Life-Cycle Analysis of Canadian Natural Gas

A Pilot Study

Final Report

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Executive Summary

For this report a Life Cycle Analysis (LCA) framework was developed and used to investigate the cradle-to-gate GHG emissions associated with natural gas produced from the Montney formation in Alberta. Cradle-to-gate analysis includes preproduction, production, and processing stages of natural gas up to but not including sales gas transmission..

The framework developed in this report relies heavily on the data reported by the oil and gas operators to Alberta Energy Regulator (AER). These data are required to meet the quality requirements set by the AER, and are believed to be the most accurate data available publicly, hence providing the most accurate representation possible of the actual oil and gas operations in Alberta.

The LCA analysis presented here takes advantage of the monthly volumetric PETRINEX reports for 2015 – 2020 that are available for free, as well as the AER's "General Well Data" dataset (that includes AER's "General Well Data" and "Individual Well Gas Analysis Data by Zone") that is available for purchase through the AER website. Data processing and analyses are mainly completed using Python, Microsoft excel, and Microsoft Power Query. In cases where data gaps exist in the reported data, alternative methods are used to estimate the missing data for use in the LCA calculations. Where possible, comparisons are made with other literature sources and relevant insights are presented.

The LCA analysis in this report estimates an average annual cradle-to-gate GHG emissions intensity of 4.04 gCO_2e/MJ gas for the production and processing of gas from the Alberta Montney region. A number of parameters are explored through a sensitivity analysis and show that the average annual cradle-to-gate GHG emissions intensity for the Montney region could be as low as 2.95 gCO_2e/MJ gas and as high as 4.88 gCO_2e/MJ gas. These annual average GHG emissions intensity estimates are based on 45 natural gas plant pathways (a pathway starts with gas producing wells, batteries, gas compression and gas gathering systems and ends at the gate of the gas plant that sells the final natural gas products). Investigating the natural gas pathways individually shows a cradle-to-gate GHG emissions intensity range of 1.72 gCO_2e/MJ gas to 9.84 gCO_2e/MJ gas. The variance observed in the GHG emissions intensity estimates could be due to a number of factors such as different operations, unusual incidents in operations, different qualities of feedstock gas or production of different products that could require different levels of processing. Given that gas plants owned by a given company may receive and produce gas from assets of several other producers, the range of cradle-to-gate GHG emissions estimates in this report is no indication of better performance of one single company over another.

The procedures developed to carry out the LCA calculations for this report are highly repeatable at any frequency (i.e. monthly, quarterly, annually) to yield updated LCA results reflective of the NG production and processing operations at any given time. This would allow for capturing changes in the NG production and processing operations (e.g., operators implementing energy efficiency projects to reduce their fuel consumption to meet the GHG reduction targets set by the Alberta Technology Innovation and Emissions Reduction Regulation, TIER).

Furthermore, data gaps and recommendations for addressing them are provided in this report. Once the data gaps are addressed and higher quality data becomes available, the procedures developed in this report can be updated and reflect the new data and provide improved LCA results.

It is expected that the framework developed in this report and the LCA estimates provided can be helpful for several stakeholders such as government organizations, academic researchers, as well as gas producers and gas consumers that seek to obtain a better understanding of their supply chain GHG emissions. As well, LCA can support a corporation'soverall GHG emissions performance and Environmental, Social and Governance (ESG) reporting.

1 INTRODUCTION

1.1 Project Overview and Objectives

Life Cycle Analysis (LCA) of Canadian Natural Gas: A Pilot Study, provides a life cycle emissions estimate using publicly available data for the gas produced from the Montney geological formation in Alberta. The pilot study identifies and uses the best available data, processes, and methods related to life cycle analysis. The study runs sensitivity analyses and identifies data gaps to be considered for future work to extend the LCA to the broader province and consequently to improve the accuracy of Canada's emissions profile related to oil and gas activities.

This study supports the Canadian oil and gas industry as it faces a wave of climate regulations and investor demands that are more acutely focused on emissions management throughout the value chain of products. The results of this study and the future work can help fill the rising imperative of the industry and domestic governments to understand the life cycle emissions associated with natural gas production in the province.

For Canada's natural gas industry to compete internationally and be the preferred global supplier of Liquified Natural Gas (LNG), a comprehensive, transparent, and credible life cycle analysis that quantifies the full system emissions profile needs to be completed. This project will help build Alberta's leadership position in emissions management.

The framework developed in this study is the first of its kind that uses a combination of monthly reported data to the Alberta Energy Regulator (AER) and publicly available datasets to estimate greenhouse gas (GHG) emissions associated with natural gas produced in Alberta. While the Montney formation is the focus of this report, the quantification methodology developed can be used to provide cradle-to-gate GHG emissions estimates for any gas plant in Alberta. The framework and procedures developed in this report are expected to be highly repeatable. Updated LCA estimates in future years are expected to improve significantly as the quality and quantity of data reported to the AER improves.. In addition, addressing the data gaps identified in this report will further improve the accuracy of the estimates provided in this report.

2 Montney in General

2.1 Montney Formation

The Montney formation spans Northeast British Columbia into Northwest Alberta, as shown in Figure 1, and holds a high potential for 18,257 billion m^3 of marketable natural gas production [1]. It covers 130,000 km^2 and ranges between 100 m and 300 m in thickness and is thickest along the Rockies.

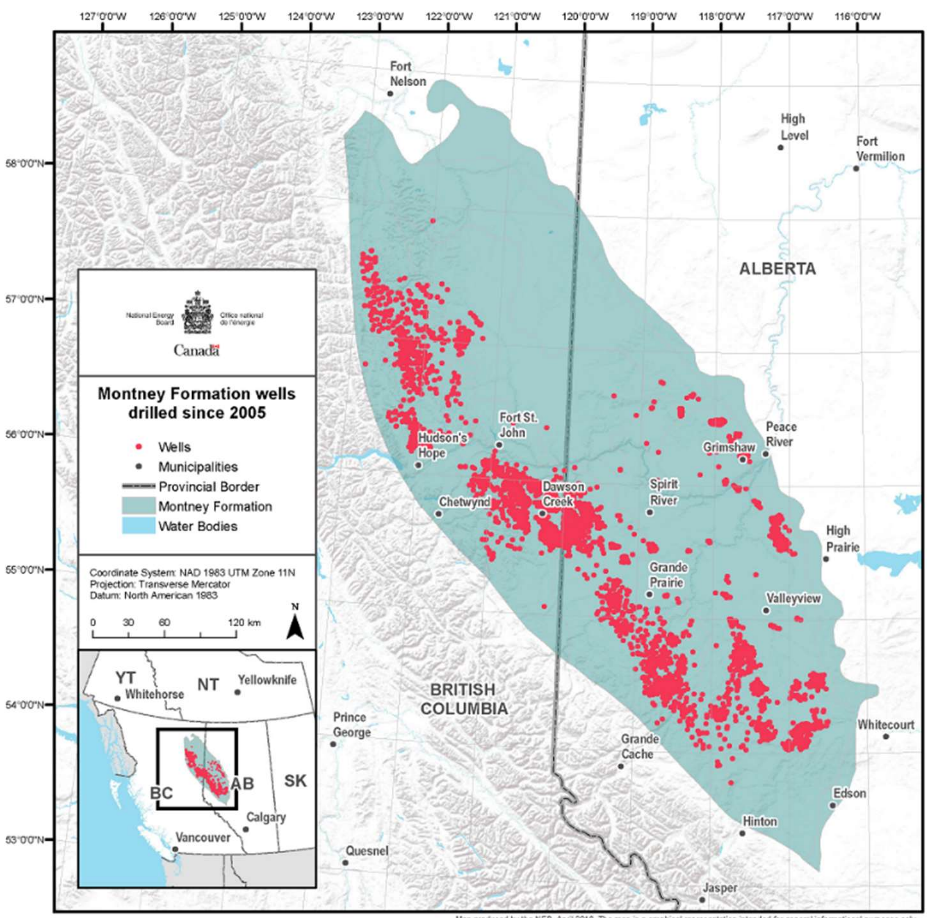

Figure 1 Montney Region in Alberta and British Columbia (adapted from [2])

2.2 Alberta Montney

In Alberta the Montney Formation is defined by the Alberta Energy Regulator. The total remaining proved and probable reserves are 46.3 $10^6 m^3$ of oil, 337.8 $10^6 m^3$ of condensate and 602,075 $10^6 m^3$ of natural gas as of November 30, 2020 [3]. The Canadian Energy Regulator's, "Canada's Energy

Future 2020" report shows that the Montney tight gas resource will lead natural gas production growth to 2040 [4]. Figure 2 shows that gas wells are most prevalent in the west of the Montney formation with liquids rich and oil plays more in the east.

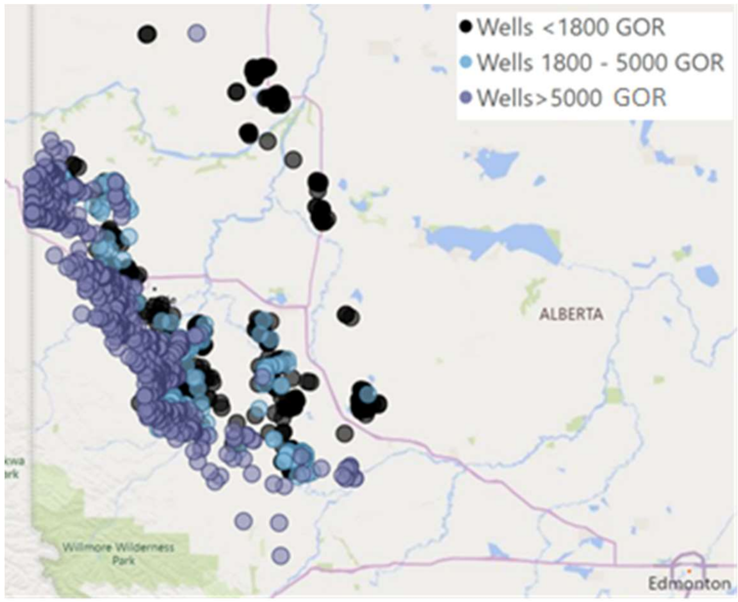

Figure 2 Well GOR by Bottomhole Location

The Montney formation has both sweet and sour gas production, with most of the highest sour gas wells clustered in the Grand Prairie area as seen in Figure 3. The data associated with the H_2S content was available at the battery level, so no other comparisons could be made with well age, depth or gas to oil ratio (GOR). A Hydrogen Sulfide mapping exercise was conducted by Geoscience BC that concluded sour wells are drilled deeper within the Montney formation [5].

Figure 4 shows that the deepest wells are drilled closest to the mountains to the west and the shallower wells are drilled on the east edge of the Montney formation. It is also noticeable that, between 2015 and 2020, well depth increases as demonstrated in Figure 5. This comes on the heels of advancements in horizontal drilling and fracturing techniques.

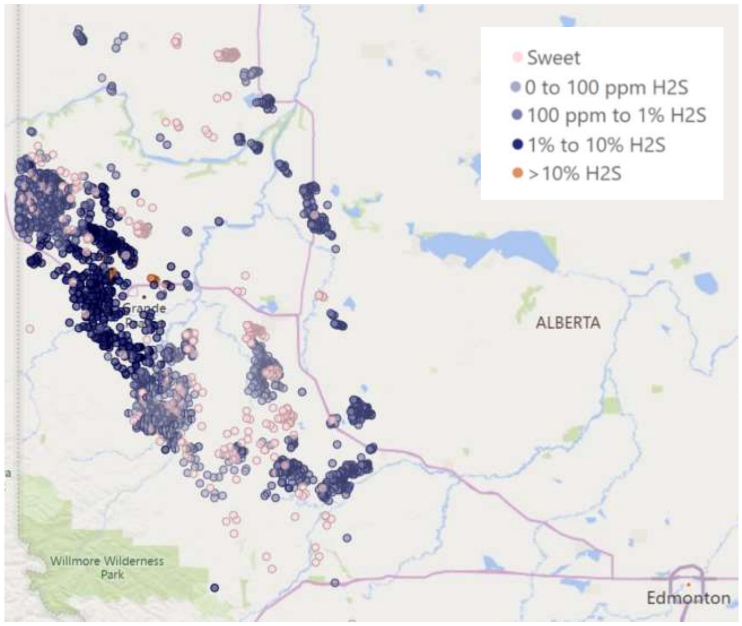

Figure 3 - H2S Content of Produced Gas in the Montney

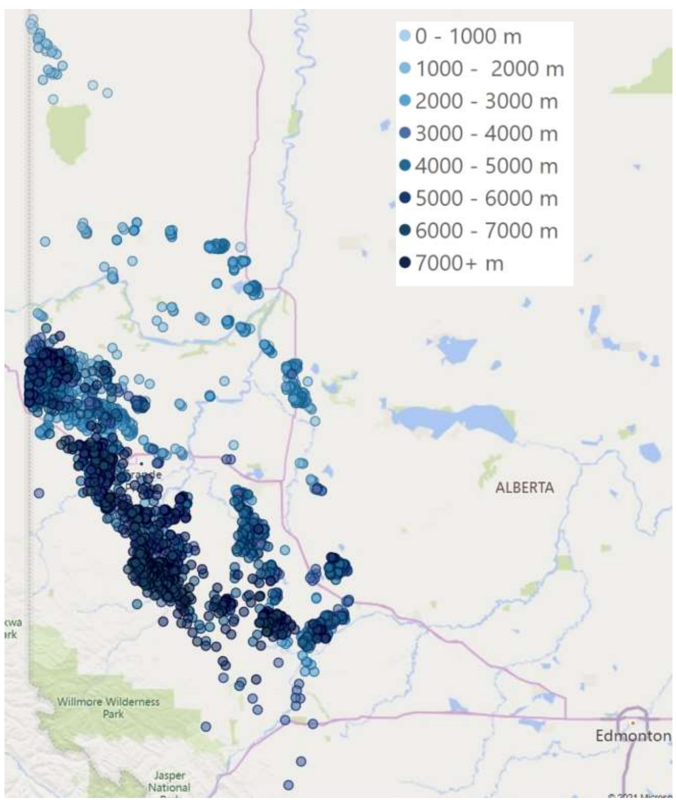

Figure 4 – Drilled Well Depth by Downhole Location

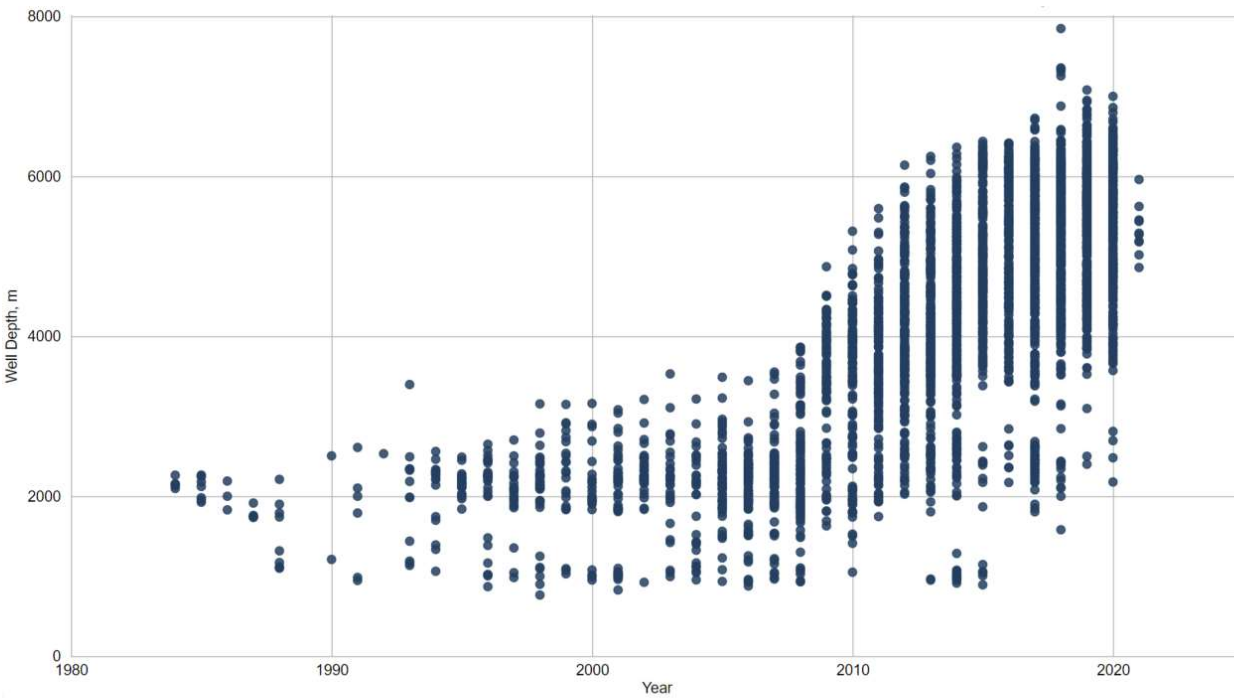

Figure 5 – Drilled Well Depth Over Time

3 Data Sources

As part of this project, we explored the data sources that are available publicly and can be used for estimating life cycle GHG emissions associated with natural gas (NG) production and processing activities in Alberta. In addition, we researched the data sources that exist (either reported to the governmental agencies and not available in the public domain or only available to the operators) but cannot be accessed by public. Several sources of data were found and used to estimate GHG emissions associated with different stages of NG production and processing. These sources and the list of data found in each source are explained in the following sections.

3.1 Public Data – Free

The Alberta oil and gas sector has extensive reporting requirements for companies to report production and emissions related data to the provincial government and/or regulators.

Some of these data sources are publicly available for everyone, free of charge. A list of the main data sources is presented below.

3.1.1 PETRINEX Volumetric Reports

All upstream oil and gas facilities report volumetric production, disposition and receipt data for different products including gas, oil, condensate, water and NGLs to PETRINEX, Canada's Petroleum Information Network, on a monthly basis [6]. This data is available in the Public Data section of PETRINEX website [7]. Production data is reported at the well level and each well is linked to a Facility ID. In addition to production, disposition and receipt data, facilities are required to report fuel gas consumption volume as well as flared and vented gas volumes in their monthly submissions. Basic facility information such as facility name, type, operator, and location are included in PETRINEX volumetric reports.

Guidelines for reporting volumetric data to PETRINEX is provided in AER Directive 017: Measurement Requirements for Oil and Gas Operations [8]. Directive 017 sets out requirements for the accuracy of the measured and reported volumetric data to PETRINEX. Some of these requirements are summarized in Table 1 below. More details can be found in sections 1.7 and 1.8 of Directive 017. The estimated uncertainty of the reported data is then used to inform the range of values tested in the sensitivity analysis in the results section of this report.

Table 1 – AER Directive 017, required accuracy for reported volumes

Measured Components	Single point measurement uncertainty	Maximum uncertainty of monthly volume
Oil Systems		
Total battery oil	0.5 – 1.0 %	NA
Total battery gas	3.0 – 10.0 %	5.0 – 20.0 %
Gas Systems		
Total battery gas	3.0 %	5.0 %
Total battery condensate	2.0 %	NA
Fuel gas	3.0 – 10.0 %	5.0 – 20.0 %
Flare and vent gas	5.0 %	20.0 %

Reported data in the PETRINEX volumetric reports are used directly and indirectly to estimate GHG emissions, allocate GHG emissions to different products, and to estimate GHG emissions intensity of sales gas at the outlet of the gas plants. More details on how this data is used in the GHG emissions calculations is explained in the Methods section.

3.1.2 PETRINEX Well and Facility Reports

Detailed information on wells and facilities can be obtained from PETRINEX infrastructure data available on PETRINEX Public Data page [7]. The reports listed below are obtained from PETRINEX and the data is used in the present study:

1) Well Infrastructure
2) Well Licence
3) Facility Infrastructure
4) Facility Licence

3.1.3 Well Infrastructure and Well Licence

In the Well Infrastructure and Well Licence reports, detailed information about wells is provided based on the unique identifier of the well (UWI) or well licence number. The most important information collected from these reports include: well surface location, projected and terminating formation, total depth, true vertical depth (TVD), drilling type (vertical vs. horizontal), finished drill date, and licensee information.

3.1.4 Facility Infrastructure and Facility Licence

Additional facility information that are not available in PETRINEX Volumetric Report, namely facility licence number, and the list of satellite facilities along with their locations are obtained from the Facility Infrastructure and Facility Licence reports. Facility licence data is used to find plot plans (PPs) and process flow diagrams (PFDs) of facilities from AER Integrated Application Registry (IAR). PPs and PFDs are then used to find a list of process equipment on site that emit GHG emissions. Not all PPs and PFDs have sufficient information about the process equipment. This is further discussed in the methods sections.

3.2 Public Data – Purchased

Some of the datasets available are not presented in a user-friendly format and could require extensive preprocessing, especially when working with large volume of data (e.g., gas composition data for 4500^{+} wells). Several tools such as Microsoft Power Query, Python, etc. are available that can help transform and process these datasets. Several reports and webtools are also available for a fee that provide insights based on the data or an interactive environment to allow for further but limited analysis. In this study, we use a number of these tools/reports to help us obtain the required data more conveniently.

3.2.1 AER Well Datasets

The Alberta Energy Regulator (AER) has an extensive database, that includes a "General Well Data Report" dataset [9]. Data found in this dataset is compiled from the reported well data by companies under the requirements set out in Directive 059: Well Drilling and Completion Data Filing Requirements. Companies are required to submit well data during the drilling phase and updated well status throughout the well life cycle. The dataset is available in Tableau format on the AER website [9]. Individual well data can be obtained by searching the well licence number or unique identifier in the search box. Well data is then presented in several tabs which cannot be exported to excel or other file formats in bulk which makes it difficult to extract and use the data for 4500^{+} Montney wells included in the scope of this study. Therefore, the complete dataset was purchased from the AER to gain access to well data for a large number of wells that can be easily exported and manipulated. The data is provided in "txt" format along with a layout file to help process the data. The purchased datasets include “General Well data” and “Individual Well Gas Analysis Data by Zone” [10]. Figure 6 below provides an overview of the data available in these two datasets.

The most important data available in the AER General Well Data Report that is used in the present study includes: well depth and TVD, well casing information (casing type and size), well status information (flowing, pumping, gas lift) and status change date, fracking data (number of times a well is fracked), gas and liquid analysis data.

We use the Python programming language and batch-processing technique to read and preprocess the AER and PETRINEX data as required for the different types of analyses that we conduct for this report. GHG emissions related calculations are also completed mainly using Python.

Alberta Energy Regulator

General Well Data

-- for **Well**: **##/##-##-###-##W#**

Overall View - Well Summary Report					
Well Summary Report	View	(**Note:** When download to PDF, select **Paper Size: Letter**, **Scaling: 50%,** data may truncate in scrolled sections)			
Single View - by Summary Information					
Well Information	View	Download	Well Log Summary	View	Download
Licence Details	View	Download	Directional Drilling	View	Download
Completion Interval	View	Download	Perf Treatment	View	Download
Well Casing	View	Download	Plugback & Abandonment	View	Download
Production Strings	View	Download	Well Tour Occurrence	View	Download
Packer	View	Download	Status History	View	Download
Single View - by Location					
Location	View	Download	Geological Tops & Markers	View	Download
Single View - by Core					
Core Analysis Line Detail	View	Download	Core Analysis Method	View	Download
Core Header	View	Download	Well Core Cut	View	Download
Core Analysis Detail	View	Download			
Well Gas Analysis					
Well Gas Analysis - Summary Report	View	(**Note:** When download to PDF, select **Paper Size: Letter**, **Scaling: 50%,** data may truncate in scrolled sections)			
Well Gas - Header	View	Download	Well Gas - Properties	View	Download
Well Gas - Reservoir Data	View	Download	Well Gas - Separator Gas Data	View	Download
Well Gas - Separator Fluid Data	View	Download			
Well Reservoir Analysis					
Well Reservoir Analysis - Summary Report	View	(**Note:** When download to PDF, select **Paper Size: Letter**, **Scaling: 50%,** data may truncate in scrolled sections)			
Reservoir Analysis - Resource Allocations	View	Download	Reservoir Analysis - Resource Evaluation Depths	View	Download
Reservoir Analysis - Resource Interval	View	Download	Reservoir Analysis - Resource Interval Property	View	Download

Figure 6 – Summary of AER General Well Data

3.2.2 Converge (GDM) Tool and Database

Converge is a webtool developed by GDM and available for use at a fee. This webtool can provide information such as where oil and gas assets are located, who owns them, what their current status is. Some asset specific documents may also be available. However, the documents are not always available and may be out of date. For this report we use the information accessible through the Converge webtool (e.g., locations, P&IDs) as much as possible to obtain a better understanding of the Montney oil and gas operations such as their characteristics of the facilities

3.3 Private Data

Some emission related data are reported by the companies to the AER or the Government of Alberta (GoA) under different regulations but are not published for public access. This data is available to the operators and the AER/GoA. The LCA Framework can incorporate this data if or when it is available. Regardless, a list of the main non-public data sources is presented here and further discussed in the relevant sections of the report.

1) Fugitive Emissions Surveys

   After AER Directive 060 was updated and new requirements came into force starting January 1, 2020, all operators are required to conduct fugitive emission surveys at their facilities. The frequency of the fugitive surveys is determined by the facility type. The details can be found in section 8 of Directive 060 [11]. Annual fugitive emissions of each facility are estimated using the results of the fugitive survey and reported to AER through OneStop submission.

2) OneStop Vent Emissions

   Under the new requirements set out in Directive 060, facility operators are required to report their annual vent emissions that are estimated based on the guidelines provided in AER Manual 015 [12].

3) Glycol Dehydrator Emissions

   The AER Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators sets out the requirements for managing reductions in benzene emissions from glycol dehydrators and for reporting these emissions. Operators are required to submit annual reports in compliance with these requirements. Methane emissions are now also included in what is reported to the AER. These emissions are also required to be reported into PETRINEX. Glycol dehydrator emissions are also regulated under the AER Directive 060.

4) Compressor Seal Vent Measurement

Another requirement under Directive 060 is the annual[1] compressor seal vent measurement for compressors above a certain size threshold. The measured vent rates are used for vent calculations and reported to AER in monthly and annual vent reports.

5) Non-PETRINEX Fuel

Oil and gas facilities that are regulated under the provincial TIER regulation (either as opt-in or aggregated facilities) are required to track all stationary fuel combustion emissions including any diesel and propane fuel combustion during drilling and completion and other activities. Depending on the type of TIER coverage (opt-in or aggregated facility), fuel consumption data is submitted to the GoA for individual facilities or as an aggregated value. In other words, oil and gas facility operators are required to keep a record of all fuel consumption data at their facilities.

6) Equipment Inventory

Oil and gas operators are required to prepare and keep annual inventories of their venting and combustion equipment. Annual inventories must reflect equipment in place at the end of each reporting period. Inventory requirements for pneumatic devices are set out in the AER Directive D060 and inventory requirements for active glycol dehydrators are set out in the AER Directive D039. In addition, inventory requirements for gaseous fuel engines, boilers and heaters (that are above a certain power rating) are set out in the Multi-Sector Air Pollutants Regulations (MSAPR). These inventory data are not available for public access but are available to the operators and can be used in future studies through data sharing agreements with the operators.

3.4 Other Reports and Literature Data

Other studies are available in the public domain that provide some information on the specific vent sources and the contribution of each vent source to the total facility emissions. For example, device

[1] the required measurement frequency can be different depending on the compressor operating hours.

count per facility type and average vent rates for various device types are presented in these studies. Data provided by these studies can be used as average values in the absence of site-specific data for venting emissions. Below is a list of studies that provide generic data on vent and fugitive emissions:

1) Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas, 2018, Clearstone Engineering Ltd., provided for Alberta Energy Regulator [13].
2) Alberta Upstream Oil & Gas Methane Emissions Inventory and Methodology, 2019, Clearstone Engineering Ltd., provided for Alberta Energy Regulator [14].
3) Greenpath 2016 Alberta Fugitive and Vented Emissions Inventory Study, 2017, Greenpath Energy Ltd. [15].
4) Cap-Op Energy Pneumatic Inventory Study, 2018, Cap-Op Energy, prepare for Alberta Energy Regulator [16].

Results of these studies are used in the present study to fill some data gaps and to provide a range of values for sensitivity analysis.

4 METHODS

4.1 Life Cycle Analysis

As explained in the previous sections, the life cycle analysis presented in this study is focused on Montney natural gas production and processing GHG emissions, from production wells up to the point where sales gas leaves the gas processing plants and sent to sales pipelines. In this study, these stages of the natural gas life cycle are referred to collectively as “cradle-to-gate”. The analysis is mainly based on the data from the 2020 year. The functional unit is selected as 1 MJ of sales NG.. GHG emissions are allocated to natural products of gas processing based on energy content of the products.

In this study, GHG emissions are calculated using publicly available data as explained in section 4.2 and following the principles of life cycle analysis. Alternative methods are introduced when there is a lack of data or if available data is considered inaccurate.

4.1.1 Life Cycle Stages

Different stages of NG life cycle considered in this study include:

1) **Pre-production:** site construction, well drilling and completion
2) **Production:** equipment operation, well maintenance
3) **Processing:** compression, dehydration, acid gas removal, other processing equipment

Each stage of the operation can be associated with different sources of GHG emissions: combustion, flaring, venting, fugitive, and embodied emissions.

4.1.1.1 Pre-production

The main source of GHG emissions during pre-production stage is from well drilling and completion activities. In addition, site preparation and construction emissions (activities that happen before well drilling starts) contribute to a very small portion of life cycle emissions and are often neglected.

Well drilling and completion activities including hydraulic fracturing of unconventional wells are the first stages of natural gas extraction process. These activities are associated with energy consumption and GHG emissions. The main sources of GHG emissions during drilling and completion include:

1) Combustion emissions from fuel used by drilling rigs and completion equipment:

   The fuel used by drilling rigs is usually diesel, however, diesel used during drilling and completion has increasingly been replaced by natural gas in recent years.

2) Flowback gas released from the reservoir after fracturing is completed:

   Flowback gas is released from a gas well as fracturing fluid is cleared from the well and returns to the surface. Flowback gas can be captured and flared or tied into a flowline (conserved). If for any reason flowback gas is not captured after it flows to the surface, it will be vented to the atmosphere. In Alberta, flowback gas is generally flared or conserved under the requirements of section 3 of Directive 060.

Methods used for estimating both emission sources above are explained in section 4.2.5.

4.1.1.2 Production and Processing

Production and processing life cycle stages include all the activities that occur at well pads (gas extraction from wells), batteries, compressor stations, gas gathering systems and gas plants.

The main sources of GHG emissions associated with natural gas production and processing include:

1) Combustion emissions - fuel used in different combustion equipment such as heaters and fossil fuel engines (for pumpjack, compressors, gensets, etc.)
2) Flaring emissions – routine or non-routine flaring (blowdown event, emergency shutdowns, etc.)
3) Venting emissions – routine venting from equipment, e.g., pneumatic devices, storage tanks, vessel blowdown, compressor seal vents, surface casing vent flow (SCVF), etc. and non-routine venting from blowdown events, liquid unloading, and other non-routine events.
4) Fugitive emissions

Methods to estimate the above emission sources are explained in section 4.2.6.

4.2 Data Manipulation and Emissions Calculation

4.2.1 Gas Production and Processing Path

Gas extracted from Montney wells is routed through batteries, gas gathering systems, and compressor stations en route to a gas plant for processing. PETRINEX data is used to obtain a list of Montney wells and to identify possible pathways from Montney wells to gas plants.

For this purpose, well infrastructure and licence data available through the PETRINEX website are used and combined to provide a list of wells (well IDs), well surface and downhole locations, producing formation, and licence numbers. This data is then combined with the PETRINEX monthly volumetric reports. Satellites and batteries are identified, and the disposition of gas from these facilities is followed to identify all of the intermediate batteries and compressor stations en route to the gas plants.

The path that raw gas from a given well travels to reach a gas plant is not always as simple as disposition from one well pad to a battery to a gas plant. In several cases the gas may be sent to other 'non Montney' facilities for purposes such as use as fuel, lift gas, and operating pneumatic devices. Identifying this type of gas movement between facilities solely based on the PETRINEX data can be a complicated task. To be able to facilitate and make this process repeatable, a Python script was developed by Modern West to automate the data extraction and analysis.

The initial list of facilities is obtained by recursively searching through the PETRINEX volumetric data and following the gas movement between the reporting facilities and the facilities that they receive gas from or dispose gas to. The facilities to which a battery sends less than 5% of its product, and facilities to which a gas gathering system sends less than 1% of its product were eliminated from the pathway. This is done because by investigating the data reported to PETRINEX it was inferred that these volumes are typically small fuel gas volumes for on-site use.

4.2.2 Selecting Montney Gas Plants

Gas plants may receive gas from various regions and formations for processing. The focus of this study is on the gas plants where gas from the Montney formation constitutes a large portion of the facility feedstock. To identify these gas plants first, a list of all gas plants that process some volume of gas from the Montney formation along with a list of all facilities with a connection to them are obtained through the recursive procedure applied on PETRINEX data as explained in section 4.2.1.

Afterward, the percentage of gas received by each of the facilities within a gas plant's pathway that is from Montney wells is calculated. To accomplish this, first the well formation information from the AER Well Licence dataset is added to the monthly volumetric PETRINEX datasets for 2020. Next, the modified monthly PETRINEX volumetric datasets are filtered for the list of facilities in each gas plant's pathway. Then, the dataset is filtered for gas received from Montney wells, and gas received from non-Montney wells. With this information the total volume received by each facility in a gas plant's pathway, and the volume of gas received specifically from Montney wells are calculated and allow for estimation of the percentage of each facility's gas receipt that is from Montney wells. Finally, the data are aggregated, and the percentage of gas received by each gas plant that is from Montney is calculated by dividing the total volume of gas (from Montney and non-Montney formations) that the facilities within their pathway receive by the volume of gas these facilities receive specifically from the Montney formation.

Based on this analysis, approximately 65 gas plants have received some volume of gas (more than 1% of their feed) from the Montney formation in 2020. Of these, 45 gas plants have had more than 25% Montney gas in their feedstock. The results of this report are based on these 45 gas plants, 1,047 batteries and 288 gas gathering facilities connected to them, and 8,170 producing wells.

4.2.3 Well Decline Curve

Productivity of hydraulically fractured wells decline rapidly over the first two years of their production. After this initial decline period, the decline rate slows down, and wells are expected to produce gas for a number of years at much smaller production rates. The Stretched Exponential (SE) model is one of the models in the literature that can mathematically describe this behavior:

$$q(t) = q_0 \exp\left[-\left(\frac{t}{\tau}\right)^n\right] \qquad \text{Equation 1}$$

In this equation, $q(t)$ is production in month t, q_0 is initial monthly production, t is time in months, and τ, n are fitting parameters.

For preparation of this report, we had access to public volumetric PETRINEX data starting from 2015. For each month PETRINEX volumetric data is combined with the PETRINEX "Well Licence" data (to obtain well formation information) and the AER "General Well Data" dataset (to obtain well production start dates). Consequently, PETRINEX data for each month is filtered for the wells in the Montney formation with production start date in 2015. This data manipulation results in a new dataset with the list of all Montney wells and their production rates for up to 72 months, 2015 thru 2020. after their first month of production. These production volumes are then aggregated for all the wells based on the number of months after first production start date to yield a typical/Montney-representative well average production rate for each month after the first month of production..

Afterward, this dataset is fitted to the Stretched Exponential (SE) equation to obtain the equation parameters with which production from Montney wells could be mathematically represented. This analysis resulted in the following SE equation parameters:

$\tau = 22.6, \quad n = 0.6$

This would allow for the estimation of the production volumes beyond December 2020. A lifetime of 20 years per wellr was assumed for this report. The SE equation was consequently used to estimate the production rate for another 180 months (15 years) after December 2020. An average decline curve representative of a Montney well is generated based on the PETRINEX data and the SE equation and presented in Figure 7. The area under this curve represents the average cumulative gas production volume of an average Montney gas well. In this report the area under the curve is estimated to represent 85,775 e^3m^3 of gas using the Trapezoidal method.

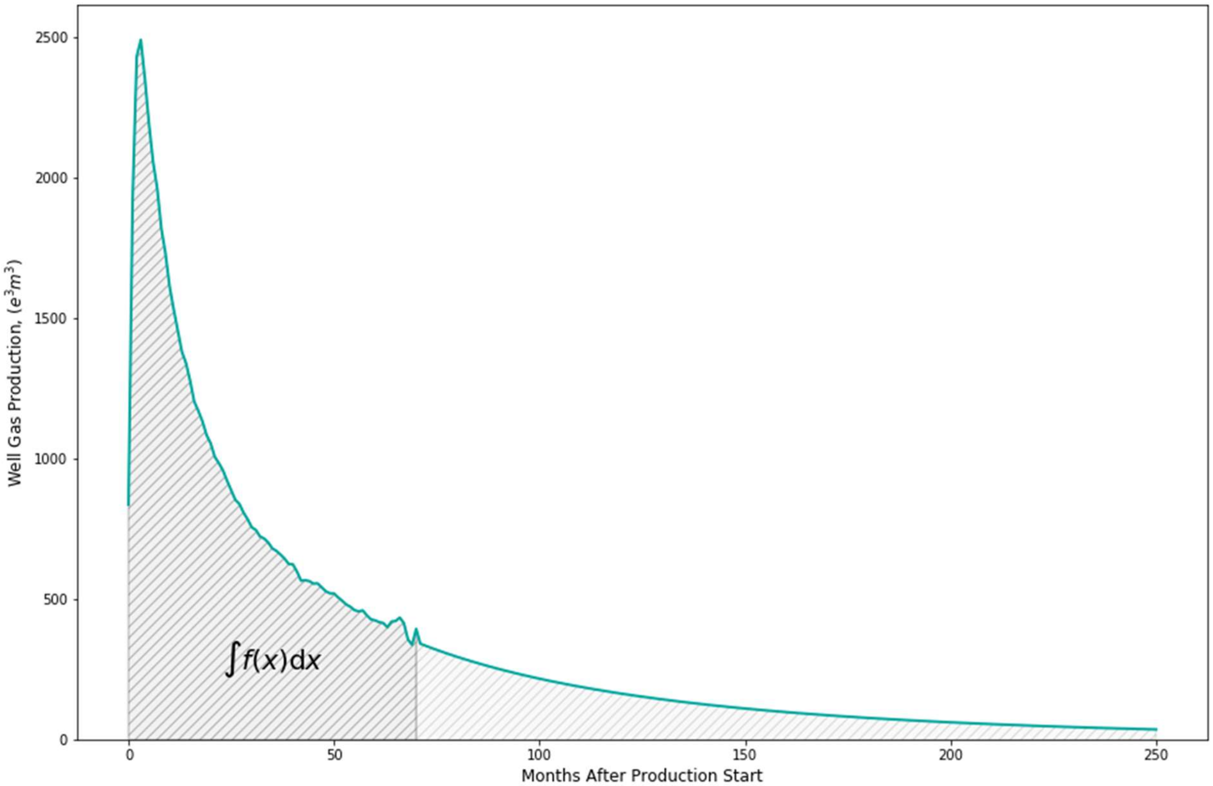

Figure 7 - Decline curve for a Montney well. This figure is based on the average production volumes reported to PETRINEX between 2015 and 2020 for Montney wells with first gas production in a month in 2015, and estimated production volumes using the SE equation for 2020 onwards. The area under the curve represents the average cumulative production volume of a Montney gas well.

4.2.4 Emissions Factor Calculations

4.2.4.1 Fuel Gas Combustion

The following equation, based on the Alberta Greenhouse Gas Quantification Methodologies document [15], is used to estimate the carbon dioxide (CO_2) emissions from natural gas combustion:

$$CO_2 = \sum_{p=1}^{n} 3.664 \times \text{fuel} \times CC_p \times 10^{-3} \qquad \text{Equation 2}$$

Where:

CO_2	=	Annual mass of CO_2 emissions from combustion of fuel gas, expressed in tonnes
n	=	Number of carbon content determinations for the calendar year
Fuel	=	Volume of fuel gas combusted in period (cubic meters at 15°C and 101.325 kPa)

CC_p	=	Carbon content of fuel gas from fuel analysis results for the period "p" (kg C per cubic meter at 15°C and 101.325 kPa)
3.664	=	Ratio of molecular weights, CO2 to carbon
10^{-3}	=	Conversion factor from kilograms to tonnes

Carbon content of fuel gas is not reported into PETRINEX. Equation 3, which is derived based on engineering fundamentals, is used along with the AER gas analysis dataset (included in the AER General Well Data dataset) to estimate a carbon content for each Montney well for which a gas analysis is available.

$$CC_G = (\sum_{i=1}^{n} C\#_{G,i} \times MG_{G,i}) \times 42.292 \times 12.01 \times 0.001 \qquad \text{Equation 3}$$

CC_G	=	Carbon content of gas (kg C/m^3 gas)
i	=	specific component gas in the still gas
n	=	number of component gases in the total gas
$C\#_{G,i}$	=	Number of carbon atoms in the component gas i
$MF_{G,i}$	=	Mole fraction of component gas i
42.292	=	Moles per m^3 at STP conditions (15 °C, 1 atm)
12.01	=	Carbon molecular weight (g/mole)

In some instances, the gas analysis of wells in the AER dataset shows a large fraction of nitrogen. This could be indicative of contamination of the gas samples with air. Therefore, we modify the gas analyses by removing nitrogen, and normalizing the gas analyses before using them in the calculations.

For CH_4 and N_2O, default sector-based emissions factors from the Alberta Quantification Methodologies are used.

4.2.4.2 Flaring

A method from Canada's Greenhouse Gas Quantification Requirements [17] is used to estimate flaring emissions factors:

$$CO_2 = CE \times 10^{-3} \times \left(\sum_{P=1}^{n} [3.664 \times (\text{Flare})_p \times \frac{MW_p}{MVC} \times CC_p] \right) \qquad \text{Equation 4}$$

Where:

CO_2	=	Annual CO_2 emissions (tonnes)
CE	=	Flare combustion efficiency measured at the facility. Assume a 0.98 flare combustion efficiency if facility efficiency data is unavailable
10^{-3}	=	Conversion factor from kilograms to tonnes
n	=	number of measurement periods
3.664	=	Ratio of molecular weights, CO2 to carbon
$Flare_p$	=	Volume of flare gas combusted during measurement period "p" at 15C and 101.325 kPa for gaseous fuels (m3/period) or, specific to petroleum refineries, at dry reference condition at 25°C, 101.325 kPa and 0% moisture (dRm3/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and set (MW)p/MVC= 1
MW_p	=	Average molecular weight of the flare gas combusted during measurement period "p" (kg/kg-mole).
MVC	=	Molar volume conversion factor at the same reference conditions as the above $(Flare)_p$ (m^3/kg-mole). = 8.3145 * [273.16 + reference temperature in °C]/[reference pressure in kilopascal].
CC_p	=	Average carbon content of the flare gas combusted during measurement period "p" (kg C per kg flare gas)

The following equations were used to estimate CH_4 and N_2O emissions factors for flaring:

$$\mathrm{CH_4} = \left(\mathrm{CO_2} \times \frac{\mathrm{EF_{CH4}}}{\mathrm{EF}}\right) + \mathrm{CO_2} \times \frac{1-\mathrm{CE}}{\mathrm{CE}} \times \frac{16}{44} \times \mathrm{f_{CH4}} \quad \text{Equation 5}$$

Where:

CH_4	=	Annual methane emissions from flared gas (tonnes)
CO_2	=	Emissions of CO2 from flared gas
EF_{CH4}	=	Apply facility specific CH_4 emission factor. When facility specific factor is not available assume default CH_4 emission factor of 0.83 x 10^{-3} kg/GJ.

EF	=	Apply facility specific CO_2 emission factor. When facility specific factor is not available assume default CO_2 emission factor for flare gas of 62.4 kg CO_2/GJ (HHV basis)
CE	=	Flare combustion efficiency measured at the facility. A 0.98 flare combustion efficiency of 0.98 can be assumed if facility efficiency data is unavailable
(1-CE)/CE	=	Correction factor for flare combustion efficiency.
16/44	=	Ratio of molecular weights, CH4 to CO2
f_{CH4}	=	Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

The default flare efficiency (CE) of 0.98 is used for this calculation. The weight fraction (f_{CH4}) of carbon (C) from CH_4 to total C in the fuel gas is calculated using the following equation based on engineering fundamentals:

$$f_{CH4,p} = MF_{CH4} \times 12.01 \div \sum_{i=1}^{n} (MF_{i,p} \times MW_{i,p}) \quad \text{Equation 6}$$

Where:

$f_{CH4,d}$	=	Weight fraction of C from CH_4 to C from the still or wild gas (kg C from CH_4 / kg C total)
i	=	Specific component gas in fuel gas
n	=	Number of component gases in fuel gas
MF_{CH4}	=	Mole fraction of CH_4 i for sampling month or period p (unitless)
$MF_{i,p}$	=	Mole fraction of component gas i for sampling month or period p (unitless).
$MW_{i,p}$	=	Molecular weight of component gas i for sampling month or period p (g/mole).
12.01	=	Molecular weight of C (g/mole).

Carbon content of the gas for input into Equation 6 is estimated using Equation 3.

$$N_2O = (CO_2 \times \frac{EF_{N2O}}{EF}) \quad \text{Equation 7}$$

Where:

N_2O	=	Annual nitrous oxide emissions from flared gas (tonnes).
CO_2	=	Emission rate of CO2 from flared gas

EF_{N2O}	=	Apply facility specific N_2O emission factor. When facility specific factor is not available assume default N_2O emission factor for petroleum products of 0.5 x 10^{-3} kg N_2O/GJ
EF	=	Apply facility specific CO_2 emission factor. When facility specific factor is not available assume default CO2 emission factor for flare gas of 62.4 kilograms CO_2/GJ (HHV basis)

4.2.4.3 Venting

Venting GHG emissions were estimated based on the composition of the fuel gas at the facilities within a gas plant's pathway. The following formula was used:

$$EF_{vent} = x_{CH4} \times \rho_{CH4} \times GWP_{CH4} + x_{CO2} \times \rho_{CO2} \times GWP_{CO2} \qquad \text{Equation 8}$$

Where:

EF_{vent}	=	Venting emissions factor
x_{CH4}	=	Volume fraction of CH_4 in vented fuel gas
x_{CO2}	=	Volume fraction of CO_2 in vented fuel gas
GWP_{CH4}	=	Global Warming Potential for CH_4, 25 (IPCC AR4, 100-year horizon)
GWP_{CO2}	=	Global Warming Potential for CO_2, 1 (IPCC AR4, 100-year horizon)

4.2.5 Drilling and Completion Emissions

4.2.5.1 Combustion Emissions

Depending on data availability, directly measured volume of fuel used for combustion can be used to calculate combustion emissions. The volume of fuel (commonly diesel or natural gas) is metered by the operators and third-party service providers during the drilling and completion activities. However, depending on the type of fuel, this fuel volume might or might not be reported to PETRINEX under the Drilling and Completion facility ID (temporary facility ID used during drilling and completion activities). In addition, Drilling and Completion facility IDs that do report the fuel volume might be removed from the PETRINEX volumetric data later because of the temporary nature of the activity.

For this study, all reported fuel volumes to PETRINEX under the Drilling and Completion facility ID type between Jan 2015 and December 2020 are compiled and analyzed. The list of drilled wells is filtered to show Montney wells only, and the volume of gas reported as fuel for drilling activities in the Montney area are obtained and used for emission quantification.

The volume of liquid fuels (e.g., diesel), if used for drilling, are not reported to PETRINEX and must be provided directly by the facility operators.

In the absence of measured fuel volume data, fuel volume can be estimated using well characteristics (e.g., depth, diameter, etc.) and drilling equipment information (e.g., efficiency). In this study we investigate two different models that are developed to estimate drilling energy consumption.

The first model is proposed by Umeozor and Gates [18], and estimates GHG emissions associated with energy consumption and flowback gas during pre-production activities. This model uses both US and Canadian drilling data. The results of this study are used in the sensitivity analysis.

The second alternative is the approach used in OPGEE and is explained in section 4.3.

4.2.5.2 Flaring/Venting Emissions

Flowback gas volume, if flared, is metered and reported to PETRINEX under the Drilling and Completion facility ID. Similar to the approach explained above for extracting fuel volume data from PETRINEX, flared volume data during drilling and completion activities is extracted from PETRINEX as well. PETRINEX data suggests that flowback gas is either completely or partially conserved, in which case the reported flared gas volume is either zero or smaller than the cases where all flowback gas is flared. The reported flared volumes are used to estimate the average volume of flowback gas flared during well drilling and completion. The results are presented in section 5.1.

A number of studies in the literature have proposed different methods for estimating the volume of flowback gas during well completion [18,19]. These studies provide a range of flowback gas volumes per completion and the results are used in the sensitivity analysis in section 5.1.1.

4.2.6 Production and Processing Emissions

4.2.6.1 Combustion Emissions

All facilities that produce or process oil and gas products in Alberta are required to report the volume of gas combusted as fuel to PETRINEX on a monthly basis as explained in section 3.1.1. The volume of fuel gas can be determined using different methods including direct measurement and using default fuel consumption rates based on equipment type and size. Both methods are acceptable for reporting the volumes to PETRINEX but have to meet certain accuracy thresholds. In this study, we use the reported fuel gas volumes for estimating combustion emissions from each facility.

Gas production facilities commonly use fuel gas to run combustion equipment on site, but other fuel types (e.g., propane and diesel) can be used at some facilities as well. Liquid fuel consumption is not reported to PETRINEX, and the consumption data is not publicly available. However, beginning in 2020 all operators are required to collect fuel consumption data (both gaseous and liquid fuels) as part of the reporting requirements under Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation and report the combustion emissions to Alberta Environment and Parks (AEP). The 2020 TIER compliance report was submitted by the operators at the end of June 2021. The data is not publicly available. Future work could include a data sharing agreement with the GoA to collect and use actual reported fuel volumes to refine the estimates of this study.

In the absence of measured fuel consumption data, an alternative approach for estimating fuel consumption is based on equipment inventory data . If a list of all combustion equipment operating on site is available, fuel consumption by each equipment can be estimated using the equipment specifications (e.g., equipment size, efficiency, etc.), equipment load, and operating hours. Complete and updated equipment inventory data is not available publicly for all facilities. Facility PFDs and P&IDs submitted to the AER as part of the facility request for approval can be used to obtain some equipment specifications, but there are a few issues associated with using the PFD and P&ID documents:

1) these documents are submitted at the facility design stage, and the actual equipment list and specification might be different,
2) equipment is added, removed, or replaced at the gas production and processing facilities over time, and all the changes are not necessarily submitted to the AER or available publically,
3) not all the equipment specifications required for estimating fuel gas consumption rate are included in a PFD.

In addition to these issues, reviewing PFD and P&ID documents for many facilities can be a very time-consuming process.

Existing LCA models like OPGEE use default equipment specifications to estimate fuel consumption. OPGEE's method for fuel consumption emissions at gas production and processing facilities is explained in section 4.3.

4.2.6.2 Flaring Emissions

Similar to fuel gas volumes explained in the previous section, flared gas volume from all upstream oil and gas facilities in Alberta are reported to PETRINEX on a monthly basis. The data is available through the PETRINEX website [20], and is used in the GHG emission calculations in this report.

4.2.6.3 Venting Emissions

Vented volumes are reported to PETRINEX by facility operators on a monthly basis. Prior to 2020, the reported vented volumes were not considered accurate, and they were based on default vent rates per facility type, and in some cases default vent rates for specific equipment type (not all venting equipment types, e.g., pneumatic devices, were included in the reported vented volumes). Starting in 2020, after the AER Directive 060 was updated, new guidelines were published for estimating and reporting vent volumes to PETRINEX that significantly improved the accuracy of the reported vent volumes. The reported vent volumes to PETRINEX should include all of the main vent sources at each facility and are based on either direct measurement or device specific vent rates. Operators calculate vent rates for each device and report the total vented gas to PETRINEX. This data (venting emissions inventory along with venting equipment inventory) is available to the operators and can be requested by the AER for review but is not publicly available. The base case results presented in this report rely on the reported vent emissions obtained from PETRINEX public reports.

If a complete inventory of venting equipment was available, device specific vent rates could be utilized to estimate venting emissions from gas production and processing facilities. In the absence of site-specific equipment inventory, average equipment count per facility could be used as proxy, based on published generic inventory data. In 2017, Clearstone Engineering Ltd. conducted a field campaign at Alberta upstream oil and gas sites under the authority of the Alberta Energy Regulator (AER) [13]. The technical report, based on the findings of the field campaign, lists the average number of venting equipment per facility type (for selected facility types that have a significant contribution to the methane emissions uncertainty in the province). This provides a partial estimate of venting emissions from some of the vent sources at each facility type, but further inventory data is still required to complete the vent estimates. A major issue associated with using the results of these studies for life cycle emissions estimates is that venting GHG emissions inventory of oil and gas facilities in Alberta has changed significantly in the past few years, i.e., vent GHG emissions have decreased. This is mainly because the operators have started to take necessary measures to become compliant with the vent limits set out in Directive 060 (starting Jan 1, 2020). A large number of pneumatic instruments have potentially been converted to non-venting devices since the time that studies such as the Clearstone study were conducted. This must be taken into consideration when interpreting the results.

4.2.6.4 Fugitive Emissions

Fugitive emissions are not reported on a monthly basis to PETRINEX. Rather, they are reported annually in OneStop as part of the Annual Methane Report to the AER. The raw data for 2020 compliance year that were reported to OneStop on June 1, 2021 has not been made public yet. The new AER Directive 060 that came into effect in 2020 requires facilities to complete Leak Detection and Repair (LDAR) activities at specific frequencies depending on each facility's type. Therefore, more information is expected to become available over time. For preparation of this report, it was not possible to access the AER OneStop data or obtain data directly from all operators. Therefore, an alternative approach based on reference [13] is used to estimate the potential fugitive emissions. It should be noted that given the new LDAR requirements mandating the repair of fugitrve emissionsthis approach may significantly overestimate the fugitive emissions. Future work should evaluate the feasibility of a data sharing agreement with the AER to enable better representation of the magnitude of fugitive GHG emissions in the natural gas life cycle GHG emissions.

In the absence of any fugitive data in the public domain, we used generic data available in the published literature to estimate fugitive emissions using the average component count per facility type [13,14]. Two methods are used for estimating fugitive emissions based on: 1) using average (mean) process equipment counts per well status from [13] to estimate the fugitive emissions from the well sites, and 2) using average (mean) process equipment counts per facility subtype along with population average leak factors from [13].

The list of facilities (and type) within the natural gas production pathway for each gas plant included in our report, and the list of wells connected to them, were obtained from the publicly available Petrinex data [20]. Well status data was obtained from the AER "General Well Data" dataset [9].

Reference [13] provides average equipment counts for each well status code (e.g., "GAS FLOW", "CR-OIL PUMP"), as well as average component counts per equipment type and average fugitive emissions rate per component. An average fugitive emissions rate per well status code was estimated based on these data. To estimate the fugitive emissions from each Montney well, first a list of all wells in the Montney formation was derived using the monthly volumetric PETRINEX reports in 2020 along with the "well licence" data also available from PETRINEX (see section 03 for more detail). Well status code data was obtained from the AER "General Well Data" dataset and merged with the well list and well formation data from PETRINEX. Finally, the fugitive emissions rates obtained from [13] were used to estimate a weighted average fugitive emissions rate (based on number of wells with each status code) for the Montney formation wells.

Number of wells in each natural gas plant pathway was then multiplied by this average per-well fugitive emissions rate to estimate the fugitive emissions from the Montney wells in each gas plant's pathway (number of wells with a connection to the Montney gas plants was obtained based on PETRINEX data). Fugitive GHG emissions from facilities with subtype codes 601 (compressor station) and 621 (Gas gathering system) were estimated based on the average process equipment counts in [13] in a similar fashion by estimating an average fugitive emissions rate for these facility types and multiplying it by the number of facilities of these types within each gas plant pathway.

The AER Directive 087 sets out the requirements for testing, reporting, and repair requirements for isolation packers, surface casing vent flows (SCVFs), gas migration, and casing failures. Data reported under this directive is publicly available through the AER website [21]. Emissions from SCVF are considered fugitive emissions but are not reported to OneStop. In this report we used the Vent Flow and Gas Migration Report data available from the AER website to estimate SCVF emissions from Montney wells. For this purpose, the dataset was filtered for the wells in Montney and a total SCVF daily rate was obtained. This volume was then converted to GHG emissions using an average gas analysis for the Montney wells and included in the GHG emissions calculations for the Montney gas plant pathways.

4.2.6.5 Indirect Emissions

The main source of indirect emission in the NG life cycle is from grid electricity consumption. Electricity consumption data are not reported by oil and gas facilities and no public data could be obtained to quantify indirect emissions associated with grid electricity consumption. To quantify grid emissions, a list of electric driven equipment is required. Equipment data is one of the data gaps discussed in section 5.4.

Another potential source of indirect emissions is upstream emissions associated with raw material use in well and pipeline construction. Based on limited available data in the literature this GHG emission source contributes to less than 0.5% of the total life cycle GHG emissions and is therefore excluded from the scope of this study.

4.2.6.6 Land Use Change Emissions

Land use change emissions are excluded from the scope of this study. This could be investigated in a future report as it is a data point with increasing importance as ESG reporting improves and requirements extend to supply chain impacts.

4.2.7 Sensitivity Analysis

Parameters such as volume of fuel gas combusted, vent and flare volumes, composition of fuel gas, etc. can affect the life cycle NG production and processing GHG emissions. A sensitivity analysis was conducted to investigate the impact of uncertainty of a number of these parameters on the NG production and processing GHG emissions intensity estimates. These parameters and the assumptions related to them are summarized in Table 2.

Table 2 – Sensitivity Analysis Parameters

Parameter	Lower Bound	Upper Bound	Note
Fuel Gas Volumes	20% less than PETRINEX volumes	20% more than PETRINEX volumes	Maximum uncertainty allowed in reporting as per AER Directive 17. Default values used are PETRINEX reported volumes.
Flare Volumes	20% less than PETRINEX volumes	20% more than PETRINEX volumes	Maximum uncertainty allowed in reporting as per AER Directive 17. Default values used are PETRINEX reported volumes.
Vent Volumes	10% less than PETRINEX reported volumes	50% more than PETRINEX reported volumes	Facilities may not yet be fully complying with the more recent and strict vent reporting requirements of AER Directive 060. Significant underreporting is expected. Sensitivity analysis bounds were chosen based on our previous projects and rough estimates based on generic equipment count data as explained in section 4.2.6.3. Default values used are PETRINEX reported volumes.
Fugitive Volumes	80% less than current estimates based on published methods	10% more than current estimates based on	The recent Leak Detection and Repair requirements are expected to significantly reduce fugitive emissions. Since 2020 data is required to be reported as per the AER Directive 060.

Parameter	Lower Bound	Upper Bound	Note
		published methods	Reported data is not publicly available at this point. Default values used in the report are estimated based on published literature discussed in section 4.2.6.4.
Fuel Gas Composition	Based on AER gas analyses dataset	Based on AER gas analyses dataset	For base case calculations gas analysis for each facility in a gas plant pathway is used for that facility, with data gaps filled with the average of available gas analysis for facilities in the pathway. In sensitivity analysis, gas analysis with lowest methane content and highest methane content were used. This was expected to reasonably capture the impact on GHG emissions (mainly combustion and venting). Note that gas analyses are also used to estimate fuel gas HHV values. HHV values are used for allocation of emissions to natural gas.
Oil HHV	Arbitrary range based on OPGEE	Arbitrary range based on OPGEE	Montney oil and condensate are expected to have APIs of 38 and higher.
Drilling and Completion	No applicable values were found.	0.29 gCO_2e/MJ gas	In the base case a GHG emissions intensity value of 0.22 gCO_2e/MJ gas is considered as explained in section 4.2.5. OPGEE yields an estimate of 0.29 gCO2e/MJ gas. A third method based on [18] yields a value of 1.6 gCO_2e/MJ gas. However, this study assumes that all flowback gas is vented into the atmosphere which is not allowed in Alberta. Assuming that all gas is flared, this value would be approximately 0.36 gCO_2e/MJ gas. For the sensitivity analysis the value obtained based on OPGEE was used.

4.3 OPGEE Model

4.3.1 Model Overview

Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model is an open-source model developed by the researchers at Stanford University. OPGEE model estimates life cycle emissions associated with production, processing and transmission of oil and gas products. In this study we intend to populate OPGEE input parameters with Canadian specific data (with a focus on the gas production from Montney formation) as much as possible and modify some of the default assumptions of the model to better reflect the Canadian operations. Note that all the default values in OPGEE cannot be replaced with Canadian specific data as all the required data is not available publicly. The details of populating OPGEE with publicly available data from Canadian natural gas production is explained in the following sections. A list of main OPGEE inputs that cannot be found in the Canadian public databases is presented as well.

OPGEE model files and a detailed model documentation is available for download on the Environmental Assessment & Optimization Group webpage at https://eao.stanford.edu/opgee-oil-production-greenhouse-gas-emissions-estimatorTo run the OPGEE model, five gas plants along with their associated gas production and processing facilities were selected and the relevant data obtained from the sources explained in the previous sections (e.g., PETRINEX). This helps use site specific data for OPGEE runs. The data are inputted into the model to calculate NG upstream emissions and the GHG estimates are compared to the results of GHG calculations explained in section 4.2. It should be noted that OPGEE_3.0a_BETA version that is used in this study is not officially published as a stable version of the model yet. Therefore, the OPGEE results are not presented separately in this report, only a comparison between the emissions estimates of certain stages and emission sources are discussed to provide high level insights about the differences between various approaches. In addition, gaps in Canadian public data for populating OPGEE are identified. The current stable version of the model, OPGEE model v2.0, is focused on oil production pathways and does not include sufficient details of natural gas production pathways, therefore, version 2.0 was not used in this study. A more detailed analysis of OPGEE results using Canadian data could be conducted as part of a future report.

4.3.2 OPGEE Inputs

Montney data used to populate OPGEE primary inputs are obtained from various data sources (data sources are explained in section 3). Below is a summary of how the relevant input data are obtained from these sources and used in OPGEE.

4.3.2.1 OPGEE Primary Inputs

Among the production methods listed in OPGEE, "Downhole pump" (or mechanical lift) and "Gas lifting" are applicable to the gas production practice in the Montney region. It should be noted that gas lifting is commonly used for oil wells only, and not for gas wells[2]. In Montney, during the production

[2] Wells are usually designated as either oil or natural gas wells based on a gas-oil ratio. EIA uses a GOR value of 6,000 (cubic feet of natural gas to barrel of oil) as the threshold. If the GOR is equal to or less than 6,000

period of a well, the gas could flow to the surface naturally without any pumping, and the well is considered to have "flowing" status in this case. Under some circumstances, if the pressure of the reservoir is not sufficient, well production might require pumping to bring the gas (or the associated liquid products) to the surface, the well is considered to have "pumping" status in this case. Wells could use a combination of both methods during their lifetime. For oil wells, in addition to flowing and pumping, gas lift might be used for production, this is reported as "gas lift" under the well status report. The data that shows the well status "mode" (whether a well is flowing or pumping or using gas lift) is found in the AER General Well Data report. In this report, the well status mode data during its lifetime, any changes in the well status along with the date of the status change are recorded. We use this data to determine what percentage of wells use each production method and use that as input in OPGEE.

Field depth is determined using well depth data which is obtained from the True Vertical Depth (TVD) information available in the AER General Well Data.

Production tubing diameter is estimated based on the well casing size data in the AER General Well Data. A list of Montney wells along with the well casing type and size are obtained and analyzed. Average well size and relevant production tubing size are calculated and used as OPGEE inputs.

Gas composition data from various wells is available in the AER General Well Data. Average gas composition is calculated for each production facility and used as input in OPGEE.

API gravity of the liquid product is estimated based on the liquid composition data and the method used in OPGEE Fuel Specs sheet. Liquid composition data is available in the AER General Well Data.

Oil production volume, number of wells, GOR and WOR are calculated based on the reported volumetric data to PETRINEX for the selected set of facilities.

Average Montney reservoir pressure and temperature are obtained from the literature data [22].

4.3.2.2 OPGEE Secondary Inputs

Some of the default secondary inputs of the OPGEE model are replaced with Canadian specific data as well. These changes are explained in this section.

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ft^3/bbl, then the well is classified as an oil well. If the GOR is greater than 6,000 ft^3/bbl, the well is classified as a natural gas well, https://www.eia.gov/petroleum/wells.

Different well complexity settings are defined in OPGEE based on the types of casings installed during the well construction. Figure 8 below from OPGEE documentation depicts these settings.

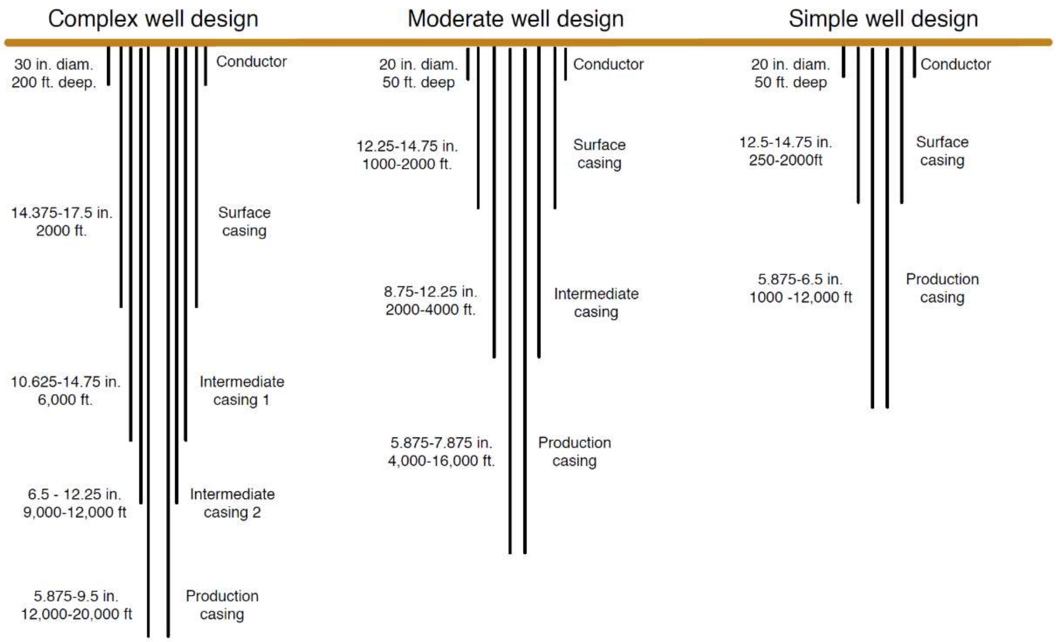

Figure 8 – Types of well design in OPGEE (adapted from *[23]*)

Well casing information for Montney wells is available in the AER General Well Data. Based on the casing information obtained for Montney wells, ~55% of the wells have intermediate casing and fall under the "Moderate" well design category. The rest of the wells seem to use the design that is consistent with the "Simple" well design. We use Moderate well design as base case assumption and explore the impact of selecting Simple well design on the GHG emissions results.

Hole size, length of lateral, gas field productivity, flowback gas volume and percent of flowback gas flared or conserved, fraction of horizontal wells, and fraction of wells fractured are modified using Montney specific data from AER General Well Data report. The rest of the parameters are left unchanged to use OPGEE default values.

4.3.3 OPGEE Methods

4.3.3.1 Drilling and Completion Emissions Calculation

In the absence of measured fuel volume data, the alternative approach for estimating GHG emissions associated with fuel combustion during well drilling and completion is using the proposed method in the OPGEE model. The OPGEE model uses well data such as well diameter and length, type(s) and number of well casings installed, well direction (horizontal or vertical), well productivity category (low, medium or high as defined in the model) as well as the efficiency of drilling and fracturing equipment to estimate the amount of energy required for well drilling and completion. Relationships for these functions are derived from the open-source drilling energy intensity model GHGfrack [24]. The GHGfrack model estimates drilling energy intensity as a function of well characteristics.

To calculate vented and flared gas emissions during drilling and completion, OPGEE model uses default values for flowback gas volume. The default values are based on US well drilling and development data. Depending on availability of operator specific data, these default values could be updated based on actual Canadian-specific data.

4.3.3.2 Production and Processing Emissions Calculation

OPGEE includes default assumptions for the number and type of equipment required for natural gas extraction. Fuel consumption by equipment type is estimated and used in the GHG emissions calculations. However, since the default assumptions used in OPGEE are based on average values/typical operations, they may not accurately represent the gas production and processing in specific facilities in Alberta. Therefore, the preferred method for estimating combustion emissions is to use reported fuel volumes by each facility instead of using OPGEE's assumptions.

OPGEE model uses two methods for estimating fugitive emissions from different stages of natural gas production and processing: 1) bottom-up approach using component count, and 2) top-down approach using total facility survey results (e.g., aerial surveys) and allocating to different equipment and components. Both methods are based on fugitive emissions databases that are mainly obtained from facilities operating in the US, therefore, the fugitive emissions estimate in OPGEE must be replaced with the Canadian-specific data. Fugitive emissions data are not publicly available.

4.4 NETL

NETL model is a life cycle model developed by the National Energy Technology Laboratory (NETL) to estimate emissions and environmental impacts of natural gas production and processing from various natural gas plays in the U.S. This model has been modified in a few studies to accommodate Canadian natural gas production [25,26]. A recent study published in 2021 has identified the data gaps that exist in the Canadian public datasets and ranked them based on their importance in estimating natural gas emission intensity [25]. The main data gaps identified in [25] are presented in section 5.4 along with the data gaps found in the present study.

5 RESULTS

5.1 LCA results

Figure 9 shows the GHG emissions intensity estimates for the Montney gas plants investigated as explained in section 4.2.2. As demonstrated in Figure 9, the analysis suggests an average annual cradle-to-gate GHG emissions intensity of 4.04 gCO_2e/MJ gas for the Montney gas plants with a minimum monthly estimate of 3.72 gCO_2e/MJ gas and maximum monthly estimate of 4.51 gCO_2e/MJ gas. Figure 9 also suggests that the cradle-to-gate GHG intensity of gas production from Montney is fairly consistent throughout the year with no significant seasonal changes occurring. Error bars in Figure 9 show the potential GHG emissions intensity ranges that may be expected due to uncertainty in a number of parameters that can affect the GHG emissions intensity estimated, i.e., fuel consumption volumes, vent and flare volumes, fugitive GHG emissions, fuel gas composition, and heating value of oil produced at the facilities in the gas plant pathways. The impact of each of these parameters individually is discussed in the sensitivity analysis section below.

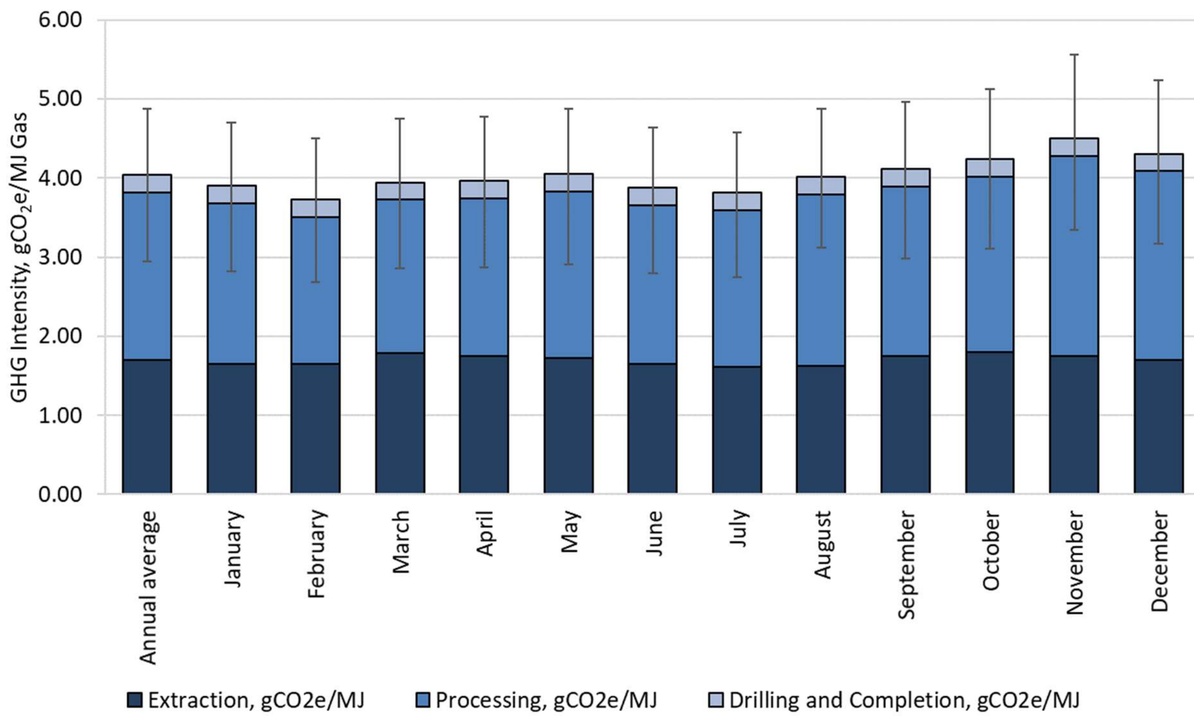

Figure 9 – GHG emissions intensity of Montney gas plants per life cycle stage

While the average annual and monthly cradle-to-gate GHG emissions intensity estimates remain consistent, a wider range of GHG emissions estimates is observed for each individual gas plant pathway. The GHG emissions estimates obtained for the individual gas plant pathways are presented in Figure 10. This figure shows a cradle-to-gate GHG emissions intensity range of 1.72 gCO_2e/MJ gas to 9.84 gCO_2e/MJ gas for the Montney gas plant pathways included in this report. The variance observed in the GHG emissions intensity estimates could be due to the effect of a number of factors such as different operations, unusual incidents in operations, different qualities of feedstock gas or production of different products that could require different levels of processing. Given that gas plants owned by a given company may receive and produce gas from assets of several other producers, this range is no indication of better performance of one single company over another.

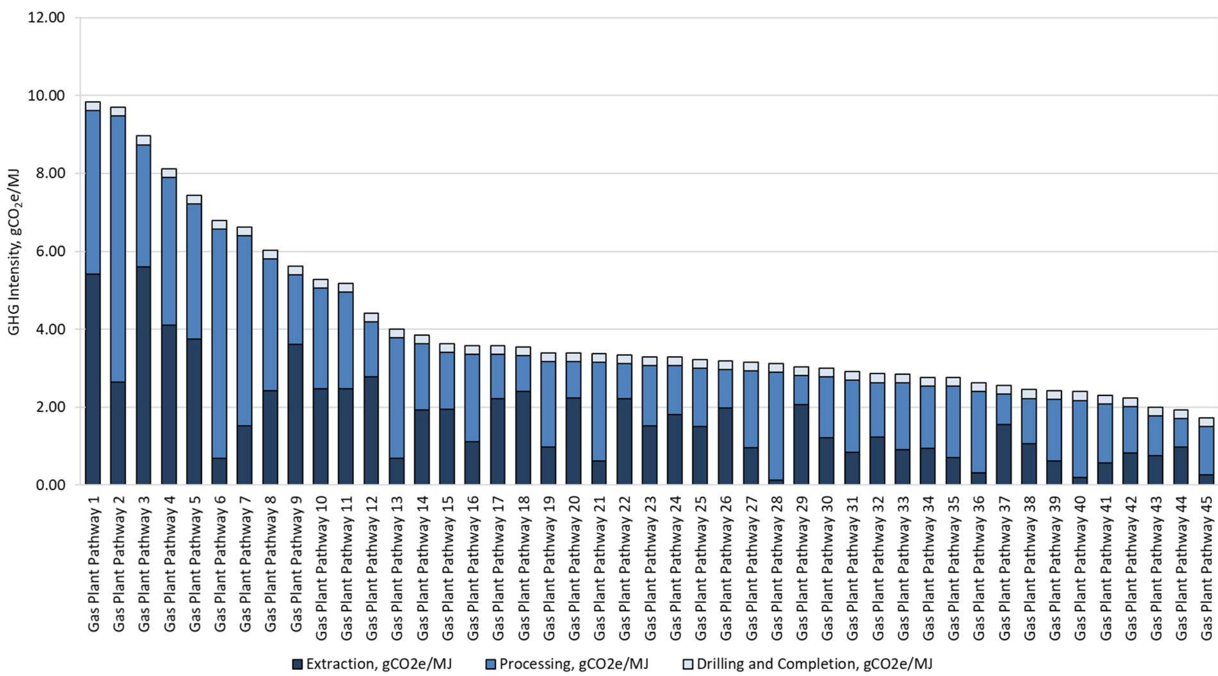

Figure 10 – GHG emissions intensity estimates per life cycle stage based on individual gas plant pathways

Figure 11 shows the breakdown of the life cycle (cradle-to-gate) Montney gas GHG emissions intensities to the sources of GHG emissions.

Figure 11 suggests that fuel gas combustion is the largest contributor to the cradle-to-gate Montney gas GHG emissions, and is followed by venting, flaring and fugitive emissions, and emissions associated with drilling and completion. It should be reiterated that fugitive emissions are estimated based on a 2018 report prepared by Clearstone for the AER. Given the new LDAR requirements that came into effect in 2020, it is likely that the fugitive emissions demonstrated in Figure 11 are significantly overestimated. The impact of this uncertainty is explored through a sensitivity analysis presented in section 5.1.1. On the other hand, venting emissions may have been underestimated as some facilities may have not yet adopted proper quantification and reporting procedures for compliance with the new Directive 060 vent reporting requirements. Flare and fuel reported volumes are expected to have an uncertainly of ±20% as per the AER Directive 17 requirements. Finally, drilling and completion emissions data are not publicly available, and are estimated for this report based on the published literature as explained in 4.2.5. Future work could include obtaining more accurate data for fugitive emissions and drilling and completion activities from the AER (OneStop reports) and operators to allow for further refinement of the current GHG emissions estimates.

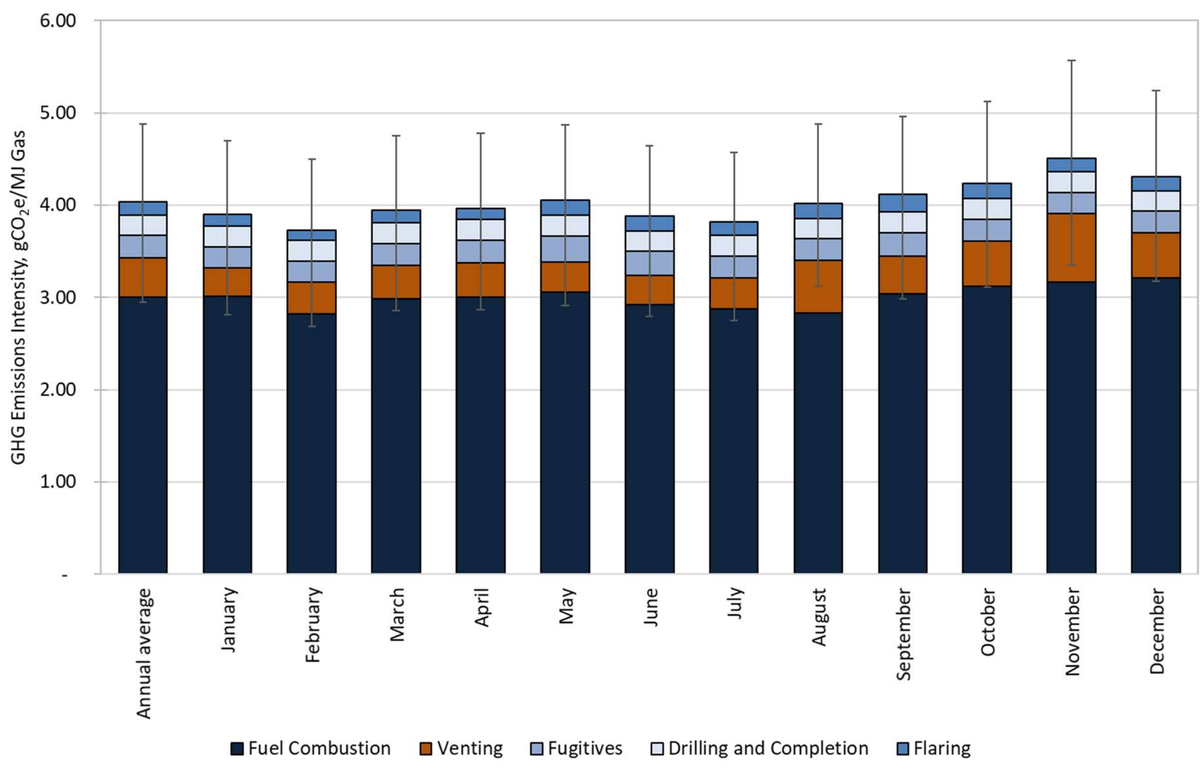

Figure 11 – GHG emissions intensity of Montney gas plants per GHG source

Similarly, Figure 12 shows the breakdown of the GHG emissions sources that constitute the GHG emissions associated with each gas plant pathway.

Figure 12 indicates that the contribution of each GHG emissions source to the GHG emissions of a gas plant pathway can be significantly different from one gas plant pathway to another. This variation could be due to the effect of a number of factors such as different operations of facilities in a given gas plant pathway (e.g., facilities with electrified pumps and controllers could have no venting), errors in PETRINEX reporting (e.g., some facilities may not be quantifying their venting emissions properly, or not including all relevant vent sources).

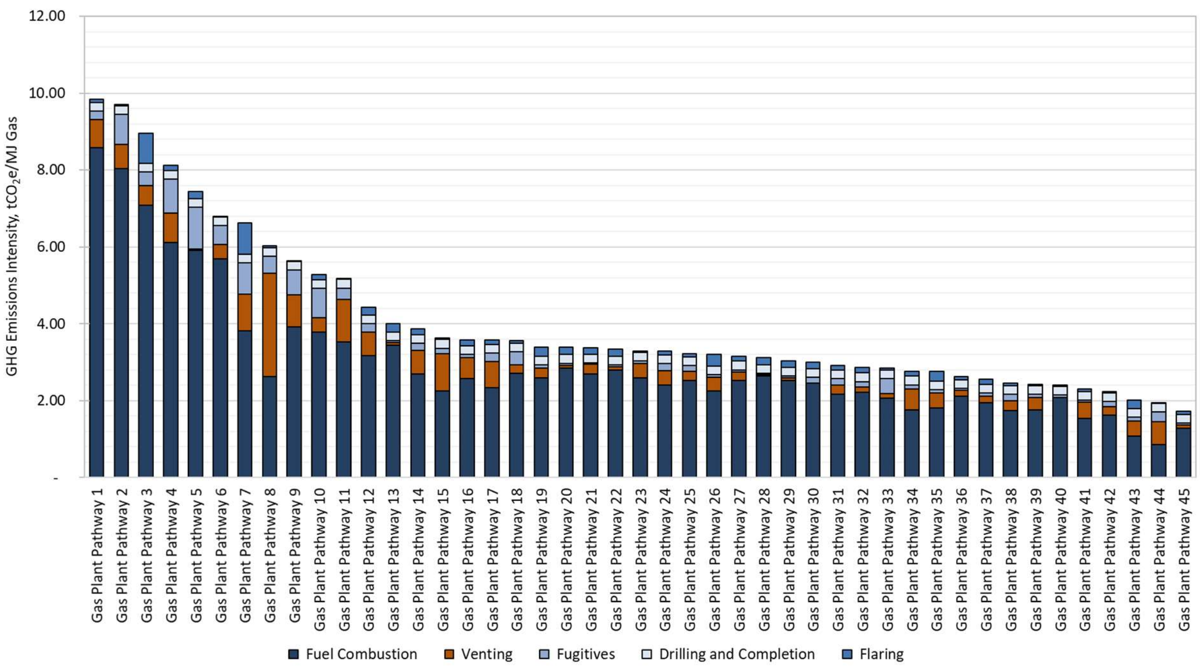

Figure 12 – GHG emissions intensity estimates per GHG source based on individual gas plant pathways

5.1.1 Sensitivity Analysis Results

A sensitivity analysis was conducted to investigate the parameters that could impact the GHG emissions intensities of each of the facilities. The results of this analysis are summarized in Figure 13. Relevant assumptions for this analysis are listed in section 4.2.7.

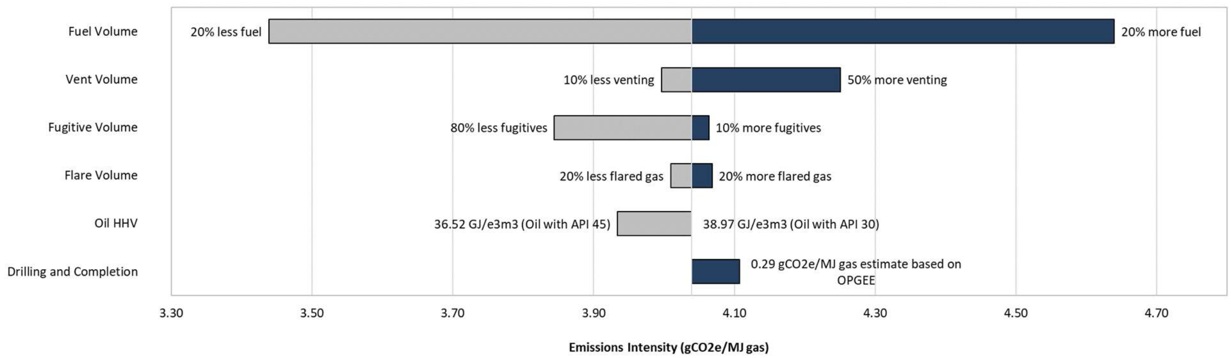

Figure 13 – Sensitivity Analysis Results

Sensitivity analysis shows that for the same magnitude of change in the reported fuel and flare volumes, the GHG emissions will be much more strongly affected by the change in the fuel consumption. It is intuitive that given the large contribution of fuel GHG emissions to the cradle-to-gate GHG emissions, a small variation in fuel consumption could have a significant impact on the total emissions. Vent volumes currently reported into PETRINEX could still be based on the previous requirements of Directive 060 that were in effect before January 1, 2020. In addition, some vent sourced are potentially missed in the data reported in 2020. Data in 2021 is expected to be more accurate than the 2020 data. Therefore, LCA estimates in this report should be recalculated each year as data such as vent volumes are expected to become more available and more accurate over time.

Future work could include obtaining the fugitive and non-PETRINEX data from the AER, AEP, and the operators to improve the estimates presented in this report.

5.2 Comparison with OPGEE

As explained in section 4.3.1, five gas plants are selected and relevant data based on them are used to run OPGEE to obtain GHG emissions estimates associated with the natural gas that they produce. Base case OPGEE results show a range of intensities between 2.66 – 6.28 gCO_2e/MJ for the selected plants, and the LCA results presented in section 5.1 show a range of 2.13 – 5.47 gCO_2e/MJ for these gas plants.

The differences between GHG intensity estimates obtained by the two methods are mainly because:

1) Gas and oil processing equipment assumed in OPGEE calculations do not always reflect the actual processing path of the oil and gas products in the production and processing facilities in Alberta. Therefore, using reported fuel consumption and other emissions related data (if the data is available and assuming the reported data are accurate) would provide more accurate estimates. To make OPGEE calculations for each specific facility better align with the reported data, a list of equipment operating at each facility would be required (equipment data such as size, fuel type, efficiency, etc.).
2) Reported vent and fugitive emissions in Alberta are not completely aligned with the estimated emissions in OPGEE. OPGEE vent and fugitive estimates are based on measured data from several references. With more Canadian data becoming available in the past few years, Canadian vent and fugitive estimates could be improved significantly once the data becomes publicly available. On the other hand, reported vent volumes in Alberta that are used for emissions calculations in this study might not include all vent sources at each facility. Vent reporting to Petrinex has become significantly more accurate since 2020 with the introduction of new reporting requirements under Directive 060, however, analyzing the monthly reported data shows that some facilities might not be reporting vent emissions accurately. This can be further investigated in future studies.

5.3 Comparison with other LCA studies

Several studies in the literature estimate NG upstream emissions intensity using a variety of methods and data sources. A recent study authored by researchers from the University of Calgary estimates a GHG intensity of 4.2 gCO_2e/MJ NG associated with upstream NG production [25]. However, this includes emissions associated with NG transmission pipeline (which is not included in the scope of the present report). If the transmission emissions are excluded to make the boundaries consistent with the present report, the estimated emission intensity at NG plant exit is approximately 2.86 gCO_2e/MJ NG. This estimate is based on site specific data obtained from one of the largest NG producers in Canada (Seven Generations Energy). Two other studies conducted by researchers from the University of British Columbia and Stanford University used a similar set of site-specific data but slightly different modeling and quantification approaches and estimated 3.26 gCO_2e/MJ NG and 2.59 gCO_2e/MJ NG emission intensities (excluding transmission emissions) for upstream NG production [27,28]. Another upstream emission intensity for Montney formation (in British Columbia) provided by GHGenius model is ~5.5 gCO_2e/MJ NG [25,29]. US average estimates for NG upstream emission intensity presented in different studies show 6 – 12.5 gCO_2e/MJ for different regions and formations [30,31].

It should be noted that each of the previous studies use specific sets of assumptions and data sources and focus on specific gas producing regions and production methods. Therefore, the boundaries and emission sources included in each study might be different and a more detailed comparison of estimated emissions from each life cycle stage and specific emission source is required to capture the similarities and difference of those studies and compare them with the results in the present report. This will be further investigated in the future work. The framework presented in this report is based on data that is reported to the AER by facilities across Alberta and meet certain criteria set by the AER. This would allow for future LCA analyses of NG produced in different regions within Alberta in a consistent manner based on similar data, boundaries, and assumptions. Furthermore, the future analyses could be expanded to include NG production in Saskatchewan and British Columbia as these provinces have similar PETRINEX reporting requirements that align well with the reporting in Alberta.

5.4 Data Gaps

In this section a list of main data gaps found in publicly available datasets is presented along with suggestions on how the data can be obtained. The main gaps found in publicly available datasets that are determined to have the highest impact on the calculated emissions intensity include:

1) A complete inventory of vent emissions per facility, including routine vent sources (e.g., storage tanks, compressor seals, etc.) and non-routine vent sources (e.g., equipment blowdown, liquid unloading from gas wells). The reporting requirements in AER Directive 060 along with the vent estimation guidelines in AER Manual 015 [12] are supposed to significantly improve the accuracy of reported vent emissions. However, reviewing the reported vent emissions in 2020 shows that all the operators might not have completely adopted the AER reporting guidelines for reporting vent emissions. This is mainly due to the extensive data collection required for estimating vent emissions and facility operators being unfamiliar with these requirements. As part of the future work, it could be helpful to start a collaboration with the operators and provide them with data collection templates (with

specified frequency of collecting each data point) to collect the data in a systematic manner. This can provide a complete and consistent set of data for all the facilities across the province and provide the opportunity to develop a database for venting emissions from oil and gas operations in the province. Ultimately, this database can be used to more accurately estimate the emission intensity of natural gas produced in different regions in the province.

2) Fugitive emissions are another important gap in public datasets. In the past couple of years, many facilities have been required to have annual or triannual fugitive (LDAR[3]) surveys, and repair the leaks that are found during each survey within a certain timeframe. Therefore, a large dataset of fugitive emissions now exists for different facilities across the province that can be used to assess the effectiveness of LDAR program and create a fugitive emissions database based on site types. In addition, several field campaigns in Alberta have conducted (or are conducting) site surveys using different leak detection and quantification devices mainly to evaluate the effectiveness and accuracy of the detection methods, but the data collected during those projects can be a valuable source of fugitive emissions data to help improve the life cycle emissions estimates of natural gas production in the province.

3) Non-PETRINEX fuel consumption is an important contributor to on-site combustion emissions but are not reported on a monthly basis, unlike fuel gas consumption. Facilities that are regulated under TIER are now required to collect the fuel consumption data and report the emissions associated with combusting that fuel as part of their TIER emissions[4]. Reported data under TIER are not available publicly but can be obtained through data sharing agreements with the operators or the GoA. This could help improve the accuracy of the emissions intensity estimates significantly.

4) Electricity consumption data for oil and gas facilities are not reported by the operators. If electricity is generated on site using fossil fuel generators, the environmental impacts would be captured by including fuel combustion emissions in the calculation. However, if a facility uses grid electricity to run electric equipment, electricity indirect emissions will not be captured unless the amount of electricity consumption is tracked. If the electricity

[3] Leak Detection and Repair
[4] Facilities that are considered "large emitters" were required to track non-PETRINEX fuel data even before TIER regulation came into effect.

consumption data is not available, electric equipment data (another data gap) can be used to estimate the electricity consumption and subsequently calculate the indirect electricity emissions.

Table 3 below shows a summary of data gaps found in this study along with potential sources to collect the data.

Table 3 – Summary of data gaps

Data Gap	Potential Source of Data
Equipment Inventory Data – Fuel consuming equipment (engines, generators, boilers, heaters, etc.)	Operators
Equipment Inventory Data – Electricity generation/consuming equipment (gensets, electric driven compressors, etc.)	Operators
Equipment Inventory Data – Venting equipment (pneumatic devices, uncontrolled storage tanks, compressor seals)	Operators
Non-PETRINEX fuel data	Operators, GoA (TIER reports)
Vehicle fuel use on site (for water delivery, shipping out crude, etc.)	Operators
Electricity consumption data	Operators
Breakdown of reported vent emissions - Vented gas volume during well drilling and completion - Routine vent emissions - Non-routine vent emissions	Operators, AER (Annual Methane Report)
Well workover events data	Operators
Fugitive emissions	Fugitive emission surveys – operators, AER (Annual Methane Report)
Gas analysis – gas gathering facilities and gas plants	Operators
Oil and condensate specifications (density, heating value, etc.)	Operators

6 RECOMMENDATIONS FOR FUTURE WORK

The LCA framework developed in this report is the only NG life cycle GHG emissions quantification framework that heavily relies on actual reported data to the AER. These data that are publicly available (free of charge or for purchase) are required to meet the quality requirements set by the AER and are believed to be the most accurate data available publicly, hence providing the most accurate representation possible of the actual oil and gas operations in Alberta. Addressing the data gaps discussed in section 5.4 could allow for improving the current estimates based on the framework represented in this report and help make it independent of average data, assumptions, or data specific to other jurisdictions that are used in other LCA models. With these data gaps the LCA method developed in this report could be transformed into a specific GHG quantification tool that is based on actual site-specific data. Consequently, we propose the following future work items:

1) Collaboration with the AER and operators to improve the quality of the vent volumes reported into PETRINEX. This would include contacting the operators of oil and gas facilities to obtain site specific data to allow for further analysis, quantification, and improvements in the vent volumes.
2) Working with the operators and the AEP to obtain non-PETRINEX fuel volumes.
3) Expanding the work to include additional regions in Alberta, as well as Saskatchewan and British Columbia gas production and processing GHG emissions. The LCA framework developed for this report is mainly based on reported data to PETRINEX and the AER. Similar reporting requirements exist in Saskatchewan and BC, however, PETRINEX data for these provinces is not publicly available. Discussing an agreement with the Governments of Saskatchewan and British Columbia to use their PETRINEX data could allow for expansion of the LCA results in this report to include additional provinces. Ideally a Canadian natural gas LCA model could be developed.
4) Natural gas pipeline transmission GHG emissions were out of the scope of the LCA analysis in this report. Future work should include expanding the boundary of the LCA to include pipeline transmission GHG emissions.

7 Conclusions

The objective of the report was to investigate the life cycle GHG emissions associated with natural gas production and processing from the Montney area in Alberta, as a pilot study that could form the basis of a more comprehensive LCA in the future to reflect on the natural gas production and processing GHG emissions in Canada. The report introduces a framework that mainly uses actual data reported by oil and gas facilities in Alberta to the AER and uses estimation methods to fill data gaps. The report identifies the data gaps and provides recommendations for further improvements.

The LCA analysis in this report, estimates an average annual cradle-to-gate GHG emissions intensity of 4.04 gCO2e/MJ gas for production and processing of gas from the Alberta Montney region. A sensitivity analysis shows that the average annual cradle-to-gate GHG emissions intensity for the Montney region (45 gas plant pathways each made up of a gas plant and the facilities connected to them) could be as low as 2.95 gCO2e/MJ gas and as high as 4.88 gCO2e/MJ gas. Investigating the natural gas pathways individually shows a cradle-to-gate GHG emissions intensity range of 1.72 gCO2e/MJ gas to 9.84 gCO2e/MJ gas. The variance observed in the GHG emissions intensity estimates could be due to the effect of number of factors such as different operations, unusual incidents in operations, different qualities of feedstock gas or production of different products that could require different levels of processing. Given that gas plants owned by a given company may receive and produce gas from assets of several other producers, the range of cradle-to-gate GHG emissions estimates in this report is no indication of better performance of one single company over another.

It is expected that the framework developed in this report and the LCA estimates provided can be helpful to several stakeholders such as government organizations, academic researchers, as well as gas producers and gas consumers that seek to obtain a better understanding of their supply chain GHG emissions for purposes such as improving their overall GHG emissions performance or Environmental, Social and Governance (ESG) reporting.

Addressing the data gaps identified in the report and expanding the analysis to include additional regions could be the main next steps for refining and adding further value to this report.

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