Alberta Energy Regulator

Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2024

December 2025

Alberta Energy Regulator
ST60B-2025: Upstream Petroleum Industry Emissions Report

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Contents

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, ground migration and, since 2020, fugitive emissions information reported to the AER.

This report includes source-specific information because of the more extensive emission reporting introduced in 2018 by *Directive 060* and production and fuel gas volumes. In 2021, the AER released *Directive 087: Well Integrity Management*, which complements *Directive 060* regarding surface casing vent flow (SCVF) management. Under *Directive 039*, licensees must complete and submit an annual dehydrator inventory list to the AER that details the emissions from all their glycol dehydrators.

Emission volumes from processing plants approved under section 11 of the *Oil Sands Conservation Act*, oil sands mining schemes, or pipelines not regulated by the AER are not included in the report.

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 2024 includes OneStop data since 2020 extracted in July 2025. The previous years' data includes amendments and late submissions, resulting in slightly different values than last year's report.

Key statistics from 2024:

Production (from ST98: Alberta Energy Outlook)

- Crude bitumen production increased by 4.3% to 206.4 10^6 m^3.
- Crude oil production increased by 3.4% to 30.7 10^6 m^3.
- Gas production increased by 0.2% to 115 230 10^6 m^3.

Fuel Use

- Total reported Petrinex fuel use increased by 7.7% to 29.5 10^9 m^3.

Flaring

- Total reported Petrinex flaring increased by 11.9% to 1534.1 10^6 m^3.
- Solution gas flaring increased by 19.3% to 914.5 10^6 m^3.

Venting

- Total reported Petrinex venting decreased by 9.7% to 273.9 10^6 m^3.
- Solution gas venting decreased by 8.5% to 101.1 10^6 m^3.

Fugitive Emissions

- Total equipment-based fugitive emissions increased 15.1% to 40.4 10^6 m^3.

Surface Casing Vent Flow and Gas Migration

- A surface casing vent flow event is the flow of gas, liquid, or both out of the surface casing or casing annulus of a well. A gas migration event is the flow of detectable gas at the surface outside of the outermost casing string.
- As of 2024, Alberta has 11 038 unresolved surface casing vent flow and gas migration events, an increase of 2.8% from 2023, emitting 97.0 10^6 m^3/year and resulting in a cumulative emission volume of 662 10^6 m^3.

Methane Reduction

- Alberta met its 45% methane reduction target in 2022, three years ahead of schedule. Using both reported and estimated emissions, results from 2024 modelling indicate that Alberta has reduced methane emissions by 51% from 2014 levels.

1 Introduction

The mandate of the Alberta Energy Regulator (AER) is to provide for the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. 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 includes flaring and venting recommendations from the multistakeholder Flaring and Venting Project Team of the Clean Air Strategic Alliance (CASA) and methane emission reduction requirements to support the Government of Alberta's methane emission reduction targets. *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*).

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*.

The data used to compile the report is primarily from Canada's Petroleum Information Network (Petrinex) and OneStop. Petrinex data is reported to the AER monthly, while OneStop data for the previous calendar year is received annually on June 1. OneStop data presented in this report was submitted on or before July 15, 2025.

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

1.1 Important Notes for this Year's Report

Changes to the fuel, flare, and vent definitions resulted in significant differences in reported volumes from 2019 to 2020. It is important to understand that these year-over-year differences do not reflect emission increases. They better represent emissions to the atmosphere than those reported using the previous definitions. Therefore, data from the two periods are graphed separately to avoid confusion.

Change in other emission reduction model assumptions, estimates, and inputs. The model assumptions, inputs, and estimates are updated annually to reflect the latest and most accurate data available; thus, the baseline may shift year over year to reflect these changes. Information about the emission reduction model is described in appendix 3.

OneStop amendments and late submissions. This report includes OneStop data from 2020; however, because the data was extracted in July 2025, the previous years' data includes amendments and late submissions, resulting in slightly different values than last year's report.

Surface casing vent flow and gas migration moved to new section. To differentiate between fugitive emissions and surface casing vent flow/gas migration, this source has been moved to its own section (section 6) in this year's edition.

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. Table 1 shows the number of facilities in each subtype (for active reporting facilities). The per cent change column compares 2023 to 2024.

Table 1. Number of facilities that must report methane emissions by subtype, 2019–2024

Facility subtype	2019	2020	2021	2022	2023	2024	% change
Crude bitumen batteries	4 164	3 519	3 228	3 342	3 312	3 387	2.26
Crude oil batteries	9 352	8 544	8 447	8 348	8 429	8 166	−3.12
Gas batteries	10 452	9 508	8 957	8 455	8 660	8 479	−2.09
Gas gathering/compressor stations	7 313	6 898	5 854	5 557	5 444	5 332	−2.06
Gas plants	553	531	511	501	501	495	−1.20
Other	2 130	1 935	1 900	1 804	1 884	1 911	1.43
Total	**33 964**	**30 935**	**28 897**	**28 007**	**28 230**	**27 770**	**−1.63**

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	206, 601, 621, 622, 631

ST60B category	Facility subtypes
Other	204, 207–209, 381, 502–505, 507, 509, 632–634, 637, 640, 651, 671–673, 675, 801, 902, 903

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. In 2024, fuel gas use was 29.5 10^9 m^3.

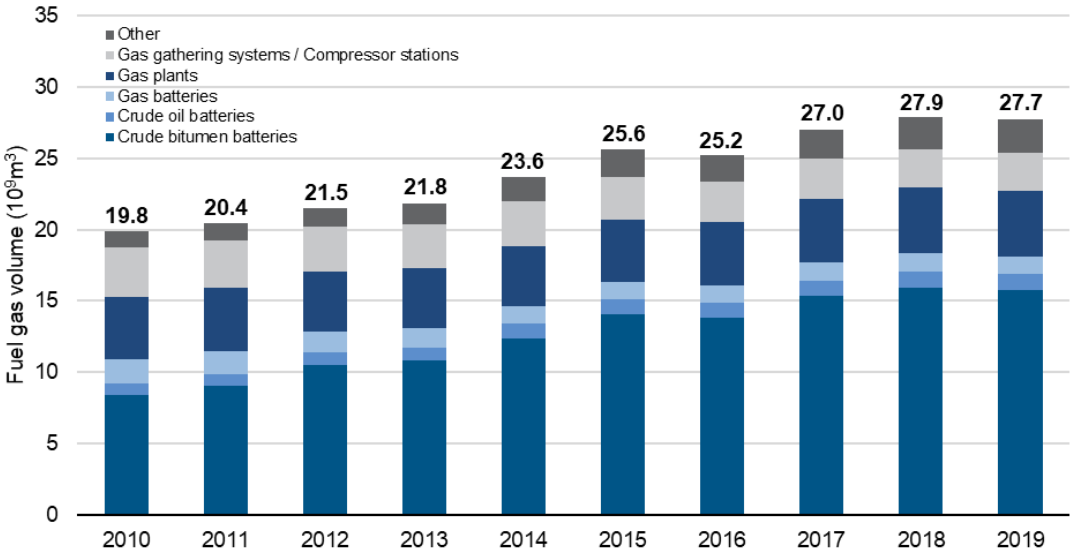


Figure 1. Fuel gas usage, 2010–2019 (Source: Petrinex)

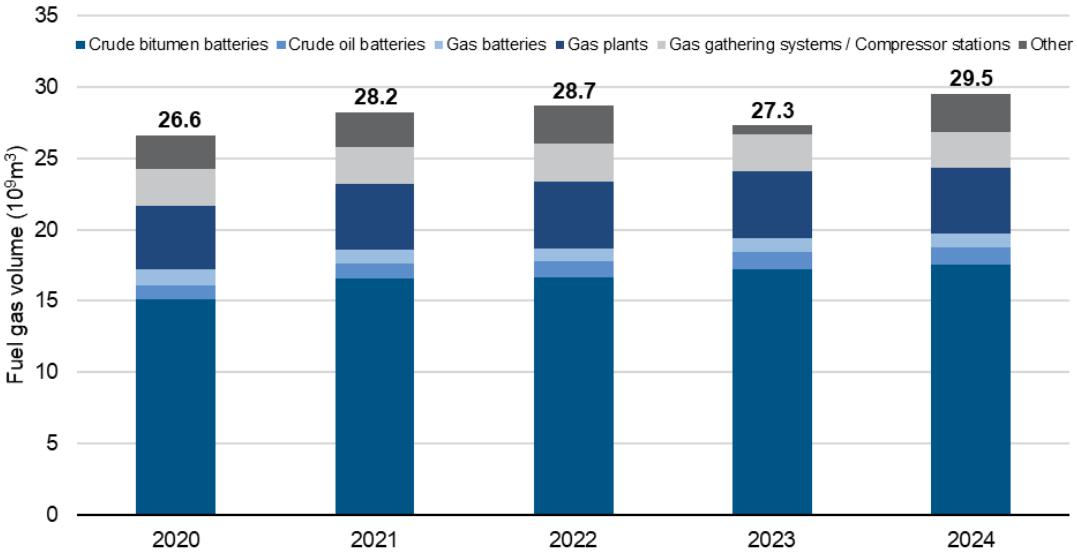


Figure 2. Fuel gas usage, 2020–2024 (Source: Petrinex)

Since 2010, fuel gas use has increased from 19.8 10^9 m^3 to 29.5 10^9 m^3 in 2024. In 2020, the decrease in fuel gas to 26.6 10^9 m^3 was likely because of the change in the definition of fuel gas in both *Directive 060* and *Directive 017*. 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. The decrease in fuel gas observed in the "Other" category in 2023 was due to one facility's reduction that has returned to pre-2023 fuel volumes in 2024.

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, 2020–2024, % change 2023–2024 (Source: Petrinex)

Facility subtype	2020 (10^9 m^3)	2021 (10^9 m^3)	2022 (10^9 m^3)	2023 (10^9 m^3)	2024 (10^9 m^3)	% change
Crude bitumen battery	15.1	16.6	16.7	17.3	17.6	1.7
Crude oil battery	1.0	1.1	1.1	1.2	1.2	0.0
Gas battery	1.1	0.9	0.9	0.9	0.9	0.0
Gas gathering/compressor station	2.6	2.6	2.6	2.6	2.5	−3.8
Gas plant	4.5	4.6	4.7	4.7	4.7	0.0
Other	2.3	2.5	2.7	0.7	2.6	271.4
Total	**26.6**	**28.2**	**28.7**	**27.3**	**29.5**	**8.1**

3 Flaring

Flaring is the controlled destruction of gas during production and processing and includes flaring, incineration, and enclosed combustion. Flaring is managed by *Directive 060*, which sets limits on the routine and nonroutine flaring allowed to occur at a given site. 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.

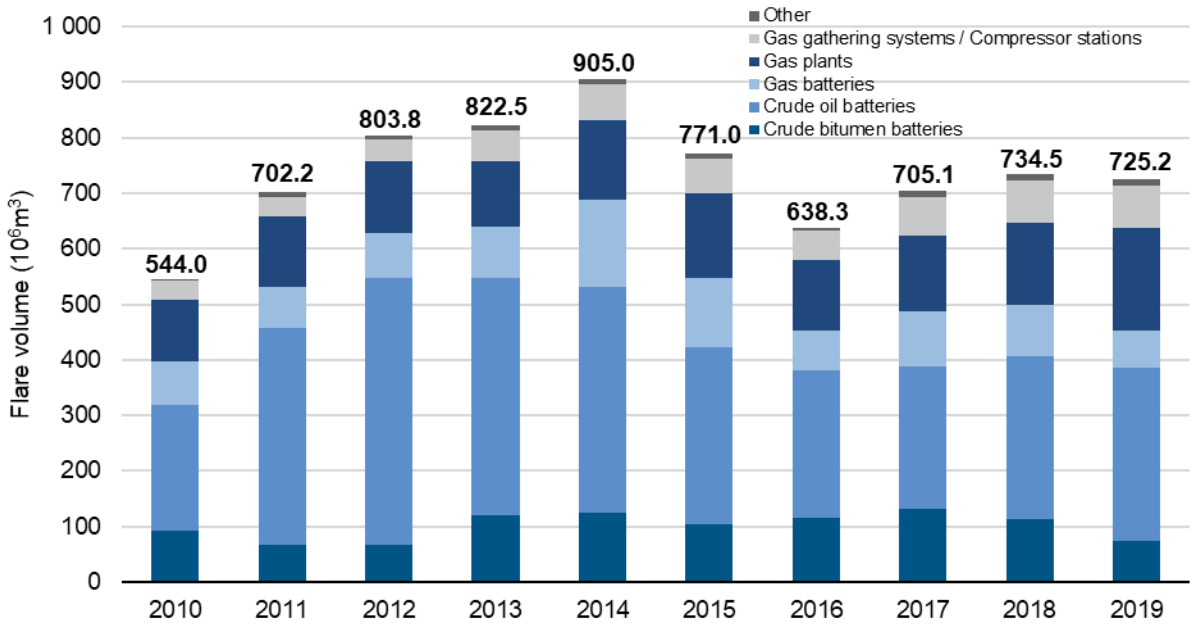


Figure 3. Flare volumes, 2010–2019 (Source: Petrinex)

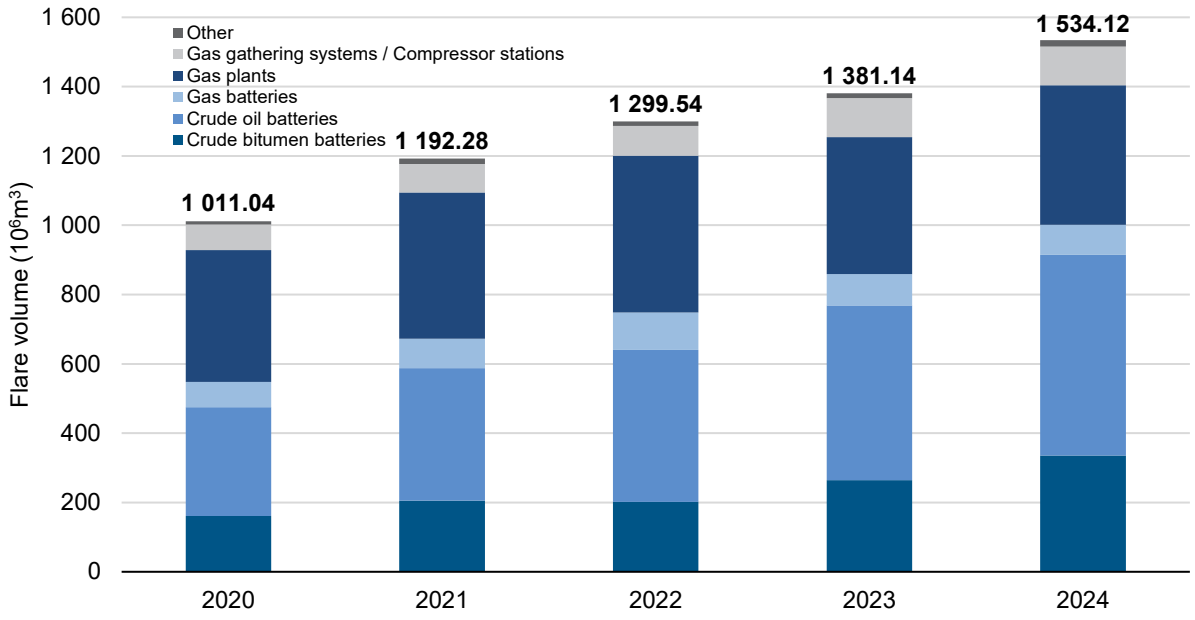


Figure 4. Flare volumes, 2020–2024 (Source: Petrinex)

3.1.1 Flaring Trends

In 2024, flaring volumes increased to 1534.1 10^6 m^3. This increase is likely because of increased crude oil and bitumen production, the changed definitions (fuel, flare, vent), and new 2020 methane requirements emphasizing methane (vent gas) reductions. Vent gas can be reduced through either conservation or combustion. As operators choose to minimize venting through combustion, reported flare volumes may increase, as observed in 2020 and onward.

Table 4 shows the year-over-year change in the annual reported flaring by facility subtype. Flaring has increased in almost all facility types, particularly crude oil and crude bitumen batteries. This increase is likely because of new vent limits and the larger ratio of solution gas produced alongside oil and bitumen production.

Table 4. Change in flared volume, 2020–2024, % change 2023–2024 (Source: Petrinex)

Facility subtype	2020 (10^6 m^3)	2021 (10^6 m^3)	2022 (10^6 m^3)	2023 (10^6 m^3)	2024 (10^6 m^3)	% change
Crude bitumen battery	161.26	205.69	201.75	264.30	335.40	26.90
Crude oil battery	313.79	382.25	438.12	504.57	579.08	14.77
Gas battery	72.56	84.79	108.41	90.50	87.04	−3.82
Gas gathering/compressor station	73.55	81.86	86.08	112.61	111.24	−1.22
Gas plant	380.73	422.20	451.93	394.54	402.77	2.09
Other	9.14	15.23	12.92	14.24	17.06	19.80
Total	**1011.03**	**1192.02**	**1299.21**	**1380.76**	**1532.59**	**11.00**

In alignment with the increased total flare volumes in 2024, the flaring intensity also increased from 2023 to 2024 (see table 5). Solution gas flaring is analyzed further in section 7.

Table 5. Flaring intensity, 2020–2024 (Source: Petrinex)

Year	Province-wide BoE	Flare volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136	1 011 039 700	0.66
2021	1 611 841 179	1 192 278 100	0.73
2022	1 692 106 893	1 299 535 700	0.76
2023	1 735 675 816	1 381 140 500	0.79
2024	1 781 539 392	1 534 118 000	0.86

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 2024 by volume and the percentage flared of the total gas received. The total amount of flaring from these top 30 gas plants (253.8 $10^6 m^3$) makes up about 63% of the total flaring at gas plants.

Table 6. Top 30 flaring gas plants, 2024 (Source: Petrinex)

Gas plant	Operator	Land location	2024 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001004	Keyera Energy Ltd.	02-05-044-01W5	36.24	1.69
ABGP0149088	Baytex Energy Ltd.	03-18-084-17W5	24.09	21.19
ABGP0001147	Pembina Gas Infrastructure Inc.	11-18-074-12W6	16.92	0.59
ABGP0001056	Cavvy Production Ltd.	02-20-004-30W4	16.58	1.49
ABGP0001892	Ovintiv Canada ULC	04-08-075-07W6	12.44	0.60
ABGP0001662	Cavvy Production Ltd.	12-35-034-06W5	12.00	1.35
ABGP0118855	Pembina Gas Infrastructure Inc.	08-13-063-05W6	11.00	0.68
ABGP0001037	Cavvy Production Ltd.	13-13-025-05W5	8.61	1.26
ABGP0001070	Btg Energy Corporation	14-32-037-03W5	8.49	3.45
ABGP0001855	Obsidian Energy Ltd.	09-15-084-14W5	8.22	16.53
ABGP0001350	Cenovus Energy Inc.	01-08-070-11W6	6.88	0.54
ABGP0001901	Plains Midstream Canada ULC	10-11-020-01W4	6.10	0.05
ABGP0001623	Strathcona Resources Ltd.	06-08-062-03W6	6.02	0.66
ABGP0001084	Peyto Exploration & Development Corp.	04-11-053-18W5	5.98	0.54
ABGP0001060	AltaGas Ltd.	09-27-031-04W5	5.95	0.16
ABGP0153429	Pembina Gas Infrastructure Inc.	14-28-062-20W5	5.54	0.29
ABGP0001113	Keyera Energy Ltd.	09-060-63-25W5	5.49	0.28
ABGP0001129	Canadian Natural Resources Limited	13-26-067-05W6	5.07	0.38
ABGP0001902	Plains Midstream Canada ULC	04-12-020-01W4	4.88	0.02
ABGP0001520	NuVista Energy Ltd.	06-19-073-08W6	4.80	0.40
ABGP0152315	AltaGas Ltd.	12-35-070-09W6	4.78	0.45
ABGP0150386	Keyera Energy Ltd.	040-7-073-08W6	4.55	0.17
ABGP0001134	Caledonian Midstream Corporation	02-04-021-04W5	4.45	3.70

Gas plant	Operator	Land location	2024 flare (10^6 m³)	Gas flared as a percentage of gas receipts (%)
ABGP0001107	Pembina Gas Infrastructure Inc.	01-12-062-20W5	4.41	0.31
ABGP0145129	Pembina Gas Infrastructure Inc.	14-28-062-20W5	4.30	0.18
ABGP0001133	Keyera Energy Ltd.	11-35-037-09W5	4.20	0.22
ABGP0169442	ARC Resources Ltd.	10-10-065-05W6	4.07	0.86
ABGP0157570	CSV Midstream Solutions Corp.	06-18-066-04W6	3.94	0.26
ABGP0001506	Canadian Natural Resources Limited	01-01-078-10W6	3.94	0.27
ABGP0001144	Pembina Gas Infrastructure Inc.	03-15-059-18W5	3.87	0.24
Total			**253.81**	

Note: Confidential facilities are not included.

3.2 Well Testing

Directive 060 requires that operators seek alternatives to well test flaring. Operators are required to test in line when it is both economically viable and safe to do so. Testing in line can mean either connecting to an existing gas gathering system directly or laying a temporary surface pipeline to connect a well to a remote gas gathering system. By either method, the gas from the well test is conserved.

If in-line testing is not possible, licensees must design completions and well-testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions.

Well-testing data must be reported to the AER under *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*. This data was 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 2024, 813 well tests were completed, up from 795 tests reported in 2023 (see table 7). In 2024, the average flaring volume per test has increased and vent volumes per test decreased from 2023.

Table 7. Well drilling and testing data, 2019–2024. (Source: COM, ST59)

Year	Total wells drilled	Number of well tests	Total flare volume during well tests (10^3 m³)	Average flare per test (10^3 m³)	Total vent volume during well tests (10^3 m³)	Average vent per test (10^3 m³)
2019	3 850	706	44 273.78	62.71	1 070.67	1.52
2020	2 338	500	41 359.63	82.72	277.95	0.56
2021	5 486	747	48 975.09	65.56	875.17	1.17
2022	8 581	923	42 143.32	45.66	1 644.60	1.78
2023	8 437	920	32 658.71	35.50	1 611.11	1.75
2024	9 923	813	35 613.20	43.80	1 146.15	1.41

4 Venting

Vent gas is uncombusted gas released into the atmosphere at upstream oil and gas operations. The AER manages vented emissions from upstream oil and gas facilities through *Directive 060*, which includes site- and equipment-specific limits. Improving venting performance is important for the protection of the environment and for meeting provincial emission reduction goals; the latest venting limits came into effect in 2023.

We collect venting data through Petrinex (monthly) and OneStop (annually). Petrinex 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.). OneStop only includes routine vent gas and fugitive emissions. However, OneStop provides a more granular emission breakdown by source type.

In the 2024 data, a gap between reported volumes was observed once again in the total vent volumes reported to Petrinex and the vent gas volumes (from routine vent gas, pneumatics, compressors, and dehydrators) reported to OneStop. This discrepancy could be due to differences in calculations between the two reporting structures, data quality issues, or other variances between equipment-level and facility-level reporting. Although these volumes are not expected to be identical (Petrinex includes nonroutine venting), the Petrinex total vent volumes are expected to be *greater* than the OneStop volumes. Year-over-year comparison between the two platforms continue to improve, and the gap is decreasing, likely due to continued inspection and auditing activities, and industry education on data reporting.

4.1 Petrinex

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 2024, vent gas reported in Petrinex was 273.9 10^6 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 2023 in nearly all facility subtypes. This decrease is mainly due to the various equipment-level vent limits that took effect in 2022 and January 1, 2023, and continued compliance and education campaigns undertaken by the AER.

As shown in table 9, vent gas volumes reported in 2024 decreased relative to 2020, when the reporting definitions changed. Considering production volumes, 2024 had the lowest venting intensity of the past five years.

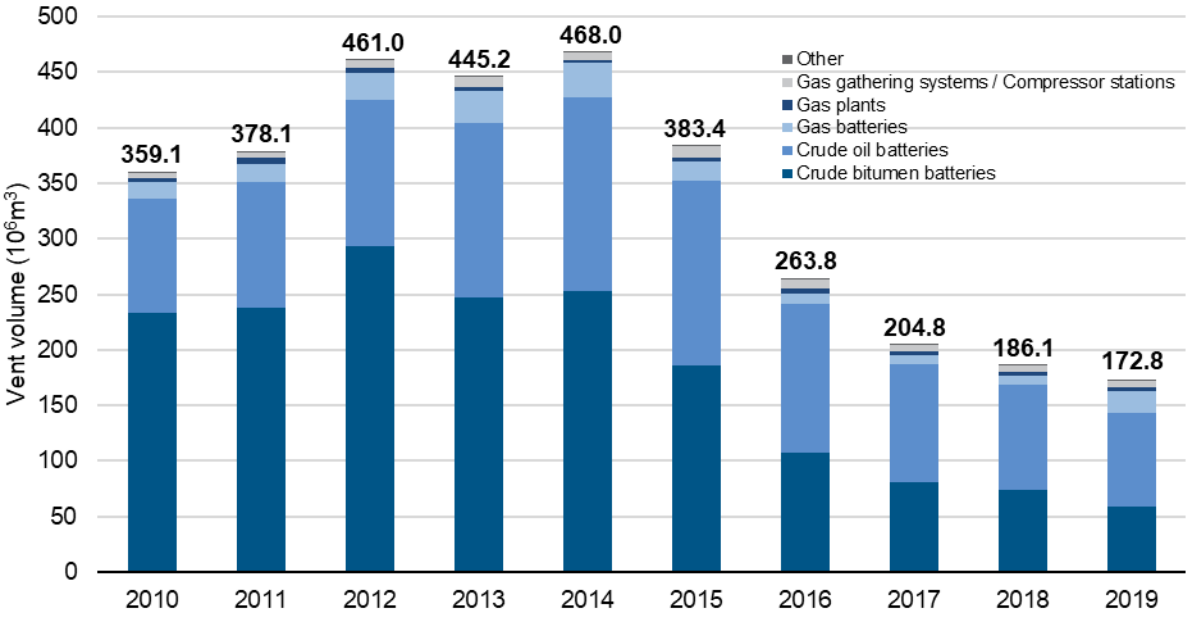


Figure 5. Vent volumes, 2010–2019 (Source: Petrinex)

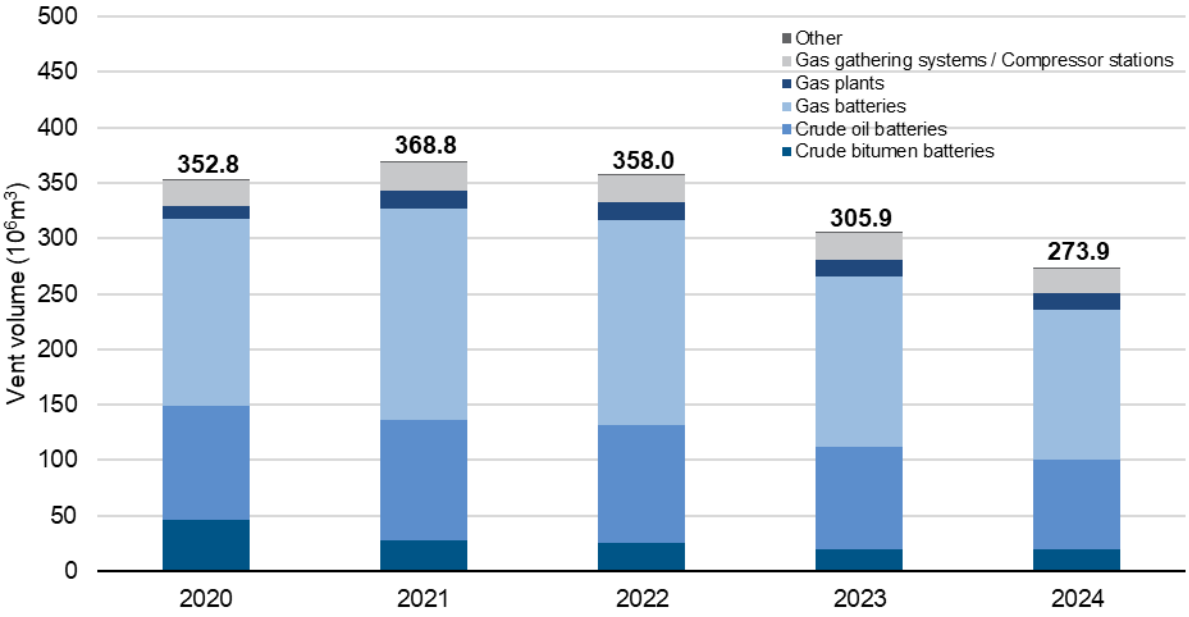


Figure 6. Vent volumes, 2020–2024 (Source: Petrinex)

Table 8. Change in vented volumes 2020–2024, % change 2023–2024 (Source: Petrinex)

Facility subtype	2020 (10^6 m^3)	2021 (10^6 m^3)	2022 (10^6 m^3)	2023 (10^6 m^3)	2024 (10^6 m^3)	% change
Crude bitumen battery	46.0	28.1	25.6	20.0	19.5	−2.9
Crude oil battery	103.3	107.7	106.0	91.7	81.5	−9.8
Gas battery	167.9	191.5	184.2	153.6	135.0	−12.1
Gas gathering/compressor station	22.4	24.9	24.5	24.7	21.9	−11.3
Gas plant	12.4	16.1	16.9	15.0	15.0	0.0
Other	0.8	0.5	0.9	0.8	0.9	12.5
Total	**352.8**	**368.8**	**358.0**	**305.9**	**273.9**	**−10.5**

Table 9. Venting intensity, 2020–2024 (Source: Petrinex)

Year	Province-wide BoE	Vent volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136	352 770 300	0.23
2021	1 611 841 179	368 781 700	0.23
2022	1 692 106 893	358 043 900	0.21
2023	1 735 675 816	305 903 700	0.17
2024	1 781 153 392	273 863 800	0.15

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

4.2 OneStop

Operators must submit an annual methane report to OneStop on June 1st of each year. This submission is subject to the regulatory requirements in section 8 of *Directive 060*.

4.2.1 Summarized Emissions

Emissions data reported to the AER through OneStop provides greater detail on source-specific methane emissions. In 2024, total emissions reported to OneStop were 323.4 10^6 m^3, a significant decrease from 2023 (343.4 10^6 m^3). This decrease is attributable to numerous vent limits that came into effect in 2022 and 2023 and continued compliance campaigns. Figure 7 shows total source-specific emissions, and figure 8 shows these 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 via OneStop. The data below represent most of the facilities required to report; as of July 15, 2025, 92.9% of the facilities had reported annual methane data to OneStop and represents over 99% of reported production.

Gas batteries are the facility subtype with the most associated emission volumes because of the many on-site pneumatic devices and the number of facility subtypes. Defined vent gas (DVG) is the greatest contributing source for crude oil and crude bitumen batteries, likely due to the presence of hydrocarbon storage tanks and solution gas at these sites. 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.

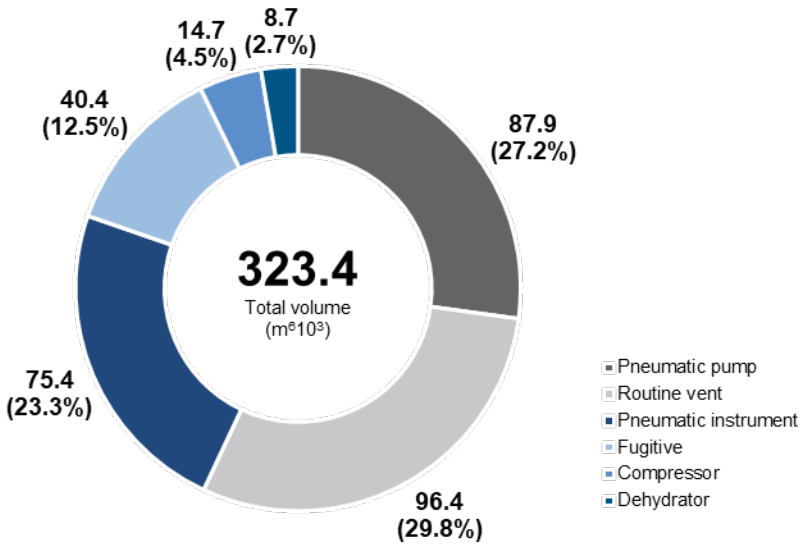


Figure 7. Breakdown of venting volumes by source, 2024 (Source: OneStop)

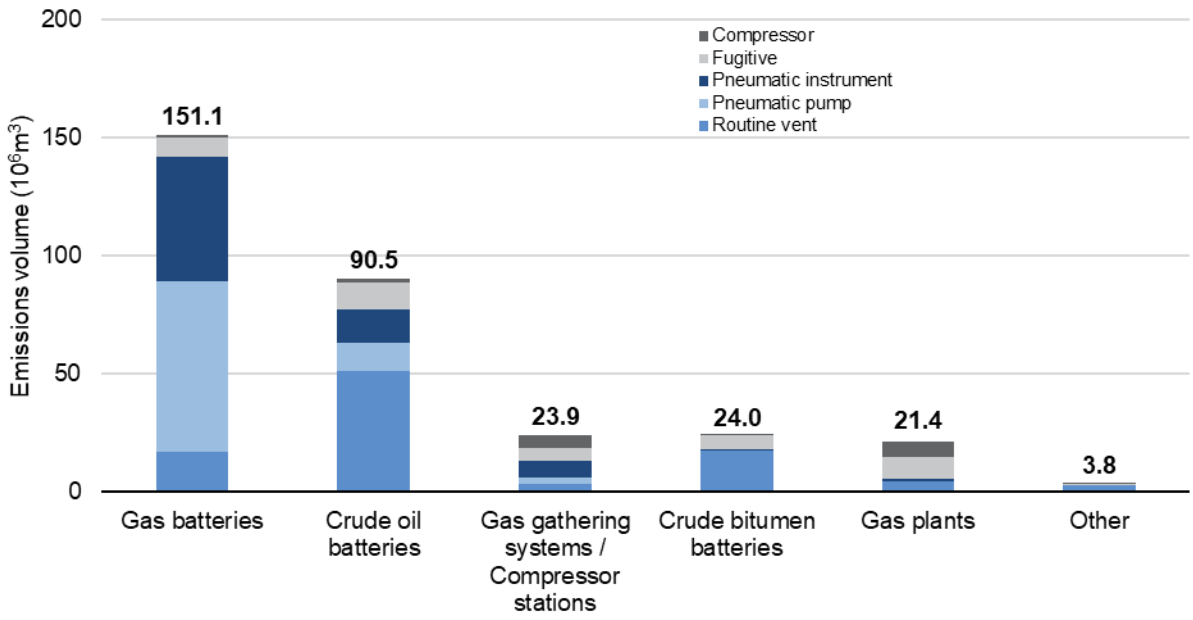


Figure 8. Breakdown of venting volumes by facility subtype, 2024 (Source: OneStop)

Figure 9 shows a side-by-side comparison of the OneStop emissions data for 2020 to 2024. Year-over-year comparisons demonstrate a continued decline from peak emissions in 2021, with a slight uptick in

DVG and fugitive emissions from 2023. 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 to OneStop 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 one or both submissions (Petrinex and OneStop). Table 10 lists the top ten companies with the largest reported emission differences in OneStop reported volumes when comparing 2023 and 2024. Data quality continues to improve year over year due to efforts in compliance and education on submission requirements. Since the data was retrieved on July 15, 2025, 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.

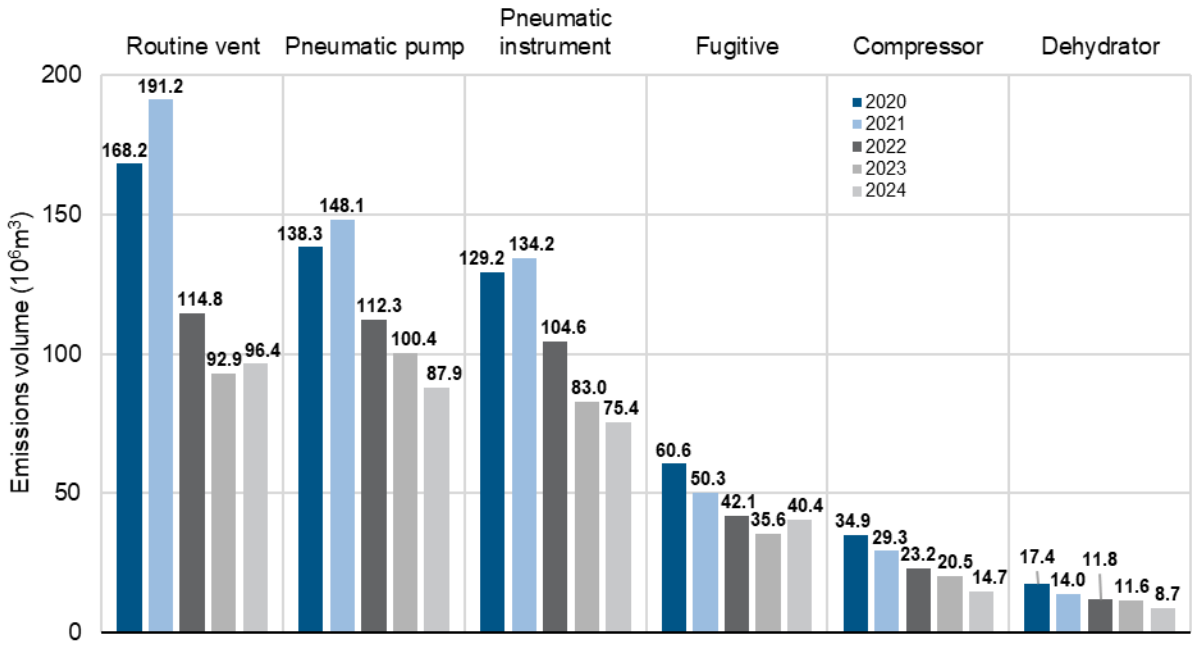


Figure 9. Comparison of emissions volumes by source, 2020–2024 (Source: OneStop)

Table 10. Top ten absolute differences in reported venting volumes, 2023–2024 (Source: OneStop)

Operator	2023 (10^6 m³)	2024 (10^6 m³)	Difference (10^6 m³)
Vermilion Energy Inc.	18.97	10.45	−8.52
Pine Cliff Energy Ltd.	6.43	14.36	7.93
Tourmaline Oil Corp.	34.60	28.35	−6.25
Canadian Natural Resources Limited	47.11	41.93	−5.18
Cenovus Energy Inc.	26.13	21.82	−4.31
Obsidian Energy Ltd.	2.15	6.18	4.03
Canlin Resources Partnership	4.16	7.90	3.74

Operator	2023 (10^6 m³)	2024 (10^6 m³)	Difference (10^6 m³)
Ish Energy Ltd.	0.52	2.55	2.04
Journey Energy Inc.	1.48	3.39	1.91
N7 Energy Ltd.	1.71	0.00	1.71

4.2.2 Defined Vent Gas

Directive 060 includes vent limits for DVG, which are reported annually to the AER through OneStop. DVG is also captured in the vent volumes reported to Petrinex. In 2024, total DVG emissions reported to OneStop were 96.4 10^6 m^3 (see figure 10), about 30% of all emissions reported to OneStop, a 6.4% increase from the reported 2023 volumes. Crude oil batteries contribute the most DVG emissions by volume, while gas batteries contributed the majority to the uptick observed in 2024. Given the greater likelihood of storage tanks at crude oil sites, it is reasonable to assume that tanks are a significant contributor in this category. Gas batteries have more venting equipment (i.e., gas analyzers), which could contribute to the increase in reported emissions.

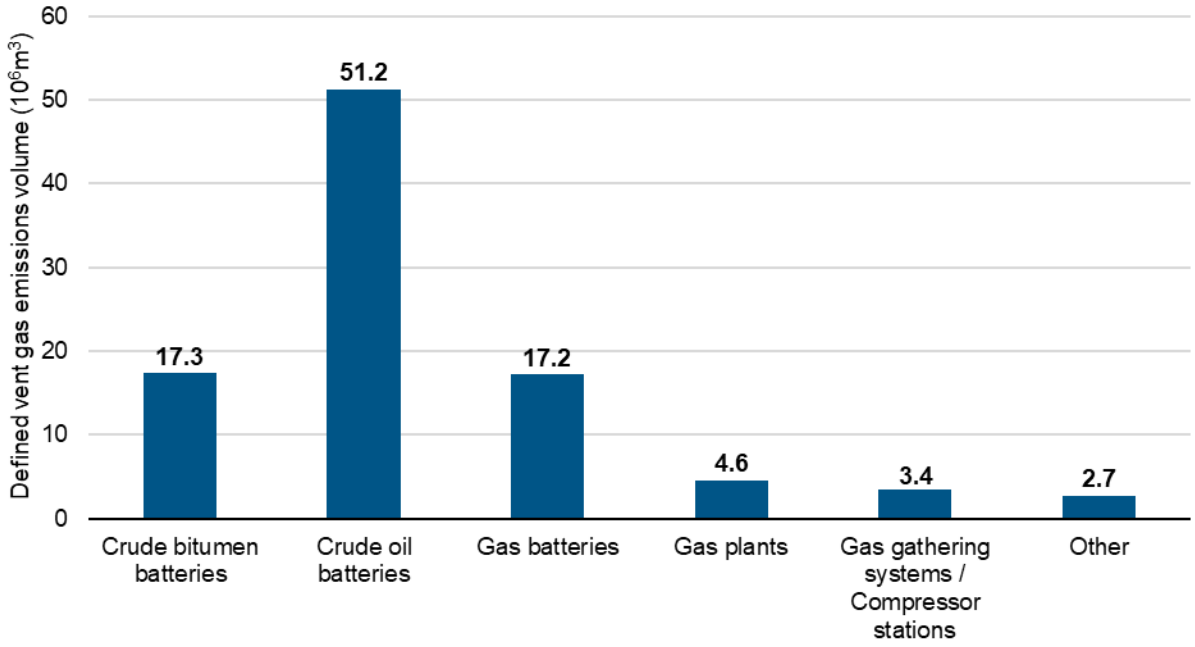


Figure 10. DVG vent volumes by facility subtype, 2024 (Source: OneStop)

4.2.3 Pneumatic Devices

Directive 060 includes limits for vent gas from pneumatic instruments and pumps, which are reported annually to the AER through OneStop. These volumes should also be captured in the vent volumes reported to Petrinex. Reporting pneumatic device inventories to the AER is not required, so comprehensive device counts are not provided here. Equipment-level limits came into effect in 2023 for pneumatic devices, including inclusion into the overall vent limit and reducing venting to less frequent actuations for level

controllers or less than 0.17 m^3/hr for pneumatic instruments other than level controllers installed on or before January 1, 2022.

In 2024, emissions reported to OneStop for pneumatic devices (instruments and pumps) were 163.25 10^6 m^3, about 50% of all emissions reported to OneStop, a 12.6% decrease from the reported 2023 volumes. Gas batteries were the most significant contributor, representing about 76% of the total pneumatic emissions. These emission volumes are because of the large number of gas batteries and the greater likelihood of gas-driven pneumatic devices at these sites, as found in the 2018 Clearstone Engineering Report *Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas*. Figure 11 shows a breakdown of pneumatic device emissions by facility subtype.

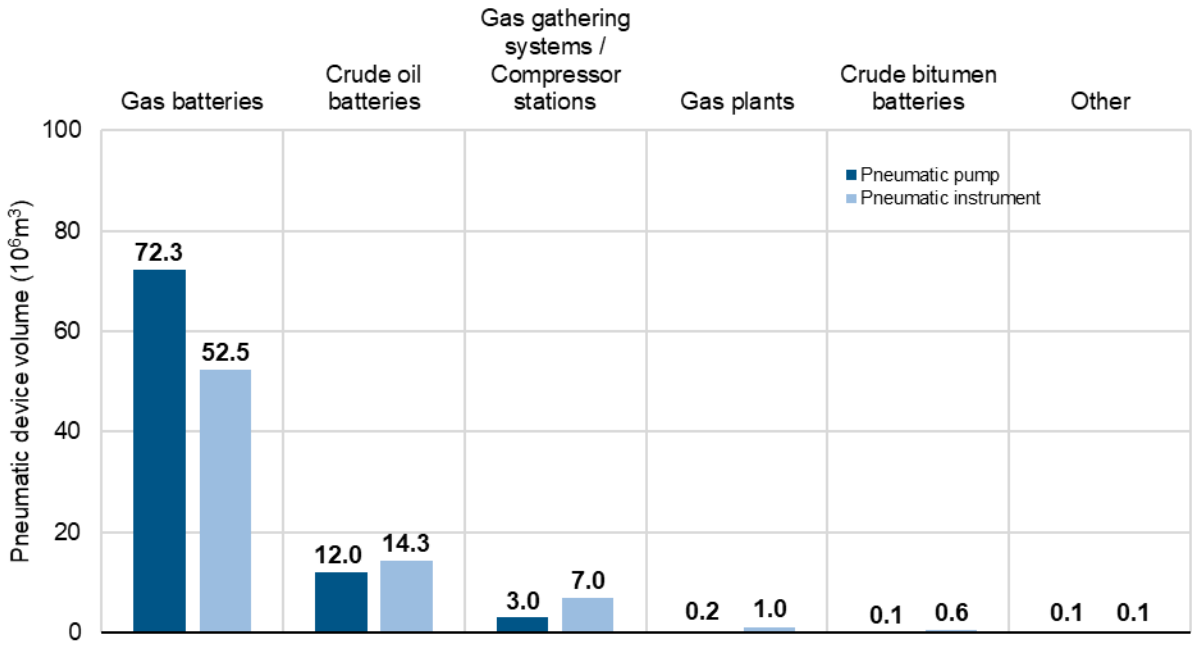


Figure 11. Pneumatic vent volumes by equipment and facility subtype, 2024 (Source: OneStop)

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 through OneStop. These volumes are captured in the vent volumes reported to Petrinex monthly.

4.2.4.1 Compressor Inventory

Directive 060 requires reporting a more detailed compressor inventory annually to the AER through OneStop in addition to reported volumes. This inventory includes compressors rated 75 kW or more and pressurized for at least 450 hours per calendar year, which must be reported individually from OneStop 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 2024, 3978 reciprocating compressors and 106 centrifugal compressors were reported, an increase from 3338 reciprocating compressors and a decrease from 110 centrifugal compressors in 2023.

4.2.4.2 Compressor Seal Emissions

In 2024, reciprocating compressor seal emissions reported to OneStop were 12.37 10^6 m^3, roughly 3.8% of all emissions reported to OneStop. Centrifugal compressor seal emissions reported to OneStop were 0.49 10^6 m^3, a minor contributor relative to the other emission sources reported here, representing only 0.15% of all emissions reported to OneStop. 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.

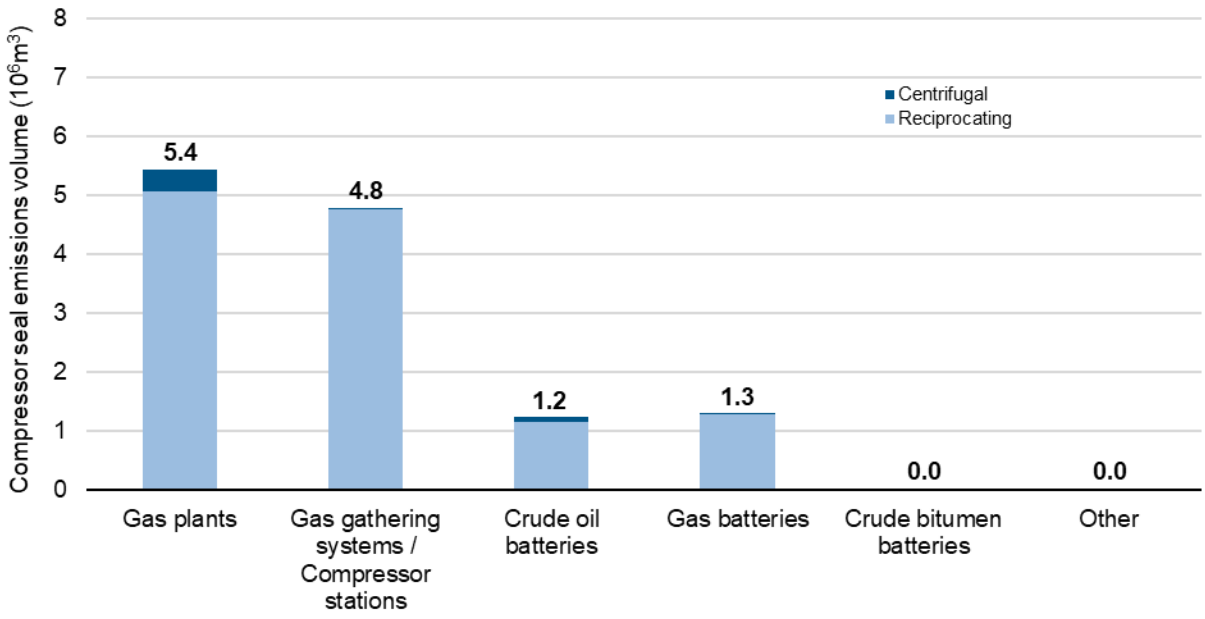


Figure 12. Compressor inventory vent volumes by compressor type and facility subtype (Source: OneStop)

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. If the crankcase is uncontrolled, any emitted gas is subject to compressor limits. Effective January 1, 2022, the duty holder must limit vent gas from the RCS fleet to less than 0.35 m^3/hr/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 2024 reported values. Highlighted cells in table 11 represent fleet averages exceeding vent limits.

Table 11. Top 20 compressor inventory venting operators with RCS fleet average, 2024 (Source: OneStop)

Operator	Vent volume (10^6 m^3)	Number of compressors	Number of throws	Average of vent gas from RCS fleet*
Canadian Natural Resources Limited	1.60	470	1612	0.11
Peyto Exploration & Development Corp.	1.02	250	866	0.20
Cenovus Energy Inc.	0.79	139	462	0.22
Spartan Delta Corp.	0.52	49	164	0.36
Keyera Energy Ltd.	0.46	87	279	0.13
Pine Cliff Energy Ltd.	0.45	50	193	0.31
TAQA North Ltd.	0.42	786	1008	0.02
Pembina Gas Infrastructure Inc.	0.40	61	230	0.26
Tourmaline Oil Corp.	0.32	97	315	0.14
Paramount Resources Ltd.	0.28	82	279	0.14
Kelt Exploration Ltd.	0.26	24	74	0.58
Whitecap Partnership	0.23	50	128	0.20
HWN Energy Ltd.	0.22	43	130	0.20
ARC Resources Ltd.	0.22	113	425	0.08
Whitecap Resources Inc.	0.20	126	375	0.12
Canlin Resources Partnership	0.20	63	240	0.10
Astara Energy Corp.	0.20	7	24	0.94
Ember Resources Inc.	0.19	92	355	0.06
Lynx Energy ULC	0.19	38	149	0.15
AltaGas Ltd.	0.19	32	100	0.17

* 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 to Petrinex.

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 list to the AER that details the emissions from all their glycol dehydrators.

4.2.5.1 Glycol Dehydrator Inventory

In 2024, there were 1181 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 2024. Table 12 shows the counts of all operating glycol dehydrators per year over the past 15 years.

Table 12. Number of operating glycol dehydrators, 2010–2024 (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

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 2024, glycol dehydrator emissions were calculated to be 8.7 10^6 m^3, representing 2.7% of all emissions reported to OneStop, and a 21.6% reduction from the reported 2023 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 and can result from equipment wear or failure. *Directive 060* includes requirements for screenings and surveys to inspect and repair leaking equipment. Fugitive emissions are reported to the AER through OneStop annually.

The first year of implementing prescribed fugitive emission requirements under *Directive 060* was 2020, and 2021 was the first year equipment fugitive emissions were reported to the AER. In 2024, fugitive emissions were 40.4 10^6 m^3 (see figure 13), representing 12.5% of all emissions reported to OneStop, a 14.8% increase from the reported 2023 volumes. The uptick in fugitive emissions could be due to a number of factors, including better adherence to fugitive emissions management programs, novel screening technologies, and experience level of technology operators that are finding more leaks than previous years.

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.

Section 8 of *Directive 060* requires increased ongoing fugitive emissions surveys at active sites, resulting in more frequent inspections of surface casing vents, which are identified as mandatory equipment within the scope of a fugitive emission survey. However, SCVF and GM emissions detected during a fugitive emission survey are not reported via OneStop. These emissions are reported via the Digital Data Submission (DDS) system. Nonserious events or volumes too small to quantify are assigned a volume of 1 m^3 per day. Serious events were assigned a volume of 300 m^3 per day when no flow rate was reported, and repair statuses were assigned based on submitted repair dates within the calendar year.

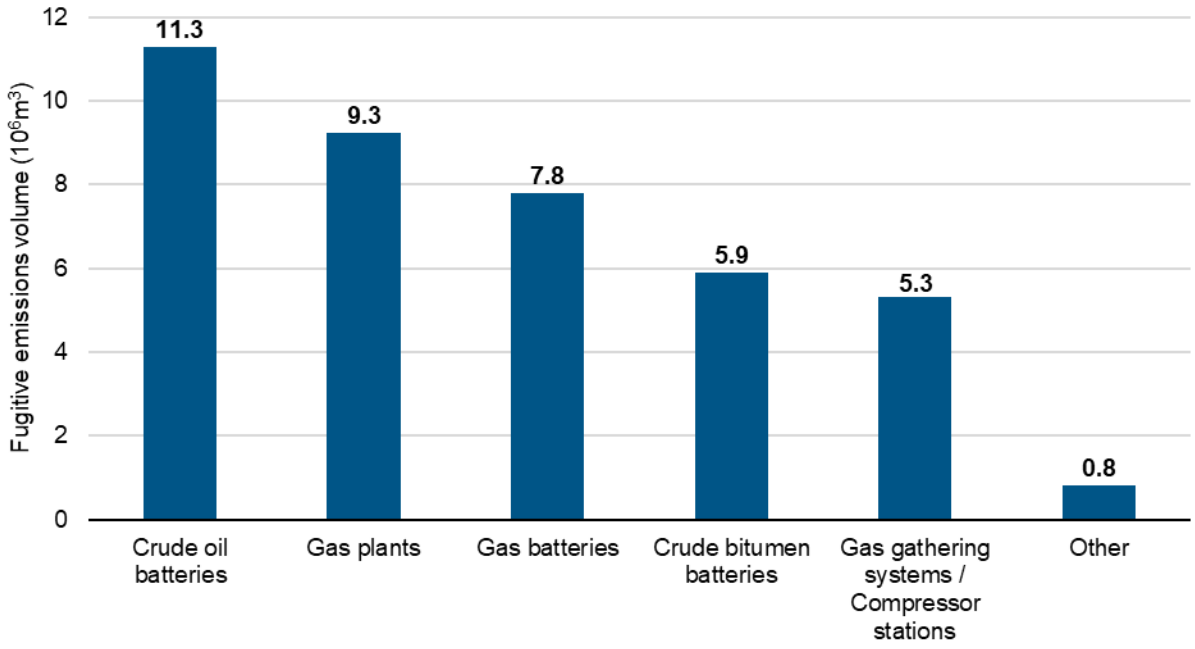
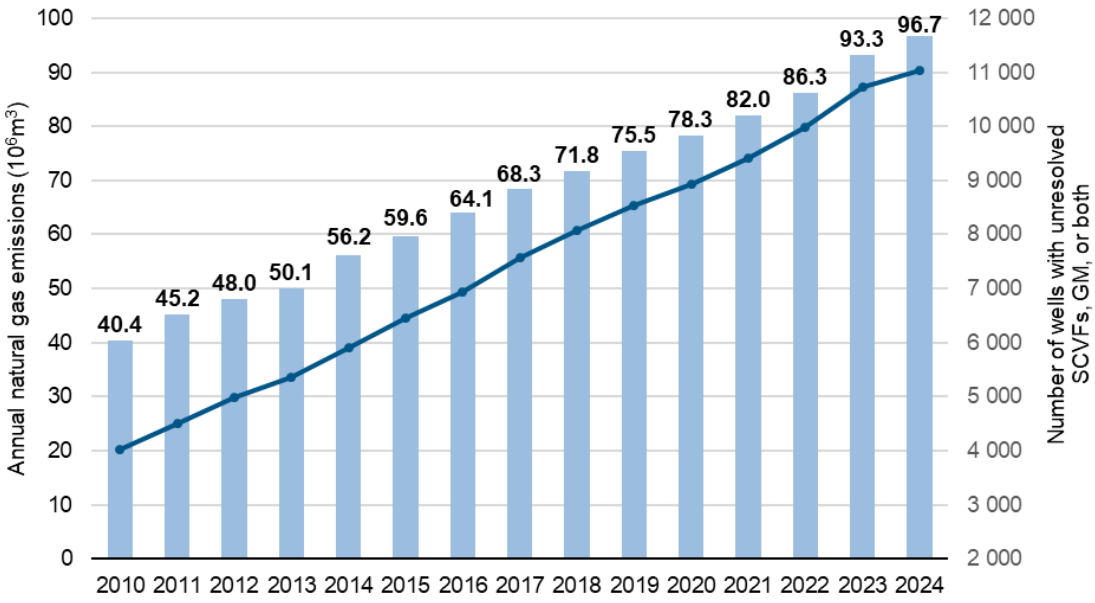


Figure 13. Fugitive emissions volume by facility subtype, 2024 (Source: OneStop)

6 Surface Casing Vent Flow and Gas Migration

In 2021, the AER released *Directive 087: Well Integrity Management*, which complements *Directive 060* regarding SCVF management. *Directive 060* contains ongoing survey requirements, whereas *Directive 087* contains testing, reporting, and repair requirements for isolation packers, SCVFs, GM, and casing failures. Over the years, the AER has worked with licensees to ensure proper reporting of SCVFs and GM.

Figure 14 shows the number of unresolved wells with SCVF, GM, or both and their respective emissions.



Notes:

For wells that have SCVF flow rates that are too small to measure and wells where a GM flow rate cannot be determined, a flow rate of 1 m^3/day was assumed. Repair statuses were assigned based on submitted repair dates within the calendar year.

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.

If no emissions type (e.g., natural gas, saline water, or nonsaline water) is provided, an SCVF or GM is assumed to be natural gas with a flow rate equal to the average of all other reported natural gas SCVFs or GM.

Figure 14. Emissions from SCVFs and GM at unrepaired wells

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

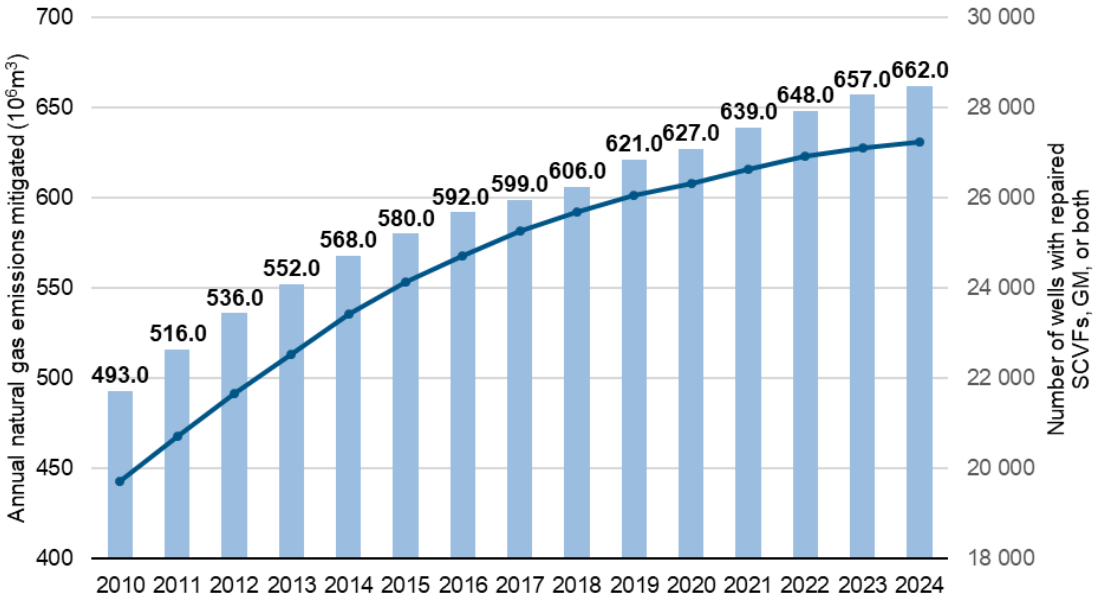


Figure 15. Emissions mitigated from SCVFs and GM at repaired wells

7 Solution Gas Performance

Solution gas is gas separated from condensate, oil, or bitumen production. To minimize the venting of solution gas, the AER developed requirements to guide the evaluation of alternative options, such as flaring or conserving.

The 2007 version of *Directive 060* emphasized solution gas conservation and recommended that all solution gas flares or vents releasing more than 900 m^3/day be evaluated to see if gas conservation is economic and viable. When *Directive 060* was revised in 2020 to include more stringent methane reduction requirements, site vent and flare limits were introduced that were lower than the 900 m^3/day threshold. This threshold can and is still used to evaluate the economics of conservation.

Improving solution gas conservation is a key factor in achieving provincial emission reduction targets. 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, 914.5 10^6 m^3 of solution gas was flared in 2024, which was a 19.3% increase over 2023. Several factors contributed to the rise in flaring, including an increase in oil production and exploration in Alberta, an increase in total reported flaring volumes due to updated reporting requirements, increase production of oil and bitumen, and an increase due to the combustion of previously vented methane to achieve methane compliance.

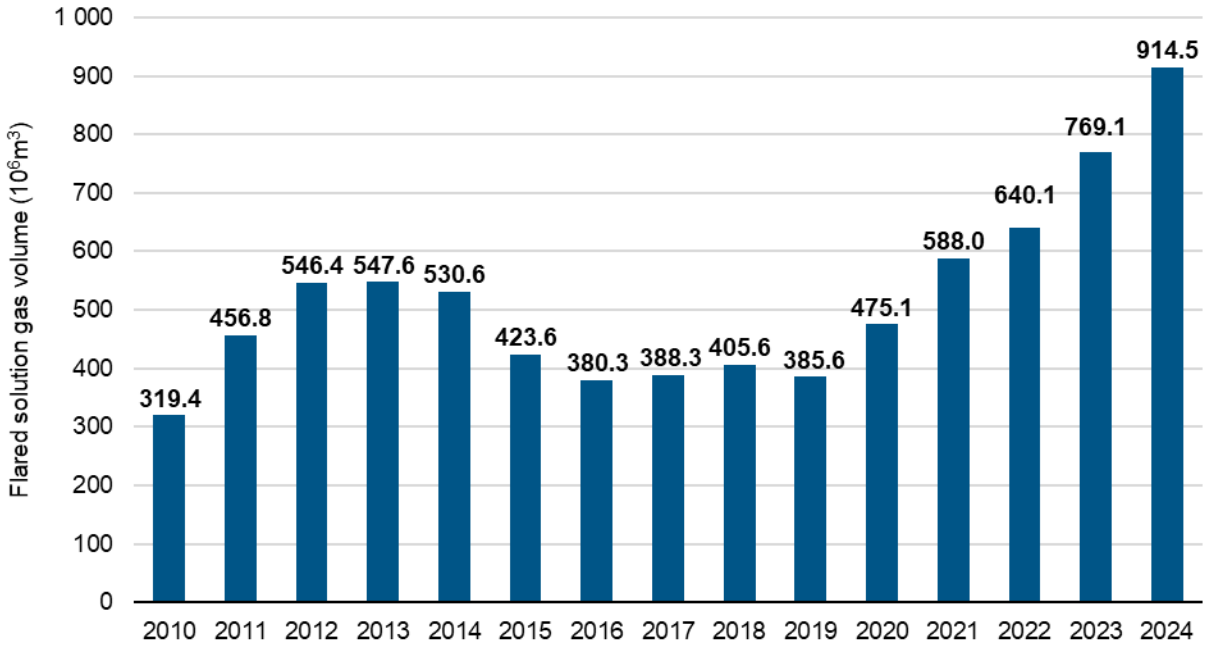


Figure 16. Solution gas flaring, 2010–2024 (Source: Petrinex)

7.2 Solution Gas Venting

In 2024, 101.1 10^6 m^3 of solution gas was vented from crude oil and crude bitumen batteries, a 9.6% decrease from 2023. This trend is expected when looking at the continuous uptrend of solution gas flaring. Solution gas vented remains well below the 2000 baseline of 704.0 10^6 m^3 (see figure 17).

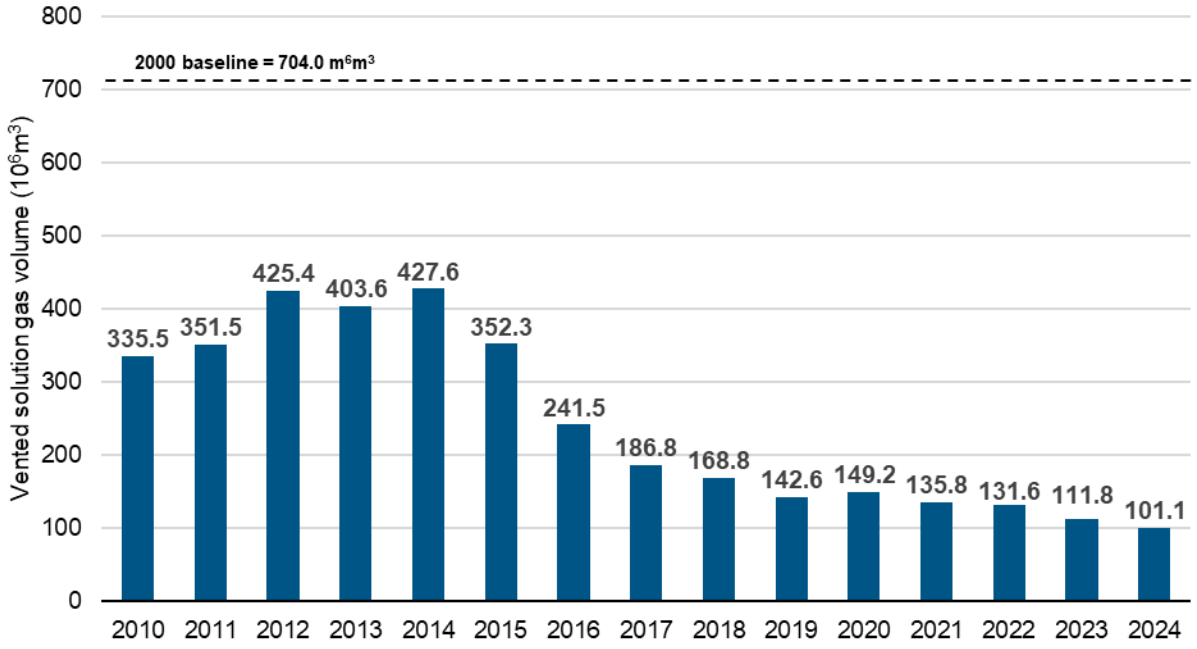


Figure 17. Solution gas venting, 2010–2024 (Source: Petrinex)

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:

$$Conservation = \frac{[Volume\ of\ gas\ produced - (Volume\ of\ gas\ flared + Volume\ of\ gas\ vented)]}{Volume\ of\ gas\ produced}$$

In 2024, 96.5% of the solution gas produced from crude oil and crude bitumen batteries was conserved, down slightly from 96.9% in 2023.

Figure 18 shows the total annual solution gas flared and vented volumes and the associated conservation rates. As shown in table 8, vent gas volumes continue to trend down because of the new limits in *Directive 060* introduced in 2020.

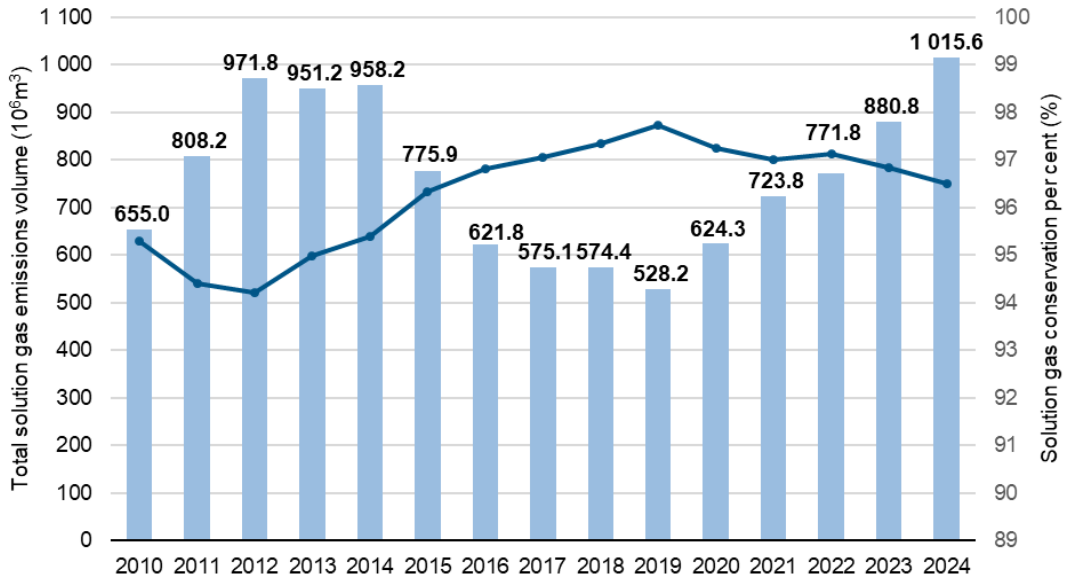


Figure 18. Solution gas conservation, 2010–2024 (Source: Petrinex)

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 because the produced gas is more economical to conserve. 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 2024. Thermal operations conservation is 98.7%, whereas nonthermal operations have a conservation rate of 86.8%.

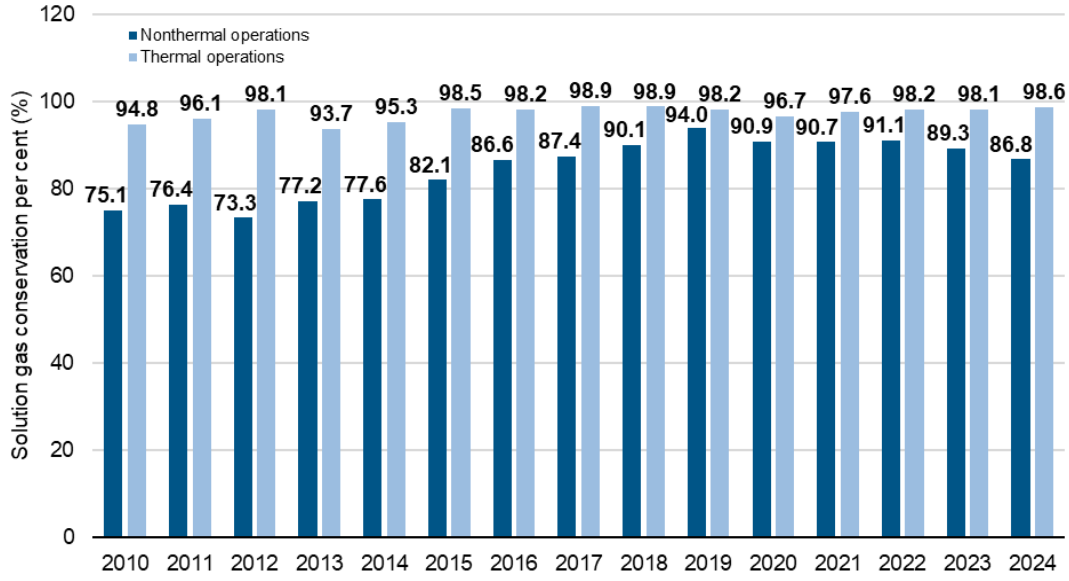


Figure 19. Solution gas conservation, 2010–2024 (Source: Petrinex)

8 Methane Performance

In 2015, the Government of Alberta directed the AER to develop requirements to reduce methane emissions from upstream oil and gas operations. To accomplish this, the AER developed requirements in *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* and *Directive 017: Measurement Requirements for Oil and Gas Operations.* To learn more about these requirements and for more information on methane performance and methane compliance assurance activities, see our methane performance webpage.

The emission reduction target set for Alberta by the Government of Alberta was to achieve a 45% reduction in oil and gas methane emissions from a 2014 baseline by 2025. The methane requirements set the oil and gas industry on the path towards achieving that target. However, the emissions data reported above is not complete enough to consider it a comprehensive oil and gas methane emission baseline. The AER continues to supplement reported information with emission estimates to allow for an evaluation of the emission reductions achieved to date. The model assumptions, inputs, and estimates are updated annually to reflect the latest and most accurate data available; thus, the baseline may shift year over year to reflect these changes. Figure 20 shows the methane emission trend line (a combination of reported data and engineering estimates from standardized methodologies) and the 45% target. These reductions are the result of early action through programs like the Technology Innovation and Emission Reduction (TIER) Regulation Offset System and the methane requirements.

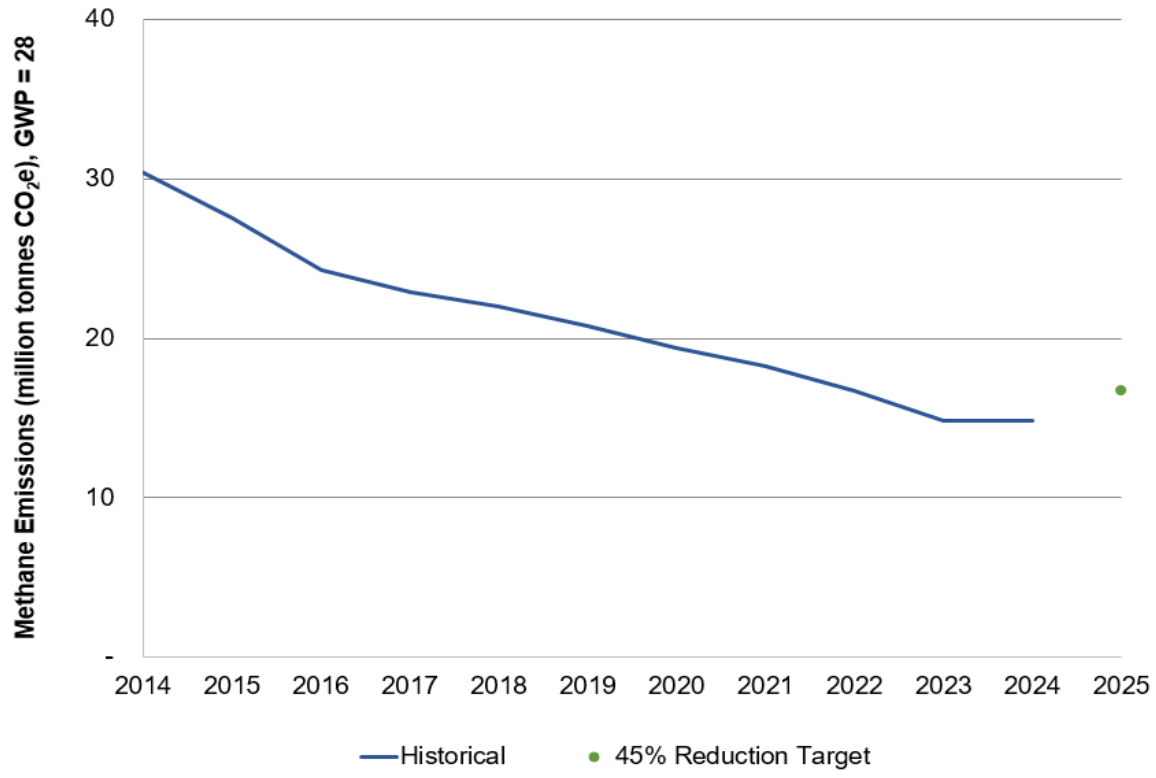
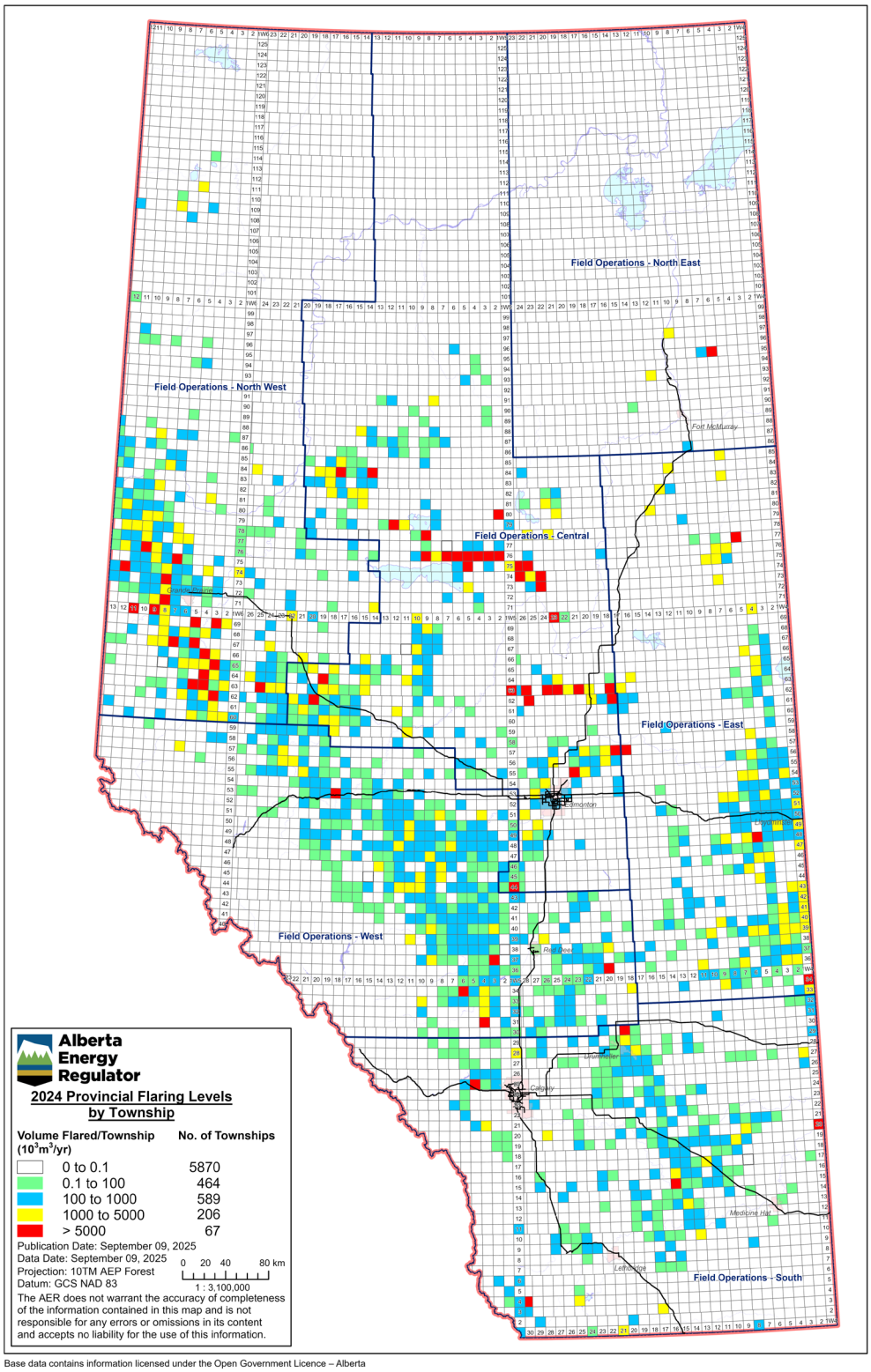


Figure 20. Methane emission reductions, 2014–2024 (reported and estimated emissions)

This graph shows that methane emission reductions from all oil and gas emissions in Alberta (excluding oil sands mining, tailings, and upgrading) are estimated to have been reduced by 51% between 2014 and 2024, which is expected with all regulations having come into effect in January 1, 2023.

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

Appendix 1 Provincial Flaring and Venting Maps



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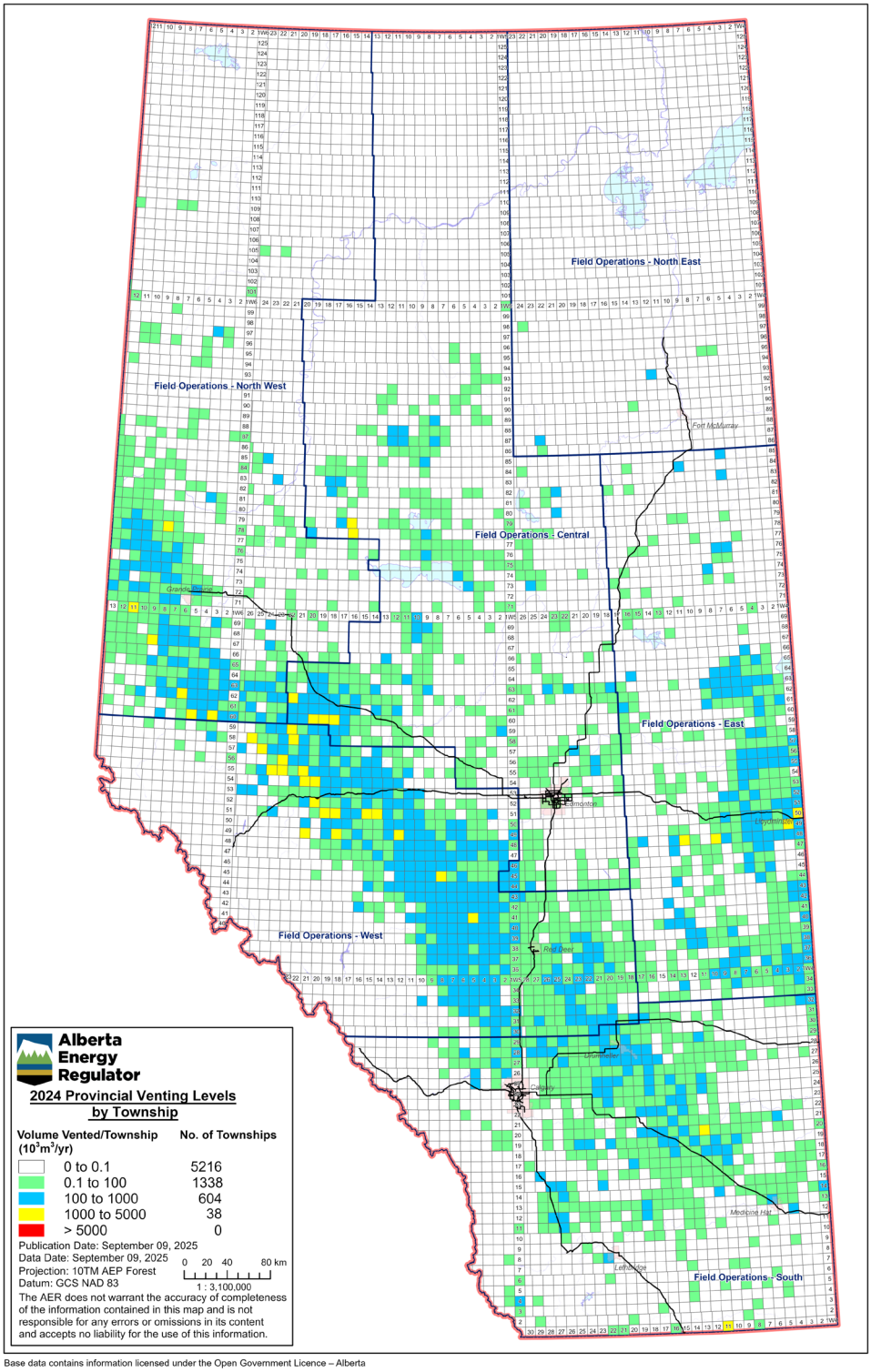

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Appendix 2 Operator Rankings

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 volume of gas vented, flared, and used as fuel are based on OneStop data as of July 15, 2025.

Venting

Oil Sands Assets

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2024-2023)
Imperial Oil Resources Limited	348 600	1	61 233 242	0.00569	0.00354	0.0022
Canadian Natural Resources Limited	345 100	2	151 455 028	0.00228	0.00248	-0.0002
CNOOC Petroleum North America ULC	332 800	3	29 269 868	0.01137	0.00472	0.0066
Suncor Energy Inc.	251 800	4	108 324 474	0.00232	0.01392	-0.0116
Cenovus Energy Inc.	185 300	5	196 058 665	0.00095	0.00085	0.0001
ConocoPhillips Canada Resources Corp.	136 700	6	53 333 002	0.00256	0.00274	-0.0002
Harvest Operations Corp.	39 700	7	2 989 163	0.01328	0.01348	-0.0002
MEG Energy Corp.	31 900	8	41 533 621	0.00077	0.00086	-0.0001
Athabasca Oil Corporation	10 100	9	13 642 516	0.00074	0.00173	-0.0010
PetroChina Canada Ltd.	2 500	10	3 934 145	0.00064	0.00003	0.0006

Non-Oil-Sands Assets

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Canadian Natural Resources Limited	39 409 300	1	117 615 669	0.34	0.43	-29.03
Tourmaline Oil Corp.	29 315 700	2	111 128 261	0.26	0.31	-18.80
Cenovus Energy Inc.	21 909 800	3	52 526 154	0.42	0.50	-19.65
Peyto Exploration & Development Corp.	11 868 200	4	45 931 292	0.26	0.25	3.12
Whitecap Resources Inc.	11 373 900	5	79 870 011	0.14	0.15	-3.37
Vermilion Energy Inc.	9 681 400	6	25 266 620	0.38	0.38	2.01
TAQA North Ltd.	7 916 400	7	24 120 519	0.33	0.35	-7.17
Pine Cliff Energy Ltd.	7 206 400	8	8 303 357	0.87	0.78	10.45
Obsidian Energy Ltd.	5 580 600	9	8 534 872	0.65	0.24	62.85
HWN Energy Ltd.	5 516 800	10	5 932 981	0.93	0.93	-0.11

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Torxen Energy Ltd.	5 167 400	11	22 104 308	0.23	0.26	-9.36
Paramount Resources Ltd.	4 476 700	12	10 056 303	0.45	0.58	-30.59
Cardinal Energy Ltd.	3 845 000	13	6 052 473	0.64	0.70	-9.76
InPlay Oil Corp.	3 591 700	14	2 866 813	1.24	1.18	4.27
Gran Tierra Canada Ltd.	3 294 700	15	4 678 726	0.70	0.70	1.06
Mancal Energy Inc.	3 121 000	16	4 066 416	0.77	0.82	-6.93
Spartan Delta Corp.	3 073 400	17	12 386 290	0.25	0.37	-49.45
Top Oil Production Ltd.	3 029 800	18	215 703	14.05	11.75	16.36
ARC Resources Ltd.	3 026 700	19	62 323 809	0.05	0.05	-11.87
Harvest Operations Corp.	2 679 500	20	3 100 018	0.86	0.92	-6.60
Ember Resources Inc.	2 655 600	21	15 482 657	0.17	0.20	-18.75
Strathcona Resources Ltd.	2 642 600	22	19 939 636	0.13	0.15	-11.64
Lynx Energy ULC	2 400 700	23	7 366 292	0.33	0.34	-5.52
Karve Energy Inc.	2 259 400	24	2 500 042	0.90	0.80	11.04
Astara Energy Corp.	1 865 400	25	3 299 582	0.57	0.63	-11.38

Combined

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Canadian Natural Resources Limited	39 754 400	1	269 070 697	0.15	0.19	-28.11
Tourmaline Oil Corp.	29 315 700	2	111 128 261	0.26	0.31	-18.80
Cenovus Energy Inc.	22 095 100	3	248 584 819	0.09	0.10	-15.13
Peyto Exploration & Development Corp.	11 868 200	4	45 931 292	0.26	0.25	3.12
Whitecap Resources Inc.	11 373 900	5	79 870 011	0.14	0.15	-3.37
Vermilion Energy Inc.	9 681 400	6	25 266 620	0.38	0.38	2.01
TAQA North Ltd.	7 916 400	7	24 120 519	0.33	0.35	-7.17
Pine Cliff Energy Ltd.	7 206 400	8	8 303 357	0.87	0.78	10.45
Obsidian Energy Ltd.	5 580 600	9	12 430 019	0.45	0.17	61.90
HWN Energy Ltd.	5 516 800	10	5 932 981	0.93	0.93	-0.11
Torxen Energy Ltd.	5 167 400	11	22 104 308	0.23	0.26	-9.36
Paramount Resources Ltd.	4 476 700	12	10 056 303	0.45	0.58	-30.59
Cardinal Energy Ltd.	3 845 000	13	6 052 473	0.64	0.70	-9.76
InPlay Oil Corp.	3 591 700	14	2 866 813	1.25	1.18	5.63
Gran Tierra Canada Ltd.	3 294 700	15	4 684 272	0.70	0.70	0.95

Company	Vent volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Mancal Energy Inc.	3 121 000	16	4 066 416	0.77	0.82	-6.93
Spartan Delta Corp.	3 073 400	17	12 386 290	0.25	0.37	-49.45
Top Oil Production Ltd.	3 029 800	18	216 589	13.99	11.75	16.03
ARC Resources Ltd.	3 026 700	19	62 323 809	0.05	0.05	-11.87
Harvest Operations Corp.	2 719 200	20	6 089 181	0.45	0.47	-5.67
Ember Resources Inc.	2 655 600	21	15 482 657	0.17	0.20	-18.75
Strathcona Resources Ltd.	2 642 600	22	44 175 646	0.06	0.07	-17.47
Lynx Energy ULC	2 400 700	23	7 366 292	0.33	0.34	-5.52
Karve Energy Inc.	2 259 400	24	2 500 042	0.90	0.80	11.04
Astara Energy Corp.	1 865 400	25	3 299 582	0.57	0.63	-11.38

Flaring

Oil Sands Assets

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2024-2023)
Suncor Energy Inc.	26 330 700	1	108 324 474	0.24307	0.29821	-0.0551
Canadian Natural Resources Limited	11 546 100	2	151 455 028	0.07623	0.09278	-0.0165
Cenovus Energy Inc.	6 432 600	3	196 058 665	0.03281	0.04467	-0.0119
Strathcona Resources Ltd.	6 140 300	4	24 236 009	0.25335	0.26700	-0.0136
MEG Energy Corp.	5 055 500	5	41 533 621	0.12172	0.08670	0.0350
ConocoPhillips Canada Resources Corp.	3 778 700	6	53 333 002	0.07085	0.04387	0.0270
Greenfire Resources Operating Corporation	3 541 300	7	10 070 390	0.35165	0.31756	0.0341
Imperial Oil Resources Limited	3 343 000	8	61 233 242	0.05459	0.18646	-0.1319
CNOOC Petroleum North America ULC	3 088 400	9	29 269 868	0.10551	0.09310	0.0124
Connacher Oil And Gas Limited	2 882 500	10	6 377 002	0.45201	0.42634	0.0257
Harvest Operations Corp.	1 069 500	11	2 989 163	0.35779	0.47939	-0.1216
Athabasca Oil Corporation	497 200	12	13 642 516	0.03644	0.03749	-0.0010

Non-Oil-Sands Assets

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Tamarack Valley Energy Ltd.	137 578 000	1	19 150 193	7.18	10.14	-41.10
Headwater Exploration Inc.	104 956 600	2	1 374 289	76.26	49.17	35.53
Baytex Energy Ltd.	89 400 000	3	6 014 980	14.51	13.20	9.02
Spur Petroleum Ltd.	88 702 300	4	10 526 153	8.43	7.10	15.70
Canadian Natural Resources Limited	68 400 200	5	117 615 669	0.58	0.63	-8.48
Rubellite Energy Inc.	51 065 200	6	2 121 439	24.07	18.05	25.01
ARC Resources Ltd.	45 080 100	7	62 323 809	0.72	0.72	0.70
Cavvy Production Ltd.	44 753 800	8	2 820 500	15.87	10.08	36.48
Cenovus Energy Inc.	42 109 500	9	52 526 154	0.80	0.79	1.53
Astara Energy Corp.	21 869 400	10	3 299 582	6.63	2.95	55.44
Whitecap Resources Inc.	21 315 600	11	79 870 011	0.27	0.33	-23.82
Ovintiv Canada ULC	21 286 400	12	36 650 820	0.58	0.46	20.54
Obsidian Energy Ltd.	20 149 300	13	8 534 872	2.36	2.30	2.39
Tourmaline Oil Corp.	19 011 500	14	111 128 261	0.17	0.17	-0.34
Peyto Exploration & Development Corp.	15 354 100	15	45 931 292	0.33	0.29	14.18

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Lycos Energy Inc.	14 049 000	16	1 348 821	10.42	2.23	78.59
TAQA North Ltd.	14 035 200	17	24 120 519	0.58	0.51	12.09
West Lake Energy Corp.	13 751 600	18	2 756 587	4.99	5.58	-11.81
Cardinal Energy Ltd.	13 732 100	19	6 052 473	2.27	1.65	27.33
NuVista Energy Ltd.	13 244 500	20	23 774 632	0.56	0.54	3.20
Surge Energy Inc.	12 339 600	21	10 056 302	1.09	1.43	-23.78
Strathcona Resources Ltd.	11 662 400	22	19 939 636	0.58	0.59	-1.69
North 40 Resources Ltd.	11 524 200	23	1 963 110	5.87	2.49	135.74
Paramount Resources Ltd.	10 990 600	24	10 056 302	1.09	1.43	-23.78
Ipc Canada Ltd.	10 598 200	25	11 665 986	0.91	0.63	44.44

Combined

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Tamarack Valley Energy Ltd.	137 578 000	1	24 516 960	5.61	7.79	-38.89
Headwater Exploration Inc.	104 956 600	2	8 874 464	11.83	7.98	32.49
Baytex Energy Ltd.	89 400 000	3	19 053 779	4.69	4.37	6.91
Spur Petroleum Ltd.	88 702 300	4	18 089 341	4.90	4.21	14.19
Canadian Natural Resources Limited	79 946 300	5	269 070 697	0.30	0.33	-9.92
Rubellite Energy Inc.	51 065 200	6	3 914 528	13.05	11.48	12.02
Cenovus Energy Inc.	48 542 100	7	248 584 819	0.20	0.20	-0.56
ARC Resources Ltd.	45 080 100	8	62 323 809	0.72	0.72	0.70
Cavvy Production Ltd.	44 753 800	9	2 820 500	15.87	10.08	36.48
Suncor Energy Inc.	26 330 700	10	108 701 181	0.24	0.30	-22.39
Astara Energy Corp.	21 869 400	11	3 299 582	6.63	2.95	55.44
Whitecap Resources Inc.	21 315 600	12	79 870 011	0.27	0.33	-23.82
Ovintiv Canada ULC	21 286 400	13	36 650 820	0.58	0.46	20.54
Obsidian Energy Ltd.	20 149 300	14	12 430 019	1.62	1.62	-0.09
Tourmaline Oil Corp.	19 011 500	15	111 128 261	0.17	0.17	-0.34
Strathcona Resources Ltd.	17 802 700	16	44 175 646	0.40	0.42	-4.60
Peyto Exploration & Development Corp.	15 354 100	17	45 931 292	0.33	0.29	14.18
Lycos Energy Inc.	14 049 000	18	1 477 455	9.51	2.18	77.12
TAQA North Ltd.	14 035 200	19	24 120 519	0.58	0.51	12.09
West Lake Energy Corp.	13 751 600	20	2 772 611	4.96	5.53	-11.53

Company	Flare volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Cardinal Energy Ltd.	13 732 100	21	6 052 473	2.27	1.65	27.33
NuVista Energy Ltd.	13 244 500	22	23 774 632	0.56	0.54	3.20
Surge Energy Inc.	12 339 600	23	4 689 538	2.63	2.44	7.12
North 40 Resources Ltd.	11 524 200	24	1 963 111	5.87	2.49	57.54
Paramount Resources Ltd.	10 990 600	25	10 056 303	1.09	1.43	-30.65

Fuel Use

Oil Sands Assets

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2024-2023)
Cenovus Energy Inc.	3 740 124 600	1	196 058 665	19.08	19.06	0.02
Canadian Natural Resources Limited	3 716 659 000	2	151 455 028	24.54	24.16	0.38
Imperial Oil Resources Limited	2 292 895 000	3	61 233 242	37.45	42.34	-4.90
Suncor Energy Inc.	1 955 769 800	4	108 324 474	18.05	19.13	-1.08
ConocoPhillips Canada Resources Corp.	1 381 162 200	5	53 333 002	25.90	25.52	0.38
Strathcona Resources Ltd.	942 827 700	6	24 236 009	38.90	40.57	-1.67
MEG Energy Corp.	751 131 500	7	41 533 621	18.08	16.84	1.25
CNOOC Petroleum North America ULC	664 125 100	8	29 269 868	22.69	21.93	0.76
Athabasca Oil Corporation	422 979 500	9	13 642 516	31.00	30.23	0.78
Greenfire Resources Operating Corporation	341 835 300	10	10 070 390	33.94	39.20	-5.26
Connacher Oil And Gas Limited	241 975 900	11	6 377 002	37.95	36.63	1.31
PetroChina Canada Ltd.	233 054 700	12	3 934 145	59.24	59.57	-0.33
Harvest Operations Corp.	96 250 300	13	2 989 163	32.20	31.11	1.09
Sunshine Oilsands Ltd.	34 240 000	14	295 925	115.71	105.35	10.35
IPC Canada Ltd.	11 787 400	15	192 323	61.29	39.72	21.57

Non-Oil-Sands Assets

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Canadian Natural Resources Limited	1 311 545 700	1	117 615 669	11.15	12.17	-9.09
Tourmaline Oil Corp.	656 275 200	2	111 128 261	5.91	5.85	1.01
ARC Resources Ltd.	447 364 600	3	62 323 809	7.18	6.66	7.26
Cenovus Energy Inc.	376 098 300	4	52 526 154	7.16	7.64	-6.69
Peyto Exploration & Development Corp.	306 664 200	5	45 931 292	6.68	6.88	-3.12
Ember Resources Inc.	200 379 700	6	15 482 657	12.94	12.82	0.95
Whitecap Resources Inc.	199 358 500	7	79 870 011	2.50	2.60	-4.08
Cavvy Production Ltd.	193 006 300	8	2 820 500	68.43	50.26	26.56
Birchcliff Energy Ltd.	168 238 200	9	26 392 239	6.37	6.69	-4.87
Torxen Energy Ltd.	161 277 600	10	22 104 308	7.30	7.68	-5.33

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Baytex Energy Ltd.	149 773 900	11	6 014 980	24.90	25.49	-2.36
TAQA North Ltd.	145 407 200	12	24 120 519	6.03	6.42	-6.43
Advantage Energy Ltd.	144 418 600	13	29 746 425	4.85	4.93	-1.50
NuVista Energy Ltd.	135 904 500	14	23 774 632	5.72	5.26	7.90
Vermilion Energy Inc.	128 396 200	15	25 266 620	5.08	4.55	10.38
Tidewater Midstream and Infrastructure Ltd.	115 619 500	16	560 353	206.33	272.13	-31.89
Tamarack Valley Energy Ltd.	110 756 000	17	19 150 193	5.78	5.49	5.09
Spartan Delta Corp.	103 086 500	18	12 386 290	8.32	8.16	1.91
Ipc Canada Ltd.	100 126 800	19	11 665 987	8.58	8.68	-1.08
Ovintiv Canada ULC	95 793 700	20	36 650 820	2.61	2.67	-2.32
Pine Cliff Energy Ltd.	95 193 800	21	8 303 357	11.46	11.80	-2.90
Lynx Energy ULC	92 077 200	22	7 366 292	12.50	12.73	-1.83
Obsidian Energy Ltd.	88 714 300	23	8 534 872	10.39	9.32	10.34
Strathcona Resources Ltd.	86 562 200	24	19 939 636	4.34	4.25	1.99
Paramount Resources Ltd.	78 035 400	25	10 056 303	7.76	8.44	-8.82

Combined

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Canadian Natural Resources Limited	5 028 204 700	1	269 070 697	18.69	18.95	-1.39
Cenovus Energy Inc.	4 116 222 900	2	248 584 819	16.56	16.73	-1.04
Imperial Oil Resources Limited	2 292 895 000	3	63 713 910	35.99	40.56	-12.70
Suncor Energy Inc.	1 955 769 800	4	108 701 181	17.99	19.02	-5.71
ConocoPhillips Canada Resources Corp.	1 381 162 200	5	53 831 972	25.66	25.26	1.54
Strathcona Resources Ltd.	1 029 389 900	6	44 175 646	23.30	23.32	-0.09
MEG Energy Corp.	751 131 600	7	44 853 632	16.75	15.60	6.86
CNOOC Petroleum North America ULC	664 125 100	8	29 566 348	22.46	21.70	3.40
Tourmaline Oil Corp.	656 275 200	9	111 128 261	5.91	5.85	1.01
ARC Resources Ltd.	447 364 600	10	62 323 809	7.18	6.66	7.26
Athabasca Oil Corporation	446 717 100	11	14 233 281	31.39	31.12	0.83
Greenfire Resources Operating Corporation	345 175 600	12	10 295 209	33.53	38.62	-15.19
Peyto Exploration & Development Corp.	306 664 200	13	45 931 292	6.68	6.88	-3.12
Connacher Oil And Gas Limited	241 975 900	14	7 036 830	34.39	33.71	1.96
PetroChina Canada Ltd.	233 054 700	15	7 519 363	30.99	31.21	-0.69

Company	Fuel volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2024 to 2023)
Ember Resources Inc.	200 379 700	16	15 482 657	12.94	12.82	0.95
Whitecap Resources Inc.	199 358 500	17	79 870 011	2.50	2.60	-4.08
Cavvy Production Ltd.	193 006 300	18	2 820 500	68.43	50.26	26.56
Birchcliff Energy Ltd.	168 238 200	19	26 392 239	6.37	6.69	-4.87
Torxen Energy Ltd.	161 277 600	20	22 104 308	7.30	7.68	-5.33
Baytex Energy Ltd.	149 773 900	21	19 053 779	7.86	8.43	-7.26
TAQA North Ltd.	145 407 200	22	24 120 519	6.03	6.42	-6.43
Advantage Energy Ltd.	144 418 600	23	29 746 425	4.85	4.93	-1.50
NuVista Energy Ltd.	135 904 500	24	23 774 632	5.72	5.26	7.90
Harvest Operations Corp.	135 215 700	25	6 089 181	22.21	21.91	1.33

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 (10^6 m^3)	Vented (10^6 m^3)
Canadian Natural Resources Limited	0.36	1	42.35	16.23
Tamarack Valley Energy Ltd.	0.29	2	117.33	1.21
Headwater Exploration Inc.	0.23	3	100.91	0.10
Spur Petroleum Ltd.	0.21	4	88.61	0.32
Baytex Energy Ltd.	0.14	5	57.97	0.56
Cenovus Energy Inc.	0.14	6	26.77	4.98
Rubellite Energy Inc.	0.13	7	51.07	0.99
Obsidian Energy Ltd.	0.10	8	11.08	4.88
Whitecap Resources Inc.	0.10	9	6.52	5.53
Cardinal Energy Ltd.	0.09	10	12.75	3.71
HWN Energy Ltd.	0.08	11	3.63	4.24
Astara Energy Corp.	0.08	12	21.53	1.68
Whitecap Partnership	0.07	13	30.10	0.31
Suncor Energy Inc.	0.06	14	26.33	0.25
Surge Energy Inc.	0.04	15	10.24	1.14
Lycos Energy Inc.	0.04	16	14.05	0.56
Tourmaline Oil Corp.	0.04	17	7.78	1.26
West Lake Energy Corp.	0.04	18	13.73	0.26
North 40 Resources Ltd.	0.03	19	11.51	0.22
Strathcona Resources Ltd.	0.03	20	6.50	0.92
Clear North Energy Corp.	0.03	21	9.94	0.27
Aspenleaf Energy Limited	0.02	22	7.78	0.30
Woodcote Oil & Gas Inc.	0.02	23	8.56	0.15
Lynx Energy ULC	0.02	24	5.94	0.38
Murphy Oil Company Ltd.	0.02	25	6.14	0.22

Total Methane Emissions

The following table ranks operators based on the total of all methane emissions reported to OneStop in 2024.

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

Company	Volume emitted ($MtCO_2e$)	Rank
Canadian Natural Resources Limited	0.68	1
Tourmaline Oil Corp.	0.46	2
Cenovus Energy Inc.	0.35	3
Pine Cliff Energy Ltd.	0.23	4
Peyto Exploration & Development Corp.	0.20	5
Whitecap Resources Inc.	0.19	6
Vermilion Energy Inc.	0.17	7
TAQA North Ltd.	0.14	8
Canlin Resources Partnership	0.13	9
Top Oil Production Ltd.	0.10	10
Obsidian Energy Ltd.	0.10	11
HWN Energy Ltd.	0.10	12
Torxen Energy Ltd.	0.09	13
Paramount Resources Ltd.	0.06	14
Cardinal Energy Ltd.	0.06	15
Spartan Delta Corp.	0.06	16
ARC Resources Ltd.	0.06	17
Journey Energy Inc.	0.05	18
Strathcona Resources Ltd.	0.05	19
Mancal Energy Inc.	0.05	20
Gran Tierra Canada Ltd.	0.05	21
InPlay Oil Corp.	0.05	22
Harvest Operations Corp.	0.04	23
Ish Energy Ltd.	0.04	24
Whitecap Partnership	0.04	25

Appendix 3 Summary of Emission Methodologies

Emission source	Methodology	Data source	Methane content (vol %)	Methane content applicability
Pneumatics	Facility Counts Component Counts Emission Factors	Petrinex National Inventory Report (2021), Clearstone (2018) Clearstone (2018), Prasino (2013), and Van Vilet (2018)	92	All
Venting: Routine & Nonroutine (2014 – 2019)	Reported Vent Volume	Petrinex	92 74 95	Natural Gas Crude Oil Primary Crude Bitumen
Venting: Routine (2020 – 2023)	Reported Vent Volume	OneStop	92 74 95	Natural Gas Crude Oil Battery Primary Crude Bitumen
Venting: Nonroutine Well Testing	Reported Vent Volume	ST60B	92	All
Venting: Nonroutine Compressor Blowdowns	Equipment Counts Emission Factors	OneStop Cheremisinoff (2016), Levelton Consultants (2014)	89 87	2014 to 2019 2020 onwards
Fugitive Emissions	Facility Counts Component Counts Emission Factors	Petrinex Greenpath (2016) Clearstone (2018)	92 74	Natural Gas (fuel gas) Crude Oil
Compressor Seals	Reported Vent Volume Equipment Counts Facility Counts	OneStop OneStop Petrinex	0.533 kg CH4/m3 0.582 kg CH4/m3 0.605 kg CH4/m3 0.603 kgCH4/m3	2014 to 2020 2021 2022 2023 onwards
Glycol Dehydrators	Facility Counts Reported Emissions Equipment Counts	Petrinex OneStop OneStop	OneStop	Methane Mass is reported to OneStop.
Methane Slip Fuel	Emission Factors Equipment Inventory	Accurata Inc, 2024 ECCC Engine Database	92	All

Emission source	Methodology	Data source	Methane content (vol %)	Methane content applicability
	Fuel Volume	Petrinex and ST98		
	Fuel Disposition	CAPP 2004		
Unlit Flares	Combustion Efficiency	Assumes 6% of flares at select	74	Crude Oil Battery
	Reported Flare Volume	sites are unlit (IEA, 2021)	92	Gas Battery
	Facility Counts	Petrinex	95	Crude Bitumen Battery
Surface Casing Vent Flows	Reported Vent Volume	ID 2003-01 Data	85	All
Spills and Ruptures	Reported Vent Volume	AER Incident Release Report	85	All