removal
Naphtha/Distillate Hydrocracker	Mild Hydrocracking (Normally less than 1,500 psig and consumes between 100 and 1,000 SCF H ₂ /bbl)	3.15	Feed	bbl/cd	Heavy Naphthas through Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Light & Heavy Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid.	Heater, Reactors, Fractionator, Hydrogen Compression, Scrubbing & Recycle
	Naphtha Hydrocracking						Saturate Gas Plant (including fuel gas treating, absorber stripper, deethanizer, depropanizer, debutanizer, deisobutanizer, naphtha splitter, sour water stripper)
	Severe Hydrocracking (Normally more than 1,500 psig and consumes more than 1,000 SCF H ₂ /bbl)						
Oxygenates ETBE	ETBE	4.90	Product	bbl/cd	Ethanol, C4 Olefins	ETBE, Unreacted C4 Olefins	Reactor, Fractionator, Methanol Extraction & Recycle
Oxygenates MBTE - Distillation Units	Distillation Units		Product	bbl/cd	Methanol, C4 Olefins	MTBE, Unreacted C4 Olefins	Reactor & Fractionator or Catalytic Distillation Vessel
	Extraction Units		Product	bbl/cd	Methanol, C4 Olefins	MTBE, Unreacted C4 Olefins	Reactor & Fractionator or Catalytic Distillation Vessel; Methanol Recovery & Recycle
Oxygenates TAME	TAME		Product	bbl/cd	Methanol, C4-C6 Mixed Olefins	Mixed Ethers, Unreacted C4-C6 Mixed Olefins	Reactor, Fractionator, Methanol Extraction & Recycle
Paraxylene Production	Orthoxylene Rerun Colum	6.50	Feed	bbl/cd	Mixed o-Xylenes & C9+ Aromatics	o-Xylenes, C9+ Aromatics	Fractionating Column
	Paraxylene: Adsorption		Paraxylene Product	bbl/cd	Mixed Xylenes	p-Xylene, Mixed Xylenes low in p-Xylene Content	Adsorption Chamber, Rotary Valve, Extract & Raffinate Columns, Finishing Column
	Paraxylene: Crystallization		Paraxylene Product	bbl/cd	Mixed Xylenes	p-Xylene, Mixed Xylenes low in p-Xylene Content	Crystallizer, Centrifuge
	Xylene Splitter		Feed	bbl/cd	Mixed C8+ Aromatics	Mixed p-/m-Xylene, Mixed o-Xylenes, C9+ Aromatics	Fractionating Column
POX Syngas for Fuel	Air Separation Unit	2.75	Product	k scf/cd	Air	Oxygen, Nitrogen	Compressor, Cold Box, Separation Equipment
	POX Syngas for Fuel		Product	k scf/cd	Resid	H ₂ , Co, CO ₂	POX Reactor, Scrubber, Soot Recovery, Gas Cleanup & Sulfur Removal
Propane/Propylene Splitter	Chemical Grade	2.10	Feed	bbl/cd	Mixed C3s	High Purity Propylene, Propane	Splitter Column
	Polymer Grade		Feed	bbl/cd	Mixed C3s	High Purity Propylene, Propane, C2-Off-Gas	Deethanizer, Splitter Column, Compressor, Driers, Treaters
Residual Desulfurization	Desulfurization of Atmospheric Resid	1.80	Feed	bbl/cd	Hydrogen, Atmospheric Resid	Fuel Gas, Atmospheric Resid	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression, Recycle System

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Desulfurization of Vacuum Resid				Hydrogen, Vacuum Resid	Fuel Gas, Vacuum Resid	Heater, Guard Bed, Reactor, Separators, Hydrogen Compression, Recycle System
Selective Hydrotreater	Deolefin to Olefin Saturation of Alkylation Feed	0.90	Feed	bbl/cd	C3s, C4s, C5s containing dienes & acetylenes, light cracked Gasoline, Light Distillate, Hydrogen	C3s, C4s, C5s with no dienes or acetylenes, low-olefin cracked Gasoline, Light Distillate	Reactor
	Selective Hydrotreating of Distillate Fuels				Distillate	Low Contaminant Distillate	Heaters, Reactor, Separator, Stripper/Stabilizer
Solvent Hydrotreating	Fractionation	0.00	Feed	bbl/cd	Distillate Mixture	High Purity Solvent, By-Product stream	Special Fractionation for Solvent Purification
	Hydrotreating		Feed	bbl/cd	Solvents, Hydrogen	Treated Solvents	Reactor, Stabilizer
Special Fractionation	Special Fractionation ex Solvents, Propylene, and Aromatics	0.80	Feed	bbl/cd	Various	Various	Fractionator, Heat Exchange
Sulfur	H ₂ S Springer Unit	140.00	Sulfur Sprung	long tons/cd	H ₂ S Rich Gas, Spent Caustic	Sweet Gas, Sulfur/ H ₂ S	
	Sulfur Recovery		Product Sulfur	long tons/cd	Acid Gas	Sulfur, Tail Gas	Burner/Reactor, Waste Heat Boiler, Converters, Condensers, Amine Unit Regenerator, Sour Water Stripper (exclude pelletizers)
	Tail Gas Recovery Unit		Sulfur Sprung	long tons/cd	Tail Gas	Sulfur, Off Gas	Reactor, Quench Tower, Absorber, Regenerator for SCOT Process & equivalent for other processes
Sulfuric Acid Regeneration	Sulfuric Acid Regeneration	37.80	Product	short tons/cd	Spent Acid	Sulfuric Acid	Combustor, Waste Heat Boiler, Converter, Absorber, SO ₃ Recycle, Gas Cleaning including electrostatic precipitator, amine regenerator
Thermal Cracking	Thermal Cracking	2.95	Feed	bbl/cd	Vacuum Gas Oil	Fuel Gas, Naphtha, Distillates, Heavy Gas Oil, Bottoms	Gas Oil Furnace, Product Fractionator
Toluene Disproportionation/ Transalkylation	Toluene Disproportionation/ Transalkylation	1.90	Feed	bbl/cd	Toluene, C9+ Aromatics, Hydrogen	Mixed Benzene, C8 Aromatics, C10+ Aromatics	Heater, Reactors, Clay Treating, Light Ends Stripper, Separator, Recycle Gas Compression
Vacuum Distillation	Heavy Feed Vacuum Unit	0.91	Feed	bbl/cd	Atmospheric Resid	Fuel Gas, Vacuum Gas Oil to Vacuum Resid	Heaters, Vacuum Distillation Colum, multiple towers in series counted as one unit
	Mild Vacuum Fractionation						
	Standard Vacuum Column						
	Vacuum Fractionating Column						
VGO Hydrotreater	VGO Hydrotreater	1.00	Feed	bbl/cd			

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
Visbreaking	Processing Atmospheric Resid (w/o a Soaker Drum)	1.60	Feed	bbl/cd	Atmospheric or Vacuum Resid	Fuel Gas, Naphtha, Distillates, Heavy Gas Oil, Resid	Furnaces, Soaker Drum, Atmospheric Product, Fractionator, Sidestream Column
	Processing Atmospheric Resid (with a Soaker Drum)						
	Processing Vacuum Bottoms Feed (w/o a Soaker Drum)						
	Vacuum Bottoms Feed (with a Soaker Drum)						
Xylene Isomerization	Xylene Isomerization	1.90	Feed	bbl/cd	Mixed Xylenes low in p-xylene content, Hydrogen	Mixed Xylenes in Equilibrium	Heater, Reactors, Stabilizer, Deheptanizer

1. The CAN-CWB Methodology for Regulatory Support: Public Report, Solomon Associates, January 2014.
2. CAN-CWB User Manual, Canadian Fuel Association, November 2016.
3. cd - calendar day
4. bbl - API barrels, 42 US liquid gallons, 0.159 cubic metres
5. k scf - 1000 standard cubic feet
6. k gallon - 1000 gallon

TABLE 13-3: UPGRADING PROCESS UNITS AND CWB FACTORS

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
Ammonia Recovery Unit	Ammonia Recovery Unit	453.00	Product	short tons/cd	Sour Water Stripper Overhead	Ammonia, Treated Water	Adsorber, Stripper, Fractionator
Bitumen Upgrader Atmospheric Distillation	Mild Atmospheric Distillation Unit	0.81	Feed	bbl/cd	Bitumen, Diluted Bitumen, Heavy Crude,	Fuel Gas, Propane, Mixed Butanes, Light & Heavy Naphtha, Kerosene, Diesel, Atmospheric Gas Oil, & Atmospheric Resid	Heaters, Preflash Tower, Outboard Flash Tower, Desalters, Bitumen Distillation Column, Diluent Recovery Unit, Sidestream Stripper Columns, Pumparound Circuits, Merox Treating, Saturate Gas Plant (including: Gas Compression, Absorber, Stripper, Deethanizer, Depropanizer, Debutanizer, Naphtha Splitter, & Sour Water Stripper)
	Standard Atmospheric Distillation Unit						
Bitumen Upgrader Vacuum Distillation	Heavy Feed Vacuum Unit	0.75	Feed	bbl/cd	Atmospheric Resid	Fuel Gas, Vacuum Gas Oils to Vacuum Resid	Heater, Vacuum Distillation Column, multiple towers in series counted as one unit
	Mild Vacuum Fractionation						
	Standard Vacuum Column						
	Vacuum Fractionating Column						
CO2 Liquefaction	CO2 Liquefaction	-160.00	Product CO ₂	short tons/cd	Gaseous CO ₂	Liquid CO ₂	Multi-Stage Compression, Dehydrators, Stripper
Coking	Delayed Coking	2.55	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oils, Coke	Heater, Coke Drums, Fractionator, Sidestream Column, Light Ends Processing (incl. Unsat Gas Plant), Coke Cutting (Resources for coke handling & storage are reported separately)
	Flexicoking	23.60	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oil, Low-Btu Gas	Reactor, Coke Burner, Gasifier, Fractionator, Light Ends Processing, Waste Heat Steam Generation
	Fluid Coking	10.30	Feed	bbl/cd	Vacuum Resid	Fuel Gas, C3s, C4s, Naphtha, Distillates, Heavy Gas Oil, Coke	Reactor, Coke Handling, Coke Burner, Fractionator, Light Ends Processing (incl. Unsat Gas Plant), Waste Heat Steam Generation, CO Boiler
Distillate Desulfurization & Treating	Aromatic Saturation of Distillates	0.90	Feed	bbl/cd	Low Sulfur Distillate, Hydrogen	Low Olefins Distillate	Heater, Reactor, Separator, Stripper/Stabilizer, Hydrogen Compression & Recycle System
	Conventional Distillate Hydrotreating				Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System
	High Severity Distillate Hydrotreating				Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System
	Middle Distillate Dewaxing				Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Wax Content Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	S-Zorb™ Process				Distillate/Gasoil	Low Sulfur Distillate	Heater, Reactor, Recycle Compressor, Exchangers, Separators, Stabilizer, & Sorbent Regenerator
	Ultra-High Severity Hydrotreating				Distillate/Light Gasoil, Hydrogen	Fuel Gas, Low Sulfur Distillate/Gasoil	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System
Flare Gas Recovery	Flare Gas Recovery	0.13	Feed	k scf/cd	Waste Gases, Steam	Compressed Gases	Compressor, Separator
Flue Gas Desulfurizing	Flue Gas Desulfurizing	0.02	Feed	k scf/cd	Flue Gas with Contaminants	Clean Flue Gas	Contactor, Catalyst/Reagent Regeneration, Scrubbing Circulation, Solids Handling
Fuels Solvent Deasphalting	Conventional Solvent	2.80	Feed	bbl/cd	Resid, Solvent	Deasphalted Oil, Asphalt	Heater plus Contactors & Separators or Extraction Column & Strippers, Solvent Recovery
	Supercritical Solvent				Hydrogen, Vacuum Resid	Fuel Gas, Vacuum Resid	Heater, Guard Bed, Reactor, Separators, Hydrogen Compression & Recycle System
Gasoline/ Naphtha Desulfurization & Treating	Benzene Saturation	0.91	Feed	bbl/cd	Naphtha/Gasoline, Hydrogen	Low Benzene Content Naphtha/Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	Conventional Naphtha Hydrotreating				Naphtha, Gasoline, Hydrogen	Fuel gas, Low sulfur naphtha, gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	Desulfurization of C4–C6 Feeds				C4–C6, hydrogen	Fuel Gas, Low Sulfur C4–C6	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	Diolefin to Olefin Saturation of Gasoline				Light Naphtha, Hydrogen	Treated Light Naphtha	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	FCC Gasoline Hydrotreating with Minimal Octane Loss				Heavy FCC Naphtha/ Gasoline, Hydrogen	Fuel Gas, Low Sulfur Heavy FCC Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	Olefinic Alkylation of Thiophenic Sulfur				Full range FCC Naphtha/ Gasoline	Low Sulfur FCC Gasoline	Exchangers, Reactors, Separators, & Recycling System
	Pyrolysis Gasoline/ Naphtha Desulfurization				Pyrolysis Naphtha/ Gasoline, Hydrogen	Fuel Gas, Low Sulfur Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	Reactor for Selective Hydrotreating				Light FCC Naphtha/ Gasoline	Low Sulfur Light FCC Gasoline	Reactors
	Selective Hydrotreating of Pyrolysis Gasoline/ Naphtha Combined with Desulfurization				Pyrolysis Naphtha/ Gasoline, Hydrogen	Fuel Gas, Low Olefin Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Selective Hydrotreating of Pyrolysis Gasoline/ Naphtha Combined with Desulfurization				Pyrolysis Naphtha/ Gasoline, Hydrogen	Fuel Gas, Low-Sulfur, Low-Olefin Pyrolysis Gasoline	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	S-Zorb™ Process				Full range FCC Naphtha/ Gasoline	Low Sulfur FCC Gasoline	Heater, Reactor, Recycle Compressor, Exchangers, Separators, Stabilizer, & Sorbent Regenerator
H-Oil	H-Oil	4.40	Feed	bbl/cd	Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heaters; Reactors; Regenerator; CO Boiler; Hydrogen Compression, Scrubbing & Recycle; Catalyst Hoppers; Atmospheric & Vacuum Fractionation
Hydrogen Generation	Steam Methane Reforming	0.00	Product	k scf/cd	Fuel Oil, Naphtha, Natural Gas	Hydrogen, Carbon Dioxide	Desulfurizer, Heaters, Reformer or Partial Oxidizer, Shift Converter, Methanation, CO2 Rejection, Hydrogen Compression
	Steam Naphtha Reforming	0.00	Product	k scf/cd			
	Partial Oxidation	0.00	Product	k scf/cd			
Kerosene Desulfurization & Treating	Aromatic Saturation of Kerosene	0.75	Feed	bbl/cd	Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Reactor, Separator, Stripper/Stabilizer, Hydrogen Compression & Recycle System
	Conventional Hydrotreating of Kerosene/Jet Fuel				Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Guard Bed, Reactor, Separators, Fractionator, Hydrogen Compression & Recycle System
	High Severity Hydrotreating of Kerosene/Jet Fuel				Kerosene, Hydrogen	Fuel Gas, Low Sulfur Kerosene	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System
LC-Fining™ and Hycon	LC-Fining™ and Hycon	4.40	Feed	bbl/cd	Atmospheric or Vacuum Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heaters; Reactors; Hydrogen Compression, Scrubbing & Recycle; Atmospheric & Vacuum Fractionation
Naphtha/ Distillate Hydrocracking	Mild Hydrocracking (Normally less than 1,500 psig and consumes between 100 and 1,000 SCF H2/b)	3.15	Feed	bbl/cd	Heavy Naphthas through Resid, Hydrogen	Fuel Gas, Propane, Isobutane, Normal Butane, Light & Heavy Naphtha, Kerosene, Diesel, Heavy Gas Oil, Resid	Heater; Reactors; Fractionator; Hydrogen Compression, Scrubbing & Recycle
	Naphtha Hydrocracking						Saturate Gas Plant (including: Fuel Gas Treating, Absorber Stripper, Deethanizer, Depropanizer, Debutanizer, Deisobutanizer, Naphtha Splitter, Sour Water Stripper)
	Severe Hydrocracking (Normally more than 1,500 psig and consumes more than 1,000 SCF H2/b)						Saturate Gas Plant (including: Fuel Gas Treating, Absorber Stripper, Deethanizer, Depropanizer, Debutanizer, Deisobutanizer, Naphtha Splitter, Sour Water Stripper)
POX Syngas for Hydrogen	Air Separation Unit	7.30	Syngas Fuel Product	k scf/cd	Air	Oxygen, Nitrogen	Compressor, Cold Box, Separation Equipment
	POX Syngas for Hydrogen and Syngas for Fuel				Resid	Syngas	POX Reactor, Scrubber, Soot Recovery, Gas Cleanup & Sulfur Removal

Processing Facilities	Process Type	CWB Factor	Throughput Basis	Unit of Measure	Feed	Product	Typical Equipment
	Hydrogen Purification	0.00			Unpurified Hydrogen	Hydrogen Product	Adsorber or Membrane Separator
Residual Desulfurization	Desulfurization of Atmospheric Resid	1.80	Feed	bbl/cd	Hydrogen, Atmospheric Resid	Fuel Gas, Atmospheric Resid	Heater, Guard Bed, Reactor, Separators, Stripper/Stabilizer, Hydrogen Compression & Recycle System
	Desulfurization of Vacuum Resid				Hydrogen, Vacuum Resid	Fuel Gas, Vacuum Resid	Heater, Guard Bed, Reactor, Separators, Hydrogen Compression & Recycle System
Selective Hydrotreating	Diolefin to Olefin Saturation of Alkylation Feed	0.90	Feed	bbl/cd	C3s, C4s, C5s containing Dienes & Acetylenes, Light Cracked Gasoline, Light Distillate, Hydrogen	C3s, C4s, C5s with no Dienes or Acetylenes, Low-Olefin Cracked Gasoline, Light Distillate	Reactor
	Selective Hydrotreating of Distillate Fuels				Distillate	Low Contaminant Distillate	Heater, Reactor, Separator, Stripper/Stabilizer
Special Fractionation	Special Fractionation	0.80	Feed	bbl/cd	Various	Various	Fractionator, Heat Exchange
Sulfur	H2S Springer Unit	132.00	Sulfur Sprung	long tons/cd	H ₂ S Rich Gas, Spent Caustic	Sweet Gas, Sulfur/ H ₂ S	
	Sulfur Recovery Unit		Product Sulfur	long tons/cd	Acid Gas	Sulfur, Tail Gas	Burner/Reactor, Waste Heat Boiler, Converters, Condensers, Amine Unit Regenerator, Sour Water Stripper (exclude pelletizers)
	Tail Gas Recovery Unit		Product Sulfur	long tons/cd	Tail Gas	Sulfur, Off Gas	Reactor, Quench Tower, Absorber, Regenerator for SCOT Process & equivalent for other processes
Thermal Cracking	Thermal Cracking	2.95	Feed	bbl/cd	Vacuum Gas Oil	Fuel Gas, Naphtha, Distillates, Heavy Gas Oil, & Bottoms	Gas Oil Furnace, Product Fractionator
VGO Hydrotreater	VGO Hydrotreater	1.00	Feed	bbl/cd			

1. The Bitumen Upgrader CAN-CWB Methodology for Regulatory Support: Public Report, Solomon Associates, October 2017.
2. cd - calendar day
3. bbl - API barrels, 42 US liquid gallons, 0.159 cubic metres
4. k scf - 1000 standard cubic feet
5. k gallon - 1000 gallon

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.

or

- Bitumen and net diluent to be distilled and otherwise processed by the bitumen upgrader.

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:

$$\text{Refinery Production}_y = \frac{(CWB_{pro} + CWB_{off} + CWB_{non}) \times Days}{1000} \quad \text{Equation 13.14-18}$$

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 benchmark 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 (E^3m^3) 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 (E^3m^3) 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 CO_2 and H_2S from the raw gas to meet the CO_2 and H_2S 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 CO_2 and H_2S from the raw gas stream.

The amine/gas sweetening throughput includes the total inlet gas volume in E^3m^3 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 (E^3m^3) in the refrigeration module is determined based on the configuration of refrigeration processes within a facility and is based on three scenarios, as follows:

When only one refrigeration process exists within a facility, the total gas throughput volume (E^3m^3) through this individual refrigeration processing module should be used.

When multiple refrigeration processes are run in series, the maximum throughput gas volume (E^3m^3) through any individual refrigeration processing module should be used.

When the refrigeration processes are run in parallel, the total throughput gas volume (E^3m^3) 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:

- Deethanizer - removal of spec product ethane (C2-SP);
- Depropanizer – removal of spec product propane (C3-SP); and
- 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 m^3 and converted to cubic metres of oil equivalent (m^3OE).

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 under PROC category 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:

The gas is transported through pipelines to a suitable place where it can be injected; and

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 under the “DISP” category, 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 AQM 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. Methods used should be documented in the facility’s Quantification Methodology Document.

Alberta Environment and Protected Areas recognizes that quantification of modular throughputs and production will require flexibility 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.

TABLE 13-4: METHODS FOR METERED AND NON-METERED THROUGHPUTS

Configuration	Method
Module throughput or production is not metered	Method 13-1
Module throughput or production is metered	Method 13-2

Method 13-1: 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 13-2: 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 13-1 or Method 13-2 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 13-1 or Method 13-2 instead and include a description of the difference in the Quantification Methodology Document.

TABLE 13-5: ALBERTA GAS PROCESSING INDEX WEIGHTING FACTORS

Module		Stream		Weighting Factor	
		Type	Unit	Value	Unit
1	Inlet Compression	throughput	e ³ m ³	0.03304	tCO ₂ e / e ³ m ³
2	Dehydration	throughput	e ³ m ³	0.00247	tCO ₂ e / e ³ m ³
3	Gas Sweetening	throughput	e ³ m ³	0.03040	tCO ₂ e / e ³ m ³
4	Total Refrigeration	throughput	e ³ m ³	0.01835	tCO ₂ e / e ³ m ³
5	Fractionation	production	m ³ OE	0.04141	tCO ₂ e / e ³ m ³
6	Stabilization	production	m ³ OE	0.05537	tCO ₂ e / e ³ m ³
7	Sales Compression	throughput	e ³ m ³	0.02135	tCO ₂ e / e ³ m ³
8	Sulphur Plant	production	tSulphur	0.4249	tCO ₂ e / tSulphur
9	Acid Gas Injection	throughput	e ³ m ³ Acid Gas	0.3960	tCO ₂ e / e ³ m ³ Acid Gas
10	Ethane Extraction	production	m ³ OE	0.1251	tCO ₂ e / m ³ OE
12	CO ₂ Plant	throughput	e ³ m ³ CO ₂	0.1881	tCO ₂ e / e ³ m ³ CO ₂
13	Flaring, Venting, Fugitives	production	m ³ OE	0.004452	tCO ₂ e / 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



Chapter 14

CO₂ from combustion of biomass

Alberta greenhouse gas
quantification methodologies



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14. Carbon Dioxide from Combustion of Biomass

14.1. Introduction

This chapter presents the methodologies for CO₂ emissions from the combustion of biomass, while CH₄ and N₂O emissions from the combustion of biomass are considered to be stationary fuel combustion and are covered in Chapter 1.

14.2. Level 1 - A fuel-specific default CO₂ emission factor

(1) Introduction

This method is used for biomass fuels based on a default CO₂ 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 CO₂ 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 CO₂ mass emissions. For facilities that have the quantity of fuel in energy basis, Equation 14-1a can be used directly to calculate the CO₂ 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 calculate the CO₂ mass emissions.

Calculate the CO₂ mass emissions for the reporting period for each type of biomass by substituting a fuel-specific default CO₂ 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 CO₂ 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. Level 3 - Measurement of fuel carbon content

(1) Introduction

Calculate the CO₂ 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, CO₂ mass emissions may be calculated using Equation 14-3e.

(2) Equations

For gaseous biofuels, where fuel consumption is measured in units of volume (m³), use Equation 14-3a:

$$CO_{2,p} = v_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001 \quad \text{Equation 14-3a}$$

For gaseous biofuels, where fuel consumption is measured in units of energy (GJ), use Equation 14-3b:

$$CO_{2,p} = \frac{ENE_{fuel(gas),p} \times CC_{gas,p} \times 3.664 \times 0.001}{HHV} \quad \text{Equation 14-3b}$$

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:

$$CO_{2,p} = v_{fuel(liq),p} \times CC_{liq,p} \times 3.664 \quad \text{Equation 14-3c}$$

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 p, calculated in accordance with Chapter 17 and Appendix C. CC _p is expressed in units of tonnes of carbon per kilolitres of liquid biofuel (tonnes C/kl).
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:

$$CO_{2,p} = m_{fuel(sol),p} \times CC_{sol,p} \times 3.664 \quad \text{Equation 14-3d}$$

Where:

CO _{2,p}	=	CO ₂ mass emissions for the biomass fuel during the report period, p (tonnes CO ₂)
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$m_{\text{fuel(sol)},p}$	=	Mass of biomass fuel combusted during the reporting period p, calculated in accordance with Chapter 17 and Appendix C (tonnes).
$CC_{\text{sol},p}$	=	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:

$$CO_{2,p} = \text{Steam} \times B \times EF \quad \text{Equation 14-3e}$$

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 accordance with Chapter 17 and Appendix C.
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.

14.4. Level 3A Continuous emissions monitoring systems

(1) Generality

This level 3A method may only be used if the facility is unable to apply a level 3 method. 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) through (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.

- 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.
- Report CO_2 emissions for the reporting period in tonnes based on the sum of hourly CO_2 mass emissions over the reporting period.
- 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.
- 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.
- 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).
- 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 17.1 of Chapter 17.

- (g) 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 CO₂ 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.
- (h) If a facility does not have a CEMS and chooses to add one in order to measure CO₂ 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) CO₂ emissions from combustion of mixture of biomass, or biomass fuels and fossil fuels

Use the procedures in this section to estimate biogenic CO₂ 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 CO₂ and the facility combusts biomass fuels that do not include waste-derived fuels (e.g., municipal solid waste and tires), use Level 1, 2 or 3, as applicable, to calculate the biogenic CO₂ 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 CO₂ (or O₂ as a surrogate) and the facility combusts biomass fuels that do not include waste-derived fuels, use Level 1, 2 or 3, as appropriate in Chapter 1, to calculate the CO₂ 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 CO₂ 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 CO₂ emission factor provided in Table 14-1 use the following to estimate biogenic CO₂ emissions:
 - (i) Level 1, 2, 3 or 4 to calculate the total CO₂ mass emissions for the reporting period, as applicable.
 - (ii) Determine the biogenic portion of the CO₂ 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 CO₂ emissions.
 - (iii) 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.”
 - (iv) Allocate total CO₂ 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.
 - (v) 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 Equation 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.

$$Fuel_i = \frac{[H \times Steam] - (HI)_{nb} \times (Eff)_{nb}}{(HHV)_{bio} \times (Eff)_{bio}} \quad \text{Equation 14-4}$$

Where:

Fuel_i = Quantity of biomass consumed during the measurement period i (tonnes/year or tonnes/month, as applicable) calculated in accordance with Chapter 17.

H	=	Average enthalpy increase of the boiler steam through the boiler for the reporting period (GJ/tonne) calculated in accordance with Chapter 17.
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 reporting period, based on company records of fuel usage and default or measured HHV values (GJ/month or GJ/year, as applicable) calculated in accordance with Chapter 17.
(HHV) _{bio}	=	Default or measured higher heating value of the biomass fuel (GJ/tonne) calculated in accordance with Chapter 17.
(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

- The default higher heating value for solid biomass (i.e. wood waste) is 20.44 GJ/tonne. This may be used in Equation 14-4 if the facility does not have measured higher heating values of the solid biomass consumed.
- Equation 14-4 is intended to be used for solid biomass only and not for spent pulping liquor (i.e. black liquor).

14.5. Emission Factors

TABLE 14-1: DEFAULT EMISSION FACTORS FOR BIOMASS FUELS

Biomass Fuel	CO ₂ Emission Factor		Reference ¹
	tonne/kl	tonne/GJ	
Ethanol	1.508	0.0644	ECCC Table 2-2
Biodiesel	2.472	0.0703	
	tonne/tonne	tonne/GJ	Reference
Wood Fuel / Wood Waste ²	1.715	0.0839	ECCC Table 2-3
Spent Pulping Liquor ²			
Softwood	1.270	0.0895	
Hardwood	1.230	0.0888	
Straw	1.320	0.0901	

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. Emission factors are based on 0% moisture in the fuel; therefore, in order to apply these emission factors, the fuel consumption must be adjusted to 0% moisture.



Chapter 15

Aggregate facilities

Alberta greenhouse gas
quantification methodologies

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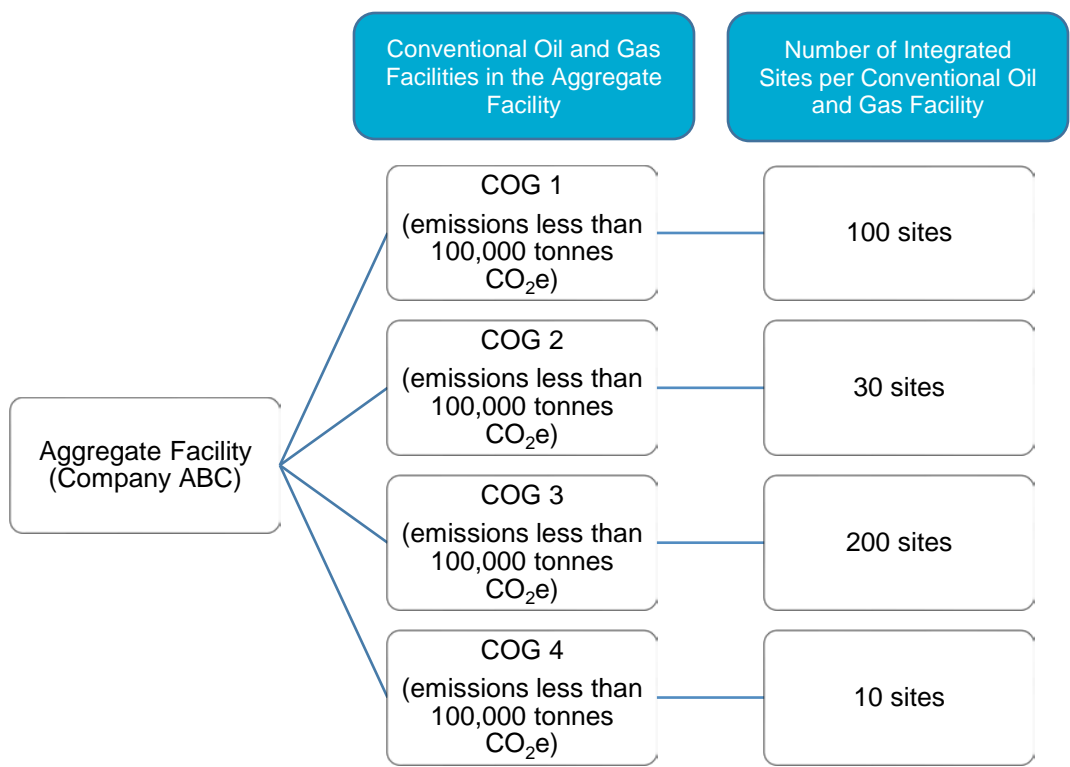
15. Aggregate Facilities

15.1. Introduction

This chapter provides quantification methodologies for stationary fuel combustion (SFC) emissions, flaring emissions and production volumes for aggregate facilities regulated under the Technology Innovation and Emissions Reduction Regulation (TIER). The quantification methodologies prescribed in this chapter are applicable for both benchmark applications and annual compliance reports. These methodologies are not applicable for other facilities regulated under TIER.

An aggregate facility consists of two or more Conventional Oil and Gas (COG) facilities. Further, multiple sites may be integrated in operation and be identified as a single COG within an aggregate facility provided each site emits less than 100,000 tonnes CO₂e per year. Figure 15-1 provides an example of an aggregate facility.

FIGURE 15-1: EXAMPLE OF AN AGGREGATE FACILITY



Throughout this chapter, criteria are provided on how to remain consistent in the application of methodologies between the benchmark and compliance periods. The same quantification methodologies should be applied to all facilities in a COG within the aggregate facility. In addition, methods used for a COG must be the same in the benchmark and compliance report. Should methods change following the benchmark setting period, a conservative methodology for re-benchmarking will apply.

Quantification methodologies for aggregate facilities are not classified by levels. The aggregate facilities should choose the most suitable methodologies for their operations and availability of data. Table 15-1 outlines the quantification methodologies provided to quantify fuel consumption, emissions from stationary fuel combustion sources, flaring emissions and production.

TIER is not intended to double price emissions from fuel consumption. If fuels used at an aggregate facility have already been subject to carbon pricing during a period when a federal fuel exemption certificate was in place, the emissions associated with these fuels should be excluded from the facility's direct emissions for compliance reporting.

TABLE 15-1: QUANTIFICATION METHODOLOGIES FOR AGGREGATED CONVENTIONAL OIL AND GAS FACILITIES

Categories	Methods
Stationary Fuel Combustion - Fuel Consumption and Composition	Method 15-1 – Single gas stream approach
	Method 15-2 – Multiple gas stream approach
	Method 15-3 – Non-Petrinex fuel
Stationary Fuel Combustion - CO₂ Emissions	Method 15-4 – Default CO ₂ emission factor for fuel gas
	Method 15-5 – Default CO ₂ emissions factors for non-variable fuels not reported in Petrinex
	Method 15-6 – CO ₂ emissions based on higher heating value (HHV) correlation
	Method 15-7 – CO ₂ emissions based on fuel gas carbon content
Stationary Fuel Combustion - CH₄ and N₂O Emissions	Method 15-8 – Non-variable fuel emission factors
	Method 15-9 – Variable fuel sector-based emission factors
	Method 15-10 – Variable fuel technology-based emission factors
Flaring CO₂ and CH₄ emissions	Method 15-11 –CO ₂ and CH ₄ emissions with flaring gas default emission factors
	Method 15-12 – CO ₂ and CH ₄ emission with flaring gas analysis
Flaring N₂O Emissions	Method 15-13 – Emission Factors
Production	Method 15-14 – Petrinex production volumes

15.2. Stationary Fuel Combustion Sources

SFC 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. 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 systems (e.g., blasting for mining purposes and drilling and completion activities). This source category does not include flare emission sources or waste incineration.

The primary greenhouse gases that are emitted from stationary fuel combustion are carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O).

This section provides quantification methodologies for fuel consumption and emissions from SFC. Based on the Table 15-1 SFC emission methods, the simplest approach for SFC emissions quantification is to apply:

- Method 15-1 for fuel consumption;
- Method 15-4 and/or Method 15-5 for carbon dioxide emissions; and
- Method 15-8 and/or Method 15-9 for methane and nitrous oxide emissions.

The quantification methodologies in this chapter are adapted from Chapter 1 Stationary Fuel Combustion with some adjustments. It is assumed that solid fuels are not combusted at aggregate facilities so quantification methodologies for solid fuels are not prescribed in this chapter. If there are solid fuels combusted at an aggregate facility, quantification methodologies prescribed in Chapter 1 must be used.

Stationary Fuel Combustion - Fuel Consumption and Composition

(1) Introduction

Fuel gas streams are characterized by varying gas compositions and higher heating values (HHVs). Common fuels consumed at COGs include fuel gas and non-variable fuels such as propane, diesel, and gasoline.

Fuel consumption at individual COGs may be calculated using the following methods:

- Method 15-1 – Fuel gas consumption based on a single gas stream treatment for reported fuels in Petrinex.
- Method 15-2 – Multiple gas streams based on varying fuel gas compositions for reported fuels in Petrinex.
- Method 15-3 – Fuel consumption of non-variable fuels or fuel gas not reported in Petrinex based on internal metering, third-party custody metering or invoices.

One or a combination of methods may be used at an individual COG to determine fuel consumption if the COG has both Petrinex fuels and non-Petrinex fuels. However, for reported fuels in Petrinex, the person responsible may only use Method 15-1 or Method 15-2 for each COG, not both.

(2) Equation

Equation 15-1 is used for the summation of fuels by fuel type for each COG.

$$v_{fuel\ i,p} = \sum_{n=1}^N v_{fuel,i,p,n} \quad \text{Equation 15-1}$$

Where:

$v_{fuel\ i,p}$	=	Total volume of fuel consumed for fuel type i at a COG in cubic meters (m^3 or kl) at standard conditions ($15^\circ C$, 1 atm) during reporting period, p .
i	=	Fuel gas type.
p	=	Reporting period.
$v_{fuel\ i,p,n}$	=	Volume of fuel for fuel type, i , combusted (m^3 or kl). For fuel gas, the volume must be at standard conditions ($15^\circ C$, 1 atm) at site, n , within the COG during the reporting period, p .
N	=	Total number of sites within the COG that uses fuel type i .

15.2.1. Method 15-1 – Single fuel gas stream approach

(1) Introduction

For this method, fuel gas volumes reported in Petrinex for a COG may be assumed to have the same gas composition and higher heating value (i.e., single fuel gas stream). For these volumes of fuel gas, a default carbon dioxide emission factor would be applied to calculate the carbon dioxide emissions (refer to Method 15-4).

(2) Equation

Using Equation 15-1, the fuels reported in Petrinex consumed by a COG are summed for the reporting period assuming that there is one fuel gas stream ($i = 1$) in the COG.

15.2.2. Method 15-2 – Multiple fuel gas stream approach

(1) Introduction

For this method, a COG is required to quantify the fuel gas consumed for each fuel gas stream that is consumed at the COG. Fuel gas streams are characterized by different gas compositions and higher heating values. This method may be used with Method 15-6 or Method 15-7 to calculate the CO_2 emissions for the COG.

(2) Equation

Using Equation 15-1, the total quantity of fuel gas consumed is calculated for each fuel gas stream ($i > 1$) consumed at a COG for the reporting period.

(3) Data requirements

- The separation of fuel gas streams must be demonstrated by metering and gas compositional analysis that is representative of the different fuel gas streams consumed by the COG in the reporting period.
- Quarterly sampling and analysis for fuel gas composition and/or HHVs is required to characterize the different fuel gas streams at a COG.
- The average gas composition and/or HHV must be calculated for each fuel gas stream using a weighted-average approach as described in Chapter 17.
- Chapter 17 provides further guidance on acceptable analytical methods that may be used for gas composition or heating value analysis.

15.2.3. Method 15-3 – Non-Petrinex Fuel

(1) Introduction

This method is required for quantifying fuel volumes that are not reported in Petrinex. Fuels that are typically not reported in Petrinex include non-variable fuels such as propane, diesel, and gasoline, which are normally invoiced by third-party. As well, there may be fuel gases not reported in Petrinex that are measured by the facility internally or by a third-party supplier.

For volumes of non-variable fuels, default carbon dioxide emission factors are applied to calculate the carbon dioxide emissions (refer to Method 15-5). For volumes of fuel gases, the reporter may use Method 15-4, Method 15-6, or Method 15-7 to calculate the carbon dioxide emissions.

(2) Equation

Using internally measured or third-party fuel volumes and Equation 15-1, the total fuel consumption is calculated for each type of non-variable fuel or fuel gas consumed at the COG for the reporting period.

(3) Data requirements

- Evidence of third-party custody metering may be in the form of invoices or other third-party documentation.
- Fuel consumption may be provided on an energy or volume basis. If the consumption is in energy units, it must be based on the higher heating value of the fuel.
- Internal facility metering should follow the requirements prescribed in Chapter 17 of the AQM.

Stationary Fuel Combustion - CO₂ Emissions

15.2.4. Method 15-4 – CO₂ emissions based on default fuel gas emission factor

(1) Introduction

For this method, the CO₂ emissions are calculated assuming a single fuel gas stream and a default emission factor (EF) in tonnes of CO₂ emissions per cubic metre of fuel consumed (tCO₂/m³). The default emission factors are presented in Table 15-2. This method is used with fuel gas volumes calculated by Method 15-1.

If this method is selected by using the default rich gas emission factor for a COG in the benchmark, it must be used for the compliance reports to keep the methodology consistent in the compliance reports with the benchmark for the COG.

If the person responsible for an aggregate facility would like to apply different methodologies for a COG, they must revise their benchmark and/or compliance report to ensure that the same methodologies are applied for both the benchmark and compliance report, or a more conservative method is used for the benchmark than the compliance report.

The default sales gas emission factor is provided in Table 15-2 and shall be applied for the following two scenarios:

1. **Benchmark development:** An aggregate facility is seeking to use the gas analysis methodology for compliance reporting, but does not have the required gas analysis for the benchmark period for a set of COGs; or
2. **Re-benchmarking:** An aggregate facility is seeking to change methodologies from the default CO₂ emission factor to the gas analysis methodology for compliance reporting, but does not have the required gas analysis for the benchmark period for a set of COGs.

(2) Equation

Using Equation 15-4, the carbon dioxide emissions for a COG are calculated using the fuel gas volumes calculated by Method 15-1 and the default emission factor presented in Table 15-2.

$$CO_{2,p} = v_{fuel,p} \times EF_{vol} \quad \text{Equation 15-4}$$

Where:

$CO_{2,p}$	=	CO ₂ mass emissions from total fuel combustion for the reporting period, p (tonnes CO ₂) in a COG.
$v_{fuel,p,i}$	=	Total volume of fuel consumed in cubic metres (m ³) for the reporting period, p at standard conditions (15°C, 1 atm) calculated using Method 15-1.
EF_{vol}	=	Default CO ₂ emission factor from Table 15-2 in tonnes of CO ₂ per cubic metres (tCO ₂ /m ³).

TABLE 15-2: DEFAULT FUEL GAS AND CARBON DIOXIDE (CO₂) EMISSION FACTORS

Parameter	Default Values
For Benchmarking and Compliance Reporting¹:	
Default Carbon Dioxide Emission Factor (volume basis (tCO ₂ /m ³))	0.00233
Default Rich Gas Composition (vol%)	
Methane (CH ₄)	80
Ethane (C ₂ H ₆)	15
Propane (C ₃ H ₈)	5
Default Higher Heating Value (GJ/m ³)	0.04477
For Benchmarking Only²:	
Default Carbon Dioxide Emission Factor (volume basis) (tCO ₂ /m ³)	0.00190
Default Sales Gas Composition (vol%)	
Methane (CH ₄)	98
Ethane (C ₂ H ₆)	1
Propane (C ₃ H ₈)	0.3
Butane (C ₄ H ₁₀)	0.1
Carbon Dioxide (CO ₂)	0.3
Nitrogen (N ₂)	0.3
Default Higher Heating Value (GJ/m ³)	0.03825

1. The prescribed CO₂ emission factor must be used for the benchmark and compliance report.
2. If a COG would like to use gas compositions or HHV to calculate CO₂ for compliance reporting but does not have gas compositions or HHV data for the benchmark period, the COG must apply this default emission factor for benchmarking.

15.2.5. Method 15-5 – CO₂ emissions for non-variable fuels not reported in Petrinex

(1) Introduction

This method is used to calculate carbon dioxide emissions from non-variable fuels that are not reported in Petrinex for an aggregate. These fuels include propane, diesel, and gasoline that are purchased for onsite operations. The compositions of these fuels are assumed to be fairly constant and therefore are provided default carbon dioxide emission factors. This method is used with fuel quantities calculated using Method 15-3.

For diesel and gasoline that is subject to the Renewable Fuels Standard (RFS) Regulation, the default CO₂ emission factors take into account the biofuel that is required as part of the fuel composition. Under the RFS, gasoline and diesel must contain an average of 5% and 2% biofuel, respectively. Note the biofuels are included in the chapter for CO₂ from biomass combustion. For facilities that have the composition of the biofuel content in the gasoline or diesel consumed, the facility may calculate the stationary fuel combustion and biomass CO₂ emissions based on actual composition instead of using the Alberta diesel and gasoline emission factors.

Note that on-site transportation emissions should not be included with the stationary fuel combustion emissions.

Fuel consumption may be provided by the third-party supplier on a volume or energy basis. Emission factors based on tonnes of CO₂ emissions per volume basis or energy basis are provided in Table 15-3.

(2) Equation

Using Equation 15-5 or 15-5a, the CO₂ emissions are calculated using the fuel volumes calculated by Method 15-3 and the default emission factor for the non-variable fuel presented in Table 15-3 for an aggregate.

$$CO_{2,p,i} = v_{p,i} \times HHV_{p,i} \times EF_{ene,i} \quad \text{Equation 15-5}$$

$$CO_{2,p,i} = (v_{pi} \times EF_{vol,i}) \text{ or } (ENE_{p,i} \times EF_{ene,i}) \quad \text{Equation 15-5a}$$

Where:

$CO_{2,p,i}$	=	CO ₂ mass emissions for the non-variable fuel type i for the reporting period, p (tonnes CO ₂) for an aggregate.
$v_{p,i}$	=	For Equations 15-5 and 15-5a, the volume of fuel for fuel type i combusted in kilolitres (kl) combusted during reporting period, p , for an aggregate
$ENE_{p,i}$	=	For Equation 15-5a, energy of fuel for fuel type i in gigajoules (GJ) combusted during reporting period, p , for an aggregate
$HHV_{p,i}$	=	Measured or supplied higher heating value in gigajoules per kilolitres (GJ/kl) for fuel type i for the reporting period, p , for an aggregate
$EF_{vol,i}$ $EF_{ene,i}$	=	Fuel-specific default CO ₂ emission factor for fuel type i from Table 15-3 in tonnes of CO ₂ per volume units (kl) or energy units (GJ).

TABLE 15-3: CARBON DIOXIDE (CO₂) EMISSION FACTORS FOR NON-VARIABLE FUELS

Non-Variable Fuels	CO ₂ Emission Factor ²	
	tonne/kl	tonne/GJ
Diesel for All Industry	2.681	0.0699
Diesel in Alberta ¹	2.610	0.06953
Biodiesel ³	See note 3	
Gasoline	2.307	0.0690
Gasoline in Alberta ¹	2.174	0.06540
Ethanol ³	See note 3	
Butane	1.747	0.0614
Ethane	0.986	0.0573
Propane	1.515	0.0599

1. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content. If the actual biofuel composition is known, a facility may use the gasoline or diesel CO₂ emission factor for the non-biofuel component and the CO₂ emission factor prescribed in Chapter 14 for the biofuel component.
2. Emission factors adapted from Environment and Climate Change Canada's (ECCC's) Canada's Greenhouse Gas Quantification Requirements, as amended.
3. CO₂ emission factors are provided in Table 14-1 in Chapter 14. CO₂ emissions from biodiesel and ethanol should be reported under the biomass emissions.

15.2.6. Method 15-6 – CO₂ emissions based on higher heating value correlation

(1) Introduction

This method is adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO₂ mass emissions from fuel gas combustion based on the measured HHV. The volumes of fuel gas consumed by a COG is calculated based on Method 15-2 or Method 15-3.

(2) Equation

Using Equation 15-6, the CO₂ emissions for a COG are calculated based on the HHV of the fuel gas provided by the fuel supplier or measured by the facility.

$$CO_{2,p,i} = v_{fuel,i,p} \times (65.53 \times HHV_{p,i} - 581.9) \times 10^{-6} \quad \text{Equation 15-6}$$

Where:

CO _{2, p,i}	=	CO ₂ mass emissions for the fuel type <i>i</i> combusted during the reporting period, <i>p</i> (tonnes CO ₂), for a COG
V _{fuel,i p}	=	Volume of fuel (m ³) for fuel type <i>i</i> at standard conditions (15°C, 1 atm) combusted during reporting period, <i>p</i> , for a COG
HHV _{p,i}	=	Weighted average higher heating value of fuel type <i>i</i> (MJ/m ³) at standard conditions (15°C, 1 atm) for the reporting period, <i>p</i> , for a COG
(65.53 × HHV _{p,i} - 581.9)	=	Empirical equation adapted from ECCC (grams of CO ₂ per cubic meter of natural gas) representing relationship between CO ₂ and volume of gas determined through higher heating value using a discrete set of data collected by ECCC.

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

(3) Data requirements

- Quarterly sampling and analysis for the fuel gas HHVs is required for each fuel gas stream identified in the COG. Sampling frequencies prescribed in Table 17-1 of Chapter 17 does not apply for this method.
- The HHV must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance for calculating weighted averages and acceptable analytical methods than can be used for heating value analysis.

15.2.7. Method 15-7 – CO₂ emissions based on fuel gas carbon content

(1) Introduction

This method is used for variable fuels and is based on the complete oxidation of the measured carbon content in the fuel gas. The volumes of fuel gas consumed by a COG is calculated using Method 15-2 or Method 15-3.

(2) Equation

Using Equation 15-7a or Equation 15-7b, the CO₂ emissions are calculated based on the carbon content of each fuel gas type consumed during the reporting period.

For gaseous fuels, where fuel consumption is measured on a volume (m³) basis, use Equation 15-7a:

$$CO_{2i,p} = V_{fuel\ gas,i,p} \times CC_{fuel\ gas,i,p} \times 3.664 \times 0.001 \quad \text{Equation 15-7a}$$

For gaseous fuels, where fuel consumption is measured on an energy (GJ) basis, use Equation 15-7b:

$$CO_{2i,p} = \frac{ENE_{fuel\ gas,i,p} \times CC_{fuel\ gas,i,p} \times 3.664 \times 0.001}{HHV_{i,p}} \quad \text{Equation 15-7b}$$

Where:

$CO_{2i,p}$	=	CO ₂ mass emissions for fuel type <i>i</i> combusted during the reporting period, <i>p</i> (tonnes CO ₂), for a COG.
$V_{fuel\ gas,i,p}$	=	Volume of fuel gas (m ³) for fuel type <i>i</i> at standard conditions (15°C, 1 atm) combusted during reporting period, <i>p</i> , for a COG
$ENE_{fuel\ gas,i,p}$	=	Energy of fuel gas (GJ) for fuel type, <i>i</i> at standard conditions (15°C, 1 atm) combusted during reporting period, <i>p</i> , for a COG.
$HHV_{i,p}$	=	Weighted average higher heating value of fuel type <i>i</i> (GJ/m ³) at standard conditions (15°C, 1 atm) for the reporting period, <i>p</i> , for a COG
$CC_{fuel\ gas,i,p}$	=	Weighted average carbon content of fuel type <i>i</i> at standard conditions (15°C, 1 atm) during the reporting period <i>p</i> , in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m ³), for a COG.
3.664	=	Ratio of molecular weights, CO ₂ to carbon.
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

- The carbon content may be provided by the third-party supplier or measured by the facility.
- Quarterly sampling and analysis for gas composition is required for each fuel gas stream identified in the COG. The gas composition must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance on calculating weighted averages and acceptable analytical methods that can be used for analysis of gas composition. Note that sampling frequencies in Table 17-1 of Chapter 17 do not apply for this method.

Stationary Fuel Combustion - CH₄ and N₂O Emissions

For all COGs, the following methods are used to calculate the CH₄ and N₂O mass emissions based on default emission factors that are volume or energy basis.

There are three types of default CH₄ and N₂O emission factors specified under three methods. Method 15-8 provides emission factors for non-variable fuels; while Methods 15-9 and 15-10 provides emission factors for variable fuels that are sector-based and technology-based, respectively.

15.2.8. Method 15-8 – Non-variable fuel emission factors

For all non-variable fuels such as propane, diesel, and gasoline, CH₄ and N₂O emission factors are provided in Table 15-4.

TABLE 15-4: DEFAULT EMISSION FACTORS FOR NON-VARIABLE FUEL TYPES

Non-Variable Fuel	CH ₄ Emission Factor ¹		N ₂ O Emission Factor ¹	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel for All industry	7.8E-05	2.0E-06	2E-05	5.8E-07
Diesel in Alberta ²	See note 3			
Biodiesel for all industry	7.8E-05	2.2E-06	2E-05	6.3E-07
Gasoline	1E-04	3.0E-06	2E-05	6E-07
Gasoline in Alberta ²	See note 4			
Ethanol	1E-04	4.3E-06	2E-05	8.5E-07
Butane	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	2.4E-05	1.4E-06	1.08E-04	6.3E-06
Propane	2.4E-05	9.5E-07	1.08E-04	4.3E-06

1. Emission factors adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements, as amended.
2. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content.
3. CH₄ and N₂O emission factors for diesel are adopted.
4. CH₄ and N₂O emission factors for gasoline are adopted.

Variable Fuel Emission Factors

Two types of emission factors are presented for variable fuels. Sector-based emission factors and technology-based emission factors are described in Method 15-9 and 15-10, respectively.

15.2.9. Method 15-9 – Variable fuel sector-based emission factors

For variable fuels, the person responsible may select sector-based emission factors that are presented in Table 15-5, if the selection criteria below have been met.

15.2.10. Method 15-10 – Variable fuel technology-based emission factors

For variable fuels, the person responsible may select technology-based emission factors provided in Table 15-6 for various equipment present at a COG, if the selection criteria below have been met.

15.2.11. Selection Criteria for Method 15-9 or 15-10

For variable fuels, the person responsible may select sector-based (Method 15-9) or technology-based (Method 15-10) CH₄ and N₂O emission factors. The following are the selection criteria:

- The person responsible must apply either the sector-based emission factors from Table 15-5 at a COG or technology-based emission factors from Table 15-6 for equipment at a COG. If combustion technologies are present which are not listed in the table 15-6, the sector-based emission factor in Table 15-5 should be used.
- The person responsible must apply the same methodologies selected for each COG in the benchmark and compliance report.
- If technology-based emission factors are selected for any COG, technology-based emission factors may be different between the benchmark and compliance report to reflect technologies that are present at the sites during the benchmark or compliance periods. For example, the person responsible may use a NO_x uncontrolled boiler emission factor for the benchmark, but apply a NO_x controlled boiler emission factor in the compliance report to reflect technologies used during the compliance period. As well, different technology-based emission factors may be applied within a compliance or benchmark period if technologies were replaced within the compliance or benchmark period.
- If a facility has the HHV for the fuel, the energy-based emission factor (tonnes of emissions per gigajoules) must be used to calculate CH₄ and N₂O. Otherwise, the facility may use the volume-based emission factors (tonnes of emissions per cubic metre) if HHV data is not available.
- If an energy-based emission factor is used, quarterly sampling and analysis for fuel gas composition and/or HHVs is required to characterize the different fuel gas streams at a COG.

(1) Equation

Using Equation 15-8 or Equation 15-8a, the CH₄ or N₂O emissions are calculated based on volumes calculated by Method 15-1, Method 15-2, or Method 15-3.

$$CH_{4,p} \text{ or } N_2O_p = Fuel_p \times HHV \times EF_{ene} \quad \text{Equation 15-8}$$

$$CH_{4,p} \text{ or } N_2O_p = Fuel_p \times (EF_{vol} \text{ or } EF_{ene}) \quad \text{Equation 15-8a}$$

Where:

$CH_{4,p} \text{ or } N_2O_p$	=	CH ₄ or N ₂ O mass emissions for the specific fuel type for the reporting period, <i>p</i> , (tonnes CH ₄ or N ₂ O).
$Fuel_p$	=	For Equation 15-8, the quantity of fuel combusted in kilolitres or cubic metres (kl or m ³) at standard conditions (15°C, 1 atm) combusted during reporting period, <i>p</i> . For Equation 15-8a, energy of fuel in gigajoules or quantity of fuel in kilolitres, or cubic metres (GJ, kl, or m ³) combusted during reporting period, <i>p</i> .
HHV_p	=	Measured or supplied higher heating value in gigajoules per kilolitres or cubic metres (GJ/kl or GJ/m ³) at standard conditions (15°C, 1 atm) for the reporting period, <i>p</i> .
EF_{vol}, EF_{ene}	=	Default emission factor: Sector-based emission factors from Table 15-5 or technology-based emission factors from Table 15-6 in tonnes of CH ₄ or N ₂ O per energy units (GJ) or volume units (kl or m ³).

TABLE 15-5: SECTOR-BASED CH₄ AND N₂O EMISSION FACTORS FOR FUEL GAS

Sectors	CH ₄ Emission Factor		N ₂ O Emission Factor	
	tonne/m ³	tonne/GJ	tonne/m ³	tonne/GJ
Oil and Gas Sector and Producer Consumption ¹	6.4E-06	1.4E-04	6.0E-08	1.3E-06

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended.

TABLE 15-6: TECHNOLOGY-BASED CH₄ AND N₂O EMISSION FACTORS FOR FUEL GAS

Natural Gas	CH ₄ Emission Factor ¹		N ₂ O Emission Factor ²	
	tonne/m ³	tonne/GJ ³	tonne/m ³	tonne/GJ ³
Boilers/Furnaces/Heaters				
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07
Internal Combustion Engine				
Turbine	1.4E-07	3.7E-06	4.9E-08	1.3E-06
2 stroke lean ⁴	2.37E-05	6.23E-04	-	-
NOx 90-105% Load	-	-	7.77E-07	2.04E-05
NOx < 90% Load	-	-	4.75E-07	1.25E-05
4 stroke lean ⁴	2.04E-05	5.37E-04	-	-
NOx 90-105% Load	-	-	1.00E-06	2.63E-05
NOx < 90% Load	-	-	2.07E-07	5.46E-06
4 stroke rich ⁴	3.76E-06	9.89E-05	-	-
NOx 90-105% Load	-	-	5.41E-07	1.43E-05
NOx < 90% Load	-	-	5.56E-07	1.46E-05

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) for the volume-based emission factor.
2. Emission factors are adapted from USEPA AP-42 Chapters 1 and 3.
3. The energy-based emission factor should be used if the fuel consumption on an energy basis is available. The volume-based emission factor should only be used if the higher heating value or energy of the fuel is not available.
4. The N₂O emission factor is based on 1.5% of the NOx emission factor, as provided in AP-42.

15.3. Flaring Emissions

Flaring emissions are direct emissions from the controlled combustion of a gas or liquid stream produced at the facility, used for routine, non-routine, or emergency disposal of a hazardous waste stream, where the main purpose is not energy production. There are a variety of flare and incineration technologies including flare pits, ground flares, flare stacks, enclosed flares and incinerators and combustors. For the definition of flaring technologies and routine/non-routine flaring refer to the Alberta Energy Regulator (AER) Directive 60. Methodologies for flaring/incineration of liquid fuel streams are not presented in this chapter.

Typical gases that are flared or incinerated include, but are not limited to waste petroleum gas, refinery or still gas, purge gas, pilot or assistance gas, and biogas. Flaring or incineration commonly occurs at the following types of operations:

- well testing;
- natural gas gathering system;
- processing plant operations;

- crude oil production;
- pipeline operations.

Note that CO₂ that is entrained in the fuel (or previously referred to as formation CO₂) is reported as an emission in the respective categories that the fuel is consumed in. For example, if there is entrained CO₂ within a fuel that is combusted or flared, it would be included in the CO₂ that is emitted in the stationary fuel combustion or flaring categories, respectively.

The flare combustion efficiency is defined as the mole or volume fraction of combustible carbon in the flare gas that is converted to CO₂ during the flaring process, which can be expressed as a percentage of carbon combusted or oxidized.

For the quantification of flaring emissions, the following flare combustion efficiencies were adopted from flare efficiency and thermal oxidizer studies conducted and published by the USEPA:

- 98.0% flare combustion efficiency for unassisted flares. These flares are typically found in remote oil and gas production operations;
- 99.5% flare combustion efficiency for properly operated, highly-turbulent, air- or steam-assisted flares. These flares are typically found in gas plants, upgraders, petroleum refineries, and chemical plants; and
- 100.0% flare combustion efficiency for incinerators, oxidizers, or other “external combustion” units that operate like boilers. As a conservative approach, methane emissions are calculated based on emission factors.

The above flaring efficiencies were applied to develop the default flaring CO₂ and CH₄ emission factors in method 15-11. COG facilities should select one representative efficiency from three default flaring efficiencies when the method 15-12 is used.

Sampling and measurement frequencies are prescribed in the quantification methodologies presented in this chapter.

15.3.1. Method 15-11 – CO₂ and CH₄ emissions with flaring gas default emission factors

(1) Introduction

CO₂ emissions from flares are generated from the oxidization of carbon in the flare gas and from any carbon dioxide entrained in the flare gas. Methane in the flare gas that is un-oxidized is released as methane emissions.

The Default Emission Factor Method is based on default CO₂ and CH₄ emission factors which were developed for different fuel gas types (sale gas, rich gas and acid gas), non-variable fuels (ethane, propane and butane) for three default flaring efficiencies provided in section 15.3. The assumed gas compositions for default CO₂ emission factors are presented under Table 15-7.

CH₄ factors are provided in Table 15-8 representing the un-combusted CH₄ in the flare gas based on the flare combustion efficiency. For incineration, methane emissions are conservatively added even though the incineration combustion efficiency was assumed to be 100%.

This method provides default emission factors for facilities that do not have gas analysis but have knowledge of the flare gas properties such as the higher heating value (HHV), or whether it is rich, sale or acid gas being sent to flare stack. Facilities are required to select emission factors from Tables 15-7 and 15-8 that would be the most representative of the flare gas. If the HHV of the flare gas falls between two HHVs in the tables, the facility is required to choose the emission factor with the higher HHV.

(2) Equations

For each flare source, use Equation 15-9a or Equation 15-9b to calculate the CO₂ and CH₄ mass emissions.

$$GHG = \sum_{F=1}^N V_{FL,F} \times EF_{vol,F} \times 10^{-6} \quad \text{Equation 15-9a}$$

$$GHG = \sum_{F=1}^N ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6} \quad \text{Equation 15-9b}$$

Where:

GHG	=	CO ₂ or CH ₄ mass emissions from flaring (tonnes) for the reporting period.
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
$V_{FL,F}$	=	Volume of the flare gas stream, F, at a flare source (standard cubic meters, sm ³) at standard conditions for the reporting period.
$ENE_{FL,F}$	=	Energy of the flare gas stream, F, at a flare source (MJ) for the reporting period.
$EF_{vol,F}$	=	Default CO ₂ or CH ₄ emission factor, selected from Table 15-7 or Table 15-8 (g/m ³).
$EF_{ENE,F}$	=	Default CO ₂ or CH ₄ emission factor, selected from Table 15-7 or Table 15-8 (g/MJ).
10^{-6}	=	Mass conversion factor (tonne/g).

TABLE 15-7: DEFAULT CO₂ FLARING EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	CO ₂ Emission Factors						
	Higher Heating Value ² (MJ/m ³)	Open Flares				Incinerators	
		Unassisted		Assisted			
		98.0% Efficiency ¹		99.5% Efficiency ¹		100% Efficiency ¹	
		(g/m ³)	(g/MJ)	(g/m ³)	(g/MJ)	(g/m ³)	(g/MJ)
Mixed Gas Types							
Sales gas ³	38.02	1,853	48.75	1,882	49.49	1,900	49.74
Rich gas ³	44.77	2,280	50.93	2,315	51.70	2,330	51.96
Acid gas ⁴	-	1,768	-	1,768	-	1,768	-
Non-Variable Gas Types							
100% Methane (C1)	37.708	1,824	48.37	1,852	49.11	1,861	49.36
100% Ethane (C2)	66.065	3,648	55.22	3,704	56.07	3,723	56.35
100% Propane (C3)	93.936	5,472	58.25	5,556	59.15	5,584	59.44
100% Butane (C4)	121.600	7,296	60.00	7,408	60.92	7,445	61.23

1. Flare combustion efficiencies have been applied in the emission factors.
2. Molecular weights used for EF development and HHVs are from Gas Processors Association 2145-09.
3. Default gas compositions used in the development of the emission factors are:
 - Sales gas - 98% CH₄, 1% C₂H₆, 0.3% C₃H₈, 0.1% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Rich gas - 80% CH₄, 15% C₂H₆, 5% C₃H₈
4. Default acid gas composition is assumed to be 95% CO₂ and CH₄ is not assumed to be a component of the acid gas. If the hydrocarbon content is over 5% in a flare gas stream, the facility is required to apply an alternative default emission factor that is more representative of the flare gas.

TABLE 15-8: DEFAULT CH₄ FLARING EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	Methane Emission Factors						
	Higher Heating Value ³ (MJ/m ³)	Open Flares				Incinerators ²	
		Unassisted		Assisted			
		(98.0% Efficiency) ¹		(99.5% Efficiency) ¹		(100% Efficiency) ¹	
		(g/m ³)	(g/MJ)	(g/m ³)	(g/MJ)	(g/m ³)	(g/MJ)
Mixed Gas Types							
Sales gas ⁴	38.02	13.27	0.35	3.32	0.09	0.037	0.0010
Rich gas ⁴	44.77	10.83	0.24	2.71	0.06	0.044	0.0010
Acid gas ⁵	-	0	-	0	-	0	-
Non-Variable Gas Types							
100% Methane	37.708	13.54	0.36	3.39	0.09	0.037	0.001
100% Ethane (C2)	66.065	0.00	0.00	0.00	0.00	0.00	0.00
100% Propane (C3)	93.936	0.00	0.00	0.00	0.00	0.00	0.00
100% Butane (C4)	121.600	0.00	0.00	0.00	0.00	0.00	0.00

1. Flare combustion efficiencies have been applied in the development of emission factors in the table.
2. Methane emission factors for incinerators are based on ECCC's Canada's Greenhouse Gas Quantification Requirements as amended, and are adjusted by HHVs of the different fuel types.
3. Molecular weights used for EF development and HHVs for each single compound are from Gas Processors Association 2145-09.
4. Default gas compositions used in the development of the emission factors are:
 - Sales gas - 98% CH₄, 1% C₂H₆, 0.3% C₃H₈, 0.1% C₄H₁₀, 0.3% CO₂, 0.3% N₂
 - Rich gas - 80% CH₄, 15% C₂H₆, 5% C₃H₈
5. Default acid gas composition is assumed to be 95% CO₂ and CH₄ is not assumed to be a component of the acid gas. If the hydrocarbon content is over 5% in a flare gas stream, the facility is required to apply an alternative default emission factor that is more representative of the flare gas.

(3) Data requirements

- If a facility finds errors in the reported Petrinex flare volumes or missed flare volumes reported to Petrinex, the facility should correct the Petrinex data before applying the corrected flare volumes for an aggregate benchmark and compliance reports.
- The flaring volume should be based on the flaring volume reported to Petrinex by the facility. The volumetric emission factors can then be applied based on the type of flare gas.
- The total flare gas volumes for different flaring efficiencies or flaring gas types should align with the reported flaring volumes in Petrinex.
- The selected methods used for benchmark and compliance reports should be consistent for a COG of the aggregate facility. However, if a COG of the aggregate facility uses gas analysis for compliance reports and the gas analysis is not available in the benchmark development, the facility must use the sale gas emission factor for the benchmark.
- Based on the facility's knowledge of the flare gas composition and flare technology, select the appropriate emission factors in Tables 15-7 and 15-8 for the flare gas type and flare efficiency.

15.3.2. Method 15-12 – CO₂ and CH₄ emission with flaring gas analysis

(1) Introduction

This method uses estimated or measured gas volumes and compositions for all or part of flare gas streams to calculate CO₂ and CH₄ emissions. The gas streams may be combined and flared as a single flare gas source or are sent to the flare stacks as multiple streams. The method is applicable for flare gas streams that are flared under routine or non-routine conditions.

Flare gas streams may have measured volumes and compositions of gases that are routinely flared such as assistant gas, pilot gas, or purge gas streams and unmeasured streams from venting sources or abnormal operating conditions, start-up or shutdown operations, or process malfunctions where measurements of flare gas volumes and/or gas compositions is not operationally possible.

These measured flare gas streams may be equipped with online analyzers or measured regularly. Unmeasured volumes or compositions of flare gas may be calculated based on engineering estimates, manufacturer specifications or fuel mass balance method.

(2) Equations

For each flare source, use Equation 15-10a and 15-10b to calculate the total CO₂ mass emissions from the flaring of multiple flare gas streams that are combined.

$$CO_{2,flaring} = \sum_{F=1}^N \frac{V_{FL,F}}{MVC} \times (CC_F \times CE_{FL} + MF_{CO_2}) \times MW_{CO_2} \times 0.001 \quad \text{Equation 15-10a}$$

$$CC_F = \sum_{i=1}^I MF_{i,F} \times NC_{i,F} \quad \text{Equation 15-10b}$$

Where:

$CO_{2, flaring}$	=	Total CO ₂ mass emissions from a flare source including entrained CO ₂ for the reporting period (tonnes).
N	=	Total number of flare gas streams.
F	=	Flare gas stream.
$V_{FL,F}$	=	Measured or estimated volume of the flare gas stream, F , (sm ³) at standard conditions for the reporting period.
MVC	=	Standard molar volume at standard conditions as defined in Appendix B, Table B-2 (23.645 m ³ /kmol).
CC_F	=	Average carbon content for flare gas stream, F , (kmol _{carbon} /kmol _{flare gas, F}) for the reporting period. This excludes carbon from entrained CO ₂ in the flare gas.
MF_{CO_2}	=	CO ₂ mole fraction in flare gas stream, F .
MW_{CO_2}	=	Molecular weight of CO ₂ (kg/kmol), as provided in Appendix B.
0.001	=	Mass conversion factor (tonne/kg).
I	=	Total number of components in the flare gas stream, F .
i	=	Type of component.
CE_{FL}	=	Flare combustion efficiency (%), selected from three default flaring efficiencies under section 15.3.

$MF_{i,F}$ = Normalized mole fraction of component, i , based on the estimated or measured weighted average flare gas composition in the flare gas stream, F , ($\text{kmol } i / \text{kmol}_{\text{flare gas}}$) for the reporting period.

$NC_{i,F}$ = Number of carbons in component, i , in the flare gas stream, F .

For methane emissions, use Equation 15-11 to calculate un-combusted methane from the flare gas, other than flare gas combusted by incineration:

$$CH_{4,flaring} = \sum_{F=1}^n [V_{FL,F} \times MF_{CH_4,F}] \times (1 - CE_{FL}) \times \frac{MW_{CH_4}}{MVC} \times 0.001 \quad \text{Equation 15-11}$$

Where:

$CH_{4,flaring}$ = Total CH_4 mass emissions from a flare source for the reporting period (tonnes);

$V_{FL,F}$ = Measured or estimated volume of flare gas stream, F , (sm^3) at standard conditions for the reporting period.

$MF_{CH_4,F}$ = Normalized mole fraction of CH_4 in estimated or measured average flare gas composition for flare gas stream, F ($\text{kmol}_{CH_4} / \text{kmol}_{GAS}$) for the reporting period.

n = Number of flare gas streams.

F = Flare gas stream.

CE_{FL} = Flare combustion efficiency (%).

MW_{CH_4} = Molecular weight of CH_4 (kg/kmol), as provided in Appendix B.

MVC = Standard molar volume conversion at standard conditions as provided in Appendix B, Table B-2 ($23.645 \text{ m}^3/\text{kmol}$).

0.001 = Mass conversion factor (tonne/kg).

(3) Data requirements

For using the method 15-12, the facility must have measured volumes and gas compositions for a minimum of 60% by volume of total flare gas streams. The following data requirements are applicable if this method is selected:

- If a facility finds errors in the reported Petrinex flare volumes or missed flare volumes reported to Petrinex, the facility should correct the Petrinex data before applying the corrected flare volumes for an aggregate benchmark and compliance reports.
- The total flare volumes for all multiple flare streams should be equal to the reported flare volumes in Petrinex.
- For pilot, purge, or assistance gas used for flaring,
 - Where the fuel type is known (i.e., propane, butane, rich gas, sales gas, etc.), the facility may use the default gas composition of the fuel type listed in Table 15-7 and Table 15-8.
 - The volume or gas composition of the pilot, purge, or assistance gas may be calculated using a mass balance approach as described in Method 1-4 in Section 1.2.5 in Chapter 1.
 - If measured gas compositions of the pilot, purge or assistance gas are used, quarterly sampling and analysis is required. A weighted average of the gas composition is required based on the quarterly measurements.
- For flare gas that is measured other than the pilot, purge, or assistance gas:
 - If there is online instrumentation, the volume and gas composition measurements must be taken daily at minimum. For online continuous measurement, a weighted gas composition must be used in calculating

emissions based on the sampling frequency. If the actual sampling frequency is higher than the prescribed daily frequency, the facility must apply the higher frequency in the weighted average.

- If online continuous measurements of gas compositions is not available, quarterly sampling and analysis is required. For compliance reporting, a weighted average of the gas composition is required based on measurements from the two quarters within the compliance year with the highest carbon contents. For benchmarking, a weighted average of the gas composition is required based on measurements from the two quarters within the benchmark year with the lowest carbon contents.
- The volume and gas composition of the remaining unmeasured flare gas streams may be estimated using engineering estimates, a mass balance, or manufacturer specifications.
- For a waste gas flare stream where the volume is not measured, but the flare gas stream is from a controlled venting emission source, the venting volume may be quantified using quantification methodologies provided in Chapter 4 Venting. Refer to the data requirements in Section 2.3.2 (Method 2-1).
- If flare gas volumes and/or gas composition measurements are missing in a reporting period, the missing data procedures outlined in Section 17.5.2 of Chapter 17 should be followed.
- The facility must select a default flare combustion efficiency provided in the Chapter that best represents the flare technology that is applied at the facility. The selection must be supported by manufacturer specification or test data.
- If the sum of the mole fractions of components do not add up to 1.000 because smaller components are excluded from the analysis or are not measurable, facilities must normalize the mole fractions of the measured components to 1.000.

15.3.3. Method 15-13 – Flaring N₂O Emissions

(1) Introduction

Default N₂O emission factors are assumed to be independent of the flare combustion efficiencies and dependent on flare gas type. N₂O Emissions factors are provided in the Table 15-9 and applicable to all flaring types including incinerators, oxidizers, or other external combustion units (e.g. enclosed combustors).

(2) Equations

For each flare source, calculate the N₂O mass emissions using Equation 15-12a or Equation 15-12b.

$$N_2O = \sum_{F=1}^N V_{FL,F} \times EF_{vol,F} \times 10^{-6} \quad \text{Equation 15-12a}$$

$$N_2O = \sum_{F=1}^N ENE_{FL,F} \times EF_{ENE,F} \times 10^{-6} \quad \text{Equation 15-12b}$$

Where:

N_2O	=	N ₂ O mass emissions from a flare source for the reporting period (tonnes of N ₂ O).
F	=	Flare gas stream.
N	=	Total number of flare gas streams.
$V_{FL,F}$	=	Volume of the flare gas stream, F, at a flare source (sm ³) at standard conditions for the reporting period. Volumes for non-variable fuel types such as ethane, propane and butane are measured in gas phase.
$ENE_{FL,F}$	=	Energy of the flare gas stream, F, at a flare source (MJ) for the reporting period.
$EF_{vol,F}$	=	Default N ₂ O emission factor in volumetric basis, selected from Table 15-9 (g/m ³).
$EF_{ENE,F}$	=	Default N ₂ O emission factor in energy basis, selected from Table 15-9 (g/MJ).

TABLE 15-9: DEFAULT N₂O EMISSION FACTORS FOR DIFFERENT FLARE GAS TYPES

Flare Gas Type	N ₂ O	
	(g/m ³)	(g/MJ)
Hydrocarbon gas (sales gas and rich gas) ¹	0.033	0.00087
100% Ethane (C ₂) ²	0.033	0.00050
100% Propane (C ₃) ²	0.033	0.00035
100% Butane (C ₄) ²	0.033	0.00027
Other Flare gas (not covered above) ³	0.0066	-

1. Natural gas combustion emission factor for the industrial sector adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements, as amended.
2. Natural gas combustion emission factor for the industrial sector is adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended, and adjusted by the HHV of the fuel for an energy-based emission factor.
3. Emission factor for other flare gas is assumed to be 20% of the hydrocarbon gas emission factor of 0.033 g/m³.

(3) Data requirements

- If a facility finds errors in the reported Petrinex flare volumes or missed reporting flare volumes to Petrinex, the facility should correct the Petrinex data before applying the corrected flare volumes for an aggregate benchmark and/or compliance reports.
- The flare volume should use the flare volume reported to Petrinex by a COG facility. The volumetric emission factors from Table 15-9 can then be applied.
- For flaring using method 15-12 with gas measurements for CO₂ emissions calculations for certain gas streams, the same measured volumes and HHV as used for CO₂ calculation must be used for N₂O calculation.

15.4. Aggregate Facility Production Quantification

Product data quantification and reporting procedures for aggregate facility will be tied to production accounting volumes, referred to as Method 15-14.

15.4.1. Method 15-14 – Petrinex production volumes

The product that an aggregate facility will report is based on a benchmark unit assigned or approved by the department. Aggregate facilities production volumes for the product unit should be quantified using the reported volumes in Petrinex for each COG in the aggregate and reported as Oil Equivalent in Cubic Meters (OE m³) in accordance with this section and Chapter 9 of the Standard for Developing Benchmarks.

COG facilities in Alberta report volumetric data to Petrinex. Each volumetric submission must identify the activity, the product and the associated volume. Please refer to Appendix 1, 2, and 3 from Manual 011, published by AER for the activity and products required to be reported to Petrinex. These volumetric submissions will be the used for quantification and reporting under TIER. Figure 15-2 shows the volumetric submission for an example COG facility in Alberta.

FIGURE 15-2: AN EXAMPLE OF THE FACILITY ACTIVITY PAGE FOR A TYPICAL COG FACILITY

Query Volumetric Submission

Facility ID:
Location: 00-01-01-001-01W4
 Production Month:

Name: Alberta Gas Plant
 Amendment #:

Reference Code:
Submitted:

AER Extracted:

View:

Filters:
Activity
Product
From/To

<input type="button" value="Save to WIP"/> <input type="button" value="Report"/> <input type="button" value="Cancel"/>				
Activity	Product	From/To	Volume	Energy
REC	GAS	AB GP 0000001	390.8	
REC	GAS	AB GS 0000001	13977.1	
REC	GAS	AB GS 0000001	370.3	
DISP	GAS	AB MS 0000001	11133.5	448269
FUEL	GAS	AB GP 0000001	3029.3	
FLARE	GAS	AB GP 0000001	56.8	
REC	WATER	AB WC	804.1	
DISP	WATER	AB IF 0000001	792.1	
DISP	WATER	AB WP 0000001	12.0	
FRAC	C3-SP		2006.3	
DISP	C3-SP	AB OT	1535.2	
DISP	C3-SP	WA	806.7	
INVOP	C3-SP		526.5	
INVCL	C3-SP		851.0	
FRAC	C4-SP		1564.8	
DISP	C4-SP	AB OT	2681.8	
INVOP	C4-SP		496.8	
INVCL	C4-SP		580.0	



Chapter 16

Cogeneration benchmark calculation

Alberta greenhouse gas
quantification methodologies



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16. Cogeneration Benchmark Calculation

16.1. Introduction

This chapter provides quantification guidelines to support large emitters and opted-in facilities submitting benchmark applications under the Technology Innovation and Emissions Reduction (TIER) Regulation when there is cogeneration of electricity and heat or generation of electricity from heat along with the production of other regulated products within the facility boundary.

The TIER approach for benchmarking sees integrated cogeneration as functionally separated from the production process. Integrated cogeneration is treated as if it occurred outside of the facility. For benchmarking calculations, cogeneration emissions are removed from TRE, and the “indirect” emissions associated with electricity and industrial heat used in production are added back in. In this way, a consistent allocation is applied in setting product benchmarks for both facilities that have integrated cogeneration and facilities that make use of imported heat and electricity from sources outside of the facility boundary.

This chapter provide instruction on how to calculate emissions from cogeneration, heat cogenerated and electricity cogenerated. These values are required for the calculation of facility specific benchmarks as described in Part 3, Sections 8.2.5 and 8.2.6 of the Standard for Developing Benchmarks and this guidance is a supplement to assist in the development of inputs to the benchmarking calculation.

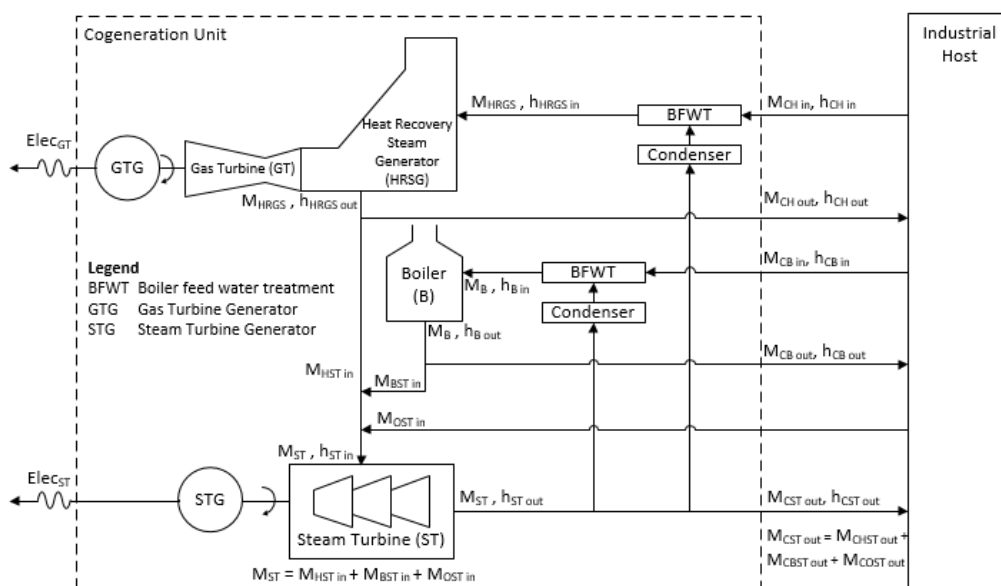
16.2. Integrated Cogeneration

Integrated cogeneration occurs in a facility that produces regulated products other than industrial heat and electricity.

16.2.1. Integrated Cogeneration Flow Diagram

Figure 16-1 illustrates a cogeneration unit consisting of a gas turbine coupled with its electrical generator, a heat recovery steam generator (HRSG), and a steam turbine coupled with its generator. In this simplified diagram, the cogeneration unit is illustrated next to an industrial host, which represents the section of the facility that uses the electricity and/or heat cogenerated for the production of the products of the facility. Both, the cogeneration unit and the industrial host in this diagram are located within the same regulated facility boundary.

FIGURE 16-1: SIMPLIFIED PROCESS DIAGRAM OF COGENERATION UNIT



16.2.2. Emissions

$$EE_{cogeneration} = E_{GT} + E_{HRSG} + E_B \times \frac{(h_{Bout} - h_{STout})M_{BST\ in}}{(h_{Bout} - h_{Bin})M_B} + E_O$$

Where:

$EE_{cogeneration}$	is the emissions from fossil fuel combustion, CH ₄ and N ₂ O from biomass combustion attributable to cogeneration at the facility.
E_{GT}	is the emissions from the combustion of fuel at the gas turbine
E_{HRSG}	is the emissions from the combustion of fuel at the HRSG
E_B	is the emissions from fossil fuel combustion, CH ₄ and N ₂ O from biomass combustion at the boiler
h_{STin}	is the enthalpy of steam at the inlet of the steam turbine
h_{STout}	is the enthalpy of steam at the outlet of the steam turbine
$M_{BST\ in}$	is the mass flow from the boiler that goes through the steam turbine
h_{Bout}	is the enthalpy of steam at the exit of the boiler
h_{Bin}	is the enthalpy of steam at the inlet of the boiler
M_B	is the mass flow through the boiler
E_O	is the onsite emissions from fossil fuel combustion, CH ₄ and N ₂ O from biomass combustion associated to the mass flow from sources other than the HRSG or the boiler that go through the steam turbine. This is 0, when this steam is imported from outside the facility boundary. Contact the department for instruction on how to allocate emissions to other steam streams.

The above equation assumes mass conservation across the steam turbine where the mass flow entering the steam turbine equals the mass flow exiting the steam turbine and where the steam entering the turbine comes from three different sources:

$$M_{ST} = M_{HST\ in} + M_{BST\ in} + M_{OST\ in}$$

Where:

M_{ST}	is the mass flow through the steam turbine
$M_{HST\ in}$	is the mass flow from the HRSG that goes through the steam turbine
$M_{OST\ in}$	is the mass flow from other sources other than the HRSG or the boiler that go through the steam turbine. Other sources include steam imported from outside the facility boundary, steam that enters the boiler directly from other processes within the industrial host, etc.

16.2.3. Electricity

$$Elec_{Cogenerated} = Elec_{GT} + Elec_{ST}$$

Where:

$Elec_{Cogenerated}$	is the outflow of electrical energy across the boundary of the cogeneration unit sent to the industrial host and the electricity grid. Electricity cogenerated is net of station loads integral to the function of the cogeneration unit, for example, auxiliary power, start-up, pumps, control systems, etc.
$Elec_{GT}$	is the electricity generated by the gas turbine net of station load

$EleC_{ST}$ is the electricity generated by the steam turbine net of station load

16.2.4. Heat

$$H_{cogeneration} = M_{CHST\ out}(h_{CST\ out}) + M_{CH\ out}(h_{CH\ out}) - M_{CHin}(h_{CHin})$$

Where:

$H_{cogeneration}$	is the net useful heat produced at the facility through cogeneration
$M_{CHST\ out}$	is mass flow from the HRSG that went through the steam turbine and then exited the cogeneration unit boundary
$h_{CST\ out}$	is the enthalpy of mass flow exiting the cogeneration unit boundary from the steam turbine
$M_{CH\ out}$	is mass flow exiting the cogeneration unit boundary from the HRSG without going through the steam turbine
$h_{CH\ out}$	is enthalpy of mass flow exiting the cogeneration unit boundary from the HRSG without going through the steam turbine
$M_{CH\ in}$	is mass flow entering the cogeneration unit boundary to go through the HRSG
$h_{CH\ in}$	is the enthalpy of mass flow entering the cogeneration unit boundary to go through the HRSG

Non-usable thermal energy streams should not be included in the calculation of $H_{cogeneration}$ as they do not provide useful energy to the industrial host. These streams include boiler blowdown, condenser cooling water, etc. For this reason, boiler feed water treatment and condensers are included inside the boundary of the cogeneration unit in Figure 16-1.

$M_{CHST\ out}$ relates to $M_{CST\ out}$ from Figure 16-1 as follow:

$$M_{CST\ out} = M_{CHST\ out} + M_{CBST\ out} + M_{COST\ out}$$

Where:

$M_{CST\ out}$	Is the mass flow that went through the steam turbine and then exited the cogeneration unit boundary
$M_{CBST\ out}$	is the mass flow from the boiler that went through the steam turbine and then exited the cogeneration unit boundary
$M_{COST\ out}$	is the mass flow from other sources that went through the steam turbine and then exited the cogeneration unit boundary

For benchmarking calculations under TIER Regulation, facilities' cogeneration emissions ($EE_{cogeneration}$), are part of the facilities' Self-generation Emissions (EE) that are subtracted from Total Regulated Emissions (TRE).

Emissions from electricity used ($E_{electricity\ used}$) and emissions from heat used ($E_{heat\ used}$) are added back to the benchmark equations.

$EleC_{Cogenerated}$ is included in the facilities' Electricity Self-Generated ($EleC_{self-generated}$) that go into the $E_{electricity\ used}$ equation.

$H_{cogeneration}$ is part of the $E_{heat\ used}$ equation .

Refer to Part 3, section 8.2.5 and section 8.2.6 of the Standard for Developing Benchmarks for the complete set of equations to calculate facility specific benchmarks.

Please note that all the equations above apply to facilities that are submitting benchmark applications with new data sets. For facilities, which benchmarks are being based on Specified Gas Emitters Regulation (SGER) data on record the following equations apply:

$$EE_{cogeneration} = G_T$$

$$E_{heat\ used} = D_h + (H_{import} - H_{export}) HPB_{heat}$$

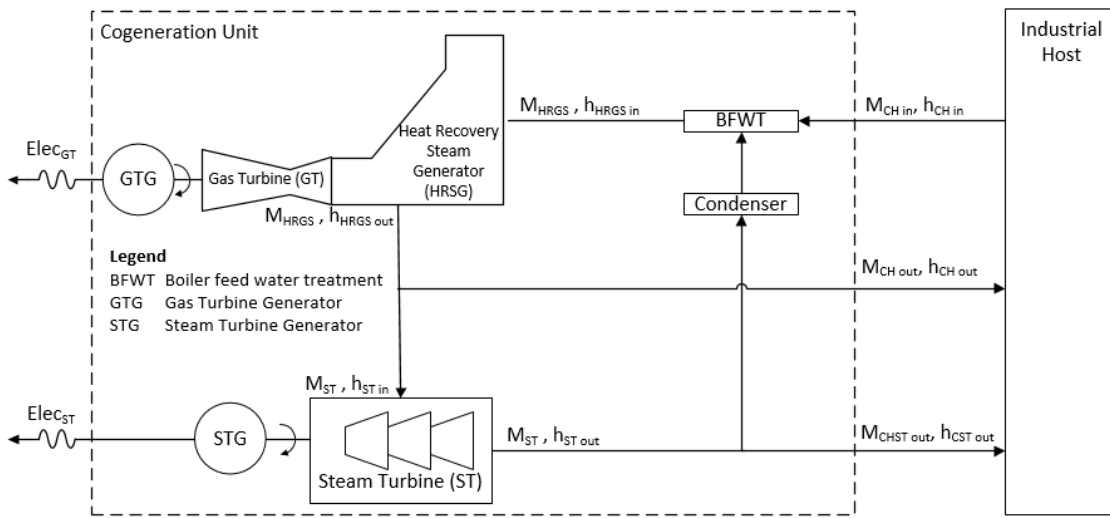
Where:

G_T	is the SGER total GHG emissions from fossil fuel combustion, CH ₄ and N ₂ O from biomass combustion attributable to cogeneration at the facility.
D_h	is the SGER deemed emissions attributable to production of heat from cogeneration at the facility
H_{import}	is the heat imported into the facility that was generated outside of the facility boundary.
H_{export}	is the heat exported from the facility by being moved outside of the facility boundary
HPB_{heat}	is the high-performance benchmark for heat.

Find below, 2 simplified diagrams for facilities with simpler cogeneration unit configurations. All the terms in the equations have been previously defined in this guideline.

16.3. Integrated Cogeneration with Steam Turbine

FIGURE 16-2: SIMPLIFIED PROCESS DIAGRAM OF COGENERATION UNIT WITH STEAM TURBINE



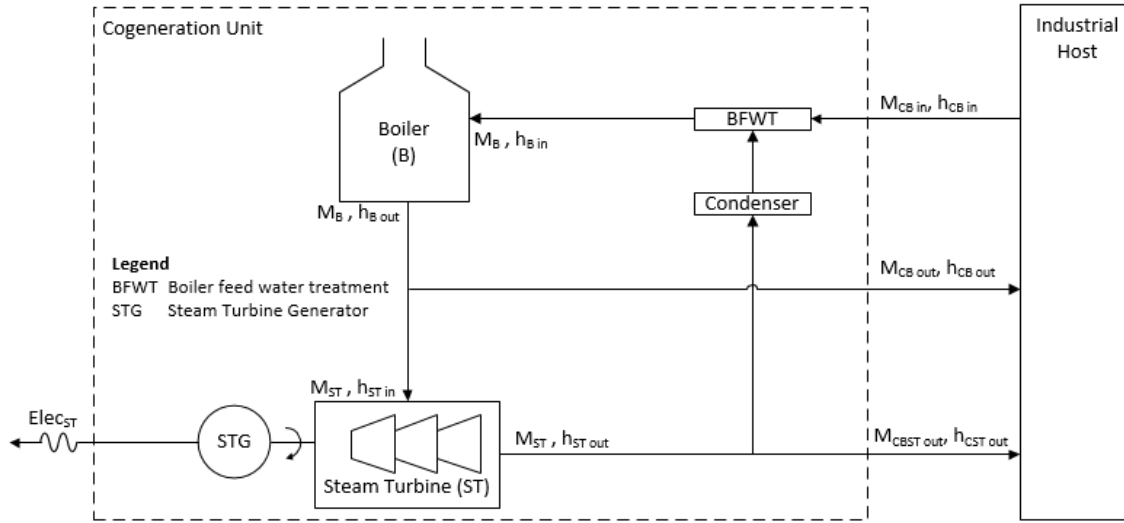
$$EE_{cogeneration} = E_{GT} + E_{HRSG}$$

$$Elec_{Cogenerated} = Elec_{GT} + Elec_{ST}$$

$$H_{cogeneration} = M_{CHST\ out}(h_{CST\ out}) + M_{CH\ out}(h_{CH\ out}) - M_{CHin}(h_{CHin})$$

16.4. Integrated Cogeneration with Boiler

FIGURE 16-3: SIMPLIFIED PROCESS DIAGRAM OF COGENERATION UNIT WITH BOILER



$$EE_{\text{cogeneration}} = E_B \times \frac{(h_{STin} - h_{STout})M_{BSTin}}{(h_{Bout} - h_{Bin})M_B}$$

$$Elec_{\text{Cogenerated}} = Elec_{ST}$$

$$H_{\text{cogeneration}} = 0$$



Chapter 17

Measurement, sampling, analysis and data management

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17. Measurements, Sampling, Analysis and Data Management

17.1. Introduction

This chapter provides measurement, sampling, analysis and data management requirements for fuel, feed, and other parameters used for greenhouse gas emissions and production quantification. Where appropriate, methodologies in this chapter are referenced in other chapters of the Alberta Greenhouse Gas Quantification Methodologies (AGM). Methodologies in this chapter are adapted from the following sources and adapted for Alberta sectors:

- Environment and Climate Change Canada (ECCC) Greenhouse Gas Reporting Program;
- Western Climate Initiative, Inc. (WCI);
- United States Environmental Protection Agency (USEPA) AP-42: Compilation of Air Emissions Factors; and
- Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories.

17.2. Fuel consumption

The measurement requirements for fuel consumption is presented for the following levels:

- For level 1, facilities may use any methodology prescribed for quantifying fuel consumption including Section 17.2, Section C.6 of Appendix C, or engineering estimates.
- For levels 2 and 3, facilities must use methodologies prescribed in Section 17.2 to quantify fuel consumption. Section C.6 of Appendix C or engineering estimates may be used to quantify fuel consumption from negligible sources. Section C.7 of Appendix C may be used to allocate fuel use for individual equipment if the total fuel consumption is known.

17.2.1. Fuel consumption measurement requirements

(1) Liquid fuels

Liquid fuel consumption is quantified 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.

$$Fuel = Fuel_p - Fuel_s + Fuel_{ii} - Fuel_{ei}$$

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) 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.
- (b) 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 fuel consumption is consistent from year to year.

- (c) 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.

(2) Gaseous fuels

For gaseous fuels, the facility must use 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.

(3) Solid fuels

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.

17.2.2. Calibration

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 consist 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.

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.

17.3. Fuel or feed properties

The following are requirements for conducting sampling and analysis for fuel or feed properties including density, heating value, and gas composition/carbon content:

- (a) Fuel or feed samples shall be taken at a location in the fuel or feed handling system that provides a representative sample of the fuel or feed combusted or consumed.
- (b) Samples shall be obtained and analysis performed at the minimum frequencies prescribed in Table 17-1. In the event that more than one sampling frequency criteria is applicable to a fuel type, the higher sampling frequency shall be applied.
- (c) If a facility is sampling at a higher frequency than the prescribed frequency in Table 17.1, the facility must apply all of the data collected at the higher sampling frequency in a weighted average calculation for parameters such as carbon content and high heating values.

17.3.1. Density

(1) Liquid fuels

The density shall be measured 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) Solid fuels

The density shall be measured using ASTM D70 "Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method).", or an alternative method that is appropriate based on a method published by a consensus-based standards organization.

17.3.2. Heating value

- (a) For heating value sampling 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

$$HHV = LHV \times CF \quad \text{Equation 17-2}$$

Where:

HHV = Fuel or fuel mixture higher heat value

LHV = Fuel or fuel mixture lower heat value

CF = Conversion factor

- (b) For gases other than natural gas, 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.

17.3.3. Gas composition or carbon content

(1) 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.

(2) 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.

(3) 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.

A facility that is subject to monthly sampling requirements for solid fuels including renewables and biomass, except for coal and waste-derived fuels, must follow the requirements below:

- The monthly solid fuel sample shall be a composite sample of weekly samples.
- Sample the solid fuel at a location before fuel consumption but after all fuel treatment operations. The samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
- Collect each weekly sub-sample at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
- Combine four weekly samples (or a sample collected during each week of operation during the month) of equal mass to form the monthly composite sample.
- The monthly composite sample shall be homogenized and well mixed prior to withdrawing a sample for analysis.
- Randomly select one in twelve composite samples for additional analysis of its discrete constituent samples, for use in monitoring the homogeneity of the composite.

17.4. Sampling and measurement frequencies

Table 17-1 provides the minimum sampling and measurement frequencies for fuel and feed properties and other reported parameters such as imported and exported steam and boiler efficiency testing.

Intervals between sampling events should be consistent. For example, if weekly sampling is prescribed, the facility should sample on the same day every week where practical. The following are minimum intervals between sampling events for different sampling frequencies prescribed:

- For weekly sampling frequency, sampling must not be conducted less than two days apart;
- For monthly sampling frequency, sampling must not be conducted less than one week apart; and
- For quarterly sampling frequency, sampling must not be conducted less than four weeks apart.

TABLE 17-1: SAMPLING OR MEASUREMENT FREQUENCY REQUIREMENTS

Type of Fuel	Level 1 ¹	Level 2	Level 3
Fuel properties for fuels and feeds (density, gas composition, and heating values)			
Purchased gasoline, and diesel,	No sampling required		
Ethane, propane, and butane	No sampling required		
Marketable natural gas (including natural gas feed used for industrial processes)	Representative sampling required	Monthly for marketable (commercial) natural gas. The fuel supplier should provide monthly analysis or, should that not be possible, as often as the supplier can provide, but no less than semi-annually.	
Liquid fuels from renewables and biomass, excluding non-variable fuels	Representative sampling required	Monthly	
Non-marketable liquid or gaseous fuels such as purge gas co-produced at an oil and gas production or petrochemical facility. This excludes marketable natural gas, gases derived from biomass and biogas, and non-variable fuels.	Representative sampling required	Monthly (online instrumentation not in place) Daily (online instrumentation in place)	
Renewable and biomass gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes	Representative sampling required	Quarterly	
Refinery fuel gas	Representative sampling required	Daily (online instrumentation in place) Weekly (online instrumentation not in place)	
Feed gases which result in industrial process emissions (excluding natural gas feed).	Representative sampling required	Daily (online instrumentation in place) Weekly (online instrumentation not in place)	
Coal / Coke	Representative sampling required	Once for each new fuel shipment or delivery. 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 including renewables and biomass other than coal and coke	Representative sampling required	Monthly	
Other reported parameters			
Heat/Steam including industrial heat exported as a product (steam flow rate, steam discharge temperature and pressure)	Weekly	Hourly	

Type of Fuel	Level 1 ¹	Level 2	Level 3
Boiler efficiency (by fuel) ³	Manufacturer Specification	Every five years or during boiler planned maintenance based on manufacturer specification, whichever is lower. Boiler efficiencies for different fuels consumed (i.e. natural gas and biomass) must be separately determined by testing.	

1. Facilities subject to ECCC's Greenhouse Gas Reporting Program (GHGRP) are required to ensure that the minimum requirements prescribed by GHGRP are met.
2. Weekly/monthly samples means the composition of several samples uniformly distributed over the period of the reported time.
3. Refer to Section 17.4.1 for the use of default boiler efficiencies.

17.4.1. Default Boiler Efficiency Approach

Table 17-2 provides default boiler efficiencies on a HHV basis that may be used by facilities for reporting periods between 2021 and 2024. For 2025 and subsequent, a facility is required to conduct boiler efficiency testing at the 5-year measurement interval outlined in Table 17-1. The facility may choose to apply the default boiler efficiencies for three years after the 5-year measurement interval.

Measured boiler efficiencies must be used in the 5-year measurement interval and default boiler efficiencies can only be used after the 5-year measurement interval. All measured or all default factors must be used for a given reporting period. They cannot be mixed. For example, a facility conducts boiler efficiency testing in 2025 and is required to apply the measured boiler efficiencies for 2025 to 2029. After this period, the facility applies the default boiler efficiencies for 2030 to 2032 instead of conducting boiler efficiency testing in 2030.

Default boiler efficiencies may only be used if the non-biogenic emissions (i.e. methane and nitrous oxide) from the combustion of the biomass fuel represent less than 25% of the Total Regulated Emissions (TRE) for regulated facilities under the Technology Innovation and Emissions Reduction Regulation (TIER).

TABLE 17-2: DEFAULT BOILER EFFICIENCIES

Type of Fuel	Boiler Efficiency (%) (based on HHV)
Natural gas	78.4
Solid biomass fuel (wood-based)	65

17.5. Data analysis and management

17.5.1. 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 17-1. 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.

$$\text{Reconciled Fuel}_{i,j} = \text{Non Adjusted Fuel}_{i,j} \times \left(1 + \frac{\Delta}{\text{Non-Adjusted Fuel}_i}\right) \quad \text{Equation 17-3}$$

$$\Delta = \text{Reference Fuel}_i - \text{Non Adjusted Fuel}_i \quad \text{Equation 17-4}$$

$$\text{Non Adjusted Fuel}_i = \sum_{j=1}^n \text{Non Adjusted Fuel}_{i,j} \quad \text{Equation 17-5}$$

Where:

Reconciled 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 fuels that are quantified by the facility that have not been adjusted by a reconciliation process.
Non-Adjusted 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 several j streams, at standard conditions. For example, a reference fuel measurement may be fuel quantities measured by alternative metering used by the facility or fuel quantities provided by a third party fuel supplier.
Δ	=	Amount of fuel to be adjusted.

17.5.2. Procedures for estimating missing data

The following method for estimating missing data was adapted from ECCC's Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.

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 Level 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, CO₂ concentration, water content or any other data sampled, the facility shall:

1. Determine the sampling or measurement rate using Equation 17-6:

$$R = \frac{QS_{Ac}}{QS_{Required}} \quad \text{Equation 17-6}$$

Where:

R	=	Sampling or measurement rate that was used, expressed as a percentage
QS Ac	=	Quantity of actual samples or measurements obtained by the facility
QS 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 for compliance reporting: 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 for compliance reporting: 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 for compliance reporting: 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 for compliance reporting: 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).
 - f. If $0.75 \leq R < 0.9$ and data directly effects estimated emissions for benchmarking: replace the missing data by the lowest data value sampled or analyzed during the calendar year for which the calculation is made.
 - g. If $0.75 \leq R < 0.9$ and data inversely effects estimated emissions for benchmarking: replace the missing data by the highest data value sampled or analyzed during the calendar year for which the calculation is made.
 - h. If $R < 0.75$ and data directly effects estimated emissions for benchmarking: 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).
 - i. If $R < 0.75$ and data inversely effects estimated emissions for benchmarking: 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).
- (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:
- (i) 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 $R \geq 0.9$: replace the missing data by the arithmetic mean of the sampling or measurement data from immediately before and after the missing data period. If no data is available from before the missing data period, the facility shall use the first available data from after the missing data period.
 - b. If $0.75 \leq R < 0.9$: replace the missing data by the highest data value sampled or analyzed during the 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

1. The CAN-CWB Methodology for Regulatory Support: Public Report. January 2014. Prepared by Solomon Associates for the Canadian Fuels Association
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>
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6. Final Essential Requirements of Mandatory Reporting. 2011 Amendments for Harmonization of Reporting in Canada Jurisdictions, December 21, 2011 with WCI Quantification Method 2013 Addendum to Canadian Harmonization Version.
7. AP 42 Compilation of Air Pollutant Emission Factors, Volume 1, Fifth Edition.
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15. A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H₂S) Emissions by the Upstream Oil and Gas Industry. Volume 5, Compendium of Terminology, Information Sources, Emission Factors, Equipment Sched’s and Uncertainty Data. September 2004.

Appendix B: Fuel Properties

TABLE B-1: TABLE OF PHYSICAL PROPERTIES FOR HYDROCARBONS AND OTHER COMPOUNDS¹

Component	Chemical Formula	HHV [GJ/e3m3]	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 ₂ S	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 ₂ H ₆	66.065	2	30.0690
Propane	C ₃ H ₈	93.936	3	44.0956
Isobutane	C ₄ H ₁₀	121.406	4	58.1222
n-Butane	C ₄ H ₁₀	121.794	4	58.1222
Isopentane	C ₅ H ₁₂	149.363	5	72.1488
n-Pentane	C ₅ H ₁₂	149.656	5	72.1488
Hexane	C ₆ H ₁₄	177.550	6	86.1754
Heptane	C ₇ H ₁₆	205.424	7	100.2019
Octane	C ₈ H ₁₈	233.284	8	114.2285
Nonane	C ₉ H ₂₀	261.191	9	128.2551
Decane	C ₁₀ H ₂₂	289.067	10	142.2817
Acetylene	C ₂ H ₂	55.038	2	26.0373
Ethylene	C ₂ H ₄	59.724	2	28.0532
Propylene	C ₃ H ₆	86.099	3	42.0797
Hexene	C ₆ H ₁₂	174.068	6	84.1595
Benzene	C ₆ H ₆	139.689	6	78.1118
Toluene	C ₇ H ₈	167.056	7	92.1384
Heptane	C ₇ H ₁₆	205.424	7	95.00
o-Xylene	C ₈ H ₁₀	194.484	8	106.1650
m-Xylene	C ₈ H ₁₀	194.413	8	106.1650
p-Xylene	C ₈ H 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 CO₂ 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/m³)
- 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.-1a provides a common conversion from mole fraction to mass fraction for gaseous fuels.

$$CC_p = \frac{\sum_{i=1}^N CC_i \times Fuel_i}{\sum_{i=1}^N Fuel_i} \quad \text{Equation C.1-1}$$

Where:

CC _p	=	Weighted average carbon content of the fuel during the reporting period, <i>p</i> .
CC _i	=	Carbon content of the fuel for sampling period <i>i</i> .
Fuel _i	=	Quantity of fuel combusted during sampling period <i>i</i> , in accordance with Chapter 17: <ul style="list-style-type: none">• Cubic metres (m³) 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.1a is used to convert the mole fraction to kilogram of carbon per cubic metre of fuel:

$$CC_i = \sum_{j=1}^c (MF_j \times NC_j) \times \frac{12.01}{MVC} \quad \text{Equation C.1-1a}$$

Where:

CC _i	=	Carbon content of the gaseous fuel <i>i</i> (kg of C/m ³).
MF _j	=	Normalized mole fraction of component <i>j</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.
NC _j	=	Number of carbons in component <i>j</i> .
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).

The weighted average is based on the prescribed sampling frequency provided in Chapter 17. If a facility is sampling at a higher frequency than the prescribed frequency, the facility must apply the data collected at the higher sampling frequency in the weighted average.

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 using the following equation:

$$\text{Period CC}_{95\% \text{ Uncertainty}} = \pm \frac{k_{95\%} \times \sigma}{\sqrt{n}} \quad \text{Equation C.2-1}$$

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.

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.

$$MW = \sum x_i MW_i \quad \text{Equation C.3-1}$$

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 15°C (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.

$$v_s = 2.8438 \times \frac{P \times v}{T} \quad \text{Equation C.4-1}$$

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:

$$HHV = \sum_i^N x_i HHV_i \quad \text{Equation C.5-1}$$

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.

$$HHV_p = \frac{\sum_{i=1}^N HHV_i \times Fuel_i}{\sum_{i=1}^N Fuel_i} \quad \text{Equation C.5-2}$$

Where:

HHV _p	=	Weighted average higher heating value of the fuel for the reporting period <i>p</i> .
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.

$$v_{fuel,j,p} = \sum_{j=1}^N \frac{P_{rated,j}}{n_j} \times \frac{LF_j}{LHV_j} \times OH_j \times 0.0036 \quad \text{Equation C.6-1}$$

$$v_{fuel,j,p} = \sum_{j=1}^N (OH_j \times HP_j \times LF_j \times BSFC_j) \times 10^{-3} \quad \text{Equation C.6-2}$$

Where:

v _{fuel,j,p}	=	Estimated fuel consumption from combustion equipment for a specific fuel type for the reporting period, <i>p</i> (m ³).
j	=	Equipment type.
P _{rated,j}	=	Maximum rated input 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.
LHV _j	=	Lower 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.

$$fuel_{actual,i} = fuel_{theoretical,i} \times \frac{(fuel_{measurement} - \sum fuel_{theoretical,non-com})}{\sum fuel_{theoretical,com}} \quad \text{Equation C.7-1}$$

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 Variables

When a variable is used in a calculation, fuel weighted averages should be calculated as per Equation C.9-1.

$$Variable_p = \frac{\sum_{i=1}^N Fuel_i \times Variable_i}{\sum_{i=1}^N Fuel_i} \quad \text{Equation C.9-1}$$

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.9 Allocation of electricity generated from multiple energy suppliers

Use Equation C.10-1 to calculate the allocation of electricity from different suppliers.

$$Electricity_i = Produced \text{ Electricity} \times \frac{Heat_i}{\sum_{j=1}^N Heat_j} \quad \text{Equation C.10-1}$$

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	=	Number of suppliers.

C.10 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.11 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}
angstrom (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
°F	$9 / 5 * ^\circ\text{C} + 32$
°C	$(^\circ\text{F} - 32) * 5 / 9$
°K	$^\circ\text{C} + 273.15$
°R	$^\circ\text{F} + 459.67$

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	760	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

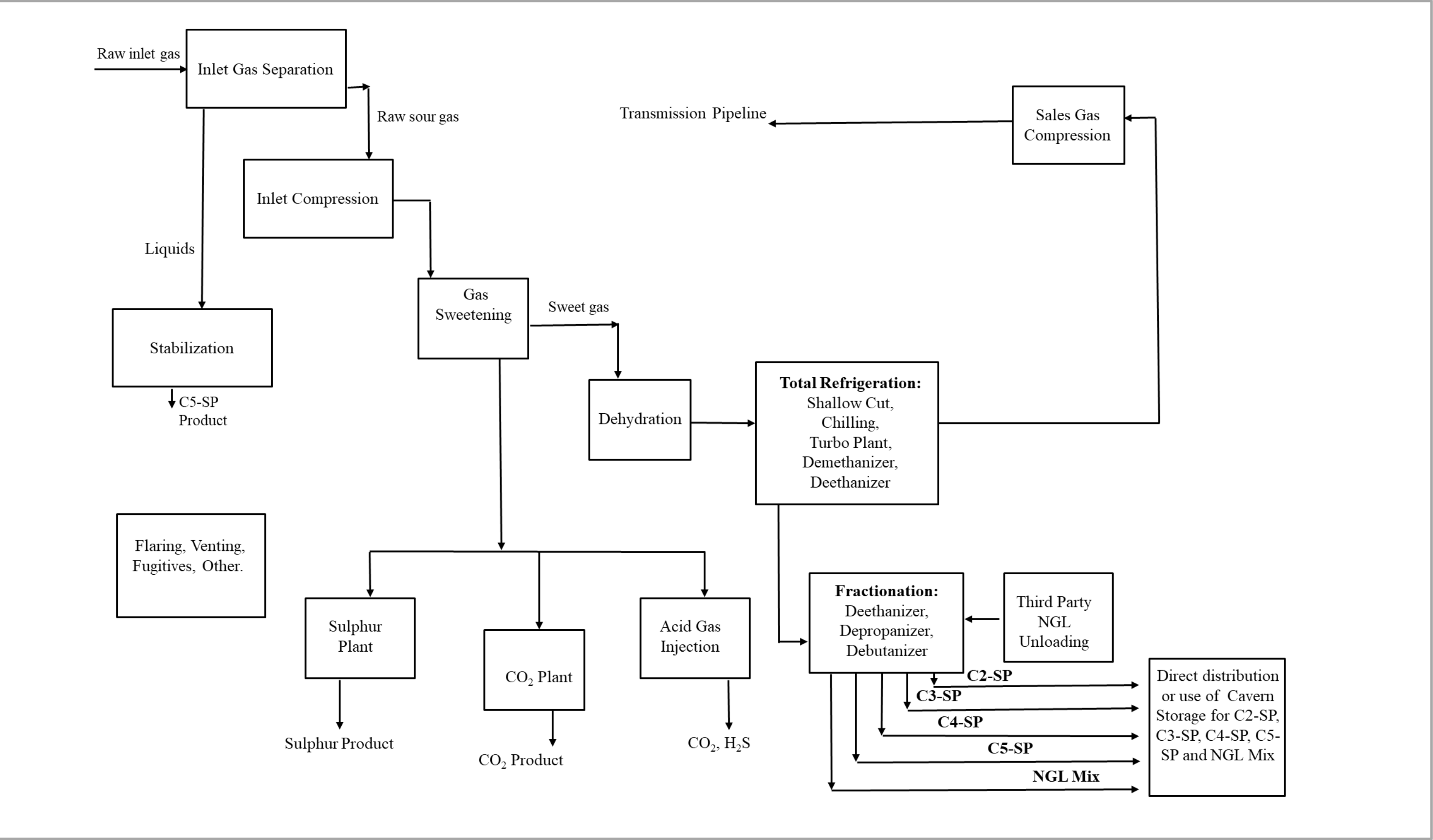
Appendix E: Additional Information for the Alberta Gas Processing Index

E.1 - Overview of natural gas processing modules

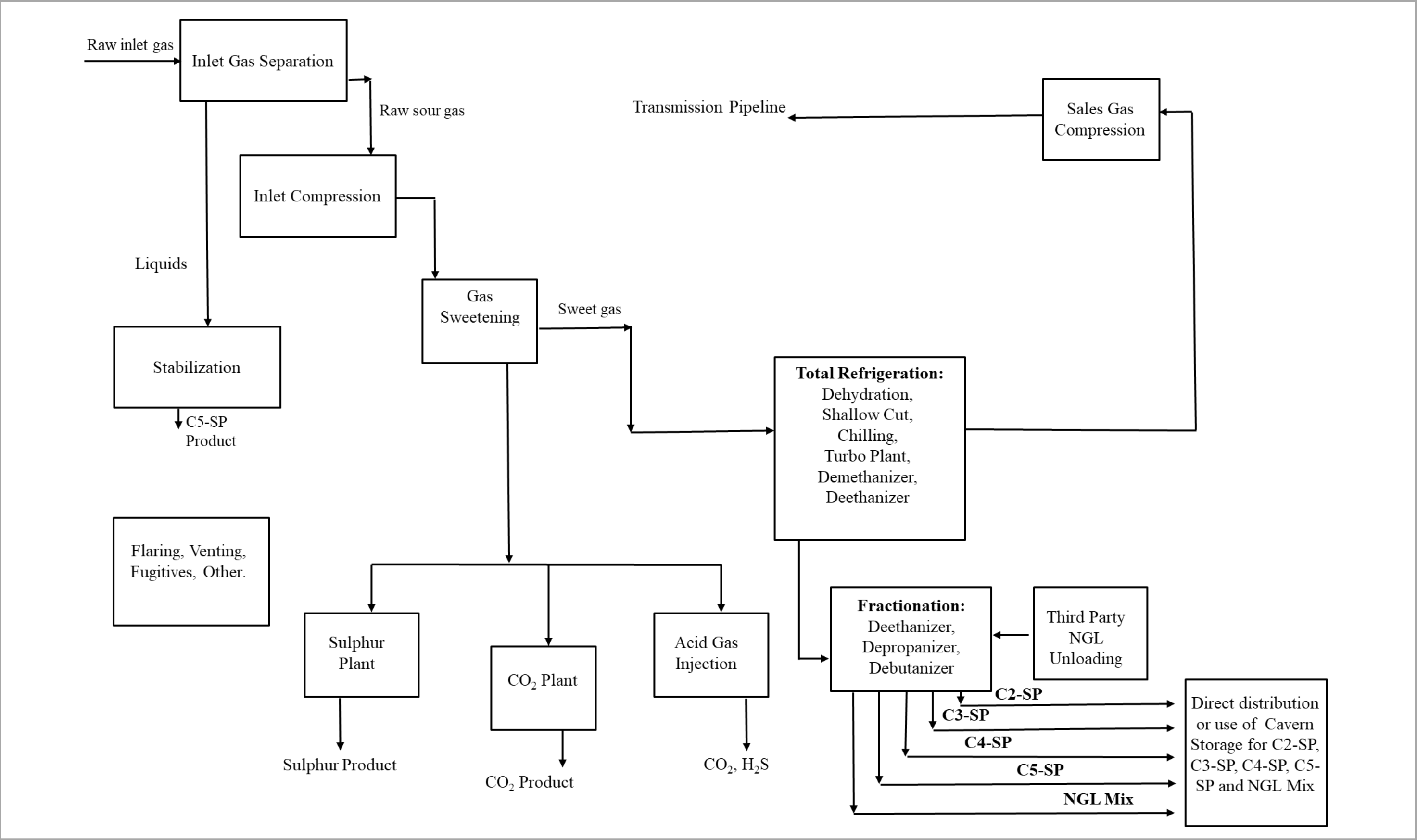
Process Unit (Module)	Inlet	Outlet	Typical Equipment	Stream Measured	Unit of Measure ¹
Inlet Compression	Inlet Gas to compression	Compressed Inlet Gas to Processes	Reciprocating engines, centrifugal compressors.	Only volume of the inlet gas requiring compression at the facility's point of entry.	E³m³
Dehydration	Gas to the dehydrator(s)	Dry gas from the dehydrator(s)	Heaters, boilers, heat exchangers, molecular sieves	All inlet gas volume requiring dehydration.	E³m³
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.	E³m³
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: <ol style="list-style-type: none"> When only one refrigeration process exists within a facility, the total gas volume through this individual refrigeration processing module should be used. When multiple refrigeration processes are run in series, the maximum gas volume through any individual refrigeration processing module should be used. 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. 	E³m³
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 m³ and converted to cubic metres of oil equivalent (m³OE). 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).	m³OE
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.	m³OE
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.	E³m³
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.	E³m³
Ethane Extraction	Marketable Gas	Sales Gas, Specification Ethane and NGLs	Heaters, boilers, Turbo-Expander, Cryogenic Expander	Ethane production reported in Petrinex.	m³OE
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).	m³
CO₂ Plant	Acid Gas from Amine Sweetening to the CO₂ Plant	Gaseous or Liquid CO₂ Product	Cryogenic technology equipment involving the removal of CO₂ from the gas stream, including CO₂ purification and/or liquefaction.	Total CO₂ gas volume from the amine sweetening through the CO₂ removal and purification process.	E³m³
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.	m³OE

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 10³ m³ . The units for Cavern Storage (m³) will be subject of a further review.

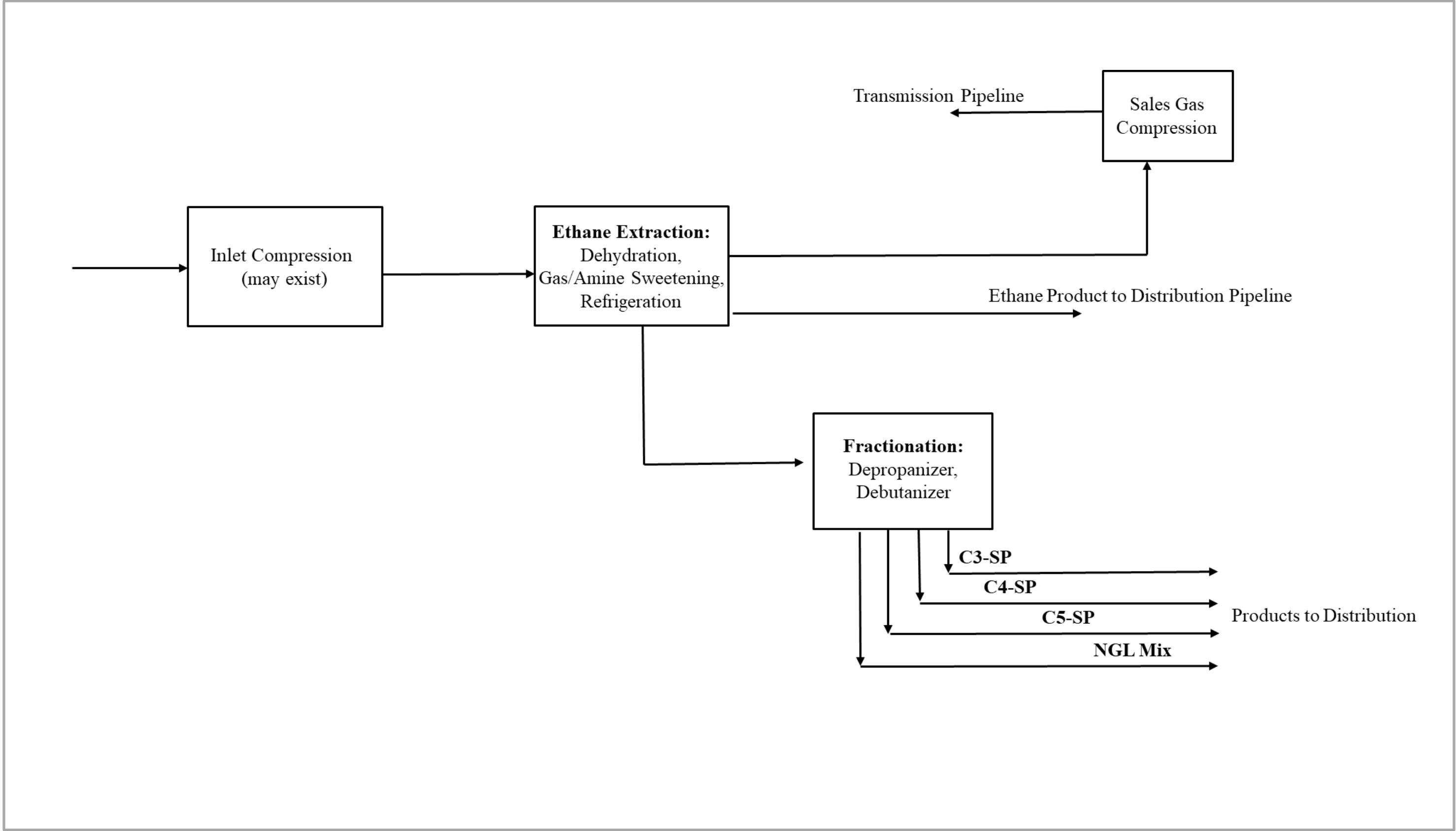
E.2 – Simplified flow diagram of a typical natural gas processing plant



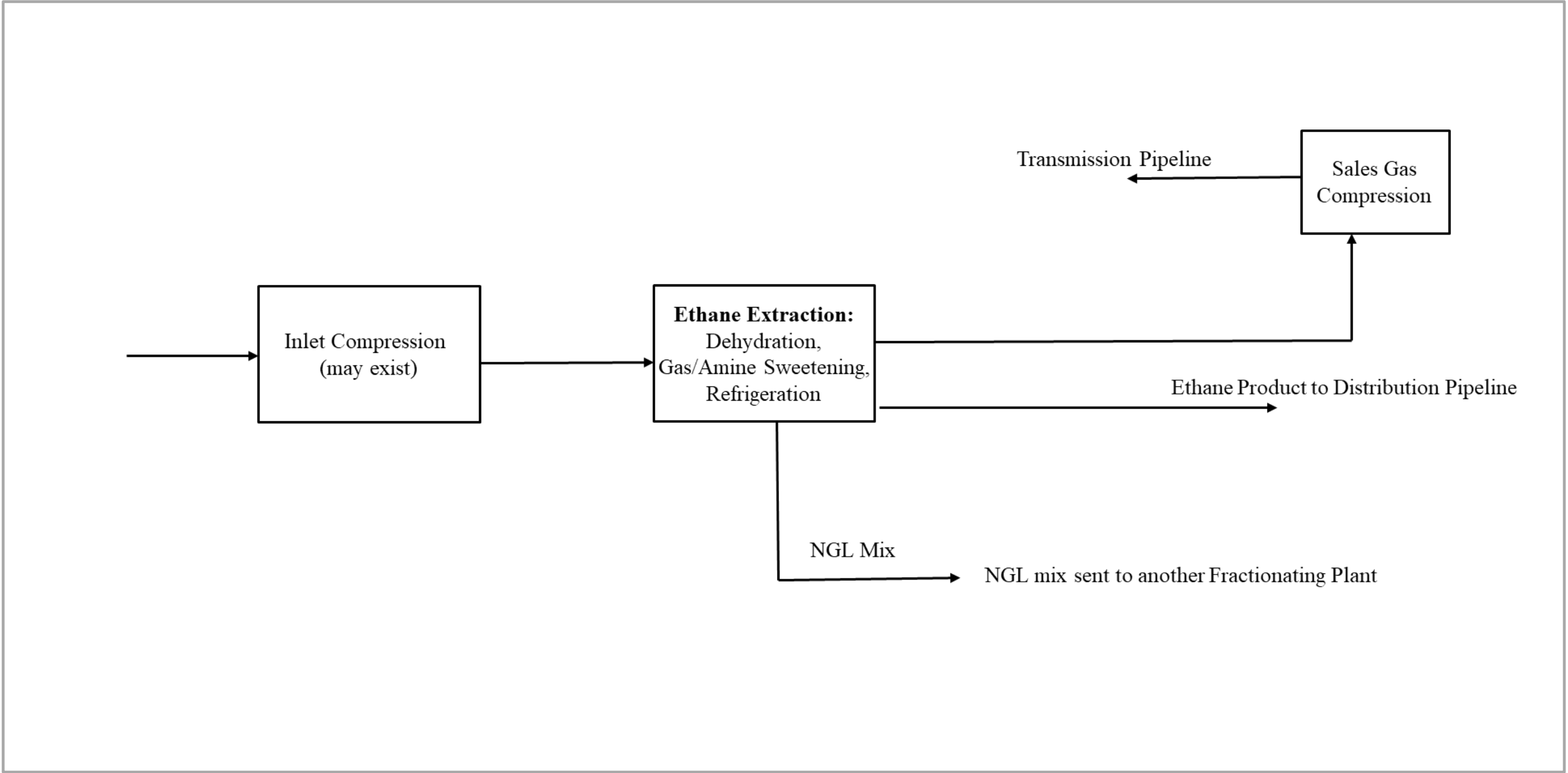
E.3 – Simplified flow diagram of a typical natural gas processing plant (dehydration within refrigeration)



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 ³ m ³	0.971	-
C1MX	Methane Mix	e ³ m ³	0.971	-
LITEMX	Lit Mix	e ³ m 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/m³ 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".