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**Quantitative Methodologies for the Carbon
Competitiveness Incentive Regulation and the
Specified Gas Reporting Regulation
Alberta Climate Change Office**

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4.0 Quantification of Venting Emissions

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

Methane (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.

Venting emissions normally exist as part of upstream oil and gas (UOG) production, processing, petroleum refining, oil sands and coal mining and upgrading industries in any facility that uses natural gas (which typically is greater than 90 mol% methane) or process materials containing CH₄ or CO₂. In Alberta, venting occurs predominantly in the UOG facilities. Venting emissions also occur in chemical, coal mining, petrochemical, pipelines and fertilizer industries.

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

- Gas Conservation – where gas is captured and sold, used as fuel, injected into reservoirs for pressure maintenance or other beneficial purpose.
- Flare Systems – where gas is captured and combusted by thermal oxidation 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 tiered and therefore, are considered to be acceptable for use by a facility under any tier classification. As well, facilities are permitted to use a higher tiered method to quantify the facility's emissions where appropriate. In addition, the chapter distinguishes venting emission sources into routine and non-routine for emission quantifications purpose. However, CCIR and SGRR do not require to report routine and non-routine venting emissions separately. Facilities should aggregate total venting emissions for reporting.

For all sources discussed in this chapter, CO₂ that is entrained in produced oil and gas are considered to be formation CO₂. Methodologies in this chapter are given for CH₄ and CO₂, but CO₂ will be reported as formation CO₂ if it meets the definition of formation CO₂. Imported CO₂ and CO₂ from IP are not considered to be formation CO₂. For facilities reporting under CCIR, formation CO₂ emissions must be reported in a separate category; while facilities reporting under SGRR must report venting and formation CO₂ emissions under the venting category.

4.1 General Calculation

4.1.1 Control Factor (CF)

(1) Introduction

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

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

For instance, a control equipment is running 95% of the time when a venting source is emitting and the capture efficiency is 98%, the $CF = 95\%$ (running time) $\times 98\%$ (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 report period.
- t_{op} = Total uptime of capture system when the venting source is emitting (hour) in the report period.
- t_{total} = Total hours of venting (hour) regardless of whether the capture system is operating or not in the report period.
- $eff_{capture}$ = Efficiency of capture system based on manufacturer data or engineering design or assessment.

(3) Data Requirements

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

4.1.2 General Calculation-Periodic or Continuous Measurement

(1) Introduction

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

(2) Equations

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

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

Where:

GHG = CH₄ or CO₂ mass emissions from a venting source (tonnes) or vent gas recovery system outlet venting to atmosphere in the report period.

i = Vent source or vent gas recovery system outlet.

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

VR_v = Average volumetric vent rate at the vent or outlet of the recovery system (Sm³/h). If the source or the gas recovery system is equipped with a continuous meter, use the metered volume (Q, Sm³) 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 CO₂ or CH₄. Measured at the location where the vent rate is measured.

ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO₂} = 1.861 kg/sm³; ρ_{CH₄} = 0.6785 kg/sm³).

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 = CH₄ or CO₂ mass emissions from a venting source (tonnes) in the report period.

i = Vent source or vent gas recovery system outlet.

- n = Total number of vents or vent gas recovery system outlets venting to the atmosphere in the report period. It is possible a number of vents are connected to one outlet where the measured vent rate may represent the total emissions from multiple vents.
- $VR_{mass,j}$ = Average vent rate at the vent or outlet of the recovery system (kg/h) expressed in mass j. If the source or the gas recovery system is equipped with a continuous meter, use the metered mass (kg) in the report period to replace $VR_{mass,j} * t$. If a continuous vent meter is not available, periodic vent rate measurement should measure the representative average vent rate for the report period.
- j = Type of compound that is metered, such as total hydrocarbons (THCs), total volatile organic compounds (VOCs), etc.
- t = Venting time if the measurement is conducted at the vent source or operating time of the recovery system if the measurement is conducted at the outlet of the recovery system during the report period (hours).
- $F_{GHG/mass,j}$ = Mass fraction of CO₂ or CH₄ 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).

1 (3) Data Requirements

- 2 • Periodic vent rate measurement at the outlet of the vent source or at the outlet of the vapor recovery
3 system if appropriate should be conducted under normal process operation. If the measurement
4 frequency is not prescribed for a particular source (as outlined throughout this chapter), quarterly
5 measurements are required at minimum.
- 6 • Facilities should follow meter installation, calibrations, vent rate measurement and vapor composition
7 sampling frequencies required by AER Directives. Non-UOG facilities may use other applicable
8 regulatory requirements or industry best practices for these parameters.
- 9 • Volume measurements must be adjusted to standard conditions as defined in Appendix C.
- 10 • If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer
11 results must be used.
- 12 • Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- 13 • Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- 14 • Gas compositions must be measured using:
- 15 ○ An applicable analytical method prescribed by AER Directives for UOG facilities;
- 16 ○ An analytical method prescribed in Section 17.2.3 of Chapter 17.

17 4.2 Routine Venting–Produced Gas at UOG Facilities

18 4.2.1 Introduction

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

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

4.2.2 Tier 1-Rule-of-Thumb Method

(1) Introduction

The produced gas volume relates to the hydrocarbon liquid production volume and the Gas in Solution (GIS). The emissions calculated by the following method are based on the rule of thumb GIS estimation in AER Directive 017. This approach is applicable for light-medium oil production. The CO₂ emissions calculated using the equations below are considered to be formation CO₂.

(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 = CH₄ or CO₂ mass emissions from produced gas venting (tonnes) in the report period.
- Q_{oil} = Total volume of oil produced for the report period, (m³ 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 CO₂ or CH₄ 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 CO₂ or CH₄ 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 (sm³ gas/sm³ oil/kPa of pressure drop).

(3) Data Requirements

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

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

(1) Introduction

Produced gas from a well must be determined based on the requirements of AER Directive 017. This may include continuous direct metering or periodic measurement. The GIS should be representative of vented

1 gas volume and production volume during normal process operations. Facilities are expected to select the
2 most representative methodology from Directive 017 to quantify vented emissions.

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

4 (2) Equations

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

7 (3) Data Requirements

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

18 4.3 Routine Venting-Continuous Gas Analyzer Purge

19 4.3.1 Tiers 1, 2 and 3-Default Vent Rate

20 (1) Introduction

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

26 (2) Equations

27 Calculate GHG emissions using Equation 4-3.

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

28 Where:

- GHG = CH₄ or CO₂ mass emissions from gas analyzer (tonnes) in the report period.
- i = Analyzer identifier.
- j = Month identifier.
- n = Total number of analyzers used in a month.
- m = Total months in the report period.
- Q_v = Vented gas volume per analyzer per month (sm³/analyzer/month) at the standard condition during the report period.

- MF_{GHG} = Mole fraction of CO₂ or CH₄ in the vented gas. Using the average gas analysis per analyzer for the report period.
- ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO₂} = 1.861 kg/sm³; ρ_{CH₄} = 0.6785 kg/sm³).
- 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 Tiers 1, 2 and 3-Physical Volume Depression

(1) Introduction

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

(2) Equations

For each desiccant dehydrator venting event, calculate CH₄ or CO₂ emissions separately and then add the emissions in the report period based on total events using the following equation. The CO₂ emissions calculated using the equations below are considered to be formation CO₂.

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 report period.
- i = Solid desiccant dehydrator identifier.
- j = Venting event identifier.
- n = Number of dehydrators having venting events in the report period.

| | | |
|---------------------------|---|--|
| m | = | Number of venting events in the report period. |
| $V_{\text{vessel},i}$ | = | Volume for vessel i, obtained through design or nameplate information, or from engineering estimates. |
| 0.001 | = | Mass conversion factor (tonne/kg). |
| $P_{\text{vessel},i,j}$ | = | 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). |
| $T_{\text{vessel},i,j}$ | = | 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. |
| $MF_{\text{GHG/Gas},i,j}$ | = | 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 ($\rho_{\text{CO}_2} = 1.861 \text{ kg/sm}^3$; $\rho_{\text{CH}_4} = 0.6785 \text{ kg/sm}^3$). |
| 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 17.2.3 of Chapter 17.
- The facility is required to measure the vessel pressure prior to depressurization and convert to absolute pressure.
- The facility may use the absolute atmospheric pressure (kPaa) at the location of the facility or 101.325 kPaa.

4.5 Routine Venting-Pigging and Purges

4.5.1 Tiers 1, 2 and 3-Physical Volume Depression

(1) Introduction

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

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

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

(2) Equations

Emissions generated from the pigging operation are from depressurization at the launch and receiver traps and re-pressurization and depressurization of the purge gas, which may not be applicable for smaller operations or may be repeated several times depending on operational needs. It is assumed that the entire volume of the purge gas is vented. 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 = CH₄ or CO₂ mass emissions from depressurization and purging events (tonnes) in the report period.
- i = Vent event identifier.
- N = Number of depressurization or purging events in the report period.
- V_{v,i} = Total physical volume of equipment chambers between isolation valves being depressurized. Volume is calculated through measured physical dimensions or engineering estimates using dimensions of components in the process system.
- 288.15 = Temperature at the standard condition (equivalent to 15 °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 CO₂ or CH₄ in the vented gas at the depressurization or purging event i.
- ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO2} = 1.861 kg/sm³; ρ_{CH4} = 0.6785 kg/sm³).
- 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 = CH₄ or CO₂ mass emissions from pigging and purges (tonnes) in the report period.
- i = Vent event identifier.
- n = Total number of events in the report period.
- $\rho_{a,1}$ = Density of gas in equipment chamber at actual conditions prior to depressurization, as estimated using real gas properties or by suitable equation of state, kg/m³.
- $\rho_{a,2}$ = Density of gas in pigging equipment chamber after depressurization, as estimated using real gas properties or by suitable equation of state, kg/m³. 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 (m³).
- \dot{m}_{purge} = Mass flow rate of gas used to purge equipment (kg/s).
- t_{purge} = Duration of equipment purge event(s).
- $F_{GHG/vapor}$ = Mass fraction of CH₄ or CO₂ components in vapor during depressurization.
- $F_{GHG/purge}$ = Mass fraction of CH₄ or CO₂ components in purge during depressurization.
- 0.001 = Mass conversion factor (tonne/kg).

(3) Data Requirements

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

4.6 Routine Venting-Atmospheric Liquid Storage Tank

4.6.1 Introduction

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

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

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

The main areas where tank flashing losses occur are at:

- Wellhead sites when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Tank batteries when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Compressors stations when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel;
- Gas plants when produced liquids are sent to an atmospheric storage vessel from the last pressurized vessel; and/or
- When the liquids in the gas lines are “pigged” (physically purged of condensate) and then sent to an atmospheric storage vessel.

The tank venting is from the vapor space at the top of the tank, which includes mostly volatile hydrocarbons.

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

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

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

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

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

1 **Figure 4-1 Tier Classification and Methodology Mapping**

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

2 **4.6.2 Method 1: Generic Vent Rate**

3 **(1) Introduction**

4 The following provides quantification methodologies for CH₄ emissions only from atmospheric pressure
 5 storage tanks using a generic vent rate. The equations for Method 1 are only applicable for refineries.
 6 Facilities other than refineries cannot use Method 1. Instead, these facilities should quantify CH₄
 7 emissions from tanks using process knowledge and/or engineering estimates.

8 **(2) Equations**

9 For storage tanks other than those that process unstabilized crude oil at refinery facilities including
 10 stabilized and intermediate crude oil, calculate total tank CH₄ emissions using Equation 4-6a. Stabilized
 11 crude oil is considered to be crude petroleum that has lost an appreciable quantity of its more volatile
 12 components due to evaporation and other natural causes during storage and handling.

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

13 Where:

- CH₄ = Methane emissions from storage tank (tonnes) in the report period.
- 6.29×10⁻⁷ = Default emission factor for storage tanks (tonnes CH₄/m³).
- Q = Total quantity of stabilized crude oil and intermediate products received from off site that are processed at the facility in the report period (m³).

14 For storage tanks that process unstabilized crude oil at refinery facilities, calculate CH₄ emissions using
 15 Equation 4-6b. Unstabilized crude oil means crude oil that is pumped from the well to a pipeline or
 16 pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at
 17 atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds
 18 per square inch absolute (psia) or greater.

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

19 Where:

| | | |
|--------------------------------|---|---|
| CH ₄ | = | Methane emissions from storage tank (tonnes) in the report period. |
| i | = | Tank identifier. |
| n | = | Number of tanks in the report period. |
| 0.025703 | = | Correlation equation factor (m ³ gas per m ³ oil per kPaa). |
| Q _{throughput,i} | = | Total throughputs of un-stabilized crude oil in the tank i in the report period (m ³). |
| ΔP | = | Pressure difference from the previous storage pressure to atmospheric pressure (kPaa). |
| MF _{CH₄,i} | = | Mole fraction of CH ₄ in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH ₄ /kg-mole gas); use 0.27 as a default for refineries if measured data are not available. |
| 16 | = | Molecular weight of methane (kg/kmol). |
| 22.4 | = | Molar volume conversion factor (m ³ /kmol). |
| 0.001 | = | Conversion factor (tonne/kg). |

(3) Data Requirements

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

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

(1) Introduction

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

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

(2) Equations

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

The CO₂ emissions calculated by Equation 4-7a are considered to be formation CO₂ and should be reported under that category.

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

1

Where:

GHG = CH₄ or CO₂ mass emissions (tonnes) from storage tank in the report period.

i = Tank identifier.

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

j = Type of product.

J = Number of products in the report period.

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

CF = Control factor (dimensionless fraction).

F_{GHG/VOC,i,j} = Mass fraction of CH₄ or CO₂ in the vented VOCs for product j in tank i.

2

(3) Data Requirements

3

- 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.

4

5

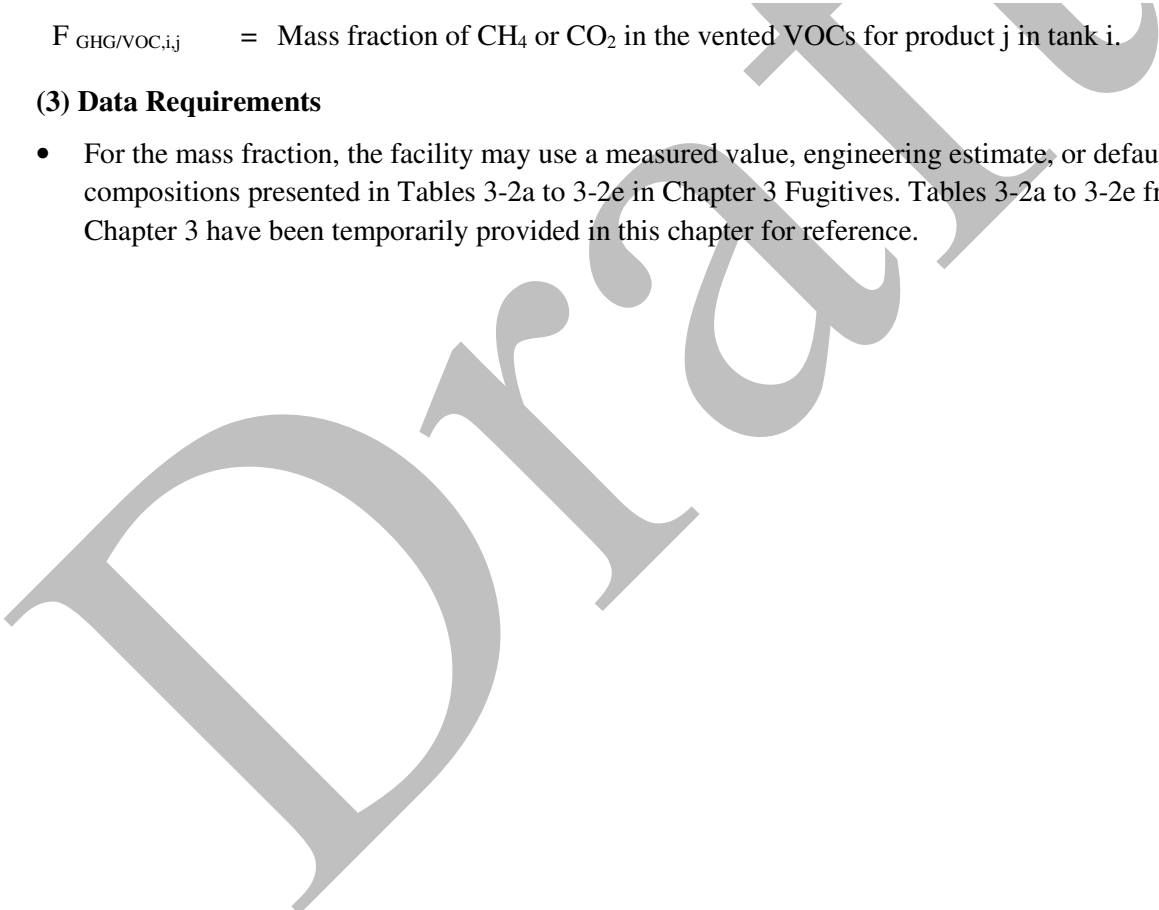


Table 3-2a Speciation Profiles (on a moisture-free basis) for Dry and Sweet Gas Production and Processing Facilities.

| Component | Dry Gas | | | | | | Sweet Gas | | | | | | | |
|-----------|---------|--------|--------------|--------|--------------|--------|-----------|--------|-------------|--------|--------------|--------|--------------|--------|
| | Gas | | Light Liquid | | Dehy Off Gas | | Gas | | Tank Vapors | | Light Liquid | | Dehy Off Gas | |
| | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % |
| N2 | 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 |
| CO2 | 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 |
| H2S | 0.0000 | 0.0000 | 0.00 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.00 | 0.0000 | 0.0000 | 0.0000 |
| 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 | 0.0000 | 0.0000 | 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 | 0.0000 | 0.0000 | 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 | 0.0000 | 0.0000 | 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 | 0.0000 | 0.0000 | 0.0254 | 0.1046 | 1.2562 | 3.2103 | 0.83 | 1.0725 | 0.0000 | 0.0000 |
| n-C5 | 0.0005 | 0.0020 | 0.99 | 1.2793 | 0.0000 | 0.0000 | 0.0296 | 0.1219 | 1.5784 | 4.0336 | 0.99 | 1.2793 | 0.0000 | 0.0000 |
| C6 | 0.0001 | 0.0003 | 5.87 | 9.0601 | 0.0000 | 0.0000 | 0.0060 | 0.0295 | 0.9312 | 2.8424 | 5.87 | 9.0601 | 0.0000 | 0.0000 |
| C7+ | 0.0001 | 0.0003 | 18.87 | 33.866 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.4215 | 1.4960 | 18.87 | 33.866 | 0.0000 | 0.0000 |
| 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 |

Note: 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 % |
| N2 | 0.6552 | 1.0140 | 2.9668 | 2.9436 | 0.01 | 0.0050 | 0.7791 | 1.2500 |
| CO2 | 0.5608 | 1.3635 | 1.3436 | 2.0944 | 0.05 | 0.0394 | 0.6160 | 1.5527 |
| H2S | 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 |

| Component | Sour Gas | | | | Natural Gas | | | |
|-----------|----------|---------|-------------|---------|--------------|---------|---------|---------|
| | Gas | | Tank Vapors | | Light Liquid | | Gas | |
| | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % | Mole % | Mass % |
| 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 |

Note: 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 % |
| N2 | 0.619 | 0.7723 | 13.9989 | 8.8642 | 0.1316 | 0.0464 | 0.1817 | 0.303 | 6.3477 | 8.9364 | 0.1046 | 0.0353 |
| CO2 | 5.243 | 10.2765 | 0.3303 | 0.3286 | 0.324 | 0.1794 | 0.0859 | 0.225 | 0.6892 | 1.5243 | 0.7665 | 0.4069 |
| H2S | 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 |

| 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 % |
| 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 |

Note: 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 |
| C ₁ | 71.7705 | 50.9011 | 7.4364 | 1.5172 |
| C ₂ | 9.0895 | 12.0828 | 3.8033 | 1.4544 |
| C ₃ | 5.3197 | 10.3703 | 6.0853 | 3.4126 |
| i-C ₄ | 0.8010 | 2.0581 | 1.9617 | 1.4500 |
| n-C ₄ | 1.6399 | 4.2138 | 5.8751 | 4.3427 |
| i-C ₅ | 0.3920 | 1.2503 | 3.5331 | 3.2418 |
| n-C ₅ | 0.4100 | 1.3077 | 4.6140 | 4.2336 |
| C ₆ | 0.2490 | 0.9485 | 19.9173 | 21.8257 |
| C ₇₊ | 0.2190 | 0.9701 | 45.4395 | 57.9049 |
| Molecular Weight | 22.6218 | 22.6218 | 78.5652 | 78.5652 |

Note: 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 % |
| N2 | 0.1932 | 0.1767 | 3.3516 | 3.0552 | 0.1044 | 0.0353 | 0.6130 | 0.6343 | 0.0000 | 0.0000 |
| CO2 | 2.6094 | 3.7485 | 16.1140 | 23.0772 | 0.7652 | 0.4066 | 28.5280 | 46.3771 | 22.0000 | 41.5226 |
| H2S | 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 |

Note: This table is adapted from Table 28 from Volume 3, Methodology on Greenhouse Gases, CAPP, 2005.

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

(1) Introduction

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

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

(2) Equations

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

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

- Bubble point pressure, kPa
- Reservoir temperature, °C
- Solution gas-to-oil ratio at bubble point pressure, sm^3/sm^3
- Oil specific gravity, °API
- 345 to 36,190
- 21 to 146
- 3.5 to 369
- 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 = CH₄ or CO₂ mass emissions (tonnes) from storage tank in the report period.
- γ_{gs} = Specific gas gravity corrected at 689.4 kPa or 100 psig with respect to air, calculated by Equation 4-7c.
- P = Absolute pressure upstream of the vessel of interest (kPaa).
- T = Temperature at upstream of the vessel of interest (K).
- γ_o = Specific gravity of the liquid hydrocarbon at final condition of the separator with respect to water, calculated by Equation 4-7d (dimensionless).
- C_1 = For $\gamma_o < 0.876$, 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 report period.
- MF_{GHG} = CH_4 or CO_2 mole fraction. Measured by the facility or if unavailable, refer to values presented in Tables 3-2a to 3-2e of Chapter 3 Fugitives.
- MW_{GHG} = Molecular weight of CH_4 or CO_2 (kg/kmol).
- VTM = Volume to mole conversion at standard condition of 101.325 kPa and 15°C; 0.042293 kmol/ m^3 .

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

Equation 4-7c

1 Where:

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

$$\gamma_o = \frac{141.5}{131.5 + ^\circ API}$$

Equation 4-7d

2 Where:

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

$$\gamma_g = \frac{MW_{sg}}{MW_{air}}$$

Equation 4-7e

3 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.

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

4 (1) Introduction

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

(2) Methods

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

(3) Data Requirements

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

4.6.6 Method 5: Flashing Losses Using the Measured GIS Method

(1) Introduction

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

(2) Equations

The equations for flashing losses are outlined in Section 4.2.3.

(3) Data Requirements

The data requirements are outlined in Section 4.2.3.

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

(1) Introduction

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

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

(2) Equations

If total VOCs are determined, calculate the CH₄ or CO₂ emissions using the Equation 4-7a and follow the data requirement in Section 4.5.4 for tank vapor analysis.

If total GHGs are determined, 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.

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

Where:

GHG = CH₄ or CO₂ mass emissions (tonnes) in the report period.

i = Tank identifier.

- I = Number of tanks holding products in the report period.
- j = Type of product.
- J = Number of products in the report period.
- Mass_{GHG,i,j} = CO₂ or CH₄ mass emissions (tonnes) for product i in tank j in the report period.
- CF = Control factor (dimensionless fraction).

(3) Data Requirements

- A facility should follow EOS to quantify model input parameters.

4.6.8 Method 7-Tank Vent Measurement

(1) Introduction

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

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

(2) Equations

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

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

Where:

- GHG = CO₂ or CH₄ emissions in the report period (tonne).
- RR_{tracer} = Release rate of the tracer gas (kg/h).
- C_{GHG} = Plume GHG concentrations above background (ppbv) at the fixed position of the downstream of tracer release.
- C_{tracer} = Plume concentration of tracer above background (ppbv) at the fixed position of the downstream of tracer release.
- MW_{GHG} = Molecular weight of CO₂ or CH₄ (kg/mol).
- MW_{tracer} = Molecular weight of tracer (kg/mol).
- t = Vent time in the report period.
- 0.001 = Constant converting kg to tonne.

(3) Data Requirements

- Data requirements are prescribed in Section 4.1.2.
- Tracer test should be performed during representative operating conditions for the tanks.
- The tracer test and composition of tank vapor including 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 Tier 1-Generic Vent Rates

(1) Introduction

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

- High-bleed pneumatic instruments means part of the gas power stream which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of 0.17 standard cubic meters per hour.
- Low-bleed pneumatic instruments mean part of the gas power stream, which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than 0.17 standard cubic meters per hour.
- Intermittent-bleed (high and low) pneumatic are snap-acting or throttling instruments that discharge the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

(2) Equations

Calculate GHG emissions using Equation 4-10.

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

Where:

- GHG = CH₄ or CO₂ mass emissions from pneumatic control device venting (tonnes) in the report period.
- i = Pneumatic device identifier.
- n = Number of pneumatic instruments in the report period.
- VR_i = Average vent rate for the device i (m³/hour/device) at the standard condition in Table 4-1a and 4-1b.
- t_i = Operating time of the instrument i in the report period (hours).
- CF_i = Control factor (dimensionless fraction) for pneumatic device i.

- MF_{GHG,i} = Mole fraction of CO₂ or CH₄ in vented gas. Refer to Table 17-3 of Chapter 17 for natural gas composition sampling requirements.
- ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρCO₂ = 1.861 kg/sm³; ρCH₄ = 0.6785 kg/sm³).
- 0.001 = Mass conversion factor (tonne/kg).

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 |

Note: 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.

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 Transmission and Underground Storage and Distribution 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 |

Note: This table is adapted from Section 24 of WCI Quantification Method 2013 Addendum to Canadian Harmonization Version which originally comes from the Prasinio 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 may be done by field survey or estimated based on the most recent piping and instrumentation drawing (P&ID) or process flow diagrams (PFD) for the facilities annually.
- The facility should update the inventory whenever there are changes in equipment at the facility during the report period.
- Information regarding the make and model, pneumatic instrument type (positioner, transducer, pressure or level controller), actuation frequency of level controllers should be documented.
- Information regarding pneumatic instrument type (low-bleed, high continuous bleed, intermittent high/low bleed) should be documented for transmission and underground storage and distribution facilities.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

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

(1) Introduction

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

(2) Equations

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

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

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 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 instruments | - | - | 0.0012 | 0.2605 |
| Low bleed Intermittent instruments | - | - | 0.0012 | 0.2476 |
| Pressure Controller | CVS | 4150 | - | 0.4209 |
| | CVS | 4160 | - | 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 | - | 0.3967 |
| | 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 | LS1100 | - | 0.2619 |
| | Murphy | LS1200, LS1200N, LS1200DVO | 0.0012 | 0.2619 |
| | Norriseal | 1001, 1001A, 1001XL | - | 0.193 |
| | Norriseal ² | EVS | - | 0.11 |
| | SOR | 1530 | - | 0.0531 |
| Temperature Controller | Kimray | HT-12 | - | 0.0351 |
| Positioner | Fisher | FIELDVUE™ DVC 6000 | 0.0011 | 0.2649 |
| | Fisher | FIELDVUE™ DVC 6010 | - | 0.2649 |

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) |
|------------------|--------------|--------------------------------------|---|---|
| | Fisher | FIELDVUE™ DVC 6020 | - | 0.2649 |
| | Fisher | FIELDVUE™ DVC 6030 | - | 0.2649 |
| Transducer | Fairchild | TXI 7800 | 0.0009 | 0.1543 |
| | Fairchild | TXI 7850 | - | 0.1543 |
| | Fisher | 546, 546S | 0.0017 | 0.3547 |
| | Fisher | i2P-100 (1 st generation) | 0.0009 | 0.2157 |

Note: This table is adapted from Table 1 of Final Report for Determining Bleed Rates for Pneumatic Instruments in British Columbia, the Prasino group, 2013.

“-” means that the coefficient is weak between pressure and vent rate or not available.

Table 4-2b Average Manufacturer Bleed Rates for Pneumatic Instruments

| Pneumatic Device | Manufacturer | Model | Operating Condition | Manufacturer Vent Rate (Sm ³ /h/device) |
|-------------------------|-----------------|--------------------------|---------------------|---|
| Liquid Level Controller | Bristol Babcock | Series 5453-Model 624-II | Continuous | 0.085 |
| Liquid Level Controller | Fisher | 2100 | Continuous | 0.0283 |
| Liquid Level Controller | Fisher | 2660 | Continuous | 0.0283 |
| Liquid Level Controller | Invalco | AE-155 | Continuous | 1.5008 |
| Liquid Level Controller | Invalco | CT Series | Continuous | 1.1327 |
| Liquid Level Controller | Wellmark | 2001 (snap) | Intermittent | 0.0057 |
| Liquid Level Controller | Wellmark | 2001 (throttling) | Intermittent | 0.0002 |
| Positioner | Becker | EFP-2.0 | Intermittent | 0 |
| Positioner | Becker | HPP-5 | Continuous | 0.1416 |
| Positioner | Fisher | 3582 | Continuous | 0.4531 |
| Positioner | Fisher | 3590 | Continuous | 0.8495 |
| Positioner | Fisher | 3660 | Continuous | 0.1982 |
| Positioner | Fisher | 3661 | Continuous | 0.2959 |
| Positioner | Fisher | 3582i | Continuous | 0.5833 |
| Positioner | Fisher | 3610J | Continuous | 0.4531 |
| Positioner | Fisher | 3620J | Continuous | 0.7532 |

| Pneumatic Device | Manufacturer | Model | Operating Condition | Manufacturer Vent Rate (Sm³/h/device) |
|-------------------------|---------------------|---------------------------|----------------------------|---|
| Positioner | Fisher | DVC 5000 | Continuous | 0.2832 |
| Positioner | Fisher | Fieldview Digital | Continuous | 0.892 |
| Positioner | Masoneilan | 7400 | Continuous | 1.0477 |
| Positioner | Masoneilan | 4600B Series | Continuous | 0.6796 |
| Positioner | Masoneilan | 4700B Series | Continuous | 0.6796 |
| Positioner | Masoneilan | 4700E Continuous | Continuous | 0.6796 |
| Positioner | Masoneilan | SV Continuous | Continuous | 0.1133 |
| Positioner | Moore | Products 73N-B | Continuous | 1.0194 |
| Positioner | Moore | Products 750P | Continuous | 1.1893 |
| Positioner | PMV | D5 Digital | Continuous | 0.0283 |
| Positioner | Sampson | 3780 Digital | Continuous | 0.0283 |
| Positioner | VCR | VP700 PtoP | Continuous | 0.0283 |
| Pressure Controller | Ametek | Series 40 | Continuous | 0.1699 |
| Pressure Controller | Becker | HPP-SB | Intermittent | 0 |
| Pressure Controller | Becker | VRP-B-CH | Continuous | 0.1416 |
| Pressure Controller | Becker | VRP-SB | Intermittent | 0 |
| Pressure Controller | Becker | VRP-SB Gap Controller | Intermittent | 0 |
| Pressure Controller | Becker | VRP-SB-CH | Intermittent | 0 |
| Pressure Controller | Becker | VRP-SB-PID Controller | Intermittent | 0 |
| Pressure Controller | Bristol Babcock | Series 5453-model 10F | Continuous | 0.085 |
| Pressure Controller | Bristol Babcock | Series 5455-model 624-III | Continuous | 0.0708 |
| Pressure Controller | Dyna-Flow | 4000 | Continuous | 0.6853 |
| Pressure Controller | Fisher | 2506 | Continuous | 0.6853 |
| Pressure Controller | Fisher | 2516 | Continuous | 0.6853 |
| Pressure Controller | Fisher | 4194 | Continuous | 0.1203 |
| Pressure Controller | Fisher | 4195 | Continuous | 0.1203 |
| Pressure Controller | Fisher | 4100 (large orifice) | Continuous | 1.4158 |
| Pressure Controller | Fisher | 4100 (small orifice) | Continuous | 0.4248 |
| Pressure Controller | Fisher | DVC 6010 | Continuous | 0.0878 |
| Pressure Controller | Foxboro | 43AP | Continuous | 0.5097 |

| Pneumatic Device | Manufacturer | Model | Operating Condition | Manufacturer Vent Rate (Sm³/h/device) |
|-------------------------|---------------------|-----------------|----------------------------|---|
| Pressure Controller | ITT Barton | 338 | Continuous | 0.1699 |
| Pressure Controller | ITT Barton | 358 | Continuous | 0.051 |
| Pressure Controller | ITT Barton | 359 | Continuous | 0.051 |
| Pressure Controller | ITT Barton | 335P | Continuous | 0.1699 |
| Pressure Controller | ITT Barton | 335P | Continuous | 0.1699 |
| Transducer | Bristol Babcock | 9110-00A | Continuous | 0.0119 |
| Transducer | Bristol Babcock | 502 A/D | Continuous | 0.1671 |
| Transducer | Fisher | 646 | Continuous | 0.2209 |
| Transducer | Fisher | 846 | Continuous | 0.3398 |
| Transmitter | Bristol Babcock | Series 5457-70F | Continuous | 0.085 |
| Transmitter | ITT Barton | 273A | Continuous | 0.085 |
| Transmitter | ITT Barton | 274A | Continuous | 0.085 |
| Transmitter | ITT Barton | 284B | Continuous | 0.085 |
| Transmitter | ITT Barton | 285B | Continuous | 0.085 |

Note: This table is adapted from Table 360-6 of 2011 Amendments for Harmonization of Reporting in Canadian Jurisdictions, Western Climate Initiative (WCI), December 21, 2011.

(3) Data Requirements

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

4.7.4 Tier 4-Direct Measurement

(1) Introduction

Direct measurements may be conducted periodically or continuously.

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

(2) Equations

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

(3) Data Requirements

- Refer to Section 4.1.2 for data requirements.
- Periodic measurements must be conducted on a quarterly basis at minimum.
- The measurement must capture both the static and dynamic bleed rates for pneumatic instruments.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.8 Routine Venting-Pneumatic Pumps

4.8.1 Introduction

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

4.8.2 Tier 1-Default Vent Rates

(1) Introduction

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

(2) Equations

Calculate 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 (Sm³/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 |

Note: 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 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 in pneumatic pumps at the facility during the report period.
- Information regarding to the pump types (piston or diaphragm), manufacturer and model types must be collected and documented.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.
- Facilities are required to follow gas sampling frequencies prescribed in Table 17.3 of Chapter 17.
- Fuel properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.

4.8.3 Tiers 2 and 3-Vent Rate Based on Correlation

(1) Introduction

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

(2) Equations

Calculate 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.

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

1 Where:

| | |
|--------|--|
| VR_i | = Average vent rate for pump i, Sm^3/hr . |
| g | = Supply pressure (SP) coefficient ($\text{m}^3/\text{hr}/\text{kPag}$) for the pump type in Table 4-4. |
| SP | = Supply pressure of the pump (kPag). |
| n | = Injection pressure coefficient (IP) ($\text{m}^3/\text{hr}/\text{kPag}$) for the pump type in Table 4-4. |
| IP | = Injection pressure of the pump (kPag). |
| p | = Strokes per minute coefficient ($\text{m}^3/\text{hr}/\text{kPag}$) for the pump type in Table 4-4. |
| SPM | = Strokes per minute of the pump (strokes/minute). |

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

| Pump Type | Supply Pressure Coefficient (g) ($\text{m}^3/\text{hr}/\text{kPag}$) | Injection Pressure Coefficient (n) ($\text{m}^3/\text{hr}/\text{kPag}$) | Strokes per minute Coefficient (p) ($\text{m}^3/\text{hr}/\text{kPag}$) |
|------------------------|---|--|--|
| 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 |

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

5 **Correlation Method 2:**

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

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

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

10 Where:

| | |
|-----------|--|
| GHG | = CH_4 or CO_2 mass emissions (tonnes) from pneumatic pump venting in the report period. |
| $Q_{c,j}$ | = Volume of liquid chemical injected by pump j (litres). |
| j | = Pump type identifier. |

- i = Number of the pump identifier.
- m = Number of pump types.
- n = Number of pumps for each type of pump.
- CF = Emission control factor (dimensionless).
- VR_j = Natural gas-driven pneumatic pump, j , venting rate ($\text{sm}^3/\text{liter}/\text{pump}$) 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 ($\rho_{\text{CO}_2} = 1.861 \text{ kg}/\text{sm}^3$; $\rho_{\text{CH}_4} = 0.6785 \text{ kg}/\text{sm}^3$).
- 0.001 = Mass conversion factor (tonne/kg).

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

1 Where:

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

2

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

| Manufacturer | Model | Plunger Diameter (in.) | Stroke length (in.) | CIP ² Coeff. (c) | CIP ¹ Coeff. (d) | CIP ⁰ Coeff. (e) |
|--------------|-----------|------------------------|---------------------|-----------------------------|-----------------------------|-----------------------------|
| ARO | 66610 | 120 psi supply | | 0.000E+00 | 8.579E-06 | 7.700E-03 |
| Bruin | BR 5000 | 0.25 | 0.5 | 0.000E+00 | 2.448E-05 | 4.603E+00 |
| Bruin | BR 5000 | 0.25 | 1.25 | 0.000E+00 | 9.530E-06 | 1.848E+00 |
| Bruin | BR 5000 | 0.375 | 0.5 | 0.000E+00 | 2.467E-05 | 2.049E+00 |
| Bruin | BR 5000 | 0.375 | 1.25 | 0.000E+00 | 9.615E-06 | 8.266E-01 |
| Bruin | BR 5000 | 0.5 | 0.5 | 0.000E+00 | 2.474E-05 | 1.133E+00 |
| Bruin | BR 5000 | 0.5 | 1.25 | 0.000E+00 | 9.731E-06 | 4.711E-01 |
| Bruin | BR 5000 | 0.75 | 0.5 | 0.000E+00 | 2.480E-05 | 5.102E-01 |
| Bruin | BR 5000 | 0.75 | 1.25 | 0.000E+00 | 9.899E-06 | 2.042E-01 |
| Bruin | BR 5000 | 1 | 0.5 | 0.000E+00 | 2.480E-05 | 2.868E-01 |
| Bruin | BR 5000 | 1 | 1.25 | 0.000E+00 | 9.932E-06 | 1.150E-01 |
| Bruin | BR 5000 | 1.25 | 0.5 | 0.000E+00 | 2.496E-05 | 1.821E-01 |
| Bruin | BR 5000 | 1.25 | 1.25 | 0.000E+00 | 9.923E-06 | 7.243E-02 |
| Bruin | BR 5000 | 0.1875 | 1 | 0.000E+00 | 9.905E-06 | 2.054E+00 |
| Bruin | BR 5000 | 0.25 | 1 | 0.000E+00 | 1.005E-05 | 1.155E+00 |
| Bruin | BR 5000 | 0.375 | 1 | 0.000E+00 | 1.009E-05 | 5.137E-01 |
| Bruin | BR 5100 | 0.5 | 1 | 0.000E+00 | 1.008E-05 | 2.887E-01 |
| CheckPoint | 1250 | 0.125 | 0.94 | 2.360E-10 | 2.278E-05 | 1.184E+00 |
| CheckPoint | 1250 | 0.25 | 0.94 | 2.224E-10 | 1.129E-05 | 2.773E-01 |
| CheckPoint | 1250 | 0.375 | 0.94 | 1.255E-10 | 1.224E-05 | 1.025E-01 |
| 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 | | 0.000E+00 | 0.000E+00 | 3.464E-01 |
| CheckPoint | LPX-08 | 0.125 | | 0.000E+00 | 0.000E+00 | 1.409E+00 |
| Linc | 84T-10-x1 | 0.1875 | 1 | 0.000E+00 | 1.513E-05 | 3.872E-01 |
| Linc | 84T-11-x1 | 0.25 | 1 | 0.000E+00 | 1.071E-05 | 1.646E-01 |
| Linc | 84T-11-x2 | 0.25 | 1 | 0.000E+00 | 1.190E-05 | 2.925E-01 |
| Linc | 84T-12-x2 | 0.5 | 1 | 0.000E+00 | 1.190E-05 | 7.313E-02 |

| Manufacturer | Model | Plunger Diameter (in.) | Stroke length (in.) | CIP ² Coeff. (c) | CIP ¹ Coeff. (d) | CIP ⁰ Coeff. (e) |
|--------------|----------------|---------------------------|------------------------|--------------------------------|--------------------------------|--------------------------------|
| Linc | 84T-12-x4 | 0.5 | 1 | 0.000E+00 | 1.058E-05 | 1.300E-01 |
| Linc | 84T-14-x4 | 1 | 1 | 0.000E+00 | 1.134E-05 | 3.250E-02 |
| Linc | 87TA-11-x1 | 1 | 1 | 0.000E+00 | 9.921E-06 | 8.545E-02 |
| Linc | 85T-10 | 0.25 | 1 | 0.000E+00 | 1.498E-05 | 1.648E-01 |
| Linc | 85T-11 | 0.5 | 1 | 0.000E+00 | 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 |
| 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 |

| Manufacturer | Model | Plunger Diameter (in.) | Stroke length (in.) | CIP ² Coeff. (c) | CIP ¹ Coeff. (d) | CIP ⁰ Coeff. (e) |
|--------------|-----------|---------------------------|------------------------|--------------------------------|--------------------------------|--------------------------------|
| 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 | 0.000E+00 | 1.176E-05 | 5.212E-02 |
| Timberline | 2522 | | 1 | 0.000E+00 | 1.164E-05 | 9.879E-02 |
| Timberline | 2530 | | 1 | 0.000E+00 | 1.114E-05 | 1.627E-01 |
| Timberline | 5030 | | 1 | 0.000E+00 | 1.100E-05 | 5.155E-02 |
| Timberline | 5040 | | 1 | 0.000E+00 | 1.255E-05 | 3.346E-02 |
| Western | DFE | 0.375 | 0.875 | 0.000E+00 | 1.636E-05 | 7.795E-01 |
| Western | DFE | 0.625 | 0.875 | 0.000E+00 | 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 | 0.000E+00 | 0.000E+00 | 7.716E-01 |
| Williams | CP250V225 | 2.25 | 1 | 0.000E+00 | 0.000E+00 | 6.173E-01 |
| Williams | CP250V300 | 3 | 1 | 0.000E+00 | 0.000E+00 | 1.138E+00 |
| Williams | CP500V225 | 2.25 | 1 | 0.000E+00 | 0.000E+00 | 1.531E-01 |
| Williams | CP500V300 | 3 | 1 | 0.000E+00 | 0.000E+00 | 2.822E-01 |
| Williams | CRP1000V4 | 4 | 1 | 0.000E+00 | 0.000E+00 | 1.224E-01 |
| Williams | CRP1000V6 | 6 | 1 | 0.000E+00 | 0.000E+00 | 2.472E-01 |
| Williams | CRP1000V8 | 8 | 1 | 0.000E+00 | 0.000E+00 | 4.360E-01 |
| Williams | CRP500V40 | 4 | 1 | 0.000E+00 | 0.000E+00 | 4.832E-01 |
| Williams | CRP750V40 | 4 | 1 | 0.000E+00 | 0.000E+00 | 2.227E-01 |

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

(3) Data Requirements

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

4.8.4 Tier 4-Direct Measurement

Refer to Section 4.7.4 for the methodology.

4.9 Compressor Seal Venting

4.9.1 Introduction

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

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

4.9.2 Tier 1-Population Average Vent Rate

(1) Introduction

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

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

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

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

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

(2) Equations

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

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

Where:

| | | |
|-------------------------|---|---|
| GHG | = | CH ₄ or CO ₂ mass emissions (tonnes) from compressor in the report period. |
| i | = | Compressor type identifier. |
| I | = | Total types of compressor in the report period. |
| VR _i | = | Average vent rate (sm ³ /hour/throw or sm ³ /hour/source) for compressor i. Refer to values in Table 4-6a for UOG facilities and Table 4-6b for non-UOG facilities. |
| N | = | Number of throws for reciprocating compressors or number of compressors for centrifugal compressors for each type of compressor i which are operating in the report period. |
| t | = | Total time the compressor i is pressurized in the report period (hours). |
| CF | = | Control factor (dimensionless fraction). |
| MF _{GHG/Gas,i} | = | Mole fraction of CO ₂ or CH ₄ in the vented gas for compressor i. |
| ρ _{GHG} | = | Density of CO ₂ or CH ₄ at standard conditions (ρ _{CO2} = 1.861 kg/sm ³ ; ρ _{CH4} = 0.6785 kg/sm ³). |
| 0.001 | = | Mass conversion factor (tonne/kg). |

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

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

Note: 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.

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

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

2

Notes:

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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.

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8

2. Refer to Table 2-1 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.

9

10

3. Refer to Table 2-2 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.

11

12

4. Refer to Table 2-3 of the Protocol for Equipment Leak Emission Estimations (EPA-453/R- 95-017), EPA, November 1995.

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(3) Data Requirements

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

4.9.3 Tiers 2 and 3-Manufacturer Vent Rate

(1) Introduction

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

(2) Equations

Calculate CH₄ and CO₂ emissions using Equation 4-14. The vent rate is provided by the manufacturer based on the same or similar models and operating conditions. If the vent rate is not available for a specific operating condition, use the highest emission rate available for the manufacturer and model.

(3) Data Requirements

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

4.9.4 Tier 4-Direct Measurement

(1) Introduction

As per AER Directive 060, facilities are required to measure compressor venting starting on January 1, 2020. If a compressor piston-rod packing is replaced on one throw of a reciprocating compressor seal after a test is completed, an average emission rate of 0.16 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 17.3 of Chapter 17.
- Vent gas properties such as gas composition must be measured using an analytical method prescribed in Section 17.2.3 of Chapter 17.
- Facilities may use the fuel gas composition if it is considered to be representative of the vented gas.

4.10 Glycol Dehydrator Venting

4.10.1 Introduction

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

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

(1) Introduction

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

(2) Equations

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

VR = Simulated gas volumetric vent rate for glycol dehydrator i before the vent control equipment (sm³/h).

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

$MF_{GHG/gas}$ = CO₂ or CH₄ mole fraction based on the output of the simulation for glycol dehydrator i (dimensionless).

Typical data inputs for various simulator programs are listed below:

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

(3) Data Requirements

- Facilities are required to follow gas sampling frequencies for wet gas analysis prescribed in Table 17-3 of Chapter 17.
- Wet gas flow rate and circulation rate should be metered continuously and documented for a glycol dehydrator.
- At glycol dehydrator sites, if the dry gas water content is routinely measured, use the measured data. Otherwise, design values for dry gas water content or the number of equilibrium stages in the absorber may be used.

4.11 Glycol Refrigeration Venting

(1) Introduction

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

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

(2) Equations

Refer to Section 4.10 for equations.

(3) Data Requirements

Refer to Section 4.10 for data requirements.

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

4.12.1 Introduction

Sour gas, which is natural gas with high concentrations of acid gas species (H₂S and CO₂), must be treated to reduce the acid gases to a concentration that meets pipeline transportation criteria. Acid Gas Removal (AGR) units remove H₂S and CO₂ by contacting the sour gas with a liquid solution (typically amines). There are other acid gas removal technologies besides amine units, including the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process, the latter of which involves the use of molecular sieves. These technologies are reported to reduce CH₄ emissions too.

Sour gas processing or sulfur recovery units (SRU) can directly vent the CO₂ removed from the sour gas stream to the atmosphere or capture the CO₂ for other uses, such as enhanced oil recovery. These

1 emissions are considered to be formation CO₂ and should be reported under that category. These
2 emissions are discussed in Chapter 10 Formation CO₂. CH₄ emission estimation methodologies are
3 provided in this chapter.

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

6 The following table assigns the methodologies to be used by AGRs and SRUs at the various tiers.
7

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1 **Figure 4-2 Tier Classification and Methodology Mapping**

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

2 **4.12.2 Method 1-Generic CH₄ Vent Rate**

3 **(1) Introduction**

4 For uncontrolled AGR units with an amine-based system, two CH₄ vent rates were developed as part of
 5 the 1996 GRI/EPA CH₄ emissions study (Volume 14, page A-13) based on process simulation results for
 6 typical unit operations of a diethanol amine (DEA) unit (Myers, 1996). Methodologies to calculate CO₂
 7 emissions from AGRs are in Chapter 10 Formation CO₂.

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

10 **(2) Equations**

11 For each AGR unit that is not connected to a flare or thermal oxidizer, calculate the CH₄ emissions using
 12 Equation 4-15.

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

13 Where:

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

14 **Table 4-7 Uncontrolled AGR CH₄ Vent Rate**

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

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

17 **(3) Data Requirements**

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

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

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

4.12.3 Method 2-Vent Rate Using Simulation

(1) Introduction

API's AMINECalc is designed to estimate hydrocarbon emissions from amine based sour gas and natural gas liquid (NGL) sweetening units. The amine system normally consists of a contactor, flash drum and regenerator. The 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 Tiers 1, 2 and 3-Algorithm

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

(1) Introduction

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

(2) Equations

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

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

Where:

- GHG = CH₄ or CO₂ mass emissions (tonnes) from loading loss of product j in the report period.
j = Product type.
n = Types of product loaded.
0.120 = Constant (k kmol/kPa m³).

- Q_j = Volume of the LVP product loaded in the report period (m³).
- MW_{vapor} = Molecular weight of vapor (kg/kmol).
- $P_{\text{true},j}$ = True vapor pressure of the loaded LVP product j (kPa) at bulk liquid temp (T_j). Determined by multiplying the vapor pressure (psi) from Equation 4-16a or Equation 4-16b by 6.8948 to convert psi to kPa.
- SF_j = Saturation factor for LVP product j from Table 4-8 to account for the effects of the method of loading (dimensionless).
- CF = Average emission control factor (dimensionless) for the control system installed, CF is 0 in absence of control system.
- T_j = Bulk temperature of the LVP product j loaded (°C).
- $F_{\text{GHG},\text{vapor}}$ = Mass fraction of CH₄ or CO₂ in vapor evaporated from product j loading.

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

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

4 Where:

- $P_{\text{true},j}$ = 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.

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

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

7 Where:

- $P_{\text{true},j}$ = 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.

1 **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 |

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

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

| Liquid Product | Oil Specific Gravity | Reid Vapor Pressure (RVP) | | Vapor Molecular Weight (kg/kmol) |
|------------------------|----------------------|---------------------------|-------|----------------------------------|
| | | (kPa) | (psi) | |
| 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 |

5 **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 (°F/vol%) |
|-------------------------|---------------------|--------------|---|
| | (psi) | (kPa) | |
| 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 |

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

8 **(3) Data Requirements**

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

4.14 Oil-Water Separator Venting for Refineries

4.14.1 Introduction

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

4.14.2 Tiers 1, 2 and 3-Generic Vent Rate

(1) Introduction

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

- CH₄ = CH₄ mass emissions (tonnes) from oil water separator in the report period.
- Q_{water} = Volume of the wastewater treated in the oil water separator in the report period (m³).
- VR_{sep} = NMHC (non-methane hydrocarbon) emission factor (kg/m³) from Table 4-11.
- CF = Control factor of the oil water separator emission control (dimensionless).
- F_{CH₄/NMHC} = Mass fraction of CH₄ to NMHC. Use either a default factor of 0.6 or species specific conversion factors determined by analysis or estimation.
- 0.001 = Convert factor from kg to tonnes.

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

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

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

⁵ Vent rates do not include ethane

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

(3) Data Requirements

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

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 Tiers 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 report 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 4-12b.

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

| Separator Pressure (psi) | Produced Water Salt Content | Water Tank Vent Rate (VR _{CH4}) tonnes CH ₄ /1000 m ³ produced water |
|--------------------------|-------------------------------|---|
| 50 | 20% | 0.009185 |
| 250 | 20% | 0.06200 |
| 250 | 10% | 0.09414 |
| 250 | 2% | 0.11137 |
| 250 | Average of 10.7% ¹ | 0.08917 |
| 1000 | 20% | 0.22273 |
| 1000 | 10% | 0.33697 |
| 1000 | 2% | 0.39896 |
| 1000 | Average of 10.7% ¹ | 0.31955 |

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

5 1: Average of vent rates at 20%, 10% and 2% salt.

6 **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 |

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

9 **(3) Data Requirements**

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

12 **4.16 Non-Routine Venting-Well Tests, Completion, and Workovers**

13 **4.16.1 Introduction**

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

15 **4.16.2 Tiers 1, 2 and 3**

16 **(1) Introduction**

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

20 **(2) Equations**

21 For each blowdown event, calculate CH₄ or CO₂ emissions and sum the CH₄ or CO₂ emissions from
 22 blowdown events to calculate total emissions in the report period using Equation 4-19.

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

23 Where:

| | | |
|-------------------|---|---|
| GHG | = | CH ₄ or CO ₂ mass emissions (tonnes) from well tests, completion and workovers events in the report period. |
| i | = | Vent event identifier. |
| n | = | Number of events in the report period. |
| Q _v | = | Total vented gas volume (m ³) during a well test, completion or workover event. |
| MF _{GHG} | = | Mole fraction of CO ₂ or CH ₄ in vented gas. |
| ρ _{GHG} | = | Density of CO ₂ or CH ₄ at standard conditions (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 vented gas volume during the event must be quantified according to AER Directive 040 for minimum standards for performing well tests, and AER Directive 059 requirements for drilling, completion, reconditioning, or well abandonment.
- The composition of the vented gas should be measured before a planned event. Gas compositions must be measured using:
 - An applicable analytical method prescribed by AER Directives for UOG facilities;
 - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

4.17 Non-Routine Venting-Process System Blowdown

4.17.1 Introduction

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

4.17.2 Tiers 1, 2 and 3-Algorithm

(1) Introduction

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

(2) Equations

For blowdown emissions, calculate 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 Tiers 1, 2, and 3-Algorithm

(1) Introduction

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

(2) Equations

For each liquids unloading venting source, calculate 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.

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

Where:

GHG = CH₄ or CO₂ mass emissions (tonnes) from gas well liquid unloading venting in the report period.

i = Gas well liquid unloading event identifier.

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

7.854×10^{-5} = $(\pi/4)/(10,000)$.

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 (Sm³/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 CO₂ or CH₄ in vented gas.

ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO2} = 1.861 kg/sm³; ρ_{CH4} = 0.6785 kg/sm³)

0.001 = Mass conversion factor (tonne/ kg).

(3) Data Requirements

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

4.18.3 Tier 4-Direct Measurement

(1) Introduction

This method is for wells that have a flow meter installed on the vent line used to vent gas from the well (e.g. on the vent line off the wellhead separator or atmospheric storage tank).

(2) Equations

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

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

Where:

GHG = CH₄ or CO₂ mass emissions (tonnes) from gas well liquid unloading venting in the report period.

i = Well identifier.

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

VR_i = The well vent average flow rate of the measured well i venting for the duration of the liquids unloading event under actual conditions (m³/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 CO₂ or CH₄ in vented gas.

ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO2} = 1.861 kg/sm³; ρ_{CH4} = 0.6785 kg/sm³).

0.001 = Mass conversion factor (tonne/ kg).

(3) Data Requirements

- Refer to Section 4.1.2 for data requirements.
- A well vent flow rate measurement should be conducted in accordance with Chapter 17.

- Determine the well vent average flow rate as specified in the following:
 - The average flow rate per hour of venting is calculated for each unique tubing diameter and producing horizon/formation combination in each producing field. The flow rates can be measured from one well representing each unique tubing diameter and producing horizon/formation combination in each producing field.
 - This average flow rate is applied to all wells in the field that have the same tubing diameter and producing horizon/formation combination.
 - Flow rates should be measured every other calendar year (if there is a change). An average flow rate is then also recalculated every other calendar year (if there is a change) for each reporting field and horizon starting the first calendar year of data collection.
- Gas compositions must be measured using:
 - An applicable analytical method prescribed by AER Directives for UOG facilities;
 - An analytical method prescribed in Section 17.2.3 of Chapter 17.
- When a measurement is not possible, the composition must be determined based on process knowledge and/or engineering estimates.

4.19 Non-Routine Venting-Engine and Turbine Starts

4.19.1 Tiers 1, 2 and 3- Generic Vent Rate

(1) Introduction

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

(2) Equations

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

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

Where:

- GHG = CH₄ or CO₂ mass emissions from engine or turbine start events (tonnes) in the report period.
- VR = Manufacturer vent rate for the engine or turbine stated in Table 4-13 (m³ NG/hour).
- i = Engine or turbine identifier.
- n = Number of engines or turbines.
- t_{total,j} = Total time for engine or turbine i starts in the report period calculated using Equation 4-22a (hr).
- CF = Control factor (dimensionless fraction).

- MF_{GHG} = Mole fraction of CO₂ or CH₄ in vented gas.
- ρ_{GHG} = Density of CO₂ or CH₄ at standard conditions (ρ_{CO₂} = 1.861 kg/sm³; ρ_{CH₄} = 0.6785 kg/sm³).
- 0.001 = Conversion factor from kg to tonne.

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

1 Where:

- t_{total,j} = Total start duration (hr) for engine or turbine j in the report period.
- t_{un,start} = Average duration per unsuccessful engine or turbine start (hr/start).
- N_{un,j} = Number of unsuccessful starts.
- T_{s,start} = Average duration per successful engine or turbine start (hr/start).
- N_{un,j} = Number of successful starts.

2 **(3) Data Requirements**

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

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

| Engine/Turbine | | | Pneumatic Starter | | | | |
|-----------------|------------------|---|-------------------------|--------------------------|------------------------|--|-----------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | |
| | | | | | | (m3/min) | (m3/hour) |
| Turbine | Allison | 501-KB | Ingersoll Rand | TS799B | 1,034 | 80 | 4,822 |
| | | 501-KC | Tech Development | 56K (Low Pressure) | 345 | 33 | 1,954 |
| | | | | 56K (Standard Pressure) | 621 | 55 | 3,288 |
| | | 570 | Ingersoll Rand | TS799G | 621 | 51 | 3,068 |
| | Dresser Clark | DC990 | Tech Development | 56B (Low Pressure) | 345 | 36 | 1,954 |
| | | | | 56B (Standard Pressure) | 1,034 | 86 | 5,172 |
| | Dresser Rand | DR990 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 |
| | | 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 | |
| Turbine (cont.) | Solar Turbines | Saturn 20 | Ingersoll Rand | TS725 | 1,551 | 27 | 1,644 |
| | | | | TS750 | 1,034 | 44 | 2,652 |
| | | | Tech Development | 56S | 1,034 | 29 | 1,725 |
| | | Centaur 40 | Ingersoll Rand | TS1401-102 | 1,551 | 62 | 3,726 |

| Engine/Turbine | | | Pneumatic Starter | | | | | | |
|--------------------------|------------------|------------------------------|-------------------------------|----------------------------------|------------------------|--|------------------|--------|-------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | | | |
| | | | | | | (m3/min) | (m3/hour) | | |
| | | Centaur 50 | | TS1435 | 1,551 | 69 | 4,164 | | |
| | | Taurus 60 | | TS1450 | 1,034 | 91 | 5,479 | | |
| | | Taurus 65 | Tech Development | T100C | 1,034 | 64 | 3,844 | | |
| | | Taurus 70 | | | | | | | |
| | | Mars 90 Mars 100 | Recommended by Solar Turbines | | 2,758 | 127 | 7,620 | | |
| Reciprocating Engine | Caterpillar | 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 | | |
| | | Reciprocating Engine (cont.) | Caterpillar | G3612 G3616 G-398 G-399 | Ingersoll Rand | SS815 | 1,034 | 62 | 3,726 |
| G3406 G3408 G3408C | Tech Development | | | | | T306-I | 827 | 17 | 1,048 |
| | | | | | | G3606 G3608 G3612 G3616 | Tech Development | T112-V | 1,034 |
| T121-V | 621 | | | | | | | 59 | 3,520 |

| Engine/Turbine | | | Pneumatic Starter | | | | |
|------------------------------|---------------------|--|-------------------|--------|------------------------|--|-----------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | |
| | | | | | | (m3/min) | (m3/hour) |
| | Cooper Ajax | C280 | | | | | |
| | | 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 |
| Reciprocating Engine (cont.) | Cooper Ajax (cont.) | DPC-280 | Tech Development | T112-B | 621 | 57 | 3,419 |
| | | DPC-230 DPC-250 DPC-325 DPC-360 DPC-600 DPC-800 | | T121-B | 1,034 | 5 | 298 |
| | Cooper Bessemer | GMX GMSC | Austart | ATS93 | 1,034 | 48 | 2,871 |
| | | 10W330 12V-250 GMVA GMVW MVWC GMXF | Ingersoll Rand | ST950 | 1,034 | 47 | 2,849 |
| | | GMXE GMXF GMXH | Ingersoll Rand | SS850 | 1,034 | 47 | 2,794 |
| | Cooper Superior | 6G-825 8G-825 | Austart | ATS83 | 1,034 | 22 | 1,293 |

| Engine/Turbine | | | Pneumatic Starter | | | | | | | | | | | | | | |
|------------------------------|-------------------------|--|-------------------|--------|------------------------|--|-----------|---------|-------|-------|----|-------|---------|-------|-------|----|-------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | | | | | | | | | | | |
| | | | | | | (m3/min) | (m3/hour) | | | | | | | | | | |
| | | 8GT | | | | | | | | | | | | | | | |
| | | 12SGT 16SGT | Austart | ATS93 | 1,034 | 48 | 2,871 | | | | | | | | | | |
| Reciprocating Engine (cont.) | Cooper Superior (cont.) | 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 5790 7042 8LAT27G | Austart | ATS73 | 1,034 | 22 | 1,293 | | | | | | | | | | |
| | | | | | | | | Austart | ATS83 | 1,034 | 22 | 1,293 | | | | | |
| | | | | | | | | | | | | | Austart | ATS93 | 1,034 | 48 | 2,871 |
| | | | | | | | | | | | | | | | | | |
| | Waukesha (cont.) | 145GZ 6GAK 6WAK F1197G F119G H1077G H1077G H24L | Ingersoll Rand | 150T | 1,034 | 26 | 1,556 | | | | | | | | | | |

| Engine/Turbine | | | Pneumatic Starter | | | | |
|------------------------------|------------------|---|-------------------|--------|------------------------|--|-----------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | |
| | | | | | | (m3/min) | (m3/hour) |
| | | 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 |
| Reciprocating Engine (cont.) | Waukesha (cont.) | 195GL 6BL V1K V1L VRG283 VRG310 | Ingersoll Rand | 3BMG | 1,034 | 12 | 712 |
| | | 140GZ 140HK 6SRK | Ingersoll Rand | 5BMG | 1,034 | 11 | 679 |
| | | 6SRB | Ingersoll Rand | SS175G | 1,034 | 18 | 1,096 |
| | | F11G (SI) F18GL (D) H24GL (D) | Ingersoll Rand | SS350G | 1,034 | 33 | 1,973 |

| Engine/Turbine | | | Pneumatic Starter | | | | | |
|------------------------------|------------------|---|---------------------|------------------|------------------------|--|-----------|-------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | | |
| | | | | | | (m3/min) | (m3/hour) | |
| | | 145GZ 6GAK 6WAK F1197G F119G H1077G H24L | Ingersoll Rand | 150BM | 1,034 | 25 | 1,490 | |
| Reciprocating Engine (cont.) | Waukesha (cont.) | 7044 7042G (SI/L) 8LAT25D 8LAT25GLF2 895G (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 | |
| | | | | T112-V | 1,034 | 54 | 3,226 | |
| | | | | Tech Development | T121-V | 621 | 59 | 3,520 |
| | | White | RXC RXLD RXLX | Ingersoll Rand | 5BMG | 1,034 | 11 | 679 |

| Engine/Turbine | | | Pneumatic Starter | | | | |
|----------------|--------------|-------|-------------------|-------|------------------------|--|-----------|
| Type | Manufacturer | Model | Manufacturer | Model | Supply Pressure (kPag) | Max. Natural Gas Consumption Rate ¹ | |
| | | | | | | (m3/min) | (m3/hour) |
| | | TDXC | | | | | |

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

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4.20 Non-Routine Venting-Pressure Relief

(1) Introduction

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

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

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

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

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

(2) Equations

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

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

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

(3) Data Requirements

- Actual process temperature and pressure conditions should be used when calculating GHG emissions for each pressure relief event. Engineering estimates should be used if process data is unavailable.

- The composition, physical and transport properties of relief fluids should either be directly measured or estimated based on process knowledge and/or engineering estimates.
- Volumes of process equipment should be calculated directly from isometric drawings as well as vessel and equipment detail drawings.

4.21 Other Venting Emission Sources

(1) Introduction

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

(2) Equations

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

Tier 1:

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

Tier 2:

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

Tier 3:

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

Tier 4:

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

(3) Data Requirements

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

5.0 Quantification Methods for On-Site Transportation

5.1 Introduction

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

Examples of on-site transportation include:

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

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

Under the Carbon Competitiveness Incentive Regulation (CCIR), specified gas emissions from the combustion of unmarked gasoline and diesel fuels are reported in a facility's compliance reports; however emissions that are priced under the carbon levy are subtracted from the facility's total regulated emissions (TRE). Specifically for the period up to May 30, 2019, emissions from unmarked fuels are subtracted from the TRE; while emissions subsequent to this date are included in the TRE. Therefore, facilities are required to report these emissions separately under CCIR (i.e. emissions from unmarked fuels for the period between January 1 to May 30, 2019 and May 31 to December 31, 2019).

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

5.2 Carbon Dioxide

5.2.1 Introduction

For each fuel type combusted from on-site transportation, calculate the mass of carbon dioxide (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 tier classification that is assigned to the facility as illustrated in Figure 1.1. A facility must also apply the sampling requirements in Chapter 17 that corresponds with the facility's tier classification.

Figure 5-1 Tier Classification and Methodology Mapping for CO₂ Emissions from On-Site Transportation

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

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

1
2 **5.2.2 Method 1 - A Fuel-Specific Default CO₂ Emission Factor for Non-Variable**
3 **Fuels**

4 Facilities are required to use Equation 1-1 or Equation 1-1a from Section 1.2.2 of Chapter 1 Stationary
5 Fuel Combustion to calculate the CO₂ emissions from on-site transportation. Facilities are also required to
6 meet the same data requirements as prescribed in Section 1.2.2. Refer to Table 1-1 of Chapter 1 for the
7 emission factors for non-variable fuels.

8 These emissions do not include CO₂ emissions from biomass combustion. For blended fuels such as
9 gasoline and diesel, a facility may use the "Diesel in Alberta" and/or "Gasoline in Alberta" to account for
10 the minimum biofuel content. Facilities may also apply Method 3 (below) to account for actual biofuel
11 content in diesel and/or gasoline usage for on-site transportation.

12 **5.2.3 Method 2 - CO₂ Emissions from Combustion of Natural Gas**

13 Facilities are required to use Equation 1-2 from Section 1.2.3 of Chapter 1 Stationary Fuel Combustion to
14 calculate the CO₂ emissions from on-site transportation. Facilities are also required to meet the same data
15 requirements as prescribed in Section 1.2.3.

16 **5.2.4 Method 3 - CO₂ Emissions from Variable Fuels Based on the Measured Fuel**
17 **Carbon Content**

18 Facilities are required to use Equation 1-3c from Section 1.2.4 of Chapter 1 Stationary Fuel Combustion
19 to calculate the CO₂ emissions from on-site transportation using variable fuels. Facilities are also required
20 to meet the same data requirements as prescribed in Section 1.2.4.

21 **5.3 Methane and Nitrous Oxide**

22 **5.3.1 Introduction**

23 Calculate the methane (CH₄) and nitrous oxide (N₂O) mass emissions for the reporting period from on-
24 site transportation emissions, for each fuel type including biomass fuels, using the methods specified in
25 this section. Figure 5-2 provides the requirements for facilities based on tier classification.

26 **Figure 5-2 Requirements Based on Tier Classification**

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

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

29 **5.3.2 Method 1 - Default CH₄ and N₂O Emission Factor**

30 Facilities are required to use Equation 1-4 or Equation 1-4a of Chapter 1 Stationary Fuel Combustion to
31 calculate CH₄ and N₂O emissions from on-site transportation. Facilities are also required to meet the same
32 data requirements as prescribed in Section 1.3.2. Table 1-1 of Chapter 1 and Table 5-1 present the
33 emission factors for various fuels in mass of CH₄ and N₂O emitted per GJ or kilolitres. For a fuel that is
34 not prescribed an emission factor in these tables, the facility may use an emission factor from an
35 alternative source or use an emission factor from a fuel that is similar in characteristics to a fuel that has a
36 prescribed emission factor.

1 For CH₄ and N₂O emission calculations, the volume of diesel and gasoline used in on-site transportation
 2 must include the biofuel content, as these emissions are not considered to be biomass combustion
 3 emissions.

4 **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) |
|--------------------------------------|--|---|
| Road Transport | | |
| Gasoline Vehicles | | |
| Light-duty Gasoline Vehicles (LDGVs) | | |
| Tier 2 | 1.4E-04 | 2.2E-05 |
| Tier 1 | 2.3E-04 | 4.7E-04 |
| Tier 0 | 3.2E-04 | 6.6E-04 |
| Oxidation Catalyst | 5.2E-04 | 2.0E-04 |
| Non-catalytic Controlled | 4.6E-04 | 2.8E-05 |
| Light-duty Gasoline Trucks (LDGTs) | | |
| Tier 2 | 1.4E-04 | 2.2E-05 |
| Tier 1 | 2.4E-04 | 5.8E-04 |
| Tier 0 | 2.1E-04 | 6.6E-04 |
| Oxidation Catalyst | 4.3E-04 | 2.0E-04 |
| Non-catalytic Controlled | 5.6E-04 | 2.8E-05 |
| Heavy-duty Gasoline Vehicles (HDGVs) | | |
| Three-way Catalyst | 6.8E-05 | 2.0E-04 |
| Non-catalytic Controlled | 2.9E-04 | 4.7E-05 |
| Uncontrolled | 4.9E-04 | 8.4E-05 |
| Motorcycles | | |
| Non-catalytic Controlled | 7.7E-04 | 4.1E-05 |
| Uncontrolled | 2.3E-03 | 4.8E-05 |
| Diesel Vehicles | | |
| Light-duty Diesel Vehicles (LDDVs) | | |
| Advanced Control | 5.1E-05 | 2.2E-04 |
| Moderate Control | 6.8E-05 | 2.1E-04 |
| Uncontrolled | 1.0E-04 | 1.6E-04 |
| Light-duty Diesel Trucks (LDDTs) | | |
| Advanced Control | 6.8E-05 | 2.2E-04 |
| Moderate Control | 6.8E-05 | 2.1E-04 |
| Uncontrolled | 8.5E-05 | 1.6E-04 |
| Heavy-duty Diesel Vehicles (HDDVs) | | |
| Advanced Control | 1.1E-04 | 1.5E-04 |
| Moderate Control | 1.4E-04 | 8.2E-05 |
| Uncontrolled | 1.5E-04 | 7.5E-05 |
| Natural Gas Vehicles | 9.0E-06 | 6.0E-08 |
| Propane Vehicles | 6.4E-04 | 2.8E-05 |
| Off-road | | |
| Off-road Gasoline 2-stroke | Refer to Table 1-1 in Chapter 1 | |

| Type of Fuel and Mobile Equipment | CH ₄ Emission Factor (tonnes/kl) | N ₂ O Emission Factor (tonnes/kl) |
|------------------------------------|--|---|
| Off-road Gasoline 4-stroke | Stationary Fuel Combustion | |
| Off-road Diesel <19kW | | |
| Off-road Diesel >=19kW, Tier 1 - 3 | | |
| Off-road Diesel >= 19kW, Tier 4 | | |
| Off-road Natural Gas | 8.8E-06 | 6.0E-08 |
| Off-road Propane | 6.4E-04 | 8.7E-05 |
| Railways | | |
| Diesel Train | 1.5E-04 | 1.0E-03 |
| Marine | | |
| Gasoline | 2.2E-04 | 6.3E-05 |
| Diesel | 2.5E-04 | 7.2E-05 |
| Light Fuel Oil | 2.6E-04 | 7.3E-05 |
| Heavy Fuel Oil | 2.9E-04 | 8.2E-05 |
| Kerosene | 2.5E-04 | 7.1E-05 |
| Aviation | | |
| Aviation Gasoline | 2.2E-03 | 2.3E-04 |
| Aviation Turbo Fuel | 2.9E-05 | 7.1E-05 |

Note: Unless otherwise indicated, emission factors are adapted from the 2018 National Inventory Report (NIR 2018) Annex 3.

Any comments or questions regarding the content of this document may be directed to:

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Original signed by: _____ Date: _____
Name of Approver
Program/branch name
Alberta Climate Change Office