Methane Mitigation Pathways

Part I: The Road to 45

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Executive Summary

- This report, "The Path to 45", is one of two reports focused on assessing Alberta's methane emissions journey. This report provides a historical review of emissions reductions achieved within Alberta's upstream oil and gas sector between 2014 and 2021. It includes a quantitative and qualitative assessment of the impact key factors like regulations, carbon markets, commodity pricing, and facility count, among others, have had Alberta's emissions profile.
- As of April 2023, the Government of Alberta indicates that the oil and gas sector has achieved a 44% methane emissions reduction from 2014 levels at year-end 2021 and that the industry is poised to meet or exceed the province's 2025 methane emissions reduction target of 45% below 2014 levels by 2025. This report analyzes how and from where those emission reductions were derived.
- Modern West Advisory (MWA) created an emissions estimation model that pulls publicly available data on methane emissions reported by the Government of Alberta between 2014 and 2021.
- The modeling suggests that in 2021, most reported emissions reductions from the 2014 baseline came from three source categories: routine venting (4.2 Mt CO_2e, 35%), pneumatic devices (4.1 Mt, 34%), and fugitive emissions (1.5 Mt, 13%).
- The largest remaining emission sources, as of 2021, are pneumatics (5.5 Mt), methane slip from engines (2.7 Mt), routine venting (2.8 Mt), and fugitive emissions (1.6 Mt).
- Approximately 6.7 Mt CO_2e (57%) of the total methane reductions can be associated with an overall decrease in Alberta's upstream oil and gas activities and the "business-as-usual" trends between 2014 and 2021. The remaining 5.1 Mt (43%) of the reductions are attributed to a combination of regulatory requirements and incentive programs targeting methane emissions reductions.
- The data used in the report is specific to Alberta's oil and gas sector, the largest oil and gas producer in Canada. Regional differences in reserves, asset classes, and regulations mean that the modelled reductions are specific to Alberta's industry. However, there are a number of key learnings from this report that can be applied to other provinces.
- Rising commodity prices that trigger a resumption of production at older, more methane-intensive facilities could pose a risk to Alberta achieving the 45% target by 2025. The overall risk level is considered low, as any increase is expected to be outpaced by methane reductions achieved due to more stringent regulations (pneumatics, compressor seals, surface casing vent flows, and glycol dehydrators) introduced in 2022.
- While the quality of methane data has improved dramatically in the past few years, there are still significant levels of uncertainty in modeled methane emissions. Increased measurement, monitoring, and reporting efforts could improve data quality and enhance the credibility of reported emissions reductions in the future.

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1. Report Objectives

Two reports are developed to inform a stakeholder working group session where participants will contemplate past and future methane emissions reduction activities in Alberta's upstream oil and gas industry. The first report, titled "The Path to 45", provides a historical review of emissions reductions achieved within the oil and gas sector between 2014 and 2021. The second report is titled "The Drive to 75" and focuses on pathways and barriers to achieving a 75% reduction in oil and gas methane emissions by 2030.

"The Path to 45" identifies the key factors that have influenced methane emissions reductions between the baseline year (2014) and the last full year for which data is available (2021). This work includes a quantitative and qualitative assessment of emission reductions achieved (measured or estimated) for the key emission source categories. It considers what impact policy, regulations, funding programs, commodity prices, and carbon markets have had on the emissions profile of the sector. The analysis is centered on oil and gas production in Alberta, given that it has the most comprehensive publicly available data set. Modeling was completed using the best publicly available data and assumptions via engagement with key informed stakeholders to ensure accuracy and relevance. The modeled reduction is presented with notable timelines to help qualitatively identify the key drivers of methane emission reductions in Alberta.

This report is guided by the following key questions:

- What portion of the measured and estimated methane emissions reductions (MER) results from regulations?
- How have government funding programs supported MER outcomes?
- Which source categories and technologies have had the most significant impact on the province's emissions reduction profile?
- What impact has the carbon market had on the oil and gas industry's emissions profile?
- What role does natural production decline play in achieving emissions reductions?
- What role do commodity price fluctuations play in the sector's emissions footprint?

2. Introduction and Background

In November 2015, the Government of Alberta (GoA) committed to reducing methane emissions from the upstream oil and gas (UOG) industry by 45 percent by 2025 from 2014 levels, making Alberta the first regional government in North America to commit to a methane emissions reduction target for the oil and gas sector. On April 6, 2023, the Government of Alberta publicly reported that oil and gas methane emissions have decreased by 44% between 2014 and 2021 and that the province is forecasted to meet and exceed their stated 2025 emission reduction target (Government of Alberta, 2023a).

A similar trend is found in other Western Canadian provinces. The Government of Saskatchewan reported that in 2021, oil and gas methane emissions declined by 60% from 2015 levels (Government of Saskatchewan, 2022). British Columbia did not specify current reductions from their baseline, but the latest reporting suggests that the sector is on track to meet the 45% reduction target by 2025 (British Columbia Energy Regulator (BC-ER), 2023). These two provinces have different production classes than each other[1], and as such employ methane regulations specific to their oil and gas sectors. Alberta has an extremely differentiated production, including natural gas, light crude and heavy oil. While this report focuses on reductions achieved in Alberta, some of the same regulatory and economic factors may have also contributed to reductions in other provinces.

Figure 1 below, published by the Government of Alberta, presents Alberta's current and forecasted progress in reducing methane emissions, showing the province is on track to meet and exceed the 2025 methane reduction commitment.

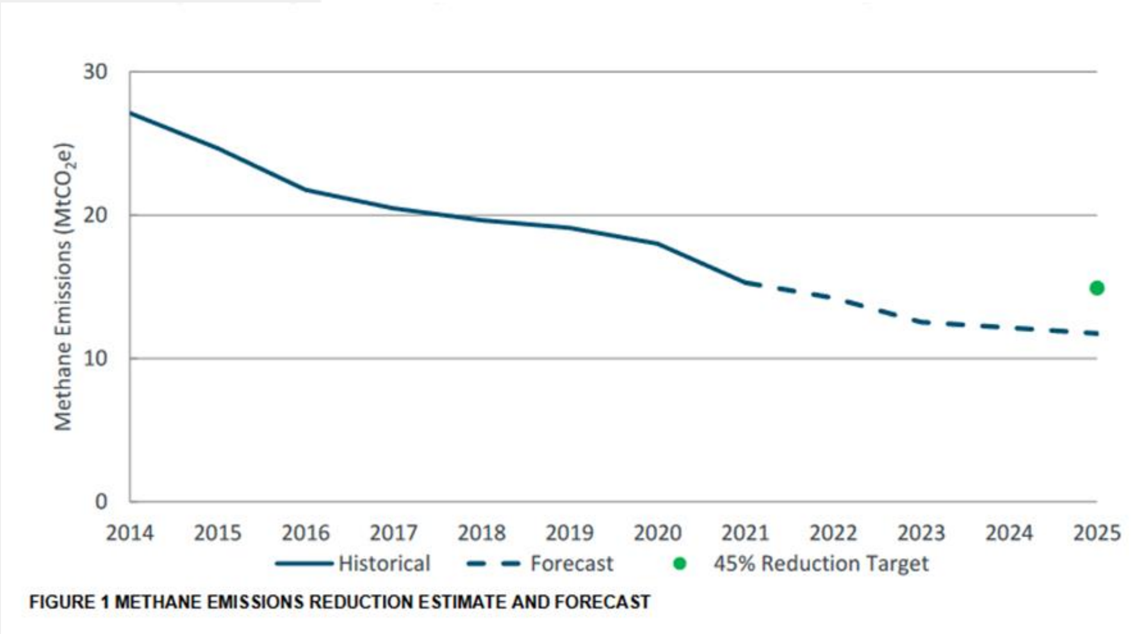


Figure 1. Alberta's Published Methane Emission Reductions and Forecasts (adapted from (Government of Alberta, 2023a))

This report provides clarity on how these emission reductions have been achieved in the province. The report also provides insights on the key factors that have driven the methane reductions in Alberta's upstream oil and gas sector.

[1] British Columbia mainly produces natural gas, Saskatchewan is mostly crude oil.

Based on the information presented in Figure 1, methane emissions from Alberta's UOG sector decreased from approximately 27.1 megatonnes[2] (Mt) of carbon dioxide equivalent (CO_2e) to approximately 15.3 Mt CO_2e at the end of 2021 (representing a 43.5% reduction). In other words, the Government of Alberta's modeling results show that methane emissions have decreased by 11.8 Mt CO_2e. Subsequent sections of this report provide a breakdown and analysis of these reported emissions reductions and identify the key factors contributing to the net decrease in methane emissions in Alberta.

2.1. Canada & Alberta Methane Emissions Reduction Targets

While this report is focused on Alberta's 2025 target and the provincial modeling results, it is important to understand and consider the interplay of the Federal Canadian policy on Alberta's requirements.

Alberta's methane emissions reduction regulations are specified by Alberta's Energy Regulator (AER) Directive 060 and the Methane Emission Reduction Regulation (MERR). This regulatory framework applies to Alberta's UOG sector, which the province defines as all facilities licensed or approved by the AER, including, but not limited to, well sites, oil and gas batteries, gas plants, compressor stations, pipelines, gas gathering systems, oil production sites, and other related facilities. This definition does not include bitumen mining and upgrading (Government of Alberta, 2023a).

On the other hand, in 2016, the Government of Canada committed to a national 40-45% methane emissions reduction below 2012 levels by 2025 from Canada's highest emitting sector, oil and gas. Unlike Alberta's target, which excludes methane emissions from bitumen mining and upgrading in the baseline, the federal target includes these sources. In other words, Canada's federal target takes into consideration the non-negligible methane emissions from bitumen mining and upgrading. Therefore, a 40 to 45 percent reduction in methane emissions from Canada's oil and gas sector represents an approximately 46 to 53 percent reduction for Alberta's upstream oil and gas sector[3]. An inspection of the GoA forecasted emissions in Figure 1 shows that the province predicts a 56% decline from the UOG sector by 2025.

A comparison between GoA and federal National Inventory Report (NIR) methane modeling is presented below in Figure 2. As discussed, the NIR model includes more sources than the GoA, and therefore reports more emissions in each year. However, both models suggest the province is on track to meet the 45% target. The NIR modeling shows that methane emissions were relatively flat prior to 2014, at which point both

[2] These volumes were extrapolated from Figure 1, by measuring the distance of the graph from x-axis.
[3] This was estimated utilizing the methane baseline reported in Canada Gazette II of the federal methane regulation and the 2012 mining and upgrading methane emission reported in the National Inventory report in 2018.

models show a linear declining trend through 2021[4]. Provincial modeling is not available for years prior to 2014.

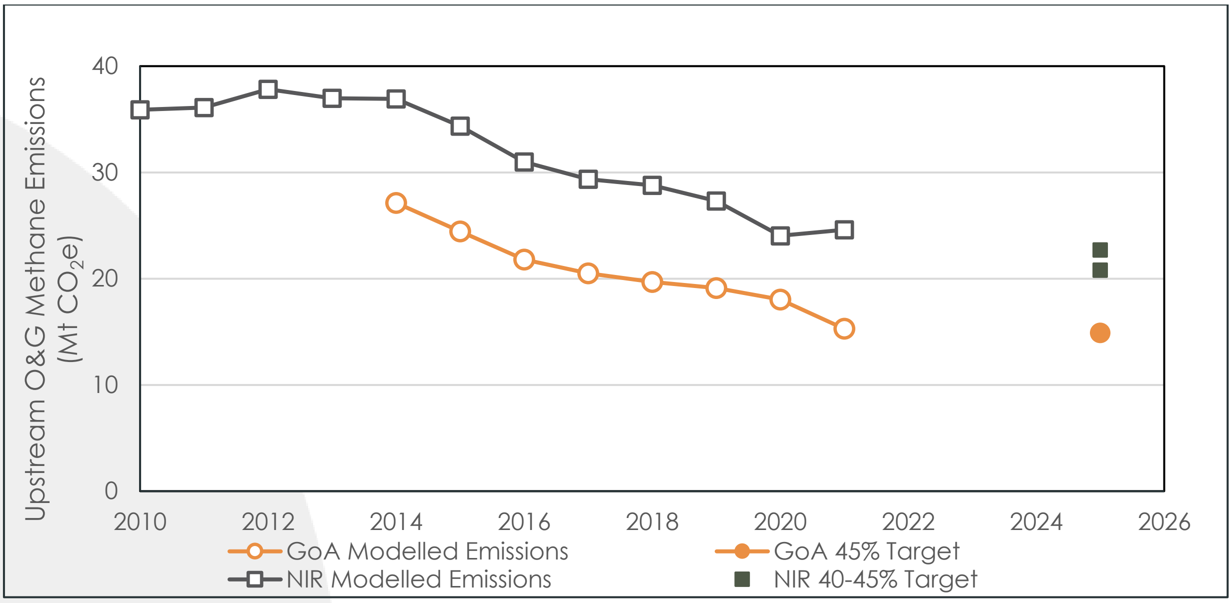


Figure 2. Government of Alberta and ECCC National Inventory Report modeled methane emissions for the upstream oil and gas sector in Alberta.

2.2. Alberta's Methane Reduction Policy Framework

Alberta uses a variety of regulatory and market-based tools, programs, and guidelines to control and promote methane emission reductions from the oil and gas industry. The effectiveness of Alberta's efforts to reduce methane emissions depends on how well these tools, programs, and guidelines function together to achieve comprehensive and substantial emission reductions.

2.2.1. Regulations and Directives

To ensure that Alberta's methane reduction commitment is met, the Alberta Energy Regulator (AER), in cooperation with the Government of Alberta, amended Directives 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting and 017: Measurement Requirements for Oil and Gas Operations in December 2018 (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 the upstream oil and gas industry. To support a better understanding of oil and gas methane emissions and tracking the emissions more effectively, the directives also include modifications to the measurement, monitoring, and reporting of methane emissions (Alberta Energy

[4] The two models have a different trendline in 2020. Without in-depth access to the methodologies, we can only speculate as to why. One potential reason is a difference in spill and rupture emission reporting. See section 3.1.8 for more details.

Regulator, 2022a, 2022b). Figure 3 shows a visualization of the AER's methane regulatory framework.

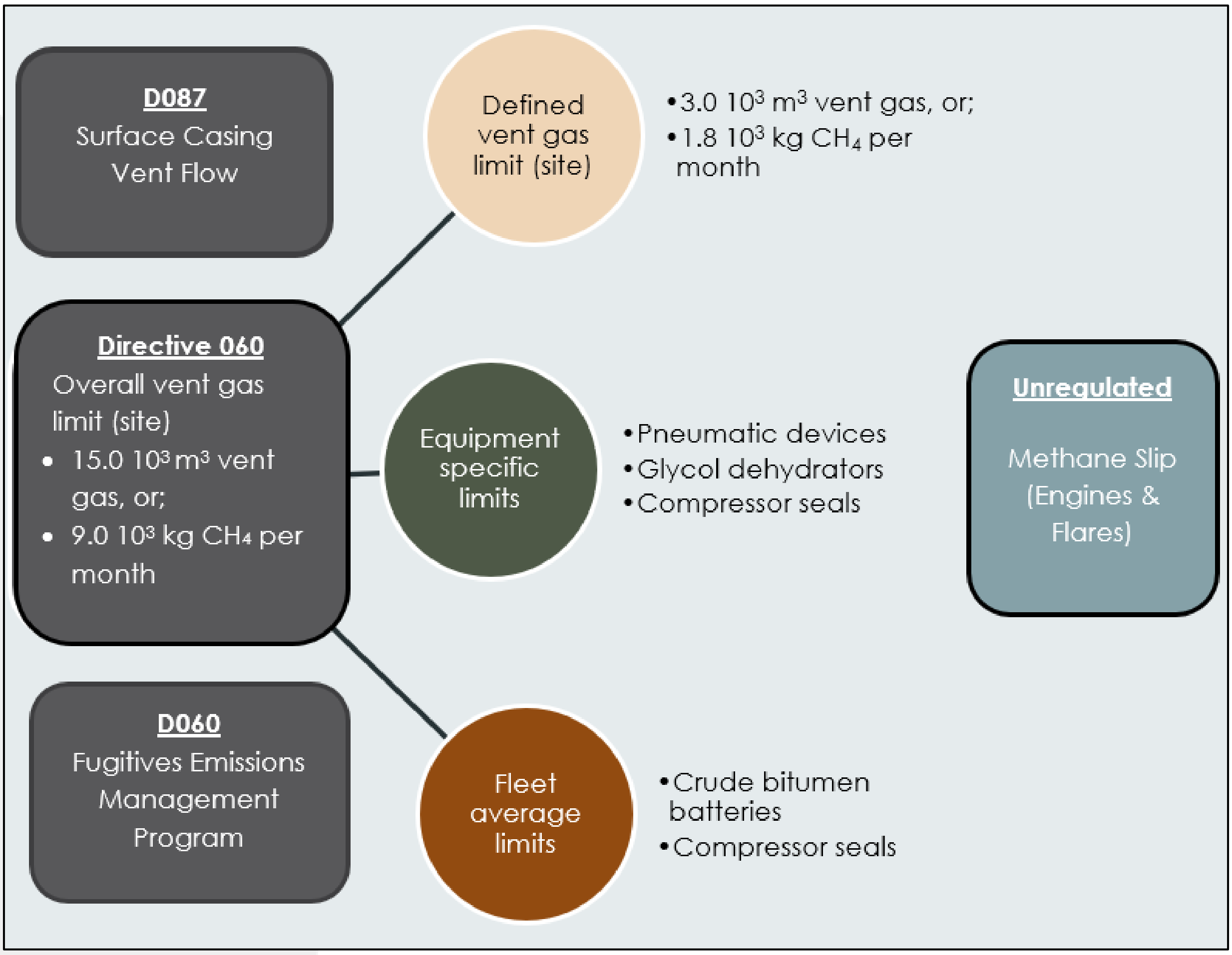


Figure 3. Visualization of the regulated methane emission sources in the Alberta upstream oil and gas sector. Note that the size of the bubbles does not represent the size of emissions.

An equivalency agreement was signed between Alberta and the Government of Canada in 2020 (Environment and Climate Change Canada, 2020), which deemed Alberta's regulatory framework to achieve equivalent emission reductio ns to the Canadian federal regulations (Government of Canada, 2023). D060 contains more stringent requirements for some pneumatic nstruments and glycol dehydrators but is less stringent on routine venting and leak detection frequencies. Ultimately, cumulative methane reductions achieved between the two regulatory frameworks differ by 0.6% (according to federal modeling), and the regulations are deemed equivalent (Environment and Climate Change Canada, 2020).

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, 2018a). The Directive limits gas venting to address the odour issue, nearly eliminating methane emissions from the region (Alberta Energy Regulator, 2020a). The investments required for gas conservation infrastructure in this area were largely supported by asset configuration in the area (i.e., tight spacing and co-located facilities). These factors vary widely in other areas of the province.

As a complement to the regulation and directives, Alberta continues to regulate methane emissions at larger oil and gas facilities through the Technology Innovation and Emissions Reduction (TIER) Regulation (Government of Alberta, 2023b), invest in programs targeting methane emissions detection, quantification & control, and establish market-based tools to incent early action and reward projects that drive methane emissions reductions beyond regulatory requirements. These policies and partnerships between government, industry, and associations have helped lower the cost of Alberta's regulatory requirements, advance innovative technology solutions, and achieve greater (more timely and deeper) methane emissions reductions.

2.2.2. Funding & Support Programs

Enabling technology, innovation, and scientific research is part of Alberta's approach to methane emissions management and reductions, as is improving the quantity and quality of data related notably to fugitive leaks and vents. Research and development have been key to developing the technologies to economically reduce methane emissions on a scale required to achieve Alberta's methane reduction target. Consequently, over the past several years, the Government of Alberta has invested funds to support the development and adoption of new technologies and techniques to support further methane emission reductions and data collection. These efforts are reflected through numerous initiatives the government has funded or diverted TIER funds towards, designed and/or delivered by Emissions Reduction Alberta, Alberta Innovates, Petroleum Technology Alliance Canada, the Methane Emissions Leadership Alliance, Sundre Petroleum Operators Group, Carbon Connect International, and others.

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

- Methane Technology Implementation Program - $25M
- Baseline and Reduction Opportunity Assessment Program (BROA) - $15M
- Alberta Methane Emissions Program (AMEP) - $17M
- Canadian Emissions Reduction Innovation Network (CERIN) - $17M[5]
- NRCan Emissions Reduction Fund (ERF) - $750M[6]
- PTAC Methane Consortium Program (various programs)
- Emissions Reductions Alberta (various projects)
- Alberta Innovates (various investments)

A more detailed description of the technology support program landscape in Alberta is presented in Appendix B of this report.

[5] CERIN is jointly funded by NRCan ($11.15M) and Alberta Innovates ($6.26M)
[6] $143M was awarded during the first two intakes. Intake 3 closed in 2022.

2.2.3. Timeline of Events

Figure 4, below, displays a timeline of the major methane policies and programs overlaid on top of the methane emissions profile reported by the Government of Alberta. This graphic allows for some assumptions about correlation, however, the remaining analysis in this report filters through the available data to develop assertions and conclusions.

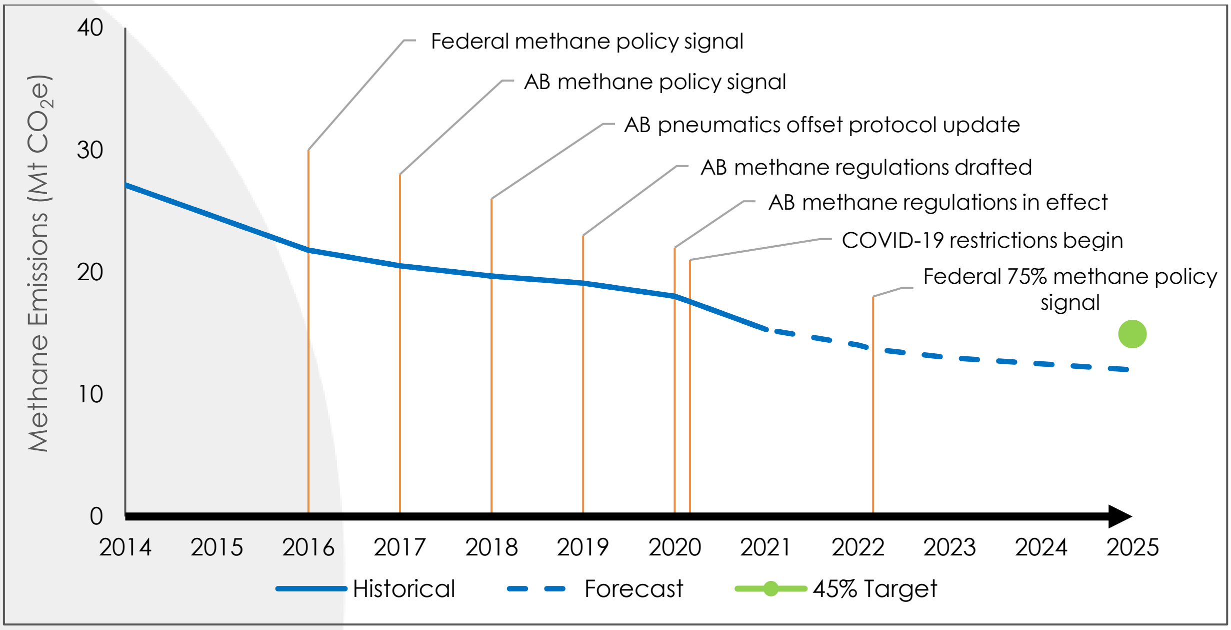


Figure 4. Timeline of AB UOG methane emissions with various policies, regulations, and incentive programs. Adapted from *(Government of Alberta, 2023a*

3. Analysis and Results

To answer the key questions about methane emissions in Alberta, Modern West Advisory created a bottom-up model called the Modern West Methane Model I[7] (MWMM). This model attempts to follow the GoA methodology to break down the reported methane emissions into eight sources: Pneumatic Devices, Compressors, Dehydrators, Fugitives, Routine Vent, Methane Slip, Surface Casing Vent Flows & Gas Migration, and Spills & Ruptures. The MWMM is based solely on publicly available data and simulates two scenarios:

- 2014 Business-as-Usual (BAU) Scenario: This scenario models the amount of methane emissions in the province in the absence of any methane mitigation activities, either regulatory or incentivized. Essentially, the BAU scenario shows how methane emissions would have trended in Alberta without the current methane framework described in Section 2. Any changes in emissions under this scenario are solely responses to economic conditions.

[7] A description of the MWMM methodology can be found in Appendix A, which highlights the methodology and assumption used to quantify methane emissions in the province of Alberta.

- Methane Mitigation Scenario (MMS): This scenario models the actual methane emissions in the province, where emission reductions are achieved because of methane mitigation activities in the oil and gas sector driven by the methane regulations, as well as the cumulative impacts of changes in upstream oil and gas activities in the province due to economic pressures.

By simulating these two scenarios, the MWMM model provides a comprehensive picture of Alberta's methane profile from 2014 to 2021. At the time of writing this report, the latest publicly available OneStop data is for the year 2021. The 2022 methane emissions are required to be submitted to OneStop in June 2023 and will be reviewed by the AER before becoming publicly available. The MWMM can be updated at that time. MWMM methodology and assumptions are explained in Appendix A of this report.

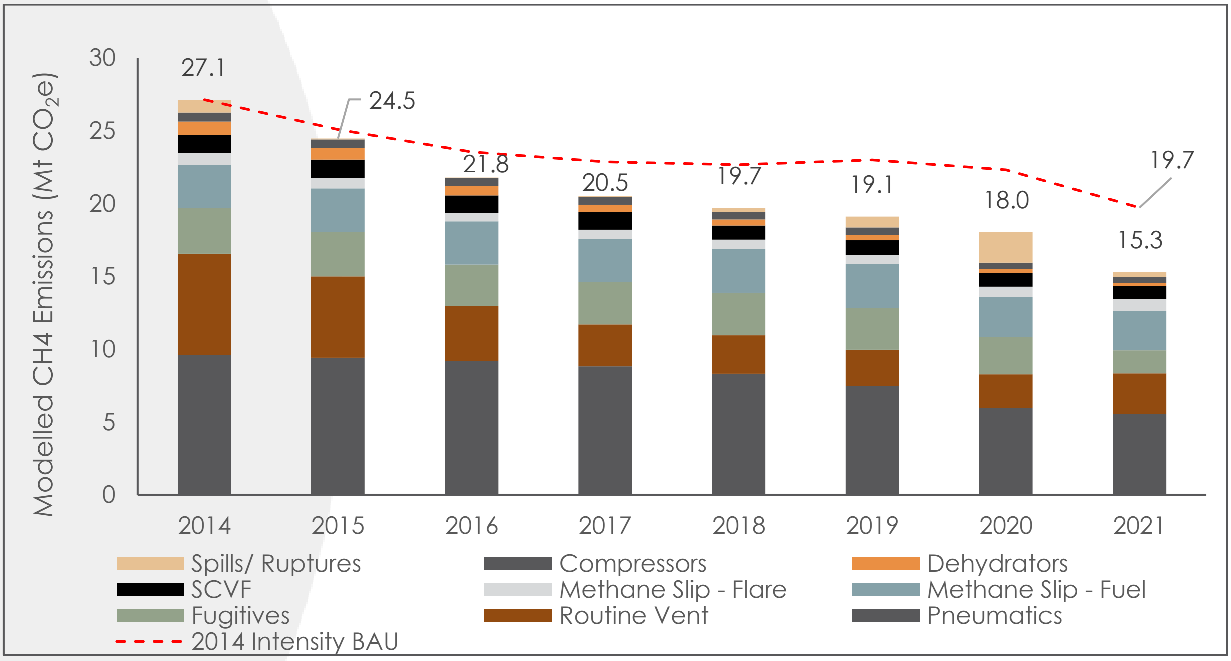
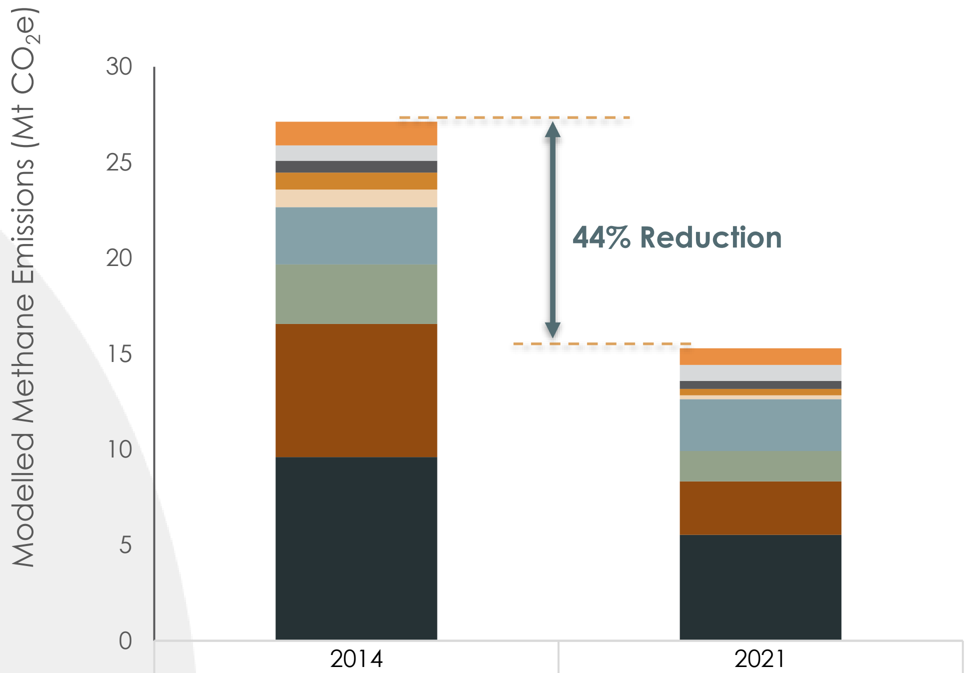


Figure 5. Annual Historical Emissions from 2014 to 2021 using the MWMM to model the Methane Mitigation Scenario. The Business-as-Usual scenario (red-dashed line) is included for comparison purposes.

Figure 5 shows the modeled UOG methane emissions under the current methane reduction framework. For the Methane Mitigation Scenario, MWMM results provide the emission source breakdown for the total methane emissions reported by the GoA presented in Figure 1.

Under the BAU scenario, methane emissions in 2021 are 19.7 Mt. This means that without the regulatory framework in place, a 27% (7.4 Mt) methane emissions reduction from 2014 levels would have been achieved[8]. This modeled decline is mainly attributable to an associated decline in production across the sector observed between 2014 and 2021. An analysis of production levels is provided in Section 4.2 of this report.

[8] The BAU scenario includes 0.7 Mt CO_2e of emissions reductions due to glycol dehydrator regulations. This is discussed in more detail in Section 3.2.3



	2014	2021
SCVF	1.2	0.9
Methane Slip - Flare	0.8	0.8
Compressors	0.6	0.4
Spills/ Ruptures	0.9	0.3
Dehydrators	0.9	0.2
Methane Slip - Fuel	3.0	2.7
Fugitives	3.1	1.6
Routine Vent	7.0	2.8
Pneumatics	9.6	5.5
Total	27.1	15.3

Figure 6. 2014 versus 2021 modeled methane emissions by source category. The data table shows modeled source emissions in Mt CO_2e for each year.

Figure 6 above compares the 2014 baseline year emissions to the latest full year of modeled methane emissions in 2021. The associated data table shows the methane emissions by source category. According to the results, major sources of reductions are Routine Vent (4.2 Mt), Pneumatics (4.1 Mt), and Fugitives (1.5 Mt).

Figure 7 shows the contribution of each source category to the total methane reductions between 2014 and 2021.

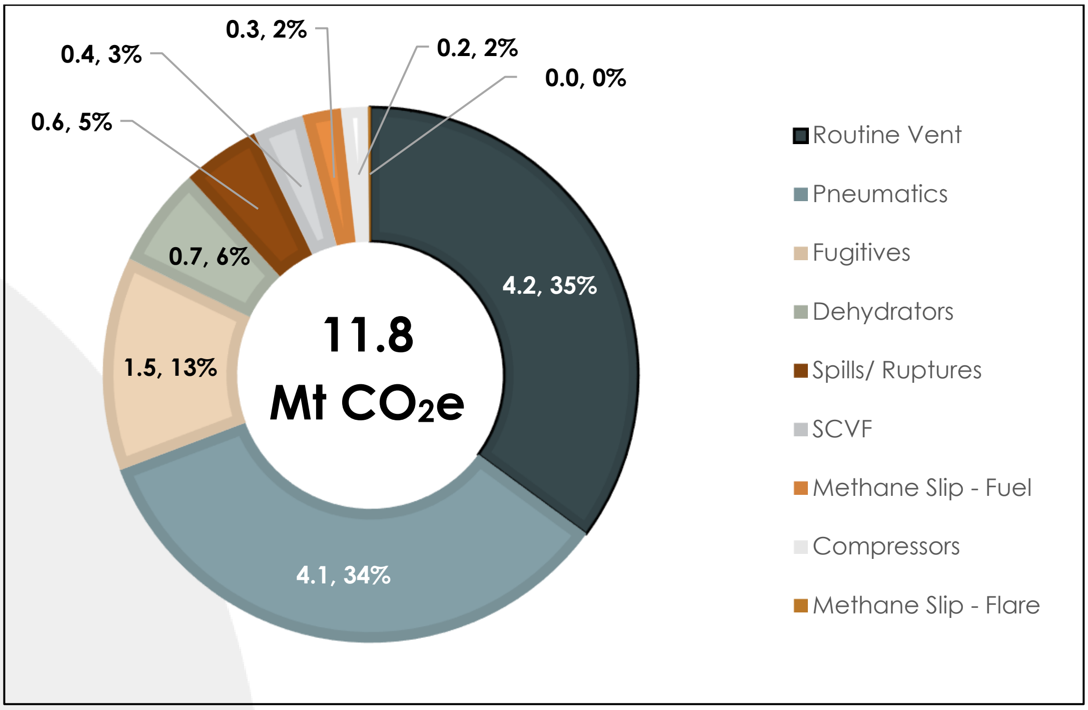


Figure 7. Modeled methane emissions reductions between 2014 and 2021 broken down by source categories (values are presented in Mt CO_2e and as a percentage of the overall reduction)

3.1. Results by Source Category

In the following subsections, the MWMM modeled emission source categories are explored in more detail to better understand how the emissions reductions were achieved.

3.1.1. Pneumatic Devices

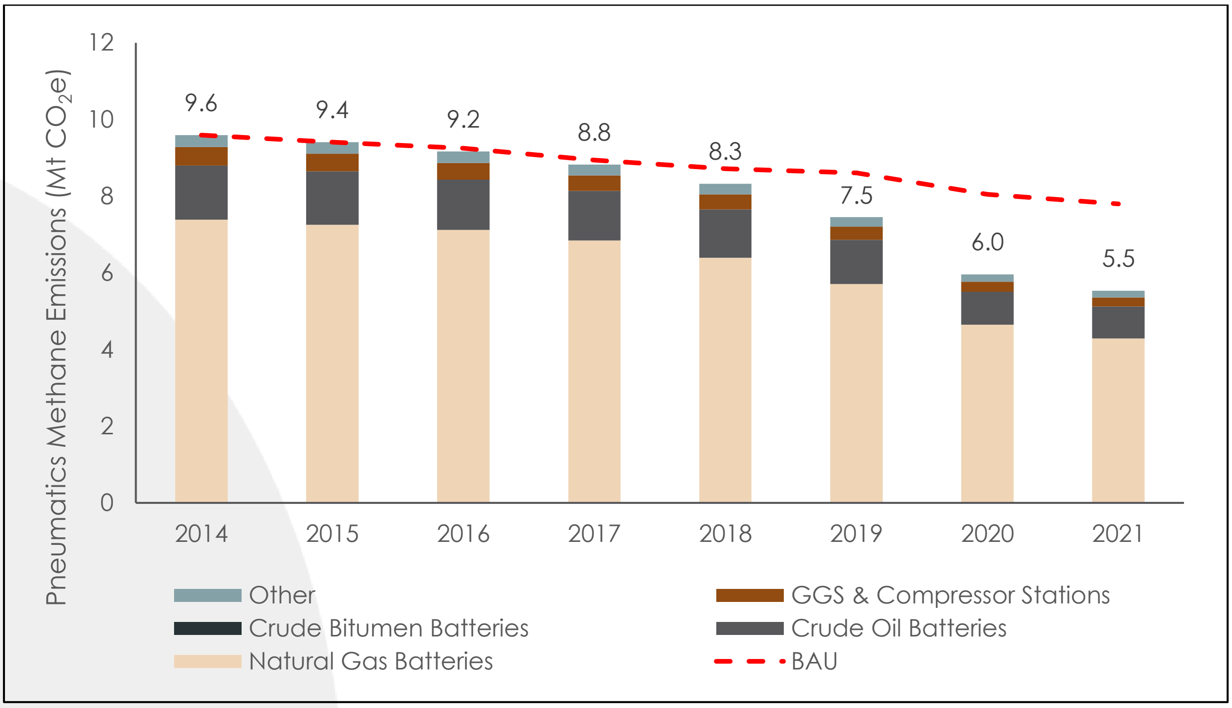


Figure 8. Modeled emissions from pneumatic devices between 2014 and 2021.

Pneumatic devices (pumps and controllers) are powered by pressurized gas (natural gas or compressed air). Modeled emissions from venting pneumatic devices decreased from 9.6 Mt CO_2e in 2014 (35% of the 2014 total) to 5.5 Mt CO_2e in 2021 (36% of the 2021 total). Approximately 44% of the total 4.1 Mt decrease in pneumatic device methane emissions (1.8 Mt) can be attributed to "Business-as-Usual" activities.

The remaining 2.3 Mt of pneumatic emissions reductions shown in Figure 8 are derived from verified carbon offset credits, serialized on the Alberta Emissions Offset Registry[9] under the *Greenhouse Gas Emissions Reductions from Pneumatic Devices* protocol (Government of Alberta, 2022). The offset program drove early action in reducing emissions from this source, with significant cuts to BAU emissions occurring in 2019-2021. Cumulatively, 6.1 Mt of offset emissions have been serialized between 2014 and 2021, with 2.3 Mt or reductions occurring in 2021. We expect an even greater number of pneumatic offset credits to be serialized for the 2022 vintage year, which is discussed in more detail in Section 4.1.

Several other programs funded pneumatic conversions between 2014 and 2021 (ERA, Alberta Innovates, MTIP). In some cases, device conversions completed using the funds from these programs were eligible to generate offset credits as well. Therefore, these funding sources are not included in the model to avoid double counting.

Some funding programs, such as MTIP, covered other methane source categories, including routine venting, in addition to pneumatics. Insufficient public data is available

[9] https://alberta.csaregistries.ca/GHGR_Listing/AEOR_Listing.aspx

from this program to clearly quantify funded emission reductions by source category for the MWMM model[10]. Should MTIP data become publicly available, the information can be used to update this model.

Directive 060 vent limit requirements for pneumatic devices came into effect on January 1st, 2022. Effective January 1st, 2022, Directive 060 requires newly installed pneumatic devices to be zero-vent, while vent gas from existing devices (installed before January 1st, 2022) must not exceed a vent rate of 0.17 m^3/hour[11] starting January 1st, 2023 (Alberta Energy Regulator, 2022a). These regulations, combined with offset projects, are expected to deliver significant reductions in pneumatic device emissions through 2025.

3.1.2. Compressor Seals

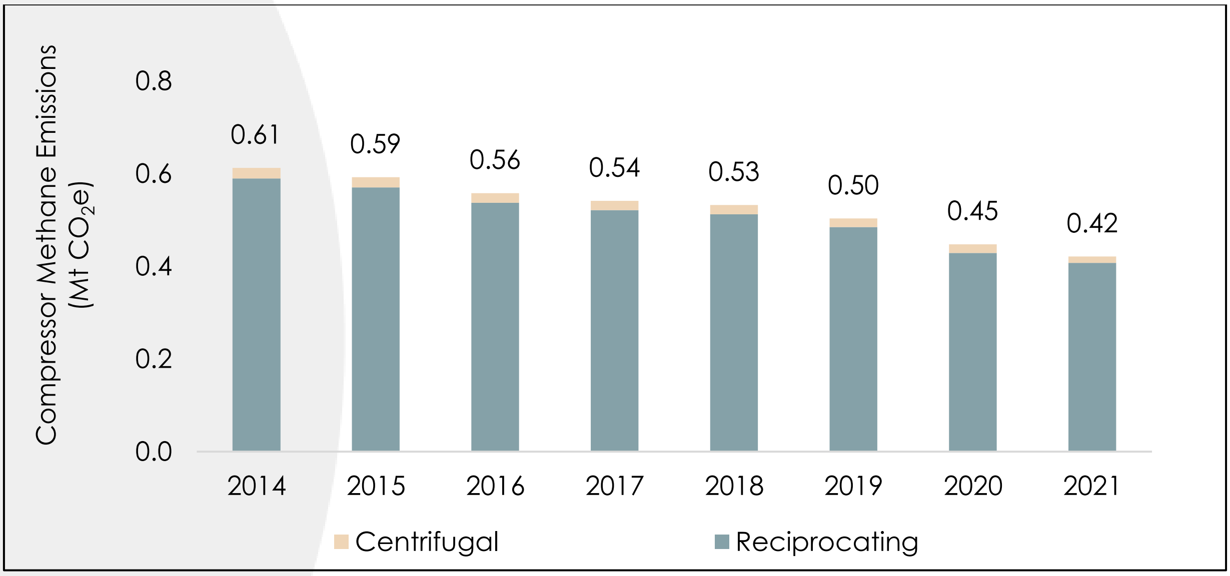


Figure 9. Modeled methane emissions from compressor seals between 2014 and 2021

Compressor seals are designed to reduce vent gas leakage, but leak rates will rise as the seals wear over time. Gas compressors are commonly located at gas batteries, gas plants, gas gathering systems, and compressor stations.

Modeled UOG compressor seal emissions decreased from 0.61 Mt in 2014 to 0.42 Mt in 2021 (~3% of the 2021 total), as shown in Figure 9. The 0.19 Mt of modeled emission reductions can be attributed to a decrease in the number of compressors in the oil and gas sector from 2014 to 2021. As the number of active facilities with compressors decreased from 2014 to 2021, so did compressor emissions.

[10] The lack of clear publicly available data of program funded methane emission reductions makes it difficult to include the data into total emission reductions, due to the risk of double counting. Some emission source categories, such as venting were determined from reported figures which would include relevant impacts from funding programs.
[11] Some conditions apply to level controllers.

Directive 060 requires frequent compressor seal testing starting in 2020, which means compressor seal vent reporting did not begin until 2021 (for the 2020 calendar year). Further, vent gas limits for compressor fleets did not come into effect until January 1, 2022. As a result, no publicly reported data is available to model the compressor seal vent reduction accurately. In this report, the general assumption is that no reductions took place prior to the regulatory limit in 2022, and therefore, the MWMM generates identical BAU and MMS scenarios for this source category.

3.1.3. Glycol Dehydrators

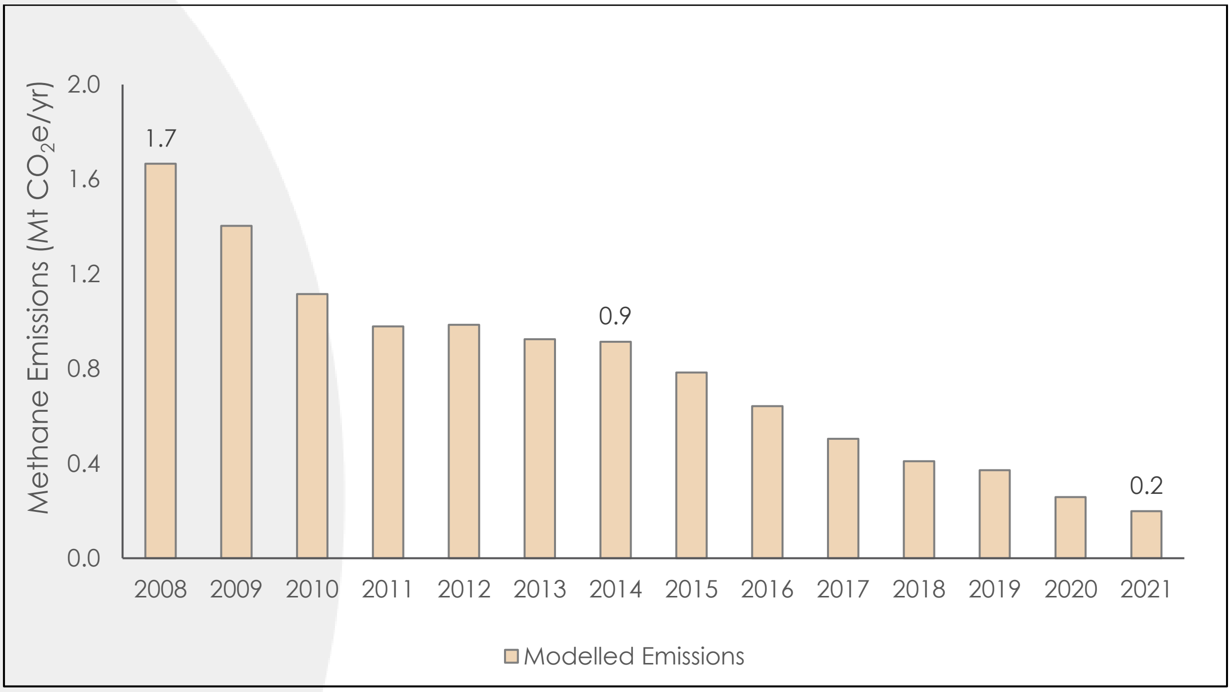


Figure 10. Methane emissions from glycol dehydrators, between 2008 and 2021.

Glycol dehydrators produce methane emissions from the still column that vents gas during the glycol regeneration phase[12] (US Environmental Protection Agency (EPA), 2011). Figure 10 shows that methane emissions from glycol dehydrators have been in decline since 2008, and in 2021 there were 0.2 Mt (1.3% of total) modeled emissions from this source.

The reductions can be attributed to the requirements set out in the AER's *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators* (Alberta Energy Regulator, 2018b). Directive 039 (D039) was first published in 2007 and came into effect in 2008 to curtail benzene emissions from dehydrator units. Benzene control technologies listed in D039 include flares, incinerators, vapour recovery units, and reciprocating engine emission control equipment. These technologies all have the added benefit of reducing methane emissions from dehydrators.

[12] Emissions from pneumatic devices associated with dehydrators are excluded from this source category and are instead included in the overall Pneumatics section.

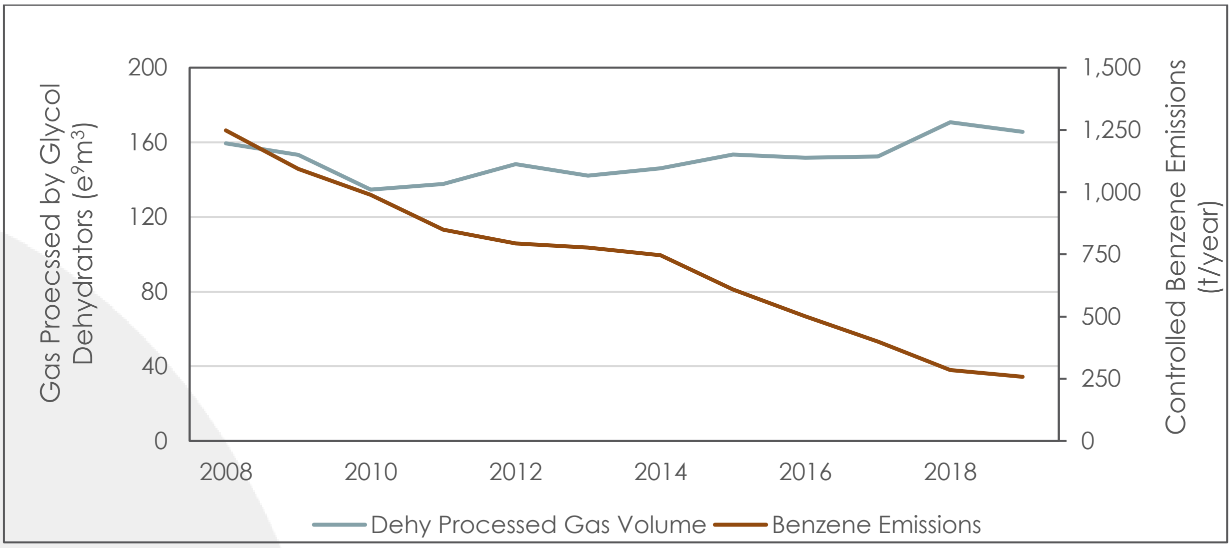


Figure 11. Comparison of volume of gas processed by glycol dehydrators and the amount of benzene emissions after engineering controls in Alberta *(Alberta Energy Regulator, 2020b)*

Figure 11 above shows a comparison between the volume of natural gas processed by glycol dehydrators and their associated benzene emissions between 2008 and 2019[13] (Alberta Energy Regulator, 2020b). The figure shows that the volume of gas processed through dehydrators increased over that span; without emission controls, we would expect benzene (and methane) to increase in lockstep with processed gas volumes. However, reported benzene emissions decreased by almost 80% instead. The MWMM estimates methane emissions for this source using an emission factor derived from Clearstone Engineering (Clearstone Engineering Ltd., 2019) and assuming that methane is reduced at the same rate as benzene, year over year.

Directive 060 requirements for glycol dehydrator emissions came into effect on January 1st, 2022, meaning that no reductions specific to D060 can be modeled yet[14]. The MWMM generates just one scenario for this source. We ascribe the modeled reductions for glycol dehydrators to D039 compliance activities. We acknowledge that some methane reductions could have occurred due to the economic incentive of gas conservation, but there is no public data to quantify this.

[13] This data was published by the AER in ST60b-2020. Data was not published for 2020 or 2021 in subsequent editions of ST60b.
[14] In 2021, the average glycol dehydrator emitted 18 kg of methane per day, well below the 2022 D060 requirement of 109 kg per day for old unit or 68 kg per day for new units.

3.1.4. Fugitive Emissions

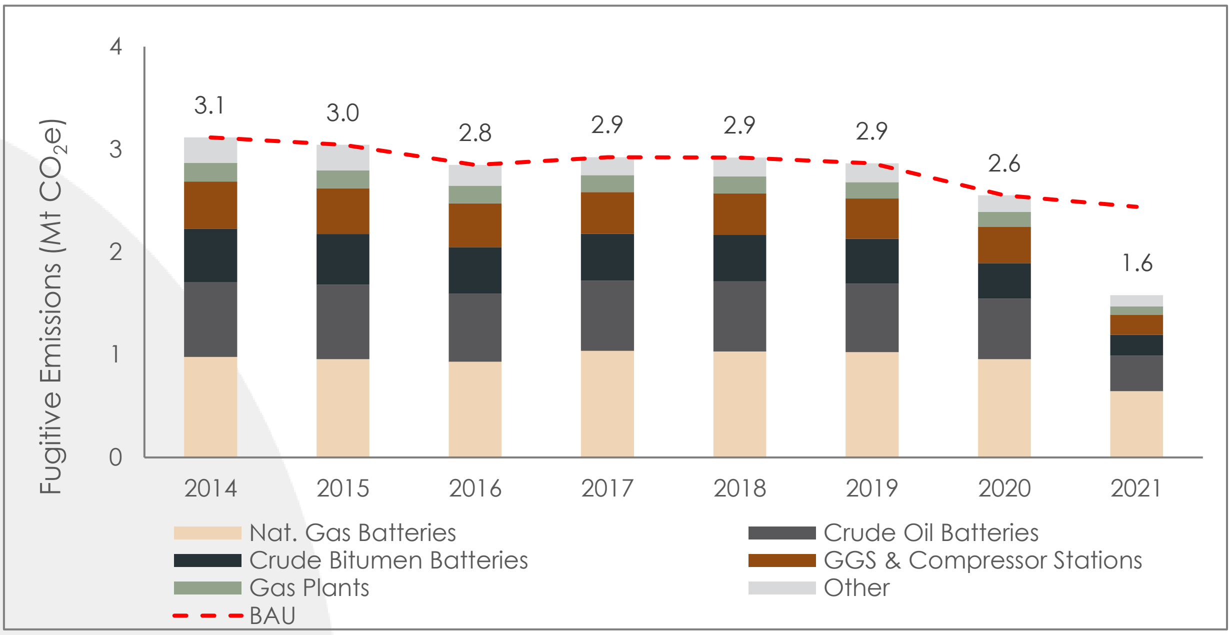


Figure 12. Modeled methane emissions from fugitives in Alberta, from 2014 to 2021.

Fugitive emissions are the unintentional releases of gas to 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 repaired. Fugitive emissions are modeled using the Clearstone study (Clearstone Engineering Ltd., 2019), which reported survey results for emission factors, component, and equipment counts by facility and well type.

Figure 12 shows that fugitive emissions decreased from 3.1 Mt (11% of the total) in 2014 to 1.6 Mt (10% of the total) in 2021. The large difference observed between MMS and BAU emissions in 2021 is likely due to the onset of fugitive leak detection and repair (LDAR) requirements[15].

There are significant levels of uncertainty surrounding the fugitive emission factors used in a bottom-up model methodology. Measurement uncertainties are explored in more detail in Section 5 of this report.

[15] LDAR survey requirements first came into effect on January 1, 2020, but were eased due to the COVID-19 pandemic. Therefore, methane mitigation activities for fugitives are first modelled in 2021.

3.1.5. Routine/Direct Venting

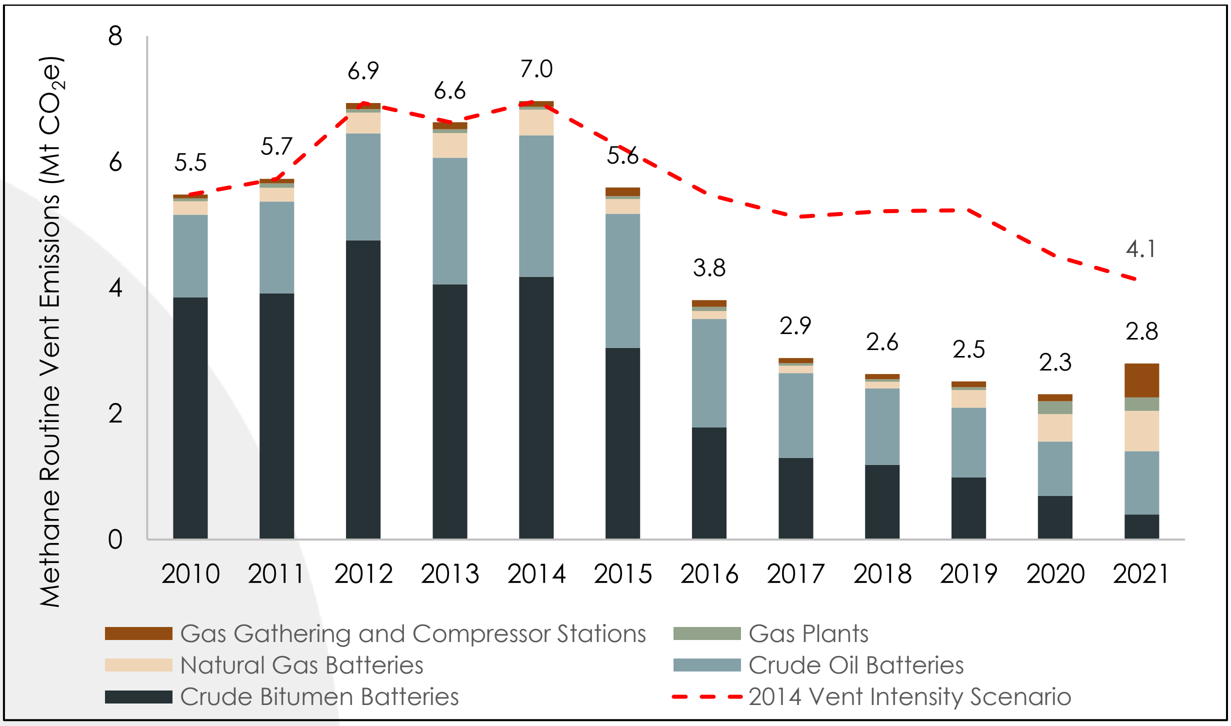


Figure 13. Modeled methane emissions from routine venting between 2014 and 2021

Routine venting covers several emission sources, most notably associated gas venting, tank vents, and purge vents (Alberta Energy Regulator, 2020c). As shown in Figure 13, routine venting peaked in 2014, with 7.0 Mt modeled methane emissions (26% of the total). After 2014, routine venting emissions declined rapidly to 2.8 Mt in 2021 in MMS (18% of the total). Routine venting represents the third largest emission source category in 2021.

In the BAU scenario, routine venting emissions decreased from 7.0 Mt in 2014 to 4.1 Mt in 2021. The 2.9 Mt reduction modeled under the BAU scenario can be attributed to a decline in the number of active facilities in the sector[16]. The additional 1.3 Mt reductions under MMS (compared to BAU), is likely due to solution gas conservation activities at crude bitumen and oil batteries. Previously published versions of Directive 060, starting in 2007, included requirements for solution gas conservation at crude oil and bitumen batteries (Alberta Energy Regulator, 2023). Increased compliance obligations under these requirements can explain these additional routine venting reductions.

[16] This decline is shown later in Section 4.2 of this report.

3.1.6. Methane Slip

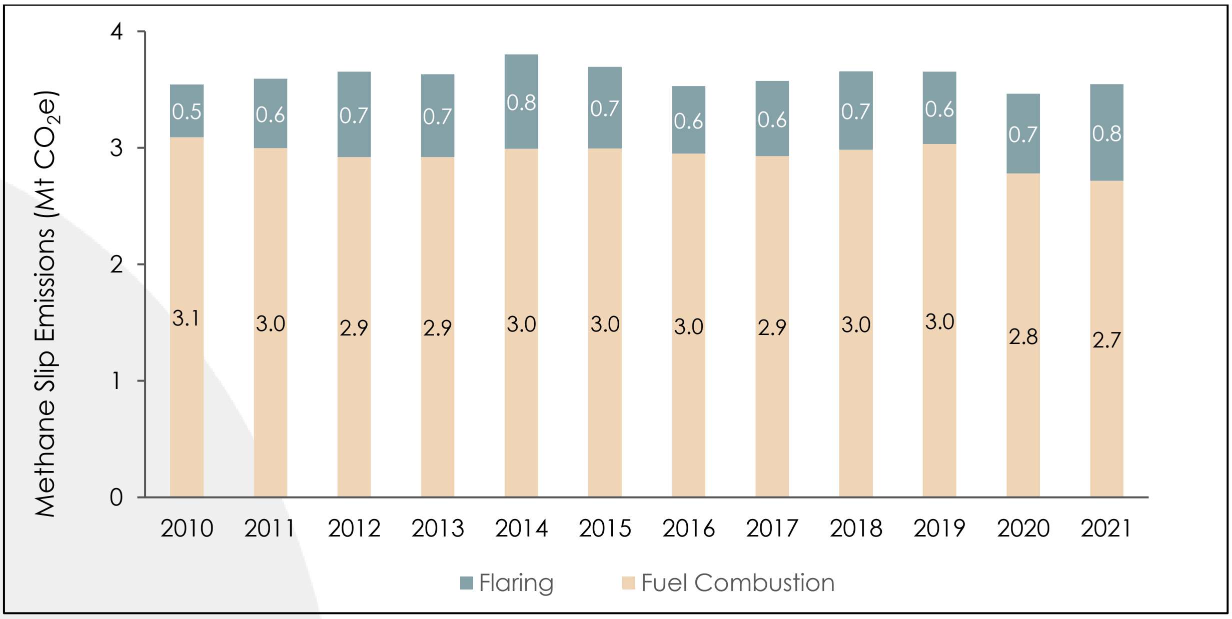


Figure 14. Modeled methane emissions methane slip between 2014 and 2021. Note that there is no difference between the BAU and MMS scenario for this source.

Methane slip is the result of the incomplete combustion of methane. Methane slip is not a regulated emission source under Directive 060, and as such, there are no modeled emission reductions for this source from 2014 to 2021. The small fluctuations seen above in Figure 14 are due to changes in reported flare and fuel consumption volumes.

Flare volumes increased from 2019 to 2021 as operators installed flare tie-ins at sites that previously vented to the atmosphere.

The 3.5 Mt of combined emissions from methane slip represents a significant portion of total methane emissions in 2021 (~23%), making it the second largest source category in that year, after pneumatics.

3.1.7. Surface Case Vent Flow and Gas Migration

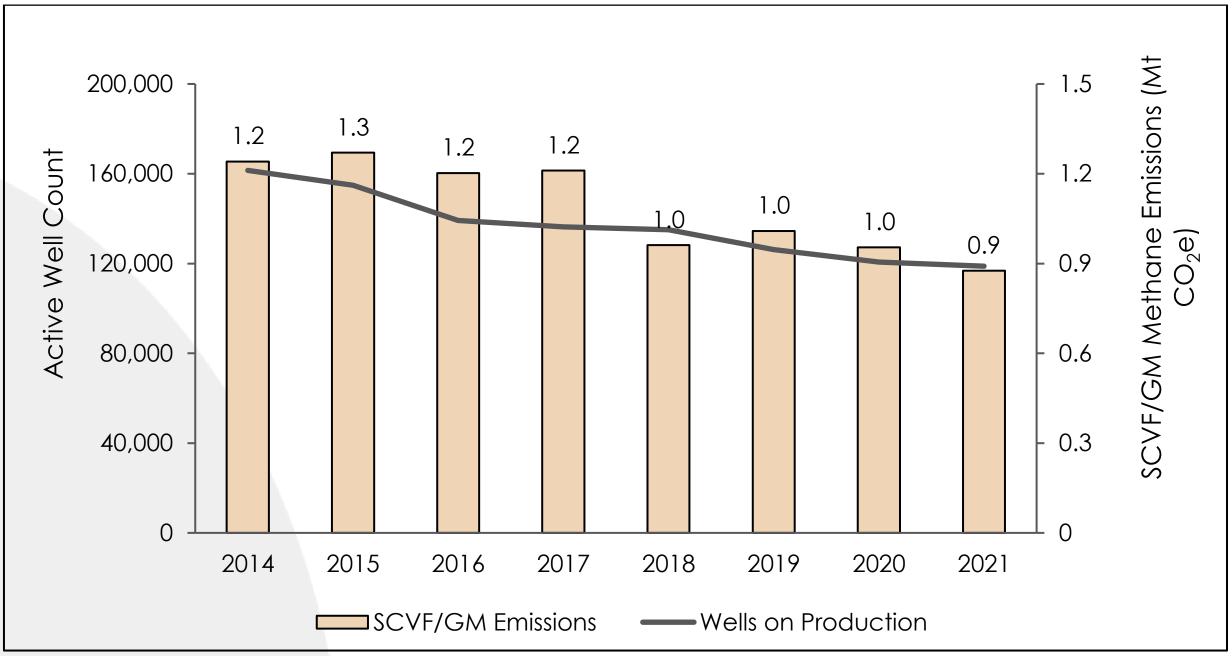


Figure 15. Modeled methane emissions from surface casing vent flow (SCVF) and gas migration (GM) between 2014 and 2021. Line graph illustrates the number of active oil and gas wells in the province (note that there is no difference between the BAU and MMS scenarios)

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. The Government of Alberta reports SCVF and GM volumes each year. These volumes are converted to a mass of methane shown in Figure 15 above. There is only one scenario modeled for SCVF and GM emissions in the MWMM. SCVF and GM emissions decreased from 1.2 to 0.9 Mt between 2014 and 2021. The 0.3 Mt of modeled emissions reductions is likely due to a decline in the number of active wells in the province.

Directive 060 introduced fugitive emissions surveys for surface casing vent flow (SCVF) and Gas Migration (GM) at active sites starting in 2021[17]. Directive 087: Well Integrity Management (Alberta Energy Regulator, 2022c), which complements survey requirements in D060, was released by the AER in 2021. These two regulations are expected to drive emissions reductions for this source in 2022 and beyond.

[17] Requirements first started in 2020 but were waived due to the COVID-19 pandemic.

3.1.8. Spills and Ruptures

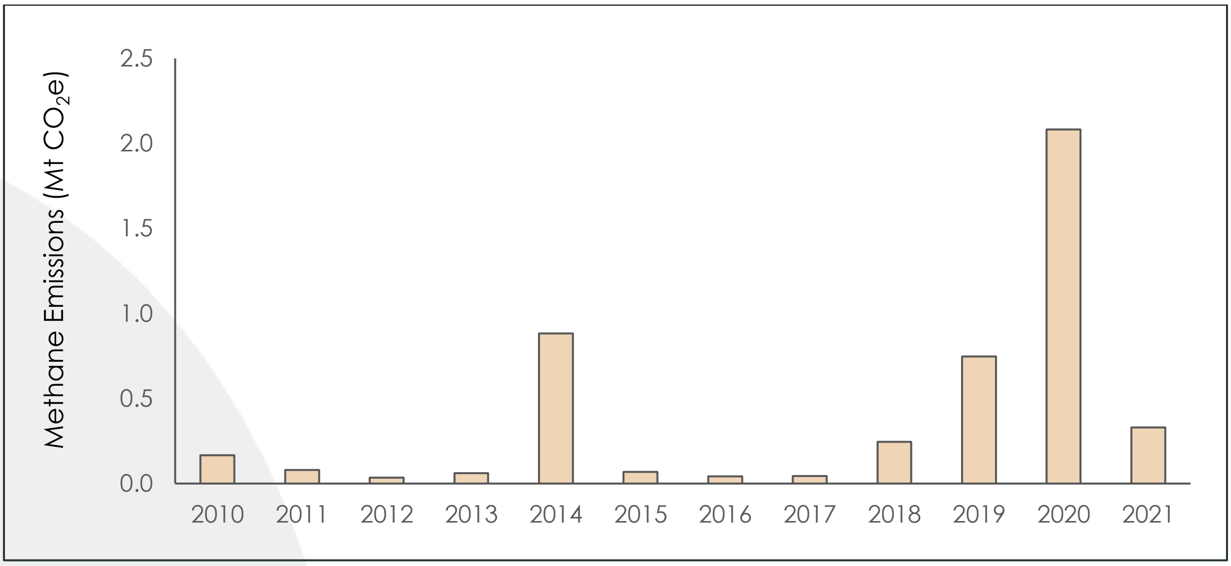


Figure 16. Modeled methane emissions from pipeline spills and ruptures between 2014 and 2021 (note that there is no difference between the BAU and MMS scenario for this source)

Pipeline spills and ruptures are reported annually in the AER incident release report. Reported released volumes are assigned a methane content according to the released substance, and the volumes are converted to Mt CO_2e. The spike in 2020 emissions visible above in Figure 16 was due to two major natural gas pipeline ruptures reported to the AER in that year. The average yearly spill and rupture emissions between 2010 and 2021 were 0.4 Mt CO_2e. It is difficult to speculate on the frequency of pipeline release incidents in the future. There are pipeline inspection and maintenance regulations in place. In addition, there are fines, lost revenue, and negative publicity associated with a release incident; plenty of incentive for pipeline operators to maintain their assets.

3.1. AER OneStop Methane Emissions

Beginning in 2020, the AER required that upstream oil and gas companies submit an annual methane report (OneStop) on June 1st of each year. As of the writing of this report, the 2020 and 2021 OneStop data are available to the public (Alberta Energy Regulator, 2023). Emission source categories reported to OneStop include pneumatics, routine venting, compressors, fugitives, and glycol dehydrators.

The MWMM incorporates emissions volumes reported to OneStop to calculate compressor seal, glycol dehydrator, and routine venting methane emissions for 2020 and 2021. The MWMM does not include OneStop data for the modeled pneumatics or fugitive emissions. Instead, a bottom-up inventory was created for these sources using data from two published studies (Clearstone Engineering Ltd., 2019; Johnson and Tyner, 2020). This approach is consistent with the GoA methodology for pneumatics and fugitive emissions. This approach models greater methane emissions for these two sources when compared to the reported OneStop emissions, as shown below in Figure 17.

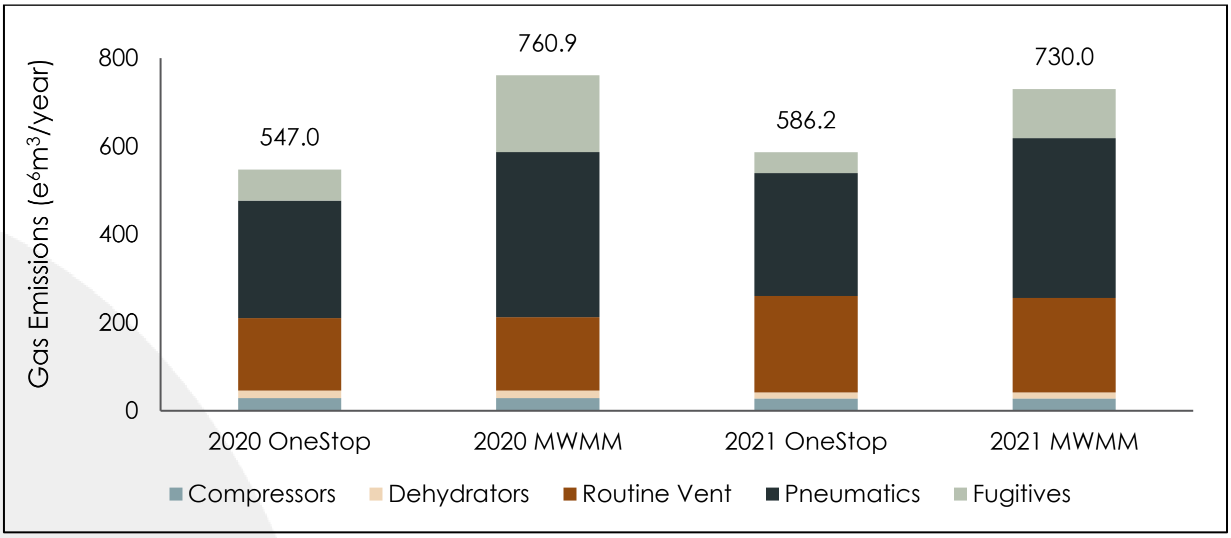


Figure 17. *Comparison of vented gas emissions reported to AER OneStop and modeled volumes in the MWMM, for 2020 and 2021.*

The figure shows that the gap between modeled and reported emissions decreased in 2021 compared to 2020. Ideally, this gap will continue to shrink as operator familiarity and compliance level increase with time. More information on the MWMM methodology is available in Appendix A of this report.

4. Key Factors Influencing Methane Emissions Reductions

This section provides insights about various factors that have impacted the methane reduction profile from different source categories discussed in section 3.

4.1. Carbon Offset Projects

Offsets are a time-limited, market-based incentive focused on achieving reductions from activities that are considered "additional". Additionality, in this case, is defined as an action that would not have been taken without the potential for offset generation – something that is beyond compliance, below economic thresholds, or not driven by other factors.

For this report, methane emissions related offsets are determined by analysing the Alberta Emission Offset Registry ("Alberta Carbon Registry," 2022) database, which lists third-party verified offset projects. Alberta offset projects[18] must follow quantification protocols developed and approved by the GoA. The following approved protocols are deemed relevant to methane emissions and are included in the analysis:

- Pneumatics Protocol
- Solution Gas Venting Protocol
- Engine Fuel Management Protocol

[18] For example: High to Low-bleed pneumatic device conversion, solar chemical injection pumps, waste heat recovery, vapour recovery unit, etc.

All project reports listed on the registry were identified and downloaded from 2015 to 2022, and reported methane reductions from each project were recorded. It should be noted that non-methane reductions (CO_2 and N_2O) reported under each project are excluded from the analysis. Table 1 and Figure 18 present the results of our analysis.

Table 1. Summary of Verified Methane Emission Reductions from the Upstream Oil and Gas Sector by Project Type, tCO_2e.

Year	Pneumatics (tCO_2e)	Vent Gas Capture (tCO_2e)	Engine Fuel Management (tCO_2e)
2015	-	-	1,213
2016	87,592	-	79
2017	118,467	-	2,070
2018	382,988	-	537
2019	1,090,339	-	1,520
2020	2,051,004	4,374	43
2021	2,307,755	16.0	5
Cumulative	**6,038,145**	**4,390**	**5,467**

Our analysis shows that pneumatic offsets have been the primary driver of offset reductions since 2015. This is likely because pneumatic device conversions have significantly lower initial capital costs compared to vent gas capture and engine fuel management technologies.

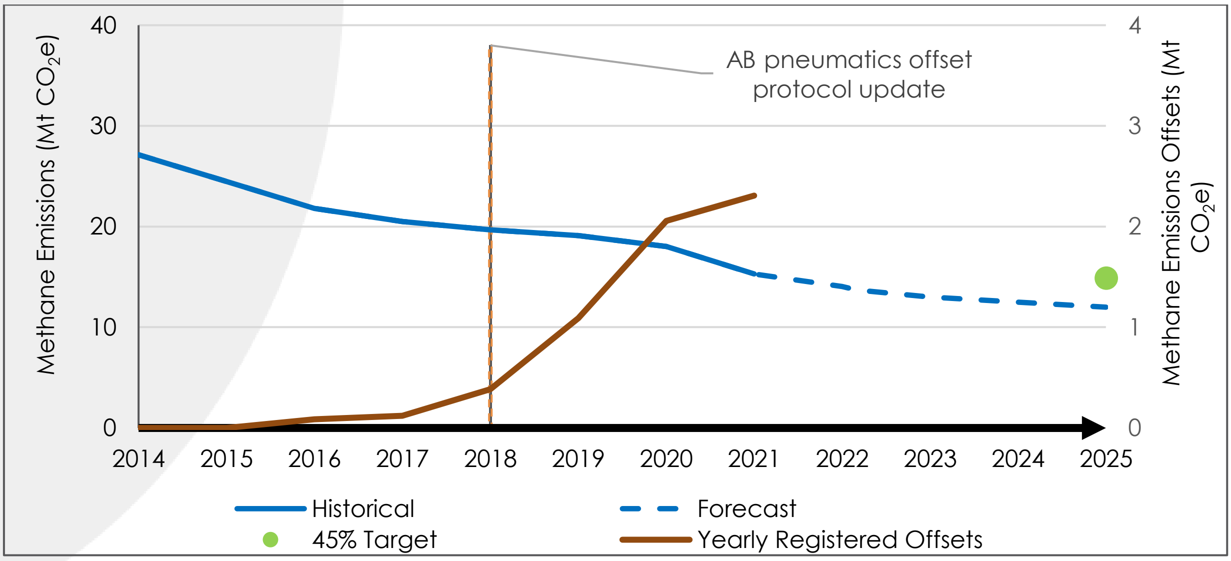


Figure 18. Comparison between modeled UOG methane emissions in Alberta and yearly registered methane emissions offsets on the Alberta Emissions Offset Registry database (*"Alberta Carbon Registry," 2022*).

Key Discussion Points

- 2022 vintage offsets have not been fully serialized at this time. We anticipate the final amount of 2022 offsets to be at least equal to or greater than the 2021 offset volumes.

- The Vent Gas Capture Protocol is relatively new (published in November 2021), and additional offsets may become available in the future as more offset projects are developed.
- It is difficult to determine if the province would have seen the same reductions from pneumatic devices if offsets were unavailable to the sector. At a minimum, we are able to qualitatively assess that the offset system provided an additional economic incentive to encourage the industry to act, respond and prepare for the upcoming pneumatic device-specific requirements that came into effect in 2023.
    - The offset incentive resulted in the industry acting early, submitting and verifying that the emission reduction project was completed, and that sufficient evidence was available to ensure methane emission reductions were verified to a reasonable level of assurance.
    - Alternatively, it's possible that without a time-limited economic incentive, action to reduce emissions from pneumatics would have been delayed until they were enforced by regulations.
- High-value, time-limited market-based incentive programs like Alberta's offsets system are impactful tools to help ensure that Alberta continues to meet their stated methane emission reduction targets.

4.2. Production and Drilling Activity

Production and drilling rates have changed substantially in Alberta since 2014. This subsection explores how this key factor may have influenced the sector's methane emissions since 2014. As seen below in Figure 19, crude oil and primary crude bitumen production both peaked in 2014 and were in decline between 2014 and 2021. Marketable natural gas production has declined year over year since 2017 (Alberta Energy Regulator, 2022d).

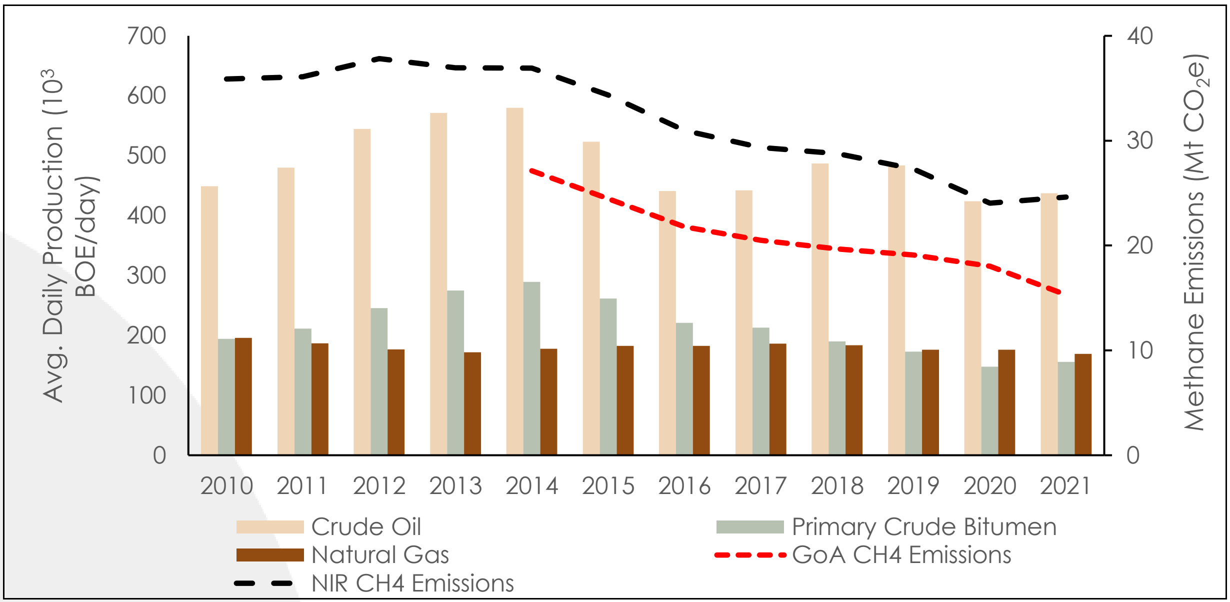


Figure 19. Crude oil, natural gas, and primary bitumen production data in Alberta, 2010 – 2021 Data (Alberta Energy Regulator, 2022d).

There is some level of correlation between primary bitumen and crude oil production with methane emissions. This is supported by the large decrease in routine venting seen in Figure 13 at these types of batteries. There is a very weak correlation between natural gas production and methane emissions. Pneumatics dominated methane emissions from natural gas batteries and gas processing facilities (see Figure 8). Reductions from this source category through pneumatic retrofits do not affect production rates.

4.2.1. Primary vs. Thermal Bitumen Production

The AER divides bitumen production into three categories based on the extraction method[19]:

- surface mining
- thermal in-situ
- primary production

As mentioned earlier in the report, methane from oil sands mining and upgrading are not covered under Alberta's methane regulations and are not included in our modelling. Thermal in-situ production includes Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS) operations. Primary bitumen wells are "wells producing bitumen without any additional recovery technologies"[20]; i.e., non-thermal operations and includes Cold Heavy Oil Production with Sand (CHOPS). Thermal operations have a much lower methane intensity than primary production, as illustrated below in Figure 20. The figure shows that primary bitumen has been the main contributor to methane emissions from bitumen production in the sector.

[19] https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53
[20] https://www.alberta.ca/oil-sands-glossary.aspx

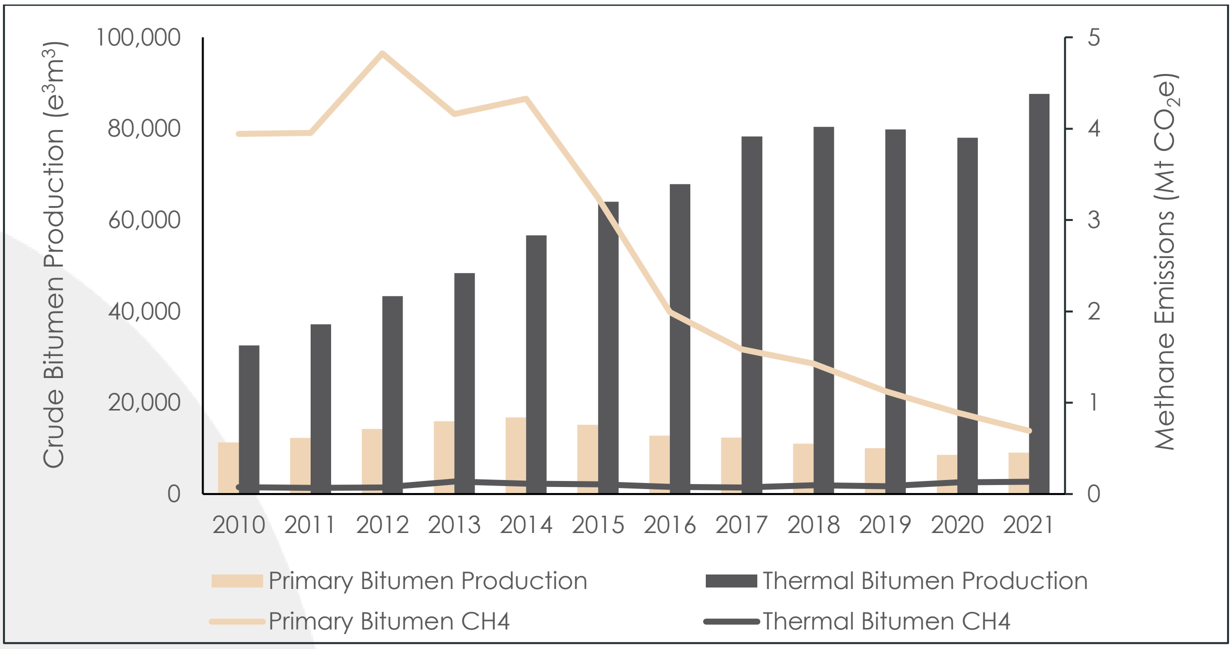


Figure 20. Comparison of production and methane emissions between primary bitumen and thermal in-stu (oil sands) bitumen operations between 2010 and 2021 (Data source: Alberta Energy Regulator, 2022).

The difference in primary and thermal bitumen methane intensity is almost entirely due to reported vent emissions. Primary crude bitumen production pulls the bitumen and solution gas up to the surface together, which produces significant venting of solution gas at the wellhead casing and in storage tanks. Thermal operations heat the oil in the underground reservoir and the heated oil and water is pumped to the surface. Solution gas separates from the bitumen during the heating process and rises to the "steam chamber" at top of the reservoir. Figure 21 illustrates this process in a typical SAGD operation. The majority of methane emissions modelled at thermal in-situ operations are due to fugitive emissions from the natural gas used to produce steam.

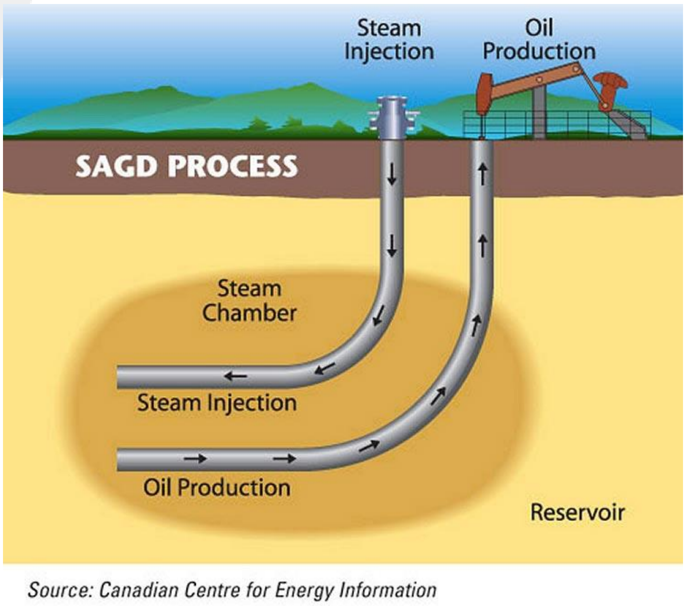


Figure 21. Diagram of a Steam Assisted Gravity Drainage in-situ operation.

4.2.2. Commodity Prices

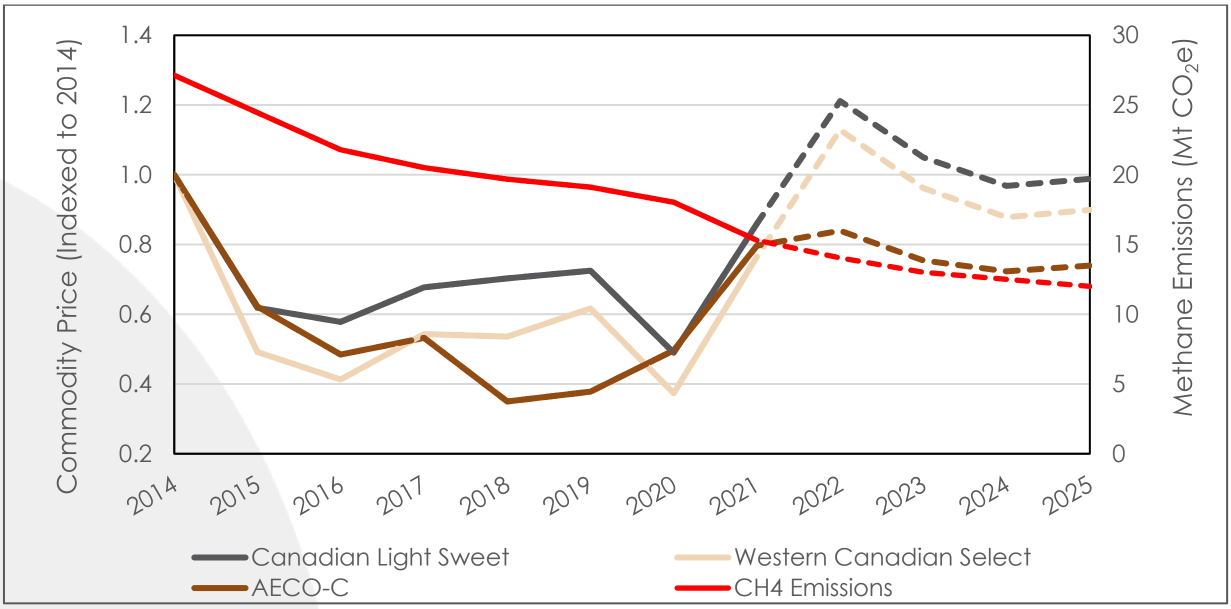


Figure 22. Relevant historical and forecast commodity prices between 2014 and 2025. WCS = Western Canadian Select, CLS = Canadian Light Sweet, AECO-C = Alberta natural gas spot price. Forecast prices (dashed lines) are from the AER "base" scenario *(Alberta Energy Regulator, 2022d)*

As shown in Figure 22 above, there was a commodity price crash in 2014 that affected bitumen, crude oil, and natural gas prices. This caused an associated drop in production[21], depicted earlier in Figure 19. Commodity price decline also affected drilling activity, which is down from 2014 levels in all sub-sectors (crude bitumen, oil, and natural gas). Drilling activity is not always a one-to-one correlation with production, however. Producers elect to drill wells at reservoirs that they expect will be the most productive. Consolidation and optimization of infrastructure means that less wells are required to maintain historic levels of production. (Alberta Energy Regulator, 2022). This activity is illustrated in Figure 23 to Figure 25 on the next page. There is a moderate correlation between commodity prices and production volumes. However, there are numerous other factors at play, including supply chain issues, price-to-production lag times, and human resource capacity. Regular updates to modeling would help capture the price-to-production correlation analysis.

[21] Marketable natural gas production continued to increase until 2017 before declining each year until 2021.

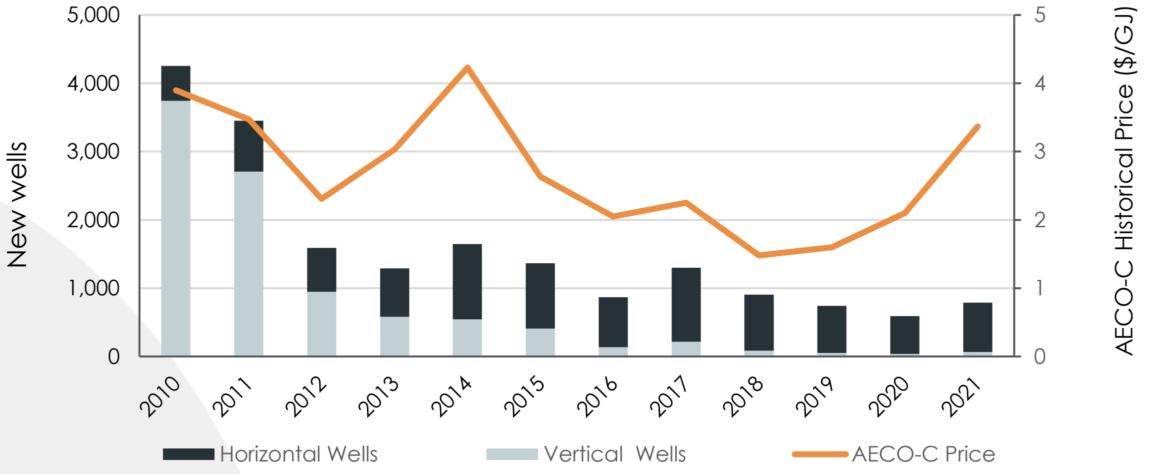


Figure 23. Natural gas well drilling activity and price history. Data source: AER ST98 (Alberta Energy Regulator, 2022d)

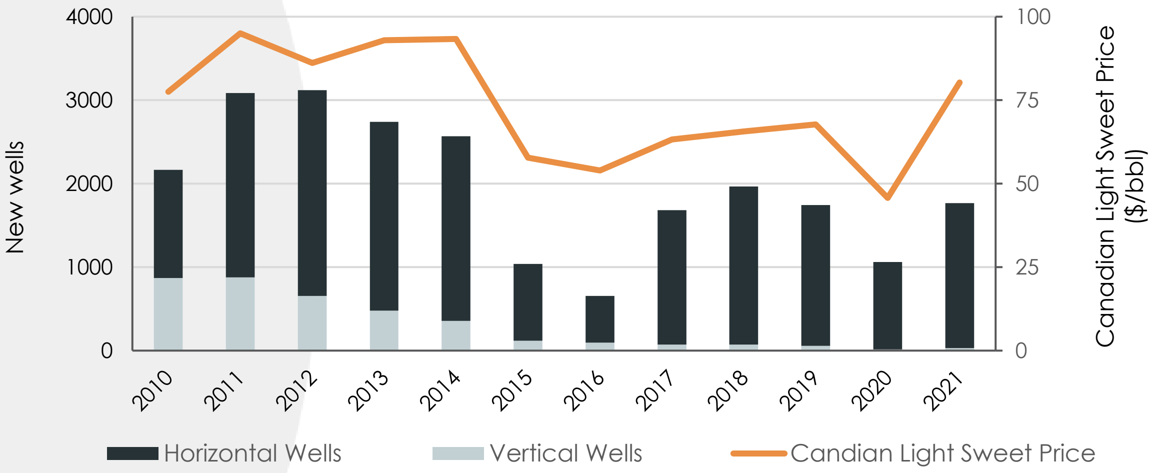


Figure 24. Crude oil well drilling activity and price history. Data source: AER ST98 (Alberta Energy Regulator, 2022d)

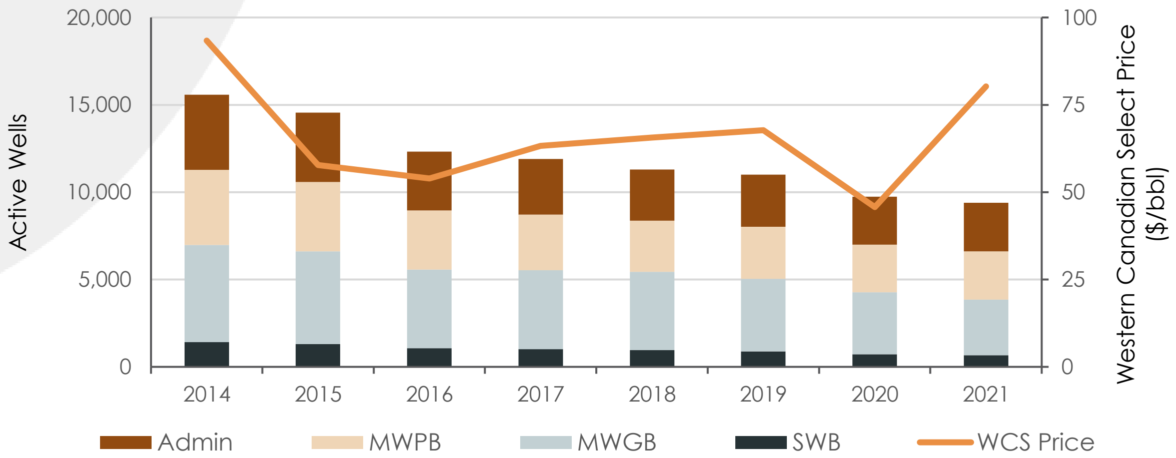


Figure 25. Active crude bitumen well and price history. SWB = Single Well Battery, MWBG = Multiwell Group Battery, MWPB = Multiwell Proration Battery, Admin = Administrative (Paper) Battery. Data sources: AER ST98 (Alberta Energy Regulator, 2022d), Petrinex.

Finally, the yearly number of active facilities follows the same declining path between 2014 and 2021. This trend is shown in Figure 26 below. Marginal, less efficient facilities were shut-in as declining prices made their operations less economical, while facilities at the end of their service lives were not replaced by new facilities at the same rate. Furthermore, it is understood that modern batteries[22] are generally designed to service many wells at once. These larger facilities have co-located or shared storage tanks, which improves the economics of methane mitigation activities[23]. This means that newly constructed multi-well batteries tend to have lower methane intensities than a single-well battery. **The declining trend in active facilities is, therefore, a combination of marginal shut-ins and increased efficiency.** Further analysis is required to delineate reductions between these two categories.

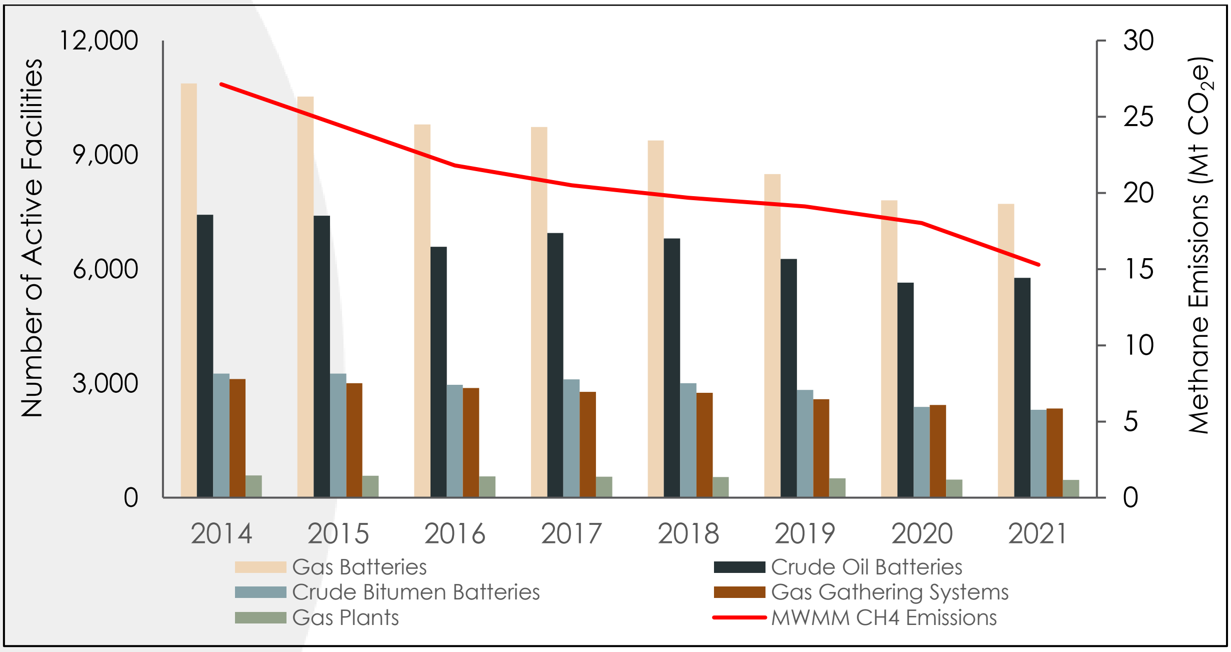


Figure 26. Active conventional oil and gas facilities in Alberta, by facility grouping, compared to modelled methane emissions from the sector. Data sources: Petrinex, MWA.

Key Discussion Points

- There is a direct correlation between active facility count and the methane emissions profile. The decline in active facility count is a result of economic pressure shutting in marginal facilities and increased efficiency in the design phase.
- There is a moderate correlation between commodity prices and production rates. However, these two factors do not have a correlation with the emissions profile of the province.

[22] A battery is a system of tanks and surface equipment that receives and stores oil, gas or bitumen from wells, before the product is transported to a processing facility.
[23] For example, vapour recovery units, combustors, site electrification.

- Directionally, the emissions trend more closely to oil production than gas production. This may be due in part to the fact that newer natural gas facilities are more efficient than historical facility configurations.

4.2.3. World Events

- COVID-19
    - Commodity prices dropped sharply in March 2020, and energy demand declined as global movement was stifled. Crude oil and bitumen production dropped in 2020 but rebounded quickly to "normal" levels by 2021.
        - The methane emissions profile has a steeper decline starting in 2020 and may be related to COVID-19. However, as noted, several other factors from 2020 onwards have influenced the emissions profile in 2020 and 2021.
    - LDAR survey requirements were temporarily waived due to the pandemic. Modeling suggests that 0.9 Mt of emissions reductions were created when the survey requirements were reinstated in 2021.

- War in Europe
    - Russia's invasion of Ukraine began in February 2022. Reported methane data is only available up to 2021, so the effect of the ongoing war cannot be quantified yet. Increased commodity prices created by the conflict lead to increased activity in the sector, and an associated increase in methane emissions may be anticipated as previously shut-in wells are brought back online. However, newer facilities generally have a lower emissions profile. Further analysis is required.

Notwithstanding these two significant global events, the key takeaway from the series of figures shown above is that production, active facilities, and drilling activity have all been in decline across the sector since 2014. Earlier in Figure 5, we modeled that this production and activity decline was responsible for a 6.7 Mt[24] (25%) decrease in 2021 methane emissions from 2014 levels. Simply stated, a net decline in sector "Business-as-Usual" activity explains about half of the total methane emissions reduction reported by the GoA from 2014 thru 2021.

Any increase in activity between now and 2025 may increase methane emissions; however, this is difficult to predict or model. New facilities will have inherently lower emissions than existing facilities. If the existing active facility count declines faster than new facilities coming online, then methane emissions may continue to trend down. Further analysis is required to confirm any trends.

[24] Total BAU reductions were 7.4 Mt, of which 0.7 Mt were from regulated glycol dehydrator emissions.

4.3. Methane Funding Programs

Over the past six years, there have been several funding programs targeting methane emissions measurement, quantification, and control from Alberta's upstream oil and gas sector. A summary table of these programs and their outcomes can be found in Appendix B of this report.

These funding programs have been essential to the field piloting of emerging methane mitigation technologies (discussed further in Section 4.5) and the deployment of detection and measurement technologies to improve data quality, as well as programs that fund the deployment of commercial methane mitigation technologies. Collecting field-level data and quantifying the emissions abatement potential of these technologies was a key driver for the widespread adoption of solutions across the sector.

Unfortunately, data collected through each program is generally not released to the public domain. Therefore, it is unclear what outcomes and benefits the programs have provided beyond the high-level statements that program operators are able to make.

The MWMM model does not consider the reductions associated with each funding program due to the lack of public data for each program. However, it is expected that any emission reductions attributed to the funding programs are captured in other reduction categories like offsets, compliance reporting, etc. It is recommended that future funding programs have key knowledge sharing requirements as part of the program, at a minimum, to attempt to identify any incremental emission reductions compared to regulatory requirements or offsets project performance, etc.

4.4. Regulatory Compliance Activities and Regulatory Certainty

Modeling indicated that the largest reductions (incremental to BAU) are in source categories that have begun implementing regulatory requirements - pneumatics (2022) and vent (2020). Therefore, there is evidence that impending regulatory requirements and limits do drive earlier methane mitigation outcomes. With clear and consistent policy and regulatory signals, producers are able to invest in early action, resulting in a declining emissions profile for the province. Alberta's offsets system enables early action reductions in methane emissions as well. As a result, all reductions in the pneumatics and vent categories can be attributed to a combination of early action and regulatory compliance activities.

New facilities are generally designed to conserve solution gas whenever economical. Regulatory risk mitigation, facility safety, and improved economics resulting from economies of scale are the key factors that drive this behaviour. For example, crude bitumen batteries will co-locate tanks at a single site to hold liquid from multiple wells, strengthening the economics for flare or vent capture tie-ins. It is difficult to delineate these activities in our model. As a result, they are rolled up in the "Business as Usual" scenario, as we are assuming they are likely to occur as the standard business practice.

Additionally, solution gas conservation rates are largely correlated to the drop in modeled routine vent emissions. Figure 27, below, from the AER's latest ST60b report, shows the relationship between the annual volume of flared or vented solution gas at crude oil and bitumen batteries and the gas conservation rates at these facilities between 2010 and 2021. Conservation rates dipped slightly in 2020 – 2021, specifically at crude oil batteries, where vent volumes increased due to definition changes in D060.

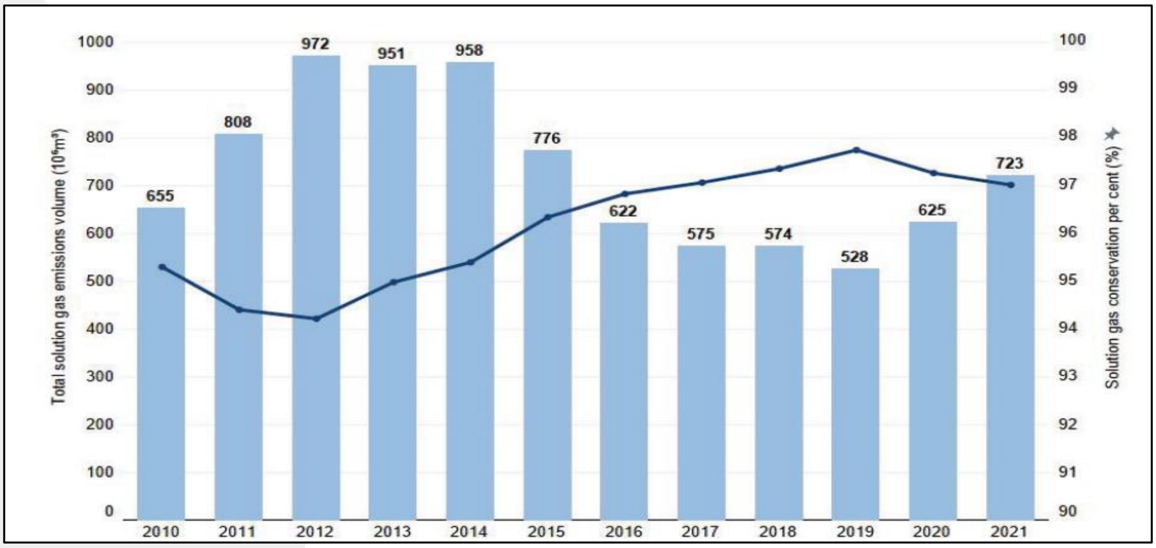


Figure 27. Comparison between vented solution gas volumes and solution gas conservation performance between 2010 – 2021 *(Alberta Energy Regulator, 2022d)*

4.5. Technology Deployment

Most of the methane emissions reductions modeled between 2014 and 2021 came from a decrease in routine venting (35%) and pneumatics (34%). There were a few key technologies that played a part in mitigating emissions from those sources:

- Low and zero-bleed pneumatic devices
- Instrument air packages
- Enclosed combustors and incinerators
- Vapour recovery units

Emissions Reductions Alberta and Alberta Innovates both funded field deployments of the above technologies between 2016 – 2018[25,26,27]. These initiatives generated real-world data on the technical and economic viability of the technologies. This data may have provided companies with some additional clarity when contemplating their own methane mitigation investments. However, the above technologies first were developed well in advance of any methane policy signals, as they have also been key technologies in the offsets market, when applicable. New technology development will

[25] Through the ERA's "$40M ERA Methane Challenge"
[26] Alberta Innovates/NRCan funded CERIN projects
[27] "Systematic Third-party Validation of Environmental and Economic Performance of Methane Reduction Technologies (STV)", funded by Alberta Innovates and AUPRF and facilitated by PTAC

certainly play an important role in achieving the recently announced 75% reduction ambition, but it seems that the 45% target will be reached using established technologies. The role of new technologies in achieving the 75% target is explored in Part 2, "The Drive to 75".

5. Findings from the Literature

The literature review we completed examined key research papers on methane emissions in Canada's oil and gas sector. A common theme presented in the peer-reviewed research is that oil and gas related methane emissions are being underestimated and underreported. Using a combination of aerial and on-the-ground surveys, several researchers have concluded that actual methane venting is significantly greater than government estimated levels, which rely heavily on emission factors. Table 2 below summarizes some of the recently published findings.

Table 2. Compilation of relevant academic research papers that suggest that upstream oil and gas emissions are being underestimated in Western Canada.

Authors, Published Year	Study Area	Underestimation Factor
(Festa-Bianchet et al., 2023)	Lloydminster	4.0
(MacKay et al., 2021)	AB & BC	1.5
(Johnson and Tyner, 2020)	Northeast B.C.	1.6 – 2.2
(Chan et al., 2020)	AB & SK	2.0
(Johnson et al., 2017)	Red Deer Lloydminster	1.0 3.6

Methane models used by ECCC and the GoA (and the MWMM) rely on component-level emission factors and population counts to produce a "bottom-up" estimate for total methane emissions. The studies listed above in Table 2 use a "top-down" methodology, by taking atmospheric measurements that quantify methane emissions at the facility level. The studies conclude that bottom-up inventories are underestimated, and underscore how there is a significant level of uncertainty when quantifying methane emissions. It is important to note, however, that there are limitations associated with the detection methodologies employed. This report does not contemplate any such limitations in the data collected in the reports. There is general agreement in these reports that increased MMR activities, including aerial surveys, can create a more robust methane data set, providing greater certainty in Alberta's modeled methane emissions going forward. This is relevant to ensuring credibility in Alberta's modeled methane emission reductions as we approach the 45% reduction target in 2025. A summary of the relevant studies is presented in Appendix C.

6. Discussion

The latest modeling by the Alberta Energy Regulator (AER) suggests that Alberta is on track to meet its ambitious 45% reduction target. Figure 28 demonstrates a breakdown of where the modeled emissions reductions have been achieved to date. Of the total

11.8 Mt (44% of 2021 emissions) modeled MER achieved in 2021 from the 2014 baseline, the majority (57%) of these reductions have come from general "Business-as-Usual" activities. BAU reductions can be associated to activity and production decline that was a response in large part to a drop in commodity prices in late 2014. Some BAU reductions can also be attributed to the consolidation and optimization of assets and infrastructure. Both types of BAU reductions would have occurred in the absence of Alberta's methane reduction framework.

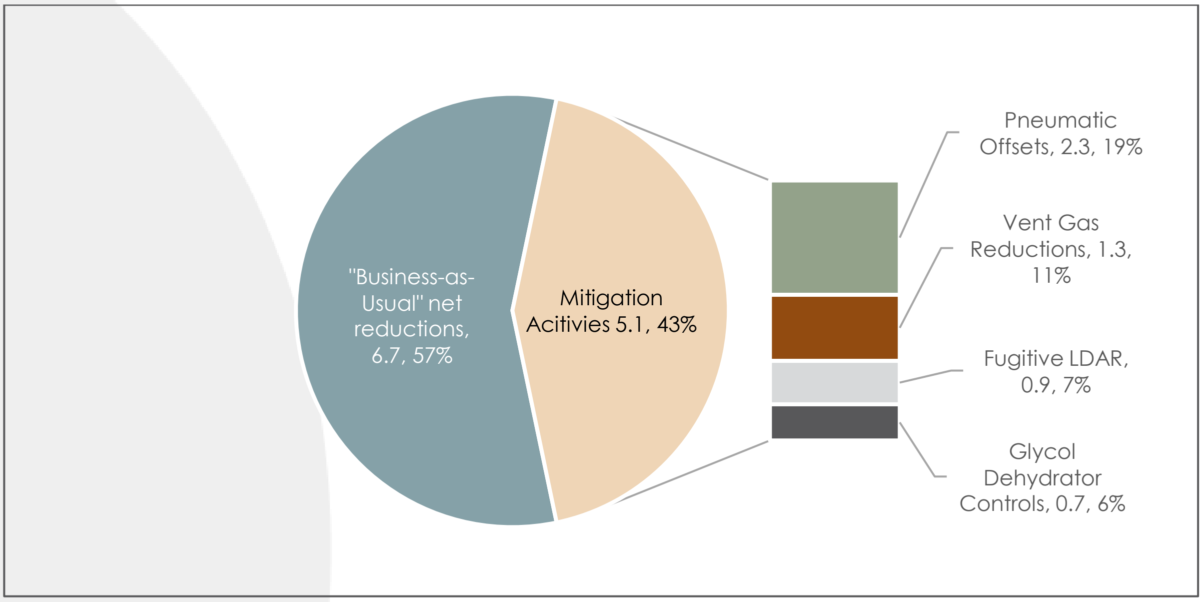


Figure 28. Breakout of the 11.8 Mt of modeled methane emission reductions (in Mt CO_2e) achieved in 2021, compared to the 2014 baseline year.

The remaining 5.1 Mt (43%) of overall reductions are the result of methane mitigation activities. Regulations, offset protocols, and funding programs have driven methane mitigation activities in Alberta. It is difficult to determine how many of these emission reductions would have occurred without these programs, as the funding programs and market incentives targeted similar activities to the regulations. However, we can conclude that incentive programs in Alberta drove earlier methane reductions than otherwise would have been achieved solely through regulatory policy.

Notably, the modeling only covers emissions up to the end of 2021, and additional methane emission requirements came into effect on January 1st, 2022, and January 1st, 2023. Therefore, we expect that more reductions will occur in 2022 and in 2023, in line with the forecasted emissions in Figure 1 of this report, if similar performance trends persist.

MWA modeled emission volumes are 30-40% greater than the corresponding OneStop reported volumes (Alberta Energy Regulator, 2023), and recent research indicates that the inventory-based models could be underestimating actual methane emissions by an additional factor between 1.5 - 2.0. Increased efforts in MMR activities would help bridge the gap between these datasets, increasing the overall confidence in Alberta's reported methane emissions reductions.

Overall, Alberta has shown encouraging progress in its efforts to achieve the 45% reduction target, and it is crucial to continue pursuing efforts to further mitigate these emissions through a combination of regulations, offsets, and programs.

7. Recommendations and Considerations

This section includes commentary on the following three items: (1) Summary of where funds have flowed historically to enable methane emissions reduction in the upstream oil and gas sector; (2) Additional research that could be completed to extend the analysis in this report; (3) Guiding statements where investment/programming could be of highest value over the coming years.

From 2014 to 2018, the majority of investment into methane mitigation activities was made directly by industry. This included investment into carbon offsets projects given that the Alberta and B.C. markets have been in play since 2008. Some investment was made by industry for the sake of good corporate business practice and reported through public sustainability reports (or other voluntary reporting initiatives). While some other investments were made when funds were cycled back to large emitters through the TIER/SGER fund managed largely by Emissions Reduction Alberta.

From 2018 to 2021, there was a significantly larger pool of funds available from government or other organizations (like Alberta Innovates, ERA, and NRCan) focused on methane emissions mitigation. These funds were an additional consideration for companies along with carbon offsets in the compliance market. The successful programs administered in this timeframe were largely focused on collecting more data from field deployment of leak detection services and/or baseline emissions measurement programs like the Methane Emissions Reduction program in 2018 and the subsequent Baseline Reduction Opportunity Assessment and Methane Technology Implementation programs. The latter program served a similar purpose to the carbon offsets system in that it provided funds for the deployment of mitigation technologies.

Since 2021, these programs, along with others like the Emissions Reduction Fund run by Natural Resources Canada, the Alberta Methane Emissions Program (focused on alternatively fugitive emissions management programs), CERIN's funding to PTAC (largely deployed to tanks and methane programs) and to Natural Gas Innovation Fund for the Emissions Testing Centre (focused on field testing emerging detection, quantification and control technologies) and others, have continued to move the dial on methane emissions reduction technologies from the sector.

To design new, future programs, the analysis in this report can be further extended to include area-based assessment by location, reservoir characteristics, and facility age, for one example. On top of this type of analysis, a strong consideration should be given to the design of a national methane emissions data hub that accumulates data from all regulatory and programming systems to build a cohesive data set. This data set could be used to repeat the analysis in this report, expand on it and complete other marginal abatement assessments on methane technologies. More generally, a centralized data hub would be the most efficient way to build new programs and design new regulations. Providing access to all key stakeholders and using standardized methodologies are critical gaps that would be addressed with a new data hub. There are challenges associated with this, but it is very likely worth additional consideration.

Finally, other new programs to be designed and implemented for the 2023 to 2030 timeframe should leverage the expertise of current program administrators, accounting systems, resource configurations, and data platforms but re-design the programs to target the hardest to abate emission sources at the most vulnerable facilities. Several new program recommendations are included in the "Drive to 75" report. In the meantime, we include two recommended initiatives for consideration.

7.1. Program Suggestions

1. Alberta Methane Data Hub
    a. **WHY:** Initial methane inventories were constructed using engineering estimates and emission factors between 2016 – 2018. The detection, measurement, and reporting of methane data only began in earnest in Alberta in 2020. This means there are large levels of uncertainty surrounding province-wide estimated emissions levels. Research by academia and ENGO's suggest that oil and gas methane emissions are underreported and underestimated, across the United States and Canada. Alberta can collaborate with ECCC on the Methane Centre of Excellence[28] to mirror international data efforts (UNEP IMEO).
    b. **BENEFIT:** Overcome the biggest barrier to the efficient operation of Canada's methane mitigation efforts.
    c. **BENEFIT:** Improve the quality of Alberta's methane dataset. Reduce uncertainty and enhance confidence/credibility of future modeled emissions reductions.

2. Facility-Level Model Analysis
    a. **WHY:** The MWMM was developed at the facility subtype level. The model can breakout mitigated methane emissions and assign them to a particular action. The same cannot be done to BAU emissions reductions. A new iteration of the MWMM could be developed at the individual facility level to derive further insights into the "BAU" activity decline modeled in this report.
    b. **BENEFIT:** Further delineate the "BAU" scenario by categorizing emissions reductions as production decline vs. operations optimization and efficiency.

[28] https://natural-resources.canada.ca/climate-change/request-for-information-on-methane-centre-excellence/24704

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Appendix A

MWMM Methodology

The Modern West Methane Model (MWMM) follows a similar bottom-up methodology and data sources reported in the Government of Alberta's annual methane equivalency report. It is comprised of eight emission source categories. Total yearly MWMM emissions were near the GoA values (±5%) and were scaled to match the GoA reported methane values for each year between 2014 and 2021. Note that the objective of this modeling endeavor was to acquire an approximation of the breakdown of the GoA's emissions, rather than to formulate a new estimate. The assumptions and limitations of MWA's modeling is described below.

<u>Inputs for all emissions categories</u>

- Methane density = 0.6785 kg/m^3 (AER Manual 015)
- Methane GWP = 25 (IPCC AR4)

<u>General Model limitations</u>

- Due to a lack of publicly available data the model does not include emissions from some non-routine sources including well testing, liquids unloading, engine/turbine start-ups, and compressor blowdowns.
- The model only attempts to estimate methane emissions from 2014 to 2021. No attempts are made to forecast emissions past this date.
- The model relies on operator reported data for the following emission sources: Routine Vent, Compressor Seals, and Glycol Dehydrators. Full reporting compliance across the sector is assumed by the model.

<u>Calculation assumptions and limitations – Vent from pneumatic devices</u>

- Estimation of vent from pneumatic devices was based on average number of devices for each facility type, average vent rate for pneumatic devices, and assumes 8,760 hours of operation in a year, which is consistent with the NIR and GoA methodologies.
- Average number of devices for each facility type was obtained from Tyner & Johnson, 2020 (for additional details refer to Table S5 in Tyner & Johnson, 2020), and, assumed to provide a reasonable representation of vent rates from these devices for years 2014 through 2022.
- Number of facilities of each type was obtained form the public Petrinex data for Alberta. MWA had access to Petrinex data going back to 2015. Therefore, number of facilities in 2014 was extrapolated based on the number of facilities from actual Petrinex data for 2014 to 2017 assuming a consistent trend in changes in facilities between 2014 and 2017.

Calculation assumptions and limitations – Vent from compressors

- Estimation of vent from compressors was based on the number of compressors at gas facilities in 2020 and 2021 and an average annual compressor vent for centrifugal and reciprocating compressors.
- Public OneStop data includes the number of compressors of each type (centrifugal and reciprocating) as well as the reported vent volumes for each type of compressor. OneStop data for years prior to 2020 is not available. Therefore, the 2020 and 2021 OneStop data were used to estimate the number of compressors for years 2014 through 2019. This process involved calculating a weighted average of the number of compressors for the years 2020 and 2021, with the weights determined based on the number of active facilities in these years. This weighted average was assumed to be representative of the number of compressors per active facility during 2014 through 2022. The number of compressors in 2014-2019, and 2022 was finally estimated by multiplying the number of active facilities reported for each year by the number of compressors (weighted average) in 2020 and 2021. This method assumes a stable relationship between the number of active facilities and the number of compressors over these years and uses this relationship to make an informed estimation for 2014-2019, and 2022.

Calculation assumptions and limitations – Vent from glycol dehydrators

- Estimation of vent from glycol dehydrators was completed in a similar manner to vent from compressors. However, the number of compressors and their emissions was estimated for the years after 2021, as this data was available through the reports submitted to the government under the Directive 039 requirements for the years prior to 2021. Note methane was not required to be reported under Directive 039 prior to 2020. Therefore, an uncontrolled dehydrator emission factor (Clearstone 2018) was used to estimate the volume of methane releases based on the volume of processed gas which was available from Directive 039 reported data.

Calculation assumptions and limitations – Surface Venting Case Flow (SCVF)

- SCVF is reported by facilities to the Government of Alberta. These volumes are used directly in MWA's modeling and converted to a mass of methane.
- Although SCVF volumes are reported publicly, this category is still scaled in the manner as the other categories, to maintain consistency.

Calculation assumptions and limitations – Fugitives

- Fugitive emission factors by facility subtype and well type were derived from Tyner & Johnson (2020) 2017-2018 fugitive inventories. These emission factors were then applied to yearly facility and well counts pulled from the public Petrinex database for the modeled years.
- For the MMS scenario, an assumption was made for reductions achieved through LDAR surveys. Annual surveys were assumed to produce a 40% fugitive

reduction, while tri-annual surveys produced a 70% reduction[29]. Annual screenings at wells were assumed to have negligible mitigation effects.

- LDAR survey frequencies were applied to each facility subtype according to Directive 060 – Table 4.

Calculation assumptions and limitations – Spills and Ruptures

- Pipeline release incidents are reported to the AER, who publishes the data on their Pipeline Performance webpage[30].
- Reported released volumes were assigned a methane content according to the released substance (see Table A.*1*) and the volumes were converted to Mt CO_2e.

[29] https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf
[30] https://www.aer.ca/providing-information/data-and-reports/activity-and-data/field-surveillance-incident-inspection-list

Table A.1. Summary of the MWMM methodology, data sources, and assumptions.

Emissions Category	Data Sources	Methane Content (% vol)	Other Assumptions
Pneumatics	• Facility and Well Counts (ICF International, 2015)(ICF International, 2015)(ICF International, 2015)(Petrinex) • Pneumatic counts (Clearstone 2018, Tyner & Johnson 2020) • Pneumatic emission factors (Clearstone 2018, Tyner & Johnson, 2020) • Pneumatic offset data (AEOR)	• 92% (All facility types)	• 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 – 2021 routine vent volumes (OneStop)	• 78% (Natural Gas) • 74% (Crude Oil) • 95% (Facility subtype 331 & 342) • 97% (Facility subtype 341 & 343)	
Methane Slip – Flare	• 2015 - 2021 flare volumes (Petrinex) • 2014 flare volume extrapolated	• 78% (Natural Gas) • 74% (Crude Oil) • 95% (Facility subtype 331 & 342) • 97% (Facility subtype 341 & 343)	• 98% flare destruction efficiency • 6% unlit flares (non-gas plants) • 0% unlit flares (gas plants)
Methane Slip – Fuel Combustion	• 2015 - 2021 fuel volumes (Petrinex) • 2014 fuel volume was extrapolated. • Fuel gas heating value (Tyner & Johnson, 2020) • Fuel gas usage ratios (Tyner & Johnson, 2020) • Engine, turbine, boiler emission factors (EPA WebFIRE Database)	• 92% (All facility types)	• 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 (Tyner & Johnson, 2020)
		• N/A[31]	• LDAR fugitive reduction factors (ICF International, 2015)[32]:
			  o 40% (annual)
			  o 70% (tri-annual)

[31] Tyner & Johnson emission factors are already in tCH_4/hour units.
[32] Annual survey factor sourced from ICF (2015). Annual well screenings were assumed to result in negligible fugitive emissions reductions.

Emissions Category	Data Sources	Methane Content (% vol)	Other Assumptions
Compressor Seals	• 2020 – 2021 compressor counts (OneStop) • 2020 – 2021 compressor vent gas volume (OneStop) • Facility counts (Petrinex)	• 92% (All)	
Glycol Dehydrators	• 2008 - 2021 dehy counts (ST60b) • 2008 – 2021 dehy processed gas volumes (ST60b) • 2020 – 2021 dehy benzene emissions (ST60b) • Uncontrolled dehy emission factor (Clearstone 2018)	• 85%	• Dehy methane emissions reductions are scaled to benzene emission reductions
SCVF/GM	• SCVF/GM annual gas emissions (GoA, 2021)	• 85%	
Spills and Ruptures	• Release volumes (AER)[33]	• 90% (marketable natural gas) • 85% (raw natural gas)	• 85 m^3/m^3 gas in solution ratio assumed for condensate and crude oil releases

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

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Appendix B

Methane Mitigation Programs in Alberta

Organization	Program	Focus Area	Active/Inactive	Outcome (if known)
Government of Alberta	Baseline Reduction Opportunity Assessment (BROA)	Equipment and emissions inventories at active facilities	Active	Improved inventory of emissions by source; Customized data management system used and accessed by all field services companies. 1500+ site inspections which identified 100+ kt CO_2e per year of methane mitigation potential.
	Methane Technology Implementation Program (MTIP)	Deployment of readily available mitigation technologies	Active	800,000 tonnes per year (2022+); Uses same customized data management system as BROA
	Alberta Methane Emissions Program (AMEP)	Deployment of alternative leak detection solutions	Active	Not known
	Carbon Offsets System (AEOR)	Pneumatics, venting, compressors	Active	Achieved 6,347 kt CO_2e cumulative methane-specific reductions to date between 2015-2022.
Natural Resources Canada	Emissions Reduction Fund (ERF)	Deployment of readily available mitigation technologies and capital investment in infrastructure projects	Inactive	Supported 81 projects across Western Canada.
	CERIN (joint funding with AB Innovates)	Funded the NGIF Emissions Testing Centre (ETC)	Inactive	
Alberta Innovates	CERIN (joint funding with NRCan)	Funded PTAC projects (CanERIC), including Tanks	Inactive	
	Clean Resources Initiatives			

Organization	Program	Focus Area	Active/Inactive	Outcome (if known)
Emissions Reduction Alberta	$40 Million Methane Challenge	Development and adoption of GHG mitigating technologies	Active	Supported over a dozen projects targeting oil and gas sector methane emissions
Clean Resource Innovation Network (CRIN)	Reducing Environmental Footprint technology competition	Measurement and quantification of methane emissions	Active	
Petroleum Technology Alliance Canada (PTAC)	Methane Consortium Program	Field deployment and testing of methane mitigation technologies	Inactive (Complete)	Supported 7 successful field deployments. Learnings and outcomes published in online reports.
	Alberta Upstream Petroleum Research Fund (AUPRF)	Methane emissions measurement and quantification	Active	Funded 31 methane-related projects since 2016
Canadian Standards Association (CSA)	Voluntary carbon offsets registry (CSA Clean Projects Registry)	Various emissions reductions projects deemed beyond regulatory compliance requirements and not registered on any compliance market	Active	

Appendix C

Research Meta-analysis

The literature review section examines key research papers on methane emissions in Canada's oil and gas sector. Johnson and Tyner (2020) compare federal and provincial methane regulations, finding that federal regulations achieve approximately 26% more methane mitigation. Seymour et al. (2022) highlight underestimation and underreporting of methane emissions, emphasizing the need for accurate reporting and accounting for all emission sources. Mackay et al. (2021) show variations in emission rates by region and fluid type, with gas-producing sites emitting less than oil-producing sites. The review also includes a study on the Heavy Oil Belt, revealing high methane emissions from casing gas venting and suggesting potential mitigation through carbon pricing mechanisms.

Overall, these studies underscore the importance of effective regulations, accurate measurement, and targeted mitigation to achieve significant reductions in methane emissions.

Johnson and Tyner (2020)[34]

This case study compares the methane regulations implemented by the Canadian federal government and the Province of Alberta in the oil and gas sector aiming to achieve equivalent reductions in methane emissions by 2023.

The study conducts a comprehensive technical analysis by considering the potential impact of the regulations on active oil and gas facilities in Alberta in 2018. It compares the regulations in terms of their impact on different emission sources, such as pneumatic pump emissions, vented emissions, and fugitive emissions. The key differences between the regulations were observed in limits on pneumatic pump emissions, vented emissions, and expected reductions in fugitive emissions through leak detection and repair surveys. The analysis was repeated using production and inventory data from 2012 and 2017 to examine sensitivities to changing production patterns and to compare with the baseline referenced in federal policy targets. The results remained consistent in all scenarios. The analysis finds that the federal regulations are stronger, achieving approximately 26% more methane mitigation compared to Alberta's regulations (Figure C1).

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[34] Johnson, MR and Tyner, DR. 2020. A case study in competing methane regulations: Will Canada's and Alberta's contrasting regulations achieve equivalent reductions? Elem Sci Anth, 8: 7. DOI: https://doi.org/10.1525/elementa.403. Available at: https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.403/112749/A-case-study-in-competing-methane-regulations-Will

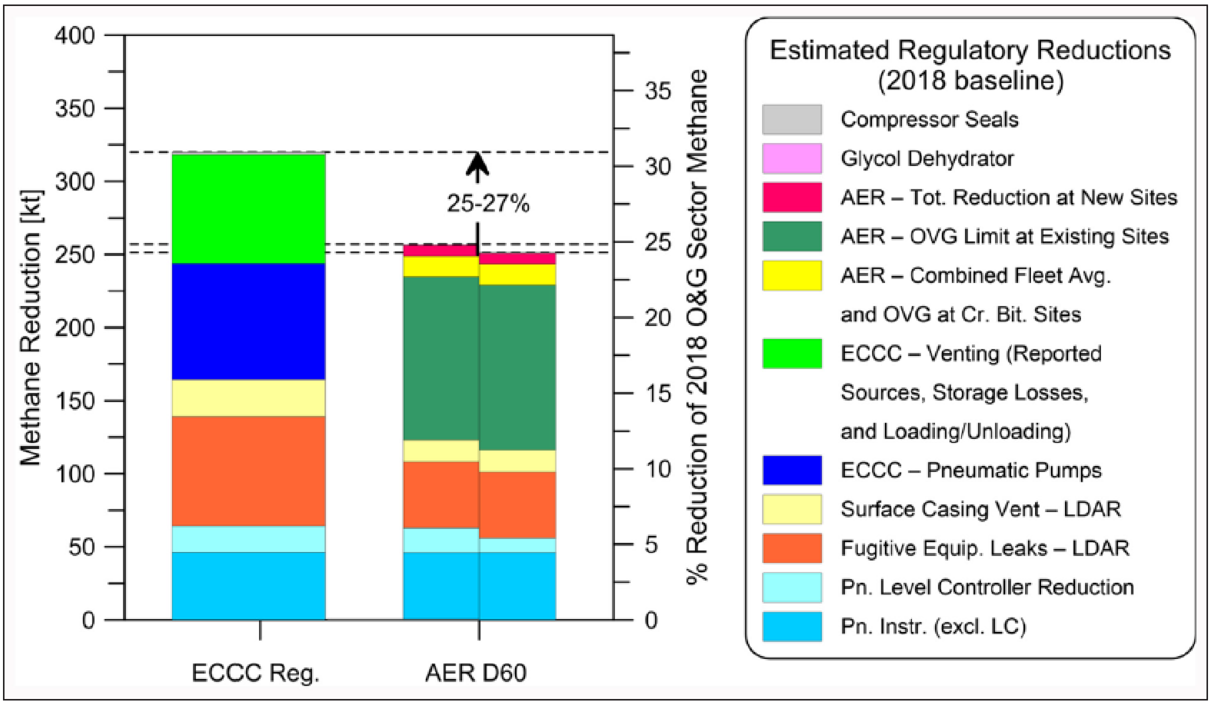

Figure C1. Anticipated methane reductions from the ECCC and AER regulations at full implementation calculated using current (2018) production and inventory data.

The study also examines different scenarios to make the regulations equivalent and discusses the implications of the achieved mitigations for designing effective and efficient methane regulations. Overall, the findings suggest that the federal regulations are more effective in reducing methane emissions, although the 40-45% reduction goal for the overall oil and gas sector may not be achieved by the 2025 target.

Seymour, SP, et al. (2022)[35]

The article discusses the underestimation and underreporting of methane emissions in Canada's upstream oil and gas (UOG) sector. The current federal inventory model used in Alberta does not account for all sources of methane emissions, leading to significant uncertainty in emission estimates and reduction trends (Figure C2).

[35] Seymour, SP, et al. 2022. Sources and reliability of reported methane reductions from the oil and gas industry in Alberta, Canada. Elem Sci Anth, 10: 1. DOI: https://doi.org/10.1525/elementa.2022.00073. Available at: https://online.ucpress.edu/elementa/article/10/1/00073/194533/Sources-and-reliability-of-reported-methane

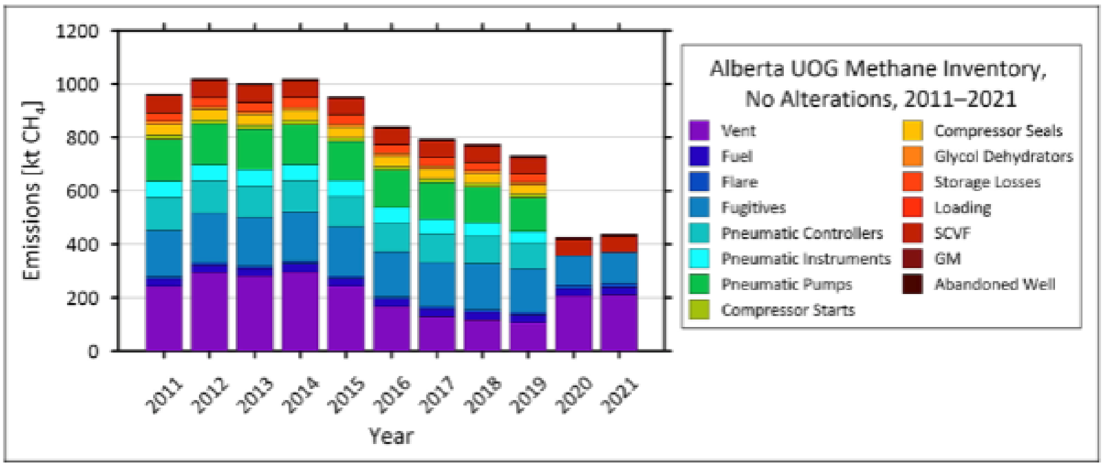

Figure C2. Alberta Upstream Oil and Gas Methane Inventory, 2011-2021 (the model is closely following federal government data sources and methodologies)

The authors developed an in-house model using operator-reported data from the Petrinex reporting system to estimate UOG methane emissions for Alberta from 2011 to 2021, excluding certain emissions. The model showed a 58% reduction in methane emissions between 2020 and 2012. However, the shift from modeled to operator-reported emissions created an inconsistency between years, which was corrected using an updated model that considers future venting limits. The authors also updated emission factors based on measurement studies to improve the accuracy of the inventory model. Figure C3 shows the updated inventory estimate.

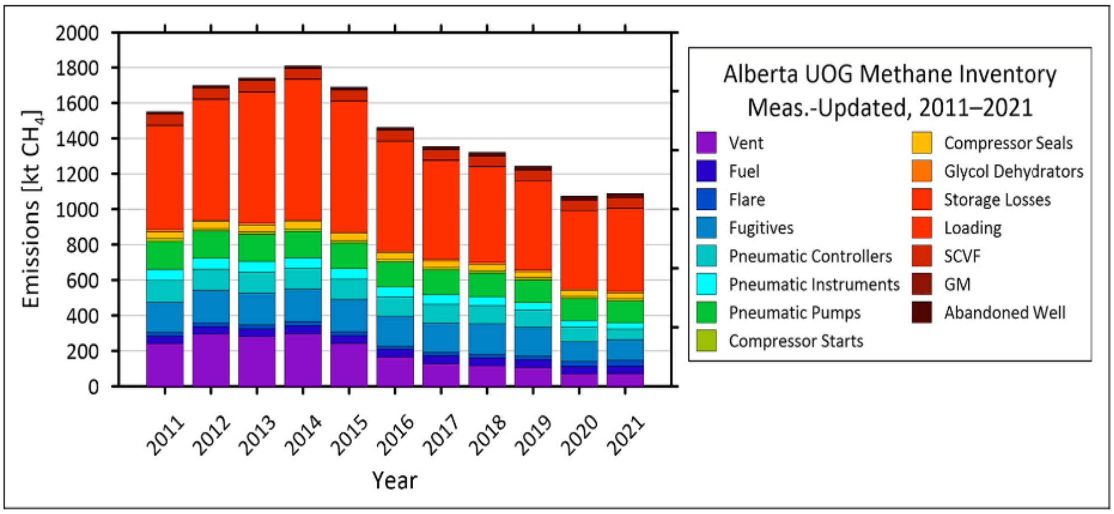

Figure C3. Measurement-updated methane inventory for Alberta, 2011-2021

The study highlights the importance of addressing reporting noncompliance and accounting for all sources of methane emissions in future models. The authors recommend adopting a measurement-based inventory, improving fugitive classification, enhancing reporting and validation processes, and setting a static emissions target to reduce uncertainty and improve accuracy.

Mackay et al. (2021)[36]

This article discusses the challenges associated with accurately measuring methane emissions and understanding the discrepancy between reported emissions and actual emissions.

The authors conducted the study in six (6) prominent oil and gas regions in Canada, collecting site-level emission data from 6650 sites across the regions. Based on the results of the study, it was found that emissions varied by fluid type and region (Figure C4), with the heavy oil region of Lloydminster having the highest emissions. Older, low-producing developments such as Medicine Hat showed high emission intensities, while newer developments in Montney had some of the lowest emission intensities in North America. The authors suggest that regulations may also contributed to regional differences in emission rates. For example, Peace River in Saskatchewan had the lowest average emission rate among the regions studied.

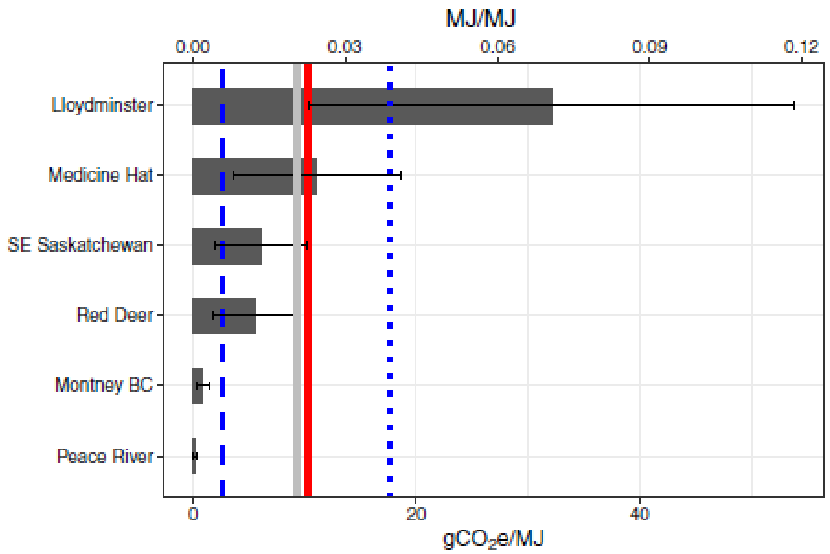

Figure C4. shows the distribution of measured emission rates by region and fluid type.

Additionally, the researchers found that gas-producing sites had lower average emission rates than oil-producing sites, with oil sites emitting approximately 3.6 times more than gas sites.

The study estimated that the Canadian upstream oil and gas methane inventory is underestimated by a factor of 1.5, which is consistent with previous studies.

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[36] MacKay K, Lavoie M, Bourlon E, Atherton E, O'Connell E, Baillie J, Fougère C, Risk D. Methane emissions from upstream oil and gas production in Canada are underestimated. Sci Rep. 2021 Apr 13;11(1):8041. doi: 10.1038/s41598-021-87610-3. PMID: 33850238; PMCID: PMC8044210. Available at: https://www.nature.com/articles/s41598-021-87610-3

In conclusion, the authors emphasize the importance of accurate measurement and reporting to effectively mitigate methane emissions in the oil and gas sector.

Other Studies and Research

The Environmental Science & Technology article[37] focuses on the Heavy Oil Belt (HOB) in Alberta and Saskatchewan, Canada, where conventional cold heavy oil production (CHOP) and coproduction of sand (CHOPS) take place. The production of CHOPS is linked to higher methane emissions, highlighting the need for better understanding and reduction of methane emissions in the region.

The article highlights the challenges in accurately measuring methane emissions in the heavy oil production industry, including discrepancies between reported and observed vent volumes and flaws in estimating methane venting using an assumed Gas Oil Ratio (GOR).

The study's findings reveal that venting high-methane content casing gas from ground-level sources accounts for approximately 81% of methane emissions from CHOPS wells. It also suggests that reported gas production underestimates the actual production, with gas being reported as fuel use but being vented instead. Additionally, inactive sites contribute to measurable methane emissions, albeit representing only 4.4% of the total emissions.

The article also discusses potential mitigation solutions for reducing methane emissions in Canada's oil and gas production, such as capturing gas for sale, combustion in auxiliary burners or heaters, or destruction in stand-alone combustors. It notes that applying the current carbon price of CA$65/t$CO_2$e could eliminate 97% of methane with payback periods of less than 2 years. Furthermore, a carbon price of CA$170/t$CO_2$e could eliminate 99% of methane with a payback period of less than 1 year. With accurate measurement and the application of current carbon price targets, methane emission reductions of 75% or more can be readily achieved.

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[37] Environ. Sci. Technol. 2023, 57, 8, 3021–3030 Publication Date: February 6, 2023, available at: https://doi.org/10.1021/acs.est.2c06255 Copyright © 2023 The Authors. Published by American Chemical Society