Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2023

January 2025

Alberta Energy Regulator
ST60B-2024: Upstream Petroleum Industry Emissions Report

January 2025

This report has been updated since its initial release in November 2024:

- Dehydrator counts in table 12 have been updated.
- Surface casing vent flow (SCVF) and gas migration (GM) counts and volumes in table 13 have been updated.
- Corrected report footer.

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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, 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. 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 2023 includes OneStop data since 2020 extracted in July 2024. The previous years' data includes amendments and late submissions, resulting in slightly different values than last year's report.

Key statistics from 2023:

Production (from ST98: Alberta Energy Outlook)

- Crude bitumen production increased by 2.8% to 197.9 10^6 m^3.
- Crude oil production increased by 5.2% to 29.7 10^6 m^3.
- Gas production increased by 1.9% to 115 000 10^6 m^3.

Fuel Use

- Total reported Petrinex fuel use decreased by 4.7% to 27.4 10^9 m^3.

Flaring

- Total reported Petrinex flaring increased by 6.7% to 1370.3 10^6 m^3.
- Solution gas flaring increased by 19.8% to 766.8 10^6 m^3. This is the first exceedance of the provincial solution gas flaring limit of 670.0 10^6 m^3.

Venting

- Total reported Petrinex venting decreased by 15.2% to 303.5 10^6 m^3.
- Solution gas venting decreased by 16.4% to 110.5 10^6 m^3.

Fugitive Emissions

- Total equipment-based fugitive emissions decreased 12.7% to 35.2 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 2023, Alberta has 10 736 unresolved surface casing vent flow and gas migration events emitting 93.0 10^6 m^3/year.

Methane Reduction

- Alberta met its 45% methane reduction target in 2022, three years ahead of schedule. Using both reported and estimated emissions, results from 2023 modelling indicate that Alberta has reduced methane emissions by 52% from 2014 levels.

1 Introduction

The mandate of the Alberta Energy Regulator (AER) is to ensure 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, 2024.

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

1.1 Important Notes for this Year's Report

Several vent gas limits came into effect as of January 1, 2023 (see section 8 of *Directive 060*):

- Emissions from pneumatics, compressors, and glycol dehydrators are now included in the overall vent gas limit.
- For level controllers installed before January 1, 2022, that emit vent gas, the duty holder must
  - prevent or control the vent gas or
  - evaluate the actuation frequency during normal operating conditions, and for level controllers that actuate between 0 and 15 minutes, use a relay designed to reduce or minimize transient or

dynamic venting or adjust the actuation frequency to ensure that the time between actuation is greater than 15 minutes.

- For pneumatic instruments other than level controllers installed before January 1, 2022, that emit vent gas, the duty holder must
  - prevent or control vent gas or
  - ensure instruments have a manufacturer-specified steady-state vent gas rate of less than 0.17 m^3/hr.

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 2024, the previous years' data includes amendments and late submissions, resulting in slightly different values than last year's report.

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 2022 to 2023.

Table 1. Number of facilities that must report methane emissions by subtype, 2019–2023

Facility subtype	2019	2020	2021	2022	2023	% change
Crude bitumen batteries	4 164	3 519	3 228	3 342	3 312	−0.90
Crude oil batteries	9 352	8 544	8 447	8 348	8 429	0.97
Gas batteries	10 452	9 508	8 957	8 455	8 660	2.42
Gas gathering/compressor stations	7 313	6 898	5 854	5 557	5 444	−2.03
Gas plants	553	531	511	501	501	0.00
Other	2 130	1 935	1 900	1 804	1 884	4.43
Total	**33 964**	**30 935**	**28 897**	**28 007**	**28 230**	**0.79**

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
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 2023, fuel gas use was 27.4 10^9 m^3.

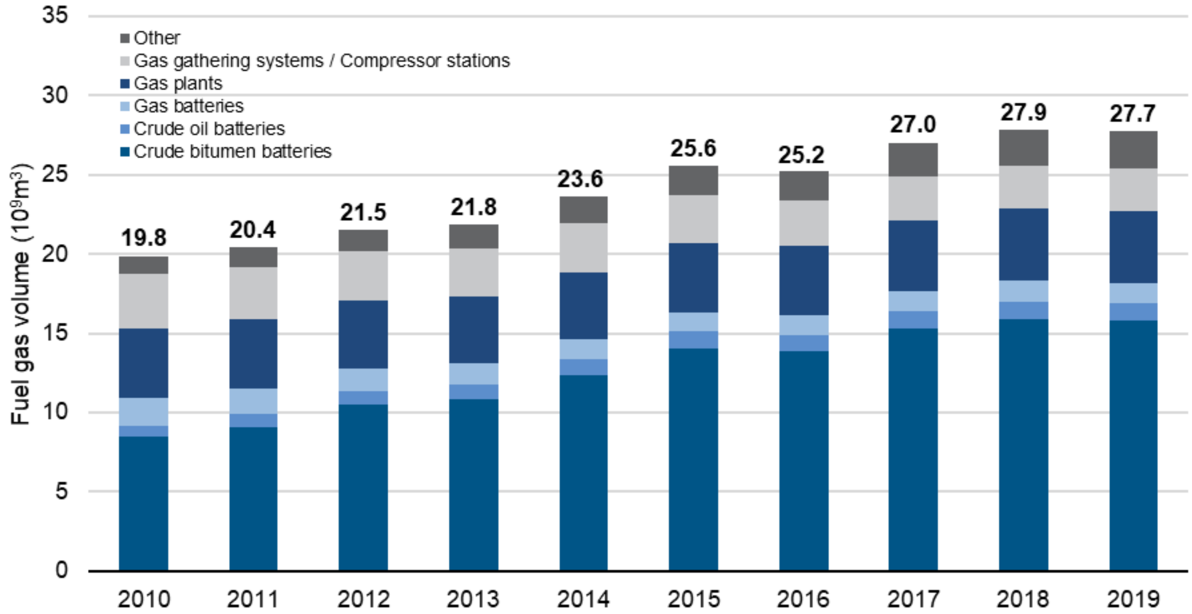


Figure 1. Fuel gas usage, 2010–2019 (Source: Petrinex)

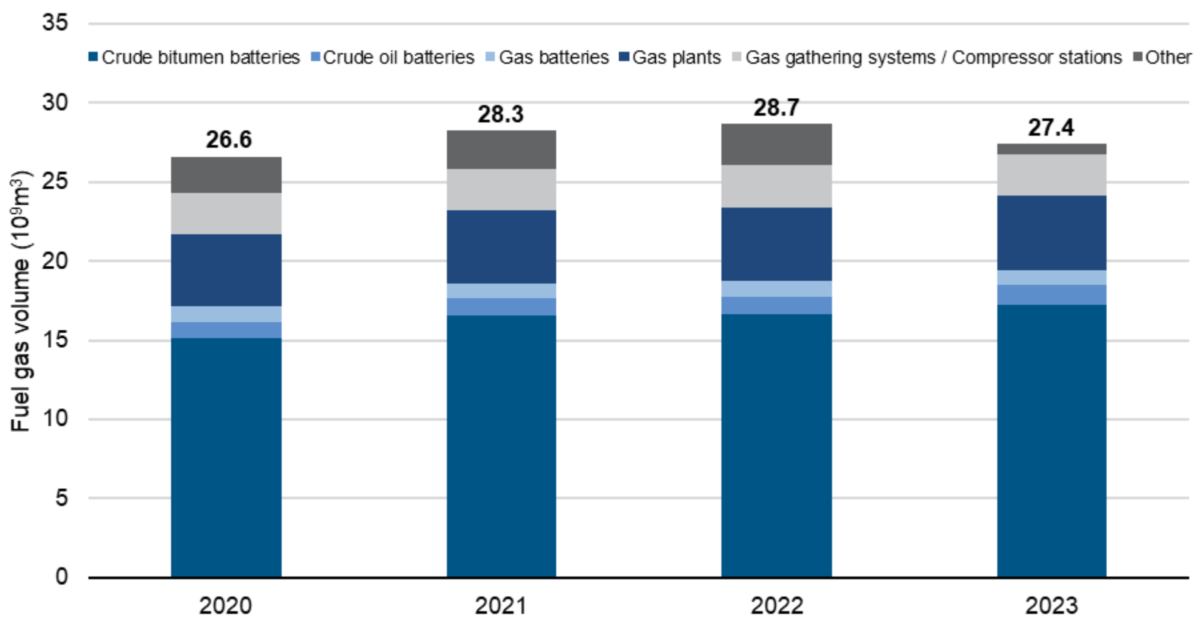


Figure 2. Fuel gas usage, 2020–2023 (Source: Petrinex)

Since 2010, fuel gas use has increased from about 19.8 10^9 m^3 to over 27.0 10^9 m^3 from 2017 to 2023, except in 2020. 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 been 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, 2020–2023, % change 2022–2023 (Source: Petrinex)

Facility subtype	2020 (10^9 m^3)	2021 (10^9 m^3)	2022 (10^9 m^3)	2023 (10^9 m^3)	% change
Crude bitumen battery	15.1	16.6	16.7	17.3	3.7
Crude oil battery	1.0	1.1	1.1	1.2	5.9
Gas battery	1.1	0.9	0.9	0.9	1.5
Gas gathering/compressor station	2.6	2.6	2.6	2.6	−1.4
Gas plant	4.5	4.6	4.7	4.7	0.8
Other	2.3	2.5	2.7	0.7	−75.4
Total	**26.6**	**28.3**	**28.7**	**27.4**	−4.6

3 Flaring

Flaring is the controlled destruction of gas occurring 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 but is presented in a subsequent section.

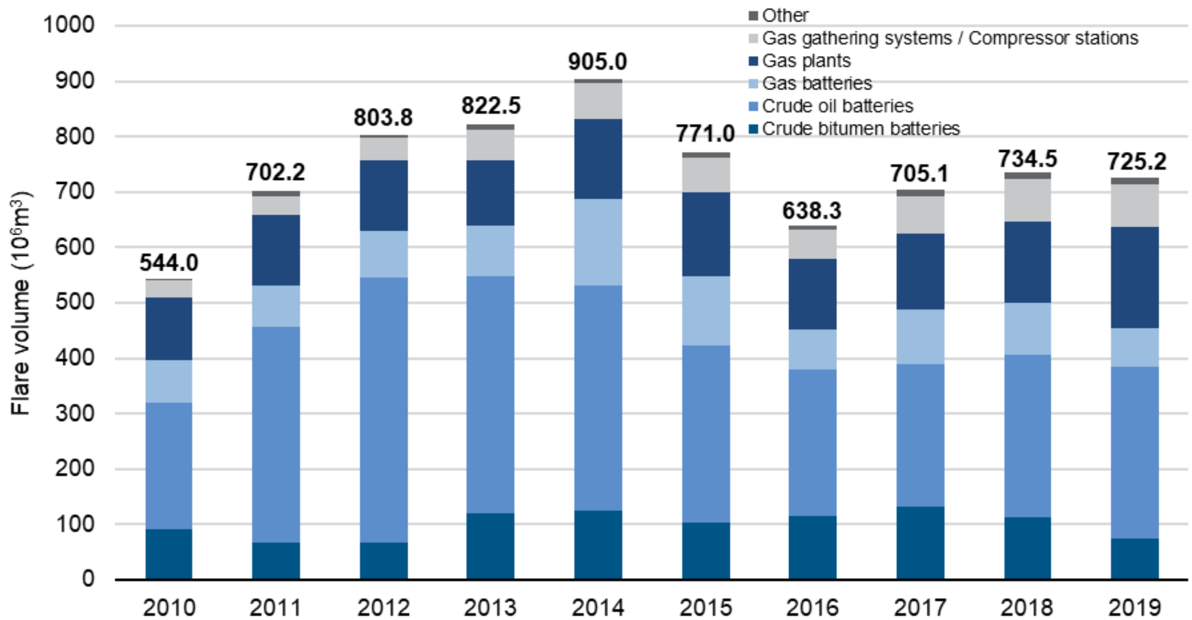


Figure 3. Flare volumes, 2010–2019 (Source: Petrinex)

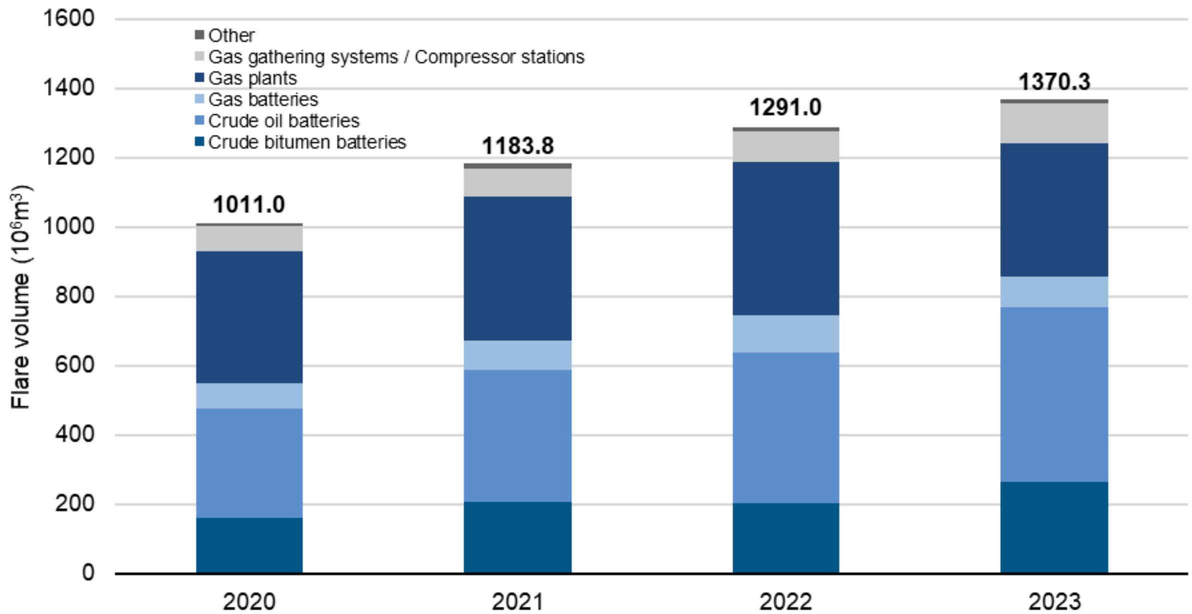


Figure 4. Flare volumes, 2020–2023 (Source: Petrinex)

3.1.1 Flaring Trends

In 2023, flaring volumes increased to 1370.3 10^6 m^3. This increase is likely because of increased crude oil and bitumen production, the changed definition, 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 batteries. This increase is likely because of the larger ratio of solution gas produced alongside oil production and new vent limits.

Table 4. Change in flared volume, 2020–2023, % change 2022–2023 (Source: Petrinex)

Facility subtype	2020 (10^6 m^3)	2021 (10^6 m^3)	2022 (10^6 m^3)	2023 (10^6 m^3)	% change
Crude bitumen battery	161.26	205.69	201.75	262.62	30.17
Crude oil battery	313.79	382.20	438.29	504.14	15.02
Gas battery	72.56	84.79	107.07	91.08	−14.94
Gas gathering/compressor station	73.55	81.86	86.02	112.19	30.42
Gas plant	380.71	413.80	443.27	385.86	−12.95
Other	9.14	15.23	12.92	14.21	10.02
Total	**1011.02**	**1183.83**	**1290.97**	**1370.34**	**6.27**

In addition to the increased total flare volumes in 2023, the flaring intensity also increased (see table 5). Solution gas flaring is analyzed further in section 6.

Table 5. Flaring intensity, 2020–2023 (Source: Petrinex)

Year	Province-wide BoE	Flare volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136	1 008 328 700	0.66
2021	1 611 841 179	1 179 519 400	0.73
2022	1 692 106 893	1 281 329 300	0.76
2023	1 735 675 816	1 497 148 900	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 2023 by volume and the percentage flared of the total gas received. The total amount of flaring from these top 30 gas plants (245.8 10^6 m^3) makes up about 63% of the total flaring at gas plants.

Table 6. Top 30 flaring gas plants, 2023 (Source: Petrinex)

Gas plant	Operator	Land location	2023 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001004	Keyera Energy Ltd.	02-05-044-01W5	36.98	1.74
ABGP0149088	Baytex Energy Ltd.	03-18-084-17W5	23.72	20.41
ABGP0001056	Pieridae Alberta Production Ltd.	02-20-004-30W4	15.45	1.52
ABGP0001662	Pieridae Alberta Production Ltd.	12-35-034-06W5	13.84	1.66
ABGP0118855	Pembina Gas Infrastructure Inc.	08-13-063-05W6	11.73	0.58
ABGP0001892	Ovintiv Canada ULC	04-08-075-07W6	11.05	0.56
ABGP0001147	Pembina Gas Infrastructure Inc.	11-18-074-12W6	10.78	0.28
ABGP0001037	Pieridae Alberta Production Ltd.	13-13-025-05W5	10.14	1.27
ABGP0001855	Obsidian Energy Ltd.	09-15-084-14W5	9.55	16.44
ABGP0001350	Cenovus Energy Inc.	01-08-070-11W6	7.61	0.55
ABGP0001084	Peyto Exploration & Development Corp.	04-11-053-18W5	6.53	0.67
ABGP0001623	Strathcona Resources Ltd.	06-08-062-03W6	6.46	0.81
ABGP0001144	Pembina Gas Infrastructure Inc.	03-15-059-18W5	6.05	0.34
ABGP0001901	Plains Midstream Canada ULC	10-11-020-01W4	5.63	0.04
ABGP0152315	AltaGas Ltd.	12-35-070-09W6	5.51	0.55
ABGP0001060	AltaGas Ltd.	09-27-031-04W5	5.48	0.15
ABGP0001113	Keyera Energy Ltd.	09-06-063-25W5	5.07	0.29
ABGP0150386	Keyera Energy Ltd.	04-07-073-08W6	4.77	0.21
ABGP0001107	Pembina Gas Infrastructure Inc.	01-12-062-20W5	4.68	0.41
ABGP0001129	Canadian Natural Resources Limited	13-26-067-05W6	4.57	0.44
ABGP0001134	Caledonian Midstream Corporation	02-04-021-04W5	4.35	4.08
ABGP0001506	Canadian Natural Resources Limited	01-01-078-10W6	4.25	0.30
ABGP0001130	Canlin Resources Partnership	02-27-040-03W5	4.13	3.86
ABGP0094954	Pembina Gas Infrastructure Inc.	08-11-060-03W6	4.12	0.16
ABGP0001902	Plains Midstream Canada ULC	04-12-020-01W4	4.12	0.01
ABGP0001520	NuVista Energy Ltd.	06-19-073-08W6	4.02	0.33
ABGP0145129	Pembina Gas Infrastructure Inc.	14-28-062-20W5	4.02	0.20
ABGP0001133	Keyera Energy Ltd.	11-35-037-09W5	3.95	0.18
ABGP0160735	TAQA North Ltd.	09-14-028-01W5	3.65	1.31
ABGP0107835	Advantage Energy Ltd.	05-02-076-12W6	3.44	0.10
Total			**245.78**	

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 2023, 920 well tests were completed, down from 923 tests reported in 2022 (see table 7). Since 2020, the average flaring volume per test has decreased and vent volumes per test increased.

Table 7. Well drilling and testing data, 2019–2023. (Source: COM, ST59)

Year	Total wells drilled	Number of well tests	Total flare volume during well tests (10^3 m^3)	Average flare per test (10^3 m^3)	Total vent volume during well tests (10^3 m^3)	Average vent per test (10^3 m^3)
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

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; new 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 greater emission breakdowns by source type.

In the 2023 data, a gap between reported volumes was observed once again in the total vent volumes reported to Petrinex and the defined vent gas (DVG) volumes (from pneumatics, compressors, and dehydrators) reported to OneStop. However, the gap has decreased significantly compared with previous years, and Petrinex vent volumes were lower than OneStop. 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 (excluding fugitive volumes).

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 2023, vent gas reported in Petrinex was 303.5 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 2022 in all facility subtypes. This decrease is mainly due to the various equipment-level vent limits that took effect in 2022 and January 1, 2023.

As shown in table 9, vent gas volumes reported in 2023 decreased relative to 2020, when the reporting definitions changed. Considering production volumes, 2023 had the lowest venting intensity of the past four years.

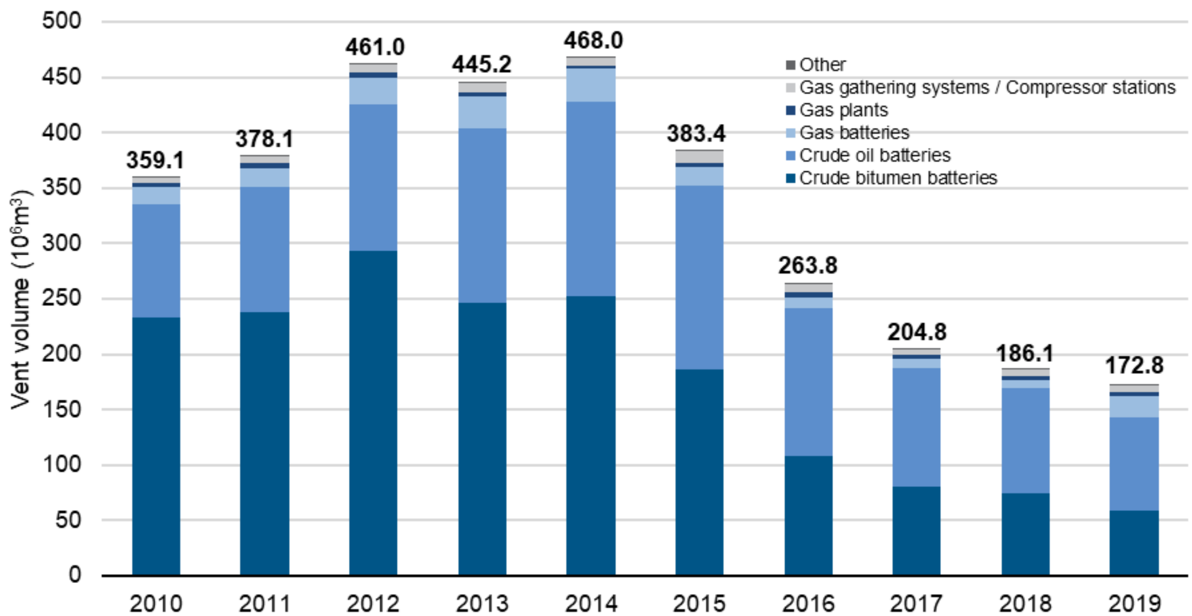


Figure 5. Vent volumes, 2010–2019 (Source: Petrinex)

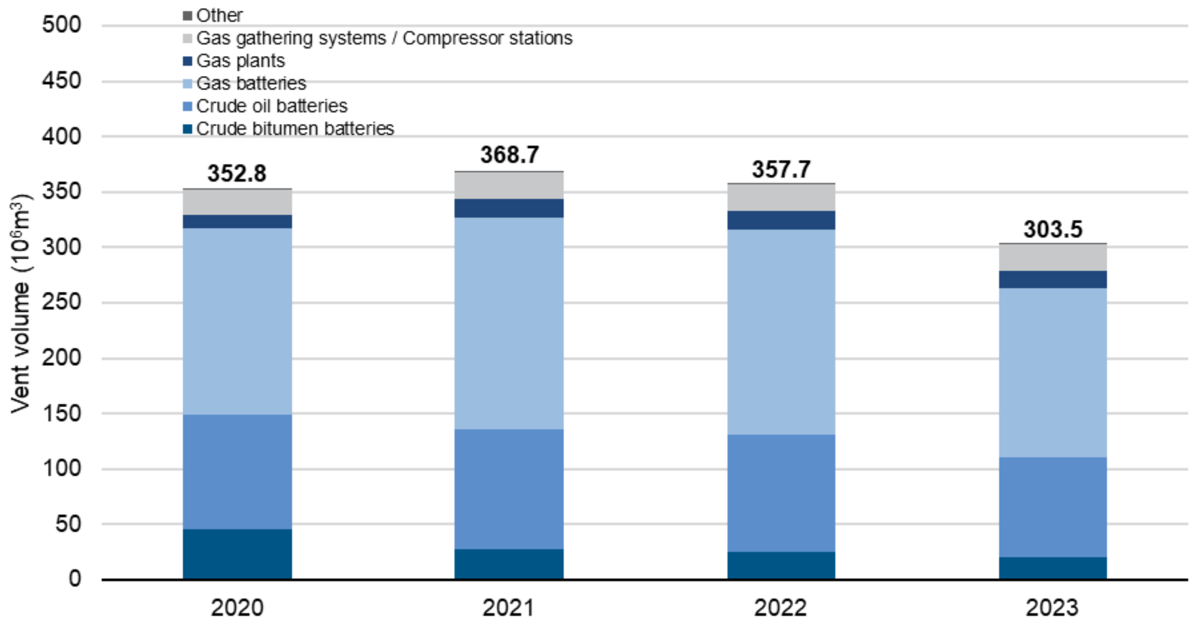


Figure 6. Vent volumes, 2020–2023 (Source: Petrinex)

Table 8. Change in vented volumes 2020–2023, % change 2021–2023 (Source: Petrinex)

Facility Subtype	2020 (10^6 m³)	2021 (10^6 m³)	2022 (10^6 m³)	2023 (10^6 m³)	% change
Crude bitumen battery	46.0	28.0	25.6	20.1	−21.51
Crude oil battery	103.3	107.7	105.8	90.4	−14.65
Gas battery	167.9	191.6	184.1	152.8	−17.03
Gas gathering/compressor station	22.4	24.9	24.3	24.3	−0.26
Gas plant	12.4	16.0	16.8	15.1	−10.15
Other	0.8	0.5	0.9	0.85	−4.43
Total	**352.8**	**368.7**	**357.7**	**303.5**	**−15.15**

Table 9. Venting intensity, 2020–2023 (Source: Petrinex)

Year	Province-wide BoE	Vent volume (m³)	Intensity (m³/BoE)
2020	1 517 386 136	352 757 700	0.23
2021	1 611 841 179	369 448 500	0.23
2022	1 692 106 893	352 142 200	0.21
2023	1 735 675 816	301 199 200	0.17

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 2023, total emissions reported to OneStop were 343.4 10^6 m^3, a significant decrease from 2022 (415.3 10^6 m^3). This decrease is attributable to numerous vent limits that came into effect in 2022 and 2023. 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 represents most of the facilities required to report; as of July 15, 2024, 92.7% of the facilities had reported annual methane data to OneStop.

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. 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.

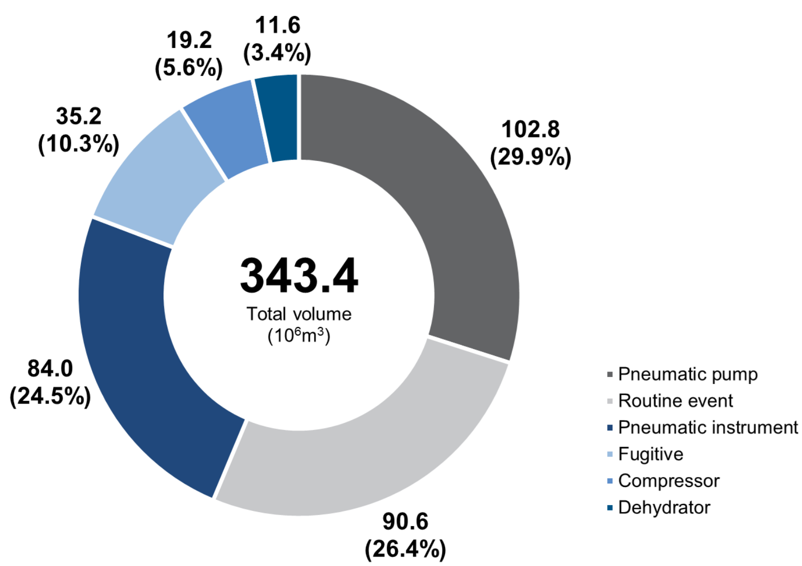


Figure 7. Total emissions by source, 2023 (Source: OneStop)

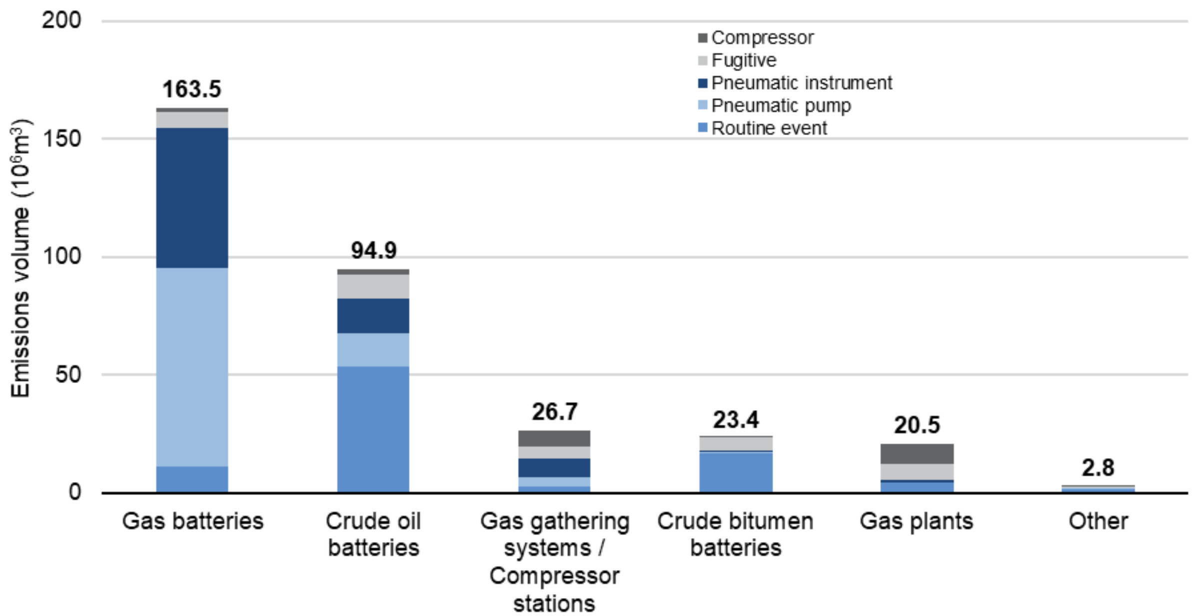


Figure 8. Total emissions by source and facility subtype, 2023 (Source: OneStop)

Figure 9 shows a side-by-side comparison of the OneStop emissions data for 2020 to 2023. Year-over-year comparisons demonstrate a continued decline from peak emissions in 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 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 2022 and 2023. 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, 2024, 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.

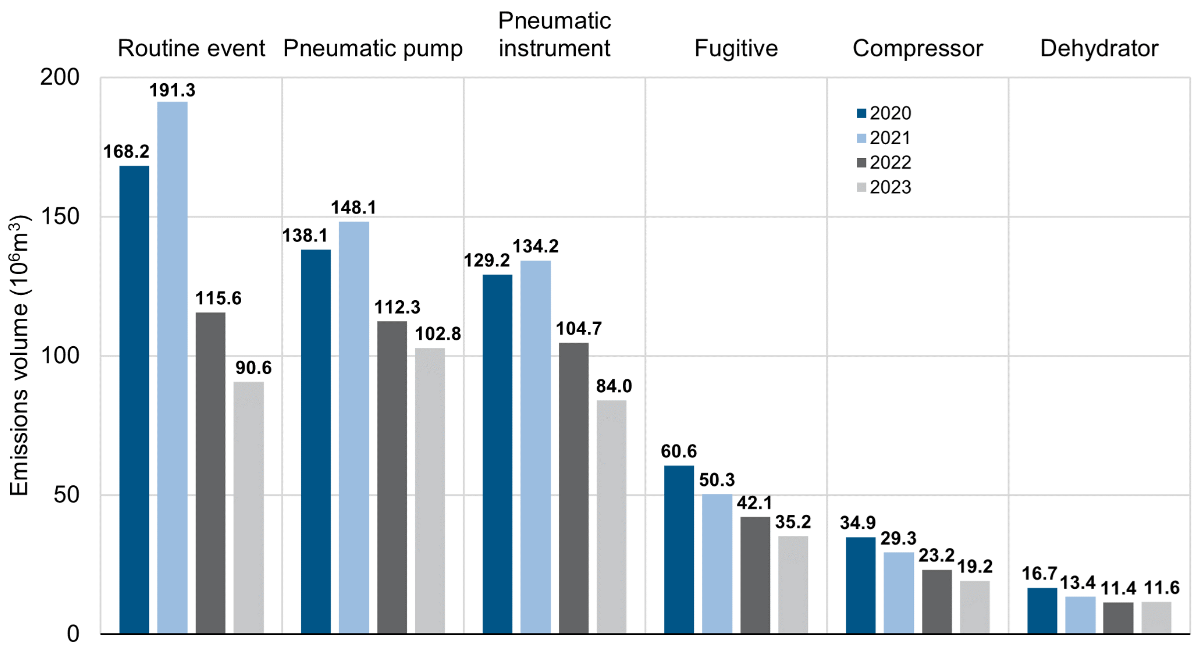


Figure 9. Comparison of emissions volumes by source, 2020–2023 (Source: OneStop)

Table 10. Top ten absolute differences in reported venting volumes, 2022–2023 (Source: OneStop)

Operator	2022 (10^3 m³)	2023 (10^3 m³)	Difference (10^3 m³)
Canadian Natural Resources Limited	72.79	51.61	-21.18
Vermilion Energy Inc.	4.39	12.55	8.16
Cenovus Energy Inc.	29.08	24.72	-4.36
Peyto Exploration & Development Corp.	13.30	9.02	-4.27
Pine Cliff Energy Ltd.	3.45	6.98	3.53
Long Run Exploration Ltd.	4.37	1.21	-3.16
CSV Midstream Solutions Corp.	3.05	0.09	-2.96
Paramount Resources Ltd.	8.23	5.42	-2.81
Tourmaline Oil Corp.	36.77	34.51	-2.26
Westbrick Energy Ltd.	8.82	6.58	-2.24

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 2023, total DVG emissions reported to OneStop were 90.6 10^6 m^3 (see figure 10), about 26% of all emissions reported to OneStop, a 20.3% reduction from the reported 2022 volumes. Crude oil batteries contribute the most DVG emissions by volume. Given the greater likelihood of storage tanks at these sites, it is reasonable to assume tanks are a significant contributor in this category.

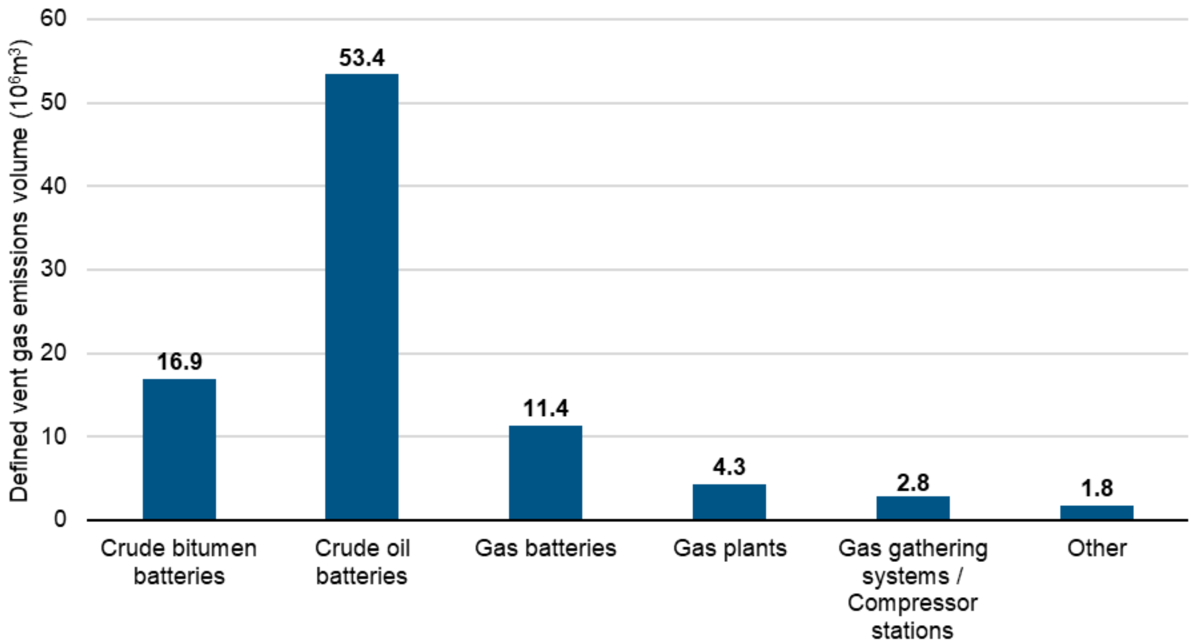


Figure 10. Total DVG emissions by facility subtype, 2023 (Source: OneStop)

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. New equipment-level limits came into effect 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 instruments other than level controllers for pneumatic instruments installed on or before January 1, 2022.

In 2023, emissions reported to OneStop for pneumatic devices (instruments and pumps) were 186.85 10^6 m^3, about 55% of all emissions reported to OneStop, a 17.3% decrease from the reported 2022 volumes. Gas batteries were the most significant contributor, representing about 77% 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.

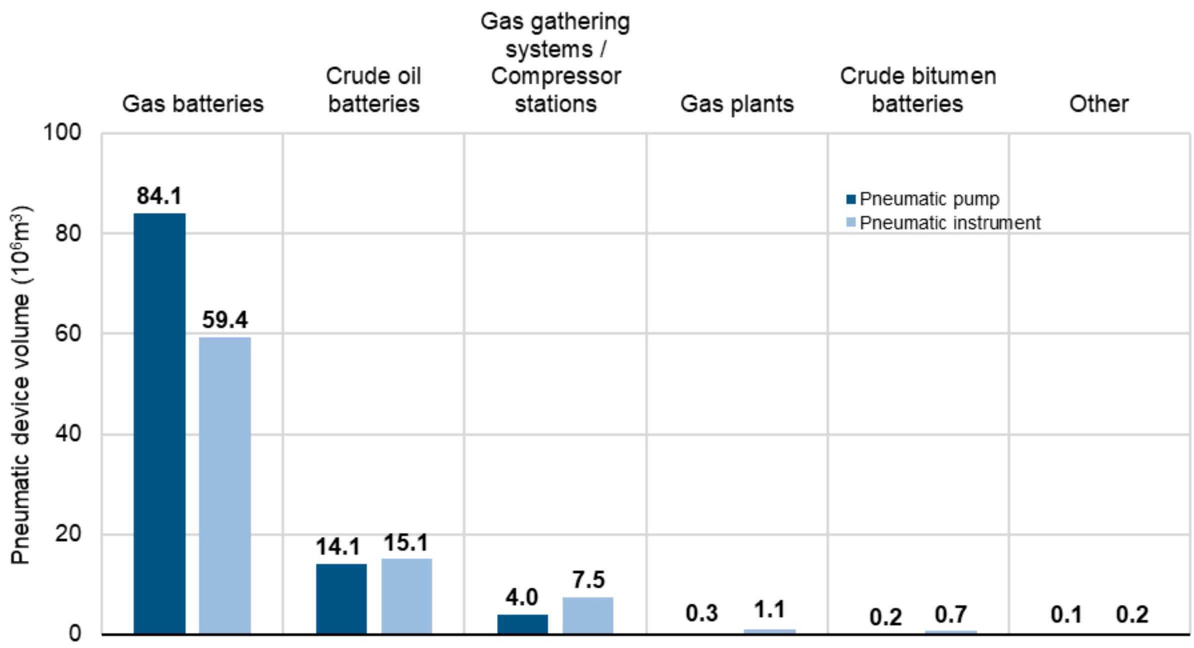


Figure 11. Pneumatic device emissions by facility subtype, 2023 (Source: OneStop)

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. 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 2023, 3338 reciprocating compressors and 110 centrifugal compressors were reported, a decrease from 3430 reciprocating compressors and 132 centrifugal compressors in 2022.

4.2.4.2 Compressor Seal Emissions

In 2023, reciprocating compressor seal emissions reported to OneStop were 16.08 $10^6 m^3$, roughly 4.6% of all emissions reported to OneStop. Centrifugal compressor seal emissions reported to OneStop were 0.47 $10^6 m^3$, a minor contributor relative to the other emission sources reported here, representing only 0.13% 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.

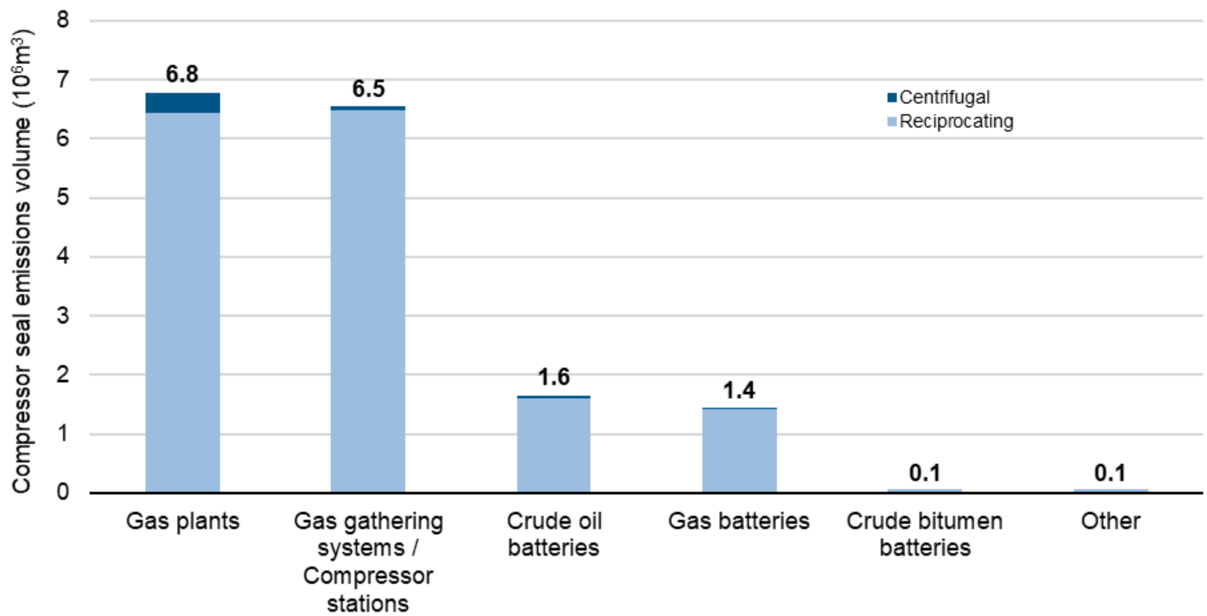


Figure 12. Compressor inventory vent volumes by compressor type and facility subtype (Source: OneStop)

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. Highlighted cells represent fleet averages exceeding vent limits.

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 2023 reported values.

Table 11. Top 20 compressor inventory venting operators with RCS fleet average, 2023 (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	3.42	517	1752	0.22
Pembina Gas Infrastructure Inc.	1.04	172	619	0.26
Tourmaline Oil Corp.	0.65	139	480	0.16
I3 Energy Canada Ltd.	0.61	51	174	0.56
Spartan Delta Corp.	0.60	42	160	0.47
Peyto Exploration & Development Corp.	0.59	127	441	0.24
TAQA North Ltd.	0.55	94	304	0.24
Cenovus Energy Inc.	0.49	74	244	0.29

Operator	Vent volume (10^6 m^3)	Number of compressors	Number of throws	Average of vent gas from RCS fleet*
Keyera Energy Ltd.	0.40	93	298	0.13
Pine Cliff Energy Ltd.	0.38	78	288	0.14
Canlin Resources Partnership	0.37	72	276	0.14
ARC Resources Ltd.	0.35	124	453	0.11
AltaGas Ltd.	0.34	51	178	0.19
Whitecap Resources Inc.	0.29	94	297	0.18
Journey Energy Inc.	0.26	24	68	0.59
Ember Resources Inc.	0.24	101	385	0.08
Westbrick Energy Ltd.	0.22	66	221	0.16
Birchcliff Energy Ltd.	0.21	28	108	0.29
HWN Energy Ltd.	0.21	38	116	0.19
Vermilion Energy Inc.	0.21	24	74	0.34

* 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 2023, there were 1329 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 2023. Table 12 shows the counts of all operating glycol dehydrators per year over the past 14 years.

Table 12. Number of operating glycol dehydrators, 2010–2023 (Source: OneStop)

Year	Number of dehydrators
2010	2107
2011	2006
2012	1985
2013	1905
2014	1886
2015	1778
2016	1646
2017	1528
2018	1399
2019	1331
2020	1366

Year	Number of dehydrators
2021	1241
2022	1244
2023	1329

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 2023, glycol dehydrator emissions were calculated to be 11.1 10^6 m^3, representing 3.2% of all emissions reported to OneStop, a 3.5% reduction from the reported 2022 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 2023, fugitive emissions were 35.2 10^6 m^3 (see figure 13), representing 10.3% of all emissions reported to OneStop, a 12.8% reduction in the reported 2022 volumes.

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.

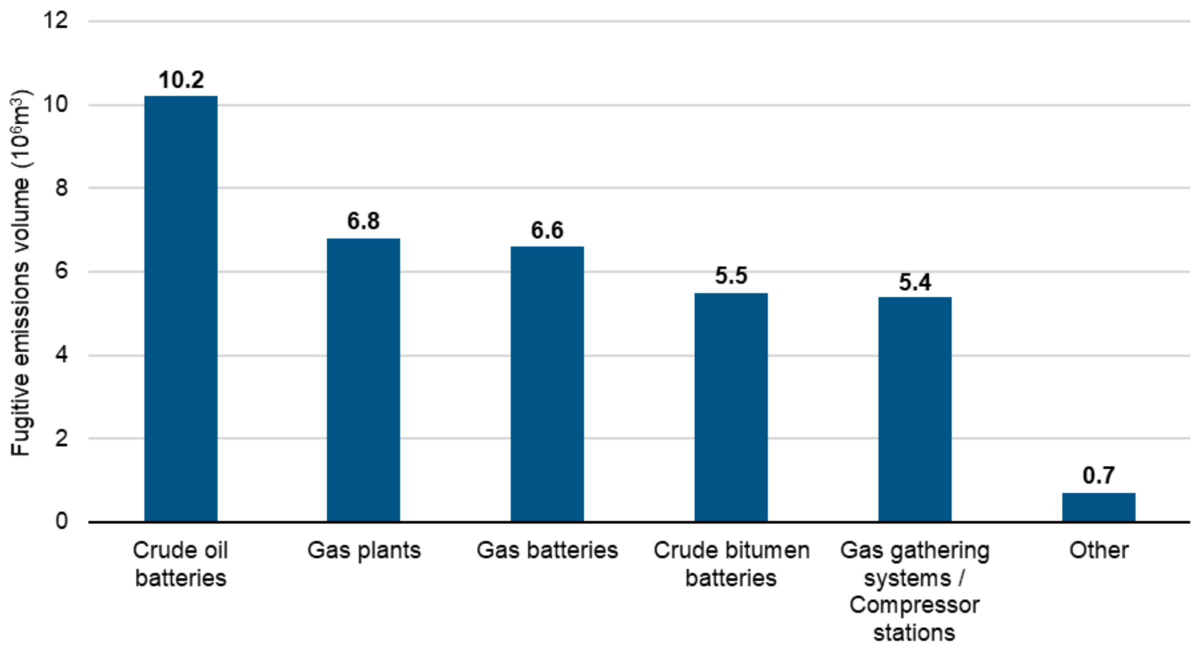


Figure 13. Fugitive emissions volume by facility subtype, 2023 (Source: OneStop)

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.

Table 13 shows the number of unresolved wells with SCVF, GM, or both and their respective emissions.

Table 13. Emissions from SCVFs and GM at unrepaired wells

Year	Number of wells with unresolved SCVFs, GM, or both	Annual natural gas emissions (10^6 m^3)
2010	4 256	43
2011	4 741	48
2012	5 307	50
2013	5 711	52
2014	6 290	59
2015	6 840	63
2016	7 346	68
2017	8 029	72
2018	8 569	77
2019	9 071	81
2020	9 502	84
2021	10 037	88
2022	10 689	94
2023	10 736	93

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. 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.

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.

6 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 Alberta solution gas flaring limit is 670.0 10^6 m^3 per year.

The 2007 version of *Directive 060* emphasized solution gas conservation and 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.

6.1 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 14, 766.8 10^6 m^3 of solution gas was flared in 2023, which was a 19.8% increase over 2022 and is a 14.4% exceedance of the annual solution gas flaring limit (96.8 10^6 m^3 above the 670.0 10^6 m^3 solution flaring limit). This exceedance volume is a first; consequently, the AER has engaged and instructed the 20 highest-flaring operators with company-wide conservation below 90% to present plans to achieve above 90% conservation. 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, and an increase due to the combustion of previously vented methane to achieve methane compliance.

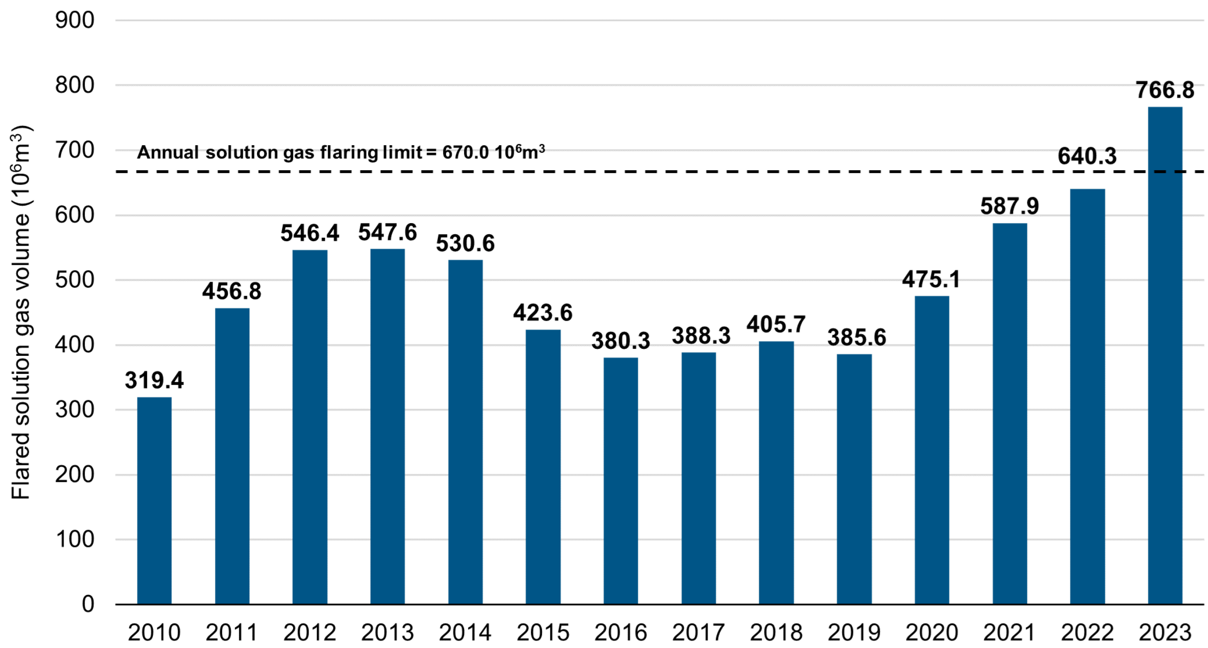


Figure 14. Solution gas flaring from oil and bitumen production, 2010–2023 (Source: Petrinex)

6.2 Solution Gas Venting

In 2023, 110.5 10^6 m^3 of solution gas was vented from crude oil and crude bitumen batteries, a 16% decrease from 2022. 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 15).

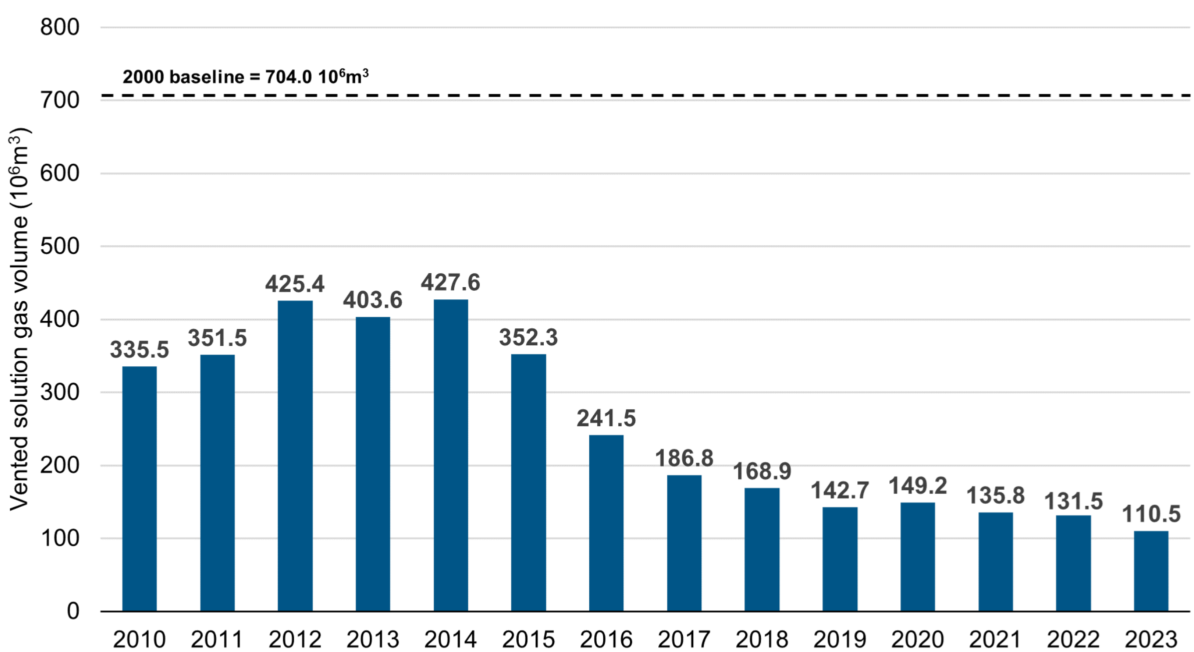


Figure 15. Solution gas venting from oil and bitumen production, 2010–2023 (Source: Petrinex)

6.3 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 2023, 96.86% of the solution gas produced from crude oil and crude bitumen batteries was conserved, down slightly from 97.12% in 2022.

Figure 16 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.

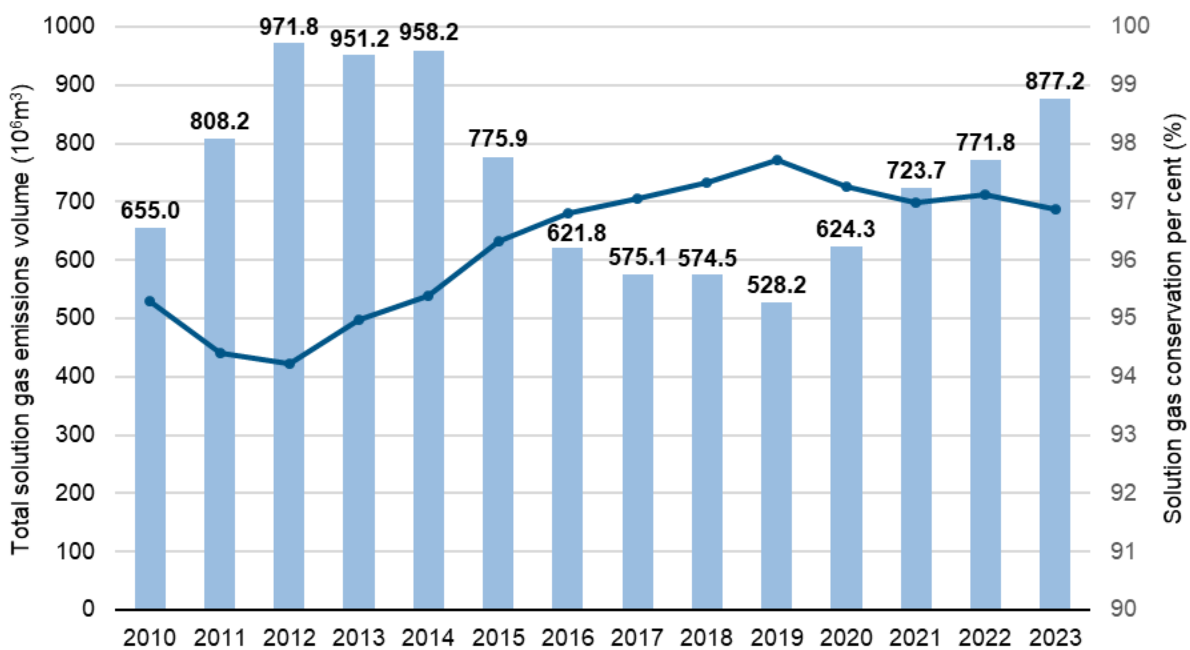


Figure 16. Solution gas emissions and conservation from oil and bitumen production, 2010–2023 (Source: Petrinex)

6.4 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 17 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 2023. Thermal operations conservation is 98.1%, whereas nonthermal operations have a conservation rate of 89.4%.

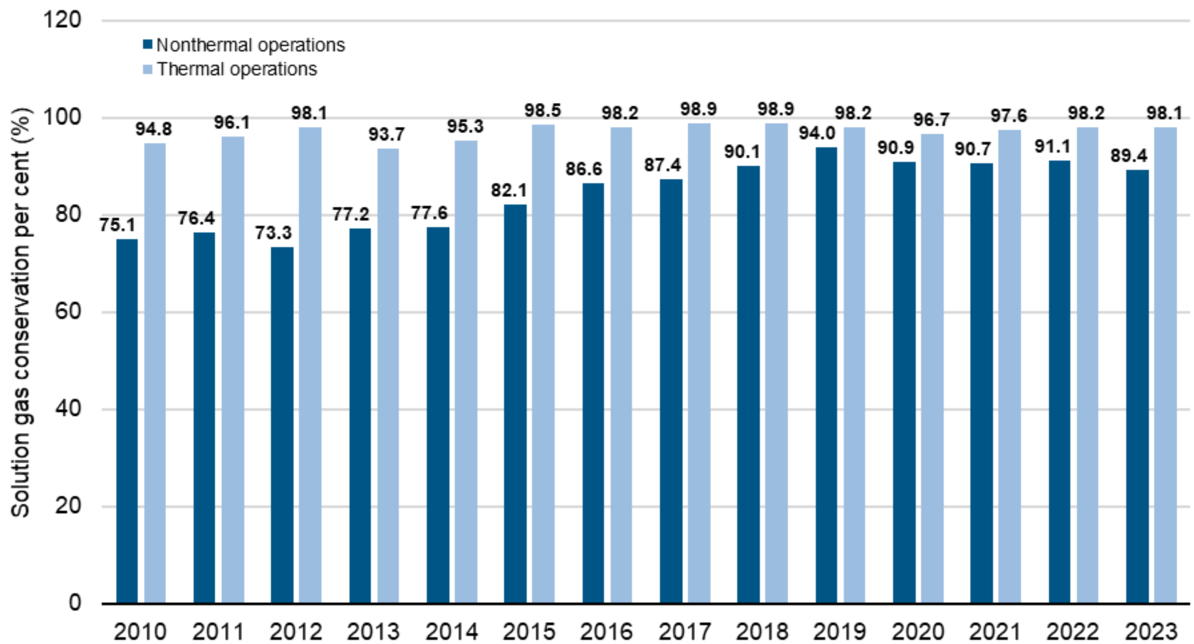


Figure 17. Solution gas conversation by operation type, 2010–2023 (Source: Petrinex)

7 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 have 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 18 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.

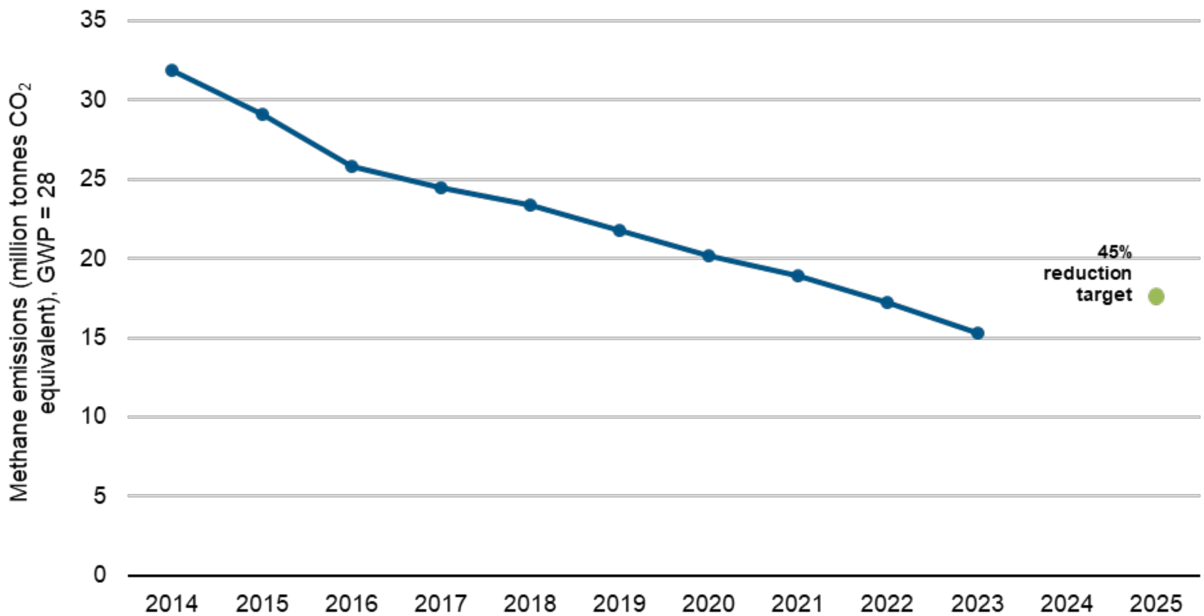
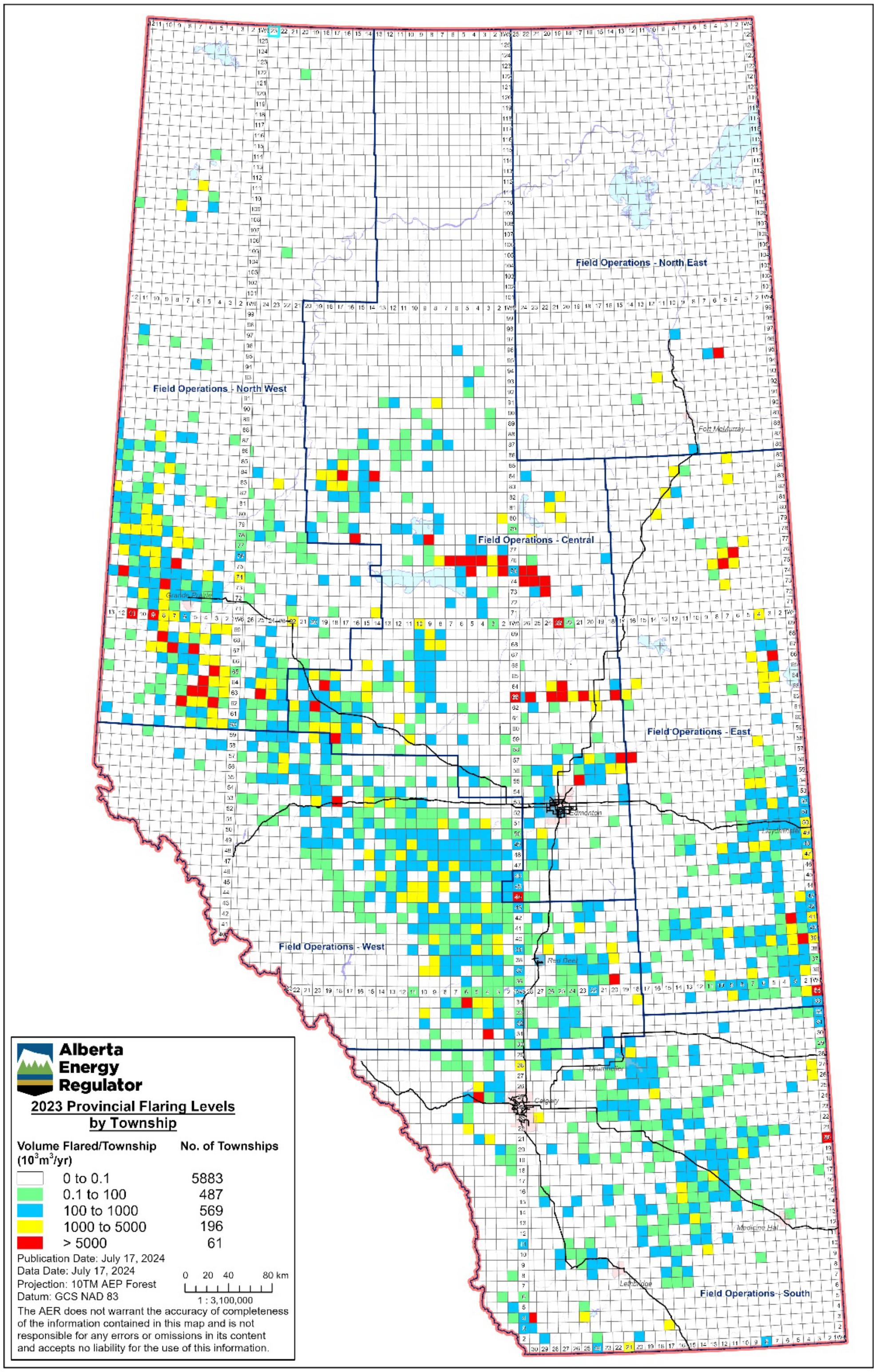


Figure 18. Methane emission reductions, 2014–2023 (reported and estimated emissions)

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 about 52% between 2014 and 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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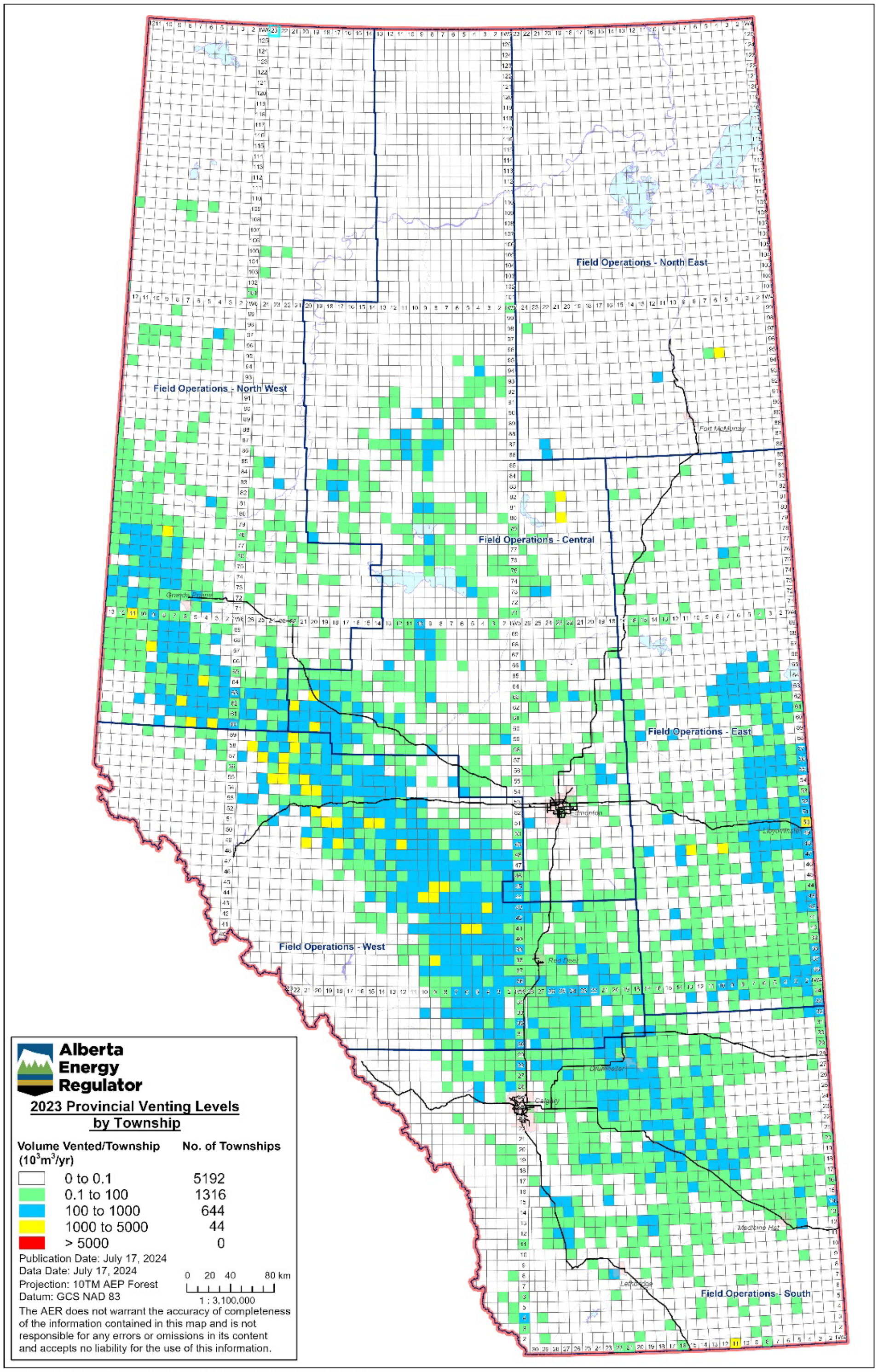

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Appendix 2 Operator Rankings

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, 2024.

Venting

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2023-2022)
Suncor Energy Inc.	1 394 500	1	102 058 587	0.01366	0.00357	0.0101
Canadian Natural Resources Limited	367 500	2	148 125 964	0.00248	0.001328	0.0012
Imperial Oil Resources Limited	196 900	3	55 622 020	0.00354	0.001856	0.0017
Cenovus Energy Inc.	163 100	4	192 412 881	0.00085	0.001719	-0.0009
CNOOC Petroleum North America ULC	127 100	5	26 902 997	0.00472	0.00132	0.0034
Harvest Operations Corp.	42 300	6	3 138 377	0.01348	0.01331	0.0002
MEG Energy Corp.	35 200	7	41 168 462	0.00085	0.00382	-0.0030
Athabasca Oil Corporation	22 600	8	12 277 912	0.00184	0.00211	-0.0003
Greenfire Resources Operating Corporation	5 900	9	9 119 693	0.00065	0.00270	-0.0021
PetroChina Canada Ltd.	100	10	3 976 216	0.00251	0.00080	-0.0008

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Canadian Natural Resources Limited	48 396 400	1	102 518 551	0.47	0.65	-27.69
Tourmaline Oil Corp.	35 775 200	2	114 219 471	0.31	0.35	-11.43
Cenovus Energy Inc.	22 851 300	3	49 210 501	0.46	0.52	-11.54
Peyto Exploration & Development Corp.	11 256 800	4	45 131 459	0.25	0.33	-24.24
Whitecap Resources Inc.	10 072 100	5	32 379 823	0.31	0.25	24.00
TAQA North Ltd.	7 908 000	6	22 444 406	0.35	0.39	-10.26
Pine Cliff Energy Ltd.	6 928 600	7	8 876 250	0.78	0.20	290.00
Westbrick Energy Ltd.	6 594 100	8	18 041 042	0.37	0.45	-17.78
Torxen Energy Ltd.	5 629 700	9	22 040 245	0.26	0.31	-16.13
Paramount Resources Ltd.	5 343 000	10	24 047 655	0.22	0.35	-37.14
Spartan Delta Corp.	4 857 100	11	13 090 327	0.37	0.47	-21.28

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
HWN Energy Ltd.	4 789 700	12	5 454 384	0.88	0.95	-7.37
Cardinal Energy Ltd.	4 275 100	13	6 128 707	0.70	0.66	6.06
Obsidian Energy Ltd.	4 250 100	14	8 093 263	0.53	0.60	-11.67
Vermilion Energy Inc.	3 950 000	15	9 584 880	0.41	0.40	2.50
I3 Energy Canada Ltd.	3 715 200	16	5 890 944	0.63	0.80	-21.25
ARC Resources Ltd.	3 598 900	17	66 243 923	0.05	0.07	-28.57
Mancal Energy Inc.	3 384 500	18	4 203 761	0.81	0.82	-1.22
Ember Resources Inc.	3 380 900	19	16 597 436	0.20	0.23	-13.04
Harvest Operations Corp.	3 072 400	20	3 233 991	0.95	0.94	1.06
Strathcona Resources Ltd.	3 009 700	21	20 489 871	0.15	0.18	-16.67
Top Oil Production Ltd.	2 647 900	22	225 377	11.75	3.40	245.59
Lynx Energy ULC	2 379 300	23	6 906 578	0.34	0.34	0.00
Surge Energy Inc.	2 268 500	24	5 433 711	0.42	0.37	13.51
Karve Energy Inc.	2 236 300	25	2 755 240	0.81	0.99	-18.18

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Canadian Natural Resources Limited	48 763 900	1	250 644 516	0.19	0.27	-34.78
Tourmaline Oil Corp.	35 775 200	2	114 219 471	0.31	0.35	-12.12
Cenovus Energy Inc.	23 014 400	3	241 623 382	0.10	0.11	-9.52
Peyto Exploration & Development Corp.	11 256 800	4	45 131 459	0.25	0.33	-27.59
Whitecap Resources Inc.	10 072 100	5	32 379 823	0.31	0.25	21.43
TAQA North Ltd.	7 908 000	6	22 444 406	0.35	0.39	-10.81
Pine Cliff Energy Ltd.	6 928 600	7	8 876 250	0.78	0.20	118.37
Westbrick Energy Ltd.	6 594 100	8	18 041 042	0.37	0.45	-19.51
Torxen Energy Ltd.	5 629 700	9	22 040 245	0.26	0.31	-17.54
Paramount Resources Ltd.	5 343 000	10	24 047 680	0.22	0.35	-45.61
Spartan Delta Corp.	4 857 100	11	13 090 327	0.37	0.47	-23.81
HWN Energy Ltd.	4 789 700	12	5 454 384	0.88	0.95	-7.65
Cardinal Energy Ltd.	4 275 100	13	6 128 707	0.70	0.66	5.88
Obsidian Energy Ltd.	4 250 100	14	10 464 784	0.41	0.46	-11.49
Vermilion Energy Inc.	3 950 000	15	9 584 880	0.41	0.40	2.47
I3 Energy Canada Ltd.	3 715 200	16	5 890 944	0.63	0.80	-23.78
ARC Resources Ltd.	3 598 900	17	66 243 923	0.05	0.07	-33.33
Mancal Energy Inc.	3 384 500	18	4 203 761	0.81	0.82	-1.23
Ember Resources Inc.	3 380 900	19	16 597 436	0.20	0.23	-13.95
Harvest Operations Corp.	3 114 700	20	6 372 368	0.49	0.47	4.17

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Strathcona Resources Ltd.	3 009 700	21	43 134 289	0.07	0.09	-25.00
Top Oil Production Ltd.	2 647 900	22	225 416	11.75	3.40	110.23
Lynx Energy ULC	2 379 300	23	6 906 578	0.34	0.34	0.00
Surge Energy Inc.	2 268 500	24	5 433 711	0.42	0.37	12.66
Karve Energy Inc.	2 236 300	25	2 793 225	0.80	0.98	-20.22

Flaring

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2023-2022)
Suncor Energy Inc.	28 626 300	1	102 058 587	0.28050	0.29610	-0.0156
Canadian Natural Resources Limited	13 732 200	2	148 125 965	0.09270	0.04860	0.0441
Imperial Oil Resources Limited	10 371 500	3	55 622 020	0.18650	0.12600	0.0605
Cenovus Energy Inc.	8 595 800	4	192 412 881	0.04470	0.01970	0.0250
Strathcona Resources Ltd.	6 046 100	5	22 644 418	0.26700	0.32130	-0.0543
MEG Energy Corp.	3 569 500	6	41 168 462	0.08670	0.11520	-0.0285
Greenfire Resources Operating Corporation	2 895 000	7	9 119 694	0.31740	0.37890	-0.0615
Connacher Oil And Gas Limited	2 664 900	8	6 250 600	0.42630	0.40680	0.0195
CNOOC Petroleum North America ULC	2 504 700	9	26 902 998	0.09310	0.08640	0.0067
Harvest Operations Corp.	1 504 500	10	3 138 377	0.47940	0.44430	0.0351
Athabasca Oil Corporation	460 300	11	12 277 913	0.03750	0.04370	-0.0062
PetroChina Canada Ltd.	100	12	3 976 217	0.00003	0.00002	0.00001

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Tamarack Valley Energy Ltd.	182 829 700	1	18 187 999	10.05	7.96	26.26
Baytex Energy Ltd.	69 266 200	2	5 253 840	13.18	7.63	72.74
Canadian Natural Resources Limited	68 857 700	3	102 518 551	0.67	0.72	-6.94
Headwater Exploration Inc.	61 109 500	4	1 222 999	49.97	38.83	28.69
Spur Petroleum Ltd.	60 588 800	5	8 308 883	7.29	7.75	-5.94
ARC Resources Ltd.	47 581 700	6	66 243 923	0.72	0.84	-14.29
Pieridae Alberta Production Ltd.	46 708 600	7	4 738 926	9.86	4.47	120.58
Cenovus Energy Inc.	33 288 600	8	49 210 501	0.68	0.55	23.64
Rubellite Energy Inc.	26 247 100	9	1 436 901	18.27	11.69	56.29
Whitecap Resources Inc.	22 645 800	10	32 379 823	0.70	0.46	52.17
Veren Inc.	22 160 600	11	36 241 882	0.61	0.84	-27.38
Obsidian Energy Ltd.	22 137 100	12	8 093 263	2.74	3.02	-9.27
Tourmaline Oil Corp.	19 562 300	13	114 219 471	0.17	0.20	-15.00
West Lake Energy Corp.	16 849 700	14	3 051 696	5.52	4.31	28.07
Ovintiv Canada ULC	15 973 700	15	19 948 969	0.80	0.86	-6.98
Peyto Exploration & Development Corp.	12 908 300	16	45 131 459	0.29	0.40	-27.50
Paramount Resources Ltd.	12 416 900	17	24 047 655	0.52	0.52	0.00
Strathcona Resources Ltd.	12 132 700	18	20 489 871	0.59	0.69	-14.49
Surge Energy Inc.	11 997 200	19	5 433 711	2.21	2.91	-24.05

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
TAQA North Ltd.	11 481 100	20	22 444 406	0.51	0.53	-3.77
NuVista Energy Ltd.	11 342 500	21	21 034 432	0.54	0.61	-11.48
Astara Energy Corp.	10 865 100	22	3 633 322	2.99	1.24	141.13
Cardinal Energy Ltd.	10 109 200	23	6 128 707	1.65	1.67	-1.20
Conifer Energy Inc.	9 507 500	24	2 284 116	4.16	3.70	12.43
IPC Canada Ltd.	9 430 800	25	12 432 101	0.76	0.65	16.92

Combined

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Tamarack Valley Energy Ltd.	182 829 700	1	23 641 509	7.73	6.14	25.90
Canadian Natural Resources Limited	82 589 900	2	250 644 516	0.33	0.32	3.13
Baytex Energy Ltd.	69 266 200	3	15 859 766	4.37	2.86	52.80
Headwater Exploration Inc.	61 109 500	4	7 655 555	7.98	6.18	29.13
Spur Petroleum Ltd.	60 588 800	5	14 383 836	4.21	4.48	-6.03
ARC Resources Ltd.	47 581 700	6	66 243 923	0.72	0.84	-14.29
Pieridae Alberta Production Ltd.	46 708 600	7	4 738 926	9.86	4.47	120.58
Cenovus Energy Inc.	41 884 400	8	241 623 382	0.17	0.13	30.77
Suncor Energy Inc.	28 626 300	9	102 304 906	0.28	0.30	-6.67
Rubellite Energy Inc.	26 247 100	10	1 868 429	14.05	8.36	68.06
Whitecap Resources Inc.	22 645 800	11	32 379 823	0.70	0.46	52.17
Veren Inc.	22 160 600	12	36 241 882	0.61	0.84	-27.38
Obsidian Energy Ltd.	22 137 100	13	10 464 784	2.12	2.32	-8.62
Tourmaline Oil Corp.	19 562 300	14	114 219 471	0.17	0.20	-15.00
Strathcona Resources Ltd.	18 178 800	15	43 134 289	0.42	0.50	-16.00
West Lake Energy Corp.	16 849 700	16	3 077 091	5.48	4.26	28.64
Ovintiv Canada ULC	15 973 700	17	19 948 969	0.80	0.86	-6.98
Peyto Exploration & Development Corp.	12 908 300	18	45 131 459	0.29	0.40	-27.50
Paramount Resources Ltd.	12 416 900	19	24 047 680	0.52	0.52	0.00
Surge Energy Inc.	11 997 200	20	5 433 711	2.21	2.91	-24.05
TAQA North Ltd.	11 481 100	21	22 444 406	0.51	0.53	-3.77
NuVista Energy Ltd.	11 342 500	22	21 034 432	0.54	0.61	-11.48
Astara Energy Corp.	10 865 100	23	3 633 322	2.99	1.24	141.13
Imperial Oil Resources Limited	10 371 500	24	58 068 911	0.18	0.12	50.00
Cardinal Energy Ltd.	10 109 200	25	6 128 707	1.65	1.67	-1.20

Fuel Use

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Difference (2023-2022)
Cenovus Energy Inc.	3 666 803 200	1	192 412 881	19.06	11.02	8.04
Canadian Natural Resources Limited	3 597 431 400	2	148 125 965	24.29	19.47	4.82
Imperial Oil Resources Limited	2 355 214 900	3	55 622 020	42.34	30.23	12.11
Suncor Energy Inc.	1 961 652 300	4	102 058 587	19.22	19.48	-0.26
ConocoPhillips Canada Resources Corp.	1 454 513 900	5	56 994 454	25.52	24.34	1.18
Strathcona Resources Ltd.	918 708 400	6	22 644 418	40.57	42.36	-1.79
MEG Energy Corp.	693 096 600	7	41 168 462	16.84	17.30	-0.46
CNOOC Petroleum North America ULC	589 880 200	8	26 902 998	21.93	19.77	2.16
Athabasca Oil Corporation	371 110 700	9	12 277 913	30.23	29.74	0.49
Greenfire Resources Operating Corporation	357 394 600	10	9 119 694	39.19	34.41	4.78
PetroChina Canada Ltd.	236 857 800	11	3 976 217	59.57	56.79	2.78
Connacher Oil and Gas Limited	228 977 300	12	6 250 600	36.63	36.91	-0.28
Harvest Operations Corp.	97 627 300	13	3 138 377	31.11	28.72	2.39
Sunshine Oilsands Ltd.	40 461 900	14	384 068	105.35	180.31	-74.96
IPC Canada Ltd.	9 746 400	15	245 379	39.72	30.20	9.52

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Canadian Natural Resources Limited	1 378 338 700	1	102 518 551	13.44	14.47	-7.12
Tourmaline Oil Corp.	666 998 500	2	114 219 471	5.84	5.77	1.21
ARC Resources Ltd.	440 996 700	3	66 243 923	6.66	7.05	-5.53
Cenovus Energy Inc.	354 949 700	4	49 210 501	7.21	6.87	4.95
Peyto Exploration & Development Corp.	310 695 900	5	45 131 459	6.88	7.05	-2.41
Pieridae Alberta Production Ltd.	239 652 600	6	4 738 926	50.57	72.75	-30.49
Ember Resources Inc.	212 482 700	7	16 597 436	12.80	13.03	-1.77
Tidewater Midstream and Infrastructure Ltd.	193 455 400	8	524 250	369.01	215.51	71.23
Whitecap Resources Inc.	178 220 700	9	32 379 823	5.50	5.46	0.73
Torxen Energy Ltd.	173 975 700	10	22 040 245	7.89	7.64	3.27
Veren Inc.	158 207 400	11	36 241 882	4.37	4.85	-9.90
TAQA North Ltd.	143 997 300	12	22 444 406	6.42	6.35	1.10
Baytex Energy Ltd.	133 735 500	13	5 253 840	25.45	27.26	-6.64
Birchcliff Energy Ltd.	132 985 000	14	25 967 548	5.12	5.03	1.79

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Advantage Energy Ltd.	119 290 700	15	23 836 148	5.00	5.47	-8.59
NuVista Energy Ltd.	110 742 400	16	21 034 432	5.26	5.28	-0.38
Ipc Canada Ltd.	108 009 900	17	12 432 101	8.69	8.83	-1.59
Spartan Delta Corp.	106 851 900	18	13 090 327	8.16	8.29	-1.57
Pine Cliff Energy Ltd.	104 806 800	19	8 876 250	11.81	12.10	-2.40
Tamarack Valley Energy Ltd.	102 448 200	20	18 187 999	5.63	5.18	8.69
Lynx Energy ULC	93 375 300	21	6 906 578	13.52	13.21	2.35
Obsidian Energy Ltd.	92 180 900	22	8 093 263	11.39	11.30	0.80
Paramount Resources Ltd.	87 846 700	23	24 047 655	3.65	4.02	-9.20
Strathcona Resources Ltd.	87 367 500	24	20 489 871	4.26	3.55	20.00
Westbrick Energy Ltd.	83 682 900	25	18 041 042	4.64	4.23	9.69

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Canadian Natural Resources Limited	4 975 770 100	1	250 644 516	19.85	17.42	13.95
Cenovus Energy Inc.	4 021 752 900	2	241 623 382	16.64	10.16	63.78
Imperial Oil Resources Limited	2 355 214 900	3	58 068 911	40.56	28.88	40.44
Suncor Energy Inc.	1 961 652 300	4	102 304 906	19.17	19.42	-1.29
ConocoPhillips Canada Resources Corp.	1 454 513 900	5	56 994 454	25.52	24.34	1.18
Strathcona Resources Ltd.	1 006 075 900	6	43 134 289	23.32	23.76	-1.85
MEG Energy Corp.	693 097 000	7	44 437 051	15.60	15.90	-1.89
Tourmaline Oil Corp.	666 998 500	8	114 219 471	5.84	5.77	1.21
CNOOC Petroleum North America ULC	589 880 200	9	27 184 057	21.70	19.60	10.71
ARC Resources Ltd.	440 996 700	10	66 243 923	6.66	7.05	-5.53
Athabasca Oil Corporation	390 999 300	11	12 562 453	31.12	30.40	2.37
Greenfire Resources Operating Corporation	361 174 200	12	9 355 260	38.61	33.77	14.33
Peyto Exploration & Development Corp.	310 695 900	13	45 131 459	6.88	7.05	-2.41
Pieridae Alberta Production Ltd.	239 652 600	14	4 738 926	50.57	72.75	-30.49
PetroChina Canada Ltd.	236 857 800	15	7 589 688	31.21	31.59	-1.20
Connacher Oil And Gas Limited	228 977 300	16	6 791 692	33.71	35.31	-4.53
Ember Resources Inc.	212 482 700	17	16 597 436	12.80	13.03	-1.77
Tidewater Midstream and Infrastructure Ltd.	193 455 400	18	524 250	369.01	215.51	71.23
Whitecap Resources Inc.	178 220 700	19	32 379 823	5.50	5.46	0.73
Torxen Energy Ltd.	173 975 700	20	22 040 245	7.89	7.64	3.27

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change (2023 to 2022)
Veren Inc.	158 207 400	21	36 241 882	4.37	4.85	-9.90
TAQA North Ltd.	143 997 300	22	22 444 406	6.42	6.35	1.10
Harvest Operations Corp.	139 409 400	23	6 372 368	21.88	20.92	4.59
Baytex Energy Ltd.	133 735 500	24	15 859 766	8.43	10.21	-17.43
Birchcliff Energy Ltd.	132 985 000	25	25 967 548	5.12	5.03	1.79

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 (Government of Alberta, *Carbon Offset Emission Factors Handbook* [2015], https://open.alberta.ca/publications/2368-9528, table 1).

Company	Mass emitted ($MtCO_2e$)	Rank	Flared (10^6 m^3)	Vented (10^6 m^3)
Canadian Natural Resources Limited	0.43	1	43.73	20.19
Tamarack Valley Energy Ltd.	0.39	2	159.88	1.37
Spur Petroleum Ltd.	0.15	3	60.59	0.41
Headwater Exploration Inc.	0.14	4	61.11	0.11
Cenovus Energy Inc.	0.12	5	23.29	4.15
Baytex Energy Ltd.	0.10	6	39.23	0.65
Whitecap Resources Inc.	0.10	7	7.40	5.16
Suncor Energy Inc.	0.09	8	28.63	1.39
Cardinal Energy Ltd.	0.08	9	8.63	4.02
Obsidian Energy Ltd.	0.07	10	8.63	3.32
HWN Energy Ltd.	0.07	11	3.34	4.05
Rubellite Energy Inc.	0.07	12	26.25	0.30
Astara Energy Corp.	0.06	13	10.86	2.03
Surge Energy Inc.	0.05	14	10.13	1.79
West Lake Energy Corp.	0.05	15	16.80	0.50
Saturn Oil & Gas Inc.	0.04	16	6.91	1.73
Tourmaline Oil Corp.	0.04	17	6.70	1.54
Strathcona Resources Ltd.	0.03	18	6.72	1.08
Veren Inc.	0.03	19	10.25	0.45
InPlay Oil Corp.	0.03	20	5.22	1.13
Imperial Oil Resources Limited	0.03	21	10.37	0.20
Murphy Oil Company Ltd.	0.02	22	8.05	0.21
Longshore Resources Ltd.	0.02	23	8.25	0.14
IPC Canada Ltd.	0.02	24	7.78	0.18
Aspenleaf Energy Limited	0.02	25	7.40	0.22

Total Methane Emissions

The following table ranks operators based on the total of all methane emissions reported to OneStop in 2023.

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

Company	Volume emitted ($MtCO_2e$)	Rank
Canadian Natural Resources Limited	0.83	1
Tourmaline Oil Corp.	0.56	2
Cenovus Energy Inc.	0.40	3
Vermilion Energy Inc.	0.20	4
Whitecap Resources Inc.	0.18	5
Peyto Exploration & Development Corp.	0.15	6
TAQA North Ltd.	0.14	7
Pine Cliff Energy Ltd.	0.11	8
Westbrick Energy Ltd.	0.11	9
Torxen Energy Ltd.	0.10	10
Paramount Resources Ltd.	0.09	11
Top Oil Production Ltd.	0.08	12
Spartan Delta Corp.	0.08	13
HWN Energy Ltd.	0.07	14
ARC Resources Ltd.	0.07	15
Obsidian Energy Ltd.	0.07	16
Canlin Resources Partnership	0.07	17
I3 Energy Canada Ltd.	0.07	18
Cardinal Energy Ltd.	0.06	19
Strathcona Resources Ltd.	0.06	20
Harvest Operations Corp.	0.05	21
Mancal Energy Inc.	0.04	22
Surge Energy Inc.	0.04	23
Ember Resources Inc.	0.04	24
Astara Energy Corp.	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	ST98 National Inventory Report (2021), Clearstone (2018) Clearstone 2018, Prasino 2013, and Van Vilet 2018	92	All
Venting: Routine & Non-Routine (2014 – 2018)	Reported Vent Volume	Petrinex	92 74 95	Natural Gas Crude Oil Primary Crude Bitumen
Venting: Routine (2019 – 2023)	Reported Vent Volume	OneStop	92 74 95	Natural Gas Crude Oil Battery Primary Crude Bitumen
Venting: Non-Routine Well Testing	Reported Vent Volume	ST60B	92	All
Venting: Non-Routine 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	ST98 Greenpath (2016) Clearstone (2018)	92 74	Natural Gas (fuel gas) Crude Oil
Compressor Seals	Reported Vent Volume Equipment Counts Facility Counts	OneStop OneStop ST98	0.533 kg $CH4/m^3$ 0.582 kg $CH4/m^3$	2014 to 2020 2021 2022 2023 onwards

			0.605 kg $CH4/m^3$ 0.603 $kgCH4/m^3$	
Glycol Dehydrators	Facility Counts Reported Emissions Equipment Counts	ST98 OneStop OneStop	OneStop	Methane Mass is reported to OneStop.
Methane Slip Fuel	Emission Factors Engine Emission Improvement from Multi-Sector Air Pollutant Regulation (MSAPR) Equipment Inventory Fuel Volume Fuel Disposition	EPA (Rich Burn Engines, Boilers, Turbines), Environ. Sci. Technol. 2021, 55, 1190−1196 (Lean Burn Engines) MSAPR Jan 1, 2026 requirement for rich-burn engine controls ECCC Engine Database Petrinex and ST98 CAPP 2004	92	All
Unlit Flares	Combustion Efficiency Reported Flare Volume	Assumes 6% of flares at select sites are unlit (IEA, 2021) Petrinex	74 92 95	Crude Oil Battery Gas Battery 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