TECHNICAL BACKGROUNDER

Moving Forward on Methane

How Alberta can demonstrate renewed leadership on oil and gas methane emissions

March 2026

Amanda Bryant

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Technical backgrounder

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These acknowledgements are part of the start of a journey of several generations. We share them in the spirit of truth, justice and reconciliation, and to contribute to a more equitable and inclusive future for all.

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Executive summary

This technical backgrounder assesses data and regulatory gaps related to methane emissions from Alberta's oil and gas sector. It draws on recent independent measurement studies, provincial and federal estimates, and industry-reported data, including newly available datasets from Alternative Fugitive Emissions Management Program (alt-FEMP) follow-up surveys. The objective is to demonstrate how regulatory approaches, reporting frameworks, and emissions estimates can be strengthened to better track progress, evaluate compliance, and support greater mitigation.

Key findings

- Alberta underestimates methane emissions by relying on outdated reporting standards and modelling methods, undermining its ability to credibly demonstrate reductions.
- Federal estimates of Alberta oil and gas methane emissions were 1.9 times higher than provincial estimates for 2023. The federal inventory integrated aerial measurement data for greater reliability, while the provincial one did not.
- Despite the discrepancy between estimates, Alberta has made progress on reducing methane emissions. The federal inventory suggests that 2023 emissions were just over three-quarters of the way towards achieving the province's target of reducing methane emissions 45% (from 2014 levels by 2025). By contrast, based on industry self-reported data, the Government of Alberta announced in 2023 that it had met its target early. The federal inventory reported a drop of 35% in 2023, while the province claimed a decrease of 52%.
- In 2024, 94% of facilities that reported vent gas volumes stayed below measurement thresholds, permitting estimation rather than metering. This approach underestimates vent volumes and compromises data quality, hindering compliance evaluation.
- According to the federal inventory, vented emissions in Alberta were about five times higher (i.e., 580 kt more methane) than Alberta's estimates based on industry self-reported data alone.
- Venting from pneumatic controllers and pumps was a frequent and large source of emissions in separation applications, according to the alt-FEMP data. Our analysis revealed that pneumatics remain a significant source of methane emissions from the province's oil and gas industry, requiring stronger regulations.
- The alt-FEMP follow-up survey data had quality and standardization issues, limiting its reliability. We attribute this to shortcomings with the reporting framework, indicating the need for improvements.

- Until 2025, the province had a solution gas flaring limit. Flaring above this limit in 2024 was not a major source of methane emissions. However, solution gas flaring has more than doubled in Alberta since 2019, and removal of the limit as it pertains to routine flaring puts the province out of step with international best practices. Flaring is a serious threat to human and animal health and has historically generated significant concern in affected communities. Flaring also represents a wasted resource. The value of the flared solution gas in 2024 was $9.1 million.

Main recommendations for Alberta

- Require top-down methods to measure methane emissions from oil and gas facilities (vehicle-based systems, aircraft, drones, or continuous monitors) in addition to the close-range methods that are commonly used in leak detection and repair programs and integrate the resulting data into reporting.
- Improve the province's ability to credibly track and demonstrate reductions by basing estimates of oil and gas methane emissions on measurement data.
- Eliminate routine venting by 2030.
- Mandate the phase-out of existing natural gas-fired pneumatics by 2030 or sooner.
- Engage diverse interest holders, including academic experts, to co-develop and improve measurement and reporting frameworks and requirements to enhance the quality and accuracy of reported data.
- Eliminate routine flaring to reduce waste gas, improve the air quality and health in nearby communities, and align regulations with Canada's commitment to the World Bank's Zero Routine Flaring by 2030 Initiative.

1. Introduction

Canada emitted a total of 3,900 kt of methane — a potent greenhouse gas — in 2023, mainly from oil and gas production (1,870 kt), agriculture (1,100 kt), and landfills (700 kt).[1] Alberta's oil and gas industry was responsible for 1,240 kt or around two-thirds of Canada's total oil and gas methane emissions, with most of it attributable to conventional (non-oilsands) production. Thus, achieving Canada's national target of reducing oil and gas methane emissions 75% below 2012 levels by 2030 largely hinges on Alberta's oil and gas industry cutting emissions.

Alberta was an early mover in developing robust oil and gas methane regulations. The province took a strong stance on flaring in the 1990s.[2] It was the first Canadian province to formally adopt a 45% reduction target (from 2014 levels by 2025).[3] It also developed the innovative alternative-Fugitive Emissions Program (alt-FEMP), which gave companies the flexibility to use a wide array of measurement and monitoring technologies to meet their leak detection and repair obligations, rather than follow prescribed requirements.[4] As a result of this progressive regulatory environment, industry developed world-leading expertise through research initiatives such as emissions testing centres, and a robust technology and service industry emerged.[5]

The regulations to reduce methane emissions from Alberta's upstream oil and gas industry 45% came into force in 2020,[6] and the provincial government claimed to have surpassed its 2025 reduction target three years ahead of schedule.[7] However, this claim is based on modelling that uses data from traditional detection and quantification methods used on-site as part of leak detection and repair (LDAR) programs (e.g., infrared cameras and volumetric samplers). These conventional approaches often fail to detect large intermittent sources and are generally unable

[1] Environment and Climate Change Canada, *National Inventory Report 1990–2023: Greenhouse Gas Sources and Sinks in Canada* (2025), Part 3, Annex 9: Canada's Greenhouse Gas Emission Tables by IPCC Sector, Table A9-3. Report: Available at https://publications.gc.ca/site/eng/9.506002/publication.html. Data: Available at ECCC Data Catalogue, "Canada's Official Greenhouse Gas Inventory." https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/

[2] Tom Marr-Laing and Chris Severson-Baker, *Beyond Eco-terrorism: The deeper issues affecting Alberta's oilpatch* (Pembina Institute, 1999), 3. https://www.pembina.org/reports/beyond-ecoterrorism.pdf

[3] Government of Alberta, "Alberta's Environmental Leadership: Enabling emissions reductions." https://www.alberta.ca/enabling-emissions-reductions

[4] Alberta Methane Emissions Program, "Alt-FEMPs Now Complete." https://amep.ca/alt-femp-applications/

[5] Carbon Management Canada, "About CMC." https://cmcghg.com/about-us/

NGIF, "Field Testing." https://etc.ngif.ca/field-testing/

Marcy Lowe, *Canada's Methane Opportunity: Innovation, exports, jobs* (Datu Research, 2025). https://www.pembina.org/pub/canadas-methane-opportunity-innovation-exports-jobs

[6] Alberta Energy Regulator (AER), *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (2025). https://static.aer.ca/prd/documents/directives/Directive060.pdf

[7] Government of Alberta, "Alberta's Methane Emissions." https://www.alberta.ca/albertas-methane-emissions

to measure emissions from large and tall sources like tanks and compressor exhausts due to access and safety issues.[8] In contrast, recent studies have used alternative technologies, such as vehicle-based systems, aircraft, and satellites, to measure emissions. These newer methods have reshaped our understanding of the major emission sources and the scale of their impact.[9]

Notably, a recent measurement-informed inventory based on aircraft observations found that methane emissions from Alberta's oil and gas industry are 1.5 times higher than previously estimated, with tank venting identified as a large source of emissions and a major contributor to the discrepancy.[10] A measurement-informed inventory is a new approach for estimating methane emissions from the oil and gas industry, offering improved accuracy compared to traditional inventories.

Traditional inventories are usually based on emissions factors (emissions per unit or activity), engineering estimates, and activity factors (counts of units or activities) and often substantially underestimate emissions and poorly resolve source contributions.[11]

Measurement-informed inventories generally combine and scale up emissions measurements taken at the equipment or site level using alternative technologies in order to estimate total methane emissions at larger scales such as the operator, basin, or national level. This approach more accurately estimates total emissions and, depending on the measurement resolution, helps to identify the relative contributions of the different sources.

Despite these new insights into Alberta's oil and gas methane emissions, little public-facing work has been done to apply the findings from independent, top-down measurement studies (e.g., aircraft-based surveys) to enhance current regulations, improve reporting frameworks, or verify the province's claim to have met its 2025 target early.

This report addresses that gap by identifying data and regulatory shortcomings related to Alberta's oil and gas methane emissions. We analyze academic studies, reported vent and flare data, and new datasets from alt-FEMP follow-up surveys. The objective is to demonstrate how regulations, reporting frameworks, and emissions estimates can be improved to further reduce

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[8] Coleman Vollrath, Chris Hugenholtz, and Thomas Barchyn, "Onshore Methane Emissions Measurements from the Oil and Gas Industry: A Scoping Review," *Environmental Research Communications* 6, no. 3 (2024), 32001. https://doi.org/10.1088/2515-7620/ad3129

[9] Bradley Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta, Canada Reveals Higher Emissions and Different Sources than Official Estimates," *Communications Earth & Environment* 4, no. 1 (2023). https://doi.org/10.1038/s43247-023-01081-0

[10] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[11] Mark Omara et al., "Constructing a Measurement-Based Spatially Explicit Inventory of US Oil and Gas Methane Emissions (2021)." *Earth System Science Data* 16, no. 9 (2024). https://doi.org/10.5194/essd-16-3973-2024

methane in the province and enhance data quality for tracking progress and evaluating compliance.

2. Federal and provincial estimates

2.1 Background

The Government of Alberta estimates that the province exceeded its target of reducing oil and gas methane emissions 45% below 2014 levels by 2025, achieving reductions of 52% three years ahead of schedule. While results from Alberta's methane emissions model corroborate this (Figure 1),[12] the model uses a combination of industry-reported data and emissions and activity factors to estimate total emissions.[13] There are several issues with this.

First, "bottom-up" approaches to estimating emissions, like those used by Alberta's methane model, tend to poorly account for abnormal emissions or large but rare sources that skew rate distributions. A number of independent studies performed in Alberta using "top-down" methods such as vehicle-based systems and aircraft have shown that actual oil and gas methane emissions are much higher than suggested by the industry-reported data or government inventories.[14] The discrepancy is due to how the data is derived.

The bottom-up approach relies on scaling generic emissions factors or manufacturer-specified rates with activity factors or production data to estimate total emissions. This approach is prone to missing emissions that are difficult to calculate. Such limitations led Canada's auditor general to conclude in a 2023 report that the underestimation of methane emissions adds significant uncertainty to determining the effectiveness of methane regulations.[15]

The top-down approach generates estimates from atmospheric measurements that capture the spatial and temporal variability of emissions, as well as generally all methane molecules emitted by target sources.

Second, the industry-reported data used in Alberta's model has well-known quality issues. For example, the database of reported surface casing vent flows (SCVFs) contains records with

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[12] Government of Alberta, "Reducing Methane Emissions." https://www.alberta.ca/climate-methane-emissions

[13] AER, *ST60B-2025: Upstream Petroleum Industry Emissions Report* (2025), 43–44. https://static.aer.ca/prd/documents/sts/ST60-B-2025.pdf

[14] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

Daniel Zavala-Araiza et al., "Methane Emissions from Oil and Gas Production Sites in Alberta, Canada," *Elementa* 6, no. 1 (2018). https://doi.org/10.1525/elementa.284

Elton Chan et al., "Eight-Year Estimates of Methane Emissions from Oil and Gas Operations in Western Canada Are Nearly Twice Those Reported in Inventories," *Environmental Science & Technology* 54, no. 23 (2020). https://doi.org/10.1021/acs.est.0c04117

[15] Office of the Auditor General of Canada, *Report 5: Emissions Reductions Through Greenhouse Gas Regulations—Environment and Climate Change Canada*, Report of the Commissioner of the Environment and Sustainable Development (2023). publications.gc.ca/collections/collection_2023/bvg-oag/FA1-26-2023-1-5-eng.pdf

missing fields and unclear entries, according to two independent analyses.[16] These issues make it challenging to use the data to reliably estimate SCVF emissions, creating uncertainty over their magnitude and contribution to total emissions.[17]

Third, bottom-up estimates are often paired with a relative reduction target, such as Alberta's target of 45% below 2014 levels by 2025. When the underlying data and assumptions used in bottom-up estimates are updated to reflect new information or methods, the baseline can change and, subsequently, so can estimated policy effectiveness.[18]

2.2 Data analysis

These issues become apparent when comparing annual estimates of oil and gas methane emissions from Alberta's methane model to Environment and Climate Change Canada's (ECCC's) 2023 National Inventory Report (NIR) for Alberta (Figure 1). Estimates from the latter are 1.9 times larger, on average, than Alberta's estimates from 2014 to 2023. This is noteworthy in that aerial data were integrated into Canada's 2023 NIR to address the large discrepancies between academic studies and previous NIRs.[19] Unlike the NIR, to our knowledge measurement data from vehicle-based systems, aircraft, or other alternative technologies — which may better represent actual emissions — are not used in Alberta's model.

NIR estimates of oil and gas methane emissions for Alberta challenge the province's claim to have met its reduction target early. Figure 1 shows that Alberta's methane emissions have declined, but by 35% since 2014, not 52%. Based on this data, the province still had another 10% to go in order to meet the 2025 target. This example highlights the poor defensibility of using relative reductions to track, evaluate, and demonstrate the performance of regulations when the underlying estimates are flawed.[20]

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[16] Amanda Bryant, *Unfinished Business: Addressing the emissions and environmental risks of Canada's non-producing oil and gas wells* (Pembina Institute, 2025). pembina.org/sites/default/files/2025-08/Unfinished_Business.pdf

Scott Seymour, Donglai Xie, and Mary Kang, "Highly Uncertain Methane Leakage from Oil and Gas Wells in Canada Despite Measurement and Reporting," *Energy & Fuels* 38, no. 14 (2024). https://doi.org/10.1021/acs.energyfuels.4c00908

[17] Seymour et al., "Highly Uncertain Methane Leakage from Oil and Gas Wells in Canada Despite Measurement and Reporting."

[18] Bradley Conrad, David Tyner, and Matthew Johnson, "The Futility of Relative Methane Reduction Targets in the Absence of Measurement-Based Inventories," *Environmental Science & Technology* 57, no. 50 (2023). https://doi.org/10.1021/acs.est.3c07722

[19] Chan et al., "Hybrid Bottom-up and Top-down Framework Resolves Discrepancies in Canada's Oil and Gas Methane Inventories."

[20] Chan et al., "Hybrid Bottom-up and Top-down Framework Resolves Discrepancies in Canada's Oil and Gas Methane Inventories."

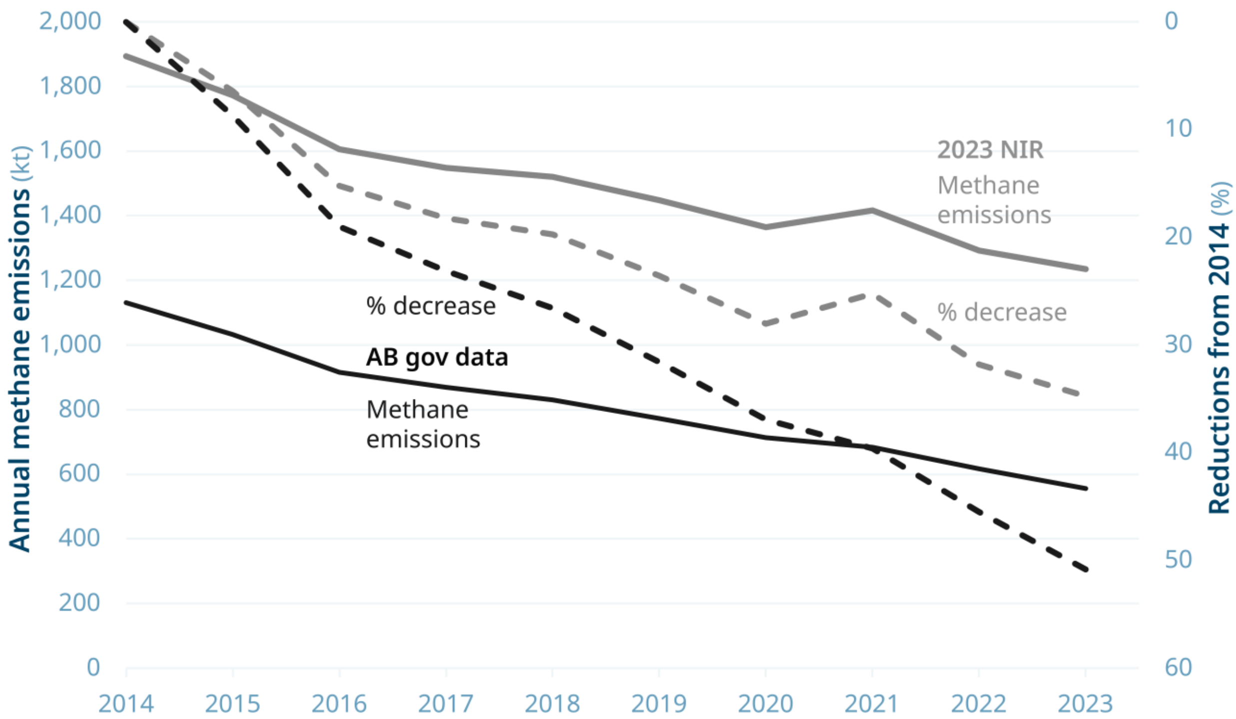

Figure 1. Federal versus Alberta estimates of the province's absolute and relative oil and gas methane emissions reductions

Data sources: Environment and Climate Change Canada, Government of Alberta[21]

It should be noted that underestimated emissions do not always translate to underestimated relative reductions. For instance, a study that independently built a bottom-up methane inventory for Saskatchewan's oil and gas industry found that despite a 30–40% upward correction in total emissions by integrating aerial measurements from cold heavy oil production with sand (CHOPS) sites, relative reductions still tracked 40–45% below 2012 levels by 2025, the target set by the federal government.[22] Most of the reductions in methane emissions in Saskatchewan have been attributed to a substantial decrease in oil and gas production at CHOPS sites (>70%) from 2012 onward.[23] In contrast, greater sensitivity of relative reductions in

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Conrad et al., "The Futility of Relative Methane Reduction Targets in the Absence of Measurement-Based Inventories."

[21] ECCC, *National Inventory Report 1990–2023*, Annex 9, Table A11-19. https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/

Government of Alberta, "Reducing Methane Emissions."

[22] Scott Seymour et al., "Saskatchewan's Oil and Gas Methane: How Have Underestimated Emissions in Canada Impacted Progress toward 2025 Climate Goals?" *Environmental Research Letters* 18, no. 8 (2023), 84004. https://doi.org/10.1088/1748-9326/ace271

[23] Conrad et al., "The Futility of Relative Methane Reduction Targets in the Absence of Measurement-Based Inventories."

Alberta to measurement data could mean that the province's model overestimates reductions or that regulations have not achieved expected outcomes in some cases.

2.3 Gaps and recommendations

The Government of Alberta has invested heavily in various programs for methane emissions measurement and mitigation technologies over the last several years, including the Alberta Methane Emissions Measurement Program, the Natural Gas Innovation Fund, Emissions Testing Centre Program, Emissions Reduction Alberta, the Baseline and Reduction Opportunity Assessment Program, and the Methane Technology Implementation Program.[24]

Despite this — and despite the abundance of new, top-down measurement data generated by these programs and others — provincial methods and data to estimate methane emissions remain flawed and outdated. While Alberta's inventory approach has not kept pace with leading practices, Canada's NIR has. This partly explains why NIR estimates of Alberta's methane emissions align with independent studies,[25] whereas Alberta's own estimates are much lower. Overall, this lack of alignment demonstrates that Alberta's data cannot be reliably used to track reductions. It also challenges the validity of Alberta's claim to have met its methane target early.

We recommend that Alberta build defensible estimates of methane emissions using up-to-date measurement data and methods so that the province can accurately track progress and reductions — and, in turn, tell credible success stories. These methods and estimates should also be fully transparent, with clearly stated assumptions and data sources to enable independent scrutiny and comparison with other emissions modelling approaches.

[24] Government of Alberta, "Alberta's Methane Emissions."

[25] Chan et al., "Hybrid Bottom-up and Top-down Framework Resolves Discrepancies in Canada's Oil and Gas Methane Inventories."

Katlyn MacKay et al., "A Comprehensive Integration and Synthesis of Methane Emissions from Canada's Oil and Gas Value Chain," *Environmental Science & Technology* 58, no. 32 (2024). https://doi.org/10.1021/acs.est.4c03651

3. Venting

3.1 Background

Intentional, routine venting is the dominant source of methane emissions from Alberta's energy sector and is estimated to be responsible for approximately 63% of total oil and gas methane emissions.[26] New empirical measurements have provided a clearer picture of the magnitude of the problem and of the emitting sources. With this information, there is an opportunity to advance methane mitigation by refining policies and updating regulations.

Major known vent sources are hydrocarbon storage tanks and pneumatic instruments (pumps and controllers).[27] This report expands on the latter within separation applications in Section 5, emphasizing their importance as a large emissions source in aggregate.

There are proven mitigation options to reduce tank and pneumatic emissions. These include tying tank vents into vapour recovery units (VRUs) to capture methane and other gases for on-site use or sale and replacing or retrofitting pneumatic instruments so that they are run on instrument air, electricity, or nitrogen.[28]

To identify data and regulatory gaps related to venting, we analyzed four main sources:

- Petrinex data for 2024[29]
- AER *ST60B-2025* summarizing the OneStop emissions data for 2024
- Canada's NIR for 2023
- aerial methane measurements across Alberta sites[30]

Petrinex and OneStop are the main reporting platforms that companies must use to submit data to the AER, with each serving a different purpose.

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[26] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[27] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[28] U.S. Environmental Protection Agency Natural Gas STAR Program, *Vapor Recovery Units* (2025). https://www.epa.gov/natural-gas-star-program/vapor-recovery-units

U.S. Environmental Protection Agency Natural Gas STAR Program, *Instrument Air Controllers* (2025). https://www.epa.gov/natural-gas-star-program/instrument-air-controllers

[29] Petrinex, "Conventional Volumetric Data Download (2024)", spreadsheet, downloaded January 8, 2026. https://www.petrinex.ca/PD/Pages/APD.aspx

[30] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

- Petrinex: Companies submit monthly volumes of production; routine and non-routine (e.g., emergencies, maintenance) venting; flaring; and on-site fuel use. These volumes are reported at the facility scale. The venting data is not broken down by vent source.
- OneStop: Companies submit annual methane emissions reports, which include estimates of fugitive emissions and routine venting (e.g., pneumatics, tanks, compressors). The venting data is broken down into five categories: pneumatic instrument, pneumatic pump, compressor, dehydrator, and routine vent (which we interpret mainly as tank but possibly other vents).[31]

3.2 Data analysis

In 2024, 12,973 unique facilities reported venting to Petrinex. Total vent volumes were 272 million m^3, with solution gas venting accounting for 99.5 million m^3 (36.6% of the total). Compared to 2023, this represents a 10.4% decrease in total venting and a 10% decrease in solution gas venting.[32] See Appendix Section A.1 for details on the method used to disambiguate between facilities that produce solution gas and those that do not.

Routine vented emissions reported in OneStop in 2024 totalled 283 million m^3. This is similar to our estimate derived from the Petrinex data; however, OneStop only includes routine venting. The AER states that Petrinex vent volumes should be higher, given that routine and non-routine vents are reported to Petrinex.[33]

Differences in how the emissions are reported to the two platforms could explain the discrepancy, but the fact that OneStop vented emissions are higher than Petrinex suggests that most venting in Alberta could be routine, while non-routine venting is potentially a minor contributor to total methane emissions. The discrepancies between Petrinex and OneStop make this unclear.

The overall vent gas (OVG) limit for oil and gas sites in Alberta is 15,000 m^3/month.[34] The AER defines a "site" and a "facility" differently. A facility is energy infrastructure licensed and regulated by the AER (e.g., gas plant). A site is the physical area defined by surface lease boundaries, which may contain one or more facilities.[35]

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[31] AER, *ST60B*.

[32] AER, "Emissions Data." https://www.aer.ca/data-and-performance-reports/industry-performance/methane-performance/emissions-data

[33] AER, *ST60B*.

[34] AER, *Directive 060*.

[35] AER, *Directive 060*.

Petrinex vent data is reported at the facility level. Given that sites could have multiple facilities, we used the Petrinex data and the OVG limit to approximate compliance. Regulations also stipulate a defined vent gas (DVG) limit of 3000 m^3/month, which is for routine venting from sources other than pneumatics, compressor seals, and dehydrators (i.e., tanks).[36] Compliance with the DVG limit could not be approximated from the Petrinex data because the reported vent volumes are undifferentiated.

Based on the annual OVG limit of 180,000 m^3/yr, extrapolated from the monthly limit (15,000 m^3/month × 12 months), 180 (1.4%) facilities were noncompliant in 2024. Combined, these noncompliant facilities vented 53 million m^3 of natural gas above the OVG limit — or 28.4 kt of methane, assuming 0.68 kg/m^3 methane and a natural gas methane content of 79%.[37] The vented emissions above the OVG limit accounted for 19.5% of total reported vent volumes in 2024.

The issue with these numbers is that they provide an inaccurate picture of total vented emissions, with academic research demonstrating that reported vent volumes substantially underestimate actual venting.[38] This may be partly because only "flared and vented volumes at all oil or gas production or processing facilities (including thermal in situ facilities…) where annual average total flared and vented volumes per facility exceed [500] m^3/d (excluding pilot, purge, or dilution gas) must be metered."[39] Flare and vent volumes below that threshold may be estimated. The method used to estimate flare and vent gas volumes at these facilities typically involves multiplying the gas-to-oil ratio (GOR) and produced oil volumes, which is a flawed approach to estimating emissions.

The most recent measurement-based inventory for Alberta's oil and gas methane emissions, derived from aircraft measurements done in 2021, suggests that actual vent emissions were 5.5 times higher than reported venting that year.[40] Canada's 2023 NIR estimated vent emissions of 730 kt — 59.1% of total oil and gas methane emissions in Alberta. Figure 2 shows that this estimate is 4.8 to 5 times higher than total vented emissions based on 2024 OneStop and Petrinex data. Although the NIR estimate is for a year earlier since 2024 data was unavailable at

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[36] AER, *Directive 060*.

[37] AER, *Directive 060*.

Government of Canada, *Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*, "Regulatory Impact Analysis Statement," *Canada Gazette*, Part I, 158, no. 50. https://gazette.gc.ca/rp-pr/p1/2023/2023-12-16/html/reg3-eng.html

[38] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[39] AER, *Directive 017: Measurement Requirements for Oil and Gas Operations* (2024), section 1.7.2(vi). https://www.aer.ca/regulations-and-compliance-enforcement/rules-and-regulations/directives/directive-017

[40] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

the time of writing, the general finding of a substantial discrepancy should hold even with the 2024 NIR data.

The variation in totals for the inventories captured in Figure 2 can be partly explained by the different source categories. For instance, the NIR includes venting at oilsands sites and midstream releases, while Petrinex and OneStop do not. However, that does not sufficiently account for the magnitude of the differences.

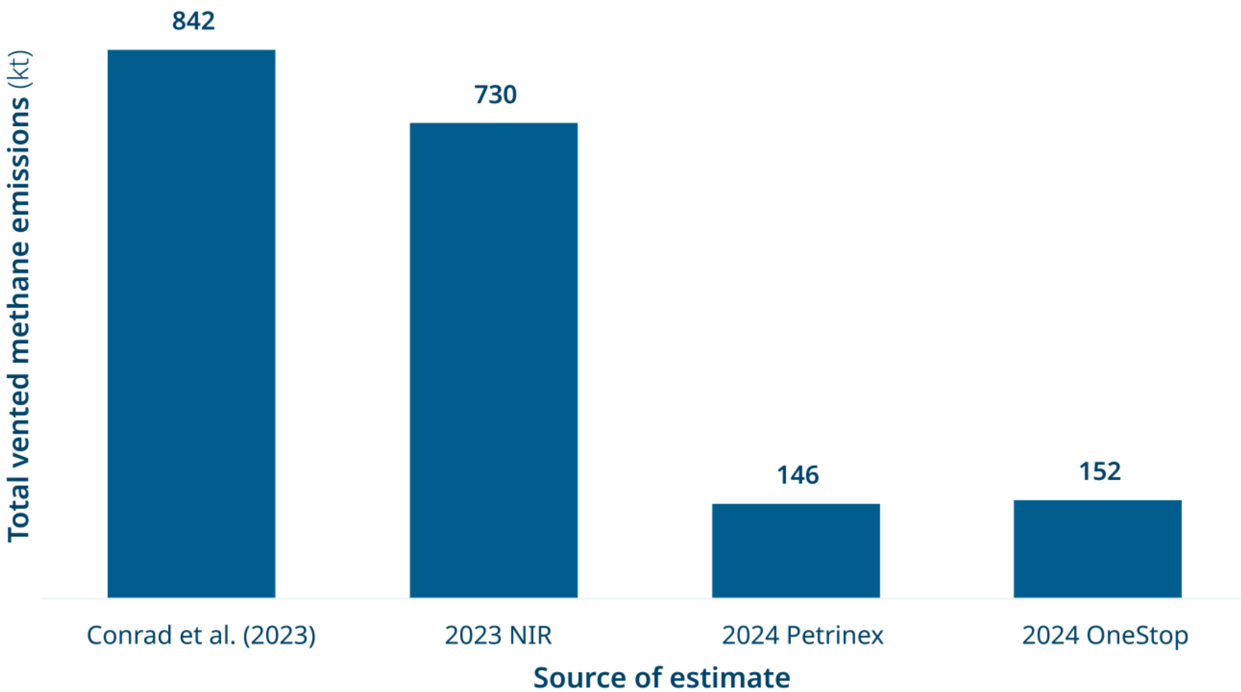

Figure 2. Comparison of venting estimates for Alberta

Data sources: Alberta Energy Regulator, Conrad et al., Government of Canada, Petrinex[41]

The major challenge with the Petrinex data is accurately capturing the number and severity of exceedances at sites. It is not possible to assess compliance by simply scaling reported volumes by a factor of 5.5 (based on the measurement-based inventory), since the actual locations and magnitudes of measured emissions may vary considerably from the reported data.

According to Petrinex, out of the 12,973 facilities reporting in 2024, 758 facilities reported combined flare and vent gas volumes that exceeded 500 m^3/d, on average. Vent volumes at these facilities totalled 65.8 million m^3, which we assumed were metered or directly measured

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[41] AER, *ST60B*.

Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

ECCC, *National Inventory Report 1990–2023*, Part 3, Annex 9: Canada's Greenhouse Gas Emission Tables by IPCC Sector, 1990-2023, Table A11-19. https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/

Petrinex, "Conventional Volumetric Data Download (2024)."

given regulatory requirements.[42] Of the remaining 12,215 facilities, 12,125 reported vent volumes ≤500 m^3/d. This indicates that vent gas volumes are likely estimated at most facilities (93.5%) since they fall under the metering threshold. However, the number of sites where vent gas volumes are unmeasured could be lower given that a site may have more than one facility. For example, if a site had three facilities, each reporting 200 m^3/d of flare/vent gas, the reported volume in aggregate would exceed the 500 m^3/d measurement threshold. Thus, when interpreting our results, bear in mind that the analysis was performed at the facility level (reflecting Petrinex reporting) instead of the site level.

The fact that most facilities reported vent volumes of ≤500 m^3/d to Petrinex in 2024 suggests that venting may be widely underestimated across Alberta, potentially due to a lack of metering or direct measurement at tens of thousands of facilities. Alternatively, the underestimation could be localized to a subset of facilities that are venting very high volumes of gas. This is an important distinction for informing mitigation. For example, if a relatively small proportion of facilities are venting substantial quantities of methane—which measurement-based[43] and 2024 OneStop estimates both indicate are mainly from tanks and pneumatics — then focusing additional action at those facilities may accelerate reductions.

3.3 Gaps and recommendations

Actual vent emissions are much higher than official estimates. According to our analysis, flawed estimation methods undermine reported data quality and, along with it, the AER's ability to assess sites' compliance with OVG and DVG limits and design enhanced mitigations. According to the federal inventory, vented emissions in Alberta were about five times higher (i.e., 580 kt more methane) than those reported in 2024 Petrinex and OneStop datasets, indicating that OVG and DVG limits have only been partially effective at reducing emissions. Although reported venting has decreased,[44] the AER cannot fully gauge the effectiveness of the province's OVG and DVG limits based on the current reported data.

We recommend that Alberta require top-down methods to measure methane emissions from oil and gas facilities and integrate the resulting data into reporting. This should include top-down measurement approaches using platforms such as vehicle-based systems or aircraft, as well as close-range methods, like those commonly used in LDAR programs. These approaches are complementary, and aligning them with reporting

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[42] AER, *Directive 017*, section 1.7.2(vi)

[43] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[44] AER, "Emissions Data."

level 5 under the Oil and Gas Methane Partnership (OGMP) 2.0 Framework can provide deeper insights.[45]

The changes to reporting should include:

- Overhauling existing industry reporting requirements and frameworks to incorporate alternative methane emissions measurement methods such as vehicle-based systems or aircraft.
- Eliminating the traditional classification system that distinguishes between fugitive and vented emissions and requiring operators to report facility-scale rates or methane intensities, complemented by close-range measurements that can diagnose root cause for mitigating emissions.
- Requiring that industry perform measurements as part of LDAR programs or broader, forward-looking emissions management programs that are less reliant on classing emissions, with data reported to the AER.

These actions would minimize overlapping regulations and duplicative costs while enhancing methane data quality and supporting more accurate, effective compliance and enforcement activities. The data should continue to be made publicly available.

We also recommend that Alberta eliminate routine venting by 2030.

This may require gradually reducing site-level vent limits to zero given the number of facilities in Alberta.

Eliminating routine venting would significantly reduce emissions, primarily from tanks and pneumatics, which are currently estimated to emit at least 47% of industry's methane in the province.[46]

To prioritize and accelerate mitigation, accurate information is urgently needed about where the highest emitting facilities are. Rapidly overhauling reporting requirements and frameworks to incorporate top-down measurements of facilities could help pinpoint and track priority targets for mitigation. Improving the data in the ways we recommend would also improve the carbon competitiveness and credibility of the province's oil and gas sector in key international markets that are now seeking verified low-methane energy imports.

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[45] United Nations Environment Program, *Mineral Methane Initiative: OGMP 2.0 Framework* (2025). https://www.ogmpartnership.org/sites/default/files/resources/2025-04/OGMP_20_Reporting_Framework.pdf

[46] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

In addition to methane, natural gas in the production or processing phase in Alberta contains volatile organic compounds — between 2% and 14%, depending on the type of site.[47] Eliminating routine venting would also limit their release, improving air quality and the health of local communities.

[47] Government of Canada, "Regulatory Impact Analysis Statement."

4. Methane emissions from separator buildings

4.1 Background

Recent measurement-informed inventory estimates of Alberta's oil and gas methane emissions totalled 1,337 kt/y. Of these emissions, 20% were attributed to separator buildings.[48] This differs from British Columbia, where 9% of measurement-informed inventory estimates were attributed to separator buildings.[49] In Saskatchewan, tanks act as separators for oil, gas, sand, and water at CHOPS wells, meaning that separator buildings may not be as relevant a source there.[50]

It is important to note that separator buildings are not a distinct emissions source. The aerial methods used in the recent studies cannot differentiate between methane emissions originating from within the buildings (e.g., pneumatic instrument vents tied into a single pipe and vented outside) and those from adjacent to them (e.g., separator tanks).

Methane emissions from separation processes can potentially be reduced in both jurisdictions, especially Alberta. However, accurately identifying the actual sources and determining whether they are covered by existing regulations is essential.

In B.C., on-site observations with infrared cameras supplemented aircraft measurements to pinpoint the emitting sources from separator buildings detected from the air.[51] The observations suggested that pneumatic instruments were likely the main source of emissions. Given the role controllers play in separation, it is reasonable to assume that these instruments are predominately pneumatic controllers. In separation, they emit methane at higher rates than in most other applications at oil and gas sites.[52] They use process gas to actuate separator valves

[48] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[49] Matthew Johnson, Bradley Conrad, and David Tyner, "Creating Measurement-Based Oil and Gas Sector Methane Inventories Using Source-Resolved Aerial Surveys," *Communications Earth & Environment* 4, no. 1 (2023). https://doi.org/10.1038/s43247-023-00769-7

[50] Simon Festa-Bianchet et al., "Methane Venting at Cold Heavy Oil Production with Sand (CHOPS) Facilities is Significantly Underreported and Led by High-Emitting Wells with Low or Negative Value," *Environmental Science & Technology* 57, no. 8 (2023). https://doi.org/10.1021/acs.est.2c06255

[51] Matthew Johnson, David Tyner, and Bradley Conrad, "Origins of Oil and Gas Sector Methane Emissions: On-Site Investigations of Aerial Measured Sources," *Environmental Science & Technology* 57, no. 6 (2023). https://doi.org/10.1021/acs.est.2c07318

[52] David Allen et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers," *Environmental Science & Technology* 49, no. 1 (2015). https://doi.org/10.1021/es5040156

when liquids (water, oil, or both) reach a certain level in the vessel, releasing them into the next process phase (e.g., additional treatment or storage in hydrocarbon tanks). Gas-driven controllers vent the gas used either continuously or intermittently.

The B.C. study estimated that the pneumatics were venting methane at much higher rates than manufacturer-specified or design rates.[53] This could indicate abnormal operation, but flawed manufacturer rate estimates cannot be ruled out. Alternatively, pneumatic vent rates could increase above design rates as the components within pneumatics degrade with age.

The largest emitting source from separator buildings pinpointed in the B.C. study was a group vent (a vent line tied into multiple sources inside the separator building). Other sources included pressure relief valves, fuel gas regulators, vent lines from other devices, and a catalytic heater. Consistent with the findings in B.C., a study in the Permian Basin in Texas found that pneumatic controllers and valves on separators were prevalent sources of emissions across sites, as identified with infrared cameras from site fencelines.[54]

There are several reasons that could explain the larger contribution of separator buildings to total oil and gas methane emissions in Alberta compared to B.C., assuming that pneumatics are the dominant source. First, pneumatic controllers on separators in Alberta could be emitting methane at higher rates than those in B.C. due to higher liquids production. A study that measured methane emissions from pneumatic controllers on well sites in different regions in the U.S. found that controllers involved in separation in liquids-rich regions such as the Gulf Coast had the highest vent rates, although the reason why was unclear.[55] Second, Alberta has a large stock of old oil and gas wells. There could be many aging pneumatic controllers in separator buildings that are degraded and emitting well above manufacturer-specified rates. Third, the AER has not mandated a timeline for the phase out of existing natural gas-driven pneumatics, whereas B.C. has.[56] B.C. has also included methane emissions from pneumatics in its provincial carbon pricing system. Thus, natural gas-driven pneumatics may be less prevalent in B.C., where an increasing number of sites could be using instrument air, electricity, or nitrogen to drive pneumatics. Regardless, it is necessary to confirm that pneumatics are a large source of emissions from separation at sites in Alberta — a question we turn to in our data analysis.

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[53] Johnson et al., "Origins of Oil and Gas Sector Methane Emissions: On-Site Investigations of Aerial Measured Sources."

[54] Dana Caulton, et al., "Abnormal Tank Emissions in the Permian Basin Identified Using Ethane to Methane Ratios," *Elementa* 11, no. 1 (2023). https://doi.org/10.1525/elementa.2022.00121

[55] Allen et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers."

[56] British Columbia Energy Regulator, *Drilling and Production Regulation*. https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/282_2010

4.2 Data analysis

In Alberta, operators must implement fugitive emissions management programs (FEMPs), which are otherwise known as LDAR programs. FEMPs consist of periodic screenings and surveys of sites to find and reduce fugitive emissions.[57] *Fugitive emissions* are the unintentional or accidental release of methane from components or on-site equipment, which can be leaks or other abnormal emissions. *Vented emissions*, on the other hand, are the intentional or routine release of methane to the atmosphere as part of normal on-site processes.

FEMP screenings and surveys have traditionally been done using audio, visual, and olfactory methods and handheld gas sniffers or infrared cameras that detect methane emissions. The AER now permits operators to use alternative technologies such as vehicle-based systems or aircraft that can meet the AER's criteria for detecting methane emissions. Programs using these technologies are called alt-FEMPs.

The premise of an alt-FEMP is to implement a tiered approach for LDAR, where a less sensitive, alternative method (e.g., vehicle-based system, aircraft, continuous monitoring) screens many sites for methane emissions, and then a more sensitive method (e.g., infrared camera, handheld gas sniffer) is used to follow up at the emitting sites to pinpoint the emitting source for repair.[58]

It is important to point out that the follow-up survey data differs critically from the screening data, which provides rate estimates from alternative methods at the equipment group or site level. While screening data is used in inventories to improve estimates of total emissions, their spatial resolution is coarser, and they do not always resolve the emitting sources. This highlights the need for accurate source attribution at more granular spatial scales, such as those provided by the alt-FEMP follow-up surveys, to confirm the emissions sources when they are unresolved in screening measurements.

In general, follow-up surveys target only a subset of emitting sites (usually those at higher rates), enabling prioritization of the largest methane volumes for abatement. This approach can save time and costs over traditional approaches such as deploying ground crews with infrared cameras to all sites, as not all sites may be emitting at sufficient rates to warrant on-site surveys. Among its limitations, though, is that alternative methods are normally less sensitive than traditional on-site survey methods, which can leave emitting sources unmitigated. Additionally, alternative methods usually cannot differentiate between fugitive emissions and vented emissions, which limits their effectiveness in tackling fugitives. Emitting sources can be

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[57] AER, *Directive 060.*

[58] Thomas Fox et al., "A Review of Close-Range and Screening Technologies for Mitigating Fugitive Methane Emissions in Upstream Oil and Gas," *Environmental Research Letters* 14, no. 5 (2019), 53002. https://doi.org/10.1088/1748-9326/ab0cc3

classified during on-site follow-up with infrared cameras and their rates directly quantified using volumetric samplers, quantitative optical gas imaging, or emissions estimation techniques following AER Manual 015. Depending on the alternative method used and its spatial resolution, source types can also be assumed based on the equipment groups from which emissions were detected on site.[59] Only fugitive emissions are within the reporting scope for traditional FEMPs, whereas for alt-FEMPs, fugitives and vents are within scope in cases where the source type is determined.[60]

The on-site measurement data needed to confirm that pneumatics are a large source of methane emissions from separation at sites in Alberta is lacking in academic studies. However, the AER recently released reports, including emissions rate data, submitted by several operators as part of pilot and full-scale alt-FEMPs implemented across facilities in the province over the last several years.[61] To better understand the sources of emissions from separator buildings in Alberta, we examined the reported follow-up data for three operators: ARC Resources, Bonavista (labelled "Tourmaline" in the AER data; due to Tourmaline's subsequent acquisition of Bonavista), and Sundre Petroleum Operators Group (SPOG) — a consortium of 11 operators in Alberta. We chose these producers given the availability of follow-up rate data for both fugitives and vents and the large number of sites covered by their alt-FEMPs (2,246). Notably, in searching for usable data, we found that some operators, such as Canadian Natural Resources Limited and Cenovus, scrubbed follow-up vent rates from their reports and only reported fugitive emissions.

AER reporting instructions for alt-FEMPs required producers to specify the emissions type (fugitive, vent, combustion slip), equipment group, and component type from which methane emissions were detected in follow-up surveys. We used these to filter for and examine the sources and rates of emissions from separators. (See section A.3 in the appendix for additional details on our methodology).

We found that separators were responsible for between 9% and 42% of total methane emissions depending on the operator, highlighting the potential for separator-related emissions across Alberta to be substantial (Figure 3). It is important to note that total methane emissions and the proportion of emissions from separation shown in Figure 3 are modulated by several factors, including the number of sites covered in each alt-FEMP, the number of screenings done to identify emitting sites, the screening technology or method used and its detection limit, site

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[59] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[60] AER, *Directive 060*.

[61] AER, "Alternative Fugitive Emission Management Program (alt-FEMP) Approvals." https://www.aer.ca/data-and-performance-reports/industry-performance/methane-performance/alternative-fugitive-emission-management-program-alt-femp-approvals

emissions profiles (i.e., the presence and magnitude of emissions, which affects detectability in screenings), the proportion of sites that received follow-up after screening (e.g., top 10% or 40% emitting sites), and company culture. Figure 3 also shows that vented emissions were the dominant source within the separator equipment group (between 69% and 87% of total separator emissions).

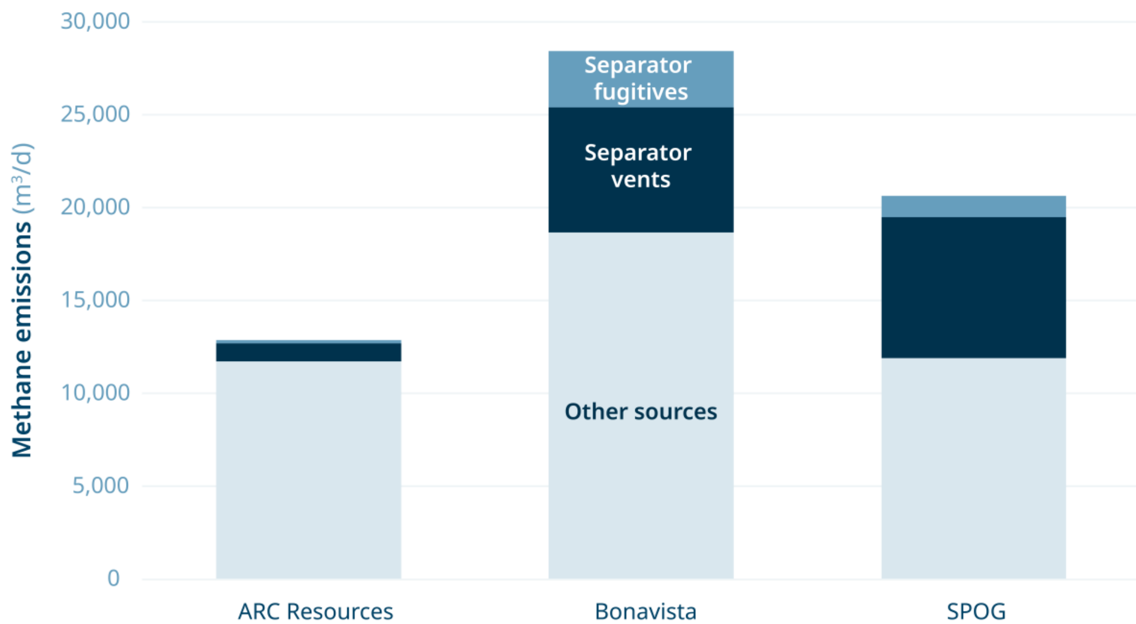

Figure 3. Measured methane emissions for selected producers and sources

Data source: Alberta Energy Regulator[62]

ARC Resources reported 1,725 emissions measurements. Of these, 148 were from the separator equipment group, with 90 vents and 58 fugitives. Most vent measurements were of the “other” component type (74), preventing source identification. These sources were responsible for 616.2 m^3/d (63.9%) of the 965 m^3/d from venting in separation. No comments on these sources were provided despite AER instructions to provide comments on all “other” types. We hypothesize that the “other” type was used to represent pneumatic (controller and pump) vents in the absence of a more representative component type in the AER’s instructions. No repairs of these sources were noted in the data, suggesting that they were vents. The exception was one case where the vent was misdiagnosed as a fugitive. ARC commented that the pump ran off instrument air, meaning that something leaking upstream in the process was causing the pump to emit methane. The proportion of sites in ARC’s alt-FEMP with air-driven pneumatics is unknown, but widespread use of this mitigation technology across sites could partly explain ARC’s lower emissions from separation compared to the other two producers. Regulators (10)

[62] AER, “Alternative Fugitive Emission Management Program (alt-FEMP) Approvals.”

were responsible for most of ARC's remaining vent emissions from separation (302.1 m^3/d, 31.3%). Fugitive component types included connectors, flanges, pressure relief valves, threaded connections, regulators, seals, and valves. Repairs involving tightening, replacing diaphragms or gaskets, or other repair actions were noted for all fugitives.

Bonavista reported 6,360 emissions measurements. Of these, 2,951 were from separation, with 1,717 vents and 1,234 fugitives. "Open-ended lines (OELs)" dominated the reported vents (1,559 out of 1,717). We reviewed the comments listed for all OEL records and found that 585 contained "controller," of which 390 had "level controller." Methane emissions from level controllers totalled 859.9 m^3/d, out of approximately 1,311.6 m^3/d from all controllers. A total of 257 records contained "pump," which represented chemical injection pumps. These were responsible for 1,004 m^3/d of emissions. "Instrument group vents" were associated with 75 unique records and 611 m^3/d of emissions. Combined, pneumatic instruments accounted for at least 2,926.6 m^3/d (30%) of all separator emissions. The actual value may be higher given variability in how similar sources were described in the data, likely reflecting differences in reporting practices between multiple operators. We noted that separator tank or "pop tank" vents have the highest emissions rates of all vent sources from separation.[63] Pop tank vents were associated with only 196 of the 1,717 vent records but were responsible for 1,984.6 m^3/d (20.3%) of all separator emissions. Regulator vents were another source prevalent in the data (112) but were responsible for fewer emissions (269.7 m^3/d, 2.8%). Fugitives were predominantly connector, valve, flange and other (seals on level controllers) types. Repair dates for most of the fugitives were included in the data.

SPOG's data required additional filtering and steps to identify emissions sources from separation as reporting practices varied among the 11 producers comprising SPOG (see the appendix for methodology). SPOG reported 1,617 emissions measurements. Of these, 630 were from separation. Our review of the data suggests that "vent" and "device" were used to describe instrument vents from separation. In total, 580 of these sources were recorded, with emissions of 7,594.8 m^3/d, representing nearly all (86.9%) of the 8,740.6 m^3/d emitted from separation. Of the 580 instrument vent records, 134 had the comment "pneumatic instrument vent rate" (2,005.2 m^3/d, 22.9%), 166 contained the term "controller" (2124.9 m^3/d, 24.3%), 55 included "pump" (882.7 m^3/d, 10.1%), and 13 had "group vent" (194.5 m^3/d, 2.2%). Other vent sources were transducers, building vents, and "level shutdowns." Thirty-one comments for vents were also left blank, suggesting that these were pneumatic or other instrument vents (672.6 m^3/d, 7.7%). In contrast to Bonavista's data, "tank" appeared in the comments for only three vent records. Fugitive component types were predominantly seals, connectors, and "body." Based on

[63] Pop tanks are tied into pressure relief devices on separators and are designed to handle vessel over-pressurization and flow from oil wells. (AER, *Frequently Asked Questions: Directive 056 – Facilities Technical* (2017). https://static.aer.ca/prd/documents/directives/Directive056_Facilities_Technical_FAQ_0.pdf)

record comments, the latter was used to represent sources such as leaking valves or regulator diaphragms or similar.

Overall, the alt-FEMP follow-up data demonstrates that venting from separation is a large source of methane emissions, which may be unsurprising to operators as this venting is intentional and part of on-site processes. Vent materiality varied by producer (between 69% and 87% of all identified separator emissions), which may reflect differences between producers in site engineering, corporate culture, and the adoption of mitigation technologies (e.g., air-driven pneumatics). Pneumatic controllers (level and other) and pump vents were a large source of methane emissions in aggregate. Pop tanks were also a large emissions source but only for Bonavista. It is unclear why pop tanks were not a more prevalent source from separation in the other producers' data. This could be due to differences in the number of liquids-producing sites in the alt-FEMPs, site engineering, implementation of mitigation options to control pop tank vapours, or differences in how the three producers reported their follow-up data despite being provided with a framework. Regulator and other instrumentation vents within separator buildings, which were often tied into a single "group vent," were responsible for most of the remaining vent emissions from separation.

Our analysis of the alt-FEMP data identified various issues with data quality and deviations from the AER reporting framework and definitions. Some of these issues appeared to stem from confusion over what constitutes an equipment group and the spatial scale of emissions. For example, pneumatic controllers and pumps, as well as separators, were all listed as possible equipment groups under the AER's instructions and definitions. If a pneumatic is installed on a separator to control liquids levels and is emitting, the reporting instructions do not clearly indicate whether it should be reported under "pneumatic instrument" or "separator." There was also no "instrument vent" component type in the instructions and definitions. This likely forced producers such as SPOG to deviate from the reporting structure, report emissions by process block instead of equipment group, and create an independent column for component subtype. These data quality issues create ambiguity over the emitting sources and have implications for using the data to develop tailored regulations and strategies to reduce methane. As such, improvements to alt-FEMP reporting frameworks with emphasis on the follow-up data are warranted.

4.3 Gaps and recommendations

Our analysis of the alt-FEMP follow-up data revealed several opportunities to deepen methane reductions and improve the quality of reported data, which are described below.

Existing natural gas-driven pneumatic controllers and pumps in separation and other applications represent an important opportunity for additional reductions. Current AER regulations stipulate that vent gas must be prevented or controlled from new pneumatic instruments (controllers) and from pumps operating more than 750 hr/yr.[64] Existing pneumatics must have a manufacturer-specified steady-state vent rate of less than 0.17 m^3/hr. Pneumatic level controllers must not actuate more than once every 15 minutes.[65]

Crucially, Alberta's regulations do not include a timeline to phase out existing gas-fired pneumatics. This is out of step with federal regulations, as well as those in Saskatchewan and B.C., which stipulate the complete phase-out of all gas-fired pneumatics at sites by 2030, 2028, and 2035, respectively.[66] In Alberta, producers have been able to partially recover the costs of replacing or retrofitting gas-fired pneumatics by generating carbon credits under the province's Technology Innovation and Emissions Reduction (TIER) Regulation and selling them through the Alberta Emissions Offset Registry.[67] By not mandating the phase-out of existing gas-fired pneumatics, the AER is missing out on an opportunity to promote greater reductions in emissions.

We recommend that Alberta mandate the phase-out of existing natural gas-fired pneumatics by 2030, consistent with the federal methane emissions regulations,[68] or sooner. Priority should be given to mitigating existing pneumatics in separation applications, where devices such as level controllers may produce disproportionally high emissions compared to other applications.

This recommendation is supported by various factors. Technology to replace and retrofit gas-fired pneumatics is available, scalable and, in the case of instrument air or nitrogen, can be implemented in remote locations. Mitigation activities also support jobs in the oil and gas sector and its associated service industries. Moreover, pneumatic conversions are no longer a cutting-edge technology.

Implementing the recommendation would require eliminating the TIER credit for switching to zero-emitting pneumatics since credit can only be given for emissions reductions that result

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[64] AER, *Directive 060*.

[65] AER, *Directive 060*.

[66] British Columbia Energy Regulator, *Drilling and Production Regulation*.

Government of Canada, "Regulatory Impact Analysis Statement."

Government of Saskatchewan, *Directive PNG036: Venting and Flaring Requirements*. https://www.saskatchewan.ca/business/agriculture-natural-resources-and-industry/oil-and-gas/environmental-protection/oil-and-gas-emissions-management

[67] Government of Alberta, "Technology Innovation and Emissions Reduction Regulation." https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation

[68] Government of Canada, "Regulatory Impact Analysis Statement."

from actions over and above regulatory requirements. This change would help mitigate Alberta's overly permissive and oversupplied credit market.[69]

For the purposes of our analysis, we have inadequate information about the root cause of emissions from pop tanks to recommend policy options for their mitigation. Bonavista's alt-FEMP data (unlike ARC's or SPOG's) showed that pop tanks were a major source of methane emissions from separation, in addition to pneumatics. However, it is not clear what is causing these emissions. Instrument vents within separator buildings could be tied into a single line and vented through the tank. If so, then most of these emissions could be addressed by requiring the phase-out of existing gas-fired pneumatics, providing more support for their elimination.

To improve the quality and accuracy of reported data, we recommend that the AER engage diverse interest holders, including academic experts, to co-develop and enhance measurement and reporting frameworks and requirements.

The deviation we noted by operators from the AER's instructions and definitions for alt-FEMP reporting suggests possible issues with the reporting framework. In particular, attributing detected emissions to a particular equipment group can be challenging when sources fit into multiple groups (e.g., a pneumatic controller on a separator could be assigned to either the pneumatic or separator group, since both identified in the instructions). Using "process block" instead of equipment group in future reporting could make it clearer, similar to SPOG's changes to the reporting template.

We also identified the need for a standardized component type to represent intentional vents in the alt-FEMP data, as there was a lack of consistency in how pneumatic vents were reported.

[69] Pembina Institute, "Alberta's Continued Weakening of Industrial Carbon Pricing Makes Canada Less Climate Competitive," media release, September 18, 2025. https://www.pembina.org/media-release/albertas-continued-weakening-industrial-carbon-pricing-makes-canada-less-climate

5. Flaring

5.1 Background

Solution gas flaring is the open combustion of unwanted waste gas that comes to the surface during oil production. The AER defines solution gas as “all gas that is separated from condensate, oil, or bitumen production.”[70] Accordingly, it defines solution gas flaring as “the combustion of excess natural gas (including methane) associated with oil and bitumen production,”[71] which it summarizes in its annual ST60B report.

Solution gas remains dissolved in oil deep underground. When oil is brought to the surface and pressure drops, the gas is released. Since oil-only sites are not in the business of producing natural gas, they tend to lack the infrastructure to conserve, transport, and route gas to sales. Venting is the simplest and most economical option to deal with the gas. However, since regulations were put in place to limit routine venting, most operators choose flaring as their primary alternative.

Flaring is a wasteful practice because it destroys an energy product that could be used or sold, resulting in reduced royalties and revenues.[72] While combusting waste gas largely generates carbon dioxide emissions — which are a less potent climate warmer than methane in the near term — the practice emits black carbon and volatile organic compounds that can compromise air quality and harm the health of humans and animals living near the flaring.[73] Health risks can include respiratory illness, adverse pregnancy outcomes, and leukemia.[74]

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[70] AER, *Directive 060*, Appendix 2.

[71] AER, *ST60B*, 21.

[72] Aaron Wolfe and Scott Seymour, “Wasted Gas, Wasted Royalties – How Common-Sense Climate Policy Can Put Money Back in People’s Pockets,” *EDF Blogs*, February 13, 2024. https://blogs.edf.org/energyexchange/2024/02/13/wasted-gas-wasted-royalties-how-common-sense-climate-policycan-put-money-back-in-peoples-pockets/

[73] Chen Chen, David McCabe, Lesley Fleischman, and Daniel Cohan, “Black Carbon Emissions and Associated Health Impacts of Gas Flaring in the United States,” *Atmosphere* 13, no. 3 (2022). https://doi.org/10.3390/atmos13030385

Huy Tran et al., “Air Quality and Health Impacts of Onshore Oil and Gas Flaring and Venting Activities Estimated Using Refined Satellite-Based Emissions,” *GeoHealth* 8, no. 3 (2024). https://doi.org/10.1029/2023GH000938

Olusegun Fawole, Xiaoming Cai, and Rob MacKenzie, “Gas Flaring and Resultant Air Pollution: A Review Focusing on Black Carbon,” *Environmental Pollution* 216 (2016). https://doi.org/10.1016/j.envpol.2016.05.075

[74] Jordy Motte et al., “Quantification of the Global and Regional Impacts of Gas Flaring on Human Health via Spatial Differentiation,” *Environmental Pollution* 291, no. 118213 (2021). https://doi.org/10.1016/j.envpol.2021.118213

Wesley Blundell and Anatolii Kokoza, “Natural Gas Flaring, Respiratory Health, and Distributional Effects,” *Journal of Public Economics* 208, no. 104601 (2022). https://doi.org/10.1016/j.jpubeco.2022.104601

Onome Oghenetega et al., “Oil Spills, Gas Flaring and Adverse Pregnancy Outcomes: A Systematic Review,” *Open Journal of Obstetrics and Gynecology* 10, no. 1 (2019). https://doi.org/10.4236/ojog.2020.1010016

Concerns about the air quality and health impacts of flaring (among other aspects of production) created significant landowner discontent in the 1990s, culminating in acts of sabotage.[75] This led the province to adopt flaring reduction targets and eventually a solution gas flaring limit.[76] More recently, due to production growth and reduced venting, solution gas flaring has been growing significantly.[77] After the limit was breached two years in a row, the AER eliminated the limit at the direction of the Government of Alberta.[78] Yet eliminating the rule doesn't solve the underlying problem. Removing restrictions on this form of flaring, which in many cases includes routine flaring, takes Alberta out of step with the international best practice of prohibiting all routine flaring (with exemptions for emergency situations and other exceptional circumstances).[79] Likewise, it is does not align with Canada's commitment to the World Bank's Zero Routine Flaring by 2030 initiative.[80]

5.2 Data analysis

We used 2024 Petrinex data, supplemented by ST60B data for the same year, to estimate methane emissions from flaring above Alberta's former solution gas flaring limit and identify policy and data gaps.[81]

The number of unique facilities that reported flaring to Petrinex in 2024 was lower (3,327) than the number of facilities that reported venting (12,973), but flared volumes were substantially higher than reported vent volumes, at 1,304 million m^3. Facilities producing solution gas reported flaring 839 million m^3, or 64.4% of total flaring. Compared with 2023, total flaring decreased 4.7% decrease (excluding acid gas flaring), while solution gas flaring increased 9.4%.[82]

[75] Tom Marr-Laing and Chris Severson-Baker, *Beyond Eco-terrorism: The deeper issues affecting Alberta's oilpatch* (Pembina Institute, 1999), 3. https://www.pembina.org/reports/beyond-ecoterrorism.pdf

[76] *Beyond Eco-terrorism*, 6.

[77] AER, *ST60B*, 21.

[78] Amanda Stephenson, "Alberta Energy Regulator stopped enforcing gas flaring limits after government pressure, documents show" *CBC News*, December 1, 2025. https://www.cbc.ca/news/canada/calgary/alberta-energy-regulator-stopped-enforcing-gas-flaring-limits-after-government-pressure-documents-show-9.6998787

[79] Amanda Bryant, *Meeting the Moment: Why finalized methane regulations will be key to Canada's climate competitiveness* (Pembina Institute, 2025), 14-15. https://www.pembina.org/sites/default/files/2025-11/Meeting_the_Moment_Final.pdf

[80] World Bank Group, *Zero Routine Flaring by 2030 (ZRF) Initiative* (2025). https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/about

[81] Petrinex, "Conventional Volumetric Data Download (2024)."

AER, *Bulletin 2025-21: Removal of the Provincial Solution Gas Flaring Limit* (2025). https://www.aer.ca/about-aer/media-centre/bulletins/bulletin-2025-21

AER, *ST60B*.

[82] AER, "Emissions Data."

Notably, solution gas flaring in 2024 was 25.2% higher than the province's solution gas flaring limit of 670 million m^3, which was removed in 2025.[83]

The removal of the limit was possibly prompted by the energy sector's exceedance of the limit two years in a row. In 2023, solution gas flaring totalled 767 million m^3,[84] while the amount for 2024, as indicated above, was 839 million m^3 based on the Petrinex data. ST60B, however, contains a higher estimate for 2024 solution gas flaring volumes: 915 million m^3. The difference may be due to how we defined and filtered for facilities producing solution gas using the Petrinex data (see the appendix for our methodology), which may have varied from the AER's method. Based on the ST60B data, solution gas flaring increased 18.9% between 2023 and 2024, and in 2024, flaring was 36.5% higher than the limit that was in place at the time.

ST60B also shows that solution gas flaring has been increasing since 2019. We extracted estimates from 2019 to 2024 in the report, which are shown in Figure 4. Solution gas flaring in Alberta has more than doubled since 2019, coinciding with operators using flaring as an alternative to venting to comply with methane emissions regulations and increased oil production in the province.[85] This trend may continue with increasing oil production if left unchecked.

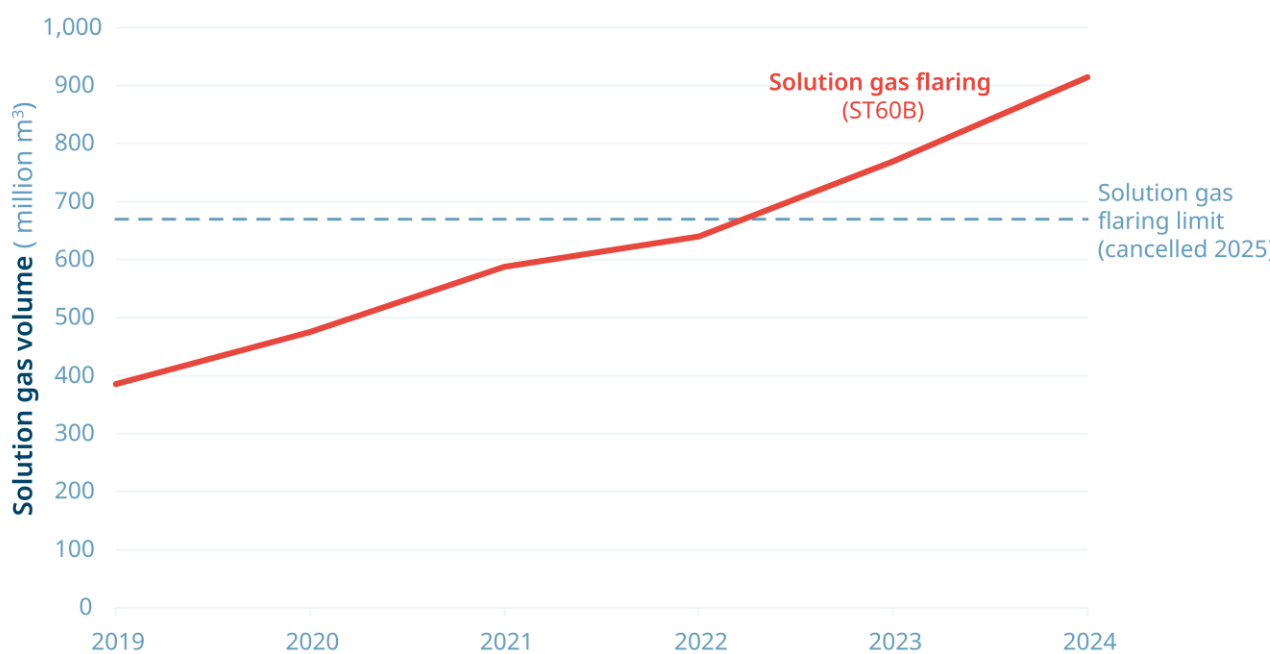

Figure 4. Solution gas flaring in Alberta

Data source: Alberta Energy Regulator[86]

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[83] AER, *Bulletin 2025-21*.

[84] AER, "Emissions Data."

[85] AER, *ST60B*.

[86] AER, *ST60B*.

Compared to vent volumes (discussed in section 3 of this report), the potential underestimation of reported flare volumes has received little attention from researchers, industry, government, and policymakers. We explored the Petrinex data to determine whether it could be used to reliably estimate methane emissions from flaring.

We filtered the 758 facilities that reported combined flare/vent volumes >500 m^3/d in the 2024 Petrinex data from the 3,327 facilities that reported flaring, leaving a total of 2,569 facilities that reported flare but not vent volumes in 2024. We found that 2,245 of these facilities reported flare volumes ≤500 m^3/d, totalling 99 million m^3 of flared gas, while 324 reported flare volumes >500 m^3/d, totalling 433 million m^3 of flared gas. The 758 facilities that had combined flare/vent gas volumes in 2024 >500 m^3/d reported a total of 773 million m^3 of flared gas.

These calculations demonstrate that, in contrast to the reported vent data, most (92.4%) of the reported flare gas is from facilities where flare/vent gas volumes are >500 m^3/d and are metered. This establishes greater certainty in the reported flare data, as well as the associated methane emissions estimates, since it mainly comes from metering.

We modelled three scenarios that assumed different flare combustion efficiencies to estimate the potential methane emissions from exceeding the solution gas flaring limit in 2024 (see appendix for methodology and assumptions). Methane emissions from flaring can result from the incomplete combustion of waste gas or from venting when the flare is unlit. The latter is a form of venting and consequently accompanied by the same air quality and health impacts. We accounted for potential emissions from both sources in our estimates while ensuring no double counting.

Figure 5 shows that methane emissions from the incomplete combustion of solution gas flared above the limit were low (1.7 kt/yr to 7.5 kt/yr). These emissions are minor compared with other sources, such as tanks (348 kt/yr), pneumatics (281 kt/yr), compressors (174 kt/yr), and wellheads/surface casing vent flows (94 kt/yr).[87] Additionally, an estimated 6.5 kt of methane could have been emitted directly to the atmosphere from unlit flares once the limit was surpassed. **We estimate that methane emissions from solution gas flaring beyond the limit totalled between 8.2 kt and 14 kt in 2024.** These emissions are equivalent to 0.6–1% of measurement-based estimates of Alberta's oil and gas methane.[88] Our estimates would be slightly higher if the ST60B data were used rather than the Petrinex data.

[87] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[88] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

The 91% combustion efficiency used in Figure 5 was the average from a study in three U.S. production basins.[89] Given that 98% may be an overestimation of actual flare efficiency across Alberta,[90] it is reasonable to assume that the emissions avoided by maintaining and enforcing the solution gas flaring limit would be on the higher end of our estimates.

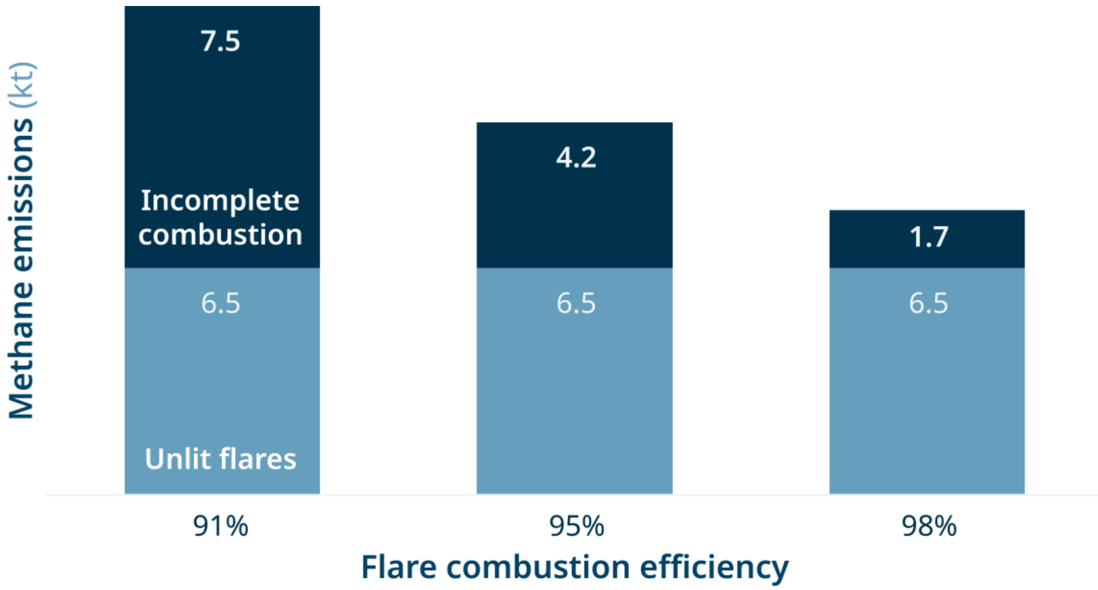

Figure 5. Estimated methane emissions from industry exceedance of Alberta's solution gas flaring limit in 2024, using different flare combustion efficiencies and accounting for unlit flares

Data source: Petrinex[91]

Not only are their environmental and health implications to flaring, but economic ones as well. The value of the gas flared above the limit was $9.1 million in 2024 and $9.9 million in 2023. The higher 2023 value reflects higher AECO-C natural gas prices, which we used in the estimates.[92] Combined, these amounts total $19 million over two years. AECO-C natural gas prices are projected to rise then stabilize around $3.8/GJ to $4.0/GJ between 2026 and 2034, meaning the value of any wasted gas will increase.

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[89] Genevieve Plant et al., "Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane," *Science (American Association for the Advancement of Science)* 377, no. 6614 (2022). https://doi.org/10.1126/science.abq0385

[90] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

[91] Petrinex, "Conventional Volumetric Data Download (2024)."

[92] AER, *AECO-C Price* (2025). https://www.aer.ca/data-and-performance-reports/statistical-reports/alberta-energy-outlook-st98/prices-and-capital-expenditure/natural-gas-prices/aeco-c-price

5.3 Gaps and recommendations

Insofar as it covers many cases of routine flaring, Alberta's removal of the solution gas flaring limit to account for increasing conventional oil production is out of step with broader oil and gas industry trends to reduce or eliminate routine flaring.[93] Although total methane emissions associated with removing this limit are small compared to other upstream sources, the gas has economic value. Moreover, flaring releases black carbon and other particulate matter into the atmosphere and has other environmental impacts. These impacts accelerate climate change and affect air quality and the health of local communities. As our analysis shows, solution gas flaring has more than doubled in Alberta since 2019 and will likely continue to increase as oil production rises if left unchecked.

We recommend that Alberta implement and enforce regulations to reduce and ultimately eliminate routine flaring.

The regulations should ensure that producers deploy known alternatives to flaring waste gas, such as tying into gas gathering infrastructure, using the gas on site as fuel, or using enclosed combustors or incinerators instead of flares (which can maintain a more reliable combustion efficiency under a range of atmospheric conditions and mitigate some air quality concerns[94]).

For necessary (i.e., non-routine) flaring, regulations requiring failed pilots and ignitors on flare stacks to be repaired within 24 hours should be better enforced to address unlit flares.[95]

Finally, more work should be done to understand whether flare gas volumes reported to Petrinex are accurate.

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[93] World Bank Group, *Zero Routine Flaring by 2030 (ZRF) Initiative*.

[94] Huilong Gai et al., "Clean combustion and flare minimization to reduce emissions from process industry," *Current Opinion in Green and Sustainable Chemistry* 23 (2020), 38. https://www.lamar.edu/midstreamcenter/_files/documents/clean-combustion-published-paper.pdf

Abel Clemente-Reyes et al., "A comparative assessment of open flame flares and enclosed ground flares for cleaner and safer hydrocarbon production in Mexico," *Cleaner Engineering and Technology* 16, no. 100671 (2023), 10. https://doi.org/10.1016/j.clet.2023.100671

[95] AER, *Directive 060*, 8.10.4(1)(b).

6. Conclusion

Our analysis revealed several critical data and policy relating to oil and gas methane emissions in Alberta:

1. Methane emissions have decreased in Alberta, but federal estimates indicate a reduction of 35%, not 52% as the province claims. Alberta's methane model is outdated and lags behind federal and academic approaches with respect to top-down data, since it does not integrate measurement data. This lowers confidence in the accuracy and credibility of the province's estimated reductions.
2. Most facilities reporting vent gas volumes in 2024 did not meet the regulatory threshold for gas metering, meaning they likely relied on methods that can underestimate vent gas volumes. This compromises data quality and limits its usefulness in determining compliance.
3. Federal estimates of vented emissions for Alberta, informed by aerial measurements, were approximately five times higher (580 kt of methane) than estimated with industry-reported data, but it is unclear whether this underestimation is widespread or if a few high emitters are responsible.
4. Excess flaring above the province's solution gas flaring limit prior to its removal contributed relatively little to total methane emissions compared with other upstream sources. However, as it pertains to routine flaring, the removal is out of step with Canada's commitment to the World Bank's Zero Routine Flaring by 2030 initiative, wastes a valuable resource, and worsens the air quality and health in nearby communities.
5. Combined, venting from pneumatic controllers and pumps was generally a large source of methane emissions, as measured in alt-FEMP follow-up surveys. This indicates that gas-fired pneumatics remain a significant contributor to methane emissions in the province and should be phased out. However, we found that the scale of their contribution varied by producer, likely due to variations in the extent to which each producer has mitigated natural gas-fired pneumatics across the assets included in their alt-FEMP.
6. Alt-FEMP follow-up survey data had quality and standardization issues, creating confusion around source attribution. These issues are also present with other AER reported data.

Addressing these gaps will require modernizing Alberta's methane emissions estimation methods and reporting requirements and frameworks, pivoting away from flawed and dated approaches that underestimate emissions and make it difficult to accurately track progress. Facilities should be required to conduct and report measurements using advanced methods such as vehicle-based systems, aircraft, drones, continuous monitors, and other platforms, with the data used to develop credible emissions estimates. Diverse interest holders should be engaged to co-develop and improve the measurement and reporting requirements to ensure better alignment of industry-reported data with independent, measurement-informed estimates.

Our study has shown that deeper reductions of methane emissions are possible by tightening limits on routine venting and flaring. Based on the magnitude of emissions from gas-fired pneumatics and well-established best practices, it is past time that Alberta phase out gas-fired pneumatics. Alberta claims to be a leader on reducing methane emissions from the oil and gas industry. However, sustained leadership requires honest self-assessment and continual improvement. That means closing data and policy gaps to ensure that emissions continue to fall and that we have credible data to prove it.

Appendix A. Methodology and assumptions

A.1 Pre-processing Petrinex data

We used industry vent and flare data for 2024 reported to Petrinex.[96] Reported volumes were summed by unique facility ID and activity (vent or flare) to calculate annual totals. We assigned facility locations from the AER's ST102 shapefile[97] to Petrinex records in Python based on facility ID for possible geospatial analysis.

We removed in situ oilsands facilities from the Petrinex data to focus the analysis on conventional oil and gas production. Before its recent removal, Alberta's solution gas flaring limit was a provincially aggregated limit. Thus, we created separate data frames for crude oil and bitumen facilities and all other facilities (single and multi-well gas batteries, gas plants, etc.) based on facility subtype. This enabled analysis of volumes reported to Petrinex for facilities producing gas-in-solution (i.e., oil producing sites).

A.2 Estimating methane emissions from exceeding the solution gas flaring limit

It was necessary to account for methane emissions from both lit flares and unlit flares, the latter of which vent methane directly to the atmosphere. We followed a series of steps to estimate methane emissions from the flaring of solution gas beyond the limit in 2024 and prevent double counting.

1. We used data from an aerial measurement-informed inventory of the province to estimate that unlit flares are present at 1.5% of conventional oil and gas sites. [98] This is likely an upper limit of unlit flare prevalence, as the study estimate includes a few lit flares that were emitting detectable quantities of methane.
2. We performed a Monte Carlo simulation in Python to estimate the potential emissions from lit flares at solution gas facilities. The simulation randomly drew reported flare

[96] Petrinex, "Conventional Volumetric Data Download (2024)."

[97] AER, ST102: Facility List, formerly Battery Codes and Facility Codes [ASCII] (updated monthly), 2025. https://www.aer.ca/data-and-performance-reports/statistical-reports/st102

[98] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta – Supplementary Information."

volumes from 98.5% of facilities producing solution gas that reported flaring in 2024, roughly approximating the proportion of facilities with lit flares. Sampled volumes were summed, and the process was repeated 10,000 times. The mean of the simulations was 826 million m^3 of natural gas. Flare combustion efficiency factors as shown in Figure 4 were applied to this volume and incompletely combusted flare volumes were converted to mass of methane assuming 0.68 kg/m^3 methane and a natural gas methane content of 79%.[99]

3. We applied the ratio of reported solution gas flaring to total flaring (64.3%) in the 2024 Petrinex data to the 50 kt/yr of estimated unlit flare emissions in Alberta to estimate that unlit flare emissions at solution gas facilities could total 32.2 kt/yr.[100] Facilities producing solution gas were identified using Python based on the methodology in the preprocessing section.
4. We estimated that the province's former solution gas flaring limit of 670 million m^3 represented 79.9% of total reported solution gas flaring in 2024. We applied the inverse of this value to the 32.2 kt/yr of methane estimated to be emitted from unlit flares at solution gas sites (Step 3). This resulted in an estimated 6.5 kt/yr of methane that could have been emitted from unlit flares at solution gas sites once the provincial limit was surpassed.
5. We added the 6.5 kt/yr to the estimates of methane emissions from solution gas sites with lit flares that assumed different combustion efficiencies (Step 2). The result was a range of possible estimates of total methane emissions from solution gas flaring in 2024 that exceeded the province's limit at the time, which accounted for lit and unlit flares.

A.3 Filtering the alt-FEMP follow-up data

Table 1 shows an example (ARC Resources follow-up data) of the alt-FEMP reporting structure based on AER instructions and definitions. The data was provided in .csv format. We used the detection equipment group to filter for methane emissions from separation. Each row represents a unique emissions detection. We summed the rates to calculate total methane emissions from separation.

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[99] AER, *Directive 060*.

Government of Canada, "Regulatory Impact Analysis Statement."

[100] Conrad et al., "A Measurement-Based Upstream Oil and Gas Methane Inventory for Alberta."

Table 1. Alt-FEMP reporting structure for ARC Resources follow-up data

Site location	Site ID	Date	Method	Emission type	Detection equipment group	Component type	Rate (m^3/d)
01-02-064-05W6	F46728	2022-09-20	OGI	Vent	Separator	Other	5.7
01-02-064-05W6	F46728	2022-09-20	OGI	Vent	Separator	Other	2.4
01-02-064-05W6	F46728	2022-09-20	OGI	Vent	Separator	Other	4.9
01-02-064-05W6	F46728	2022-09-20	OGI	Vent	Separator	Other	3.3
01-02-064-05W6	F46728	2022-09-20	OGI	Vent	Separator	Other	4.5
01-02-064-05W6	F46728	2023-09-24	OGI	Fugitive	Separator	Seal	6.5

Data source: Alberta Energy Regulator[101]

We then filtered the emissions type for either vent or fugitive to determine the number of detections and volume of emissions by type. We also examined the component type for each row to understand the emissions sources, counts, and emissions rates. While not shown in Table 1, the reported data included a comment column where operators left comments on individual sources. We used these comments to supplement the component type column in understanding the emissions sources. In some cases, the sources of emissions from separation were not always obvious if a component type of “other” was reported (Table 1) without a comment. As such, we analyzed the reported data in tandem with the AER’s reporting instructions and definitions for alt-FEMPs to understand where operators may have deviated from this structure and to infer the emissions sources. This procedure was repeated for each of the three producers.

We noted differences and a lack of standardization in terms of how the three producers identified similar sources of emissions using the AER reporting instructions and definitions, particularly for vented sources. Analyzing the data reported by the Sundre Petroleum Operators Group (SPOG) required a modified approach. We found that the emissions type did not correctly identify vent and fugitive sources based on the comment and other columns included in the data. SPOG included a component subtype column, which was not specified in AER instructions. To identify vent sources and rates, we filtered this column for “vent” or “device”

[101] AER, “Alternative Fugitive Emission Management Program (alt-FEMP) Approvals.”

component subtypes and filtered the comment column so that rows could not contain the word "leak." Fugitive emissions were estimated by subtracting the vent emissions from total separator emissions. Fugitive emission types were identified by examining component subtypes other than "vent" or "device" and the comments left for each record.

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