Alberta Greenhouse Gas Quantification Methodologies

Technology Innovation and Emissions Reduction Regulation

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Alberta Greenhouse Gas Quantification Methodologies

Summary of Revisions

Version	Date	Summary of Revisions
DRAFT (TIER)	May 2020	Draft Chapter 15 Aggregate Facilities posted for stakeholder comments.
2.0 (TIER)	October 2020	Final publication of Chapter 15 Aggregate Facilities.

Chapter 15
Aggregate Facilities

Technology Innovation and Emissions Reduction Regulation

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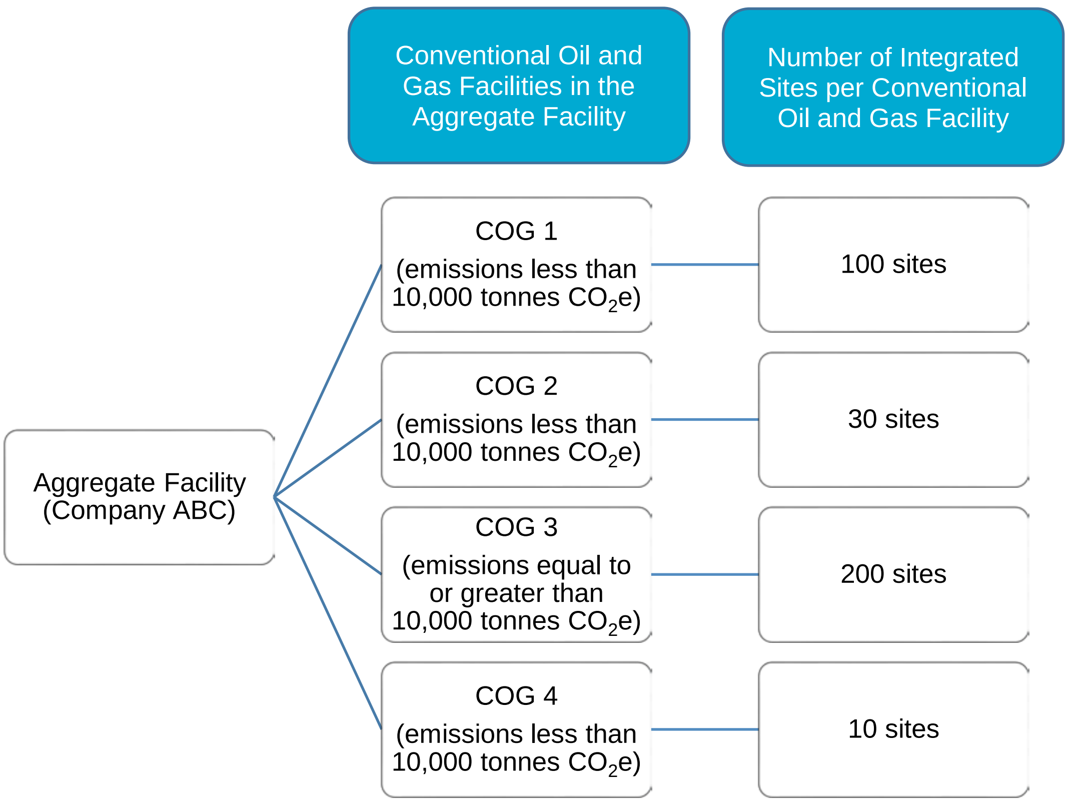
15. Aggregate Facilities

15.1. Introduction

This chapter provides quantification methodologies for aggregate facilities regulated under the Technology Innovation and Emissions Reduction Regulation (TIER). The methodologies prescribed in this chapter are not applicable for other facilities regulated under TIER or the Specified Gas Reporting Regulation (SGRR). An aggregate facility consists of two or more conventional oil and gas facilities (COG). Further, multiple sites may be integrated in operation and be identified as a single COG within an aggregate facility provided the integrated site emits less than 100,000 tonnes CO_2e. Figure 15-1 provides an example of an aggregate facility.

Figure 15-1: Example of an aggregate facility



Under TIER, aggregate facilities' regulated emissions only include stationary fuel combustion emissions and total production for benchmarking applications and annual compliance reports.

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

This document details quantification methodologies for both the benchmark application and annual compliance reports for aggregate facilities under TIER. Annual compliance reports are mandatory for regulated facilities and must be submitted by the deadline established in the TIER regulation. Benchmark applications for aggregate facilities are elective.

If the person responsible for an aggregate facility does not submit a benchmark application by the aggregate benchmark application deadline, as established by the TIER regulation, a facility-specific benchmark and benchmark unit will be determined by the Director and assigned to the person responsible for the aggregate facility. The determination and assignment will follow the facility-specific benchmark methodology outlined in the Standard for Developing Benchmarks and the benchmark unit methodology and criteria outlined in Section 15.4 of this document.

The Director’s default determination will be based solely on available data reported in the Petrinex reporting system. Emissions associated with any fuel volumes that were not reported will be excluded from the determination, which may result in a lower benchmark than if those volumes are disclosed and incorporated as part of a complete benchmark application.

Quantification methodologies in the Alberta Greenhouse Gas Quantification Methodologies (AQM) are classified by levels of stringency and accuracy with the lowest at level 0 and highest at level 4. The minimum levels required to be used for benchmarking applications and compliance reporting are provided in the Standard for Developing Benchmarks and the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports, respectively.

COGs that have facility emissions equal to or greater than 10,000 tonnes of carbon dioxide equivalent emissions must ensure that the requirements prescribed by Environment and Climate Change Canada (ECCC) for the Greenhouse Gas Reporting Program (GHGRP) are met. ECCC publishes annual updates to these requirements and it is the responsibility of the reporter to ensure that these requirements are met.

Table 15-1 provides the quantification methodology levels for different methods that may be used to quantify fuel consumption, emissions, and production for each COG within the aggregate. In general, methods selected for COGs within the aggregate facility must be the same in the benchmark and compliance report. Throughout this chapter, criteria are provided on how to remain consistent in the application of methodologies between the benchmark and compliance periods.

Table 15-1: Quantification Methodologies for Conventional Oil and Gas Facilities

Level[1]	Methods
Fuel Consumption	
0	Method 15-1 – Single gas stream approach
1	Method 15-2 – Multiple gas stream approach
	Method 15-3 – Third party supplied fuels
Carbon Dioxide Emissions	
0	Method 15-4 – Single default CO_2 emission factor
1	Method 15-5 – Default CO_2 emissions factors for non-variable fuels
	Method 15-6 – Higher heating value correlation
	Method 15-7 – Gas compositional analysis
Methane and Nitrous Oxide Emissions	
0, 1	Method 15-8 – Default emission factors for non-variable fuels (Table 15-4)
0, 1	Method 15-9 – Variable fuel sector-based emission factors (Table 15-5)
0, 1	Method 15-10 – Variable fuel technology-based emission factors (Table 15-6)
Production	
0, 1	Method 15-11 – Petrinex production volumes

1. This is the minimum level prescribed to a corresponding method. A COG is permitted to use a method that is prescribed at a higher level.

Based on the above level classifications, the simplest approach for emissions quantification is to apply:

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

“Negligible emission sources” are sources with combined carbon dioxide equivalent (CO_2e) emissions that represent less than 1% of a facility’s total regulated emissions or allowable emissions and do not exceed 10,000 tonnes of CO_2e for a facility under TIER. Alternative quantification methodologies may be used to quantify and assess the negligibility of these emissions. These emissions must still be included in the total regulated emissions.

15.2. Fuel Consumption and Composition

(1) Introduction

Fuel consumption at individual COGs may be calculated using one or more of the following methods:

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

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

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

(2) Equation

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

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

Where:

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

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

(1) Introduction

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

(2) Equation

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

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

(1) Introduction

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

(2) Equation

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

(3) Data requirements

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

15.2.3. Method 15-3 - Fuel consumption based on internal facility metering or third party metering or invoicing (not reported in Petrinex)

(1) Introduction

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

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

(2) Equation

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

(3) Data requirements

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

15.3. Stationary Fuel Combustion Emissions

Stationary fuel combustion (SFC) sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of providing useful heat or energy for industrial, commercial, or institutional use. Stationary fuel combustion sources include, but are not limited to boilers, simple and combined-cycle combustion turbines, engines, emergency generators, portable equipment, process heaters, furnaces and any other combustion devices or systems (e.g. blasting for mining purposes and drilling and completion activities). This source category does not include flare emission sources or waste incineration.

The primary greenhouse gases that are emitted from stationary fuel combustion are carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

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

15.3.1. Method 15-4 - CO_2 emissions based on default fuel gas emission factor

(1) Introduction

For this method, the CO_2 emissions is calculated assuming a single fuel gas stream and a default emission factor in tonnes of CO_2 emissions per cubic metre of fuel consumed (tCO_2/m^3). The default emission factor assumes a rich gas composition as presented in Table 15-2. This method is used with fuel gas volumes calculated by Method 15-1.

If this method is selected for a COG or group of COGs, it must be used for the benchmark and compliance report. If the person responsible for an aggregate facility would like to apply different methodologies for a COG or group of COGs, they must revise their benchmark and/or compliance report to ensure that the same methodologies are applied for both the benchmark and compliance report.

The person responsible for a COG or group of COGs that would like to:

(1) apply gas compositions or HHV to calculate CO_2 emissions and do not have the required gas compositions or HHV for the benchmark period; or

(2) change methodologies from using the default CO_2 emission factor to gas composition or HHV to calculate CO_2 emissions for compliance reporting and do not have the required gas compositions or HHV for the benchmark period,

may apply a default sales gas emission factor for the benchmark period. The default sales gas composition and emission factor is provided in Table 15-2 can only be applied for these scenarios.

(2) Equation

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

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

Where:

$CO_{2,\,p,i}$	=	CO_2 mass emissions for fuel type *i* for the reporting period, *p* (tonnes CO_2).
$v_{fuel,\,p,i}$	=	Volume of fuel consumed for fuel type *i* in cubic metres (m^3) for the reporting period, *p* at standard conditions (15°C, 1 atm) calculated using Method 15-1.
EF_{vol}	=	Default CO_2 emission factor from Table 15-2 in tonnes of CO_2 per cubic metres (tCO_2/m^3).

Table 15-2: Default Fuel Gas and Carbon Dioxide Emission Factor

Parameter	Default Values
For Benchmarking and Compliance Reporting[1]:	
Default Carbon Dioxide Emission Factor (volume basis (tCO_2/m^3)	0.00233
Default Rich Gas Composition (vol%)	
Methane (CH_4)	80
Ethane (C_2H_6)	15
Propane (C_3H_8)	5
Default Higher Heating Value (GJ/m^3)	0.04477
For Benchmarking only[2]:	
Default Carbon Dioxide Emission Factor (volume basis) (tCO_2/m^3)	0.00190
Default Sales Gas Composition (vol%)	
Methane (CH_4)	98
Ethane (C_2H_6)	1
Propane (C_3H_8)	0.3
Butane (C_4H_{10})	0.1
Carbon Dioxide (CO_2)	0.3
Nitrogen (N_2)	0.3
Default High Heating Value (GJ/m^3)	0.03825

1. The prescribed CO_2 emission factor must be used for the benchmark and compliance report.
2. If a COG would like to use gas compositions or HHV to calculate CO_2 for compliance reporting, but does not have gas compositions or HHV data for the benchmark period, the COG may apply this default emission factor for benchmarking.

15.3.2. Method 15-5 - CO_2 emissions based on default emission factors for non-variable fuels not reported in Petrinex

(1) Introduction

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

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

Fuel consumption may be provided by the third party supplier on a volume or energy basis. Emission factors based on tonnes of CO_2 emissions per volume basis or energy basis are provided in Table 15-3.

(2) Equation

Using Equation 15-5 or 15-5a, the CO_2 emissions are calculated using the fuel volumes calculated by Method 15-3 and the default emission factor for the non-variable fuel presented in Table 15-3.

$$CO_{2,p,i} = v_{fuel,p,i} \times HHV_i \times EF_{ene,i} \qquad \text{Equation 15-5}$$

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

Where:

$CO_{2, p, i}$	=	CO_2 mass emissions for the non-variable fuel type *i* for the reporting period, *p* (tonnes CO_2).
$v_{fuel, p,i}$	=	For Equations 15-5 and 15-5a, the volume of fuel for fuel type *i* combusted in kilolitres (kl) combusted during reporting period, *p*.
$ENE_{fuel,p,i}$	=	For Equation 15-5a, energy of fuel for fuel type *i* in gigajoules (GJ) combusted during reporting period, *p*.
$HHV_{p,i}$	=	Measured or supplied higher heating value in gigajoules per kilolitres (GJ/kl) for fuel type *i* for the reporting period, *p*.
$EF_{vol,i}$, $EF_{ene,i}$	=	Fuel-specific default CO_2 emission factor for fuel type *i* from Table 15-3 in tonnes of CO_2 per volume units (kl) or energy units (GJ).

Table 15-3: Carbon Dioxide Emission Factors for Non-Variable Fuels

Non-Variable Fuels	CO_2 Emission Factor[2]	
	tonne/kl	tonne/GJ
Diesel	2.681	0.0699
Diesel in Alberta[1]	2.610	0.06953
Gasoline	2.307	0.069
Gasoline in Alberta[1]	2.174	0.06540
Butane	1.747	0.0614
Ethane	0.986	0.0573
Propane	1.515	0.0599

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

15.3.3. Method 15-6 - CO_2 emissions based on high heating value correlation

(1) Introduction

This method is consistent with ECCC's Canada's Greenhouse Gas Quantification Requirements for calculating CO_2 mass emissions from fuel gas combustion based on the measured HHV. The volumes of fuel gas consumed by a COG is calculated based on Method 15-2 or Method 15-3.

(2) Equation

Using Equation 15-6, the CO_2 emissions are calculated based on the HHV of the fuel gas provided by the fuel supplier or measured by the facility.

$$CO_{2,p,i} = v_{fuel,i,p} \times (60.554 \times HHV_{p,i} - 404.15) \times 10^{-6} \qquad \text{Equation 15-6}$$

Where:

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

$v_{fuel,i\ p}$	=	Volume of fuel (m^3) for fuel type *i* at standard conditions (15°C, 1 atm) combusted during reporting period, *p*.
$HHV_{p,i}$	=	Weighted average higher heating value of fuel type *i* (MJ/m^3) at standard conditions (15°C, 1 atm) for the reporting period, *p*.
$(60.554 \times HHV_{p,i} - 404.15)$	=	Empirical equation adapted from ECCC (grams of CO_2 per cubic meter of natural gas) representing relationship between CO_2 and volume of gas determined through higher heating value using a discrete set of data collected by ECCC.
10^{-6}	=	Mass conversion factor (t/g).

(3) Data requirements

- Quarterly sampling and analysis for the fuel gas HHVs is required for each fuel gas stream identified in the COG. Sampling frequencies prescribed in Table 17.1 of Chapter 17 does not apply for this method.
- The HHV must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance for calculating weighted averages and acceptable analytical methods than can be used for heating value analysis.

15.3.4. Method 15-7 - CO_2 emissions based on fuel gas carbon content

(1) Introduction

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

(2) Equation

Using Equation 15-7a or Equation 15-7b, the CO_2 emissions are calculated based on the carbon content of each fuel gas type consumed during the reporting period.

For gaseous fuels, where fuel consumption is measured on a volume (m^3) basis, use Equation 15-7a:

$$CO_{2,p,i} = v_{fuel\,(gas),i,p} \times CC_{gas,p,i} \times 3.664 \times 0.001 \qquad \text{Equation 15-7a}$$

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

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

Where:

$CO_{2,p,i}$	=	CO_2 mass emissions for fuel type *i* combusted during the reporting period, *p* (tonnes CO_2).
$v_{fuel(gas),i,\,p}$	=	Volume of fuel (m^3) for fuel type *i* at standard conditions (15^oC, 1 atm) combusted during reporting period, *p*.
$ENE_{fuel(gas),p}$	=	Energy of fuel (GJ) for fuel type, *i* at standard conditions (15^oC, 1 atm) combusted during reporting period, *p*.
$HHV_{p,i}$	=	Weighted average higher heating value of fuel type *i* (GJ/m^3) at standard conditions (15^oC, 1 atm) for the reporting period, *p*.
$CC_{gas,p}$	=	Weighted average carbon content of fuel type *i* at standard conditions (15^oC, 1 atm) during the reporting period *p*. CC_p is in units of kilogram of carbon per standard cubic metre of gaseous fuel (kg C/m^3).
3.664	=	Ratio of molecular weights, CO_2 to carbon.
0.001	=	Mass conversion factor (t/kg).

(3) Data requirements

- The carbon content may be provided by the third party supplier or measured by the facility.
- Quarterly sampling and analysis for gas composition is required for each fuel gas stream identified in the COG. The gas composition must be calculated for each fuel gas stream using a weighted-average approach. Chapter 17 provides guidance on calculating weighted averages and acceptable analytical methods that can be used for gas compositional analysis. Note that sampling frequencies in Table 17.1 of Chapter 17 do not apply for this method.

15.3.5. Methane and nitrous oxide emissions

For all COGs, the following methods are used to calculate the CH_4 and N_2O mass emissions based on default emission factors that are volume or energy basis.

There are three types of default CH_4 and N_2O emission factors specified under three methods. Method 15-8 provides emission factors for non-variable fuels; while Methods 15-9 and 15-10 provides emission factors for variable fuels that are sector-based and technology-based, respectively.

Method 15-8 - Non-variable fuel emission factors

For all non-variable fuels such as propane, diesel, and gasoline, methane and nitrous oxide emission factors are prescribed in Table 15-4.

Method 15-9 - Variable fuel sector-based emission factors

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

Method 15-10 - Variable fuel technology-based emission factors

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

(1) Selection Criteria

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

- The person responsible must apply either the sector-based emission factors (Table 15-5) at a COG or technology based emission factors (Table 15-6) for equipment at a COG;
- The person responsible must apply the same methodologies selected for each COG in the benchmark and compliance report;
- If technology based emission factors are selected for any COG, technology based emission factors may be different between the benchmark and compliance report to reflect technologies that are present at the sites during the benchmark or compliance periods. For example, the person responsible may use a NOx uncontrolled boiler emission factor for the benchmark, but apply a NOx controlled boiler emission factor in the compliance report to reflect technologies used during the compliance period. As well, different technology based

emission factors may be applied within a compliance or benchmark period if technologies were replaced within the compliance or benchmark period.

- If a facility has the HHV for the fuel, the energy based emission factor (tonnes of emissions per gigajoules) must be used to calculate the methane and nitrous oxide emissions. Otherwise, the facility may use the volume based emission factors (tonnes of emissions per cubic metre) if heating value data is not available.

(2) Equation

Using Equation 15-8 or Equation 15-8a, the CH_4 or N_2O emissions are calculated based on volumes calculated by Method 15-1, Method 15-2, or Method 15-3.

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

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

Where:

$CH_{4,\mathbf{p}}$ or $N_2O_{\mathbf{p}}$	=	CH_4 or N_2O mass emissions for the specific fuel type for the reporting period, *p,* (tonnes CH_4 or N_2O).
$Fuel_p$	=	For Equation 15-8, the quantity of fuel combusted in kilolitres or cubic metres (kl or m^3) at standard conditions (15ºC, 1 atm) combusted during reporting period, *p*. For Equation 15-8a, energy of fuel in gigajoules or quantity of fuel in kilolitres, or cubic metres (GJ, kl, or m^3) combusted during reporting period, *p*.
HHV_p	=	Measured or supplied higher heating value in gigajoules per kilolitres or cubic metres (GJ/kl or GJ/m^3) at standard conditions (15ºC, 1 atm) for the reporting period, *p*.
EF_{vol}, EF_{ene}	=	Fuel-specific default emission factor, from Table 15-4, Table 15-5, or Table 15-6 in tonnes of CH_4 or N_2O per energy units (GJ) or volume units (kl or m^3).

Table 15-4: Default emission factors for non-variable fuel types

Non-Variable Fuel	CO_2 Emission Factor[1]		CH_4 Emission Factor[1]		N_2O Emission Factor[1]	
	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ	tonne/kl	tonne/GJ
Diesel						
All industry	2.681	0.0699	7.8E-05	2.0E-06	2E-05	5.8E-07
Diesel in Alberta[2]	2.610	0.06953	see note 3			
Biodiesel						
All industry	see note 4		7.8E-05	2.2E-06	2E-05	6.3E-07
Gasoline	2.307	0.069	1E-04	3.0E-06	2E-05	6E-07
Gasoline in Alberta[2]	2.174	0.06540	see note 5			
Ethanol	See note 4		1E-04	4.3E-06	2E-05	8.5E-07
Butane	1.747	0.0614	2.4E-05	8.4E-07	1.08E-04	3.8E-06
Ethane	0.986	0.0573	2.4E-05	1.4E-06	1.08E-04	6.3E-06
Propane	1.515	0.0599	2.4E-05	9.5E-07	1.08E-04	4.3E-06

1. Emission factors adapted from ECCC Canada's Greenhouse Gas Quantification Requirements, as amended from time to time.
2. Fuels that are impacted by Alberta's Renewable Fuels Standard, where gasoline and diesel emission factors are adjusted to account for required biofuel content. If the actual biofuel composition is known, a facility may use the gasoline or diesel CO_2 emission factor for the non-biofuel component and the CO_2 emission factor prescribed in Chapter 14 for the biofuel component.
3. Diesel CH_4 and N_2O emission factors are used.
4. CO_2 emission factors are provided in Table 14-1 in Chapter 14. CO_2 emissions from biodiesel and ethanol should be reported under the biomass emissions.
5. Gasoline CH_4 and N_2O emission factors are used.

Table 15-5: Sector based CH_4 and N_2O emission factors for fuel gas

Sectors	CH_4 Emission Factor[2]		N_2O Emission Factor[2]	
	tonne/m^3	tonne/GJ	tonne/m^3	tonne/GJ
Oil and Gas Sector and Producer Consumption[1]	6.4E-06	1.4E-04	6.0E-08	1.3E-06

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

Table 15-6: Technology based CH_4 and N_2O emission factors for fuel gas

Natural Gas	CH_4 Emission Factor[1]		N_2O Emission Factor[2]	
	tonne/m[3]	tonne/GJ[3]	tonne/m[3]	tonne/GJ[3]
Boilers/Furnaces/Heaters				
NOx Controlled	3.7E-08	9.7E-07	1.0E-08	2.7E-07
NOx Uncontrolled	3.7E-08	9.7E-07	3.5E-08	9.3E-07
Internal Combustion Engine				
Turbine	1.4E-07	3.7E-06	4.9E-08	1.3E-06
2 stroke lean	2.37E-05	6.23E-04	-	-
NOx 90-105% Load	-	-	7.77E-07	2.04E-05
NOx < 90% Load	-	-	4.75E-07	1.25E-05
4 stroke lean	2.04E-05	5.37E-04	-	-
NOx 90-105% Load	-	-	1.00E-06	2.63E-05
NOx < 90% Load	-	-	2.07E-07	5.46E-06
4 stroke rich	3.76E-06	9.89E-05	-	-
NOx 90-105% Load	-	-	5.41E-07	1.43E-05
NOx < 90% Load	-	-	5.56E-07	1.46E-05

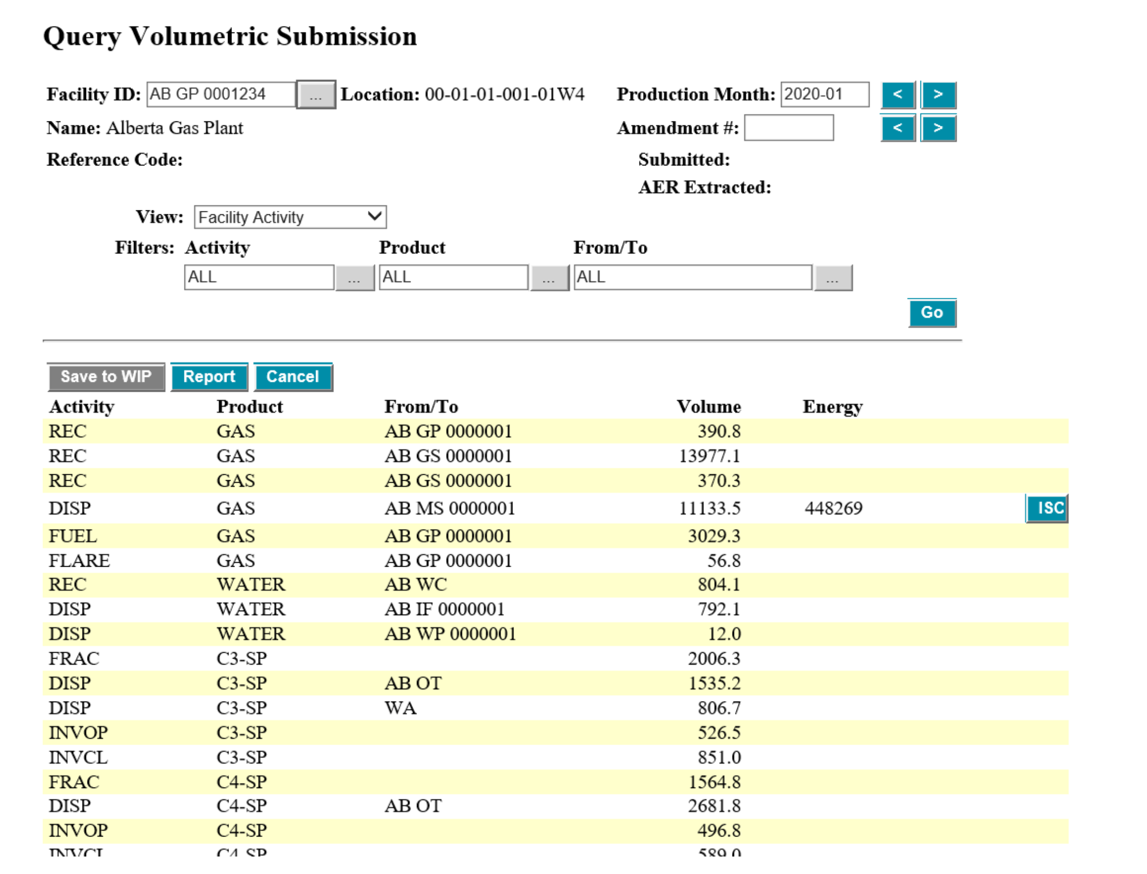
1. For emission factors adapted from USEPA AP-42, the default emission factor is based on a natural gas heating value of 1,020 British thermal units per standard cubic feet (Btu/scf) for the volume based emission factor.
2. Emission factors are adapted from USEPA AP-42 Chapters 1 and 3.
3. The energy-based emission factor should be used if the fuel consumption on an energy basis is available. The volume-based emission factor should only be used if the higher heating value or energy of the fuel is not available.
4. The N_20 emission factor is based on 1.5% of the NOx emission factor, as provided in AP-42.

15.4. Aggregate Facility Production Quantification

Product data quantification and reporting procedures for aggregate facility will be tied to production accounting volumes, referred to as Method 15-11.

15.4.1. Method 15-11 - Petrinex production volumes

Aggregate facilities production volumes quantified and reported will be the volumes that are reported in Petrinex for each COG. The production quantities that the person responsible for an aggregate facility will report will be based on the benchmark unit requested in accordance to Section 15.4 and the Standard for Developing Benchmarks. COG facilities in Alberta report volumetric data to Petrinex. Each volumetric submission must identify the activity, the product and the associated volume. Please refer to Appendix 1, 2, and 3 from Manual 011, published by the Alberta Energy Regulator for information on the activity and products required to be reported to Petrinex. These volumetric submissions will be the used for quantification and reporting under TIER. Figure 15-2 shows the volumetric submission for an example COG facility in Alberta. These volumes shown will be used in calculating the benchmark unit referred to in Section 15.4.


Query Volumetric Submission

Facility ID: AB GP 0001234 ... Location: 00-01-01-001-01W4 Production Month: 2020-01 < >
Name: Alberta Gas Plant Amendment #: < >
Reference Code: Submitted:
AER Extracted:
View: Facility Activity
Filters: Activity Product From/To
ALL ... ALL ... ALL ...
Go

Save to WIP Report Cancel

Activity	Product	From/To	Volume	Energy	
REC	GAS	AB GP 0000001	390.8		
REC	GAS	AB GS 0000001	13977.1		
REC	GAS	AB GS 0000001	370.3		
DISP	GAS	AB MS 0000001	11133.5	448269	ISC
FUEL	GAS	AB GP 0000001	3029.3		
FLARE	GAS	AB GP 0000001	56.8		
REC	WATER	AB WC	804.1		
DISP	WATER	AB IF 0000001	792.1		
DISP	WATER	AB WP 0000001	12.0		
FRAC	C3-SP		2006.3		
DISP	C3-SP	AB OT	1535.2		
DISP	C3-SP	WA	806.7		
INVOP	C3-SP		526.5		
INVCL	C3-SP		851.0		
FRAC	C4-SP		1564.8		
DISP	C4-SP	AB OT	2681.8		
INVOP	C4-SP		496.8		
INVCL	C4-SP		589.0		

Figure 15-2: An example of the facility activity page for a typical COG facility

If a COG facility has no volumes reported in Petrinex, or believes the volumes reported in Petrinex are not reflective of the actual production volumes it is recommended that the aggregate facility contact the director for additional direction.

15.5. Aggregate Facility Benchmark Unit

The person responsible for an aggregate facility may request a benchmark unit for the aggregate facility using one of the two following approaches:

Option 1 – The person responsible for an aggregate facility may request to utilize one of the following benchmark units: production, disposition, or receipts of specified energy products, expressed in m^3 oil equivalent volumes.

Option 2 – The person responsible for an aggregate facility may propose to use an alternative benchmark unit if option 1 is not applicable to the aggregate facility. The alternative must be derived from correlation coefficients of emission to production.

Once a benchmark unit is requested by an aggregate facility as part of the aggregate benchmark application, the director will review the requested benchmark unit against the criteria listed in this section as part of the facility-specific benchmark review process. If approved, the requested benchmark unit will be assigned to the aggregate facility when the facility-specific benchmark is assigned. At this time an aggregate facility will only be allowed to utilize their assigned facility-specific benchmark and most of the high performance benchmarks in schedule 2 of TIER. Aggregate facilities will not be allowed to receive an allocation rate for the natural gas processing benchmark. Information on how the facility benchmark unit will be utilized in determining the facility-specific benchmark for an aggregate facility can be found in the Standard for Developing Benchmarks. The Standard for Developing Benchmarks also contains information on how to apply for a facility-specific benchmark. Aggregate facilities should note that once a benchmark unit is set there will be limited opportunities to change the benchmark unit until the complete baselining period for the aggregate facility has passed.

At this time, high performance benchmarks have not been developed for aggregate products and will not be available to aggregate facilities for 2020.

15.5.1. Option 1 – Request a benchmark unit from the predetermined options

Three benchmark unit options have been identified that are expected to apply to the majority of aggregate facilities. The identified options are:

- Production of energy products in m^3 oil equivalent volumes
- Disposition of energy products in m^3 oil equivalent volumes
- Receipts of energy products in m^3 oil equivalent volumes.

A person responsible for an aggregate facility may request one of these three options to utilize as their benchmark unit. Once a benchmark unit has been selected the volumes associated with the benchmark unit are determined in accordance with Equation 15-9 below:

$$P_k = \sum_i^n v_{Product_i} \times Conversion\ Factor_i \qquad \text{Equation 15-9}$$

$$P_{Agg} = \sum_{k=1}^r P_k \qquad \text{Equation 15-9a}$$

Where,

P_k, is the quantity of benchmark unit in m^3 oil equivalent volumes for an each conventional oil and gas facility, *k*

P_{Agg}, is the quantity of benchmark unit in m^3 oil equivalent volumes for the aggregate facility

r, is the number of individual facilities in the aggregate

n, is the number of required specified products outlined in Table 15-7

$v_{Product_i}$, is the volume of the specified energy product outlined in Table 15-7 for each option of option 1.

$Conversion\ Factor_i$, is the conversion factor used to convert the volumes of specified energy products to m^3 oil equivalent volumes outlined in Table 15-8.

Table 15-7: Energy products required for option 1

Option 1	Activity ID[1]	Product ID[1]	Units
Production	PROD	COND	m^3
	PROD	GAS	e^3m^3
	PROD	OIL	m^3
	PROC	C2-SP	m^3
	PROC	C3-MX	m^3
	PROC	C3-SP	m^3
	PROC	C4-MX	m^3

Option 1	Activity ID[1]	Product ID[1]	Units
	PROC	C4-SP	m^3
	PROC	C5-MX	m^3
	PROC	C5-SP	m^3
	FRAC	C2-SP	m^3
	FRAC	C3-SP	m^3
	FRAC	C4-SP	m^3
	FRAC	C5-SP	m^3
	FRAC	C6-SP	m^3
Disposition	DISP	COND	m^3
	DISP	GAS	e^3m^3
	DISP	OIL	m^3
	DISP	C1-MX	m^3
	DISP	C2-MX	m^3
	DISP	C2-SP	m^3
	DISP	C3-MX	m^3
	DISP	C3-SP	m^3
	DISP	C4-MX	m^3
	DISP	C4-SP	m^3
	DISP	C5-MX	m^3
	DISP	C5-SP	m^3
	DISP	C6-MX	m^3
	DISP	C6-SP	m^3

Option 1	Activity ID[1]	Product ID[1]	Units
	DISP	IC4-MX	m^3
	DISP	IC4-SP	m^3
	DISP	IC5-MX	m^3
	DISP	IC5-SP	m^3
	DISP	LITEMX	m^3
	DISP	NC4-MX	m^3
	DISP	NC4-SP	m^3
	DISP	NC5-MX	m^3
	DISP	NC5-SP	m^3
Receipts	REC	COND	m^3
	REC	GAS	e^3m^3
	REC	OIL	m^3
	REC	C1-MX	m^3
	REC	C2-MX	m^3
	REC	C2-SP	m^3
	REC	C3-MX	m^3
	REC	C3-SP	m^3
	REC	C4-MX	m^3
	REC	C4-SP	m^3
	REC	C5-MX	m^3
	REC	C5-SP	m^3
	REC	C6-MX	m^3

Option 1	Activity ID[1]	Product ID[1]	Units
	REC	C6-SP	m^3
	REC	IC4-MX	m^3
	REC	IC4-SP	m^3
	REC	IC5-MX	m^3
	REC	IC5-SP	m^3
	REC	LITEMX	m^3
	REC	NC4-MX	m^3
	REC	NC4-SP	m^3
	REC	NC5-MX	m^3
	REC	NC5-SP	m^3

1. Definitions for the Activity and Product ID can be found in Manual 011, published by the Alberta Energy Regulator and updated from time to time.

Table 15-8: Oil Equivalent (OE) Conversion Factors

Product Code	Product Name	Units	Conversion Factors to m^3 OE
OIL	Crude Oil, Crude Bitumen	m^3	1.00
GAS	Gas	e^3m^3	0.971
C1-MX	Methane Mix	m^3	0.000971
LITEMX	Lite Mix	m^3	0.000971
C2-SP	Ethane Spec	m^3	0.48
C2-MX	Ethane Mix	m^3	0.48
C3-SP	Propane Spec	m^3	0.66

Product Code	Product Name	Units	Conversion Factors to m^3 OE
C3-MX	Propane Mix	m^3	0.66
IC4-MX	Iso-Butane Mix	m^3	0.72
IC4-SP	Iso-Butane Spec	m^3	0.72
C4-SP	Butane Spec	m^3	0.75
C4-MX	Butane Mix	m^3	0.75
NC4-MX	Normal Butane Mix	m^3	0.75
NC4-SP	Normal Butane Spec	m^3	0.75
IC5-MX	Iso-Pentane Mix	m^3	0.79
IC5-SP	Iso-Pentane Spec	m^3	0.79
C5-MX	Pentane Mix	m^3	0.80
C5-SP	Pentane Spec	m^3	0.80
NC5-MX	Normal Pentane Mix	m^3	0.80
NC5-SP	Normal Pentane Spec	m^3	0.80
COND	Condensate	m^3	0.86
C6-MX	Hexane Mix	m^3	0.86
C6-SP	Hexane Spec	m^3	0.86

6. Gas = 10^3 m^3 (thousands of cubic metres) at 15°C and 101.325 kPa (kilopascals), rounded to one decimal place; Liquids = m^3 at 15°C and 101.325 kPa, rounded to one decimal place.
7. Conversion factors derived from Higher Heating Values based on 38.5 GJ/m^3 higher heating value of light crude oil
8. HHVs Sources: CAPP, "Calculating Greenhouse Gas Emissions", 2003; GPSA, "Engineering Data Book", 1998; AER, "ST98: Alberta's Energy Reserves and Supply/Demand Outlook", 2018, EPA, "AP-42: Compilation of Air Emissions Factors", 20

15.5.2. Assessment of requested benchmark unit from Method 15-11

A benchmark unit requested from Method 15-11 will be evaluated by the director as part of the facility specific benchmark assignment process. Additional details on the benchmark application process can be found in the Standard for Developing Benchmarks. A requested benchmark unit will be evaluated based on the following criteria:

- Achieves a strong month-to-month correlation between the requested benchmark unit and aggregate emissions.
- Minimizes variability of month-to-month emissions intensities over the course of a year.
- Represents the composition and operation of the aggregate facility.

The equations below have been developed to support the director's assessment of an aggregate facility's requested benchmark unit. Applicants are encouraged to ensure that their selected benchmark units achieve the expected outcomes of the equations.

Equation 15-10 tests how well the benchmark unit follows a linear relationship with the aggregate facility's emissions for the baseline year(s) in the facility specific benchmark application. An ideal benchmark unit will have a correlation of 1, the director will assess how close the request benchmark unit is to the ideal correlation.

$$r_{Agg} = \frac{\sum_{i=1}^{m=12}\left(P_{Agg_i} - \overline{P}_{Agg}\right) \times \left(CO_{2_i} - \overline{CO}_2\right)}{\sqrt{\sum_{i=1}^{m=12}\left(P_{Agg_i} - \overline{P}_{Agg}\right)^2} \times \sqrt{\sum_{i=1}^{m=12}\left(CO_{2_i} - \overline{CO}_2\right)^2}} \qquad \text{Equation 15-10}$$

Where,

r_{Agg}, is the correlation between the requested benchmark unit and stationary fuel combustion emissions for the aggregate facility based on the initial baseline year of the benchmark application

m, is the number of months in a year

P_{Agg_i}, is the monthly quantity of requested benchmark unit in m^3 oil equivalent volumes

$\overline{P}_{Agg} = \frac{1}{m}\sum_{i=1}^{m=12} P_{Agg_i}$, the monthly average of requested benchmark unit in m^3 oil equivalent volumes

CO_{2_i}, is the monthly quantity of stationary fuel combustion emissions in tonnes of CO_2 equivalent

$\overline{CO}_2 = \frac{1}{m}\sum_{i=1}^{m=12} CO_{2_i}$, the monthly average of stationary fuel combustion emissions in tonnes of CO_2 equivalent.

Equation 15-11 assesses month to month variation in an aggregate facility's emission intensity based on the requested benchmark unit in the baseline year. An ideal benchmark unit variance will be 0, the director will assess how close the requested benchmark unit is to the ideal variation.

$$\boldsymbol{CV_{Agg}} = \frac{\sqrt{\sum_{i=1}^{m=12}\left(EI_{Agg_{m_i}} - \overline{EI}_{Agg_m}\right)^2}}{(m-1)^2} \times \frac{1}{\overline{EI}_{Agg_m}} \quad \text{Equation 15-11}$$

Where,

CV_{Agg}, is the coefficient of variance of the monthly emission intensity of an aggregate facility

m, is the number of months in a year

$EI_{Agg_{m_i}} = \frac{CO_{2_i}}{P_{Agg_i}}$, is the monthly emission intensity for an aggregate facility in tonnes of CO_2 equivalent/ m^3 oil equivalent volumes

$\overline{EI}_{Agg_m} = \frac{1}{m}\sum_{i=1}^{m=12} EI_{Agg_{m_i}}$, is the monthly emission intensity for an aggregate facility in tonnes of CO_2 equivalent/ m^3 oil equivalent volumes

Equation 15-12 assesses how the emission intensities of COG facilities vary relative to the emission intensity of the aggregate. An ideal result would be 0. I.e. most of the COG facilities have emissions associated with the benchmark unit. The director will assess how closely the requested benchmark unit's behaviour matches the ideal behaviour.

$$\boldsymbol{CV_{COG}} = \frac{\sqrt{\sum_{i=1}^{r}\left(EI_{COG_i} - \overline{EI}_{Agg_Y}\right)^2}}{(r-1)^2} \times \frac{1}{\overline{EI}_{Agg_Y}} \quad \text{Equation 15-12}$$

Where,

CV_{COG}, is the coefficient of variance of COG facility emission intensity of an aggregate facility

r, is the number of individual facilities in the aggregate

$EI_{COG_i} = \frac{CO_{2_i}}{P_{k_i}}$, is the annual emission intensity for an individual COG facility in tonnes of CO_2 equivalent/ m^3 oil equivalent volumes

$\overline{EI}_{Agg_Y} = \frac{\sum_{i=1}^{r} CO_{2_i}}{\sum_{i=1}^{r} P_{k_i}}$, is the annual emissions intensity for an aggregate facility in tonnes of CO_2 equivalent/ m^3 oil equivalent volumes

15.5.3. Option 2 – Request an alternative benchmark unit

The person responsible for an aggregate facility may propose to use an alternative benchmark unit if option 1 is not applicable to the aggregate facility. Option 2 applies a set process that identifies one or multiple production accounting metrics that produce a linear relationship with the aggregate facility's emissions. These identified production accounting metrics would then be requested to be used as the benchmark unit in the facility specific benchmark application. If the identified production unit does not seem appropriate, or Option 2 does not identify a benchmark unit, it is recommended that the aggregate facilities contact the director for additional guidance and to discuss alternative options. Alberta Environment and Parks has developed a Microsoft Excel® model for aggregate facilities that will follow the process outline in Option 2 and recommend a benchmark unit for the aggregate facility. This model can be found on the TIER webpage.

15.5.4. Step 1 – Determine the correlations between emissions and production

In the first step the person responsible (applicant) determines the correlation between each of the available production accounting metrics and the aggregate's emissions. A production accounting metric is an Activity and Product ID pair that a conventional oil and gas facility reports under in Petrinex. This correlation will be calculated on a monthly basis for the initial baseline year. Aggregate facilities are requested to reference Appendix 1 of Alberta Energy Regulator's Manual 11 for the production accounting metrics that should be compared to the aggregate's emissions. All relevant Activity IDs should be included except, DIFF, EMIS, FLARE, FUEL, IMBAL, INVADJ, INVCL, INVOP, LDINVADJ, LDINVCL, LDINVOP, SHUTIN, and VENT. Equation 15-13 will then be used to calculate the correlations between the applicable production accounting volumes and emissions.

$$|r_x| = \left| \frac{\sum_{i=1}^{m=12} (x_i - \bar{x}) \times (CO_{2_i} - \overline{CO}_2)}{\sqrt{\sum_{i=1}^{m=12} (x_i - \bar{x})^2} \times \sqrt{\sum_{i=1}^{m=12} (CO_{2_i} - \overline{CO}_2)^2}} \right| \qquad \text{Equation 15-13}$$

Where,

$|r_x|$, is the correlation between the production accounting volume and stationary fuel combustion emissions for the aggregate facility based on the initial baseline year of the benchmark application.

m, is the number of months in a year

x_i, is the monthly quantity of the production accounting metric

$\bar{x} = \frac{1}{m} \sum_{i=1}^{m=12} x_i$, the monthly average of the production accounting metric

CO_{2_i}, is the monthly quantity of stationary fuel combustion emissions in tonnes of CO_2 equivalent

$\overline{CO}_2 = \frac{1}{m}\sum_{i=1}^{m=12} CO_{2_i}$, the monthly average of stationary fuel combustion emissions in tonnes of CO_2 equivalent.

15.5.5. Step 2 – Identify the key features

Once Equation 15-13 has been applied to each available production accounting metric, identify which production accounting metrics best correlate with emissions. Equations 15-14 and 15-14a define the relations that $\quad_x$ must meet to be considered a relevant metric. A correlation of 0.9 or greater indicates a strong linear relationship. A correlation of greater than 0.8 or greater indicates an acceptable linear relationship.

$$|r_x| \geq 0.9 \qquad \text{Equation 15-14}$$

$$|r_x| \geq 0.8 \qquad \text{Equation 15-14a}$$

First the applicant will identify all the production accounting metrics that meet Equation 15-14 as the key features. If no metric exists that satisfy Equation 15-14, the aggregate will identify all metrics that satisfy Equation 15-14a as the key features. If the aggregate has no metrics that meet the requirements of Equation 15-14 or Equation 14a, it is recommend that the aggregate contact the director for additional direction. This could include but not limited to decreasing the correlation threshold.

If only one relevant metric has been identified for step 2, that metric would be the benchmark unit identified in accordance to option 2. The following steps are required if multiple metrics have been identified with Step 2.

15.5.6. Step 3 – Determine the correlations between the identified key features

If multiple key production metrics have been identified, determine the correlations between the identified metrics. The goal of this step is to remove highly correlated metrics to ensure the benchmark unit approximates a linear relationship with the aggregate facility's emissions. Equation 15-15 calculates the pairwise correlations between the key metrics. An applicant must calculate the correlation for every pairing of key metrics identified in Step 2.

$$|r_{f_1 f_2}| = \left| \frac{\sum_{i=1}^{m=12}(f_{1_i} - \bar{f}_1) \times (f_{2_i} - \bar{f}_2)}{\sqrt{\sum_{i=1}^{m=12}(f_{1_i} - \bar{f}_1)^2} \times \sqrt{\sum_{i=1}^{m=12}(f_{2_i} - \bar{f}_2)^2}} \right| \qquad \text{Equation 15-15}$$

Where,

$|r_{f_1 f_2}|$, is the correlation between the between two key features for the aggregate facility based on the initial baseline year of the benchmark application *m*, is the number of months in a year

f_{1_i}, is the monthly quanitity of the production accounting volume of one key feature

$\overline{f}_1 = \frac{1}{m}\sum_{i=1}^{m=12} f_{1_i}$, the monthly average of the production accounting volume of one key feature

f_{2_i}, is the monthly quanitity of the production accounting volume of the second key feature

$\overline{f}_2 = \frac{1}{m}\sum_{i=1}^{m=12} f_{2_i}$, the monthly average of the production accounting volume of the second key feature

15.5.7. Step 4 – Remove highly correlated features

Based on the correlations calculated as part of Step 3, the applicant will eliminate one of the metrics from any pair that are highly correlated with each other. Highly correlated metrics have a result of Equation 15-15 that is greater than 0.9. This relationship is shown in question 15-16.

$$\left|r_{f_1 f_2}\right| \geq 0.9 \qquad \text{Equation 15-16}$$

The metrics that the applicant removes are up to the discretion of the applicant. The applicant should focus on metrics that are the most common and best represent the operations of the aggregate facility. If after step 4 there is only one metric remaining than that metric is the benchmark unit for the aggregate that the applicant will request in accordance with option 2. If there are multiple features remaining the applicant will need to proceed with step 5 and 6.

15.5.8. Step 5 – Conduct a multi-variable linear regression

If multiple key metrics remain after step 4, the next step is to conduct a multi-variable linear regression analysis with the remaining features and the stationary fuel combustion emissions. This multi-variable linear regression analysis is done on the monthly emissions and production accounting volumes for the initial baseline year. An aggregate facility may request to utilize additional data points in selecting a benchmark unit under option 2.

Commonly utilized software such as Microsoft Excel® has capabilities to conduct multi-variable linear regression analysis. It is recommend that the applicant utilize a 95% confidence interval for the regression analysis and force a zero intercept for the regression analysis. A non-zero intercept may be appropriate for some aggregate facilities. Aggregate facilities are requested to contact the director if they would like to incorporate a non-zero intercept.

The regressions analysis should result in an output of a real number coefficient for each of the key feature used in the linear regression analysis. It is recommended that the applicant test the statistical significance of the outputs and the intercept with the linear model, which can be done using statistical hypothesis testing. The key features that are incompatible with the linear model should be not included in the regression analysis. On the other hand, if an intercept is deemed to be statistically significant in linear model, the applicant should contact the director for additional information. This results of the regression analysis are explained in the Equation 15-17.

$$y = c_1 \times f_1 + c_2 \times f_2 + c_3 \times f_3 + \cdots c_n \times f_n \qquad \text{Equation 15-17}$$

Where,

y, is the output of the multi-variable linear regression analysis

c_1, c_2, c_3, c_n, are the key outputs of the regression analysis, representing coefficient for the key features

f_1, f_2, f_3, f_n, are the key production accounting features used in the regression analysis.

15.5.9. Step 6 – Normalize the output of the regression analysis

The last step of option 2 is to normalize output of the coefficients from step 6. Normalization of the output coefficients will help ensure the benchmark units recommended by option 2 for different aggregate facilities are comparable. Equation 15-18 shows how to determine the normalization factor from the linear regression coefficients.

$$NF_{Agg} = \sqrt{{c_1}^2 + {c_2}^2 + {c_3}^2 + \cdots {c_n}^2} \qquad \text{Equation 15-18}$$

Where,

NF_{Agg}, is the normalization factor for an aggregate

The final benchmark unit determine in accordance to option 2 is outlined in Equation 15-19. This is the benchmark unit that the aggregate facility would request in their application for a facility – specific benchmark.

$$BU_{Agg} = \frac{c_1 \times f_1 + c_2 \times f_2 + c_3 \times f_3 + \cdots c_n \times f_n}{NF_{Agg}} \qquad \text{Equation 15-19}$$

Where,

BU_{Agg}, is the benchmark unit determined in accordance with option 2.