Alberta Energy Regulator

Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2025

November 2026



Alberta Energy Regulator
ST60B-2026: Upstream Petroleum Industry Emissions Report

November 2026

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Executive Summary

The Alberta Energy Regulator (AER) has published this report annually since 2001. It provides stakeholders with fuel, flare, vent, surface casing vent flow, gas migration and, since 2020, fugitive emissions information reported to the AER. This report includes emissions subject to reporting requirements under *Directive 060*. Emissions from oil sands mining schemes and pipelines not subject to *Directive 060* reporting requirements are excluded.

The primary data used to compile the report are obtained from Canada's Petroleum Information Network (Petrinex) and the AER's OneStop reporting tool. This report for 2025 includes annual emissions data since 2020 extracted in July 2026. The previous years' data include amendments and late submissions, resulting in slightly different values than last year's report.

Indicator	2024	2025	Change
Crude bitumen production (million m^3)	106.6	113.1	+6.1%
Crude oil production (million m^3)	30.7	31.8	+3.6%
Raw gas production (billion m^3)	128.8	130.9	+1.6%
Marketable gas production (billion m^3)	115.2	118.3	+2.7%
Condensate production (million m^3)	5.0	5.1	+2.0%
Fuel gas use (billion m^3)	26.9	27.4	+1.9%
Total flaring (million m^3)	1 531.5	1 407.6	−8.1%
Total venting (million m^3)	274.6	238.6	−13.1%
Total reported fugitive emissions (million m^3)	42.8	42.8	+0.0%
Surface casing vent flow and gas migration venting (million m^3)	122.2	126.5	+3.5%
Solution gas conservation	96.5%	97.1%	+0.6%
Flaring intensity (m^3/BoE)	0.86	0.76	−11.6%
Venting intensity (m^3/BoE)	0.15	0.13	−13.3%
Methane reduction from 2014 baseline (%)	57	62	+5
Methane intensity (%)*	0.29	0.25	−0.04

* Methane intensity is calculated using the Natural Gas Sustainability Institute (NGSI) methodology, as organized by the Edison Electric Institute (EEI) and the American Gas Association (AGA). More details on the calculation are available in appendix 4.

- Venting volumes continued to decline in 2025, reaching the lowest reported level since implementation of annual methane reporting requirements in 2020.
- Total flaring volumes decreased in 2025 while oil and bitumen production increased, likely reflecting a combination of improved operational performance, expanded gas conservation efforts, and growing economic incentives to reduce combustion-related emissions.
- For the first time since implementation of the annual methane reporting requirements, Alberta reported simultaneous reductions in both venting and flaring volumes while oil and bitumen production continued to increase.
- Solution gas conservation increased to 97.1%, continuing a long-term trend of improved recovery and utilization of associated gas.
- Alberta surpassed its methane reduction target of 45%, with reductions indicating methane emissions have declined by approximately 62% from 2014 levels.

1 Introduction

Our mandate is to provide for the efficient, safe, orderly, and environmentally responsible development of energy and mineral resources in Alberta through our regulatory activities. Under this mandate, the AER is responsible for disseminating energy-related information, including emissions information.

Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting sets out requirements for flaring, incinerating, and venting for all upstream petroleum industry wells and facilities in Alberta. These requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters) licensed by the AER in accordance with the *Pipeline Act* and all schemes and operations approved under section 10 of the *Oil Sands Conservation Act*, except for oil sands mining schemes and operations approved under section 10 of the *Oil Sands Conservation Act*.

Directive 060 requirements ensure that public safety concerns and environmental impacts are addressed before and during flaring, incinerating, or venting events. Requirements in this directive are aligned to ensure compliance with *Alberta Ambient Air Quality Objectives and Guidelines* (*AAAQOG*).

Companies must also meet the benzene emission requirements for glycol dehydrators (dehydration and refrigeration) set out in *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators*. Under *Directive 039*, licensees must complete and submit an annual dehydrator inventory to the AER that details the emissions from all their glycol dehydrators.

ST60B: Upstream Petroleum Industry Emissions Report, published annually, fulfils the AER's commitment to report flaring and venting volumes as set out in *Directive 060*.

For information on flaring, incinerating, and venting requirements, see *Directive 060*.

1.1 Important Notes for This Year's Report

Annual methane emissions reporting for the 2025 reporting year was submitted through Petrinex in 2026, with glycol dehydrator reporting remaining in OneStop. This may result in differences when comparing annual emissions data with previous report editions.

Historical facility counts were recalculated back to 2014 using updated inclusion criteria aligned with the *Directive 060* definition of "active reporting facilities and wells." Facility counts reported in this edition differ from previous editions of the report.

Facility subtype codes not included within the 45 facility subtypes listed in *Manual 015* were excluded from this report and from historical trend graphics. Historical fuel, flare, and vent totals differ from values published in previous editions of the report.

Historical data amendments. Previous reporting years include amended submissions, corrected inventories, and late filings available as of July 2026. Historical values may differ from those presented in earlier reports.

Fuel, flare, vent definition changes. Previously reported fuel, flare, and vent volumes were significantly changed between 2019 and 2020 reporting years. Trends before and after 2019 should be interpreted separately.

Methane reduction model updates. Annual updates were made to emission factors, activity data, inventories, assumptions, and calculation methodologies used in the methane reduction model (see appendix 3). Methane reduction estimates and baseline values may differ between report editions.

Methane intensity has been added. This enables evaluation of methane emissions performance to be assessed on a production-normalized basis, providing additional context beyond absolute emissions totals. This also facilitates year-over-year tracking of methane management performance and quantification of emissions reduction progress.

1.2 Facility Information

For this report, an aggregate of subtype codes is used to report emissions (see *Manual 015*, table 4). This categorization is relevant to both Petrinex and OneStop, as reporting is required by facility ID, which includes a facility subtype identifier. To provide additional context for the emission data presented in this report, a count of the active facilities is listed below. Note that the facility count has changed from previous reports due to a change in the inclusion/exclusion definition of facilities that are required to report methane emissions. Table 1 shows the number of facilities in each subtype (for active reporting facilities). The per cent change column compares 2024 to 2025.

Table 1. Number of facilities that must report methane emissions by subtype, 2019–2025

Facility subtype	2019	2020	2021	2022	2023	2024	2025	% change
Crude bitumen batteries	4 150	3 520	3 268	3 396	3 297	3 368	3 482	3.38
Crude oil batteries	9 188	8 461	8 387	8 455	8 273	8 009	7 834	−2.19
Gas batteries	9 534	8 890	8 506	8 336	8 083	7 920	7 852	−0.86
Gas gathering/compressor stations	3 589	3 516	3 446	3 434	3 412	3 378	3 329	−1.45
Gas plants	539	518	496	486	486	480	477	−0.63
Other	1 716	1 594	1 589	1 596	1 606	1 597	1 566	−1.94
Total	**28 716**	**26 499**	**25 692**	**25 703**	**25 157**	**24 752**	**24 540**	**−0.86**

Table 2 shows the facility subtype codes for which emissions data were used for this report.

The crude bitumen battery facility subtype category includes batteries producing thermal and nonthermal bitumen, such as crude bitumen multiwell proration batteries and in situ oil sands batteries (as described in AER's *Manual 11: How to Submit Volumetric Data*).

Facility subtypes within the "other" category include meter stations, disposal facilities, pipelines, tank farms, etc. Emissions and production data from facilities associated with bitumen mining are not included in this report.

Table 2. Mapping of ST60B category to facility subtype codes (*Manual 015*, table 4)

ST60B category	Facility subtypes
Crude bitumen batteries	331, 341–345, 501, 506, 508
Crude oil batteries	311, 321, 322, 611, 612
Gas batteries	351, 361–367, 371
Gas plants	401–407
Gas gathering/compressor stations	601, 621, 622
Other	381, 502–505, 507, 509, 671, 673, 701, 702, 902

1.3 Data Quality and Reporting

The primary datasets used in this report are obtained from Petrinex and the AER's OneStop reporting systems. Monthly fuel, flare, and vent volumes are reported through Petrinex, while annual methane emissions data are submitted through Petrinex starting in 2026, with the exception of glycol dehydrator emissions, which continue to be reported through OneStop.

Data presented in this report represent a snapshot extracted in July 2026. As a result, values may differ from those reported in previous editions due to amendments, late submissions, facility transfers, corrections to inventories, or updates to emission quantification methodologies. Historical values presented through this report have been updated where amended information was available at the time of data extraction.

For the 2025 reporting year, approximately 98% of facilities required to submit annual methane emissions data had reported by July 15, 2026, representing approximately 99% of production volumes. While the AER continues to perform data validation and compliance assurance activities, some reporting discrepancies may remain and are addressed through ongoing audits, inspections, industry outreach, and education initiatives.

The migration of annual methane emissions reporting from OneStop to Petrinex in 2026 is expected to improve consistency between monthly and annual reporting datasets. However, differences may still occur because the reporting systems capture emissions at different levels of aggregation and may include different reporting requirements, methodologies, and temporal considerations. Users should consider these factors when interpreting year-over-year changes and comparisons between data sources and prior reports.

2 Fuel Use

The upstream oil and gas industry uses natural gas to fuel equipment when producing, gathering, and processing natural gas, oil, and bitumen. Fuel use volumes are provided in this report to complement the flaring and venting volumes reported to Petrinex. Fuel use volumes are also important to include when reviewing the impacts of the change in fuel, flare, and vent definitions.

Figure 1 shows fuel volume usage reported to Petrinex for 2010 to 2019 by facility subtype, and figure 2 shows the fuel volumes reported for 2020 onward. These volumes represent the annual total of the monthly fuel volumes reported by facility subtype.

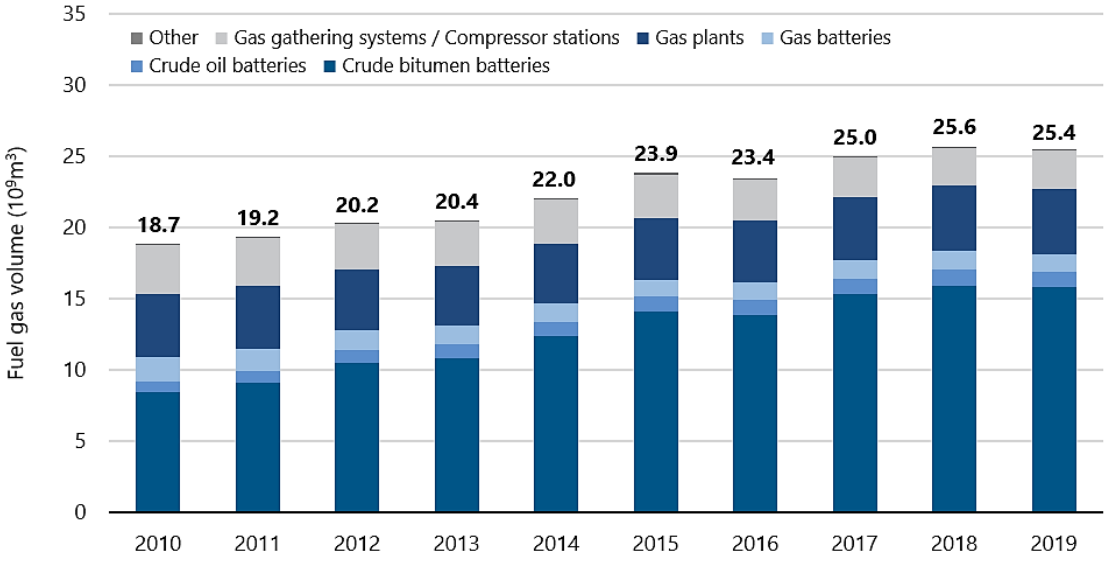


Figure 1. Fuel gas usage, 2010–2019 (Source: Petrinex)

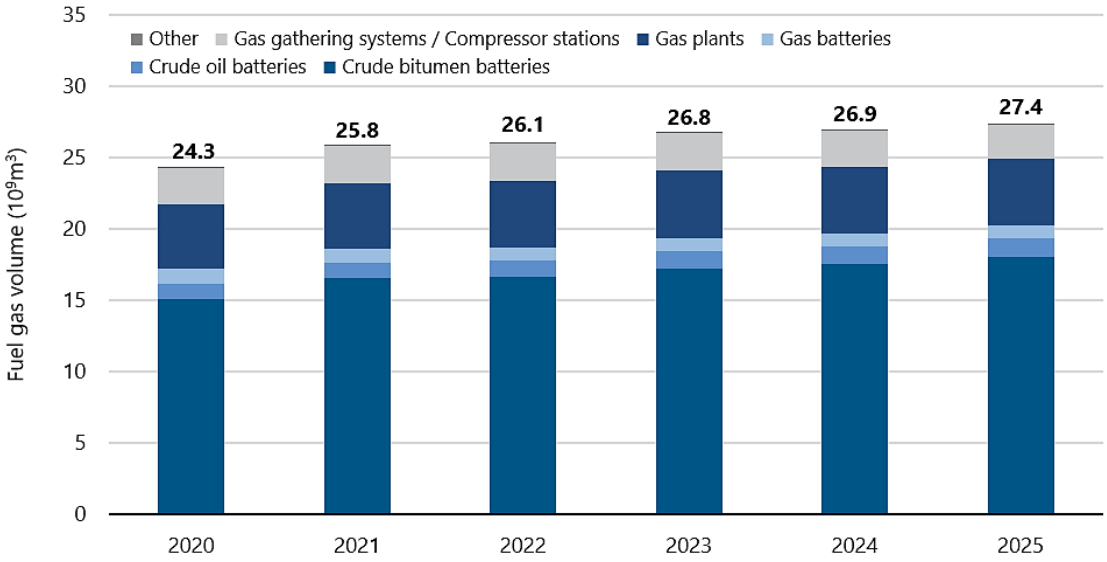


Figure 2. Fuel gas usage, 2020–2025 (Source: Petrinex)

Since 2010, fuel gas use has increased from 18.7 billion m^3 to 27.4 billion m^3 in 2025. In 2020, the decrease in fuel gas to 24.3 billion m^3 is consistent with the change in the definition of fuel gas in both *Directive 060* and *Directive 017* and industry disruptions due to the COVID-19 pandemic. Volumes previously reported as fuel gas are now reported as vent gas. For example, the previous definition of fuel gas would have included gas used to drive a pneumatic device. However, since this gas is vented into the atmosphere, the definition was changed, and it is now considered vent gas and reported as such in Petrinex.

Table 3 shows the year-over-year change in the annual reported fuel gas use by facility subtype. Fuel gas usage fluctuates with production volumes across the province.

Table 3. Change in fuel gas use volumes, 2020–2025, % change 2024–2025 (Source: Petrinex)

Facility subtype	2020 (billion m^3)	2021 (billion m^3)	2022 (billion m^3)	2023 (billion m^3)	2024 (billion m^3)	2025 (billion m^3)	% change
Crude bitumen battery	15.1	16.6	16.7	17.3	17.6	18.0	2.3
Crude oil battery	1.0	1.1	1.1	1.2	1.2	1.3	8.3
Gas battery	1.1	0.9	0.9	0.9	0.9	0.9	0.0
Gas gathering/compressor station	2.6	2.6	2.6	2.6	2.5	2.4	−4.0
Gas plant	4.5	4.6	4.7	4.7	4.7	4.7	0.0
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Total	**24.3**	**25.8**	**26.1**	**26.7**	**26.9**	**27.4**	**1.9**

3 Flaring

Flaring is the controlled destruction of gas during production and processing and includes flaring, incineration, and enclosed combustion. Flare volumes are reported to the AER through Petrinex monthly.

3.1 Reported Flare Data

Figure 3 shows flare volumes reported to Petrinex by facility subtype for 2010 to 2019, and figure 4 shows flare volumes reported for 2020 onward. Well testing is not included and is presented in a subsequent section.

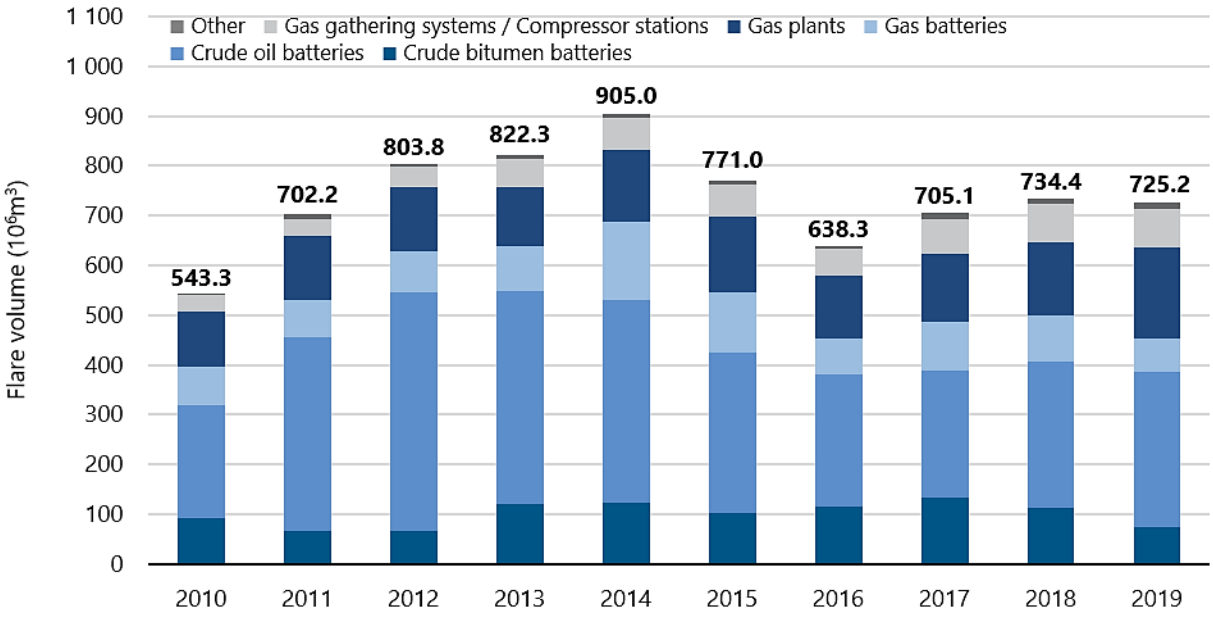


Figure 3. Flare volumes, 2010–2019 (Source: Petrinex)

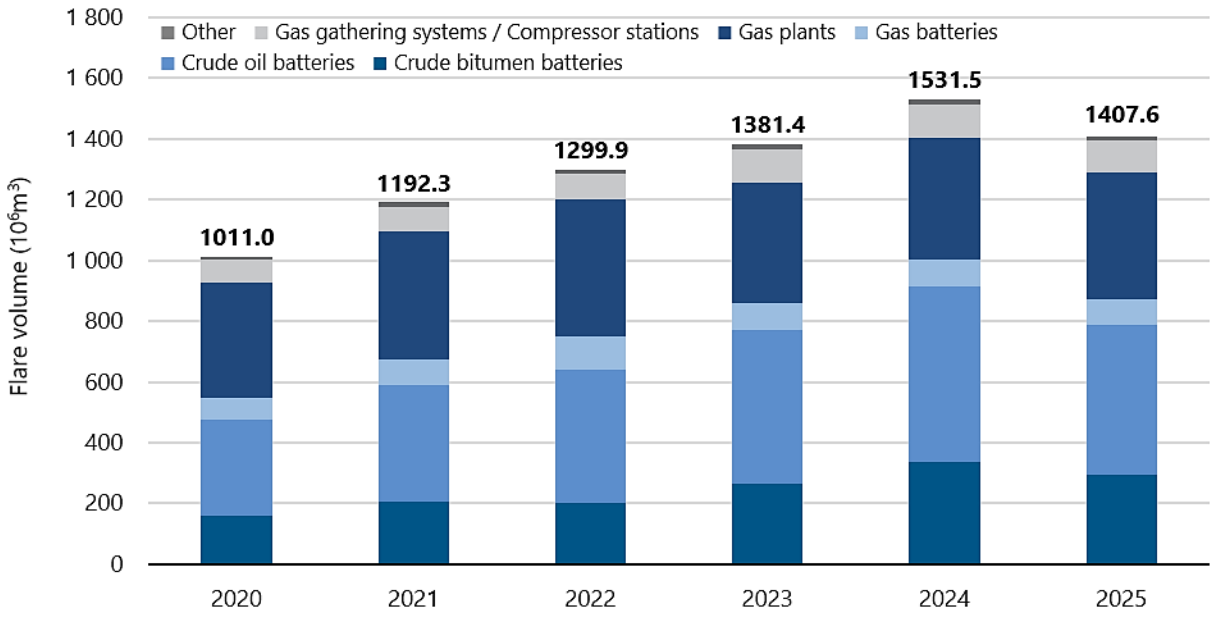


Figure 4. Flare volumes, 2020–2025 (Source: Petrinex)

3.1.1 Flaring Trends

In 2025, flaring volumes decreased to 1407.6 million m^3, down 8.1% from peak observed in 2024. While crude oil and bitumen production continues to grow, the reduction in flaring likely reflects a combination of improved operational performance, expanded gas conservation efforts, and growing economic incentives to reduce combustion-related emissions. From 2023 to 2025, flaring emissions have been incorporated into Alberta's *Technology Innovation and Emission Reduction (TIER) Regulation*

compliance framework for aggregate facilities, increasing the cost associated with flared gas and encouraging operators to prioritize conservation, operational reliability, and emission reduction opportunities where feasible. Early methane reductions were often achieved by directing vent gas to combustion. More recent improvements suggest conservation projects and equipment upgrades that reduce both venting and flaring simultaneously.

Table 4 shows the year-over-year change in the annual reported flaring by facility subtype. Most facility subtypes experienced reductions, particularly crude oil batteries and crude bitumen batteries. Gas plant flaring was the only major category to show a modest increase. The reduction likely reflects improved operational performance and conservation efforts even with continued growth in production.

Table 4. Change in flared volume, 2020–2025, % change 2024–2025 (Source: Petrinex)

Facility subtype	2020 (million m^3)	2021 (million m^3)	2022 (million m^3)	2023 (million m^3)	2024 (million m^3)	2025 (million m^3)	% change
Crude bitumen battery	161.26	205.70	202.08	264.58	336.01	294.77	−12.27
Crude oil battery	313.79	382.36	438.38	504.79	578.32	493.00	−14.75
Gas battery	72.56	84.73	108.40	90.47	86.88	83.16	−4.28
Gas gathering/compressor station	73.55	81.86	86.08	112.61	110.45	105.24	−4.72
Gas plant	380.73	422.20	451.92	394.75	402.79	420.71	+4.45
Other	9.14	15.44	12.95	14.24	17.04	10.72	−37.09
Total	**1 011.04**	**1 192.28**	**1 299.82**	**1 381.43**	**1 531.50**	**1 407.60**	**−8.09**

In alignment with the decreased total flare volumes in 2025, the flaring intensity also decreased from 2024 to 2025 (see table 5). Solution gas flaring is analyzed further in section 7. The 11.6% reduction in flaring intensity exceeded the 8.1% reduction in absolute flare volume because production increased during the same period. This indicates that, on average, less gas was flared per unit of hydrocarbon produced in 2025 compared to 2024.

Table 5. Flaring intensity, 2020–2025 (Source: Petrinex)

Year	Province-wide BoE	Flare volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136	1 011 039 700	0.67
2021	1 611 841 179	1 192 278 100	0.74
2022	1 692 106 893	1 299 821 300	0.77
2023	1 735 675 816	1 381 432 200	0.80
2024	1 781 153 392	1 531 501 300	0.86
2025	1 843 843 863	1 407 600 600	0.76

Appendix 1 shows the locations of venting and flaring within Alberta.

3.1.2 Flare Volumes at Gas Plants

Table 6 shows the top 30 gas plants that flared in 2025 by volume and the percentage flared of the total gas received. The total amount of flaring from these top 30 gas plants (264.2 million m^3) makes up about 63% of the total flaring at gas plants.

Table 6. Top 30 flaring gas plants, 2025 (Source: Petrinex)

Gas plant	Operator	Land location	2025 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001004	Keyera Energy Ltd.	02-05-044-01W5	32.38	1.54
ABGP0149088	Baytex Energy Ltd.	03-18-084-17W5	28.60	22.31
ABGP0001147	Pembina Gas Infrastructure Inc.	11-18-074-12W6	18.22	0.59
ABGP0001056	Cavvy Production Ltd.	02-20-004-30W4	18.19	1.68
ABGP0001662	Cavvy Production Ltd.	12-35-034-06W5	13.00	0.97
ABGP0118855	Pembina Gas Infrastructure Inc.	08-13-063-05W6	12.34	0.72
ABGP0001855	Obsidian Energy Ltd.	09-15-084-14W5	11.37	23.16
ABGP0001037	Cavvy Production Ltd.	13-13-025-05W5	9.55	1.15
ABGP0169442	ARC Resources Ltd.	10-10-065-05W6	8.62	0.55
ABGP0001070	Btg Energy Corporation	14-32-037-03W5	8.34	3.1
ABGP0001144	Pembina Gas Infrastructure Inc.	03-15-059-18W5	7.81	0.59
ABGP0001892	Ovintiv Canada ULC	04-08-075-07W6	6.91	0.33
ABGP0153429	Pembina Gas Infrastructure Inc.	14-28-062-20W5	6.65	0.25
ABGP0001901	Keyera Midstream Canada Ltd.	10-11-020-01W4	6.35	0.05
ABGP0001129	Canadian Natural Resources Limited	13-26-067-05W6	6.28	0.35
ABGP0001703	Keyera Midstream Canada Ltd.	02-23-055-22W4	6.23	10.7
ABGP0001350	Cenovus Energy Inc.	01-08-070-11W6	6.17	0.48
ABGP0001623	ARC Resources Ltd.	06-08-062-03W6	5.60	0.77
ABGP0152315	AltaGas Ltd.	12-35-070-09W6	5.58	0.49
ABGP0001113	Keyera Energy Ltd.	09-06-063-25W5	5.44	0.23
ABGP0001060	AltaGas Ltd.	09-27-031-04W5	4.78	0.12
ABGP0145129	Pembina Gas Infrastructure Inc.	14-28-062-20W5	4.76	0.16
ABGP0001902	Keyera Midstream Canada Ltd.	04-12-020-01W4	4.18	0.01
ABGP0001107	Pembina Gas Infrastructure Inc.	01-12-062-20W5	4.06	0.24
ABGP0150704	Pembina Gas Infrastructure Inc.	07-35-067-07W6	4.04	0.18
ABGP0001506	Canadian Natural Resources Limited	01-01-078-10W6	4.04	0.26
ABGP0150386	Keyera Energy Ltd.	04-07-073-08W6	3.96	0.15
ABGP0094954	Pembina Gas Infrastructure Inc.	08-11-060-03W6	3.63	0.14
ABGP0001134	Caledonian Midstream Corporation	02-04-021-04W5	3.5	4.13
ABGP0168934	CSV Midstream Solutions Corp.	13-34-072-09W6	3.46	2.33
Total			**264.21**	

Note: Confidential facilities are not included.

3.2 Well Testing

Well testing is the process of evaluating a well's performance and reservoir characteristics by measuring flow rates, pressures, fluid properties, and other operational data.

Well-testing data must be reported to the AER under *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*. These data were obtained (as reported) from the AER's compliance and operations

management (COM) system. Because flaring during a well test is a unique subset of flaring, it is presented separately here.

In 2025, 824 well tests were completed, up from 780 tests reported in 2024 (see table 7). In 2025, the total flaring volume increased, and vent volumes decreased from 2024.

Table 7. Well drilling and testing data, 2019–2025 (Source: COM, ST59)

Year	Total wells drilled	Number of well tests	Total flare volume during well tests (10^3 m^3)	Total vent volume during well tests (10^3 m^3)
2019	3 850	686	42 721.69	1 043.89
2020	2 338	480	34 618.57	213.78
2021	5 486	739	47 312.80	1 103.38
2022	8 581	891	40 742.90	1 649.12
2023	8 437	903	34 204.26	1 610.42
2024	9 923	780	33 683.82	905.49
2025	9 151	824	44 770.85	188.72

4 Venting

Vent gas is uncombusted gas released into the atmosphere at upstream oil and gas operations. The AER collects venting data through Petrinex monthly and annually. Monthly vent gas volumes include both routine (including venting from pneumatic devices, compressor seals, dehydrators, tanks, etc.) and nonroutine vent gas (i.e., process upsets, emergencies, maintenance blowdowns, pipeline depressurizing, turnarounds, etc.). Uncombusted gas from incomplete combustion or oxidation from fuel, flare slip, and catalytic heaters are not currently reported to the AER. Annual emissions data only include routine vent gas and fugitive emissions. However, the annual emissions data provide a more granular emission breakdown by source type.

In 2025, annual routine vent gas emissions reported totalled 227.7 million m^3 after excluding fugitive emissions, while total monthly venting volumes reported to Petrinex were 238.6 10^6 m^3. This result is consistent with expectations because monthly venting volumes include both routine and nonroutine venting events, whereas annual methane reporting is limited to specific routine emission sources. Although differences between the two reporting streams will continue to exist because of reporting scope, calculation methodologies, and aggregation differences, the close agreement between the datasets demonstrates improved reporting consistency and data quality. Ongoing compliance assurance activities, audits, and industry education efforts continue to support this alignment.

4.1 Monthly Emissions Data

Routine and nonroutine volumes are reported as a combined monthly volume to Petrinex. Figure 5 shows vent volumes reported to Petrinex by facility subtype for 2010 to 2019, and figure 6 shows the annual vent gas volumes for 2020 onward. In 2025, vent gas reported in Petrinex was 238.6 million m^3.

Table 8 shows the year-over-year change in the annual reported vent gas by facility subtype. Venting continued to decrease compared with 2024 in all facility subtypes. This decrease is mainly due to the various equipment-level vent limits that took effect on January 1, 2022 and 2023; continued compliance and education campaigns undertaken by the AER; and government incentives and investments that drive emission reduction.

As shown in table 9, vent gas volumes reported in 2025 decreased relative to 2020, when the reporting definitions changed. Considering production volumes, 2025 had the lowest venting intensity of the past six years.

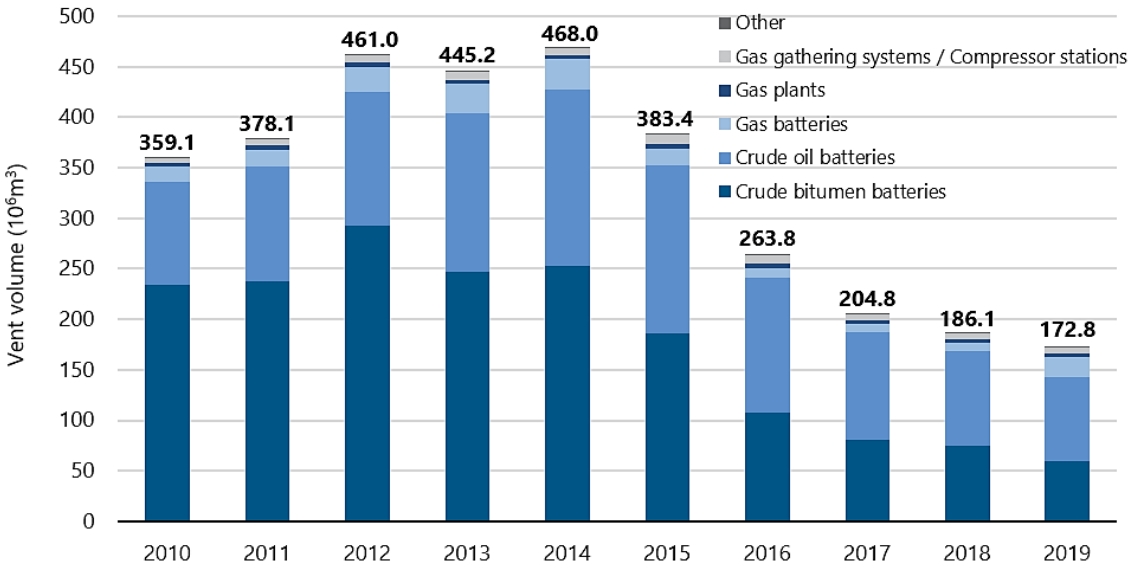


Figure 5. Vent volumes, 2010–2019 (Source: Petrinex)

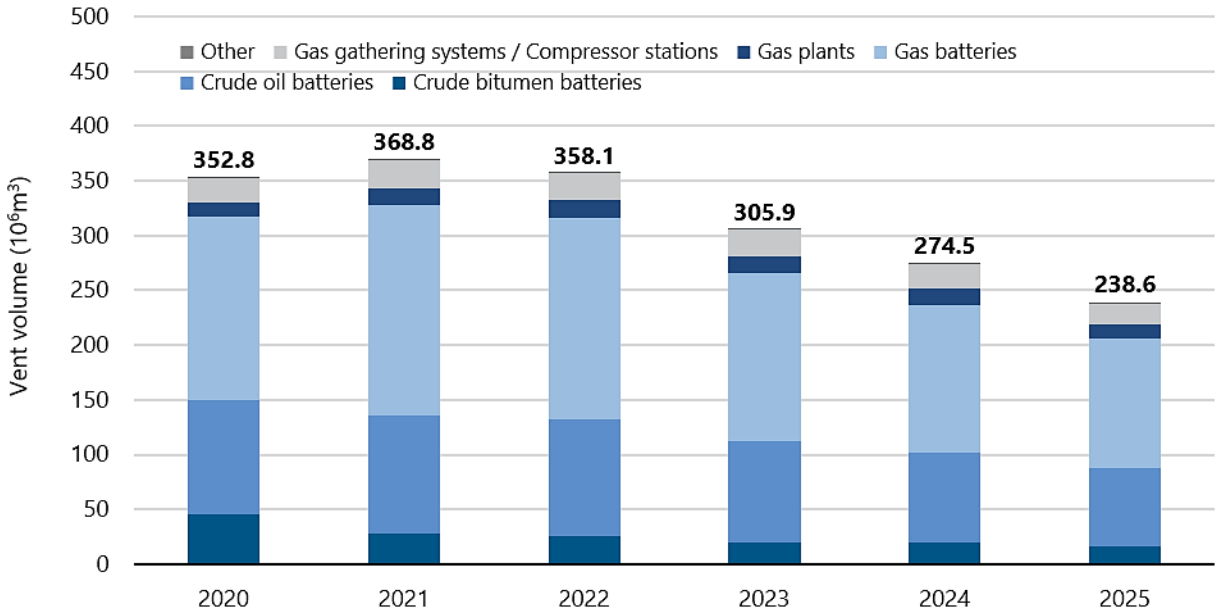


Figure 6. Vent volumes, 2020–2025 (Source: Petrinex)

Table 8. Change in vented volumes 2020–2025, % change 2024–2025 (Source: Petrinex)

Facility Subtype	2020 (million m³)	2021 (million m³)	2022 (million m³)	2023 (million m³)	2024 (million m³)	2025 (million m³)	% change
Crude bitumen battery	46.0	28.1	25.6	20.0	19.5	16.1	−17.4
Crude oil battery	103.3	107.7	106.0	91.7	82.0	71.1	−13.3
Gas battery	167.9	191.5	184.2	153.6	135.2	118.9	−12.1
Gas gathering/compressor station	22.4	24.9	24.5	24.7	21.8	19.3	−11.5
Gas plant	12.4	16.1	16.9	15.0	15.1	12.3	−18.5
Other	0.8	0.5	0.9	0.9	1.0	0.9	−10.0
Total	**352.8**	**368.8**	**358.0**	**305.9**	**274.6**	**238.6**	**−13.1**

Table 9. Venting intensity, 2020–2025 (Source: Petrinex)

Year	Province-wide BoE	Vent volume (m³)	Intensity (m³/BoE)
2020	1 517 386 136	352 784 300	0.23
2021	1 611 841 179	368 785 500	0.23
2022	1 692 106 893	358 062 100	0.21
2023	1 735 675 816	305 943 310	0.18
2024	1 781 153 392	274 549 200	0.15
2025	1 843 843 863	238 591 700	0.13

Appendix 1 shows the locations of venting and flaring within Alberta.

4.2 Annual Emissions Data

Operators must submit an annual methane report on June 1st of each year. This submission is subject to the regulatory requirements in section 8 of *Directive 060*. Annual reported emissions do not represent all existing sources of methane from the upstream oil and gas industry.

4.2.1 Summarized Emissions

Annual emissions data reported to the AER provide greater detail on source-specific methane emissions. In 2025, total emissions reported were 270.5 million m^3, a significant decrease from 2024 (323.4 million m^3). Figure 7 shows total source-specific emissions reported to Petrinex and OneStop, and figure 8 shows these reported emissions by source and facility subtype. The 2020 reporting year was the first year that the AER required reporting of both vent and fugitive emissions data.

Dehydrator emissions were excluded from figure 8 as they do not always report to the reporting facility identifier, meaning no facility subtype is generally available.

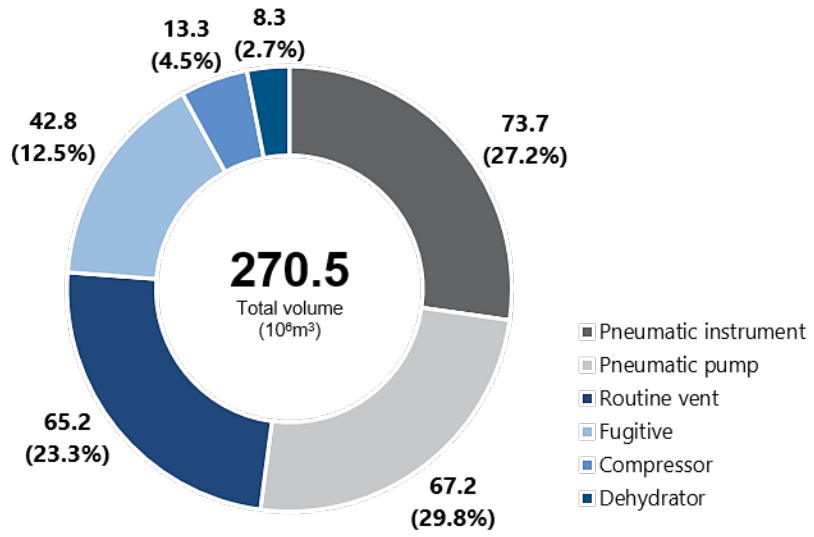


Figure 7. Breakdown of reported volumes by sources subject to annual reporting, 2025 (Source: Petrinex/OneStop)

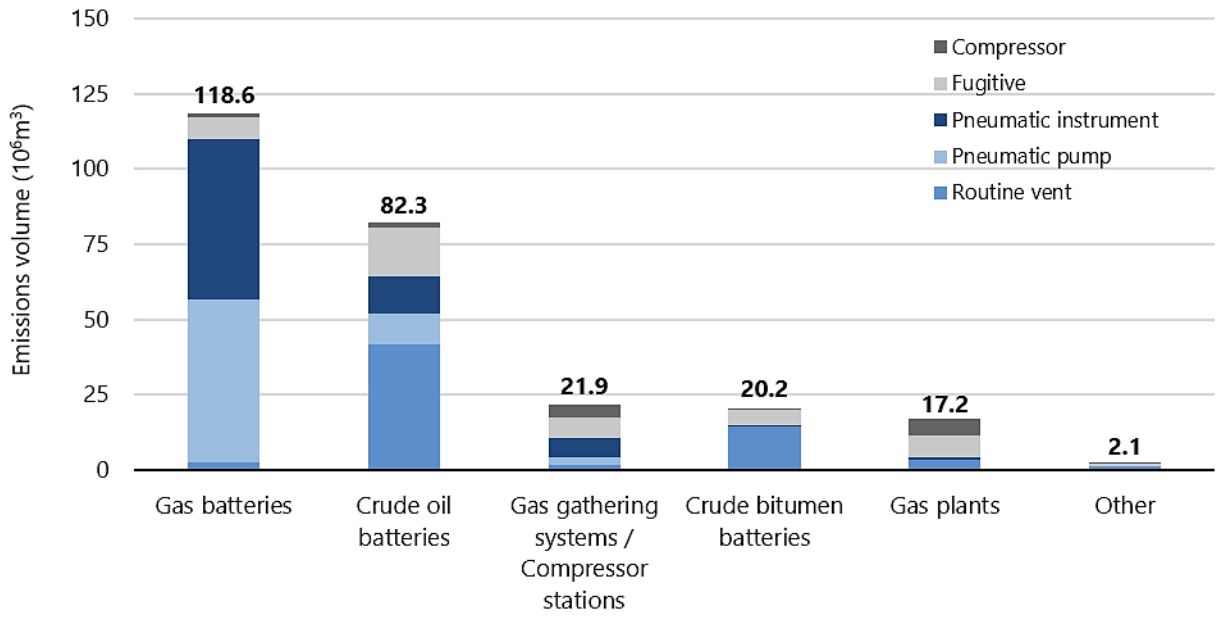


Figure 8. Breakdown of venting volumes by facility subtype, 2025 (Source: Petrinex)

Figure 9 shows a side-by-side comparison of the annual emissions data for 2020 to 2025. Year-over-year comparisons demonstrate a continued decline from peak emissions in 2020/2021. The reported data is a snapshot in time, and these volumes could change as companies review and update their data.

Large increases or decreases in emissions reported are possible for various reasons, including acquisitions, divestitures, insolvencies, changes in operating conditions/statuses, improvements in operator equipment inventories, or changes in emission quantification methodologies. It could also indicate potential data quality issues within submissions. Table 10 lists the top ten companies with the largest reported emission differences in annual reported volumes when comparing 2024 and 2025. Data quality continues to improve year over year due to efforts in compliance and education on submission requirements. Since the data were retrieved on July 15, 2026, the report does not reflect amendments made after this date. When warranted, the AER follows up with companies to determine if compliance action is required.

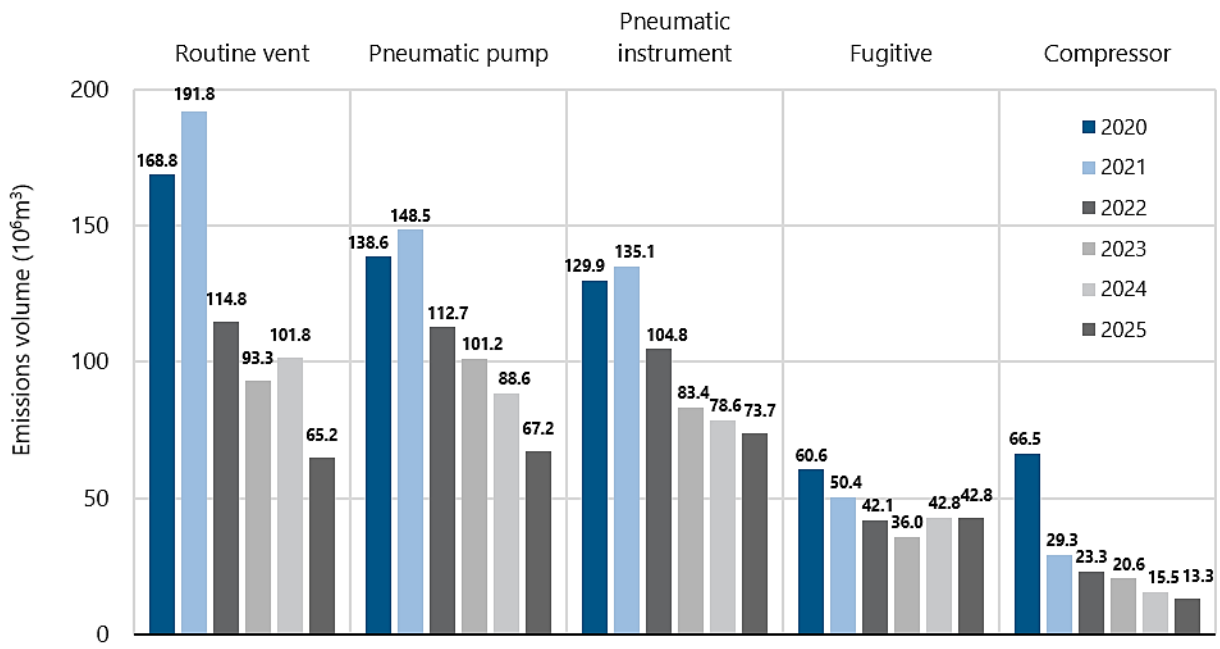


Figure 9. Comparison of emissions volumes by source, 2020–2025 (Source: Petrinex/OneStop)

Table 10. Top ten largest differences in reported emission volumes, 2024–2025 (Source: Petrinex/OneStop)

Operator	2024 (million m^3)	2025 (million m^3)	Difference (million m^3)
Canlin Resources Partnership	8.37	1.29	–7.08
Canadian Natural Resources Limited	49.01	42.03	–6.98
Tourmaline Oil Corp.	31.19	25.35	–5.84
Top Oil Production Ltd.	6.28	1.91	–4.37
Obsidian Energy Ltd.	6.30	3.38	–2.92
Cenovus Energy Inc.	22.60	20.18	–2.42
Ipc Canada Ltd.	0.67	2.65	1.98
Ish Energy Ltd.	2.55	0.71	–1.85
Journey Energy Inc.	3.31	1.56	–1.75
Rubellite Energy Inc.	0.43	2.16	1.73

4.2.2 Defined Vent Gas

Defined vent gas (DVG) is the cumulative volume of vent gas from venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators. *Directive 060* includes vent limits for DVG, which are reported annually to the AER and is also captured in the monthly vent volumes reported. In 2025, total DVG emissions reported were 65.2 million m^3 (see figure 10), about 24% of all emissions reported, a 36% decrease from the reported 2024 volumes. Crude oil batteries contribute the most DVG emissions by volume and contributed the majority to the reductions observed in 2025.

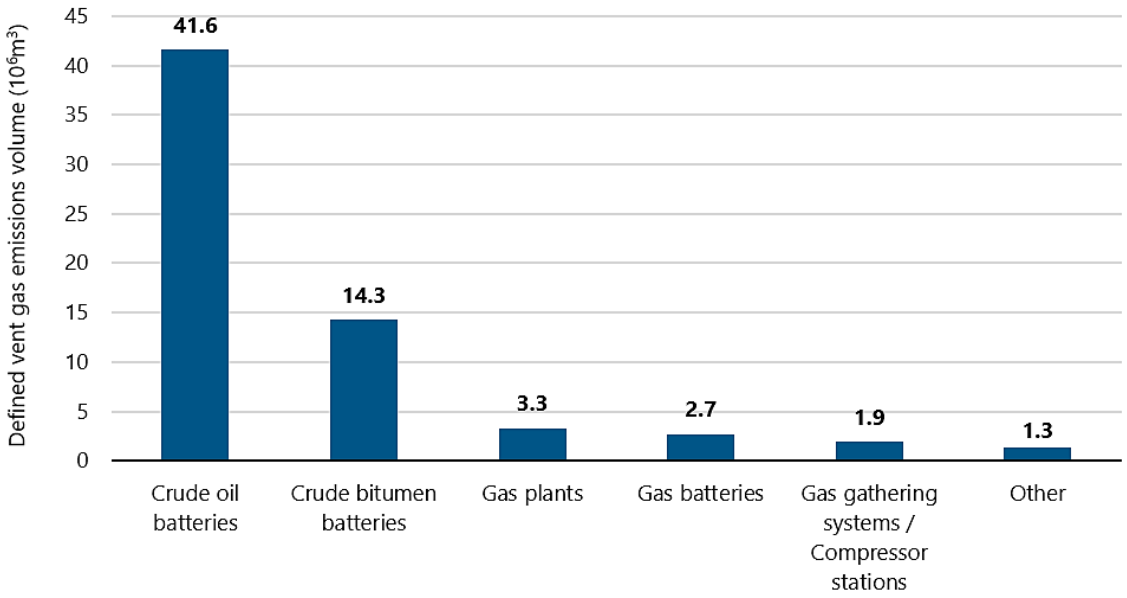


Figure 10. DVG vent volumes by facility subtype, 2025 (Source: Petrinex)

4.2.3 Pneumatic Devices

Directive 060 includes limits for vent gas from pneumatic instruments and pumps, which are reported annually to the AER.

In 2025, emissions reported for pneumatic devices (instruments and pumps) were 140.9 million m^3, about 52% of all emissions reported, a 13.7% decrease from the reported 2024 volumes. Gas batteries were the most significant contributor, representing about 76% of the total pneumatic emissions.

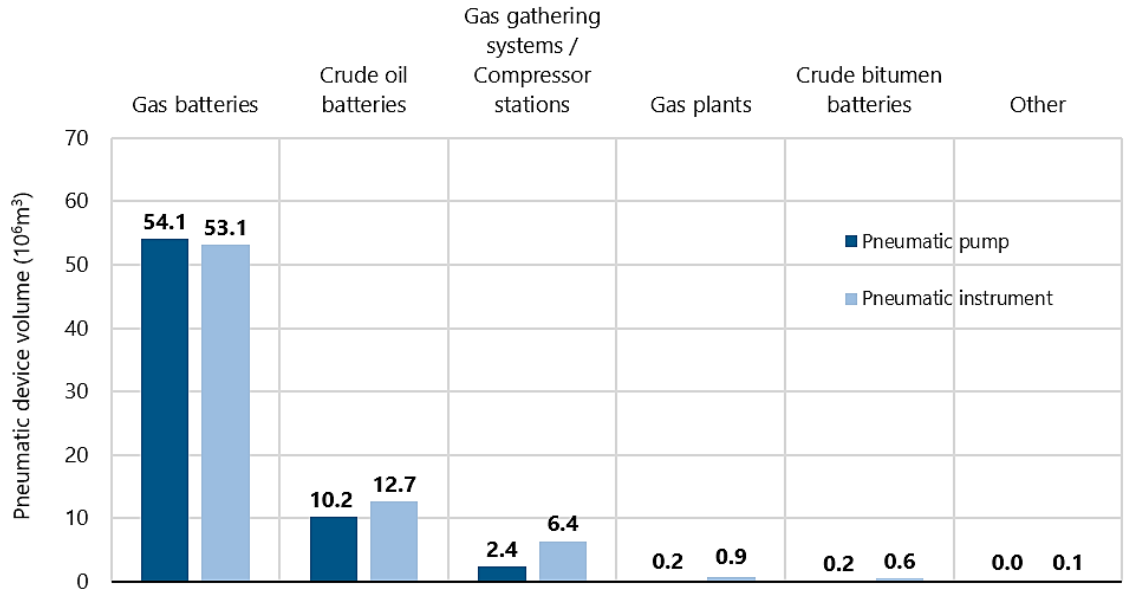


Figure 11. Pneumatic vent volumes by equipment and facility subtype, 2025 (Source: Petrinex)

4.2.4 Compressor Seals

Directive 060 includes testing requirements and vent limits for reciprocating and centrifugal compressor seals. Emission volumes for this source include tested (measured) and estimated volumes, which are reported annually to the AER. These volumes are captured in the vent volumes reported monthly.

4.2.4.1 Compressor Inventory

This inventory includes compressors rated 75 kW or more and pressurized for at least 450 hours per calendar year, which must be reported individually, separately from aggregate compressor volumes. The data in figure 12 and table 11 only include the compressors itemized in this inventory; thus, the volumes here are less than the total compressor volumes reported in figure 7. In 2025, 3599 reciprocating compressors and 87 centrifugal compressors were reported, a decrease from 3978 reciprocating compressors and 106 centrifugal compressors in 2024.

4.2.4.2 Compressor Seal Emissions

In 2025, reciprocating compressor seal emissions reported were 12.24 million m^3, roughly 4.5% of all emissions reported. Centrifugal compressor seal emissions reported were 0.46 million m^3, a minor contributor relative to the other emission sources reported here, representing only 0.17% of all emissions reported. The most significant contributions came from gas gathering systems, compressor stations, and gas plants. Figure 12 shows a breakdown of compressor emissions by facility subtype.

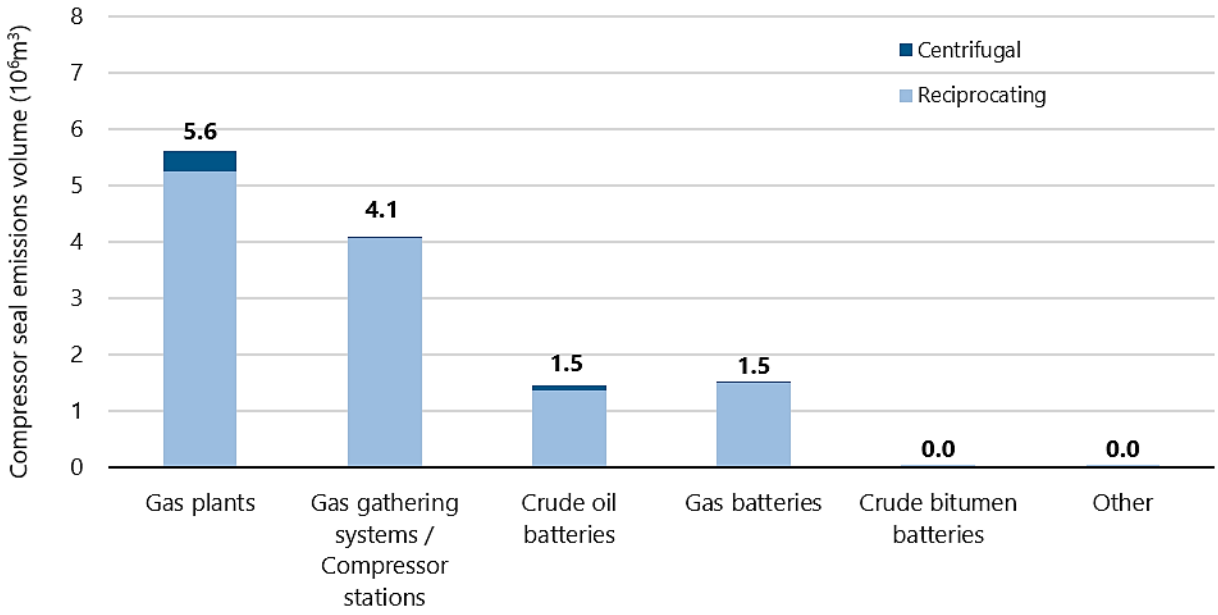


Figure 12. Compressor inventory vent volumes by compressor type and facility subtype, 2025 (Source: Petrinex)

4.2.4.3 Reciprocating Compressor Seal Fleet Average

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents/drains and the distance-piece vents/drains on each throw.

The RCS fleet average can be calculated using the formula found in section 8.6.2.2 of *Directive 060*. Table 11 shows the estimated RCS fleet averages for the top 20 compressor venting operators using 2025 reported values.

Table 11. Top 20 compressor inventory venting operators with RCS fleet average, 2025 (Source: Petrinex)

Operator	Vent volume (10^6 m^3)	Number of compressors	Number of throws	Average of vent gas from RCS fleet*
Canadian Natural Resources Limited	2.14	651	2210	0.12
Tourmaline Oil Corp.	0.91	244	892	0.13
Pembina Gas Infrastructure Inc.	0.90	166	619	0.17
Cenovus Energy Inc.	0.74	147	518	0.19
Spartan Delta Corp.	0.53	51	184	0.34
Peyto Exploration & Development Corp.	0.49	125	439	0.19
Vermilion Energy Inc.	0.41	89	284	0.19
Keyera Energy Ltd.	0.33	90	291	0.11
Journey Energy Inc.	0.32	33	89	0.50
TAQA North Ltd.	0.28	118	358	0.14
Paramount Resources Ltd.	0.28	83	281	0.13
ARC Resources Ltd.	0.28	138	509	0.07
Karve Energy Inc.	0.25	23	73	0.34
Whitecap Partnership	0.24	81	250	0.11
Pine Cliff Energy Ltd.	0.19	45	177	0.12
Murphy Oil Company Ltd.	0.19	25	59	0.32
Lynx Energy ULC	0.18	40	155	0.14
Mancal Energy Inc.	0.16	23	75	0.23
Conifer Energy Inc.	0.15	33	98	0.26
Ovintiv Canada ULC	0.15	82	297	0.09

* Cubic metres per throw-hour; see section 8.6.2.2 of *Directive 060* for details on how this is calculated. Averages above the limit are highlighted.

4.2.5 Glycol Dehydrators

Directive 060 includes methane emission limits for glycol dehydrators. Glycol dehydrator emissions must be reported to the AER through OneStop annually. These volumes should also be captured in the vent volumes reported monthly to Petrinex.

4.2.5.1 Glycol Dehydrator Inventory

In 2025, there were 1156 operating glycol dehydrators in Alberta. Not all dehydrators would be active for the full year but are counted in this inventory if they operated in 2025. Table 12 shows the counts of all operating glycol dehydrators per year over the past 16 years.

Table 12. Number of operating glycol dehydrators, 2010–2025 (Source: OneStop)

Year	Number of dehydrators
2010	2 107
2011	2 006
2012	1 985
2013	1 905
2014	1 886
2015	1 778
2016	1 646
2017	1 528
2018	1 399
2019	1 331
2020	1 366
2021	1 241
2022	1 244
2023	1 329
2024	1 181
2025	1 156

Note: Benzene occurs in varying concentrations in natural gas streams throughout the province, and some locations may not have any benzene. All operating dehydrators are included, regardless of the concentration of benzene in the gas stream.

4.2.5.2 Glycol Dehydrator Emissions

The reporting requirements for glycol dehydrators differ from all other source categories in that the AER only requires the methane mass emissions to be reported. The data presented in this section reflect a conversion of the reported mass to volume using methane density and an 85% methane concentration estimate. In 2025, glycol dehydrator emissions were calculated to be 8.3 million m^3, representing 3.1% of all annual emissions reported, and a 4.6% reduction from the reported 2024 volumes. Detailed visuals on glycol dehydrator emissions are not included in this report because not all facility subtypes and reporting codes could be identified.

5 Fugitive Emissions

Fugitive emissions are unintentional releases of hydrocarbons into the atmosphere associated with equipment design and maintenance factors and can also result from equipment failure. This category excludes methane slip and emissions from incomplete combustion, as well as SCVF emissions. *Directive 060* includes requirements for screenings and surveys to inspect and repair leaking equipment. Fugitive emissions are reported to the AER through Petrinex annually.

The first year of implementing prescribed fugitive emission requirements under *Directive 060* was 2020, and 2020 was the first year equipment fugitive emissions were reported to the AER. In 2025, fugitive emissions were 42.8 million m^3 (see figure 13), representing 15.8% of all emissions reported to Petrinex.

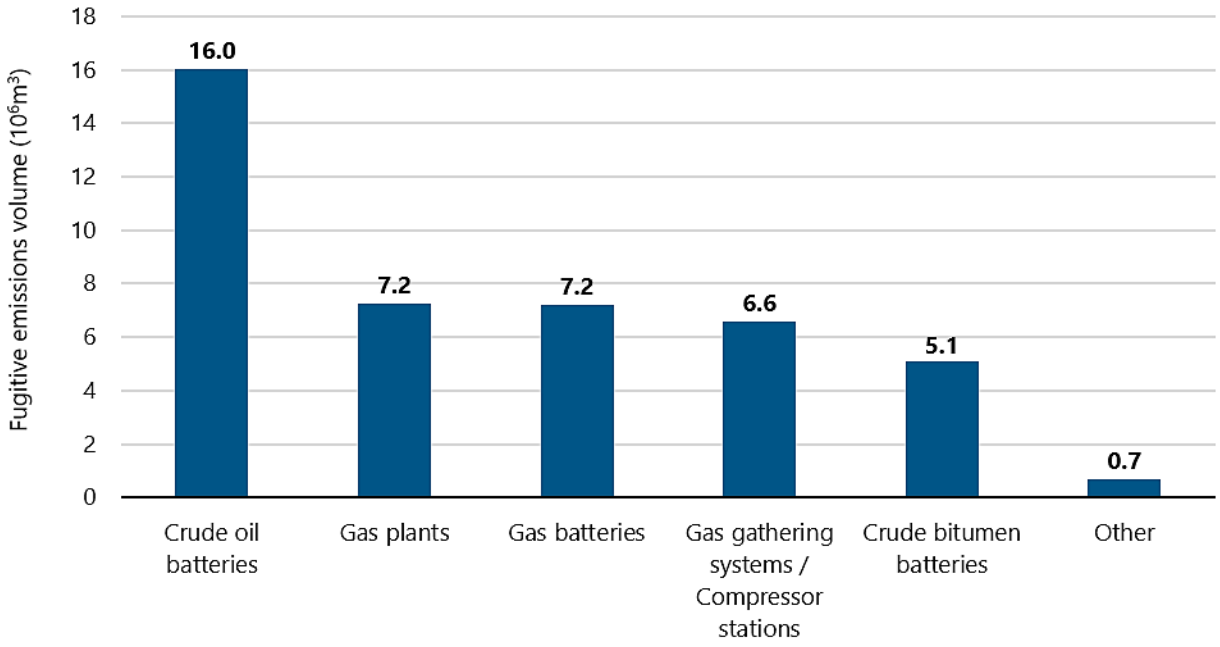


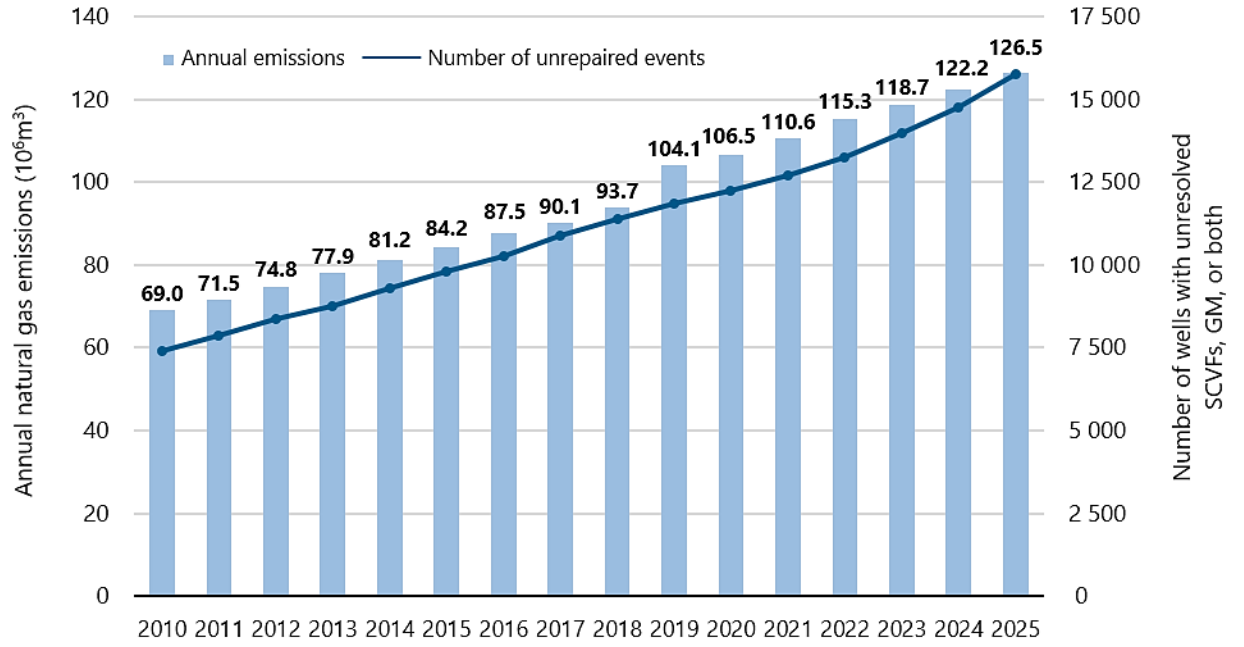
Figure 13. Fugitive emissions volume by facility subtype, 2025 (Source: Petrinex)

6 Surface Casing Vent Flow and Gas Migration

A surface casing vent flow (SCVF) event is the flow of gas, liquid, or both out of the surface casing or casing annulus of a well. A gas migration (GM) event is the flow of detectable gas at the surface outside of the outermost casing string.

SCVF and GM emissions detected during a fugitive emission survey are not reported via Petrinex. These emissions are reported via the Digital Data Submission (DDS) system. Nonserious events or volumes too small to quantify are assigned an average vent flow rate of all nonserious reported vent rates. Serious events with no vent flow submitted were assigned a volume of 300 m^3 per day, and repair statuses were assigned based on submitted repair dates within the calendar year.

Figure 14 shows the number of unresolved wells with SCVF, GM, or both and their respective emissions. Figure 15 shows the number of repaired wells per year with SCVF, GM, or both, and their respective vent emission reductions.



Notes:

For wells that have SCVF flow rates that are too small to measure and wells where a GM event is found, a flow rate of 1 m^3/day was assumed. Repair statuses were assigned based on submitted repair dates within the calendar year.

If the SCVF event was labeled as serious with no vent flow submitted, a default vent flow rate of 300 m^3/day was assigned.

Where the vent flow rate is not available and SCVF event was labeled as nonserious, the vent flow rate is estimated using the average measured vent flow rate from nonserious vent flow records greater than 0.

The flow rates reported are from a single point in time and are extrapolated to determine annual emissions. Flow rates for SCVFs and GM can fluctuate significantly over time.

Figure 14. Emissions from SCVFs and GM at unrepaired wells

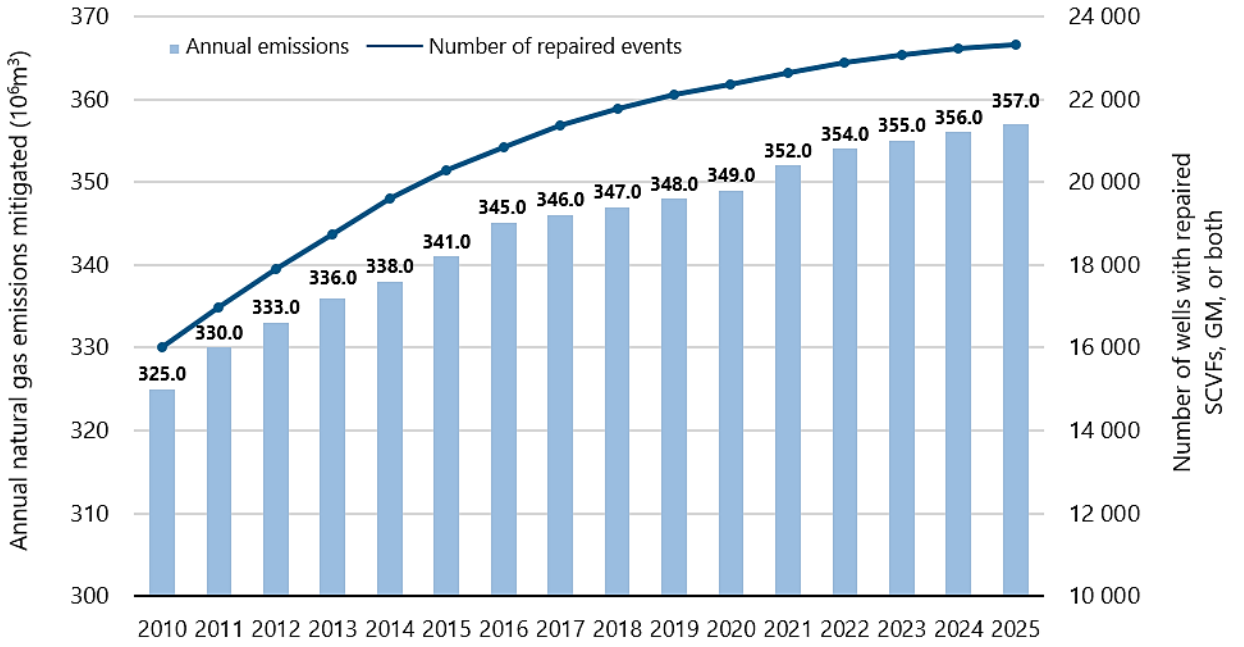


Figure 15. Emissions mitigated from SCVFs and GM at repaired wells

7 Solution Gas Performance

Solution gas is gas separated from condensate, oil, or bitumen production. To minimize the venting of solution gas, requirements to guide the evaluation of alternative options, such as flaring or conserving, are outlined in section 4 of *Directive 060*.

Operator rankings for solution gas performance can be found in appendix 2.

7.1 Solution Gas Flaring

Solution gas flaring is the combustion of excess natural gas (including methane) associated with oil and bitumen production. As shown in figure 16, 787.8 million m^3 of solution gas was flared in 2025, which was a 13.9% decrease over 2024.

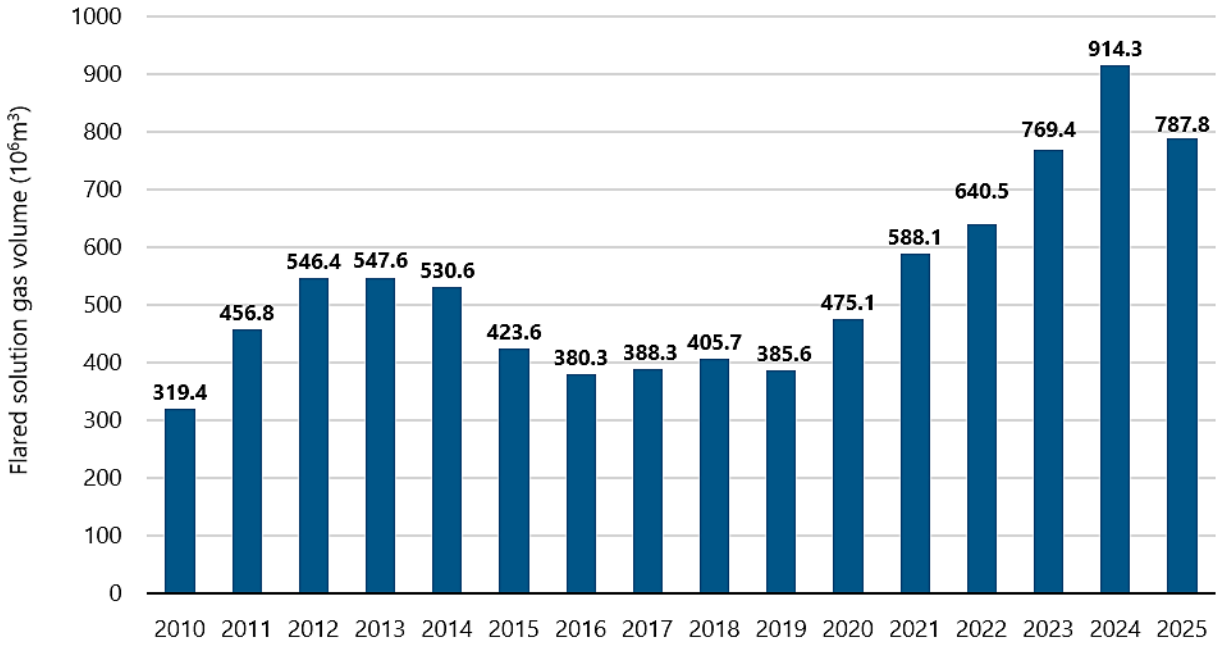


Figure 16. Solution gas flaring, 2010–2025 (Source: Petrinex)

7.2 Solution Gas Venting

In 2025, 87.2 million m^3 of solution gas was vented from crude oil and crude bitumen batteries, a 13.7% decrease from 2024. The decrease in solution gas venting is consistent with industry efforts to reduce methane emissions through conservation and combustion measures.

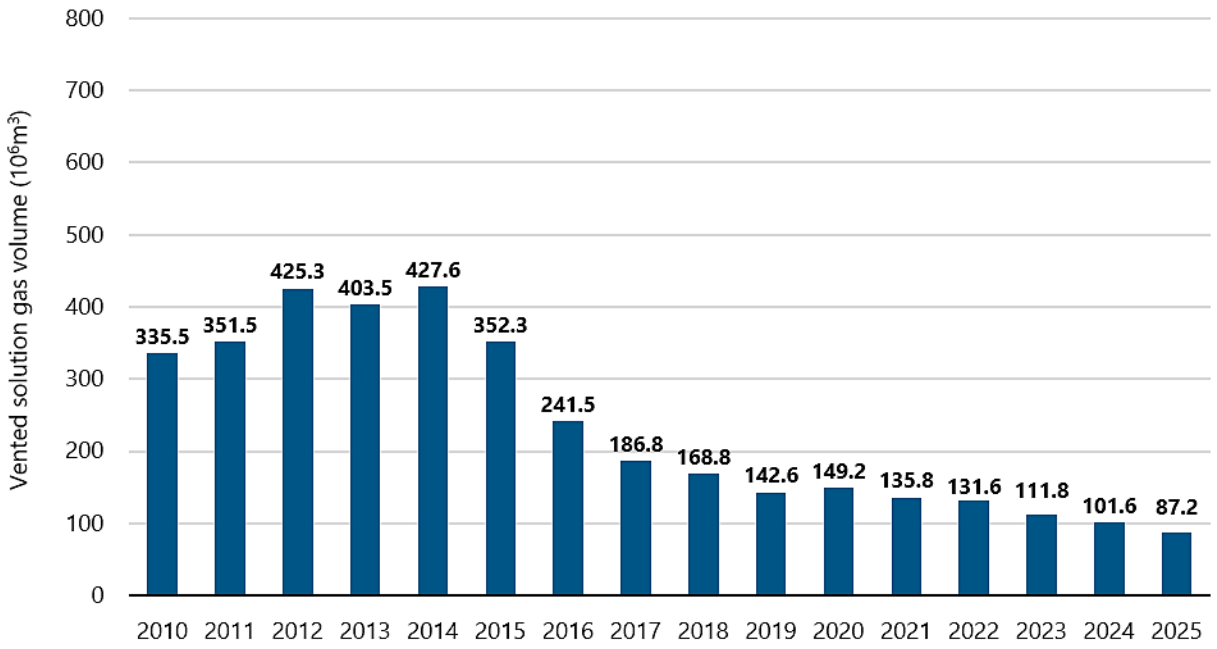


Figure 17. Solution gas venting, 2010–2025 (Source: Petrinex)

7.3 Solution Gas Conservation

Gas conservation is the recovery of solution gas to use as fuel for production facilities, to sell, to inject for enhanced recovery from oil or condensate pools, or to generate power, among other uses. It is calculated as follows:

$$Conservation\ (\%) = \frac{Produced\ Gas - (Flared\ Gas + Vented\ Gas)}{Produced\ Gas} \times 100$$

In 2025, 97.1% of the solution gas produced from crude oil and crude bitumen batteries was conserved, up slightly from 96.5% in 2024.

Figure 18 shows the total annual solution gas flared and vented volumes and the associated conservation rates.

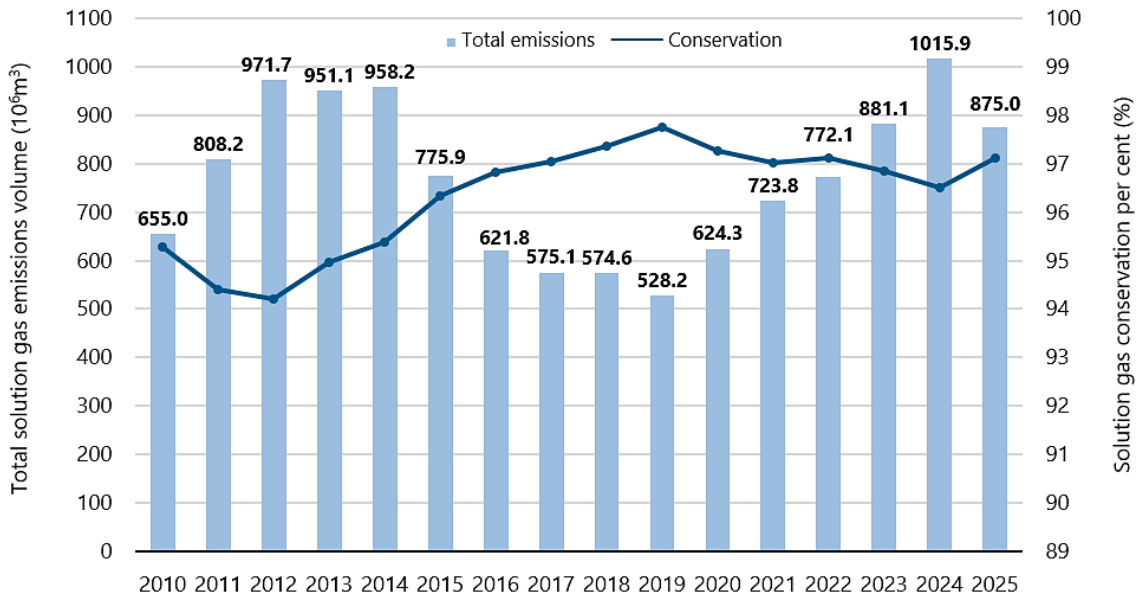


Figure 18. Solution gas conservation rate and total emissions, 2010–2025 (Source: Petrinex)

7.4 Nonthermal and Thermal Operations

There are two types of crude bitumen operations: nonthermal (e.g., cold heavy oil production) and thermal (e.g., steam-assisted gravity drainage or cyclical steam stimulation). Thermal operations generally have less flaring and venting than nonthermal operations. Figure 19 shows the annual solution gas conservation percentages for crude bitumen batteries by nonthermal and thermal operations. Historically, conservation rates are higher for thermal operations, which is the case for 2025. Thermal operations conservation is 97.9%, whereas nonthermal operations have a conservation rate of 87.7%.

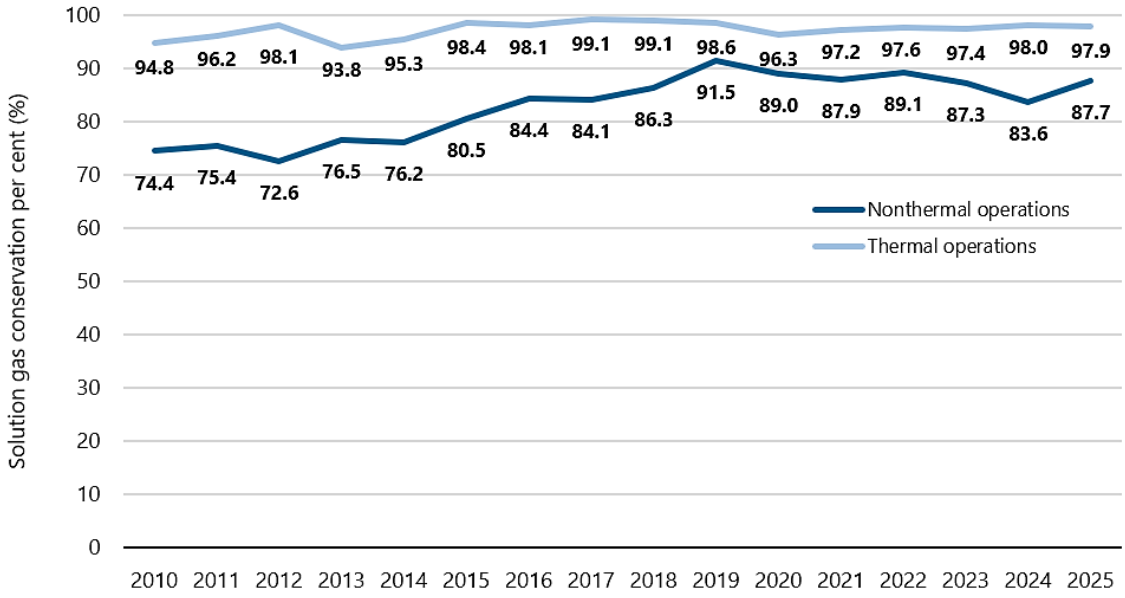


Figure 19. Solution gas conservation by production operations, 2010–2025 (Source: Petrinex)

8 Methane Performance

The emissions data reported above is not complete enough to consider it a comprehensive oil and gas methane emission inventory. The AER continues to supplement reported information with emission estimates to allow for an evaluation of the emission reductions achieved to date, according to table 13 data. The model assumptions, inputs, and estimates are updated annually to reflect the latest and most accurate data available; thus, the inventory may shift year over year to reflect these changes.

To learn more about these requirements and for more information on methane performance and methane compliance assurance activities, see our methane performance webpage.

8.1 Methodology Updates and Interpretation of Trends

Figure 20 shows Alberta's upstream oil and gas methane emissions, excluding oil sands mining, tailings, and upgrading, relative to the target of reducing emissions by 45% from 2014 levels by 2025 and the annual per cent reductions from 2014. The methane emissions profile is based on a combination of reported data and engineering calculations. Results from 2025 indicate that Alberta has achieved a 62% reduction in methane emissions, exceeding Alberta's methane reduction target of 45%.

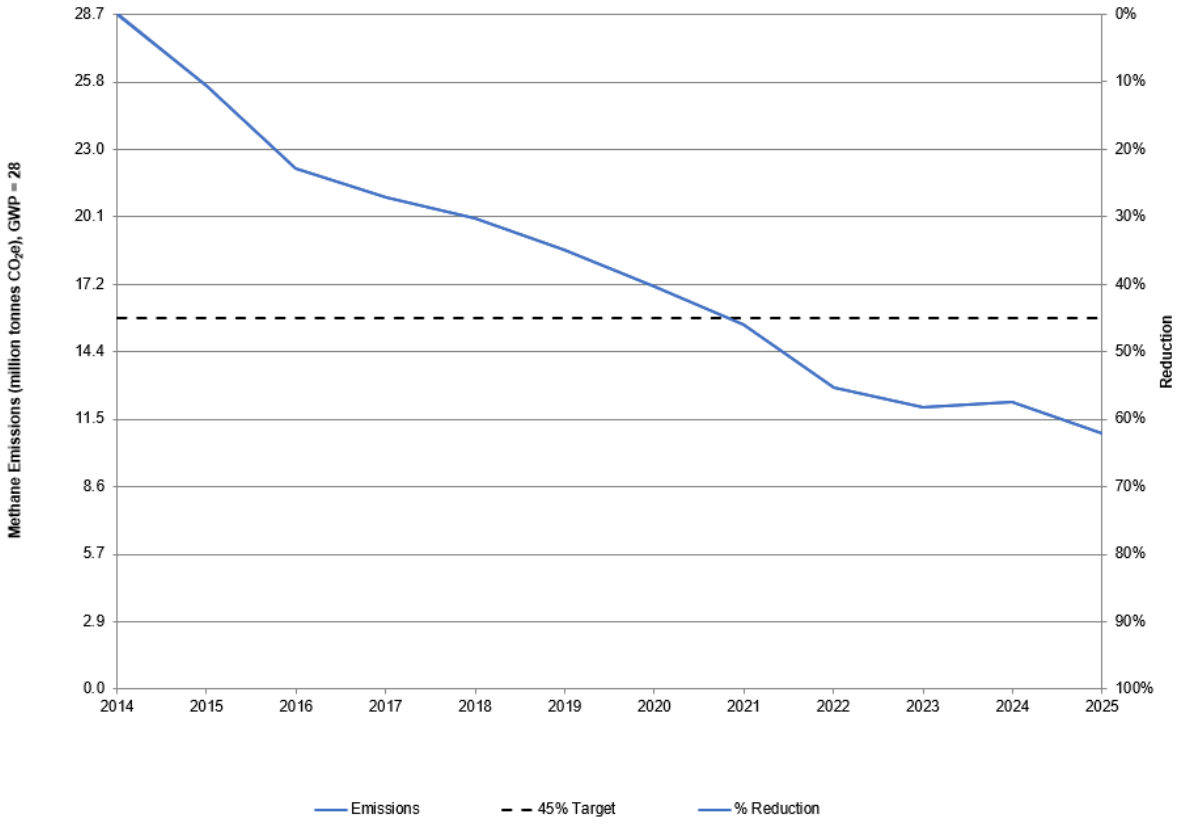


Figure 20. Methane emissions and percent reduction from 2014.

For the current reporting year, the AER inventory includes substantive revisions to pneumatic and fugitive emissions estimates, along with minor revisions to other source categories. The most significant methodological change was the shift to using volumetric data reported directly by industry to the AER for pneumatic and fugitive emissions, rather than province-wide facility counts, average equipment counts, and emission factors. This update leverages five years of reported industry data and is intended to better reflect facility-level operating conditions and reported emissions characteristics. The use of industry-reported data is an established approach used across the AER's compliance and reporting programs. The data is subject to ongoing validation and compliance assurance activities and, where appropriate, are supplemented by engineering calculations or modelling and other information sources.

Table 13 provides a source-by-source summary of whether emissions were based on reported data or modelling, along with the corresponding 2014 and 2025 values. Methane emissions for sources based on reported data decreased by 79%, while modelled sources increased by 17% from 2014 to 2025.

Table 13. Summary of emission quantification methods and values by source, 2014 and 2025

Source	2014 emissions ($MtCO_2e$)	2025 emissions ($MtCO_2e$)	Quantification method
Pneumatics	10.303	2.538	2014–2020 Modelled 2021–2025 Reported
Venting – excluding in situ	8.447	1.071	Reported
Methane slip fuel	2.436	2.288	Modelled
Fugitives	2.331	0.762	2014–2019 Modelled 2020–2025 Reported
SCVF	1.489	2.186	Modelled
Dehydrators	1.122	0.136	2014–2017 Modelled 2018–2025 Reported
Unlit flares	1.095	1.401	Modelled
Spills and ruptures	0.906	0.105	Reported
Compressor seals	0.552	0.376	2014–2019 Modelled 2020–2025 Reported
Venting – in situ	0.034	0.025	Reported
Catalytic heaters	0.001	0.001	Modelled

Facility counts used to backcast emissions in the absence of reported data were also updated to better align with the *Directive 060* definition of active facilities and wells and the *Manual 015* facility subtype list for annual methane reporting. To preserve comparability, these updated criteria were applied retrospectively to facility counts back to 2014. As a result, facility counts and reported totals for fuel use, flaring, and venting differ slightly from those published in previous editions.

In addition to tracking absolute methane emissions relative to Alberta's 2025 reduction target, methane performance can also be expressed as an estimated methane intensity. Methane intensity provides a production-normalized measure of methane emissions and offers additional context for interpreting changes in emissions alongside changes in industry activity. While methane intensity is gaining traction in some jurisdictions, there is currently no universally adopted methodology for calculating it. For this

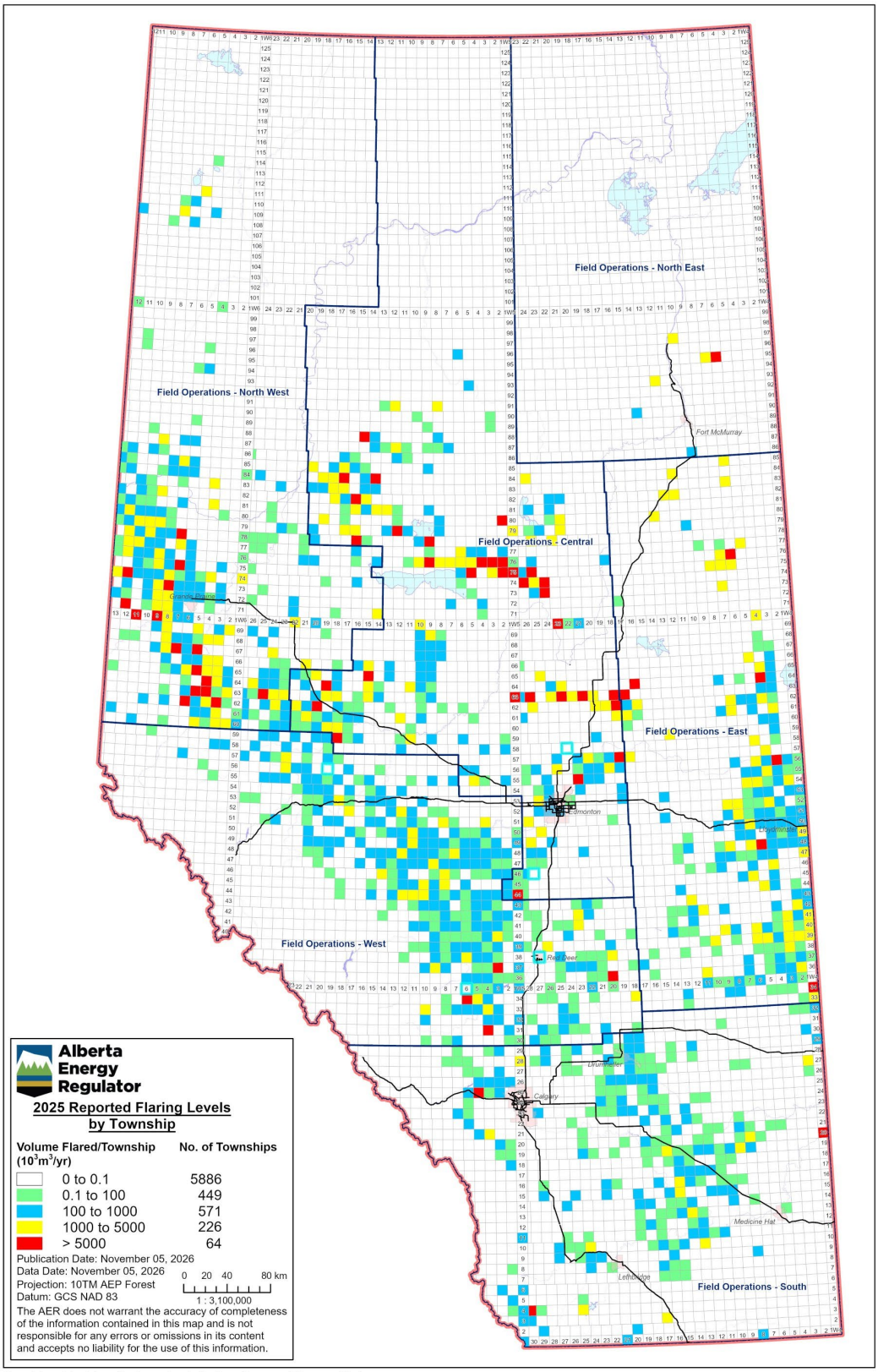
report, Alberta's methane intensity is presented using the *Natural Gas Sustainability Initiative (NGSI) Methane Emissions Intensity Protocol: Version 3.0*, which accounts for Alberta's mix of gas and liquids production. Table 14 shows a steady decline in Alberta's methane intensity from 0.48% in 2020 to 0.25% in 2025, which indicates continued improvement in methane performance relative to production. Details on the methodology are provided in appendix 4.

Table 14. Methane Intensity

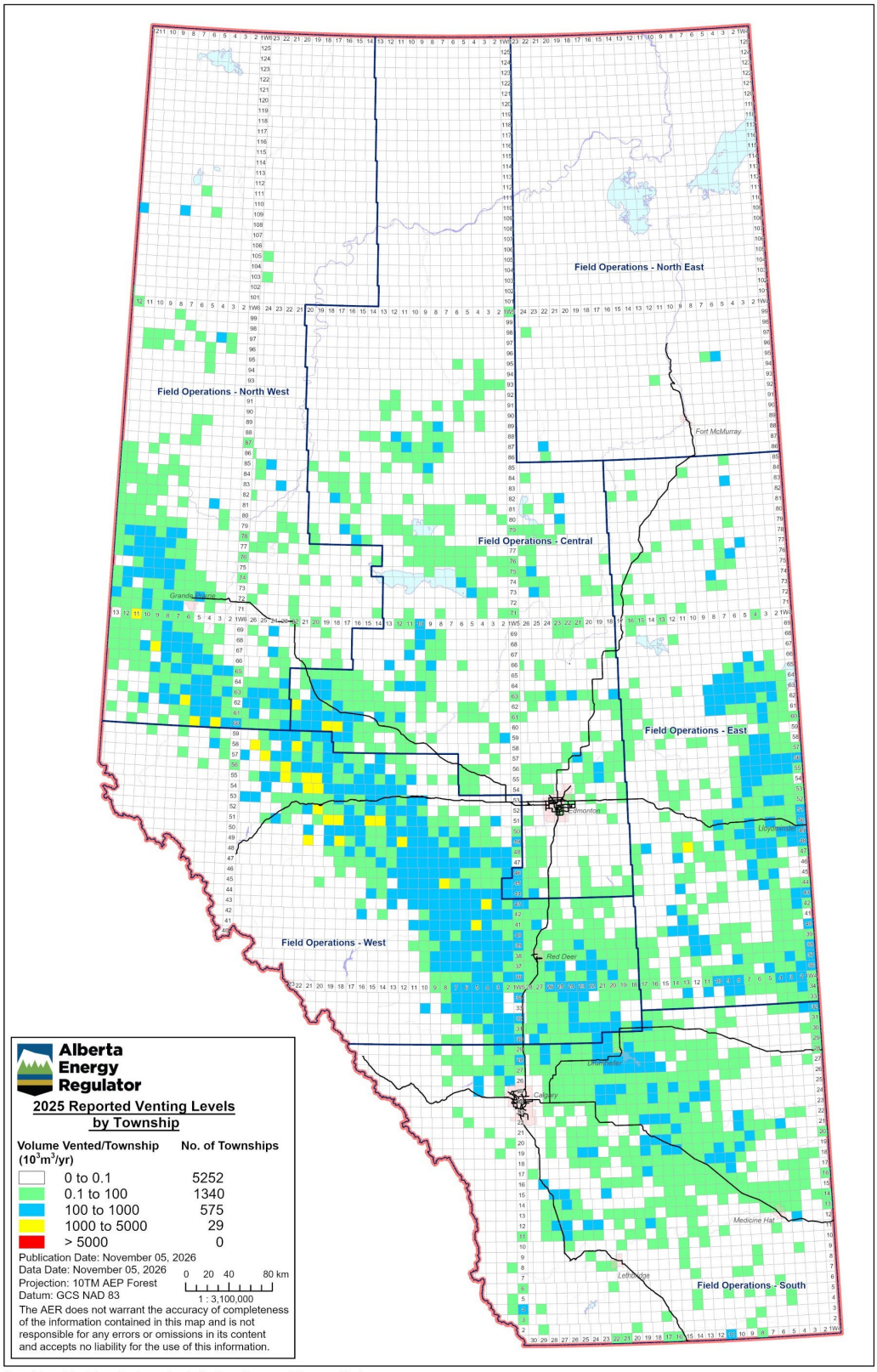
Year	Methane Intensity (%)
2020	0.48
2021	0.41
2022	0.32
2023	0.29
2024	0.29
2025	0.25

The AER will continue with compliance assurance activities and data quality assessments to shift towards using reported and measured data when possible and minimize the reliance on estimation over time (appendix 3). The AER will evaluate the emission reductions annually as part of this report.

Appendix 1 Reported Flaring and Venting Maps



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Base data contains information licensed under the Open Government Licence – Alberta

Appendix 2 Operator Rankings

Caution is required when comparing with last year's report due to mergers, acquisitions, and divestments. This year's report provides the total volumes and differentiates oil sands assets from other assets.

The operator rankings for the reported volume of gas vented, flared, and used as fuel are based on Petrinex data as of July 15, 2026.

Venting

Oil Sands Assets

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Cenovus Energy Inc.	331 300	1	242 961 034	0.00136	0.00091	49%
Canadian Natural Resources Limited	258 400	2	154 764 028	0.00167	0.00168	-1%
Imperial Oil Resources Limited	257 600	3	63 519 553	0.00406	0.00569	-29%
Suncor Energy Inc.	239 200	4	112 831 550	0.00212	0.00232	-9%
ConocoPhillips Canada Resources Corp.	146 600	5	62 869 000	0.00233	0.00260	-10%
CNOOC Petroleum North America ULC	84 400	6	30 590 406	0.00276	0.01137	-76%
Harvest Operations Corp.	19 700	7	3 141 517	0.00627	0.01340	-53%

Non-Oil-Sands Assets

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Canadian Natural Resources Limited	40 396 800	1	163 390 746	0.25	0.29	-14%
Tourmaline Oil Corp.	27 244 000	2	108 001 730	0.25	0.28	-11%
Cenovus Energy Inc.	18 415 100	3	56 968 743	0.32	0.39	-18%
Peyto Exploration & Development Corp.	11 491 100	4	48 786 194	0.24	0.27	-11%
Whitecap Resources Inc.	10 770 600	5	85 965 411	0.13	0.14	-7%
Vermilion Energy Inc.	9 102 400	6	24 746 380	0.37	0.38	-3%
TAQA North Ltd.	7 425 200	7	25 353 567	0.29	0.33	-12%
Pine Cliff Energy Ltd.	5 987 100	8	7 265 335	0.82	0.84	-2%
ARC Resources Ltd.	4 110 500	9	70 236 602	0.06	0.07	-14%
Spartan Delta Corp.	3 769 200	10	14 066 029	0.27	0.31	-13%
Acerta Operating Corporation	3 430 700	11	2 447 949	1.40	1.49	-6%
Paramount Resources Ltd.	3 322 800	12	10 784 931	0.31	0.44	-30%
InPlay Oil Corp.	3 184 600	13	6 148 503	0.52	0.61	-15%
Mancal Energy Inc.	2 837 300	14	3 907 939	0.73	0.77	-5%

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Karve Energy Inc.	2 771 100	15	3 691 239	0.75	0.78	-4%
Obsidian Energy Ltd.	2 459 800	16	4 729 129	0.52	1.03	-50%
Cardinal Energy Ltd.	2 271 300	17	5 584 688	0.41	0.56	-27%
Gran Tierra Canada Ltd.	2 256 900	18	4 171 061	0.54	0.59	-8%
Ember Resources Inc.	2 244 200	19	13 107 256	0.17	0.17	0%
Ovintiv Canada ULC	2 213 900	20	61 031 536	0.04	0.04	0%
Top Oil Production Ltd.	1 873 600	21	159 697	11.73	13.68	-14%
Saturn Oil & Gas Inc.	1 657 000	22	4 282 001	0.39	0.48	-19%
Lynx Energy ULC	1 633 000	23	6 467 175	0.25	0.33	-24%
Journey Energy Inc.	1 606 500	24	3 990 046	0.40	0.35	14%
Sinopec Canada Energy Ltd.	1 554 200	25	6 573 754	0.24	0.19	26%

Combined

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Canadian Natural Resources Limited	40 655 200	1	318 154 773	0.13	0.15	-13%
Tourmaline Oil Corp.	27 244 000	2	108 001 730	0.25	0.28	-11%
Cenovus Energy Inc.	18 746 400	3	299 929 777	0.06	0.08	-25%
Peyto Exploration & Development Corp.	11 491 100	4	48 786 194	0.24	0.27	-11%
Whitecap Resources Inc.	10 770 600	5	85 965 411	0.13	0.14	-7%
Vermilion Energy Inc.	9 102 400	6	24 746 380	0.37	0.38	-3%
TAQA North Ltd.	7 425 200	7	25 353 567	0.29	0.33	-12%
Pine Cliff Energy Ltd.	5 987 100	8	7 265 335	0.82	0.84	-2%
ARC Resources Ltd.	4 110 500	9	70 236 602	0.06	0.07	-14%
Spartan Delta Corp.	3 769 200	10	14 066 029	0.27	0.31	-13%
Acerta Operating Corporation	3 430 700	11	2 447 949	1.40	1.49	-6%
Paramount Resources Ltd.	3 322 800	12	10 784 931	0.31	0.44	-30%
InPlay Oil Corp.	3 184 600	13	6 148 503	0.52	0.61	-15%
Mancal Energy Inc.	2 837 300	14	3 907 939	0.73	0.77	-5%
Karve Energy Inc.	2 771 100	15	3 691 239	0.75	0.78	-4%
Obsidian Energy Ltd.	2 459 800	16	9 643 500	0.26	0.60	-57%
Cardinal Energy Ltd.	2 271 300	17	5 584 688	0.41	0.56	-27%
Gran Tierra Canada Ltd.	2 256 900	18	4 250 701	0.53	0.59	-10%
Ember Resources Inc.	2 244 200	19	13 107 256	0.17	0.17	0%
Ovintiv Canada ULC	2 213 900	20	61 031 536	0.04	0.04	0%
Top Oil Production Ltd.	1 873 600	21	159 697	11.73	13.83	-15%
Saturn Oil & Gas Inc.	1 657 000	22	4 282 001	0.39	0.48	-19%
Lynx Energy ULC	1 633 000	23	6 467 175	0.25	0.33	-24%
Journey Energy Inc.	1 606 500	24	3 990 046	0.40	0.35	14%

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Sinopec Canada Energy Ltd.	1 554 200	25	6 573 754	0.24	0.19	26%

Flaring

Oil Sands Assets

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	Difference (2025 to 2024)
Suncor Energy Inc.	25 154 300	1	112 831 550	0.2229	0.2431	-8%
Cenovus Energy Inc.	14 173 300	2	242 961 034	0.0583	0.0483	21%
Canadian Natural Resources Limited	12 615 600	3	154 764 028	0.0815	0.0762	7%
Strathcona Resources Ltd.	9 624 500	4	24 892 111	0.3866	0.2534	53%
Greenfire Resources Operating Corporation	3 613 100	5	8 017 270	0.4507	0.3517	28%
Imperial Oil Resources Limited	3 310 700	6	63 519 553	0.0521	0.0546	-5%
CNOOC Petroleum North America ULC	3 166 200	7	30 590 406	0.1035	0.1055	-2%
Connacher Oil And Gas Limited	3 043 800	8	7 236 274	0.4206	0.4667	-10%
ConocoPhillips Canada Resources Corp.	2 642 100	9	62 869 000	0.0420	0.0709	-41%
Harvest Operations Corp.	1 906 700	10	3 141 517	0.6069	0.3611	68%
Ipc Canada Ltd.	886 200	11	260 172	3.4062	1.8261	87%
PetroChina Canada Ltd.	874 900	12	3 854 022	0.2270	0.0009	25 122%
Athabasca Oil Corporation	553 900	13	14 572 970	0.0380	0.0364	4%

Non-Oil-Sands Assets

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Tamarack Valley Energy Ltd.	114 627 300	1	19 681 044	5.82	7.45	-22%
Spur Petroleum Ltd.	103 803 500	2	13 453 744	7.71	8.24	-6%
Canadian Natural Resources Limited	101 154 400	3	163 390 746	0.62	0.58	7%
Baytex Energy Ltd.	56 417 800	4	6 927 039	8.14	14.74	-45%
ARC Resources Ltd.	53 778 800	5	70 236 602	0.77	0.74	4%
Cavvy Production Ltd.	46 612 500	6	934 553	49.88	16.67	199%
Cenovus Energy Inc.	40 445 600	7	56 968 743	0.71	0.74	-4%
Rubellite Energy Inc.	38 923 200	8	2 714 357	14.34	24.02	-40%
Obsidian Energy Ltd.	37 253 200	9	4 729 129	7.88	3.71	112%
Headwater Exploration Inc.	27 375 600	10	1 198 346	22.84	73.84	-69%
Ovintiv Canada ULC	23 497 700	11	61 031 536	0.39	0.57	-32%

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Caltex Trilogy Inc.	23 063 600	12	390 973	58.99	22.56	161%
Whitecap Resources Inc.	20 163 200	13	85 965 411	0.23	0.27	-15%
Paramount Resources Ltd.	17 958 100	14	10 784 931	0.93	1.00	-7%
Cardinal Energy Ltd.	17 157 300	15	5 584 688	3.07	2.29	34%
Surge Energy Inc.	13 358 500	16	5 576 305	2.40	2.58	-7%
TAQA North Ltd.	13 114 900	17	25 353 567	0.52	0.59	-12%
Lycos Energy Inc.	11 517 600	18	946 715	12.11	10.36	17%
Tourmaline Oil Corp.	10 980 800	19	108 001 730	0.10	0.10	0%
West Lake Energy Corp.	10 969 400	20	2 743 458	4.00	4.98	-20%
Spartan Delta Corp.	10 198 100	21	14 066 029	0.73	0.76	-4%
Clear North Energy Corp.	9 983 600	22	110 901	90.02	107.94	-17%
Peyto Exploration & Development Corp.	9 634 000	23	48 786 194	0.20	0.33	-39%
Ipc Canada Ltd.	9 623 300	24	11 078 301	0.87	0.91	-4%
Btg Energy Corporation	9 327 000	25	2 217 392	4.21	4.53	-7%

Combined

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Tamarack Valley Energy Ltd.	114 627 300	1	25 348 597	4.52	5.86	-23%
Canadian Natural Resources Limited	113 770 000	2	318 154 773	0.36	0.33	9%
Spur Petroleum Ltd.	103 803 500	3	22 381 417	4.64	4.91	-5%
Baytex Energy Ltd.	56 417 800	4	20 865 153	2.70	4.71	-43%
Cenovus Energy Inc.	54 618 900	5	299 929 777	0.18	0.18	0%
ARC Resources Ltd.	53 778 800	6	70 236 602	0.77	0.74	4%
Cavvy Production Ltd.	46 612 500	7	934 553	49.88	16.67	199%
Rubellite Energy Inc.	38 923 200	8	4 734 006	8.22	13.02	-37%
Obsidian Energy Ltd.	37 253 200	9	9 643 500	3.86	2.16	79%
Headwater Exploration Inc.	27 375 600	10	9 368 544	2.92	11.84	-75%
Suncor Energy Inc.	25 154 300	11	113 356 925	0.22	0.24	-8%
Ovintiv Canada ULC	23 497 700	12	61 031 536	0.39	0.57	-32%
Caltex Trilogy Inc.	23 063 600	13	5 389 472	4.28	1.48	189%
Whitecap Resources Inc.	20 163 200	14	85 965 411	0.23	0.27	-15%
Paramount Resources Ltd.	17 958 100	15	10 784 931	1.67	1.00	67%
Cardinal Energy Ltd.	17 157 300	16	5 584 688	3.07	2.29	34%
Surge Energy Inc.	13 358 500	17	5 579 920	2.39	2.58	-7%
TAQA North Ltd.	13 114 900	18	25 353 567	0.52	0.59	-12%
Lycos Energy Inc.	11 517 600	19	946 715	12.17	10.36	17%
Tourmaline Oil Corp.	10 980 800	20	108 001 730	0.10	0.10	0%
West Lake Energy Corp.	10 969 400	21	2 757 771	3.98	4.95	-20%

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Ipc Canada Ltd.	10 509 500	22	11 338 473	0.93	0.92	1%
Spartan Delta Corp.	10 198 100	23	14 066 029	0.73	0.76	-4%
Strathcona Resources Ltd.	9 994 800	24	28 071 023	0.36	0.24	50%
Clear North Energy Corp.	9 983 600	25	771 851	12.93	15.96	-19%

Fuel Use

Oil Sands Assets

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Cenovus Energy Inc.	4 692 271 700	1	242 961 034	19.31	18.86	2%
Canadian Natural Resources Limited	3 834 708 900	2	154 764 028	24.78	24.69	0%
Imperial Oil Resources Limited	2 212 753 700	3	63 519 553	34.84	37.45	-7%
Suncor Energy Inc.	2 037 546 600	4	112 831 550	18.06	18.05	0%
ConocoPhillips Canada Resources Corp.	1 512 634 300	5	62 869 000	24.06	25.90	-7%
Strathcona Resources Ltd.	897 529 300	6	24 892 111	36.06	38.90	-7%
CNOOC Petroleum North America ULC	724 962 200	7	30 590 406	23.70	22.69	4%
Athabasca Oil Corporation	439 033 300	8	14 572 970	30.13	31.00	-3%
Greenfire Resources Operating Corporation	303 168 700	9	8 017 270	37.81	33.94	11%
Connacher Oil And Gas Limited	233 662 400	10	7 236 274	32.29	34.07	-5%
PetroChina Canada Ltd.	224 621 600	11	3 854 022	58.28	59.24	-2%
Harvest Operations Corp.	86 715 100	12	3 141 517	27.60	32.49	-15%
Ipc Canada Ltd.	16 407 800	13	260 172	63.07	61.29	3%

Non-Oil-Sands Assets

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Canadian Natural Resources Limited	1 613 522 900	1	163 390 746	9.88	10.07	-2%
Tourmaline Oil Corp.	595 459 700	2	108 001 730	5.51	5.75	-4%
ARC Resources Ltd.	538 831 300	3	70 236 602	7.67	7.16	7%
Cenovus Energy Inc.	377 016 000	4	56 968 743	6.62	6.60	0%
Peyto Exploration & Development Corp.	311 448 500	5	48 786 194	6.38	6.68	-4%
Ovintiv Canada ULC	246 763 400	6	61 031 536	4.04	3.79	7%
Whitecap Resources Inc.	226 599 000	7	85 965 411	2.64	2.51	5%
Cavvy Production Ltd.	194 773 900	8	934 553	208.41	71.90	190%

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Ember Resources Inc.	168 913 300	9	13 107 256	12.89	12.91	0%
Birchcliff Energy Ltd.	167 524 300	10	27 317 246	6.13	6.37	-4%
Baytex Energy Ltd.	167 444 900	11	6 927 039	24.17	25.11	-4%
TAQA North Ltd.	148 597 600	12	25 353 567	5.86	6.08	-4%
Advantage Energy Ltd.	140 238 800	13	29 330 303	4.78	4.85	-1%
Vermilion Energy Inc.	124 274 700	14	24 746 380	5.02	5.08	-1%
Spartan Delta Corp.	110 793 700	15	14 066 029	7.88	8.95	-12%
Ipc Canada Ltd.	97 487 900	16	11 078 301	8.80	8.58	3%
Tamarack Valley Energy Ltd.	95 626 700	17	19 681 044	4.86	4.39	11%
Obsidian Energy Ltd.	92 257 700	18	4 729 129	19.51	16.34	19%
Pine Cliff Energy Ltd.	85 601 700	19	7 265 335	11.78	11.13	6%
Lynx Energy ULC	84 840 200	20	6 467 175	13.12	12.50	5%
Paramount Resources Ltd.	83 183 300	21	10 784 931	7.71	7.85	-2%
Spur Petroleum Ltd.	74 631 000	22	13 453 744	5.55	5.53	0%
Conifer Energy Inc.	63 713 600	23	2 141 653	29.75	31.61	-6%
Kiwetinohk Energy Corp.	61 627 600	24	8 217 883	7.50	9.29	-19%
Karve Energy Inc.	54 200 000	25	3 691 239	14.68	13.59	8%

Combined

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Canadian Natural Resources Limited	5 448 231 800	1	318 154 773	17.12	17.23	-1%
Cenovus Energy Inc.	5 069 287 700	2	299 929 777	16.90	16.52	2%
Imperial Oil Resources Limited	2 212 753 700	3	65 903 271	33.58	35.99	-7%
Suncor Energy Inc.	2 037 546 600	4	113 356 925	17.97	17.99	0%
ConocoPhillips Canada Resources Corp.	1 513 309 800	5	63 434 784	23.86	25.65	-7%
Strathcona Resources Ltd.	904 664 100	6	28 071 023	32.23	34.72	-7%
CNOOC Petroleum North America ULC	724 962 200	7	30 876 590	23.48	22.46	5%
Tourmaline Oil Corp.	595 459 700	8	108 001 730	5.51	5.76	-4%
ARC Resources Ltd.	538 831 300	9	70 236 602	7.67	7.16	7%
Athabasca Oil Corporation	466 347 200	10	15 228 408	30.62	31.39	-2%
Peyto Exploration & Development Corp.	311 448 500	11	48 786 194	6.38	6.68	-4%
Greenfire Resources Operating Corporation	306 214 600	12	8 211 866	37.29	33.53	11%
Ovintiv Canada ULC	246 763 400	13	61 031 536	4.04	3.79	7%
Connacher Oil And Gas Limited	233 662 400	14	7 727 525	30.24	31.25	-3%

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity (m^3/BoE)	Previous year intensity	% change (2025 to 2024)
Whitecap Resources Inc.	226 599 000	15	85 965 411	2.64	2.51	5%
PetroChina Canada Ltd.	224 621 600	16	7 752 668	28.97	30.99	-7%
Cavvy Production Ltd.	194 773 900	17	934 553	208.41	71.90	190%
Ember Resources Inc.	168 913 300	18	13 107 256	12.89	12.91	0%
Birchcliff Energy Ltd.	167 524 300	19	27 317 246	6.13	6.37	-4%
Baytex Energy Ltd.	167 444 900	20	20 865 153	8.03	7.83	3%
TAQA North Ltd.	148 597 600	21	25 353 567	5.86	6.08	-4%
Advantage Energy Ltd.	140 238 800	22	29 330 303	4.78	4.85	-1%
Vermilion Energy Inc.	124 274 700	23	24 746 380	5.02	5.08	-1%
Ipc Canada Ltd.	113 895 700	24	11 338 473	10.05	9.44	6%
Spartan Delta Corp.	110 793 700	25	14 066 029	7.88	8.96	-12%

Total Solution Gas Emitted (tCO_2e)

The AER has ranked companies based on the mass of greenhouse gas (GHG) emitted from operated crude oil and crude bitumen batteries from solution gas flaring and venting.

It is possible for an operator to flare or vent a significant volume of solution gas due to the magnitude of the company's operations and still have a high percentage of gas conserved.

GHG emissions are expressed in tonnes of carbon dioxide equivalent (tCO_2e).[1] The AER uses a conservative approach and assumes a 95% flare conversion efficiency and 85% mole fraction of methane content. The GHG emission factors used to quantify emissions from flaring and venting are as follows:

- Flared gas GHG emission factor: 2.3 tCO_2e per thousand cubic metres (10^3 m^3) of gas
- Vented gas GHG emission factor: 16.1 tCO_2e per thousand cubic metres (10^3 m^3) of gas

[1] tCO_2e is a way of expressing the global warming potential (GWP) of a greenhouse gas relative to carbon dioxide. Since every greenhouse gas has a different capacity to absorb and trap heat in the atmosphere, carbon dioxide is used as a frame of reference for easy comparison. The GWP of other gases can be calculated and converted into the equivalent amount of carbon dioxide. For example, one tonne of methane, which is a major component in venting, has 28 times more GWP than carbon dioxide over 100 years (https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/quantification-guidance/global-warming-potentials.html).

Company	Mass emitted ($MtCO_2e$)	Rank	Flared (million m^3)	Vented (million m^3)
Spur Petroleum Ltd.	0.24	1	103.13	0.37
Tamarack Valley Energy Ltd.	0.22	2	96.33	0.36
Canadian Natural Resources Limited	0.14	3	63.03	17.31
Rubellite Energy Inc.	0.08	4	36.25	0.75
Cenovus Energy Inc.	0.08	5	33.19	4.64
Baytex Energy Ltd.	0.06	6	25.40	0.39
Suncor Energy Inc.	0.06	7	25.15	0.24
Obsidian Energy Ltd.	0.06	8	25.05	1.87
Caltex Trilogy Inc.	0.05	9	23.03	1.24
Headwater Exploration Inc.	0.04	10	19.35	0.10
Cardinal Energy Ltd.	0.03	11	15.21	2.12
Lycos Energy Inc.	0.03	12	11.52	0.21
Whitecap Partnership	0.03	13	11.41	0.27
West Lake Energy Corp.	0.03	14	10.97	0.19
Surge Energy Inc.	0.02	15	10.48	1.14
Clear North Energy Corp.	0.02	16	9.98	0.15
Strathcona Resources Ltd.	0.02	17	9.94	0.69
Whitecap Resources Inc.	0.02	18	8.36	5.67
Aspenleaf Energy Limited	0.02	19	7.67	0.24
Astara Energy Corp.	0.02	20	7.62	1.27
HWN Energy Ltd.	0.02	21	6.78	1.24
Ipc Canada Ltd.	0.01	22	6.51	0.18
Gmt Exploration Zama Inc.	0.01	23	6.34	0.00
Longshore Resources Ltd.	0.01	24	5.69	0.02
Saturn Oil & Gas Inc.	0.01	25	5.18	1.41

Total Methane Emissions

The following table ranks operators based on the total of all methane emissions reported to Petrinex in 2025.

$$MtCO_2e = Volume\ (e^6m^3) \times 85\%\ (methane\ concentration) \times 0.6785\ (methane\ density) \times 0.001\ (kg\ to\ MT) \times 28\ (GWP)$$

Company	Volume emitted ($MtCO_2e$)	Rank
Canadian Natural Resources Limited	0.67	1
Tourmaline Oil Corp.	0.40	2
Cenovus Energy Inc.	0.31	3
Peyto Exploration & Development Corp.	0.19	4
Whitecap Resources Inc.	0.18	5
Vermilion Energy Inc.	0.18	6
TAQA North Ltd.	0.12	7
Pine Cliff Energy Ltd.	0.10	8
ARC Resources Ltd.	0.08	9
Spartan Delta Corp.	0.07	10
Acerta Operating Corporation	0.06	11
Whitecap Partnership	0.06	12
Paramount Resources Ltd.	0.06	13
Obsidian Energy Ltd.	0.05	14
Ovintiv Canada ULC	0.05	15
InPlay Oil Corp.	0.05	16
Karve Energy Inc.	0.05	17
Mancal Energy Inc.	0.05	18
Ipc Canada Ltd.	0.04	19
Ember Resources Inc.	0.04	20
Parallax Energy Operating Inc.	0.04	21
Cardinal Energy Ltd.	0.04	22
HWN Energy Ltd.	0.04	23
Pembina Gas Infrastructure Inc.	0.03	24
Barrel Oil Corp.	0.03	25

Appendix 3 Summary of Emission Methodologies

Emission source	Methodology	Data source	Methane content	Methane content applicability
Pneumatics	Facility Counts Reported Data Compliance Rate Offset Data	Petrinex OneStop 2021–2024 Petrinex starting in 2025 AEPA, 2026	92 vol %	All
Venting: Excluding In Situ				
Venting Routine & Nonroutine (2014–2019)	Reported Vent Volume	Petrinex	92 vol % 74 vol % 95 vol %	Natural Gas Crude Oil Bitumen
Venting Routine (2020–2025)	Reported Vent Volume	OneStop 2020–2024 Petrinex starting in 2025	92 vol % 74 vol % 95 vol %	Natural Gas Crude Oil Battery Bitumen
Venting: Nonroutine Well Testing	Reported Vent Volume	ST60B	92 vol %	All
Venting: Nonroutine Compressor Blowdowns	Equipment Counts Emission Factors	OneStop Cheremisinoff (2016) Levelton Consultants (2014)	See compressor seals	See compressor seals
Venting: In Situ				
Venting: Routine & Nonroutine	Reported Vent Volume	Petrinex	95 vol %	Bitumen
Fugitive Emissions	Facility Counts Reported Volumes	Petrinex OneStop 2020–2024 Petrinex starting in 2025	kg CH_4/m^3 0.584 0.560 0.554 0.560 0.524 0.530	Year 2014–2020 2021 2022 2023 2024 2025 onwards
Compressor Seals	Reported Vent Volume Equipment Counts Facility Counts	OneStop 2020–2024 Petrinex starting in 2025 Petrinex Petrinex	kg CH_4/m^3 0.592 0.583 0.598 0.608 0.601 0.584	Year 2014–2020 2021 2022 2023 2024 2025 onwards
Glycol Dehydrators	Facility Counts Reported Emissions Equipment Counts	Petrinex OneStop OneStop	N/A	Methane mass is reported to OneStop
Methane Slip Fuel	Emission Factors Equipment Inventory Fuel Volume Fuel Disposition	Accurata Inc, 2024 ECCC Engine Database Petrinex and ST98 CAPP 2004	N/A	Source specific emission factors.
Unlit Flares	Combustion Efficiency Reported Flare Volume Facility Counts	Assumes 6% of flares at select sites are unlit (IEA, 2021) Petrinex	74 vol % 92 vol % 95 vol %	Crude Oil Battery Gas Battery Crude Bitumen Battery

Emission source	Methodology	Data source	Methane content	Methane content applicability
Surface Casing Vent Flows	Reported Vent Volume	*ID 2003-01* data	85 vol %	All
Spills and Ruptures	Reported Vent Volume	AER Incident Release Report	85 vol %	All
Catalytic Heaters	Facility Counts Equipment Counts/ Factors Equipment Fuel Use	Petrinex BROA/MTIP (de-identified) Thermon Product Sheets	85 vol %	All

Appendix 4 NGSI Methane Intensity Methodology

Methane intensity is calculated following the NGSI methodology, with the calculation adapted to use metric units and inputs available from Alberta's methane model, while preserving the intent and outcome of the original method. The adopted equation is presented in equation 1.

$$Methane\ Intensity = \frac{(Methane\ Emissions)\times(Gas\ Ratio)\times(10^9 kg/Mt)}{(Natural\ Gas\ Throughput)\times(Methane\ Content)\times(Methane\ Density)\times(GWP_{CH4})} \times 100\% \quad (1)$$

Methane Emissions	$MtCO_2e$
Gas Ratio	see equation 2
GWP_{CH4}	dimensionless
Natural Gas Throughput	raw gas production in m^3
Methane Content	volume methane ÷ volume raw gas (m^3 / m^3)
Methane Density	0.6785 kg/m^3 at 101.325 kPa and 15°C (see *Manual 015*)

$$Gas\ Ratio = \frac{E_{ng}}{E_{ng} + E_{liq}}$$

$$E_{ng} = (Raw\ Gas\ Production) \times HHV_{Raw\ Gas}$$

$$E_{liq} = [(Raw\ Condensate\ Production) \times HHV_{Raw\ Cond}] + [(Crude\ Oil\ Production) \times HHV_{Crude\ Oil}] + [(Crude\ Bitumen\ Production) \times HHV_{Crude\ Bit}] \quad (2)$$

Raw Production	resource production in m^3
HHV	higher heating value of the resource in GJ/m^3

The values we used to calculate methane intensity are provided in table 15.

Table 15. Values used to calculate methane intensity

Input	2020	2021	2022	2023	2024	2025	Source
Methane Emissions ($MtCO_2e$)	17.15	15.53	12.85	11.97	12.24	10.89	AER Methane Model, 2026
$GWPCH_4$	28	28	28	28	28	28	IPCC 5th Assessment
Raw Gas Production (m^3)	117 746 389 246	120 720 673 370	127 450 143 613	128 830 814 458	129 151 910 071	130 896 432 749	AER ST98, 2026
Raw Condensate Production (m^3)	4 546 709	4 223 205	4 584 542	4 111 545	4 969 966	5 101 335	AER ST3, 2026
Crude Oil Production (m^3)	24 674 273	25 384 910	28 209 182	29 710 887	30 822 611	31 765 345	AER ST98, 2026
Crude Bitumen Production (m^3)	86 804 163	96 577 015	98 565 517	102 259 023	106 860 961	113 101 178	AER ST98, 2026
Methane Content (raw gas) (vol/vol)	0.85	0.85	0.85	0.85	0.85	0.85	AER ST60B, 2026
Methane Density (kg/m^3 at 101.325 kPa and 15°C)	0.6785	0.6785	0.6785	0.6785	0.6785	0.6785	AER Manual 015, 2026
$HHV_{Raw\ Gas}$ (GJ/m^3)	0.046	0.046	0.046	0.046	0.046	0.046	EEI and AGA 2026
$HHV_{Raw\ Cond}$ (GJ/m^3)	33.1	33.1	33.1	33.1	33.1	33.1	AER ST98, 2025
$HHV_{Crude\ Oil}$ (GJ/m^3)	38.5	38.5	38.5	38.5	38.5	38.5	EEI and AGA, 2026, AER ST98 2025
$HHV_{Bitumen}$ (GJ/m^3)	42.8	42.8	42.8	42.8	42.8	42.8	AER ST98, 2025