Upstream Oil and Gas Methane Mitigation

Part III: High-Impact Opportunities for Alberta

Prepared For: Emissions Reduction Alberta
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Final Report

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Executive Summary

Alberta has committed to reducing methane emissions from its upstream oil and gas sector by 45% below 2014 levels by 2025, a goal it achieved two years ahead of schedule[1]. The province currently uses a combination of prescriptive regulations and incentive programs designed to achieve this reduction target.

This report, the third in a series prepared by Modern West Advisory (MWA), updates and extends the analysis of Alberta's methane emissions performance and trajectory from upstream oil and gas operations, using the latest publicly available Petrinex and OneStop datasets. The objective of this report is to update source category estimates, document where the largest reductions have occurred, and characterize the emission sources with potential for further reductions. The analysis is based on the Modern West Methane Model (MWMM). This model draws on methodologies from government reports and academic studies to replicate the annual emissions profile published by the Alberta Energy Regulator. The model's accuracy depends on the completeness of reported data and several key assumptions, which are detailed in the main text. A full description of the MWMM methodology is provided in Appendix B.

Figure 3-1 illustrates modelled UOG methane emissions from 2014 through 2025, comparing Methane emissions under the D060 scenario (orange solid line), the Business-as-Usual (BAU) scenario (black dashed line), and GoA's published data (blue dashed line) for cross-reference.

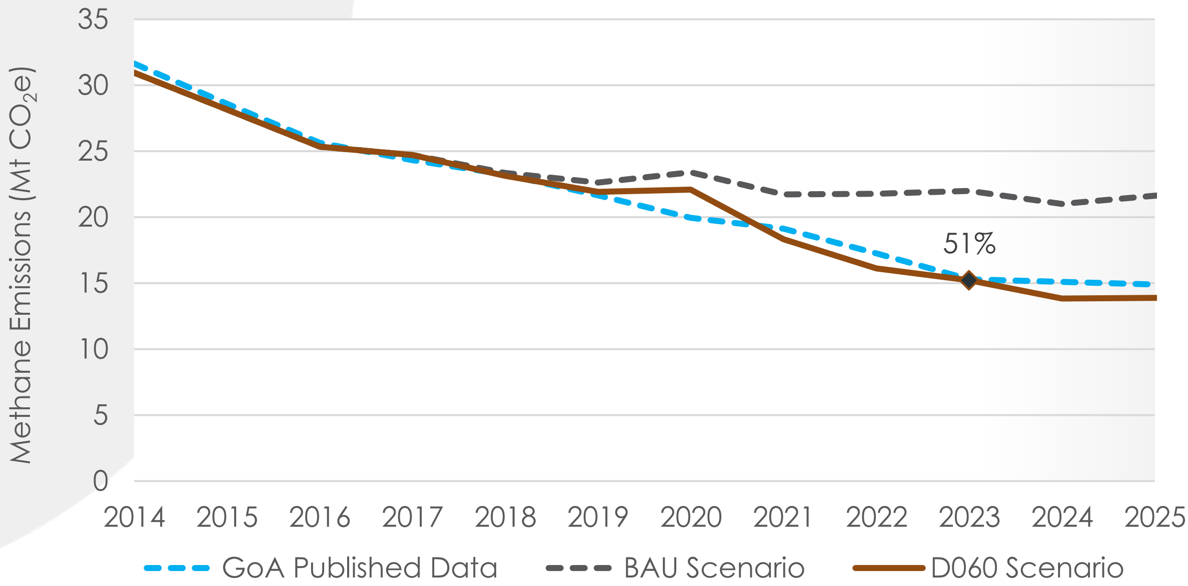

Figure ES-1. Timeline of Alberta UOG methane emissions since 2014 modelled by the MWMM, with modelled data released by the GoA for comparison purposes. Methane emissions under the D060 scenario (orange solid line), The Business-as-Usual (BAU) scenario (black dashed line), and GoA's published data (blue dashed line) for cross-reference.

[1] Government of Alberta – Methane Emissions Performance

Key Findings:

- In 2023, an estimated 51% reduction in methane emissions was achieved, compared to the 2014 Baseline (Figure ES-1). This is closely aligned with the Government of Alberta estimates of a 52% reduction.
- The D060 regulations, Alberta offsets system, and other government funded programs have helped drive Provincial emissions down towards the target levels.
- Figure ES-2 shows the largest methane emission contributors in 2023:
    - Pneumatics (4.5 Mt CO_2e, 30% of total)
    - Methane slip from fuel combustion (3.3 Mt CO_2e, 21%)
    - Fugitives (2.0 Mt CO_2e, 13%)
    - Defined Venting and Surface Casing Vent Flow/Gas Migration (1.5 Mt CO_2e, 10% each, respectively)

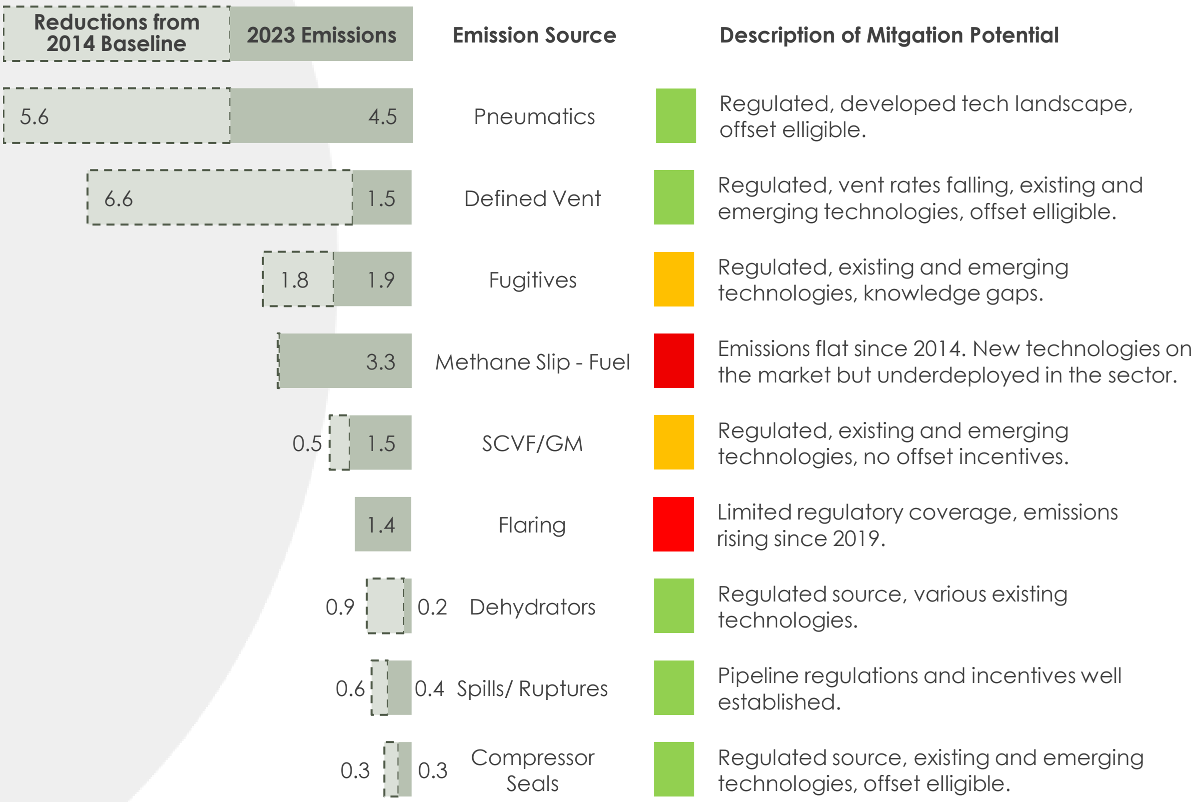

Figure ES-2. MWMM modelled emissions by source category in 2023 and a qualitative difficulty level for further reductions. Values are in tonnes of carbon dioxide equivalent (in 2023).

Figure ES-2 also shows the emissions reductions achieved to date, as well as the mitigation landscape for each major source category of methane emissions. A traffic light system is used to rate each source category's progress. The traffic light color scheme reflects MWA's internal subject matter expertise and judgment in relation to the availability of technology solutions, levels of achieved reductions, and extent of commercial deployment across the province for each emission category. Note the following:

- Most of the absolute emission reductions were achieved in the Pneumatics and Defined Vent categories. These two sources both benefited from an established technology landscape, regulatory clarity and availability of offset incentives.
- Methane slip remains largely unaddressed due to a combination of limited regulatory frameworks and the limited availability of cost-effective control solutions.
- SCVF/GM events have remained difficult to mitigate cost-effectively; emissions from non-serious flows (as defined by AER) lack financial or regulatory drivers for mitigation.
- According to the MWMM, emission reductions slow after 2023 as Directive 060 and other regulations reach equilibrium.

Mitigation Opportunities:

We identify some additional near-term opportunities to support Alberta's methane leadership, including:

- Encouraging the development and deployment of technology solutions for high-impact methane reduction opportunities (e.g., low-emission engines, methane oxidation systems, SCVF/GM).
- Addressing data gaps, particularly around engine types, combustion slip rates, rate of unlit flares, and catalytic heater emissions.
- Supporting the development of the most promising technologies to achieve cost-effective, reliable emissions reduction, particularly for those areas where significant reductions have not already been achieved.

This report does not include details of technology abatement costs but rather includes details regarding commercially available solutions within each emissions source category. The work presented here is intended to aid in the identification and prioritization of opportunities for further emissions reduction and provide awareness to industry and innovators of these remaining opportunities. It is designed to complement and build upon the efforts already undertaken across Alberta's oil and gas value chain.

List of Acronyms

Acronym	Definition
AEOR	Alberta Emission Offset Registry
AER	Alberta Energy Regulator
Alt-FEMP	Alternative Fugitive Emissions Management Program
AMEP	Alberta Methane Emissions Program
BAU	Business-As-Usual
BROA	Baseline and Reduction Opportunity Assessment Program
CERIN	Canadian Emissions Reduction Innovation Network
CO_2e	Carbon Dioxide Equivalent
D039	Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators
D060	Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting
D087	Directive 087: Well Integrity Management
DVG	Defined Vent Gas
ECCC	Environment and Climate Change Canada
EFR	Emission Reduction Fund
ERA	Emissions Reduction Alberta
GM	Gas Migration
GoA	Government of Alberta
LDAR	Leak Detection and Repair
MERR	Methane Emission Reduction Regulation
MSAPR	Multi-Sector Air Pollutants Regulations
MTIP	Methane Technology Implementation Program
MWA	Modern West Advisory
MWMM	Modern West Methane Model
NGIF	Natural Gas Innovation Fund
NIR	National Inventory Report
NRCan	Natural Resources Canada
OVG	Overall Vent Gas
SCVF	Surface Casing Vent Flow
TIER	Technology Innovation and Emissions Reduction
UOG	Upstream Oil and Gas
US EPA	United States Environmental Protection Agency
VRU	Vapour Recovery Unit

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1. Report Objectives

This report analyzes results from the Modern West Methane Model (MWMM), designed to estimate and forecast Alberta's upstream oil and gas (UOG) sector methane emissions profile. The MWMM employs various existing methodologies to estimate methane emissions by source category, including pneumatics, routine venting, fugitives, compressors, glycol dehydrators, SCVF/GM, spills/ruptures, methane slip from stationary combustion, and flaring. The model's accuracy depends on the completeness of reported data and several key assumptions, which are detailed in the main text. A full description of the MWMM methodology is provided in Appendix B.

The MWMM was developed in 2022/2023 to support a report on UOG methane emissions in Alberta. This updated report incorporates two additional years of data under Alberta's methane regulations to reassess the outcomes of the implemented regulations. Furthermore, our model uses a set of assumptions and commodity price forecasts to make reasonable look-ahead predictions of how methane emissions may change under the framework through 2025. The results here demonstrate the trending inventories of key emission source categories, describe some of the factors affecting performance over the past two years, and identify technology types driving mitigation activities in the field.

It is important to note that this report evaluates publicly available data to analyze and forecast the methane emissions profile of the UOG sector. Our recommendations are intended to be subjective assessments of past pathways and applying those learnings to potential opportunities in the future. At no point do we intend to make any suggestions or implications for specific policy or regulatory changes. We understand and appreciate that each stakeholder will have their own view of the data and different experiences with past and ongoing programs and compliance obligations. Every effort was made to rely on the latest and most comprehensive available data and our domain expertise when completing the analysis.

The objectives of this report are as follows:

- Assess UOG methane emissions in Alberta between 2014 and 2023, by source category under the existing policy framework.
- Evaluate major source categories that have persisted since the baseline year and may require new targeted actions.
- Assess the technically achievable reductions in each source category using existing mitigation technologies. Specific technology costs are not contemplated in this report.

2. Introduction and Background

The Government of Alberta (GoA) introduced the *Methane Emission Reduction Regulation* (MERR) in 2018, committing to a 45% reduction in methane emissions from conventional upstream oil and gas operations by 2025, relative to 2014 levels (GoA, 2018). According to the latest GoA modelling released in April 2025, Alberta achieved a 51% reduction in methane emissions by 2023, achieving the 45% target two years early. (GoA, 2025).

Alberta employs a combination of regulatory, market-based, and programmatic tools to drive methane reductions in the oil and gas sector. The effectiveness of this approach depends on the coordinated implementation of these instruments, which are summarized in the following sections.

2.1. Methane Regulations

In December 2018, the Alberta Energy Regulator (AER), in cooperation with the Government of Alberta, amended two key directives:

- *Directive 060*: *Upstream Petroleum Industry Flaring, Incinerating, and Venting*
- *Directive 017*: *Measurement Requirements for Oil and Gas Operations* (Alberta Energy Regulator, 2022a, 2022b).

These changes added new requirements for reporting and reducing methane emissions. The new requirements assign overall site vent limits as well as equipment-specific limits for pneumatics, compressor seals, and glycol dehydrators, which are common sources of methane emissions from UOG sites. Directive 060 (D060) prescribes differing requirements for new and existing facilities[2]. A summary of the existing methane requirements under D060 is shown in Table 2 in Appendix A.

In 2014, Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area was created in response to odour complaints from residents in the region (Alberta Energy Regulator, 2018). The directive resulted in near-elimination of methane emissions in the region. This was possible in large part due to infrastructure advantages such as tight well spacing and co-located facilities - conditions not consistently present elsewhere in the province.

2.2. Alberta Emissions Offset System

The Alberta Emissions Offset System provides compliance flexibility for emitters regulated under the *Technology Innovation and Emissions Reduction* (TIER) program. Regulated entities can generate verified offset credits by voluntarily reducing emissions beyond regulatory requirements. These credits can be retired to meet a TIER obligation or sold, offering a financial incentive for additional reductions. There are two active offset protocols that target methane emissions in the UOG:

[2] A "new" site is one with first receipt or production on or after January 1, 2022.

1. *Greenhouse Gas Emission Reductions from Pneumatic Devices, (v3.0)*
2. *Vent Gas Reduction, (v1.0)*

Together, over 10.6 Mt CO_2e of verified GHG emission offsets have been registered on the Alberta Emission Offset Registry (AEOR) since 2018, using these two protocols.

2.3. Funded Methane Programs and Initiatives

Multiple funding initiatives have been launched over the years to support the testing, piloting, and deployment of emerging and proven clean technologies in the UOG sector. These strategic investments have played a crucial role in de-risking clean technologies and catalyzing their wider adoption throughout the UOG sector.

Examples of programs to support technology and innovation related to methane emissions reductions include, but are not limited to:

- Methane Technology Implementation Program (MTIP) - $25M
- Baseline and Reduction Opportunity Assessment Program (BROA) - $15M
- Alberta Methane Emissions Program (AMEP) - $17M
- Canadian Emissions Reduction Innovation Network (CERIN) - $17M[3]
- Natural Gas Innovation Fund (NGIF) Industry Grants Program and Emissions Testing Centre Program - $30M
- NRCan Emissions Reduction Fund (ERF) - $750M[4]
- PTAC Methane Consortium Program (various programs)
- Emissions Reduction Alberta (ERA)
    - $58.4M “Natural Gas Challenge” funding for 20 methane-focused projects
    - $7.1M support for methane abatement via the Continuous Intake Program
- Alberta Innovates (various investments)

[3] CERIN is jointly funded by NRCan ($11.15M) and Alberta Innovates ($6.26M)
[4] $143M was awarded during the first two intakes. Intake 3 closed in 2022.

3. Model Analysis and Results

This section presents the results of the MWMM for the period 2014 – 2025 under Alberta's current regulatory framework (D060 scenario) and using the best available public data available to MWA as of the writing of this document. The MWMM aligns closely with the AER's modelling methodology[5], supplemented with select assumptions from Environment and Climate Change Canada (ECCC) model methodologies published in Annex 3.2 of the National Inventory Report (ECCC, 2025b). A detailed description of the model is available in Appendix B.

Figure 3-1 illustrates modelled UOG methane emissions from 2014 through 2025, comparing:

- Methane emissions under the D060 scenario (orange solid line),
- The Business-as-Usual (BAU) scenario (black dashed line), and,
- GoA's published data (blue dashed line) for cross-reference.

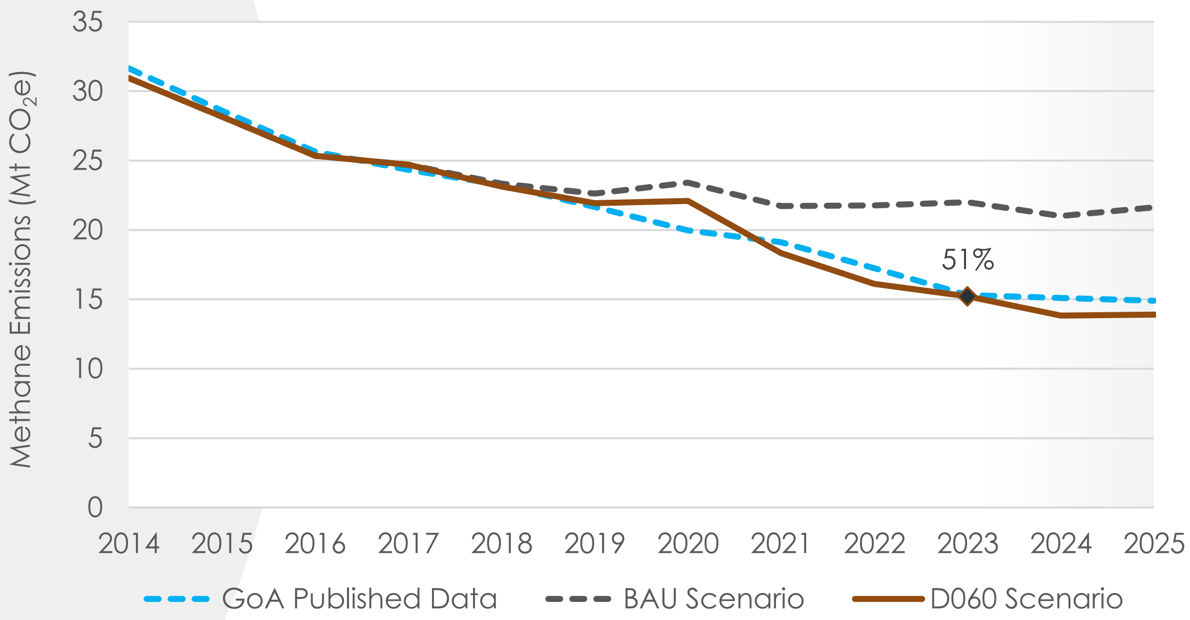

Figure 3-1. Timeline of Alberta UOG methane emissions since 2014 modelled by the MWMM, with modelled data released by the GoA for comparison purposes.

Discussion points:

The MWMM estimates a 51% reduction in UOG methane emissions through 2023, from a 2014 baseline. This aligns well with the 52% reduction result for the same year published by the GoA[6]. By the end of 2025, we estimate that the existing methane framework will result in a 55% reduction from the 2014 baseline.

[5] The AER's emissions methodology is summarized in the appendix of *ST60B-2024: Upstream Petroleum Industry Emissions Report*.
[6] https://www.alberta.ca/climate-methane-emissions

The pace of reductions following the full implementation of Directive 060 slowed by the end of 2022. Looking ahead, further reductions are expected from new wells and batteries, which are subject to stricter regulatory standards, that will replace older, higher intensity methane-emitting production infrastructure. This progress may be partially offset by projected production growth forecasted in the AER's 2025 Energy Outlook (AER 2025).

3.1. The 2023 Methane Inventory

Figure 3-2 shows the methane emissions inventory for 2023 (15.2 Mt CO_2e), the most recent year with a full set of historical data.

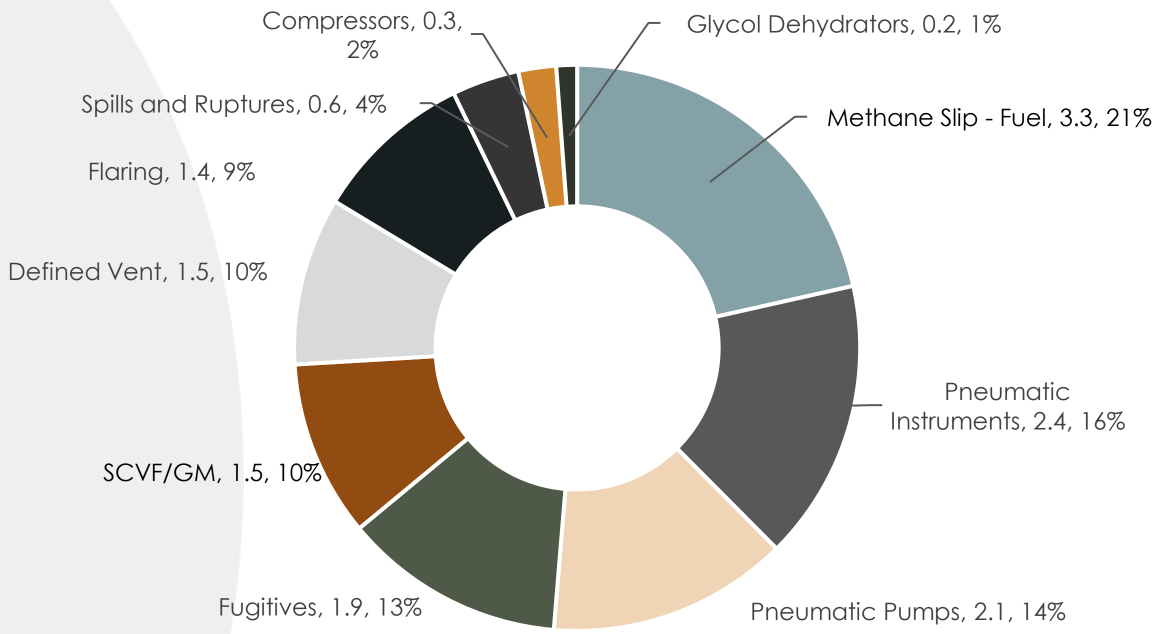

Figure 3-2. The 2023 methane inventory in Alberta as modelled by the MWMM. Absolute emissions are in units of Mt CO_2e.

<u>Discussion Points:</u>

Alberta's regulatory framework and incentive programs have successfully driven substantial reductions in methane emissions from key source categories, including pneumatics, routine venting, compressor seals, and glycol dehydrators, compared to the 2014 baseline year (see Table 1).

Despite this progress, methane slip from incomplete fuel combustion remains a key source of emissions in 2023, accounting for 21% of the total. As discussed in Section 3.2.3, reducing or mitigating emissions from this category poses considerable technical and economic challenges. In aggregate, absolute emissions from methane slip, SCVF/GM, flaring, and fugitives are expected to remain flat or even increase slightly by 2025, in response to increased production of conventional oil and gas in the sector.

Pneumatics are still a significant contributor, making up 37% of emissions in 2023, even after full implementation of Directive 060 requirements and ongoing offset project activity. Fortunately, mitigation technologies for pneumatics are well established, as detailed in Section 3.2.1. However, there may be technical and/or financial challenges on the margin as lowest-cost pneumatic conversions reach saturation. These challenges most notably relate to limitations created by the need for site electrification and the ongoing need for operational reliability.

Venting and Flaring together account for 19% of emissions in 2023, and both can be reduced further through gas capture and conservation projects – though the high cost of pipeline tie-ins to gas infrastructure often remains a key barrier.

Table 1 below summarizes the modelled methane emissions by source category in selected years, along with total sector production rates and calculated methane intensities. Note that this table includes volumes and emissions of facilities regulated by D060, i.e., in-situ bitumen extraction is included, but oil sands surface mining operations are excluded.

Table 1. Historical and forecasted methane emissions by source category under the existing methane regulatory framework in Alberta.

Emission Source	2014	2023	2025 (Projected)
Pneumatic Instruments	7.1	2.4	2.1
Pneumatic Pumps	3.1	2.1	1.9
Routine Venting	8.0	1.5	1.1
Fugitives	3.7	1.9	2.0
Compressors	0.7	0.3	0.3
Glycol Dehydrators	1.1	0.2	0.2
SCVF/GM	2.0	1.5	1.5
Spills and Ruptures	1.0	0.6	0.3
Methane Slip - Fuel	3.3	3.3	3.3
Flaring	1.0	1.4	1.4
Total	**30.9**	**15.2**	**13.9**
% Reduction	**Baseline**	**51%**	**55%**
Total Production (10^3 m^3 OE/day)	596	715	769
CH4 Intensity (kg CO_2e/m^3 OE)	142	58	50

The potential reductions by technology subtype are summarized in Figure 3-3. The inner layer represents the 2023 methane inventory by emission source category. The wedges in the outer layer represent the indicative emissions mitigation potential of specific technology types based on MWA's internal analysis and informed assumptions. Note that each emission source has an "Other / Remaining" wedge in the outer ring, which represents our best effort to illustrate the level of methane that would be very difficult or impossible to abate under the current technology landscape. Also note that this figure ignores the $/tonne abatement costs associated with the potential reductions by technology type. The intent of the figure is to illustrate the complex ecosystem of methane reduction technologies available to the sector, and the relative levels of abatement available for each source category.

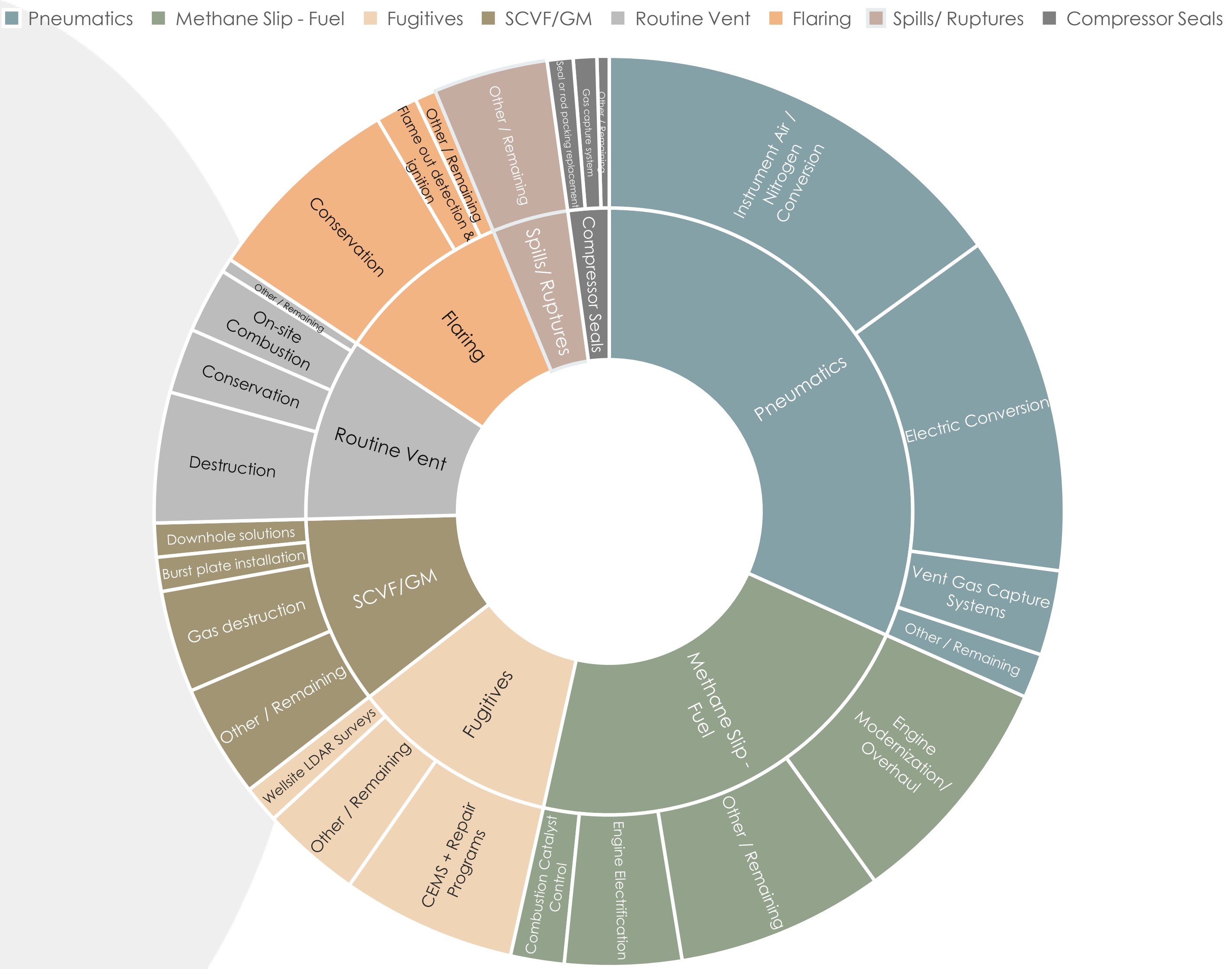

Figure 3-3. The Alberta UOG methane inventory in 2023. The inner layer shows the relative size of each emission source category for the overall 15.2 Mt CO_2e inventory which is shown in Figure 3-2. The outer layer represents the potentially achievable emission reductions by technology type within each emission category. There are some "Other / Remaining" emissions for each source category in the figure.

3.2. Breakdown by Emission Source Category

This section of the report will explore the modelled methane source categories in more detail. The annual emission profile of each category will be presented and discussed along with details related to the available mitigation technologies, the potential for further reductions, and barriers to reductions.

3.2.1. Pneumatics

Pneumatic devices (pumps and instruments) are powered by pressurized gas (natural gas or compressed air). There were 4.5 Mt CO_2e of methane emissions across all pneumatic devices in Alberta in 2023 (37% of total), making this the largest source of methane emissions for that year.

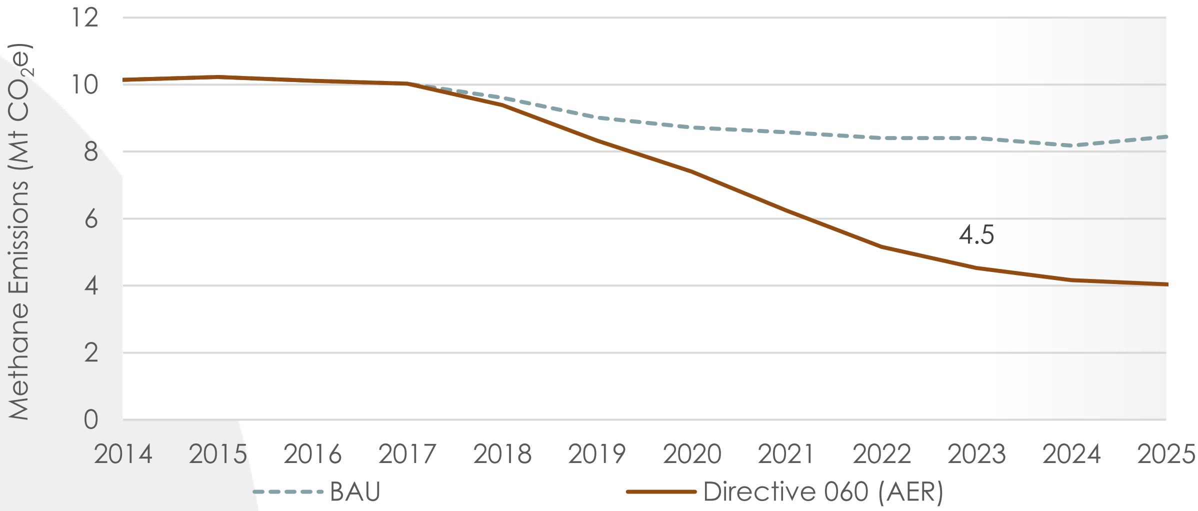

Figure 3-4. Timeline of pneumatic emissions (instruments plus pumps) between 2014 and 2023, then forecasted out to 2025.

Spotlight: Modelled vs. AER OneStop Volumes

The AER and Modern West models use a facility count and average equipment count by facility subtype methodology to create a bottom-up estimate of the inventory of pneumatic devices driven by fuel gas in the province. The estimated device inventory is presented below in Figure 3-5.

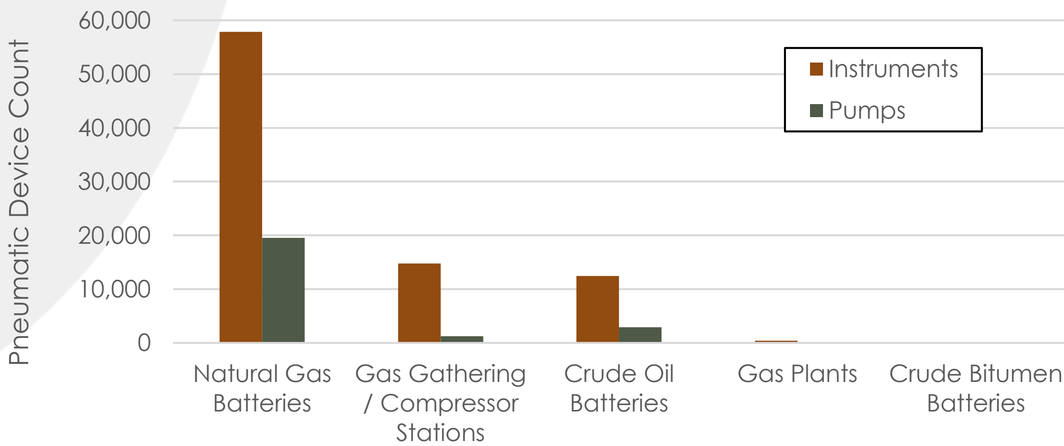

Figure 3-5. Distribution of estimated pneumatic device inventory for the Alberta UOG sector in 2023. Note that intermittent venting instruments are excluded from this figure.

Since 2020, operators have been required to report pneumatic vent gas volumes to the AER via the OneStop system. These reported figures have consistently fallen below the modelled estimates as depicted in Figure 3-6, even when the MWMM model accounts for registered pneumatic offsets. Notably, the equipment count surveys supporting both the AER's and the MWMM's pneumatics methodology were conducted between 2017 and 2018 (AER, 2025a). The consistent discrepancy between modelled and reported data suggests that the equipment count method may overstate pneumatic methane emissions, potentially by as much as 1.5 Mt CO_2e in 2023. The pneumatics methodology used by ECCC adjusts modelled values using OneStop reporting, according to the National Inventory Report (NIR) Annex 3.2 (ECCC, 2025b). Should the AER update its methodology to rely on directly reported pneumatic gas volumes, the MWMM would be revised to reflect this change.

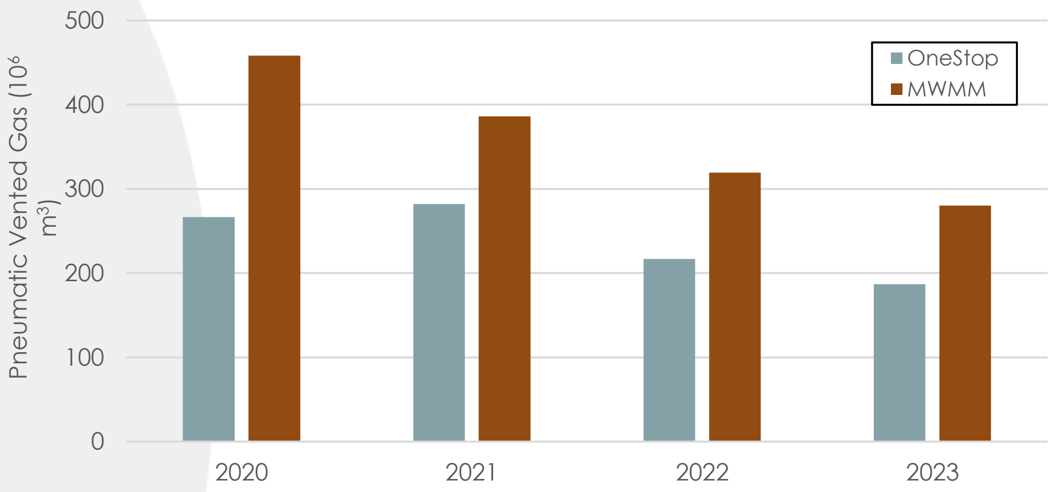

Figure 3-6. Comparison between pneumatic vent gas volumes reported to OneStop vs. volumes modelled by the MWMM.

Discussion Points:

Pneumatic emissions are covered under the Directive 060 OVG limits starting in 2023. Some operators may choose to comply with the OVG through pneumatic conversions, driving a faster reduction from this source than currently modelled.

The Pneumatic Offset Protocol, under the AEOR, was very successful at driving reductions in this source category prior to the phasing in of pneumatic requirements under D060. Alternative energy sources for pneumatic devices include electrification, compressed air or nitrogen, and fuel cells. Pneumatic devices can also be tied into a vent gas capture system to eliminate vented emissions. Since 2018, 9.7 Mt CO_2e of cumulative pneumatic offsets have been registered as carbon offsets eligible in the province ("Alberta Carbon ," 2025)[7].

[7] Data aggregated from an MWA analysis of the AEOR database.

Looking forward, there are some headwinds facing further reductions from this source category. Many operators will have already retrofitted their higher-emitting pumps, which means that much of the remaining retrofits will be lower-emitting pumps and low-to-zero vent instruments, which could be more challenging to replace. Compliance offsets were already trading at a significant discount (30 $/tonne vs. the 80 $/tonne TIER price) for the 2024 compliance cycle. Combined with the regulatory uncertainty (TIER price freeze, anticipated TIER opt-outs in 2025/2026, lack of a clear federal methane policy signal since the April 2025 election), companies may wait for further regulatory clarity before progressing their planned pneumatic retrofit programs.

3.2.2. Defined Venting

Venting was the second largest source of methane emissions in 2023, although significant reductions have been achieved since 2014. This report uses the AER's definition of Defined Venting[8], as described in Manual 015: "Defined venting is vent gas from all routine sources, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators" (AER, 2020). Examples of defined venting include:

- Associated gas venting, including production casing vents
- Uncontrolled tank vents
- Other vent gas from tank flashing, breathing, blanketing, and liquid unloading
- Pig trap opening and purge vents

The timeline of modelled defined vent emissions is presented below in

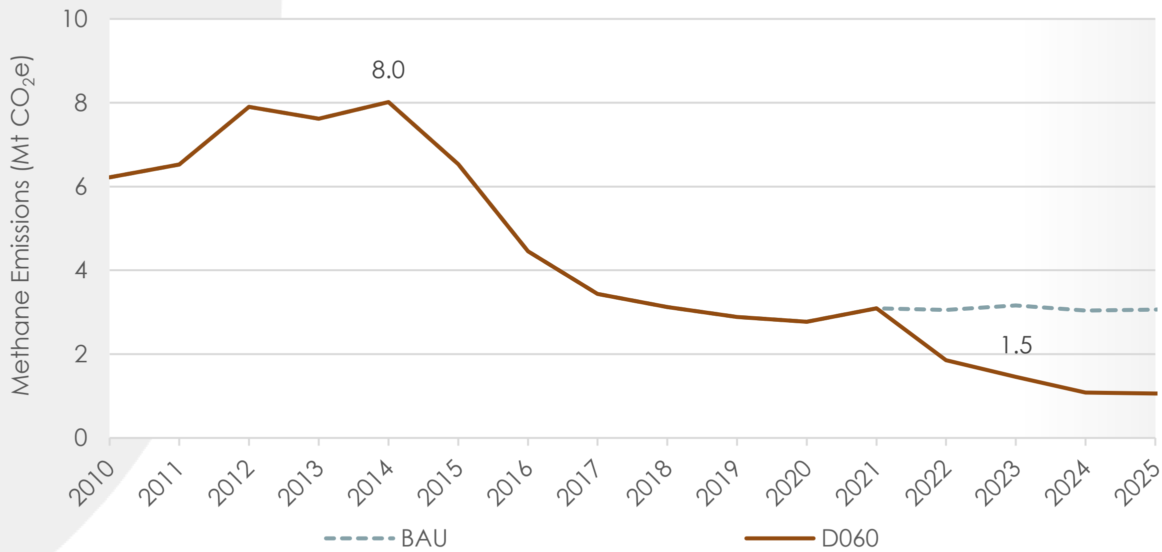

Figure 3-7.

[8] In Directive 060, the Overall Vent Gas limit applies to both routine and non-routine venting. A lack of quality data means that non-routine venting is not included in this MWMM module.

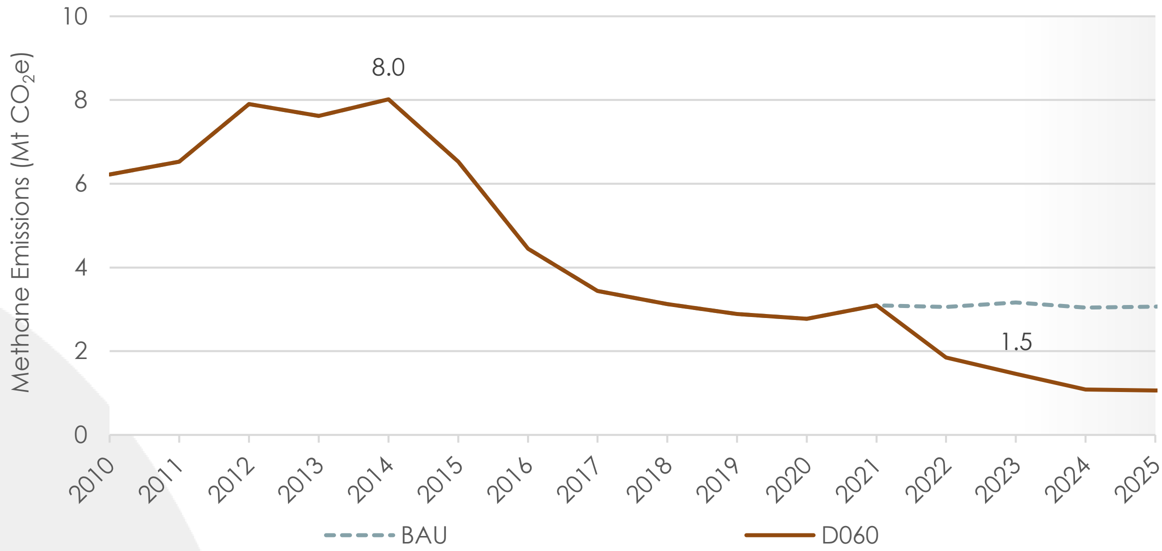

Figure 3-7. Timeline of modelled defined venting emissions) between 2014 and 2023, then forecasted out to 2025.

Discussion Points:

Significant emissions reductions (80% from the 2014 baseline) have been achieved in this source category since 2014, when vent emissions were the largest source category in the inventory. Earlier versions of Directive 060 mandated solution gas conservation well before the introduction of the new methane regulations in 2020. The implementation of Overall Vent Gas (OVG) and Defined Vent Gas (DVG) limits in 2020 and 2022, respectively, drove further reductions in this category.

Some examples of available technology options to reduce methane emissions from routine vent sources are listed below:

- Vapour Recovery Units (VRU) capture and compress the associated gas at the tank headspace. The compressed gas can be used on-site or sent to a sales gas line. VRUs can be prone to leakage, require regular maintenance, and may not be economical solutions for single tanks with low associated gas production (Sentio Engineering, 2015).
- Incinerators/Enclosed Combustors destroy captured vent gas, with destruction efficiencies greater than 99%, These technologies are smaller and more compact than a flare stack, making them a cost-effective option to flares, and considered a good option when gas conservation options are not available.

Vent gas reduction projects are eligible to generate compliance offsets provided the reductions are additional to OVG or DVG limits, if applicable. Project developers should note that the eligible crediting period for vent gas destruction projects ends on September 30, 2025, at which point only gas conservation projects will be eligible for offset generation.

While the industry has made significant strides in cutting venting rates at wells and facilities, some key barriers exist to further reductions:

- **Lack of gas pipeline infrastructure at remote sites**. Conserved gas needs to be sent to a gas plant for processing before transmission and distribution. Gas gathering infrastructure may not exist at crude oil sites that were not originally designed to conserve associated gas. Sites without accessible gas infrastructure will be forced to combust or flare the recovered gas on site (if it cannot be used for on-site power requirements).

- **Large capital cost of abatement technologies.** Over the lifetime of a vent reduction project, economic returns can be generated through the value of the conserved gas and offset credits. However, a significant initial capital investment may be required, which may discourage producers from implementing these solutions. A baseline reduction opportunity assessment program for uncontrolled tanks could help producers target facilities where vent gas capture projects are preferred options compared to gas destruction.

3.2.3. Methane Slip – Fuel Combustion

Combustion sources are not a 100% efficient process. Methane slip refers to methane that escapes a combustion source before it fully oxidizes. This section will focus on methane slip from sources that use natural gas as a fuel source.

Methane slip from fuel combustion was a significant source of emissions, responsible for 3.3 Mt CO_2e of methane in 2023 (21% of total). Methane slip emissions have been essentially flat since 2014 in Alberta, as shown below in Figure 3-8. Methane slip limits are not prescribed under Directive 060 or ECCC methane regulations. Rather, as a component of stationary combustion exhaust, these emissions are already regulated and priced in Alberta under TIER.

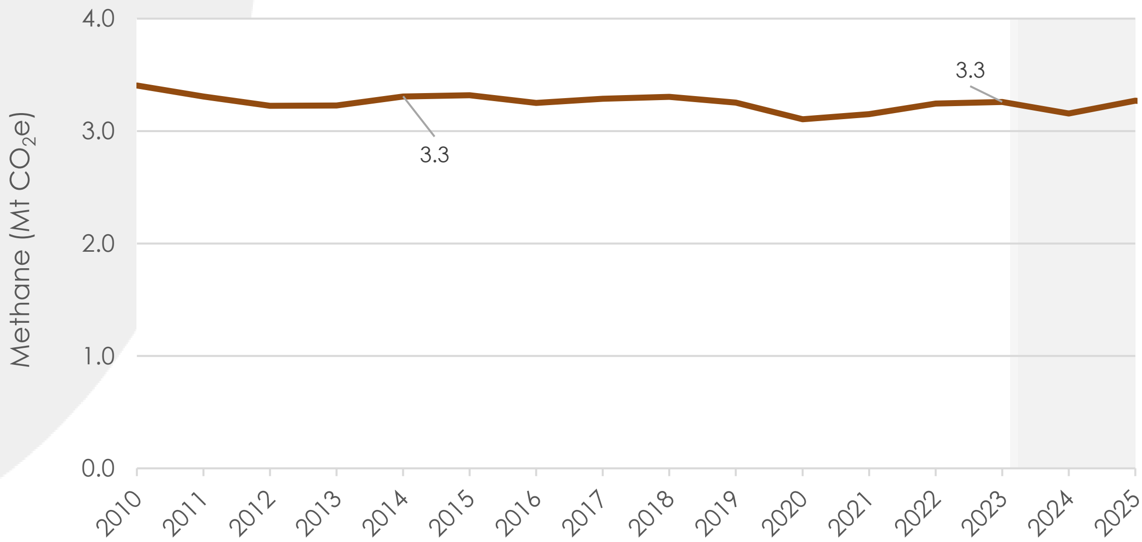

Figure 3-8. Timeline of the modelled methane slip emissions from fuel combustion between 2014 and 2023.

<u>Discussion Points:</u>

There is a wide range of estimates for this emission source, which are highly dependent on the selected engine exhaust emission factors. More public sharing of the sector's engine inventory, including engine types, control status, and observed methane slip rates would be extremely beneficial to more accurate impact assessment modelling of this category. Much of this data is already collected by Operators and submitted to ECCC as part of the Multi-Sector Air Pollutants Regulations (MSAPR), although the database is not publicly available. The set of assumptions used to model this source are listed in the MWMM methodology document contained in Appendix B.

For each facility subtype, the MWMM apportions fuel gas volumes to specific equipment types (turbines, boilers, or engines) based on ratios published by Johnson and Tyner (2020). Methane slip emission factors are sourced from US EPA AP-42 and Vaughn et al (2021). Reciprocating engines have a methane slip factor two to three orders of magnitude greater than boilers, therefore facility types that send more fuel gas to engines will experience greater levels of slip. This explains the distribution observed in Figure 3-9. There is potential to target a subset of the largest engine fuel gas consumers (compressor stations, gas plants) for electrification. This is being done in Northeastern B.C., where reliable clean hydropower is available, but reliable grid access may be a barrier in Alberta.

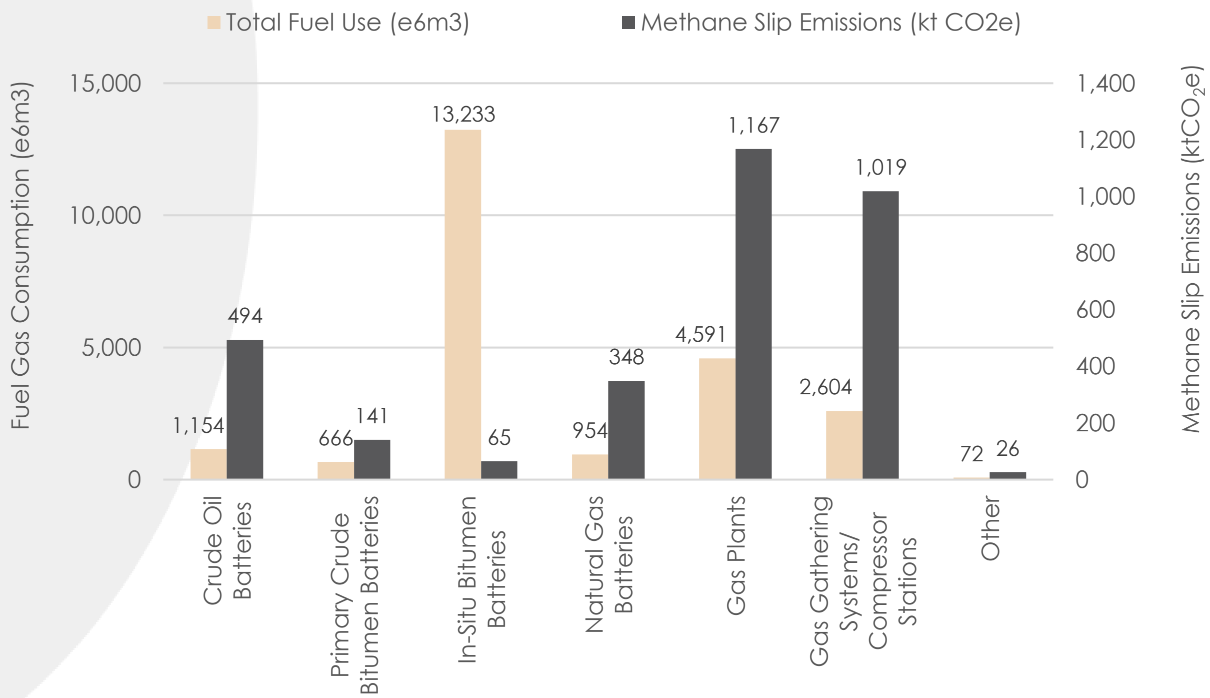

Figure 3-9. Breakdown of methane slip emissions in 2023 by facility subtype. Reciprocating engines are responsible for most slip emissions. Facilities with large engine-driven gas compressors therefore will experience more methane slip than other facility subtypes.

Mitigation approaches include catalytic technologies that improve methane oxidation in engine exhaust systems, along with newer reciprocating engine designs engineered for lower methane slip. Some next-generation models are already commercially available, and retrofit kits are offered for certain existing engines.

It should be noted that the MSAPR currently regulates engines to reduce NO_x emissions. Lean burn engines have lower NO_x emissions but greater CH_4 emissions than rich burn engines (Nowak and Beshouri, 2019, Vaughn et al., 2021). Through conversations with industry stakeholders, some operators have indicated that they are electing to comply with MSAPR through rich to lean burn engine conversions and that they are preferentially installing lean burn engines in their new facilities, which is expected to increase methane slip. Alternatively, operators could be encouraged to employ rich burn engines installed with catalyst conversion technology to minimize both CH_4 and NO_x emissions, where technically feasible.

3.2.4. Fugitives/Equipment Leaks

Fugitive emissions are the unintentional releases of gas into the atmosphere from equipment components, such as valves, connectors, and meters. Equipment leaks are unpredictable, and the amount of methane released depends on how quickly a leak is detected and then repaired. Fugitives were estimated as the third largest source of methane in 2023, with 1.9 Mt CO_2e of emissions (13% of total).

Directive 060 fugitive survey requirements first began in 2020, but these requirements were eased due to the COVID-19 pandemic, meaning that 2021 was the first full year where LDAR survey and repair activities were mandated. An annual LDAR survey is required at all active facility subtypes, except at compressor stations and sweet gas plants, where surveys are required three times per year (Alberta Energy Regulator, 2022a).

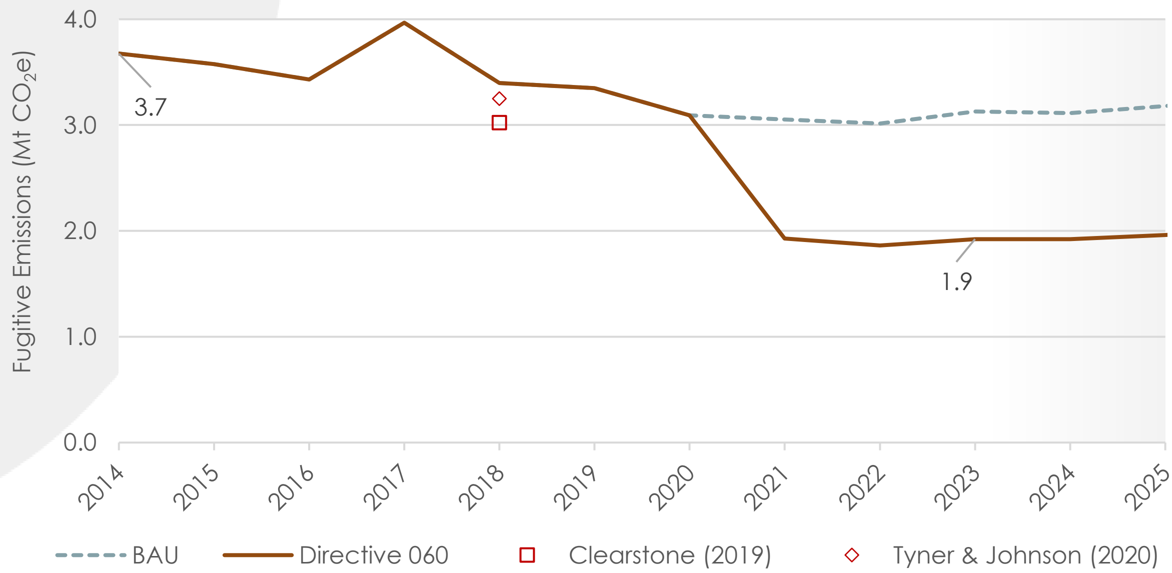

Figure 3-10. Timeline of modelled fugitive emissions between 2014 and 2023, then forecasted out to 2025.

Discussion Points:

Many of the technology options for fugitive emission mitigation involve the timely detection and quantification of fugitive releases. Operators can reduce their fugitive emission profile by increasing the frequency of LDAR survey and repair programs; however, this requires additional cost. Published data show that there are diminishing returns as LDAR survey frequency increases (Ravikumar & Brandt, 2017) as there are only small incremental reductions past a quarterly survey frequency.

Under Directive 060, the AER allows for companies to apply to use an alternative Fugitive Emissions Management Program (alt-FEMP). An alt-FEMP program may use a combination of long-range or remote sensing technologies such as UAVs, aircraft, satellites, truck-mounted sensors, or continuous monitoring technologies. As of April 2025, alt-FEMPs can be implemented provided they meet the criteria outlined in Directive 060 section 8.10.6.

There continues to be significant investment into and testing of emerging aerial detection technologies, the focus primarily on increasing accuracy at reduced inspection frequency, thereby decreasing the cost burden on producers while effectively meeting the regulatory requirements. Additional programs are underway to continue to test these emerging technologies and complete the associated techno-economic analyses required to understand field-level performance[9,10].

3.2.5. Compressors

Compressor seals are designed to reduce vent gas leakage in reciprocating and centrifugal compressors, but leak rates will rise as the rod packing and seals wear over time. This source category includes vent gas emissions from reciprocating and centrifugal compressor seals, plus blowdown and startup events. Crucially, it does not include methane slip from compressor engines; those emissions are instead modelled in the "Methane Slip – Fuel Combustion" category in Section 3.2.3.

Gas compressors are commonly located at gas batteries, gas plants, gas gathering systems, and compressor stations. There were 0.3 Mt CO_2e of methane emissions from compressor seals in 2023. The timeline of reductions from this category are shown below in Figure 3-11.

[9] Alternative Methane Detection Technologies Evaluation
[10] Canadian Natural Fugitive Emissions Study Using Aerial Detection Technology

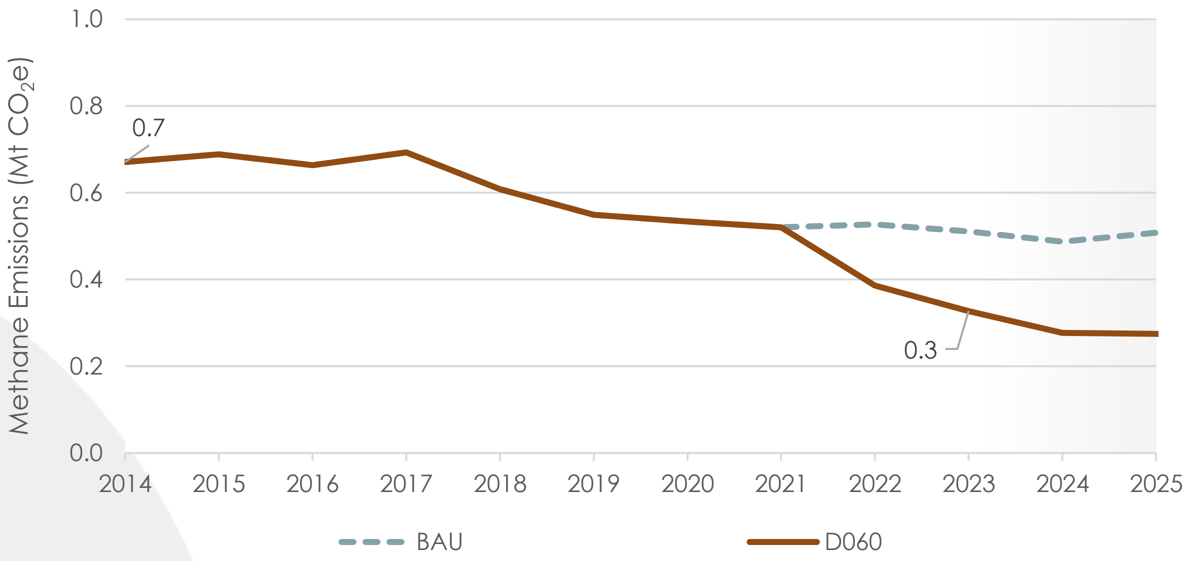

Figure 3-11. Timeline of modelled compressor emissions between 2014 and 2023, then forecasted out to 2025.

<u>Discussion Points:</u>

Annual testing of the vent rate from compressor seals is required under Directive 060 (8.6.2). If the test result is greater than the maximum rate prescribed in the regulation, the seals (or reciprocating compressor rod packing) are replaced.

Centrifugal compressors with wet seals can be retrofitted with dry gas seals, which have been shown to vent significantly less gas. Even at full industry adoption, this would result in minimal emission reductions as reciprocating compressors significantly outnumber centrifugal compressors (3,338 to 110 in 2023, according to the AER).

For reciprocating compressors, seals can be retrofitted with next-gen, low-emission rod packing materials that can reduce seal leakage by up to 70%.[11,12]

Finally, vent gas from both reciprocating and centrifugal compressor seals can be tied into a vent gas capture system header, eliminating the potential for venting gas to atmosphere. The Alberta *Quantification Protocol for Vent Gas Reduction* allows operators to generate offset credits through these vent gas capture activities.

3.2.6. Glycol Dehydrators

Glycol dehydrators are used during gas processing to remove water from raw natural gas. Dehydrators produce methane emissions from the still column that vents gas during the glycol regeneration phase[13]. Dehydrators are a relatively minor source of methane, responsible for 0.2 Mt CO_2e of emissions in 2023.

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[11] Emissions Elimination Rod Rings by Hoerbirger
[12] Low-Emissions Rod Packing by Cook Compression
[13] Emissions from pneumatic pumps associated with dehydrators are excluded from this source category and are instead included in the overall Pneumatics section.

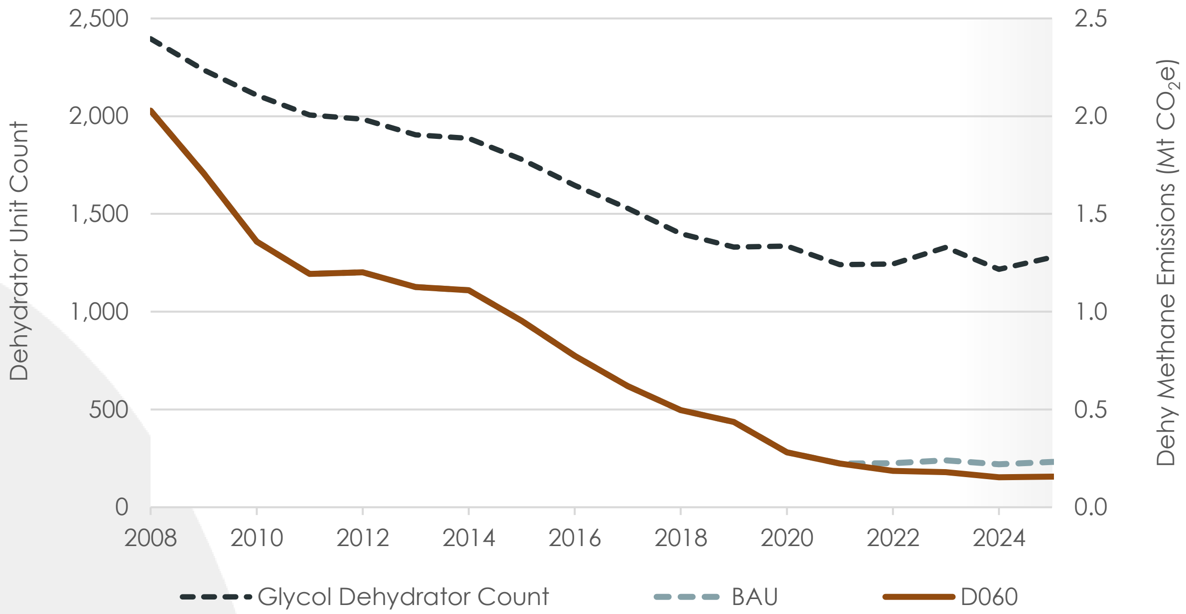

Figure 3-12. Timeline of modelled glycol dehydrator emissions between 2014 and 2023, then forecasted out to 2025. D060 and BAU scenario emissions are very similar because dehydrator controls were first regulated in 2007 under AER Directive 039 and therefore D060 regulations have had only minor effects on emissions.

Discussion Points:

There has been a significant decline from the 0.9 Mt CO_2e of emissions modelled in the 2014 baseline year. The modelled emissions reductions for this source are mainly attributed to the AER's *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* (D039) (Alberta Energy Regulator, 2018a). Directive 039 was first published in 2007 and came into effect in 2008 to curtail benzene emissions that were being measured from dehydrator units. Benzene control technologies listed in D039 include flares, incinerators, vapour recovery units, and reciprocating engine emissions control equipment. These technologies all have the added benefit of reducing methane emission from dehydrators.

Directive 060 introduced vent gas limits for dehydrators starting on January 1st, 2022:

- New units must limit methane emissions to less than 68 kg of methane per day.
- Old units (installed before January 1, 2022) must limit emissions to less than 109 kg of methane per day.
- In 2023, dehydrators only vented an average of 13.2 kg of methane per day (0.37 tCO_2e/day).

3.2.7. Flaring

This section focuses on methane emissions from gas sent to flare stacks, including:

1. Incomplete destruction of CH_4 (flare destruction efficiency < 100%)

2. Unlit flares venting gas directly into the atmosphere[14]

While Directive 060 does not set limits on methane from flaring, these emissions are regulated under TIER in Alberta. There were an estimated 1.4 Mt CO_2e of methane emissions that resulted from flared gas in 2023.

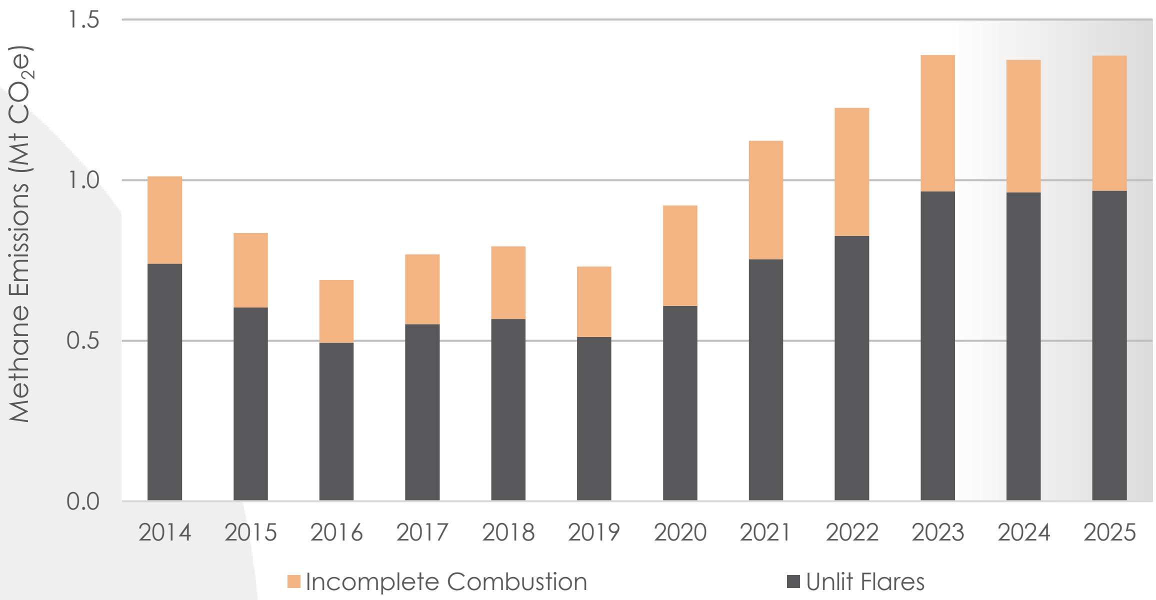

Figure 3-13. Timeline of methane emissions from flaring, split between incomplete combustion and unlit flares, between 2014 and 2023, then forecasted out to 2025.

Discussion Points:

Two key assumptions are used in the model methodology to estimate methane emissions from flaring. First, flaring gas is assumed to have a destruction efficiency of 98%. This is a standard assumption that aligns with assumed combustion efficiencies used in the NIR and Alberta GHG Quantification Methodologies. Using this methodology, we estimate that about 0.4 Mt CO_2e of methane emissions occurred in 2023 due to incomplete flaring combustion.

Secondly, to align with the AER's methodology, it was assumed that 6% of flares in the province were unlit and therefore venting gas directly to the atmosphere. Flares at gas plants were exempt from this assumption and instead assumed to always be lit. In 2023, about 1.0 Mt CO_2e of methane emissions were estimated due to unlit flares.

There is a high amount of uncertainty associated with any assumed unlit flare rate, which are drawn from limited data sets. Site-specific rates of unlit flares will vary widely by flare type, weather conditions, and operational practices. Recent academic research using aerial measurements found that unlit flares were a source of methane emissions in Alberta in 2021 (Conrad et al. 2023) and in other jurisdictions (Plant et al, 2022). However, individual producers may have an alternative view to this research,

[14] AER ST60b assumes a 6% unlit flare rate at selected sites, and the MWMM uses the same 6% assumption for all non-gas plant facilities.

based on an accurate and well-founded understanding of their own unlit flare rates, often much lower than sector-wide assumptions. A better understanding of the true prevalence of unlit flares in the province is crucial before allocating resources to reducing methane from this source.

There has been a general uptick in reported flare gas volumes across the sector since 2019, as companies adapted to the direct venting limit regulations by tying tank and compressor vents to a site's flare stacks or enclosed combustors. The most effective method to reduce methane slip from flaring is to simply reduce flared gas volume, via gas conservation activities. Various gas conservation technologies are discussed in Section 3.2.2. of this report. When flaring is still necessary, flame-out detection and auto-ignition devices installed at unsupervised flare stacks can ensure a maximum flare combustion efficiency (United States Environmental Protection Agency, 2011). However, there is limited data available regarding the cost and commercial availability of auto-ignition devices.

3.2.8. Surface Casing Vent Flow and Gas Migration

Surface casing vent flow (SCVF) and gas migration (GM) are both detected gas flows that occur at the wellhead surface. SCVFs occur from within the well casing annulus, while GMs are detected outside the well casing. There were 1.5 Mt CO_2e of methane emissions from SCVF/GM in 2023, representing 10% of the total methane inventory. The historical profile for SCVF/GM emissions is presented below in Figure 3-14.

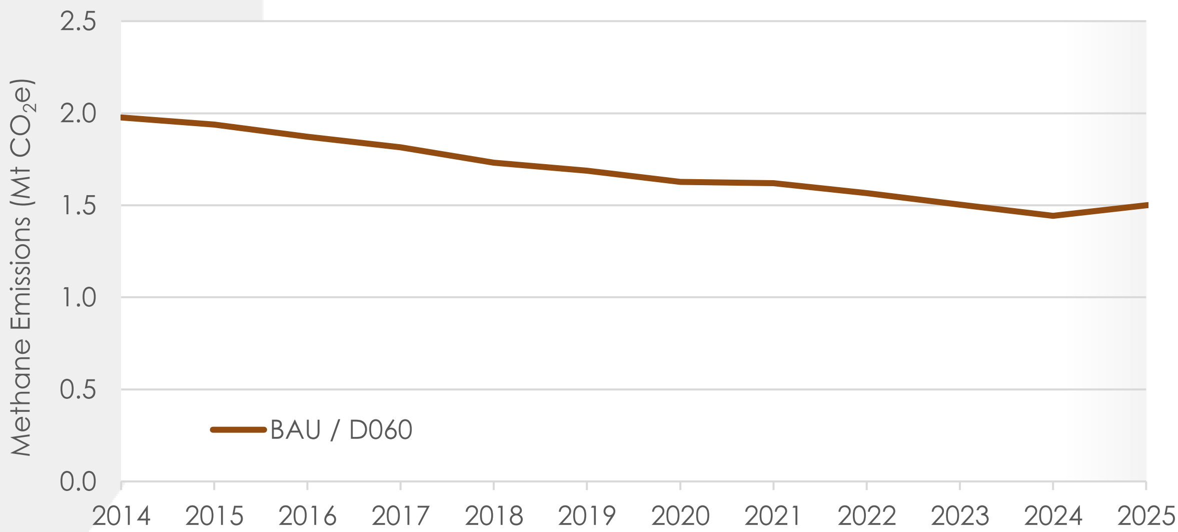

Figure 3-14. Timeline of SCVF/GM methane emissions between 2014 and 2023, then forecasted out to 2025. As SCVF/GM events are regulated separately under Directive 087, only one combined BAU/D060 scenario was modelled for this source category.

Discussion Points:

SCVF and GM events are reported to the AER and are published annually in the Well Vent Flow/Gas Migration Report[15]. SCVF is regulated in Alberta under Directive 087, which prescribes testing, reporting, and repair requirements based on the classification of the flow as Serious or Non-Serious. SCVF events with flow rates greater than 300 m^3/day and GM events that pose a risk to public safety are classified as Serious and must be repaired within 90 days of detection[16]. Non-Serious flows must be repaired at the time of well abandonment.

Figure 3-15 shows the breakdown of SCVF/GM events reported in 2024. 620 events, just 5% of the total, were classified as Serious and flagged for repair within 90 days. This subset is estimated to account for 27% of the 1.5 Mt CO_2e of methane emissions in that year. Meanwhile, 9,446 events were classified as Non-Serious or Considered Non-Serious and were responsible for the remaining 73% of methane emissions from this source. It should be noted that recent studies have concluded that surface casing vent flows are an underreported source category, particularly at abandoned wells in Alberta (Bowman et al., 2023).

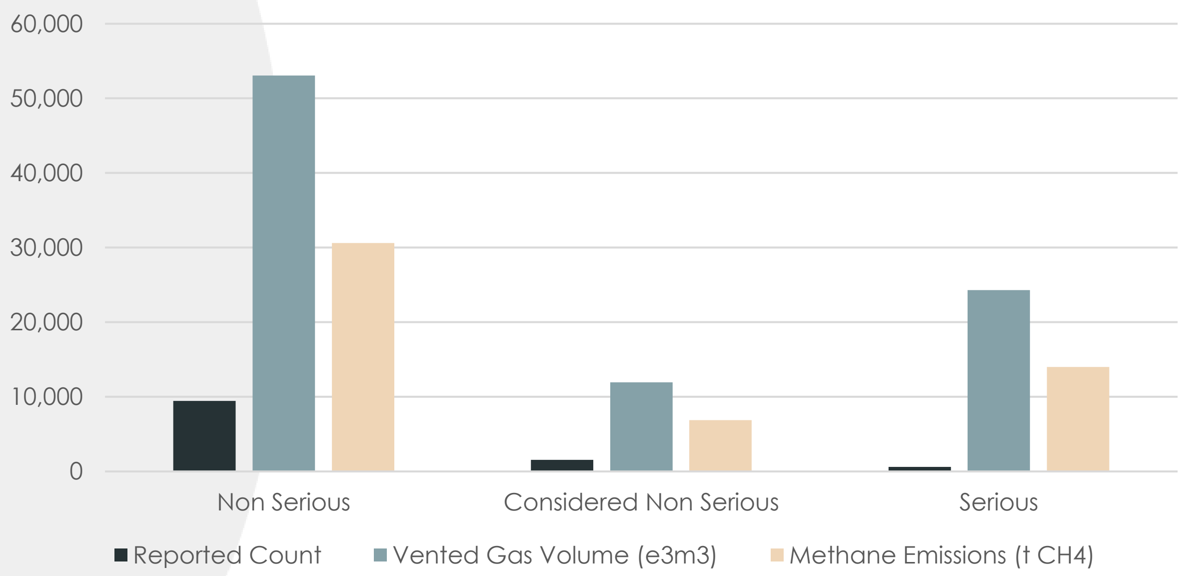

Figure 3-15. Analysis of the SCVF/GM events reported to the AER in 2024, with calculated vent gas volumes and methane emissions.

Mitigation options for these sources fall into one of two categories: downhole solutions, which involve trying to plug or stop the leak at its source, and emissions capture projects, which attempt to capture and either destroy or conserve the vented gas at the surface.

Emission reductions at Non-Serious flows can have relatively high abatement costs due to their lower flow rates. It can take multiple attempts to seal a downhole leak

[15] AER Well Vent Flow/Gas Migration Report
[16] An SCVF is also classified as Serious if H_2S, oil, or water is present in the vent flow or if the well's stabilized shut-in pressure exceeds a pre-determined threshold.

with a cement squeeze. There are some promising results from field trials of technologies that oxidize the methane at the surface. However, it is unclear if these technologies are at a Technology Readiness Level where they can be counted on as a near-term solution. The *Drilling and Production Regulation* in B.C. allows operators to install burst plates at Non-Serious flows, minimizing venting at these wells while also eliminating the requirement for follow-up testing. This approach would currently be beyond regulatory requirements in Alberta.

Without some sort of targeted investments or expansion of existing offset protocols to include SCVF/GM volumes to overcome the financial barriers to abatement, significant reductions are not expected to be achieved from this source category.

3.2.9. Spills and Ruptures

Spill and rupture emissions occur from unintentional releases of natural gas from transmission and distribution pipelines. Release incidents are reported to the AER and include information on the released substance, average flow rate, and duration. Historical and projected emissions for this source Figure 3-16.

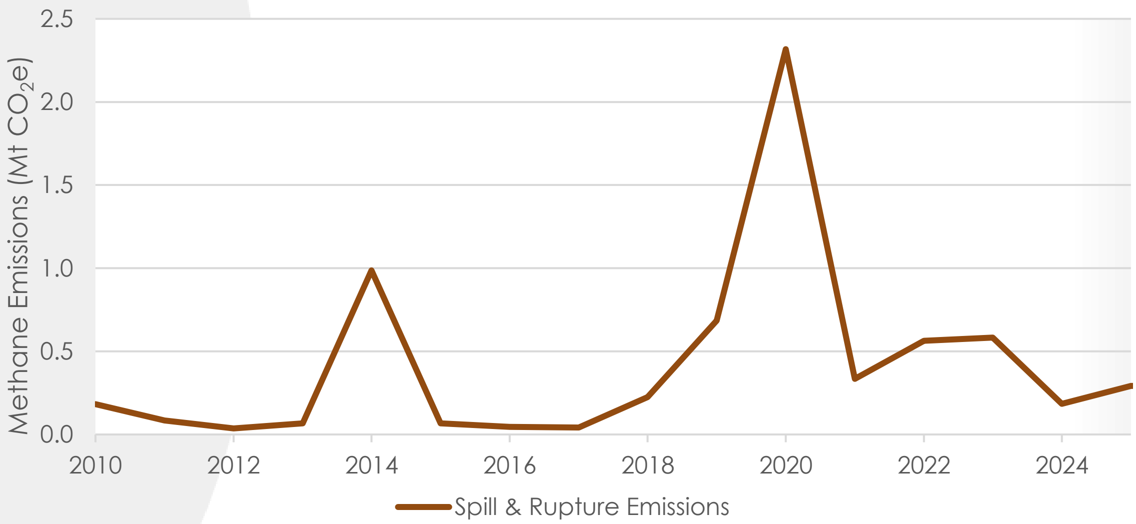

Figure 3-16. Historical and forecasted methane emissions from spill and rupture events, modelled by the MWMM.

Discussion Points:

There is no correlation between spill and rupture emissions and commodity production rates. An analysis of the AER release incident database found that a small number of very large releases were responsible for most of the emissions in the years 2014 and 2020.

It is difficult to estimate the frequency of pipeline release incidents in the future. There are pipeline inspection and maintenance regulations already in place, and significant diligence from asset owners to manage this risk. There are fines, lost revenue, health & safety, and negative stakeholder impacts associated with a release incident, which provide plenty of incentive for pipeline operators to maintain their assets to world-class integrity standards. Instead, future spill and rupture emissions are forecasted based on average historical data and scaled to forecasted production levels each year.

4. Conclusions

Alberta's methane reduction framework—anchored by Directive 060, market-based incentives, and strategic funding initiatives—has successfully reduced UOG methane emissions by 51% from 2014 to 2023. Our modelling suggests that a cumulative total 55% reduction may be achieved by the end of 2025.

Figure 4-1 summarizes the methane emissions source categories modelled for 2023. Each source category was assigned a qualitative "mitigation difficulty" that describes the sector's ability to further reduce emissions from 2023 levels using the current regulatory, incentive, and technological framework (to the best of our knowledge).

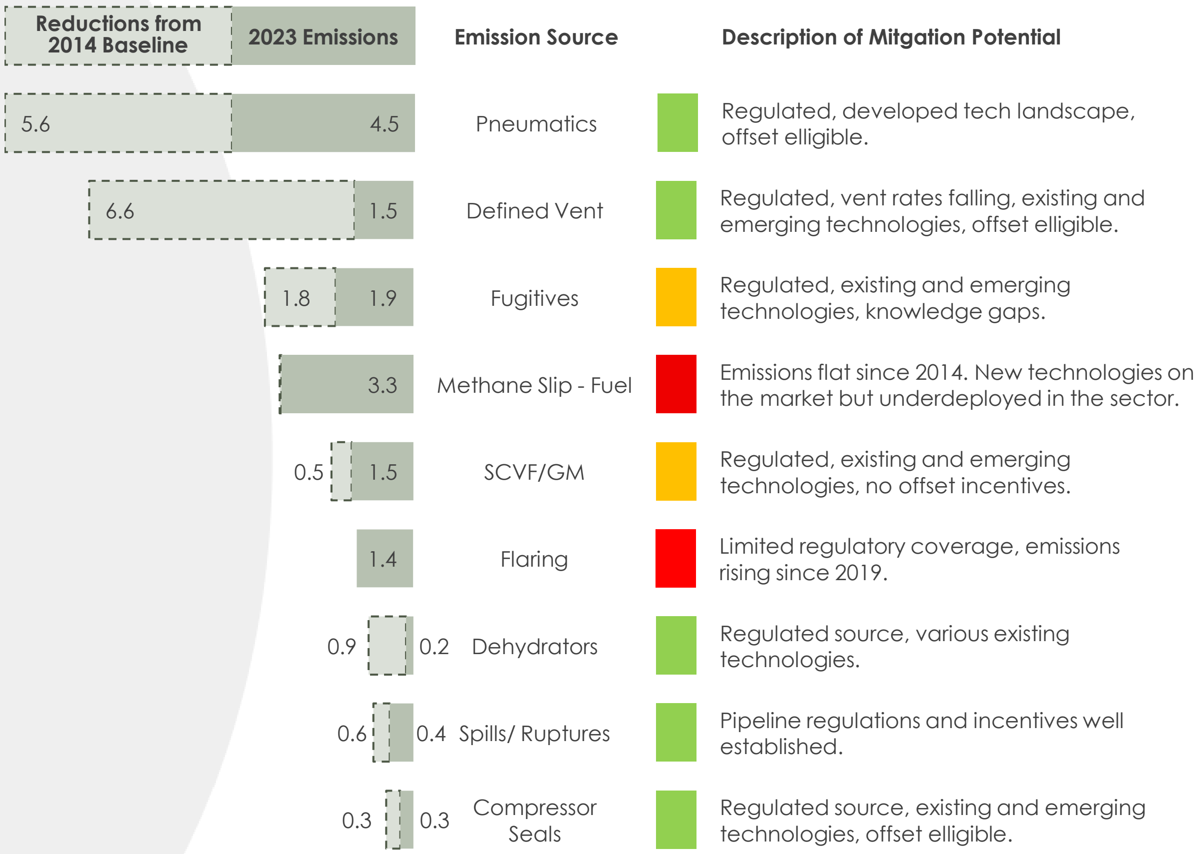

Figure 4-1. MWMM modelled emissions by source category in 2023 and a qualitative difficulty level for further reductions. Values are in tonnes of carbon dioxide equivalent.

4.1. Key Insights

Driven by robust regulations, industry commitment, technology innovation, and strategic investments in mitigation solutions, Alberta has meaningfully reduced methane emissions two years ahead of schedule. However, deeper cuts will be required for the sector to achieve the post-2025 ambitions stated by both Provincial and Federal governments. The analysis presented here suggests there are a few key areas where reductions can be achieved within the next few years:

- **Pneumatics:** The prescriptions in Directive 060 are forecasted to help lower this source category by 60% from 2014 levels by the end of 2025, and minor reductions would continue to be achieved year over year thereafter. Reductions may be accelerated through low-cost (10 – 30 $/tonne) retrofits (Modern West Advisory, 2023), especially while offset credits can still be generated.
- **Defined Vent:** Venting rates have declined dramatically across most facility subtypes since 2014, but a small subset of facilities (oil single-well batteries without separators in particular)[17] continue to account for a disproportionate share of emissions. Targeted reduction projects at these outlier facilities would be the most efficient way to achieve further reductions from this category, pending financial consideration and other adjacent factors (regulatory impacts, operational considerations, etc.). Casing gas conservation projects and vent tie-ins at batteries typically fall in the 40 – 80 $/t$CO_2$e abatement range (Modern West Advisory, 2023).
- **Methane Slip from Fuel Combustion:** This is the second largest emission source category. Our modelling has not shown any meaningful reductions in this source category since 2014 due to its current regulatory status[18] and technological limitations. The technology readiness of air-fuel ratio kits, catalysts, and crankcase vent loop systems has improved in recent years such that targeted investments in these systems could help spark their wider adoption across industry.
- **Catalytic Heaters:** A recent study found that seasonal emissions from catalytic heaters could account for up to 6% of the methane inventory in British Columbia (Festa-Bianchet et al. 2024). As catalytic heaters are commonly employed at O&G facilities in Alberta, it stands to reason that this could be a meaningful source in Alberta's methane inventory as well. This category is not currently modelled either by the AER or in the MWMM. Catalytic heater emissions may be included in future iterations of our model.

4.2. Strategic Outlook

Alberta's early success in surpassing its 2025 methane target should be celebrated. The combination of regulatory frameworks and industry investment has fostered along a world-class cleantech sector simultaneously. Looking ahead, there are opportunities to expand on the sector's global methane mitigation leadership. Encouragingly, the technologies needed to drive additional reductions are commercially available; increased awareness and experience with these abatement solutions could help catalyze a more widespread deployment across the sector and ensure that

[17] Methods for Estimating Emissions from Tanks, Modern West Advisory (2023)
[18] As a component of combustion exhaust, methane slip emissions as regulated under TIER, not Directive 060.

Canada's oil and gas industry produces the lowest onshore methane emissions intensity product.

The opportunity exists for Alberta to deepen its leadership in methane mitigation through:

- Strategic investments in high-impact abatement projects[19];
- Accelerated deployment of underutilized technologies[20];
- Stronger coordination across regulatory frameworks
- Enforce the value of market-based solutions.

With continued collaboration among government, industry, and innovators, Alberta is well-positioned to lead the global economy in low-emissions energy production. The graphic below provides a visual representation of technology solutions currently available to the sector to help it meet this end.

[19] New funding program(s) similar to MTIP/BROA/ERF would be beneficial in the short-term.
[20] Largely through offsets eligibility and/or government funded programs.

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Appendix A – Directive 060 Requirements

Table 2. Summary of current Directive 060 requirements

Source	Subcategory	Requirement
Venting	Overall Vent Gas (OVG) Limit	15,000 m^3/month/site or 9,000 kg CH_4/month/site at all sties.
	Defined Vent Gas (DVG) Limit	3,000 m^3/month/site or 1,800 kg CH_4/month/site at new sites
	Crude Bitumen Battery Fleet Average	For new and existing crude bitumen batteries, either: • DVG limit for each site, or • 1,500 m^3/Facility ID fleet average limit
Pneumatics	Existing Controllers	• Level controllers must prevent/control vent gas or use a relay that has been designed to reduce or minimize transient or dynamic venting or adjust the actuation frequency to ensure that the time between actuations is greater than 15 minutes. • Non level controllers must prevent/control vent gas or ensure that the instruments have a manufacturer-specified steady-state vent gas rate of less than 0.17 m^3/hr.
	New Controllers	Prevent or control gas from pneumatic instruments
	Existing Pumps	No requirement.
	New Pumps	Prevent or control vent gas from pneumatic pumps operating more than 750 hours per year
Compressor Seals	New Reciprocating Compressors	Units with 4 or more throws must control vent gas.
	All Reciprocating Compressors	• Fleet vent rate limit of 0.35 m^3/hr/throw • Single compressor seal vent limit of 5.00 m^3/hr/throw
	New Centrifugal Compressors	Single compressor seal vent limit of 3.40 m^3/hr/compressor
	Existing Centrifugal Compressors	Single compressor seal vent limit of 10.20 m^3/hr/compressor
Glycol Dehydrators	New Dehydrators	Vent limit of 68 kg CH_4/day per unit
	Existing Dehydrators	Vent limit of 109 kg CH_4/day per unit

Source	Subcategory	Requirement
Fugitives	Sweet Gas Plants Sweet Compressor Stations (<0.1 mol/kmol H_2S) Liquid hydrocarbon storage tanks with vent gas control Produced water storage tanks with vent gas control	Triannual fugitive emissions surveys
	Gas Plants Straddle and fractionation plants Sour compressor stations Batteries and associated satellites Custom treating facilities Terminals Injection/disposal facilities	Annual fugitive emissions surveys
	Well sites	Annual screenings

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Appendix B: Modern West Methane Model (MWMM)

Methodology Description

September 4, 2025

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1. Introduction

The Modern West Methane Model (MWMM) attempts to estimate methane emissions from the Alberta upstream oil and gas (UOG) sector. The MWMM aligns closely with the AER's bottom-up modelling methodology[21], supplemented with select assumptions from Environment and Climate Change Canada (ECCC) model methodologies published in Annex 3.2 of the National Inventory Report. It is comprised of nine emission source categories.

The objective of this modeling endeavor was to acquire an approximation of the breakdown of the most recent emission profile published by the GoA, rather than to formulate a new estimate. The assumptions and limitations of MWA's modeling is described below.

1.1. Model Structure

- The model estimates methane emissions from the following nine sources:
    - Pneumatics vent gas, defined vent gas, fugitives, compressors, glycol dehydrators, surface casing vent flow (SCVF) and gas migration (GM), methane slip from fuel combustion, methane from flaring, and spills and ruptures.
- The model estimates methane emissions under the following scenarios:
    - The Business-as-Usual (BAU) scenario estimates emissions in the absence of the methane frame work in Alberta, including the 2018 updated Directive 060 regulations, offset protocols, and targeted funding programs. any methane regulations or incentive programs. In this scenario, changes in methane emissions after 2018 are purely due to changes in sector activity/production levels.
    - Directive 060 (D60) scenario estimates emissions under the existing regulatory framework currently in place in Alberta. The scenario includes early action reductions in a few categories, and required reductions enforced by the Directive 060 update released in 2018.
- The MWMM uses average component counts for facility subtypes from field investigations to estimate emissions for many of the source categories. Once an emission rate is derived for each facility subtype, it is multiplied by the number of historical or forecasted active facilities/wells in a year to produce a total volume of methane emissions in each year.

[21] The AER's emissions methodology is summarized in the appendix of *ST60B-2024: Upstream Petroleum Industry Emissions Report*.

1.2. General Model limitations

- Due to a lack of publicly available data, the model does not include emissions from some non-routine sources, including well testing, liquids unloading, and engine/turbine start-ups.
- The model relies on operator reported data (OneStop) for the following emission sources: Defined Venting, Compressor Seals, and Glycol Dehydrators. Full reporting compliance across the sector is assumed by the model.
- The model estimates methane emissions under the AER's Directive 060 requirements. The model does not incorporate an economic analysis component. The effect of stringent policies on well/facility shut-ins is not modelled. The effects of the TIER carbon price, was recently fixed at $95 per tonne CO_2e until 2030, is also not modelled.
- The MWMM estimates emissions at the facility subtype level, it is not designed to estimate methane emissions for individual facilities. The model treats all facilities of a particular subtype (crude oil single well batteries, gas plants, etc.) as the same. In reality, individual facilities of the same subtype can be very different in terms of the type and number of equipment on site. The model relies on average component counts by facility subtype from field surveys, which sampled a statistically significant number of sites. These average component counts should produce reasonably accurate estimates at the facility subtype level, but they should not necessarily be used to estimate emissions for individual facilities.

1.3. Inputs for all emissions categories

- Methane density = 0.6785 kg/m^3 (AER Manual 015)
- Methane GWP = 28 (IPCC AR5)
- Natural gas methane content is assigned by facility subtype. Gas composition data is sourced from the Energy and Emissions Research Lab at Carleton University (Tyner & Johnson, 2020).

2. Facility and Well Counts

The number of active facilities and wells in a given year is required to estimate emissions for many of the source categories in the MWMM. This section describes how this data was estimated.

2.1. Historical Counts (2015 – 2024)

Counts of active facilities and wells in the years 2015 – 2024 are sourced from Petrinex public reports. An active facility is defined as a facility that reports a non-zero production, receipts, disposition, fuel, or vent volume in a given year. Unique well identifier codes were counted from Petrinex volumetric reports to determine active well counts in each year. Wells were grouped by their linked facility subtype using Petrinex infrastructure files. Unfortunately, MWA only has access to Petrinex volumetric reports beginning in 2015. Therefore, active facility counts for 2014 had to be estimated as described in section 2.2.

2.2. Forecasted Counts (2014 and 2025)

To estimate emissions for future years, a few assumptions were made in order to project the final number of active facilities and wells in 2025. The AER released the latest version of ST98: Alberta Energy Outlook[22] in June 2025. The ST98 includes forecasts for commodity prices, production rates and drilling activity. Historical and forecasted daily production rates are extracted from the most recent report, indexed to 2014 levels, and are shown in Figure B-2 below.

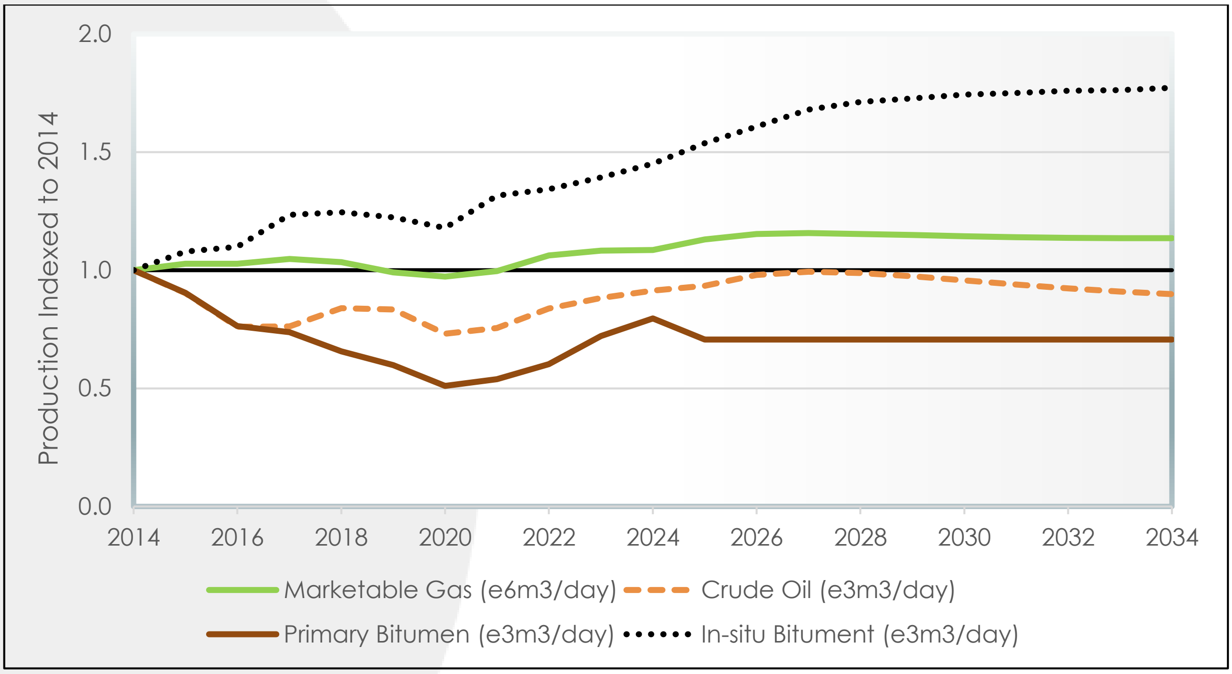

Figure B-2. Historical and forecasted oil and gas production rates in Alberta, by commodity type. Graph by MWA, Data source: AER ST98.

As Figure B-2 illustrates, there was a significant decline in the production rates of crude oil and primary bitumen between 2014 and 2021. Natural gas production stayed relatively flat during that time, while in-situ bitumen production rose by 71% in the same period. The latest production forecasts project that natural gas and crude oil production will rise in the near term, peaking around 2027 before leveling out. The historical growth in in-situ bitumen production is expected to continue until 2034. Primary bitumen production rates are not forecasted by the AER specifically. Instead, primary bitumen production was forecasted to stay constant from 2025 – 2030 as the majority of bitumen sector expansion is expected to focus on thermal in-situ schemes.

[22] https://www.aer.ca/data-and-performance-reports/statistical-reports/alberta-energy-outlook-st98

To forecast active facilities in 2025, it was assumed that active facilities will follow the same trend as forecasted production. Active facility counts in 2024 were multiplied by the yearly production index to forecast the number of active facilities required to maintain the forecasted production level in 2025:

$$N_{y,i} = N_{2024,i} * \frac{P_{y,j}}{P_{2024,j}}$$

Where:

- $N_{y,i}$ = Number of active facilities of subtype *i* in year *y*
- $N_{2024,i}$ = Number of historical active facilities of subtype *i* in 2024
- $P_{y,j}$ = Forecasted production volume of commodity type *j* in year *y*
- $P_{2024,j}$ = Historical production volume of commodity type *j* in 2024

Facility subtypes are grouped by commodity type (j) according to the table below. This allows future facility and well count projections to be tied to the relevant commodity production rates forecasted in AER ST98.

Table B-3. Commodity groupings for facility subtypes used for future facility and well count projections.

Facility Category	Petrinex Facility Subtypes	AER ST98 Commodity (j)
Crude Oil Batteries	311, 321, 322, 508	Crude Oil
Primary Bitumen Batteries	331, 341 – 343	Primary Bitumen
In-situ Bitumen Batteries	344, 345, 501, 506	In-situ Bitumen
Natural Gas Batteries	351, 361 – 367, 371, 381	Natural Gas
Natural Gas Processing	401 – 407, 621, 622	Natural Gas

Active facilities and wells were estimated in 2014 in a similar fashion, except the reference year was changed to 2015. Historical and forecasted active facility counts used in the model are illustrated below in Figure B-3.

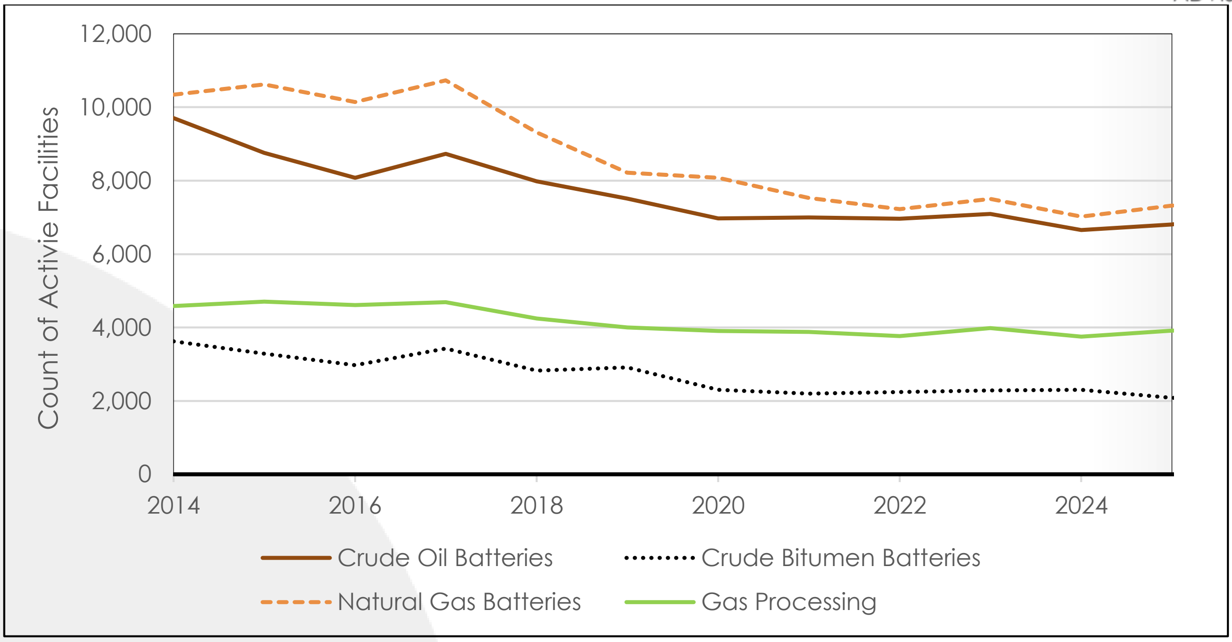

Figure B-3. Historical and forecasted active facilities in the Alberta upstream oil and gas sector. 2025 counts were estimated using the latest AER production forecasts. Graph by MWA. Data sources: Petrinex, AER.

2.3. New vs. Existing Facilities

The modelled scenarios apply different requirements based on the first operating year of an individual facility (before or after January 1st, 2022). To model these requirements, it was necessary to estimate the proportion of facilities brought online in each year. The first operating year for each facility was sourced from the Petrinex Facility Infrastructure file ("Alberta Public Data," n.d.)[23]. The total number of facilities, grouped by facility subtype, in their first operating year was calculated for 2014 – 2024 and compared to the total number of active facilities, calculated in Section 2.1. A weighted average of yearly "new builds" for each facility subtype was calculated. An assumption was made that this rate of new builds will remain constant for 2025. The new build rate was then multiplied by the active facility forecasts from section 2.2 to estimate the total number of newly constructed facilities in 2025.

3. Emission Categories

3.1. Pneumatics

The estimation of vent gas from pneumatic devices was based on the average number of devices for each facility type, the average vent rate for pneumatic devices, and it assumes 8,760 hours of operation in a year, which is consistent with the NIR and GoA methodologies.

The average pneumatic device counts, device vent rates (both high bleed and low bleed), and the proportion of facilities on fuel gas were provided by Environment and Climate Change Canada (ECCC, 2025b), which were themselves derived from various

[23] Petrinex Alberta Public Data

field samples (Clearstone, 2018, Spartan Controls, 2018). From this data, an average pneumatic controller and pneumatic pump vent rate was calculated for each facility subtype, for both high bleed and low bleed requirements.

The effect of the pneumatic offset protocol to voluntary reductions from this source was incorporated into the MWMM. An analysis was performed on the Alberta Emissions Offset Registry (AEOR) Listing database. The total number of pneumatic offset credits were isolated from the database and grouped by year. These values were used to adjust the D060 scenario reductions for the years 2018 – 2023.

3.1.1. Quantification

Pneumatic controller and pump emissions are calculated using the following equation.

$$Emis_{i,j,k} = FC_i * NC_{i,j} * EF_{j,k} * P_k * GD_i * \phi_{CH4} * \rho_{CH4} * 8760$$

Where:

$Emis_{i,j,k}$ = Pneumatic emissions for facility/well subtype *i* and device type *j*, under vent state[24] *k* (kg CH_4/year)
FC_i = Active facility/well count for facility subtype *i*
$NC_{i,j}$ = Average number of pneumatic device type *j* at facility subtype *i*
$EF_{j,k}$ = Pneumatic device emission factor for device type *j* under vent state *k* (m^3/hr)
P_k = Proportion of pneumatic devices operating under vent state *k*
GD_i = Proportion of active facilities/wells of subtype *i* operating with fuel gas driven pneumatics (%)
Φ_{CH4} = molar fraction of methane in the vent gas (%)
ρ_{CH4} = density of methane (0.6785 kg/m^3)
8,760 = number of hours in a year

3.1.2. Pneumatic Device Vent States

The main differentiator that drives emission reductions from pneumatic devices in each modelled scenario is the proportion of devices in either high, low, or zero vent states. The proportion of devices in each state changes in each modelled scenario in response to the scenario's policy signal. For example, the Directive 060 scenario requires that pumps installed after January 1st, 2022 control their vent gas, but there are no requirements for existing pumps. The model assumes that some operators will elect to retrofit their existing pumps to generate offset credits. The rate of retrofits is assumed, but the assumptions are informed by observed rates of pneumatic offset uptake on the AEOR and pneumatic vent gas volumes reported each year to OneStop The vent states used in the Directive 060 scenario modelled by the MWMM are shown in Table B-17.

Since 2020, operators have been required to report pneumatic vent gas volumes to the AER via the OneStop system. These reported figures have consistently fallen below the

[24] High, low, or zero vent.

modelled estimates as depicted in Figure 3-6, even when the MWMM model accounts for registered pneumatic offsets. Notably, the equipment count surveys supporting both the AER's and the MWMM's pneumatics methodology were conducted between 2017 and 2018 (AER, 2025a). The consistent discrepancy between modelled and reported data suggests that the equipment count method may overstate pneumatic methane emissions. The pneumatics methodology used by ECCC adjusts modelled values using OneStop reporting, according to the National Inventory Report (NIR) Annex 3.2 (ECCC, 2025a). Should the AER update its methodology to rely on directly reported pneumatic gas volumes, the MWMM methodology would be revised to reflect this change.

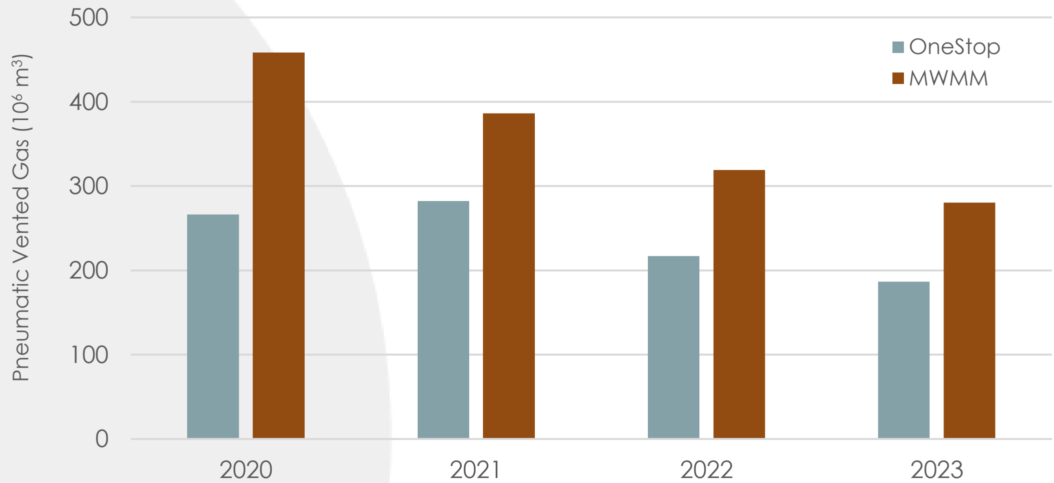

Figure B- 4. Comparison between pneumatic vent gas volumes reported to OneStop vs. volumes modelled by the MWMM.

3.2. Direct Venting

3.2.1. Historical Venting (2014 – 2023)

For the years 2014 – 2019, vent gas volumes were pulled from public Petrinex volumetric reports and grouped by facility subtype. Between 2020 and 20223, the model uses defined vent gas volumes from OneStop reports published annually by the AER.

3.2.2. Forecasted Venting (2024 – 2025)

To model future vent gas volumes, the average venting rate for each facility subtype in 2023 was calculated, then multiplied by the number of forecasted active facilities. For the Directive 060 scenario, it was necessary to model compliance rates with the Overall Vent Gas (OVG) and Defined Vent Gas (DVG) limits. This was done using the 2023 OneStop report. The average defined vent gas venting rates for compliant and non-compliant facilities were calculated[25]. For 2024 – 2025, it was assumed that all non-compliant facilities would become compliant and vent at exactly the OVG or DVG.

[25] This analysis excluded all facilities in the Peace River area, those facilities are regulated differently under the AER Directive 084.

Previously compliant facilities would continue to vent at the average rate of all compliant facilities.

Facilities that went online prior to January 1st, 2022 are subject only to the OVG venting limit, which includes vented gas volumes from defined venting, pneumatics, compressor seals, and glycol dehydrators. It is important to note that the MWMM models these sources separately, and suffers from a limitation in its ability to predict how individual facilities will choose to comply with the OVG.

Vent volumes were calculated using the following equation:

$$Q_{y,i} = N_{y,i} * [(P_c * Q_c) + (P_{nc} * Q_{nc})]$$

Where:

- $Q_{y,i}$ = Vent volume in year y for facility subtype i (m^3)
- $N_{y,i}$ = Number of facilities in year y for facility subtype i
- P_c = Percentage of compliant facilities venting below the limit
- Q_c = Average vent rate of compliant facilities
- P_{nc} = Percentage of non-compliant facilities venting above the limit
- Q_{nc} = Vent limit prescribed by the requirement (i.e. OVG or DVG)

3.2.2.1. Crude Bitumen Batteries

Under Directive 060, operators must limit vent gas at crude bitumen batteries (subtypes 331, 341 or 342) to either the DVG limit or to less than an average vent gas rate of 1,500 m^3/month per facility ID. The distribution of monthly vent rates at crude bitumen batteries is highly skewed (Tyner & Johnson, 2020), as illustrated in Figure 1 below.

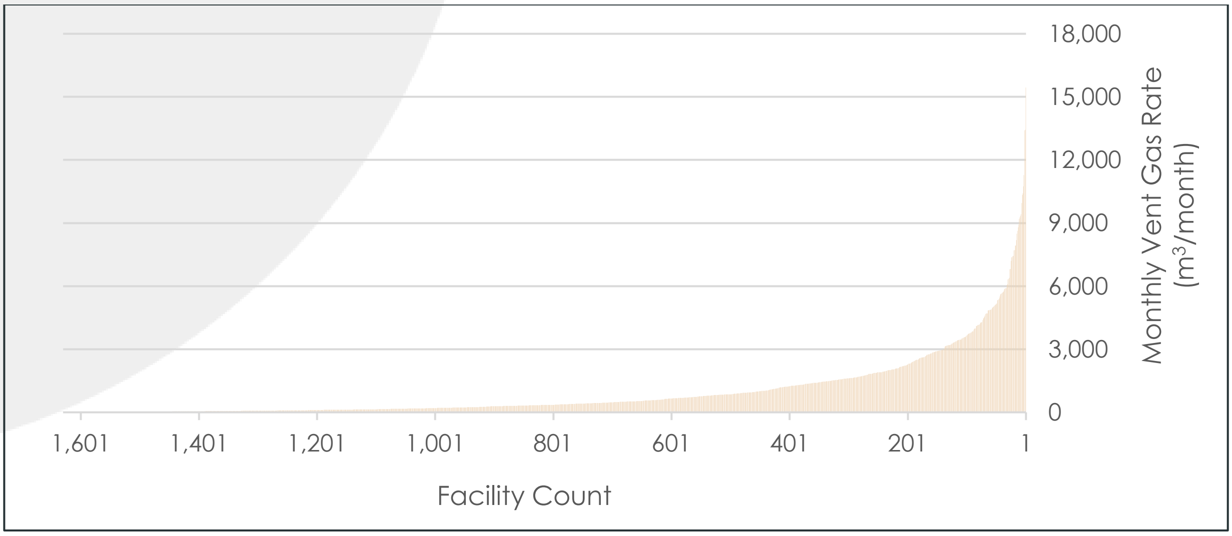

Figure B-5. Distribution of monthly vent gas rates at all active crude bitumen batteries (subtypes 331, 341, 342) reported to OneStop in 2021.

Under the fleet average limit, operators can keep some high emitting sites so long as they have a sufficient number of low emitting sites such that their average vent rate is below the limit. To estimate the effectiveness of the fleet average approach, an analysis was performed using the 2023 OneStop data. All active reporting crude bitumen batteries were grouped by operator, and the fleet average for each operator was calculated. Next, the necessary vent gas reductions were calculated for each operator that had a fleet average above the limit. The sum of compliance reductions was compared to the total province-wide vent gas volume for crude bitumen batteries in 2023 to calculate a reduction factor. This reduction factor was then applied to forecasted crude bitumen battery vent rates for the years 2024 – 2025. The calculation for the operator fleet average and associated reduction factor for 2023 is shown below in Table 1.

Table B-4. Crude bitumen battery vent rate fleet average for all reporting operators in Alberta in 2023. Operators with fleet averages greater than 1.5 e3m3/month were required to reduce vent gas emissions to become compliant. Batteries located in the Peace River area are excluded from the calculation.

Operator	Active Battery Count	Total Vent Gas (e3m3)	Actual Fleet Avg. (e3m3/mo)	Required Emission Reduction (e3m3)
Canadian Natural Resources Limited	1333	14,006	0.88	0
Cenovus Energy Inc.	78	359	0.38	0
Baytex Energy Ltd.	49	54	0.09	0
Spur Petroleum Ltd.	41	151	0.31	0
Caltex Trilogy Inc.	41	428	0.87	0
Headwater Exploration Inc.	35	46	0.11	0
Rife Resources Ltd.	26	115	0.37	0
Woodcote Oil & Gas Inc.	22	110	0.42	0
Tamarack Valley Energy Ltd.	22	37	0.14	0
Buffalo Mission Energy Corp.	21	7	0.03	0
Gear Energy Ltd.	20	394	1.64	**34**
West Lake Energy Corp.	12	128	0.89	0
Lycos Energy Inc.	11	1	0.01	0
PetroFrontier Corp.	11	0	0.00	0
Ipc Canada Ltd.	9	47	0.43	0
Bighorn Energy Corporation	6	0	0.00	0
Lineup Resources Corp.	4	1	0.02	0
Clear North Energy Corp.	4	52	1.08	0
Harvest Operations Corp.	4	50	1.05	0
Check Energy Ltd.	3	38	1.05	0
Perpetual Energy Inc.	3	48	1.33	0
Croverro Energy Ltd.	2	0	0.00	0
Obsidian Energy Ltd.	2	4	0.19	0
Rubellite Energy Inc.	1	0	0.01	0
Revitalize Energy Inc.	1	0	0.00	0
Alberta Total	**1,761**	**16,075**	**0.76**	**34**

$$R = \frac{16{,}075\ e3m3 - 34\ e3m3}{16{,}075\ e3m3} * 100\% = 0.2\%$$

Crude bitumen vent volumes for forecasted years are then calculated using the following equation:

$$Q_{bit,y,i} = N_{y,i} * Q_{avg} * (1 - R)$$

Where:

- $Q_{bit,y,i}$ = Vent volume for crude bitumen battery of subtype i in year y, i = {331,341,342}
- $N_{y,i}$ = Number of crude bitumen batteries of subtype i in year y
- $Q_{avg,i}$ = Average vent rate of crude bitumen batteries of subtype i in 2021
- R = Crude bitumen battery fleet average reduction factor for the modelled policy

3.3. Compressors

3.3.1. Compressor Counts

AER ST60b reports include the number of compressors of each type (centrifugal and reciprocating) as well as the reported vent volumes for each type of compressor for 2020 – 2023. This data is summarized below in Table 2.

Table B-5. Province-wide reciprocating compressor counts and seal vent gas emissions between 2020 and 2023. Source: AER ST60b.

Year	Reciprocating Compressor Count[1]	Total Seal Vent Gas[2] (e6m3/yr)	Avg. Seal Vent Rate (e3m3/ compressor/ year)
2020	3433	27.0	7.86
2021	3357	26.6	7.92
2022	3430	19.17	5.59
2023	3338	16.08	4.82

Notes:
1. Number of compressors rated 75 kW or more and pressurized for at least 450 hours per year, reported in ST60b
2. Reported to OneStop and published in annual ST60b reports.

Table B-6. Province-wide centrifugal compressor counts and seal vent gas emissions between 2020 and 2023. Source: AER ST60b.

Year	Centrifugal Compressor Count[1]	Total Seal Vent Gas[2] (e6m3/yr)	Avg. Seal Vent Rate (e3m3/ compressor/ year)
2020	202	1.2	5.94
2021	165	0.9	5.45
2022	132	0.68	5.15
2023	110	0.47	4.27

Notes:
1. Number of compressors rated 75 kW or more and pressurized for at least 450 hours per year, reported in ST60b
2. Reported to OneStop and published in annual ST60b reports.

3.3.1.1. Historical Compressor Counts

The data in Tables 2 and 3, along with the active facility counts derived in Section 2, was used to estimate compressor counts for 2014 – 2019. The ratio of the number of compressors to the count of active gas facilities (gas batteries, gas plants, gas gathering systems, and compressor stations) in 2020 was first calculated. This ratio was then multiplied by the estimated active gas facility count in the years 2014 – 2019 to estimate the number of compressors that were likely to be active in those years prior to this data being reported to the AER. This method assumes that there is a stable correlation between the number of compressors and number of active gas handling facilities.

3.3.1.2. Forecasted Compressor Counts

For the years 2024 – 2025, total reciprocating and centrifugal compressors are calculated in the same manner as above, but using the ratio of gas handling facilities to compressor counts between 2022 - 2023 instead of 2020.

Several assumptions were made in order to forecast the number of venting compressors in the years 2024 – 2025. Directive 060 introduces testing and repair requirements for compressors in 2022, as well as a fleet average limit for reciprocating compressors. Through conversations with industry, it is understood that the existing single-compressor limits and the fleet average are not driving any significant emissions reductions, and thus they are not modelled in the MWMM.

Starting in 2024, compressor seal emissions are included under a facilities' OVG. In the D060 scenario, the model assumes that operators will elect to install compressors with emission control technologies at all of their newly constructed facilities between 2024 and 2025. The model calculates the number of new, controlled compressors and removes them from the total compressor count for each forecasted year. The final number of uncontrolled compressors is used to estimate compressor seal emissions for forecasted years.

3.3.2. Compressor Seal Emissions Quantification

Compressor seal emissions are calculated using the following formula:

$$Q_{comp,y} = N_{recip,y} * EF_{recip} + N_{cent,y} * EF_{cent}$$

Where

- $Q_{comp,y}$ = Compressor seal emissions in year y (m3/year)
- $N_{recip,y}$ = Number of uncontrolled reciprocating compressors in year y
- EF_{recip} = Emission factor for reciprocating compressor seals (m3/year)
- $N_{cent,y}$ = Number of uncontrolled centrifugal compressors in year y
- EF_{cent} = Emission factor for centrifugal compressor seas (m3/year)

3.4. Glycol Dehydrators

3.4.1. Historical Emissions (2014 – 2019)

The 2020 edition of the AER's ST60b report published historical counts of dehydrator units in the province, the total volume of gas processed by dehydrators in each year, and benzene emissions data. This information is summarized below in Table B-7.

Table B-7. Glycol dehydrator inputs for historical emissions. Source: AER ST60b (2020).

Value	2008	2014	2015	2016	2017	2018	2019
Glycol Dehydrator Count	2,396	1,886	1,778	1,646	1,528	1,400	1,328
Gas Volume Processed by Dehydrators (e^6m^3/d)	437	400	421	416	418	468	454
Controlled Benzene Emissions (t/year)	1,248	746	609	501	399	285	258

The AER's Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators (D039) requires operators to reduce benzene emissions from their fleet of dehydrators. Commonly employed benzene control technologies include flash tanks, gas capture, flares or incinerators. These technologies have the added benefit of capturing or controlling methane emissions as well. For this reason, it was assumed that methane emissions from dehydrators follows the same historical trend as benzene emissions. D039 was first released in 2007 with 2008 as the first year with available data, therefore 2008 was selected as the 'baseline' year for tracking benzene reductions. Methane emissions from glycol dehydrators in 2014- 2019 are then scaled to the relative % benzene reduction in each year.

An uncontrolled dehydrator emission factor of 0.8451 m^3 THC/e3m3 of gas production was derived from Clearstone (2018) Table 27. This value uses the factors for still column off-gas (no flash tank) and the stripping gas factor. The pneumatic pump factor was not included since these emissions are calculated in section 3.1.

Historical dehydrator emissions between 2014 - 2019 are calculated using the following equation:

$$Q_{dehy,y} = V_{gas,y} * EF_{dehy} * \phi_{CH4} * \frac{B_y}{B_{2008}}$$

Where:

- $Q_{dehy,y}$ = Methane emissions from dehydrators in year y (m^3)
- $V_{gas,y}$ = Volume of gas processed by dehydrators in year y (e3m3)
- EF_{dehy} = Uncontrolled glycol dehydrator emission factor (0.8541 m^3 THC/e3m3 processed gas)
- Φ_{CH4} = Assumed methane concentration of gas processed by dehydrators (85%)
- B_y = Controlled benzene emissions in year y
- B_{2008} = Controlled benzene emission in 2008

3.4.2. Historical Emissions (2020 – 2023)

The total volume of vented gas from glycol dehydrators was published in ST60b starting in 2020. Methane emissions for these years is estimated by using the total reported vent gas and assuming a methane content of 85%.

Year	Dehydrator Count	Total Vent Gas (e6/m3/yr)	Average Vent Rate (e6m3/yr)
2020	1366	17.4	0.0127
2021	1241	13.9	0.0112
2022	1244	11.5	0.0092
2023	1329	11.1	0.0084

3.4.3. Forecasted Emissions (2024 – 2025)

The AER's ST60b reported that in 2023 there were 1,329 dehydrators that collectively vented 11.1 e6m3 of gas, meaning that the average dehydrator vented 0.0084 e6m3 in that year. For forecasted years in the model, dehydrators were assumed to vent at this 2023 rate going forward.

The number of dehydrators in forecasted years was estimated by calculating the ratio of historical dehydrators and active gas plants between 2021 – 2023. It was assumed that this ratio would remain constant for all forecasted years. The number of forecasted dehydrators was then estimated by multiplying this ratio by the number of forecasted gas plants as determined earlier in Section 2.2. The number of forecasted gas plants and dehydrators are summarized below in Table B-8.

Table B-8. Historical and forecasted number of gas plants and glycol dehydrators in Alberta between 2019 and 2025. Source: AER ST60b (2025a). Values from 2019 – 2023 are reported, while values from 2024 – 2025 are projections.

Value	2020	2021	2022	2023	2024	2025
Active Gas Plants	493	481	452	487	453	*476*
Glycol Dehydrators	1336	1241	1244	*1329*	*1217*	*1279*

Dehydrator methane emission for 2024 – 2030 are estimated using the following equation:

$$Q_{dehy,y} = N_{dehy,y} * 0.0084 \frac{e6m3}{dehydrator} * \phi_{CH4}$$

Where:

- $Q_{dehy,y}$ = Methane emissions from dehydrators in year y (m^3)
- $N_{dehy,y}$ = Number of dehydrators in year y
- Φ_{CH4} = Assumed methane concentration of gas processed by dehydrators (85%)

3.5. Fugitives

Fugitive emission factors by facility subtype and well type were derived from Tyner & Johnson (2020), who calculated annual fugitive emission factors for each facility subtype and well fluid type in Alberta for 2017 and 2018. These emission factors were then applied to the yearly facility and well counts derived earlier.

$$Emis_{fug,i,j} = FC_i * EF_{fug,i} * \left[1 - \left(LF_{i,j} * CR\right)\right]$$

Where:

- $Emis_{fug,i,j}$ = Methane emissions from fugitive equipment leaks for facility subtype i under policy scenario j (tCH_4/yr)
- FC_i = Number of active facilities/wells of subtype i
- $EF_{fug,I}$ = Average fugitive emission rate for each facility of subtype i (t CH_4/yr)
- LF = LDAR reduction factor for facility of subtype i under policy scenario j
- CR = LDAR survey compliance rate under policy scenario j

The Directive 060 scenario requires triannual comprehensive LDAR surveys at sweet gas plants and compressor stations that handle sweet gas. Annual surveys are required at all other facility subtypes. LDAR reduction factors were either sourced from the ICF 2015 report or were interpolated, as shown in the table below. Audio-Visual-Olfactory (AVO) screenings were assumed to produce negligible reductions and were not modelled.

Table B-9. Facility LDAR survey reduction factors applied to modelled scenarios.

Survey Frequency	Reduction Factor	Source
Annual Surveys	0.40	ICF (2015)
Semi-Annual Surveys	0.60	ICF (2015)
Tri-annual surveys	0.70	Assumed.
Quarterly Surveys	0.80	ICF (2015)
6x per year surveys	0.85	Assumed.
Monthly Surveys	0.90	Assumed

Directive 060 also stipulates that well sites co-located at their associated battery site are included as part of the facility's comprehensive fugitive survey, while isolated wells receive an annual AVO screening. It was therefore necessary to estimate what proportion of wells are co-located and what proportion are isolated. The surface location of all the active wells and their linked facilities were pulled from Petrinex infrastructure files. If the well license location matched the licked facility ID location, the well was considered to be co-located. The LDAR reduction factors from Table 6 were multiplied by the percentage of co-located wells to create a well specific LDAR reduction factor, for each facility subtype.

Yearly Operator compliance with Directive 060 fugitive survey requirements are tracked by the AER and provided to ECCC. These compliance statistics are published in the ECCC's Fugitive Emissions Methodology document (ECCC, 2025b). The same compliance rates, shown in the table below, are used in the MWMM to adjust the LDAR reduction factors.

Table B-10. LDAR compliance rates used in the estimation of fugitive methane emissions.

Year	LDAR Compliance Rate
2021	91%
2022	95%
2023	95%
2024 - 2030	95%

3.6. Methane Slip – Fuel

3.6.1. Fuel Consumption and Emission Factors

Historical fuel consumption volumes were sourced from Petrinex volumetric reports for 2014 – 2023. Fuel gas consumption was assigned to either reciprocating engines, gas turbines, or heaters/boilers according to the proportions from table S16 of the Tyner & Johnson (2020) study. Note that no adjustment was made to Petrinex fuel gas volumes in 2014 – 2019 to account for pneumatics vent volumes that were reported as fuel during that period. It remains unclear how many operators powered pneumatics from metered vs. un-metered fuel sources.

Methane slip emission factors were sourced form either the U.S. EPA WebFire database or from a 2021 study on engine slip at compressor stations in the U.S. Slip emission factors are summarized in Table 3.

To forecast fuel gas consumption volumes for 2024-2025, it was assumed that facilities would continue to use fuel gas at the same average rate as calculated in 2023, the most recent year with available fuel gas data.

Based on conversations with regulators, it was assumed that Alberta's fleet of reciprocating engines is approximately 70:30 lean burn to rich burn engines. We acknowledge that some Operators are preferentially installing lean burn engines at their facilities as a pathway to MSAPR compliance by 2026, however lack of granular data on engine flee composition means that this trend is not modelled. It was assumed that the 70:30 ratio would stay constant for all modelled years.

Table B-11. Methane exhaust emission factors for various natural gas combustion sources. Emission factors are derived from US EPA WebFIRE (United States Environmental Protection Agency, 2023) database and ECCC proposed regulations and converted to a common g/GJ unit.

Fuel Destination	Methane Emission Factor	Source

	(g CH_4/GJ)[26]	
Natural Gas Turbine	3.7	U.S. EPA AP-42
Natural Gas Boiler	0.97	U.S. EPA AP-42
Uncontrolled NG Engine (4-cycle Rich Burn)	98.9	U.S. EPA AP-42
Controlled NG Engine (4-cycle Rich Burn)	43.0	Vaughn et al. (2021)
Uncontrolled NG Engine (4-cycle Lean Burn)	537.4	U.S. EPA AP-42
Uncontrolled NG Engine (4-cycle Lean Burn)	494.4	Vaughn et al. (2021)

3.6.2. Methane Slip Quantification

Methane emissions from stationary combustion were calculated using the following formula:

$$E_{fuel,i,j} = Q_{fuel,j} * HHV_j * P_{i,j} * EF_i * 10^{-6}$$

Where:

$E_{fuel,i}$ = Methane emissions from fuel combustion for source i (Engines, turbines, or heaters/boilers) (t CH_4/year)
$Q_{fuel,j}$ = Annual volume of combusted fuel gas by facility subtype j (e^3m^3)
HHV_j = Higher heating value of fuel gas used at facility subtype j (GJ/e^3m^3)
P_i = Proportion of total fuel volume used by source i at facility subtype j
EF_i = Source-specific emission factor for methane slip by source i (g CH_4/GJ)

3.7. Flaring

Historical flare gas volumes were sourced from Petrinex volumetric reports for 2014 – 2023. The average rate for flared gas in 2023 was calculated for each facility subtype, then multiplied by the forecasted number of facilities to estimate total volume of flared gas in 2024 – 2025.

This model uses the same assumptions as the GoA for methane slip from flares. It is assumed that flares have a destruction efficiency of 98%. Then, all non-gas plant facilities have 6% of flares that are unlit, while gas plants do not have any unlit flares. Methane emissions from flared gas are then calculated as follows:

$$E_{flare,i} = Q_{flare,i} * (1 - DE_i) * \phi_{CH4,i} * \rho_{CH4} * GWP * 10^{-3}$$

Where:

$E_{flare,i}$ = Methane emissions from flaring at facility subtype i (t CH_4/year)
$Q_{flare,i}$ = Annual volume of flared gas at facility subtype i (m^3/year)
DE_i = Flare destruction efficiency at facility subtype i (92% non-gas plants, 98% gas plants)

[26] Emission factors converted to a common energy-based unit by assuming a fuel gas heat value of 39.2 MJ/m^3.

$\Phi_{CH4,i}$ = Methane concentration in flared gas at facility subtype i
ρ_{CH4} = Density of methane (0.6785 kg/m^3)
GWP = Global Warming Potential of methane

3.8. Surface Casing Vent Flow and Gas Migration

3.8.1. Historical SCVF/GM Counts (2014 – 2024)

Surface Case Vent Flow (SCVF) and Gas Migration (GM) events are reported by the AER in the *Well Vent Flow/Gas Migration Report*[27]. Relevant data from that report used in the MWMM are summarized in Tables 8 and 9. When reporting or resolution dates are not entered, some assumptions were made in order to estimate a leak duration. The MWMM uses the same assumptions used by the NIR to model this source (ECCC, 2025a), which are summarized below in Table B-17.

Table *B*-12. Assumptions used to estimate SCVF leak duration based on reporting scenarios.

Scenario	Assumption by Event Classification	
	Serious	Non-Serious
Report Date before Resolution Date	Starts 90 days before Report Date; ends at Resolution Date	Starts at Finished Drill Date; ends at Resolution Date or Abandonment or continues to present
Report Date equals Resolution Date	Starts 90 days before Report Date; ends at Resolution Date	Starts at Finished Drill Date; ends at Resolution Date or Abandonment or continues to present
Report Date after Resolution Date	Starts 90 days before Resolution Date	Starts at Finished Drill Date
No resolution reported	Ends 90 days after Report Date	Continues to present day

Table *B*-13. Number of wells with SCVF, GM, or both classification category.

Year	Non-Serious	Considered Non-Serious & <100 m3/day	Considered Non-Serious & >=100 m3/day	Serious	Total
2014	9,983	1,314	61	717	12,075
2015	10,308	1,365	61	643	12,377
2016	10,306	1,389	67	616	12,378
2017	10,526	1,399	67	596	12,588
2018	10,287	1,398	67	573	12,325
2019	10,247	1,421	67	581	12,316
2020	10,166	1,413	63	586	12,228
2021	10,162	1,408	61	629	12,260
2022	10,387	1,437	67	657	12,548

[27] https://www1.aer.ca/productcatalogue/365.html

Table B-14. Annual vent gas volumes, in cubic meters, from wells with SCVF, GM, or both by classification category.

Year	Non-Serious	Considered Non-Serious & <100 m3/day	Considered Non Serious & >=100 m3/day	Serious	Total
2014	17,528	17,726	5,922	6,181	32,314
2015	17,387	17,414	5,768	5,958	32,346
2016	16,989	16,989	5,680	5,564	31,452
2017	16,551	16,605	5,490	5,323	31,666
2018	16,068	16,503	5,343	5,009	28,194
2019	15,752	16,099	5,158	4,739	27,956
2020	15,434	15,744	4,964	4,529	27,044
2021	14,964	15,256	4,853	4,486	28,526
2022	14,316	14,752	4,549	4,200	27,679

3.8.2. Forecasted SCVF/GM Counts (2025)

Historical and forecasted total oil and gas wells were generated as described earlier in this document. A three-year average ratio of the number of leaking wells in Table B-13 to the number of total active wells was calculated for 2021 – 2024. This ratio was then multiplied by the forecasted number of wells in 2025 to forecast the number of leaking wells during that period.

3.8.3. SCVF/GM Emissions Quantification

Gas volumes for each SCVF/GM event were calculated by multiplying the reported leak rate by the leak duration. A methane content of 85% was assumed for all SCVF/GM events.

SCVF/GM emissions were estimated using the following equation:

$$Q_{SCVF/GM,y} = N_{SCVF/GM,y} * \frac{Q_{2022}}{N_{2022}} * (1 - RF) * 0.85 * \rho_{CH4}$$

Where:

- $Q_{SCVF/GM,y}$ = Methane emissions from SCVF/GM leaks in year y (t CH_4)
- $N_{SCVF/GM,y}$ = Number of wells with SCVF/GM leaks in year y
- RF = Reduction Factor for modelled policy
    - (D060 = 0)
- 0.85 = Assumed methane content for all SCVF/GM leaks
- ρ_{CH4} = Density of methane (0.6785 t/e3m3)

3.9. Spills and Ruptures

Pipeline release incidents are reported to the AER, who publishes the data on their Pipeline Performance webpage[28]. Reported released volumes were assigned a methane content according to the released substance (see Table B-15) and the volumes were converted to Mt CO_2e using density and GWP. The estimated methane emissions for each reported incident were summed to calculate total emissions for each modelled year.

To estimate spill and rupture emissions in 2025 – 2030, the average annual emissions from the years 2010 – 2024 was calculated and assigned to all future years.

Table B-15. Assumed methane contents used to estimate methane emission from spill and ruptures. Any substance not listed here was assumed to have a methane content of zero.

Substance Released	Methane Composition
Methane	1.00
Fuel Gas	0.92
Gas Production (Marketable)	0.92
Total Hydrocarbons (THC)	0.85
Gas Production (Raw)	0.85
Condensate	0.10
Crude Oil	0.05
Crude Bitumen	0.01

4. Document Control

The model outputs used in this report were generated using "1_Methane Model Summary_Sep_03_2025.xlsx".

[28] https://www.aer.ca/providing-information/data-and-reports/activity-and-data/field-surveillance-incident-inspection-list

Table B-16. Summary of the MWMM methodology, data sources, and assumptions.

Emissions Category	Data Sources	Other Assumptions
Pneumatics	• Facility and Well Counts (ICF International, 2015), (Petrinex) • Pneumatic counts ((Clearstone Engineering Ltd., 2019), (Johnson and Tyner, 2020)) • Pneumatic emission factors (Clearstone 2019, Johnson & Tyner, 2020) • Pneumatic offset data (AEOR)	• Pneumatic chemical injection pumps operate 6 months per year (October – March)
Routine Vent	• 2015 - 2019 routine vent volumes (Petrinex) • 2014 routine vent volume extrapolated. • 2020 – 2023 routine vent volumes (OneStop)	
Methane Slip – Flare	• 2015 - 2023 flare volumes (Petrinex) • 2014 flare volume extrapolated	• 98% flare destruction efficiency • 6% unlit flares (non-gas plants) • 0% unlit flares (gas plants)
Methane Slip – Fuel Combustion	• 2015 - 2023 fuel volumes (Petrinex) • 2014 fuel volume was extrapolated. • Fuel gas heating value (Johnson & Tyner, 2020) • Fuel gas usage ratios (Johnson & Tyner, 2020) • Engine, turbine, boiler emission factors (US EPA AP-42)	• Assume 70:30 split between lean burn and rich burn engines, from industry conversations.

Fugitives	• Facility and well counts (Petrinex)
	• Facility and well type fugitive emission factors (Johnson & Tyner, 2020)
		• LDAR fugitive reduction factors (ICF International, 2015)[29]:
		  ○ 40% (annual)
		  ○ 70% (tri-annual)

Compressor Seals	• 2020 – 2023 compressor counts (OneStop) • 2020 – 2023 compressor vent gas volume (OneStop) • Facility counts (Petrinex)	
Glycol Dehydrators	• 2008 - 2023 dehy counts (ST60b) • 2008 – 2023 dehy processed gas volumes (ST60b) • 2020 – 2023 dehy benzene emissions (ST60b) • Uncontrolled dehy emission factor (Clearstone 2018)	• Dehy methane emissions reductions are scaled to benzene emission reductions • 88% methane content assumed for all gas processed by glycol dehydrators
SCVF/GM	• SCVF/GM annual gas emissions (GoA, 2025)	
Spills and Ruptures	• Release volumes (AER)[30]	• Methane contents assumed for various reported substances

[29] Annual survey factor sourced from ICF (2015). Annual well screenings were assumed to result in negligible fugitive emissions reductions.
[30] https://www.aer.ca/providing-information/data-and-reports/activity-and-data/field-surveillance-incident-inspection-list

Table B-17. Directive 060 scenario pneumatic device vent state proportions.

Device Type	Facility Online Before/After Jan 1, 2022?	Vent State	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Instruments	Before	**% High - Total**	**100%**	**100%**	**100%**	**100%**	**93%**	**79%**	**62%**	**35%**	**14%**	**0%**	**0%**	**0%**
		% Low - Offset	0%	0%	0%	0%	6%	17%	27%	35%	42%	42%	42%	42%
		% Low - Requirement	0%	0%	0%	0%	0%	0%	3%	16%	24%	34%	30%	26%
		% Low - Total	**0%**	**0%**	**0%**	**0%**	**6%**	**17%**	**30%**	**51%**	**66%**	**76%**	**72%**	**68%**
		% Zero - End of Life Retirement	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	6%
		% Zero - Offset	0%	0%	0%	0%	1%	4%	8%	14%	20%	22%	24%	26%
		% Zero - Total	**0%**	**0%**	**0%**	**0%**	**1%**	**4%**	**8%**	**14%**	**20%**	**24%**	**28%**	**32%**
		Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Instruments	After	**% High**									**0%**	**0%**	**0%**	**0%**
		% Low									**0%**	**0%**	**0%**	**0%**
		% Zero - Requirement									100%	100%	100%	100%
Pumps	Before	**% Vent**	**100%**	**100%**	**100%**	**100%**	**99%**	**98%**	**95%**	**90%**	**85%**	**82%**	**78%**	**74%**
		% Zero - OVG Requirement	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%	2%
		% Zero - End of Life Retirement	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%
		% Zero - Offset	0%	0%	0%	0%	1%	2%	5%	10%	12%	14%	16%	18%
Pumps	After	**% Vent**									**5%**	**0%**	**0%**	**0%**
		% Zero - Requirement									95%	100%	100%	100%

Table B-15 Key Assumptions:

1. Pre-2023 offset vent states were determined from an analysis of the AEOR offset registry listing. Vent states were calibrated to align with offsets registered by year.
2. Reductions from low-to-zero instrument offsets, zero-vent pump retrofit offsets, and end of life device retirements are assumed to grow at 2% per year following the full implementation of D060 requirements in 2023.

Table B-18. Methane content, fuel gas heat value, and fuel gas destination by facility subtype used by the MWMM. Heating values and fuel gas destinations were sourced from Tyner and Johnson (2020) and the methane contents were produced by the Energy and Emissions Research Lab at Carleton University.

Facility Subtype	Facility Subtype Description	Methane Content	Fuel Gas HHV (MJ/m3	Fuel Gas Destination		
				Reciprocating Engines	Gas Turbines	Heaters or Boilers
311	CRUDE OIL SINGLE-WELL BATTERY	0.84	40.9	0.914	0	0.086
321	CRUDE OIL MULTIWELL GROUP BATTERY	0.84	39.9	0.914	0	0.086
322	CRUDE OIL MULTIWELL PRORATION BATTERY	0.83	41.3	0.914	0	0.086
331	CRUDE BITUMEN SINGLE-WELL BATTERY	0.97	37.2	0.498	0	0.502
341	CRUDE BITUMEN MULTIWELL GROUP BATTERY	0.95	37.1	0.498	0	0.502
342	CRUDE BITUMEN MULTIWELL PRORATION BATTERY	0.96	37.4	0.498	0	0.502
343	CRUDE BITUMEN/HEAVY OIL ADMINISTRATIVE GROUPING	0.96	36.9	0.498	0	0.502
344	IN-SITU OIL SANDS	0.97	37	0.007	0	0.993
345	SULPHUR REPORTING AT OIL SANDS	0.95	36.4	0.007	0	0.993
351	GAS SINGLE WELL BATTERY	0.84	41.8	0.792	0.044	0.164
361	GAS MULTIWELL GROUP BATTERY	0.86	40.9	0.792	0.044	0.164
362	GAS MULTIWELL EFFLUENT MEASUREMENT BATTERY	0.86	40.8	0.792	0.044	0.164
363	GAS MULTIWELL PRORATION SE ALBERTA BATTERY	0.95	38	0.792	0.044	0.164
364	GAS MULTIWELL PRORATION OUTSIDE SE ALBERTA BATTERY	0.89	38.4	0.792	0.044	0.164
365	GAS MULTIWELL GROUP BATTERY (ISSUED BY AER ONLY)	0.82	39.9	0.792	0.044	0.164
366	GAS MULTIWELL PRORATION SE AB BATTERY (ISSUED BY AER ONLY)	0.96	36.6	0.792	0.044	0.164
367	GAS MULTIWELL PRORATION OUTSIDE SE AB (ISSUED BY AER ONLY)	0.79	41.3	0.792	0.044	0.164
371	GAS TEST BATTERY	0.84	42.6	0.792	0.044	0.164
381	DRILLING AND COMPLETING	0.84	40.1	0.792	0.044	0.164
401	GAS PLANT SWEET	0.86	41.1	0.849	0	0.151
402	GAS PLANT ACID GAS FLARING < 1T/D SULPHUR	0.85	40.5	0.82	0	0.181
403	GAS PLANT ACID GAS FLARING > 1T/D SULPHUR	0.85	41.3	0.82	0	0.181
404	GAS PLANT ACID GAS INJECTION	0.85	38.5	0.961	0	0.039
405	GAS PLANT SULPHUR RECOVERY	0.83	41	0.156	0.102	0.743
406	GAS PLANT MAINLINE STRADDLE	0.91	39	0	0.926	0.074
407	GAS PLANT FRACTIONATION	0.78	40.4	0	0.392	0.608
501	ENHANCED RECOVERY SCHEME	0.84	40.9	0.914	0	0.086
502	CONCURRENT PRODUCTION/CYCLING SCHEME	0.81	43.6	0.914	0	0.086
503	DISPOSAL	0.92	39.1	0.914	0	0.086
504	ACID GAS DISPOSAL	0.80	40.4	0.914	0	0.086
505	UNDERGROUND GAS STORAGE	0.92	40	0.792	0.044	0.164
506	IN-SITU OIL SANDS	0.97	36.9	0.007	0	0.993
507	DISPOSAL (APPROVED AS PART OF A WASTE PLANT)	0.86	40.9	0.961	0	0.039
508	ENHANCED RECOVERY SCHEME (ISSUED BY AER ONLY)	0.74	39.9	0.914	0	0.086
509	DISPOSAL (ISSUED BY AER ONLY)	0.95	37.9	0.961	0	0.039
601	COMPRESSOR STATION	0.92	37.4	1.00	0.00	0.00
621	GAS GATHERING SYSTEM	0.86	40.7	0.792	0.044	0.164
902	WATER SOURCE BATTERY	0.93	40.3	0.007	0	0.993
903	BRINE PRODUCTION	0	37.4	0.914	0	0.86

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