Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2022

November 2024

Alberta Energy Regulator
ST60B-2023: Upstream Petroleum Industry Emissions Report

November 2024

This report has been updated since its initial release in November 2023:

- Dehydrator volumes in figure 9 have been updated.
- Section 4.2.4.1 has been updated to explain the difference between volumes in the OneStop totals and the compressor section totals.
- Section 8 was updated to describe model exclusions.
- Appendix 2 solution gas conversion methodology was updated and a third correction to table data.

Published by
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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 fugitive emissions information reported to the AER.

As a result of the more extensive emission reporting introduced in 2018 by *Directive 060*, this report now includes source-specific information and fugitive emissions information. It also includes production and fuel gas volumes. The report does not include emission volumes from processing plants approved under section 11 of the *Oil Sands Conservation Act*, oil sands mining schemes, or pipelines that are not regulated by the AER. The primary data used to compile the report is obtained from Canada's Petroleum Information Network (Petrinex) and the AER's OneStop reporting tool. This year's publication includes the OneStop data for 2022, 2021, and 2020, but because it was extracted in August 2023, the 2020 and 2021 data will include amendments and late submissions, resulting in slightly different values compared to last year's report.

Key statistics from 2022:

Production (from ST98: Alberta Energy Outlook)

- Crude bitumen production increased by 1.8 per cent to 192.4 10^6 m^3.
- Crude oil production increased by 10.4 per cent to 28.2 10^6 m^3.
- Gas production increased by 11.0 per cent to 112 800 10^6 m^3.
- Solution gas production from crude oil and bitumen batteries decreased by 2.8 per cent to 23 400 10^6 m^3.

Fuel Use

- Total reported Petrinex fuel use increased by 1.4 per cent to 28.71 10^9 m^3.

Flaring

- Total reported Petrinex flaring increased by 8.6 per cent to 1281.2 10^6 m^3.
- Solution gas flaring increased by 9.2 per cent to 641.99 10^6 m^3.

Venting

- Total reported Petrinex venting decreased by 4.7 per cent to 353.6 10^6 m^3.
- Solution gas venting decreased by 4.8 per cent to 130.2 10^6 m^3.

Fugitive Emissions

- Total equipment-based fugitive emissions decreased 19.0 per cent to 40.36 10^6 m^3.

Surface Casing Vent Flow (SCVF) and Gas Migration (GM)

- As of 2022, Alberta has 10 689 unresolved surface casing vent flow (SCVF) and gas migration (GM) events emitting a total of 94 10^6 m^3/year.

New Facilities Compliance

- There were 1264 facilities with first production or receipt in 2022. Using the 2021 OneStop reported data as a baseline for comparison, the 2022 total vent volumes were 79.7 per cent lower than facilities with first production or receipt in 2021.

Methane Reduction

- Results from 2022 indicate that Alberta has met its 45 per cent reduction target in 2022. Using both reported and estimated emissions, Alberta has reduced methane emissions by 45 per cent 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) as well as methane emission reduction requirements that were designed 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 represents data that was submitted on or before August 8, 2023.

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

1.1 Important Notes for this Year's Publication

A number of vent gas limits came into effect as of January 1, 2022 (see *Directive 060* for details):

- sites with first reception or production on or after January 1, 2022
- crude bitumen battery fleets (if fleet averaging is preferred)
- pneumatic devices installed on or after January 1, 2022
- reciprocating compressors installed on or after January 1, 2022
- centrifugal compressor seals installed on or after January 1, 2022
- glycol dehydrators installed on or after January 1, 2022

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 are not reflective of emission increases and should be a better reflection of what is being emitted to atmosphere than what was reported using previous definitions. To avoid confusion, the data from the two different time periods are graphed separately.

Change in surface casing vent flow and gas migration methodology. In this report, the methodology used to determine SCVF and GM volumes from unresolved emissions has been updated from last year's version to conservatively estimate the source emissions. Non-serious events or volumes too small to quantify were 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.

Change in global warming potential (GWP) of methane. In their 2013 *Fifth Assessment Report*, the International Panel on Climate Change (IPCC) updated the GWP of methane to 28 (up from 25 in previous years). Our emission reduction model has been updated to reflect this change.

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 published by the Government of Alberta: https://open.alberta.ca/publications/methane-emissions-management-upstream-oil-and-gas-sector.

Differences in Petrinex and OneStop total vent volumes. In the 2022 data, differences were observed once again in the total vent volumes reported to Petrinex and the defined vent gas (DVG), pneumatics, compressor, and dehydrator volumes reported to OneStop; however, the difference has decreased from the 2021 reported data. While it is not expected that these volumes be identical (Petrinex includes nonroutine venting), it is expected that Petrinex total vent volumes be *greater* than OneStop DVG volumes. We continue to investigate the reasons for these differences.

2020/2021 OneStop amendments and late submissions. This publication includes the OneStop data for both 2021 and 2020, but because it was extracted in August 2023, the 2020 and 2021 data will include amendments and late submissions, resulting in slightly different values compared to 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 2021 to 2022.

Table 1. Number of facilities that must report methane emissions by subtype, 2019–2022

Facility subtype	2019	2020	2021	2022	% change
Crude bitumen batteries	4 164	3 519	3 228	3 342	3.53
Crude oil batteries	9 352	8 544	8 447	8 347	−1.18
Gas batteries	10 452	9 508	8 957	8 455	−5.60
Gas gathering/compressor stations	7 313	6 898	5 854	5 558	−5.06
Gas plants	553	531	511	501	−1.96
Other	2 130	1 935	1 900	1 800	−5.26
Total	**33 964**	**30 935**	**28 897**	**28 003**	**−3.09**

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, and tank farms, etc. Emissions and production data from facilities associated with bitumen mining are not included in the data for 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 and figure 2 show fuel volume use since 2010 as reported to Petrinex. These volumes represent the yearly total of monthly reported fuel volume by facility subtype. In 2022, fuel gas use was 28.71 10^9 m3.

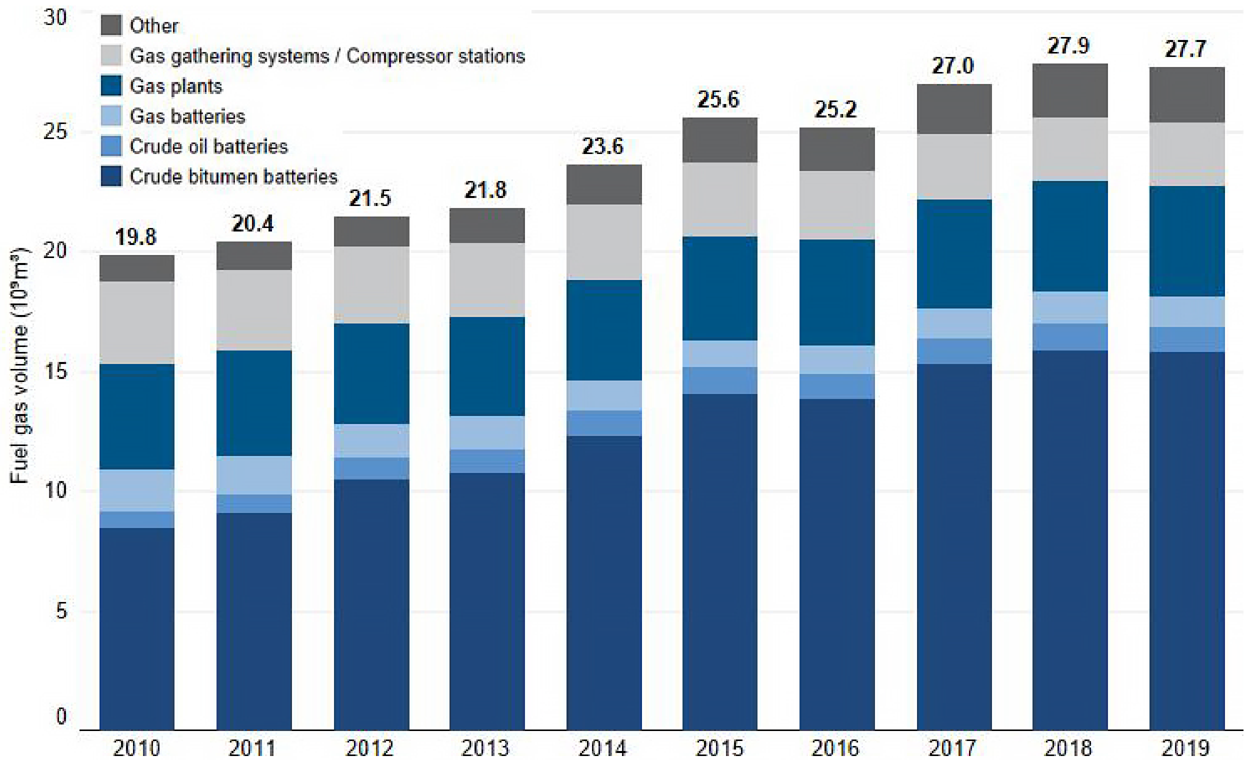


Figure 1. **Fuel gas usage, 2010–2019 (Source: Petrinex)**

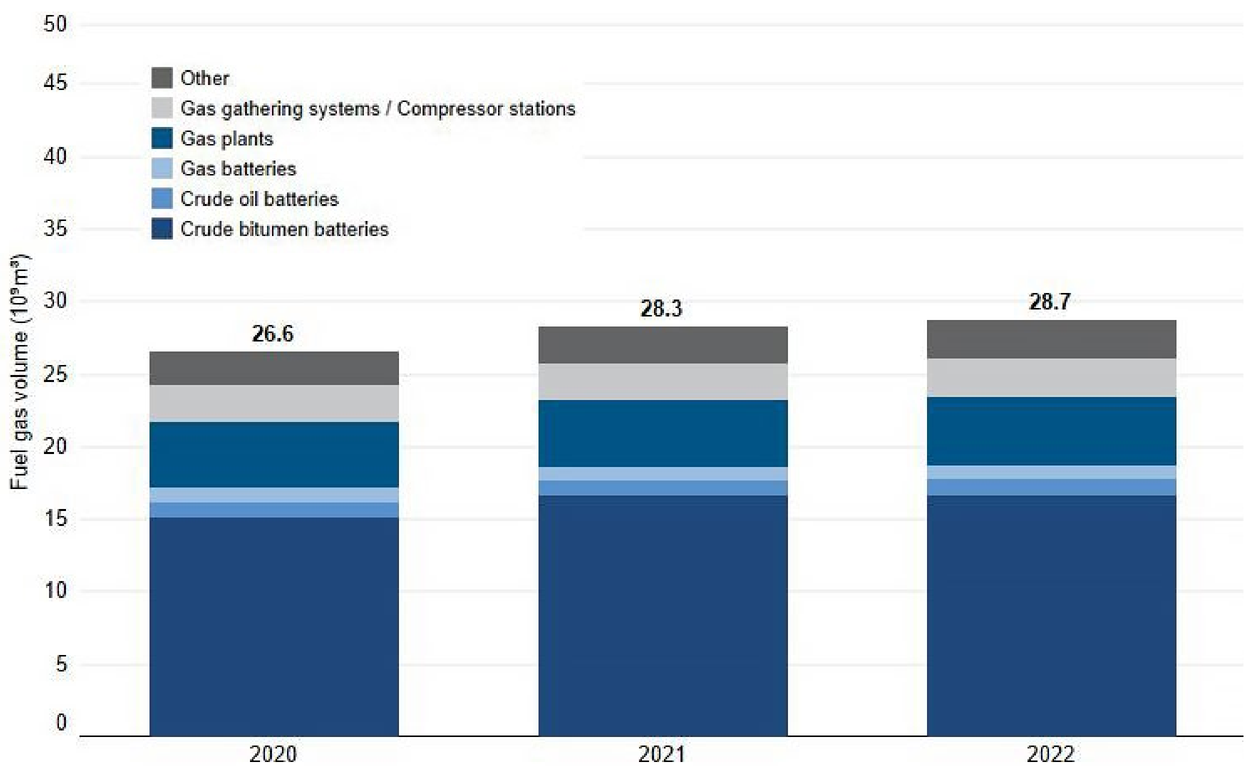


Figure 2. **Fuel gas usage, 2020–2022 (Source: Petrinex)**

Fuel gas use has primarily been increasing each year from about 19.85 10^9 m^3 in 2010 to over 27.00 10^9 m3 in the last 6 years. In 2020, fuel gas use decreased to 26.57 10^9 m^3 because of a change in the fuel gas definition within both *Directive 060* and *Directive 017*. Volumes that would have previously been reported as fuel gas are now being 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 to the atmosphere, the definition was changed to now consider this as vent gas and require it to be reported as such in Petrinex.

Table 3 shows the change in fuel gas use by facility subtype from the previous year. Fuel usage increased accordingly with increase production across the province.

Table 3. Change in fuel gas use volumes, 2020–2022, % change 2021–2022 (Source: Petrinex)

Facility subtype	2020 (10^9 m^3)	2021 (10^9 m^3)	2022 (10^9 m^3)	% change
Crude bitumen battery	15.11	16.58	16.66	0.46
Crude oil battery	1.00	1.05	1.12	6.72
Gas battery	1.07	0.95	0.94	−0.80
Gas gathering/compressor station	2.58	2.61	2.64	1.35
Gas plant	4.51	4.60	4.68	1.75
Other	2.28	2.47	2.66	7.90
Total	**26.57**	**28.26**	**28.71**	**1.59**

3 Flaring

Flaring is the controlled destruction of gas that takes place 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 and figure 4 show reported flare volumes since 2010, as reported to Petrinex, broken down by facility subtype. Well testing is not included but is presented in a subsequent section.

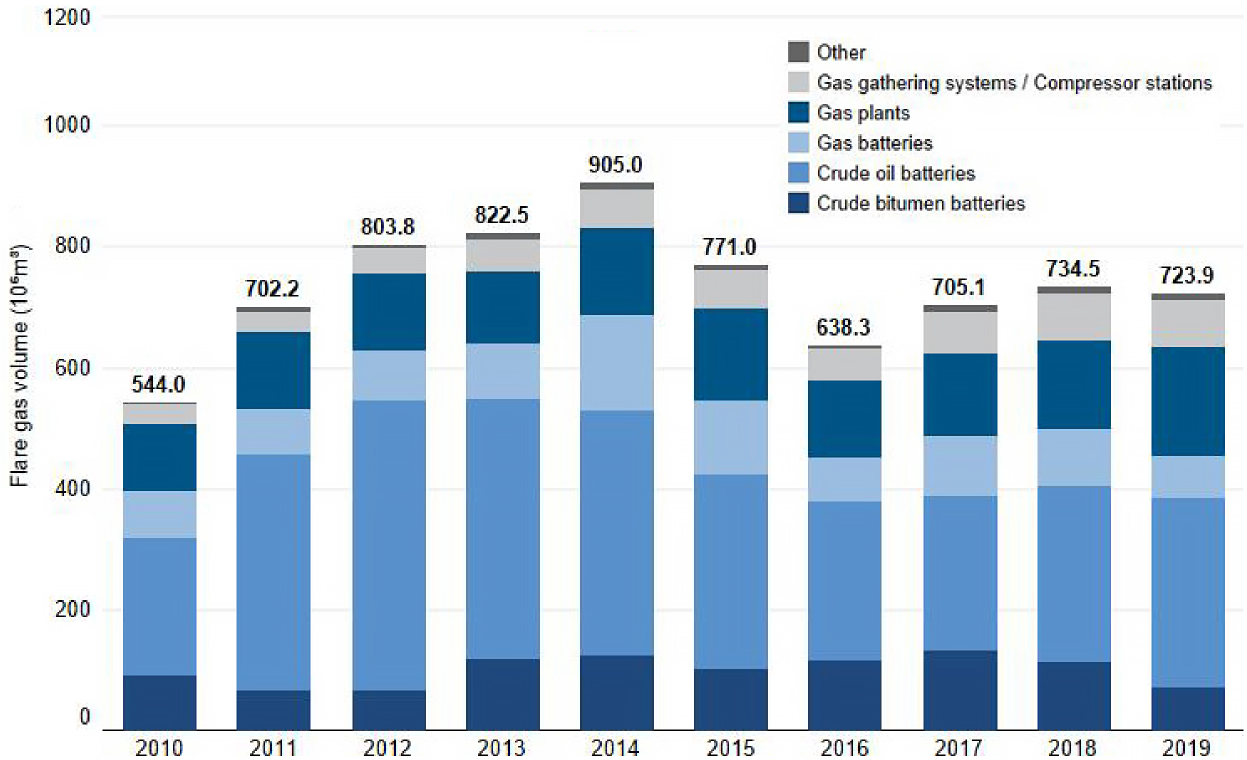


Figure 3. Flare volumes, 2010–2019 (Source: Petrinex)

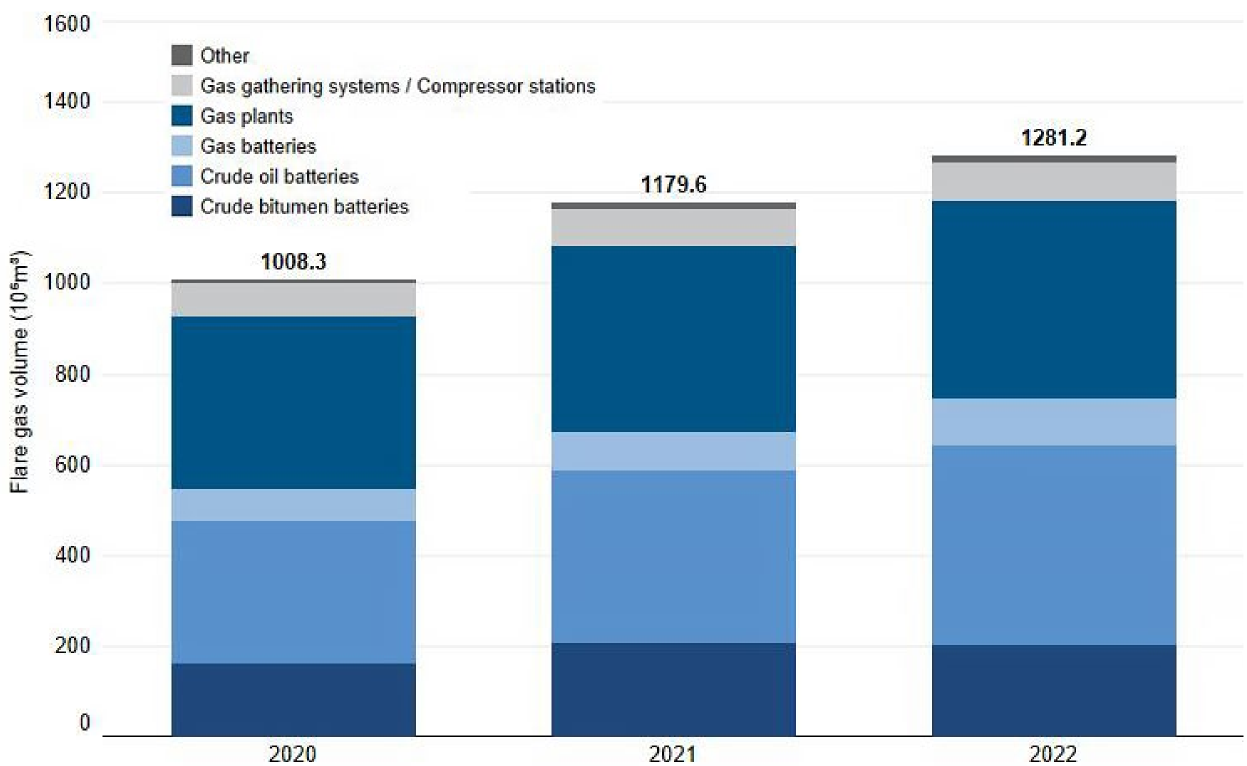


Figure 4. Flare volumes, 2020–2022 (Source: Petrinex)

3.1.1 Flaring Trends

In 2022, flaring volumes increased to 1281.2 10^6 m3. This is likely the result of both the definition change and the introduction of new methane requirements in 2020 that emphasize 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 was observed since 2020.

Table 4 shows the change in reported flaring by facility subtype. Flaring has increased in all facility types, particularly crude oil batteries. This increase is likely attributed to the larger ratio of solution gas produced alongside oil production and new DVG limits.

Table 4. Change in flared volume, 2020–2022, % change 2021–2022 (Source: Petrinex)

Facility subtype	2020 (10^6 m^3)	2021 (10^6 m^3)	2022 (10^6 m^3)	% change
Crude bitumen battery	163	206	202	−2.16
Crude oil battery	314	382	440	15.21
Gas battery	72	85	103	22.18
Gas gathering/compressor station	74	82	86	5.29
Gas plant	379	411	438	6.65
Other	7	14	12	−16.69
Total	**1 008**	**1 180**	**1 281**	**8.62**

In addition to the total amount of flare volume increasing in 2022, the flaring intensity also increased (see table 5). Solution gas flaring is analyzed further in section 6.

Table 5. Flaring intensity, 2020–2022 (Source: Petrinex)

Year	Province-wide BoE	Flare volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136.77	1 008 328 700.00	0.66
2021	1 611 841 179.37	1 179 519 400.00	0.73
2022	1 692 106 893.62	1 281 329 300.00	0.76

3.1.2 Flare Volumes at Gas Plants

Table 6 shows the top 30 gas plants that flared in 2022 by volume and the percentage of the total gas received at each plant that is flared. The total amount of flaring from these top 30 gas plants (304 10^6 m3) makes up approximately 70 per cent of total flaring at gas plants.

Table 6. Top 30 flaring gas plants, 2022 (Source: Petrinex)

Gas plant	Operator	Land location	2022 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001147	Pembina Gas Infrastructure Inc.	11-18-074-12W6	83.51	1.87
ABGP0001004	Keyera Energy Ltd.	02-05-044-01W5	38.98	1.81
ABGP0149088	Baytex Energy Ltd.	03-18-084-17W5	23.02	18.80
ABGP0001892	Ovintiv Canada ULC	04-08-075-07W6	12.59	0.61
ABGP0001037	Pieridae Alberta Production Ltd.	13-13-025-05W5	12.57	1.44
ABGP0118855	Pembina Gas Infrastructure Inc.	08-13-063-05W6	10.52	0.89
ABGP0001855	Obsidian Energy Ltd.	09-15-084-14W5	9.43	14.16
ABGP0001901	Plains Midstream Canada ULC	10-11-020-01W4	8.18	0.10

Gas plant	Operator	Land location	2022 flare (10^6 m^3)	Gas flared as a percentage of gas receipts (%)
ABGP0001350	Cenovus Energy Inc.	01-08-070-11W6	7.41	0.54
ABGP0001084	Repsol Oil & Gas Canada Inc.	04-11-053-18W5	6.48	0.65
ABGP0150386	Keyera Energy Ltd.	04-07-073-08W6	6.04	0.29
ABGP0001060	AltaGas Ltd.	09-27-031-04W5	5.76	0.18
ABGP0001623	Strathcona Resources Ltd.	06-08-062-03W6	5.65	0.78
ABGP0152315	Tidewater Midstream and Infrastructure Ltd.	12-35-070-09W6	5.40	0.58
ABGP0153429	Pembina Gas Infrastructure Inc.	14-28-062-20W5	5.15	0.32
ABGP0001902	Plains Midstream Canada ULC	04-12-020-01W4	4.91	0.02
ABGP0001129	Canadian Natural Resources Limited	13-26-067-05W6	4.91	0.53
ABGP0001113	Keyera Energy Ltd.	09-06-063-25W5	4.89	0.30
ABGP0001107	Pembina Gas Infrastructure Inc.	01-12-062-20W5	4.81	0.35
ABGP0001133	Keyera Energy Ltd.	11-35-037-09W5	4.52	0.21
ABGP0094954	Pembina Gas Infrastructure Inc.	08-11-060-03W6	4.49	0.18
ABGP0145129	Pembina Gas Infrastructure Inc.	14-28-062-20W5	4.44	0.20
ABGP0001506	Canadian Natural Resources Limited	01-01-078-10W6	4.40	0.31
ABGP0001130	Canlin Resources Partnership	02-27-040-03W5	4.11	3.38
ABGP0001134	Caledonian Midstream Corporation	02-04-021-04W5	4.04	3.48
ABGP0160735	TAQA North Ltd.	09-14-028-01W5	3.75	1.55
ABGP0001144	Pembina Gas Infrastructure Inc.	03-15-059-18W5	3.68	0.23
ABGP0001108	Keyera Energy Ltd.	06-12-046-14W5	3.60	0.20
ABGP0001520	NuVista Energy Ltd.	06-19-073-08W6	3.44	0.31
ABGP0150355	Keyera Energy Ltd.	03-19-067-07W6	3.32	0.21
Total			**304.00**	

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 retrieved, as reported, through the AER's compliance and operations management (COM) system. Due to the fact that they are a unique subset of flaring, they are presented separately here.

In 2022, 923 well tests were completed, up from 747 tests being reported in 2021 (table 7). On average, flaring volumes per test decreased and vent volumes per test increased.

Table 7. Well drilling and testing data, 2019–2022. (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	1 644.6	1.78

4 Venting

Vent gas is uncombusted gas that is released to the atmosphere at upstream oil and gas operations. The AER manages vented emissions from upstream oil and gas facilities through *Directive 060*, which includes both site-specific and equipment-specific limits. Improving venting performance is important both for the protection of the environment and for meeting provincial emission reduction goals; several new venting limits came into effect in 2022.

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.), while OneStop only includes routine vent gas and fugitive emissions. However, OneStop provides greater emission breakdowns by source type, as discussed and shown below.

In the 2022 data, a gap between reported volumes was observed once again in the total vent volumes reported to Petrinex and the defined vent gas (DVG), pneumatics, compressor, and dehydrator volumes reported to OneStop; however, the gap has decreased compared to the 2021 reported data, and Petrinex vent volumes were lower than OneStop. While it is not expected that these volumes be identical (Petrinex includes nonroutine venting), it is expected that Petrinex total vent volumes be *greater* than OneStop DVG volumes. We continue to investigate the reasons for these differences.

4.1 Petrinex

Routine and nonroutine volumes are reported as a combined monthly volume to Petrinex. Figure 5 and figure 6 show annual vent gas volumes over the past 12 years by facility subtype. In 2022, reported vent gas in Petrinex was 353.6 10^6 m^3.

The vent gas volumes reported in 2022 continued to decrease in relation to 2020 when reporting definitions changed. When looking at production, 2022 had the lowest venting intensity of the past three years (table 9).

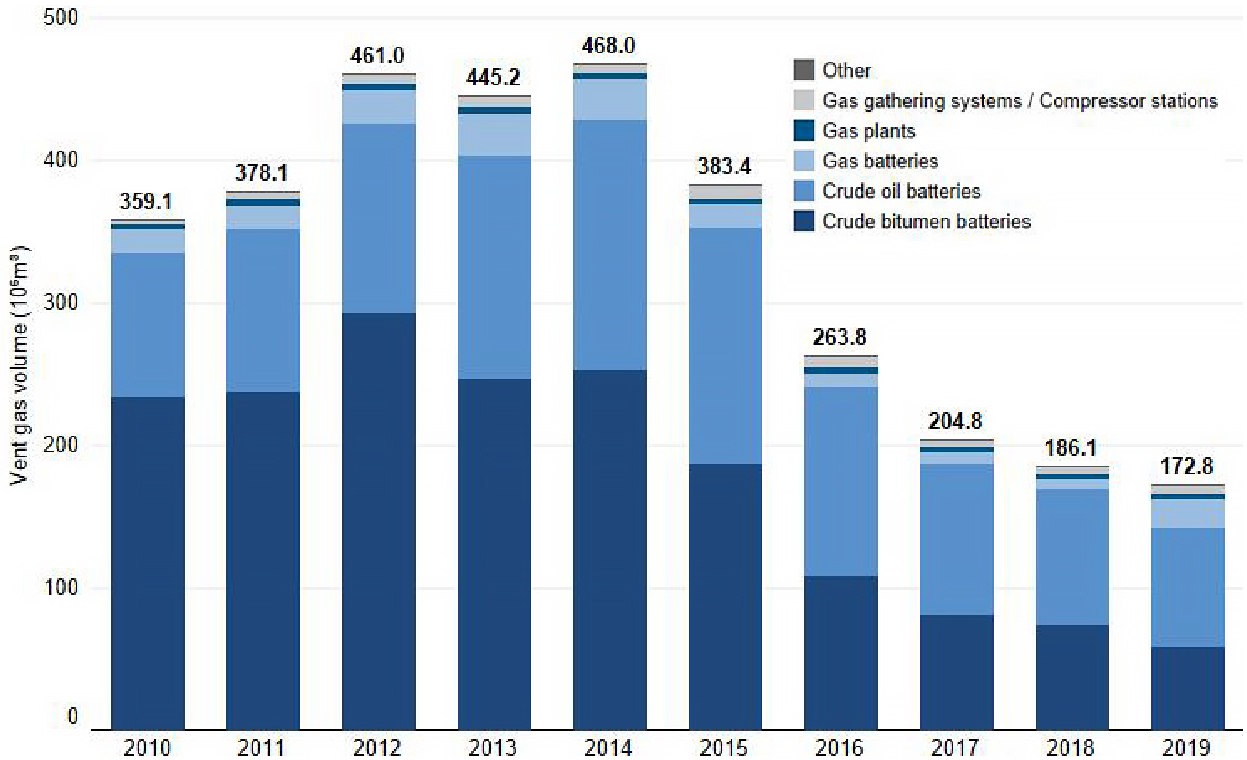


Figure 5. Vent volumes, 2010–2019 (Source: Petrinex)

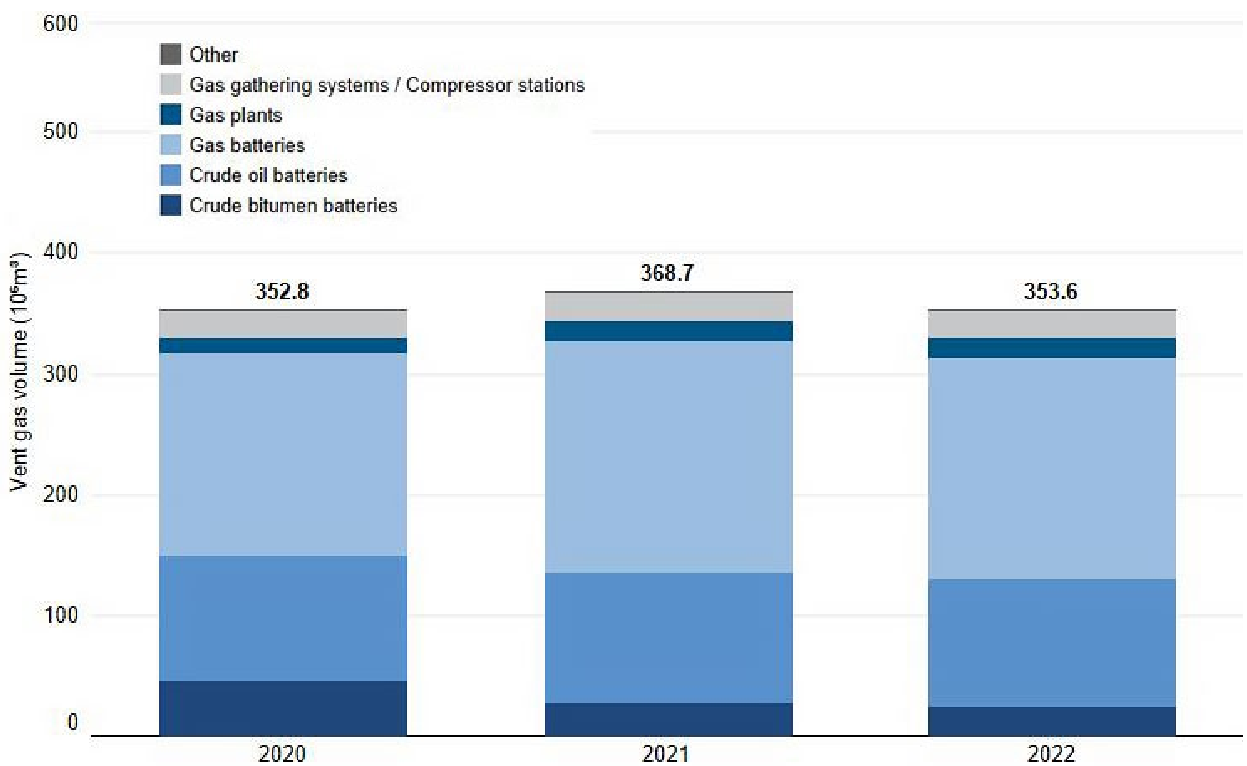


Figure 6. Vent volumes, 2020–2022 (Source: Petrinex)

Table 8 shows the change in reported vent gas by facility subtype. Venting continued to decrease compared to 2021 in almost all facility subtypes.

Table 8. Change in vented volumes 2020–2022, % change 2021–2022 (Source: Petrinex)

Facility Subtype	2020 (10^6 m^3)	2021 (10^6 m^3)	2022 (10^6 m^3)	% change
Crude bitumen battery	46.0	28.0	25.5	−9.13
Crude oil battery	103.3	107.7	104.7	−2.75
Gas battery	167.9	191.6	183.3	−4.31
Gas gathering/compressor station	22.4	24.9	23.2	−6.84
Gas plant	12.4	16.0	16.1	0.32
Other	0.8	0.5	0.8	47.62
Total	**352.8**	**368.7**	**353.6**	**−4.12**

Table 9. Venting intensity, 2020–2022 (Source: Petrinex)

Year	Province-wide BoE	Vent volume (m^3)	Intensity (m^3/BoE)
2020	1 517 386 136.77	352 757 700.00	0.23
2021	1 611 841 179.37	369 448 500.00	0.23
2022	1 692 106 893.62	352 142 200.00	0.21

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 contained 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 2022, total emissions reported to OneStop were 415.3 10^6 m^3, which was a significant decrease from 2021 (570.2 10^6 m^3). This can be attributed to numerous equipment-level vent limits that came into effect on January 1, 2022, and early adoption of equipment retrofits in order to come into compliance with vent limits that will come into effect January 1, 2023. Figure 7 shows total source-specific emissions, and figure 8 shows these emissions broken down by source category 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 that were required to report; as of August 8, 2023, 95 per cent of the facilities had reported.

Gas batteries are the facility subtype with the greatest associated emission volumes because of the high presence of pneumatic devices on site. DVG is the greatest contributing source for both 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.

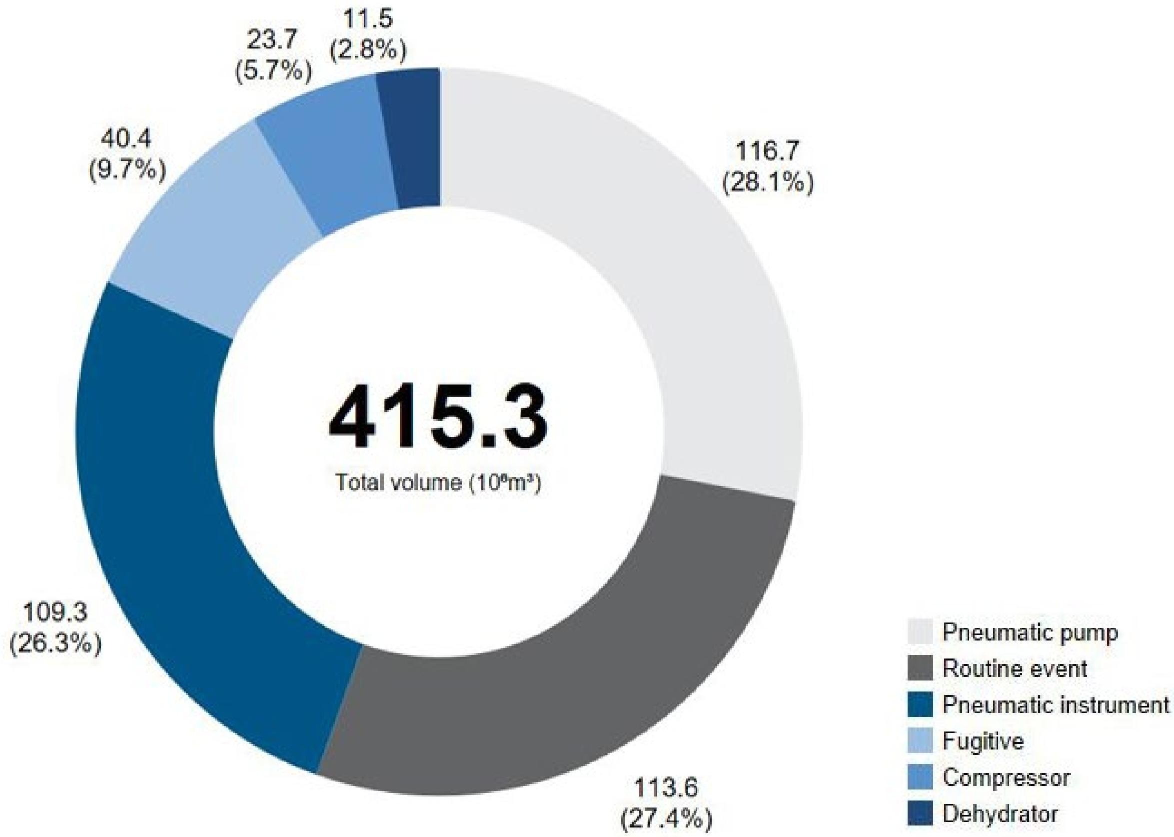


Figure 7. Breakdown of venting volumes by source, 2022 (Source: OneStop)

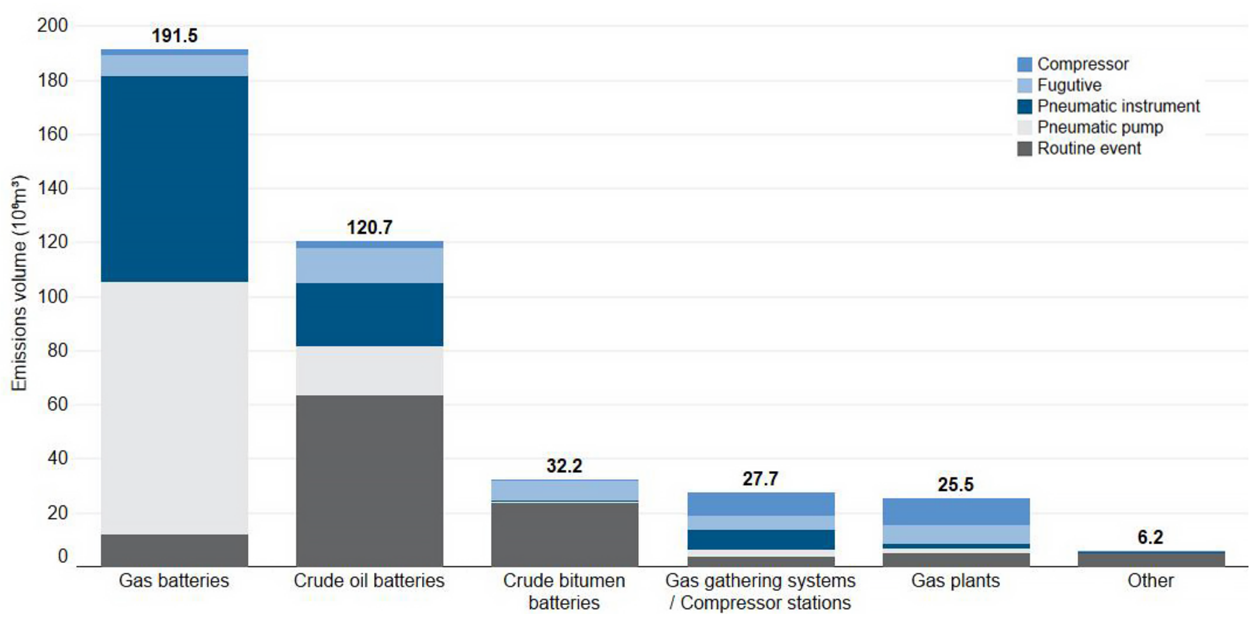


Figure 8. Breakdown of venting volumes by facility subtype, 2022 (Source: OneStop)

Figure 9 shows a side-by-side comparison of the OneStop emissions data for 2020, 2021, and 2022. Year-over-year comparisons are challenging because of potential data quality issues. The reported data is a snapshot in time, and these volumes could change as companies review and update their data.

One potential contributing factor to this data quality issue is inconsistent reporting. Large increases or decreases in OneStop emissions 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. Table 10 breaks down the top 10 companies with the largest reported emission differences in OneStop reported volumes when comparing 2021 and 2022. Note that the data was retrieved on August 8, 2023; therefore, amendments made after this date are not reflected in the report. When warranted, the AER follows up with companies to determine if compliance action is required.

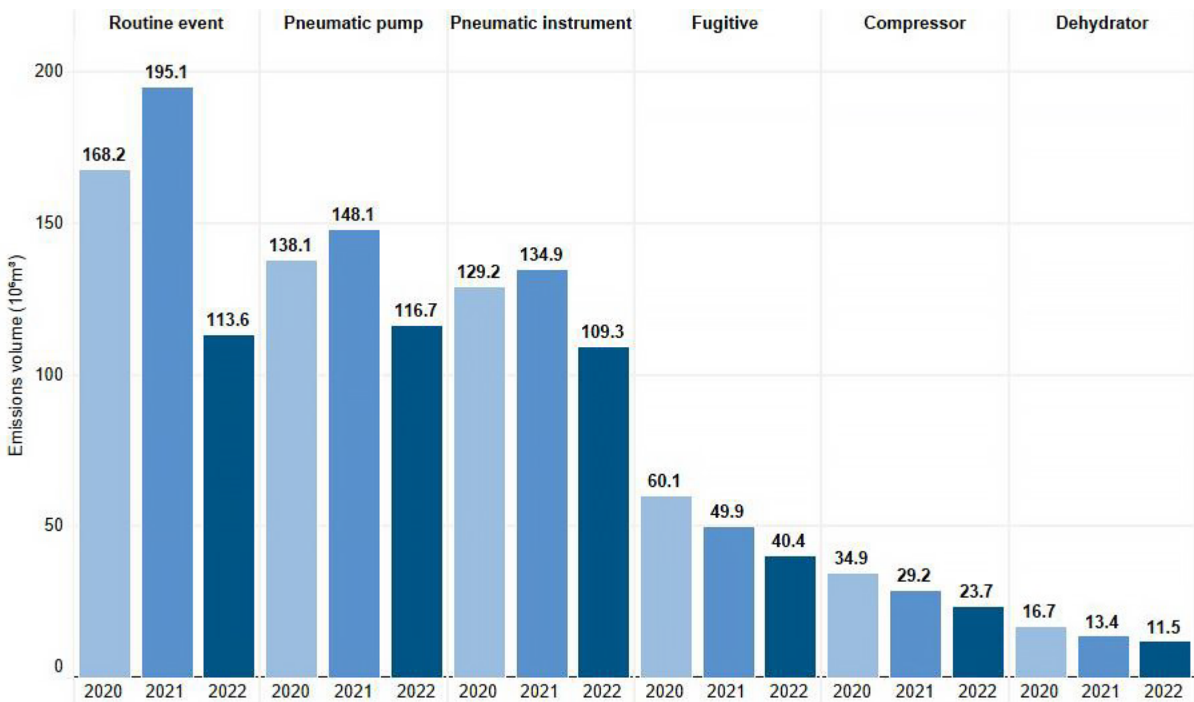


Figure 9. Comparison of venting volumes by source, 2020–2022 (Source: OneStop)

Table 10. Top ten absolute differences in reported venting volumes, 2021–2022 (Source: OneStop)

Operator	2021 (10^6 m³)	2022 (10^6 m³)	Absolute difference (10^6 m³)
Long Run Exploration Ltd.	656.2	47.3	608.8
Cenovus Energy Inc.	483.5	340.4	143.1
AlphaBow Energy Ltd.	117.3	0.0	117.3
TAQA North Ltd.	210.8	97.3	113.5
New Star Energy Ltd.	109.4	1.0	108.4
Canadian Natural Resources Limited	858.4	760.4	98.0
Repsol Oil & Gas Canada Inc.	123.1	68.8	54.3
Crescent Point Energy Corp.	29.6	70.4	40.8
Tourmaline Oil Corp.	286.7	256.8	29.9
CSV Midstream Solutions Corp.	3.9	30.8	26.9

4.2.2 Defined Vent Gas

Directive 060 includes vent limits for defined vent gas (DVG), which is reported annually to the AER through OneStop. DVG should also be captured within the vent volumes reported to Petrinex. In 2022, DVG emissions reported to OneStop were 113.64 10^6 m^3 (figure 10), approximately 27 per cent of all emissions reported to OneStop. This represents a 41.7 per cent reduction from reported volumes in 2021. Crude oil batteries contribute the most DVG emissions by volume. Given the greater likelihood of tanks at these sites, it is reasonable that they would be the most significant contributor in this category.

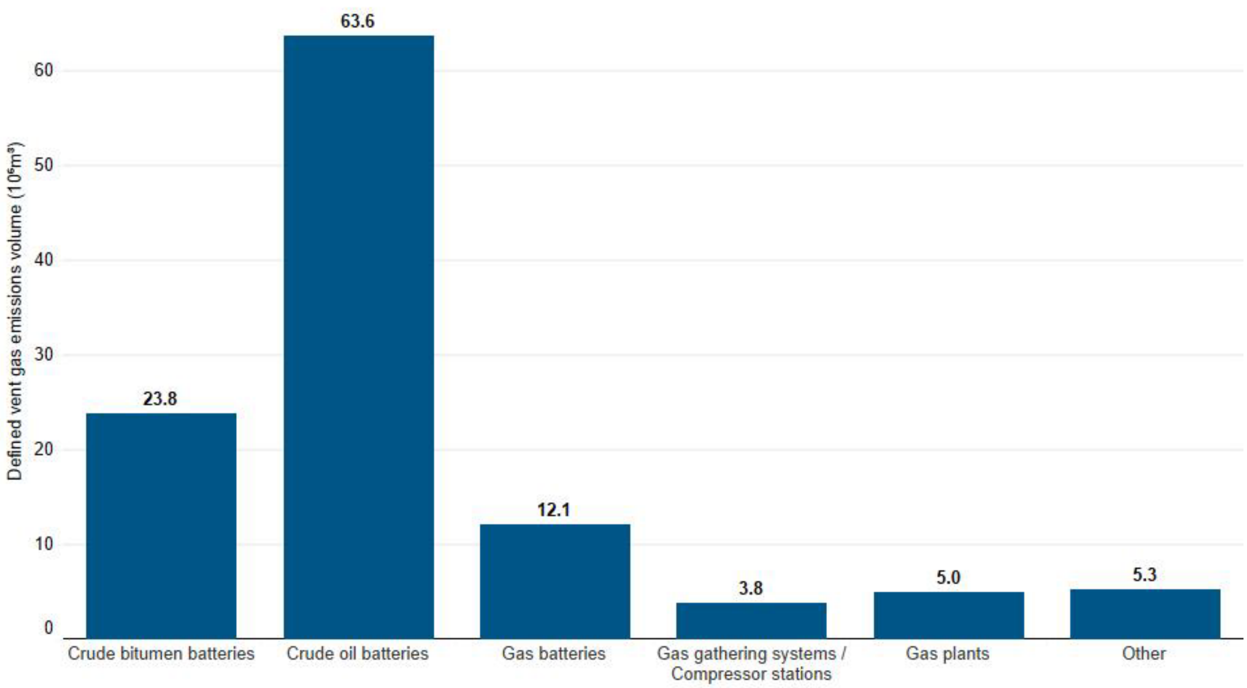


Figure 10. DVG vent volumes by facility subtype, 2022 (Source: OneStop)

4.2.3 Pneumatic Devices

Directive 060 includes vent limits for vent gas from both pneumatic instruments and pumps. Emissions from pneumatic instruments and pumps are reported annually to the AER through OneStop. These volumes should also be captured within the vent volumes reported to Petrinex. Pneumatic device inventories are not required to be reported to the AER, so comprehensive device counts are not provided here.

In 2022, emissions reported to OneStop for pneumatic devices (instruments and pumps) were 226.05 10^6 m^3, approximately 55 per cent of all emissions reported to OneStop. This represents a 20.1 per cent decrease from reported volumes in 2021. Gas batteries were the most significant contributor, representing around 75 per cent of the total pneumatic emissions. This is a result of a large number of gas batteries and a higher likelihood for 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.

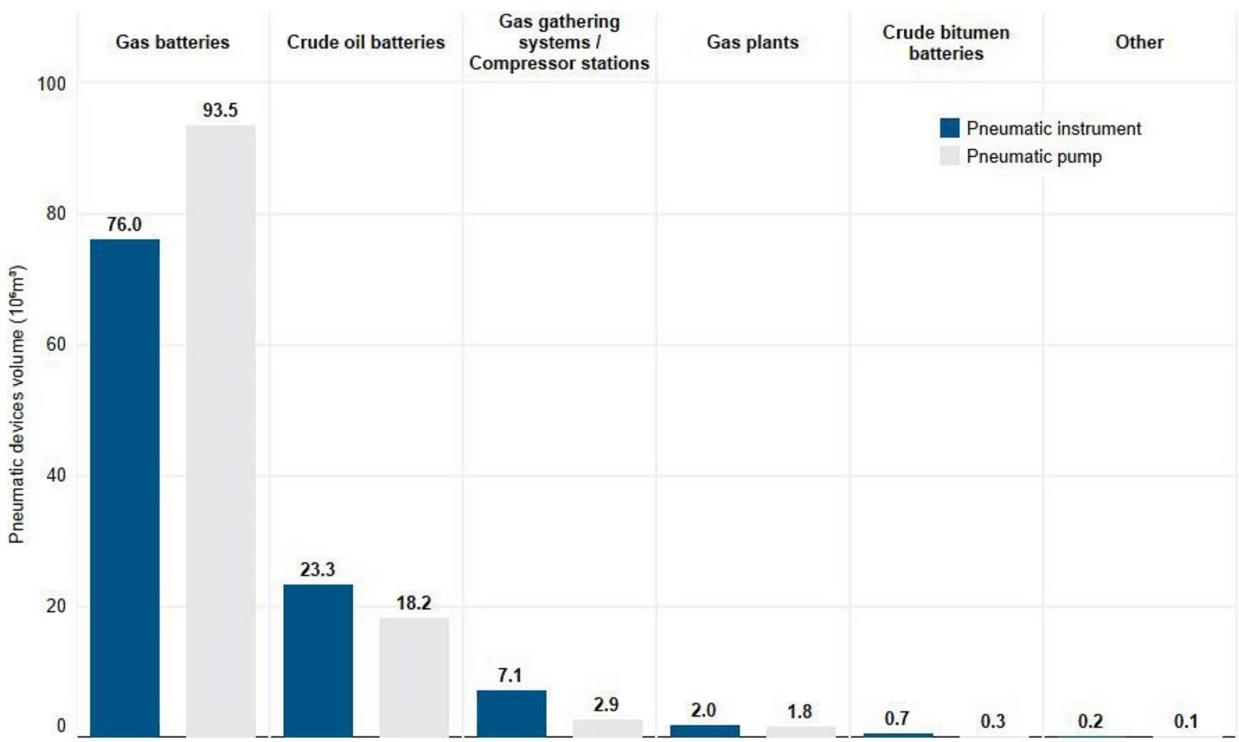


Figure 11. Pneumatic vent volumes by equipment and facility subtype, 2022 (Source: OneStop)

4.2.4 Compressor Seals

Directive 060 includes testing requirements and vent limits for both reciprocating and centrifugal compressor seals. Emission volumes for this source are both tested (measured) and estimated and are reported annually to the AER through OneStop. These volumes are captured within the vent volumes reported to Petrinex monthly.

4.2.4.1 Compressor Inventory

Directive 060 requires a more detailed compressor inventory be reported 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 must be reported individually. The data in figure 12 and table 11 only include the compressors itemized in this inventory, so the volumes here are less than the total compressor volumes reported in figure 7. In 2022, there were 3430 reciprocating compressors and 132 centrifugal compressors that reported, an increase from 3357 reciprocating compressors and a decrease from 165 centrifugal compressors in 2021, respectively.

4.2.4.2 Compressor Seal Emissions

In 2022, reciprocating compressor seal emissions reported to OneStop were 19.17 10^6 m^3. This represents roughly 4.6 per cent of all emissions reported to OneStop. Centrifugal compressor seal emissions reported to OneStop were 0.68 10^6 m^3, a small emission contributor relative to the other sources reported here, representing only 0.2 per cent 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.

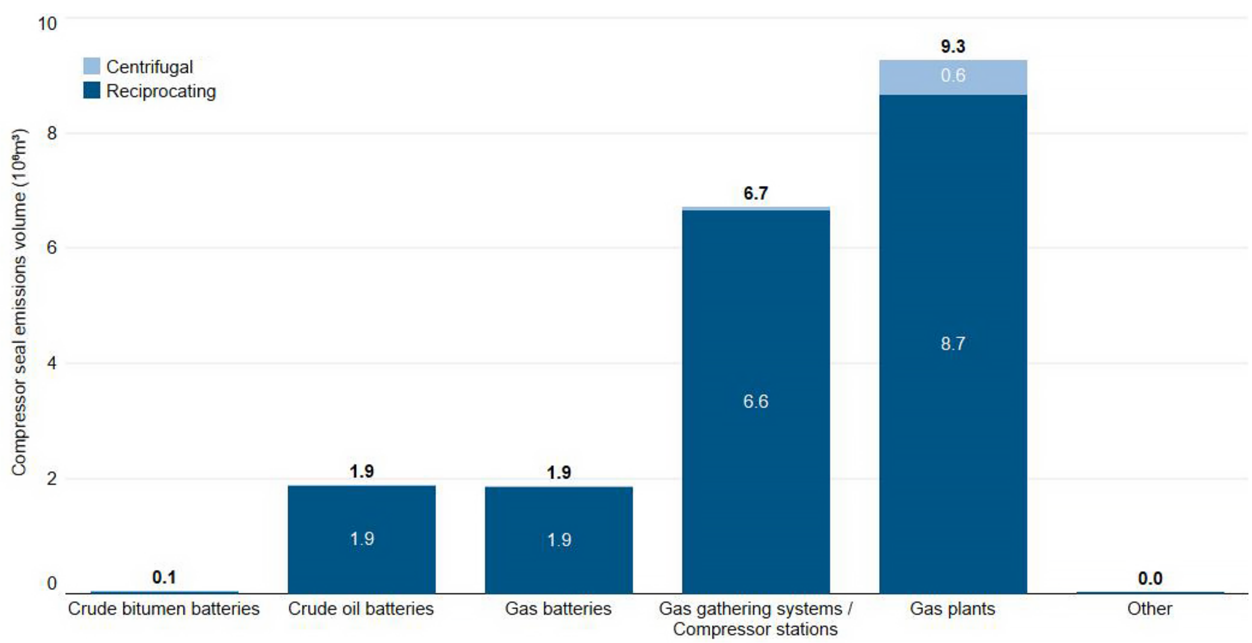


Figure 12. Compressor inventory vent volumes by compressor type and facility subtype (Source: OneStop)

4.2.4.3 Reciprocating Compressor Seal (RCS) Fleet Average

A reciprocating compressor seal (RCS) includes the piston-rod-packing vents/drains and the distance-piece vents/drains on an individual 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 2022 reported values. The requirements in section 8.6.2.2 of *Directive 060* came into effect January 1, 2022, so the RCS fleet averages listed below are following the operator compliance deadline.

Table 11. Top 20 compressor inventory venting operators with RCS fleet average, 2022 (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	3.00	424	1,475	0.24
Tourmaline Oil Corp.	1.08	173	626	0.21
NorthRiver Midstream Inc.	0.88	19	58	1.90
Keyera Energy Ltd.	0.77	106	356	0.23
Cenovus Energy Inc.	0.69	225	714	0.17
I3 Energy Canada Ltd.	0.61	57	188	0.62
Canlin Resources Partnership	0.60	72	282	0.03
TAQA North Ltd.	0.57	115	365	0.25
Pembina Gas Infrastructure Inc.	0.57	101	357	0.17
Peyto Exploration & Development Corp.	0.52	76	283	0.24
Bonavista Energy Corporation	0.50	101	366	0.17
PGI Processing ULC	0.47	65	242	0.32
Repsol Oil & Gas Canada Inc.	0.40	53	164	0.26
Paramount Resources Ltd.	0.39	93	320	0.06
AltaGas Ltd.	0.39	29	102	0.30
Vermilion Energy Inc.	0.39	27	91	0.48
Whitecap Resources Inc.	0.36	66	171	0.38
Pine Cliff Energy Ltd.	0.32	48	178	0.22
Karve Energy Inc.	0.31	25	75	0.65
Lynx Energy ULC	0.30	45	173	0.20

* 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 within the vent volumes reported to Petrinex.

Companies are also required to 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 to the AER an annual dehydrator inventory list that details the emissions from all their glycol dehydrators.

4.2.5.1 Glycol Dehydrator Inventory

In 2022, there were 1244 operating glycol dehydrators in Alberta. Not all dehydrators would be active for the full year but are counted in this inventory if they were operated at all in 2022. Table 12 shows the counts of all operating glycol dehydrators per year over the past 12 years.

Table 12. Number of operating glycol dehydrators, 2010–2022 (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

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 88 per cent methane concentration estimate. In 2022, glycol dehydrator emissions were calculated to be 11.5 10^6 m^3, representing 2.8 per cent of all emissions reported to OneStop. This represents a 14.2 per cent reduction from reported volumes in 2021. More 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 hydrocarbon to the atmosphere and can result from the wear or failure of equipment. *Directive 060* includes requirements for screenings and surveys to inspect for and repair fugitive emissions. These emissions are reported to the AER through OneStop annually.

2020 was the first year of implementing prescribed fugitive emission requirements under *Directive 060*, and 2021 was the first year equipment fugitive emissions were reported to the AER. In 2022, fugitive emissions were 40.4 10^6 m^3 (figure 13), representing 9.7 per cent of all emissions reported to OneStop. This represents a 19 per cent reduction in reported volumes from 2021.

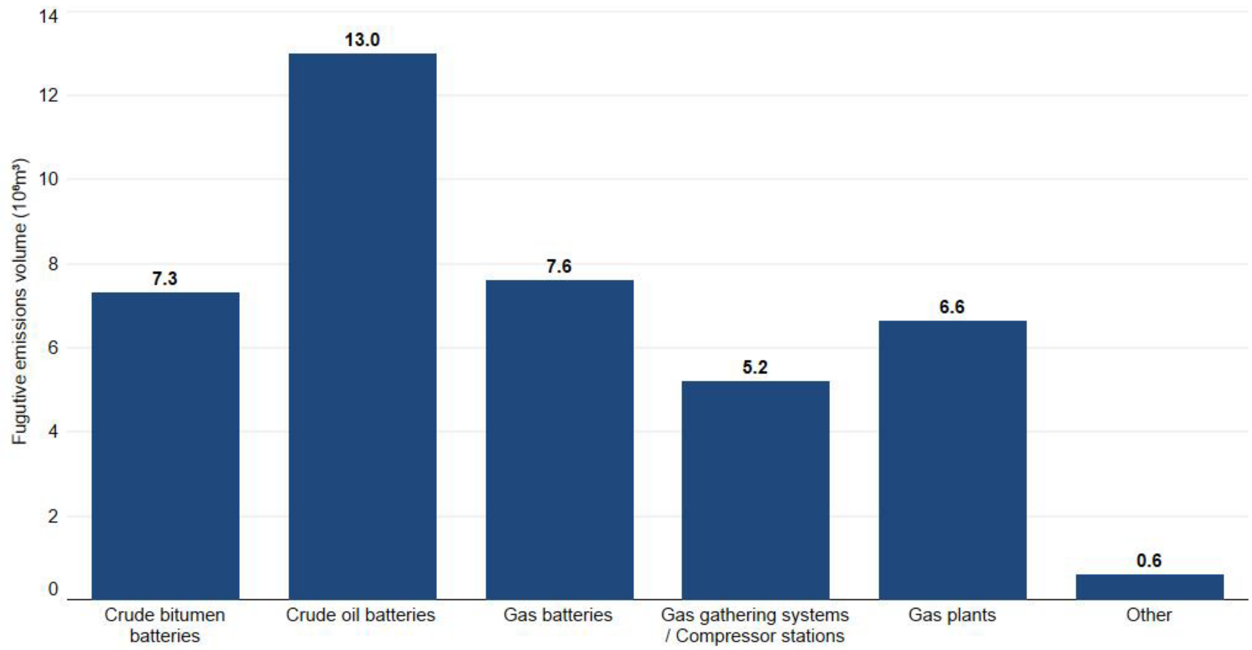


Figure 13. Fugitive emission volumes by facility subtype, 2022 (Source: OneStop)

5.1.1.1 Surface Casing Vent Flow and Gas Migration

A surface casing vent flow (SCVF) is the flow of gas, liquid, or both out of the surface casing or casing annulus of a well. Gas migration (GM) 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. This increase will result in more frequent inspections of surface casing vents, as these are identified as mandatory equipment within the scope of a fugitive emission survey. However, the SCVF and GM emissions detected during a fugitive emission survey are not reported under OneStop, rather they are reported under the Digital Data Submission (DDS) system. In this report, the methodology used to determine SCVF and GM volumes from unresolved emissions has been updated from last year's version to estimate the source emissions and was retroactively applied to previous years' estimates. Non-serious events or volumes too small to quantify were 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.

In 2021, the AER released *Directive 087: Well Integrity Management*, which complements *Directive 060* when it comes to SCVF management. *Directive 060* contains ongoing survey requirements while *Directive 087* contains testing, reporting, and repair requirements for isolation packers, surface casing vent flows gas migration, 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 in 2021 and 2022, along with 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

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 a period of 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 and have a flow rate equal to the average of all other reported natural gas SCVFs or GM.

6 Solution Gas Performance

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

The 2007 version of *Directive 060* placed significant emphasis on solution gas conservation and required 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, however, still used to evaluate the economics of conservation.

Improving solution gas conservation is a key factor in the achievement of provincial emission reduction targets. Operator rankings for solution gas performance can be found in appendix 2.

6.1 Solution Gas Flaring

As shown in figure 14, 641.9 10^6 m^3 of solution gas was flared in 2022, which was a 67 per cent increase over 2019 and a 9.2 per cent increase over last year. 641.9 10^6 m^3 of flared solution gas is approximately 28 10^6 m^3 below the 670 10^6 m^3 solution flaring limit. As facilities continue to reduce venting and crude oil and bitumen production continues to rise, solution gas flaring is expected to continue to increase.

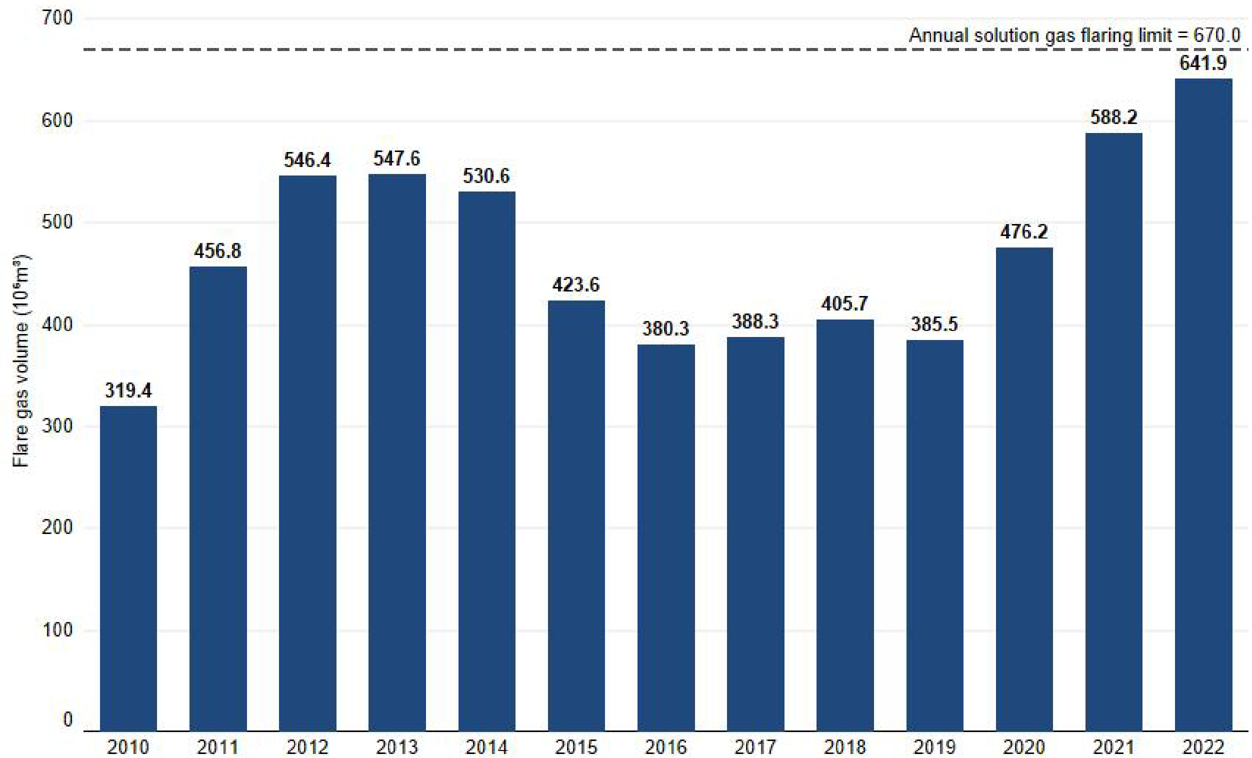


Figure 14. Solution gas flaring, 2010–2022 (Source: Petrinex)

6.2 Solution Gas Venting

In 2022, 130.2 10^6 m^3 of gas was vented from crude oil and crude bitumen batteries, which was a 4.8 per cent decrease from 2021. This is expected when looking at the continuous uptrend of solution gas flaring. The amount of solution gas vented continues to be well below the 2000 baseline of 704 10^6 m^3 (see figure 15).

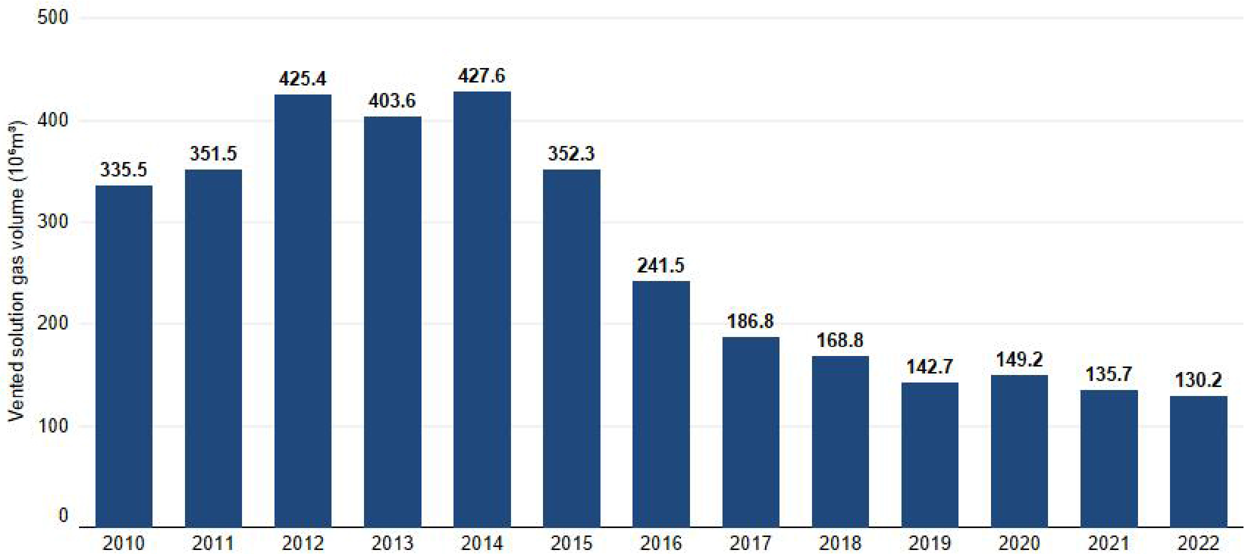


Figure 15. Solution gas venting, 2010–2022 (Source: Petrinex)

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:

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

In 2022, 97.12 per cent of the solution gas produced from crude oil and crude bitumen batteries was conserved, up slightly from 96.99 per cent conservation in 2021.

Figure 16 shows total annual solution gas flared and vented volumes as well as the associated annual conservation rates. As shown in table 8, vent gas volumes decreased from 2021 to 2022 because of the new limits in *Directive 060* introduced in 2022. This results in a minor increase in solution gas conservation in 2022.

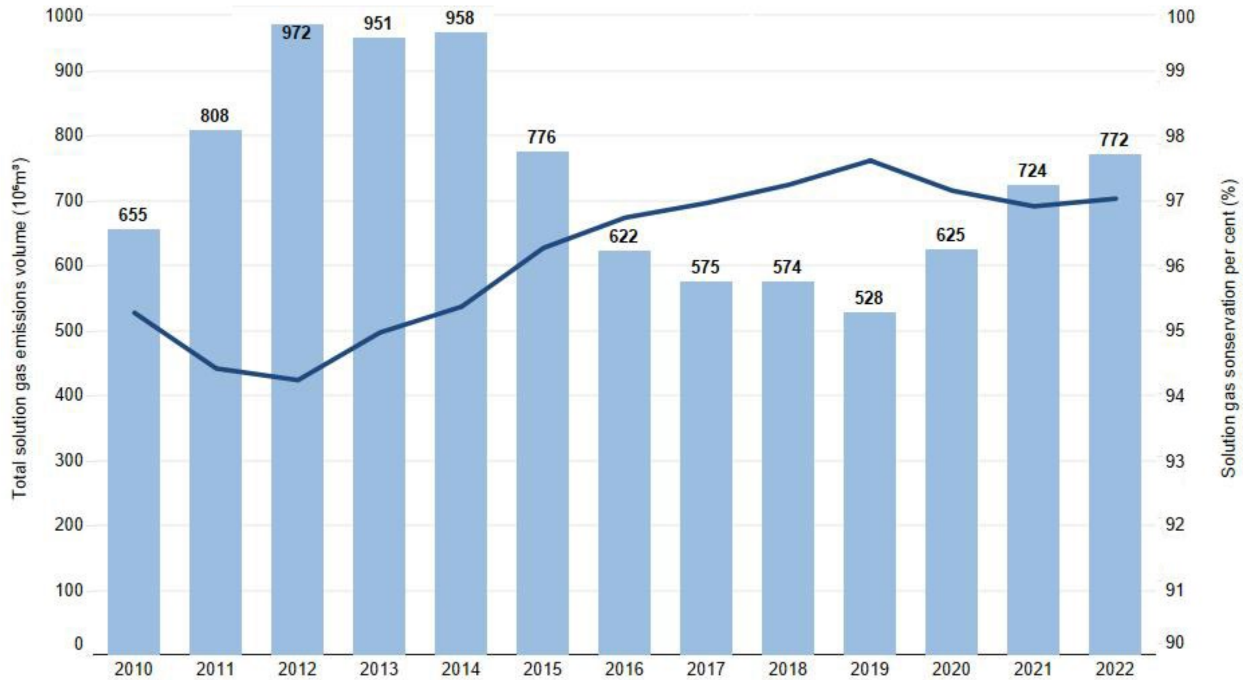


Figure 16. Solution gas conservation, 2010–2022 (Source: Petrinex)

6.4 Nonthermal and Thermal Operations

There are two types of crude bitumen operations: nonthermal operations (e.g., cold heavy oil production) and thermal operations (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 annual solution gas conservation percentages for crude bitumen batteries broken down by nonthermal and thermal operations. Historically, there have been greater conservation rates associated with thermal operations. This remains the case for 2022, where thermal operation conservation is 98.2 per cent while nonthermal operations have a conservation rate of 91.1 per cent.

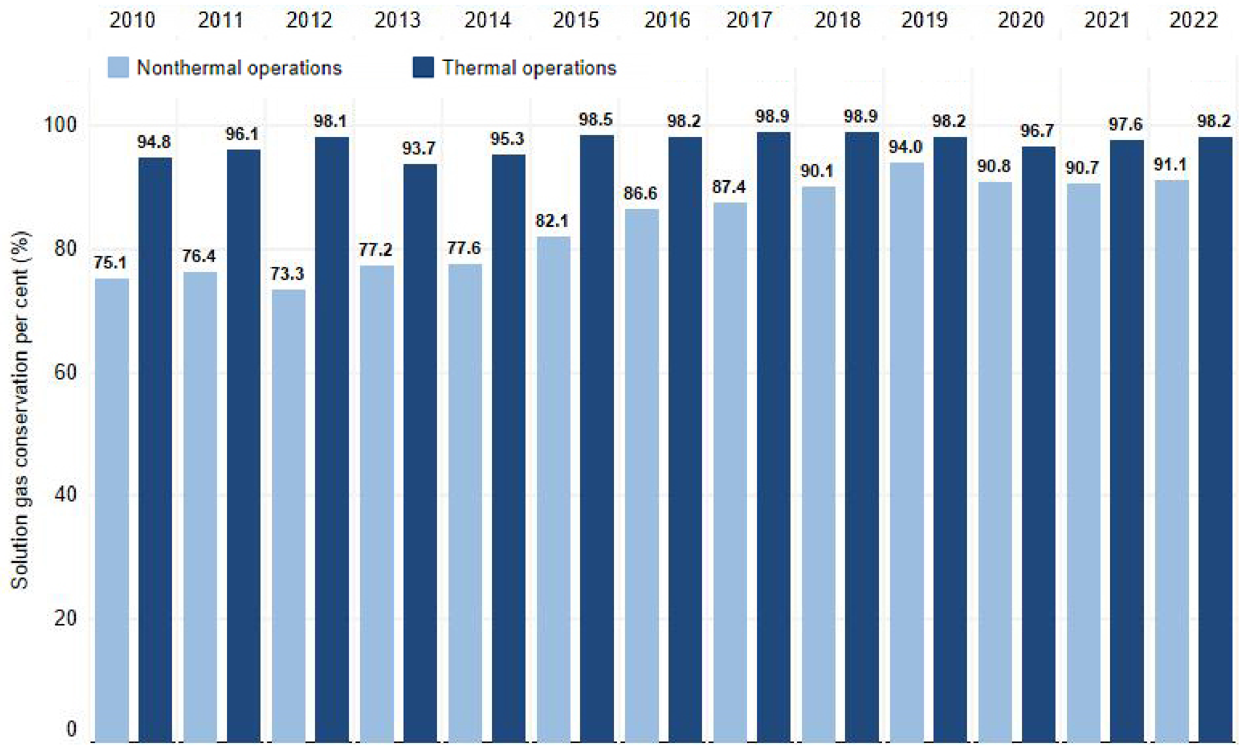


Figure 17. Solution gas conversation by operation type, 2010–2022 (Source: Petrinex)

7 New Facilities Compliance

In 2022, new equipment-level and facility-level vent limits were introduced for facilities with first production or receipt on or after January 1, 2022. These new limits affected DVG limits, pneumatic devices, reciprocating and centrifugal compressors, and glycol dehydrators. It is therefore expected that facilities with a start date in 2022 would have lower reported OneStop methane emissions than older facilities; however, some of the reduction can be attributed to new facilities with partial annual methane data due to their start date later in the reporting year. Using the 2021 OneStop reported data as a baseline for comparison, the 2022 total volumes were 79.7 per cent lower than facilities with first production or receipt in 2021 compared to a 68.1 per cent difference when comparing 2020 to 2021 data (see figure 18).

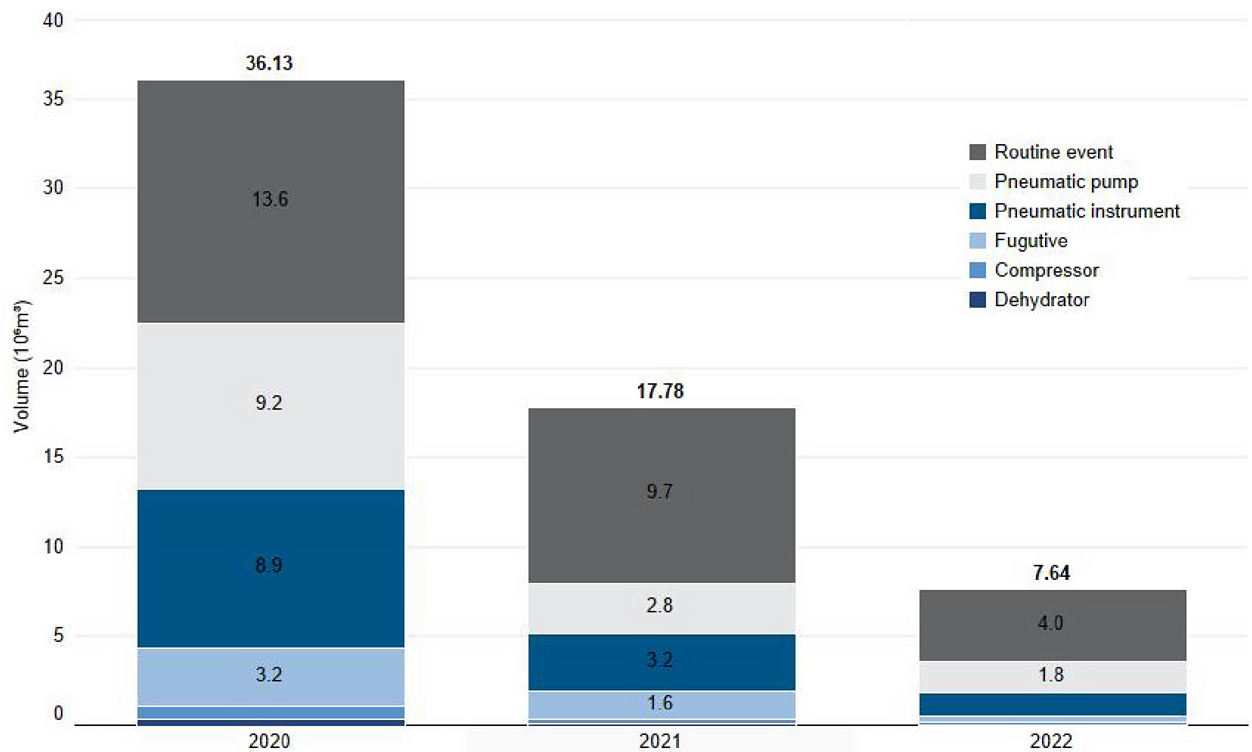


Figure 18. Methane Emissions by Facility Start Date (Source: OneStop)

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 reduction page.

The emission reduction target set for Alberta by the Government of Alberta was to achieve a 45 per cent 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 that is reported above is not complete enough to be considered 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 19 shows the methane emission trend line (a combination of reported data and engineering estimates from standardized methodologies) and the 45 per cent target. These reductions are the result of both early action through programs like the Technology Innovation and Emission Reduction (TIER) regulation Offset System and the methane requirements.

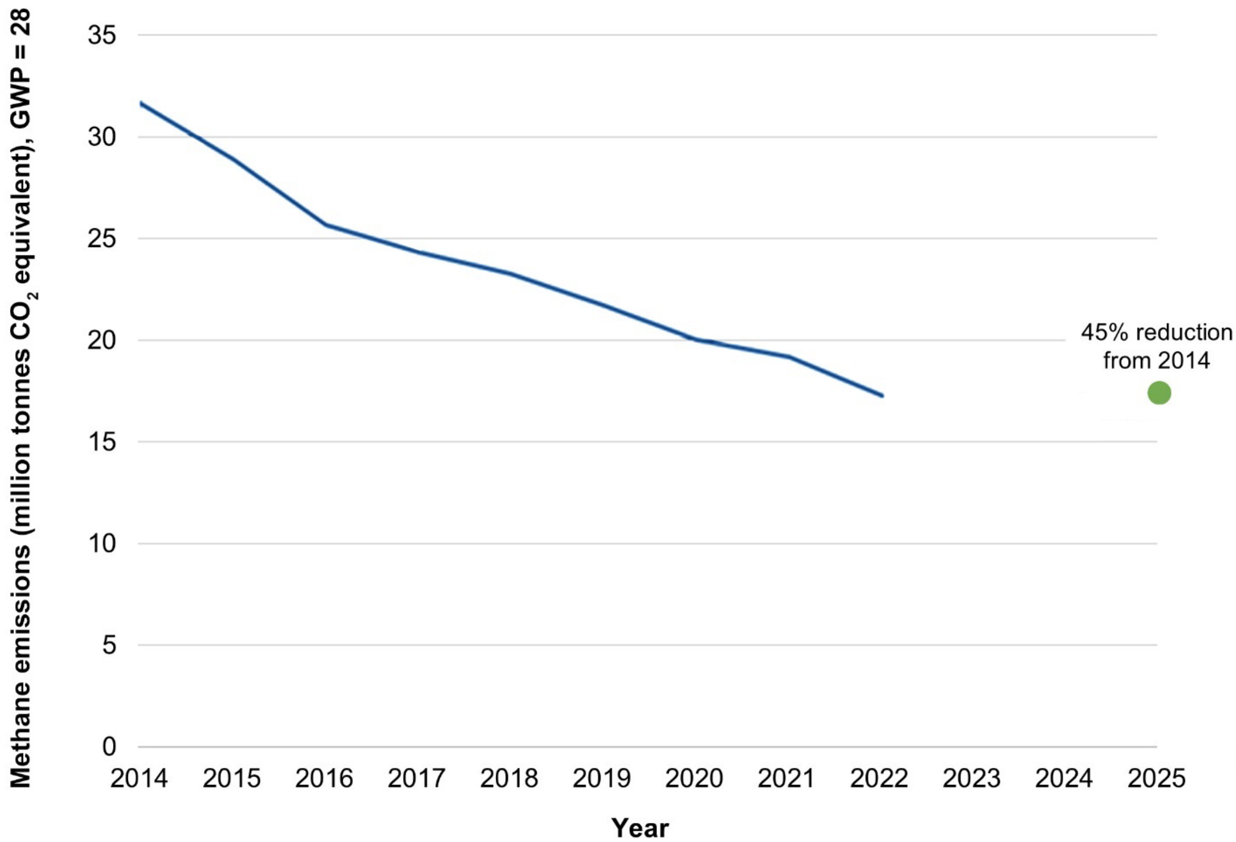
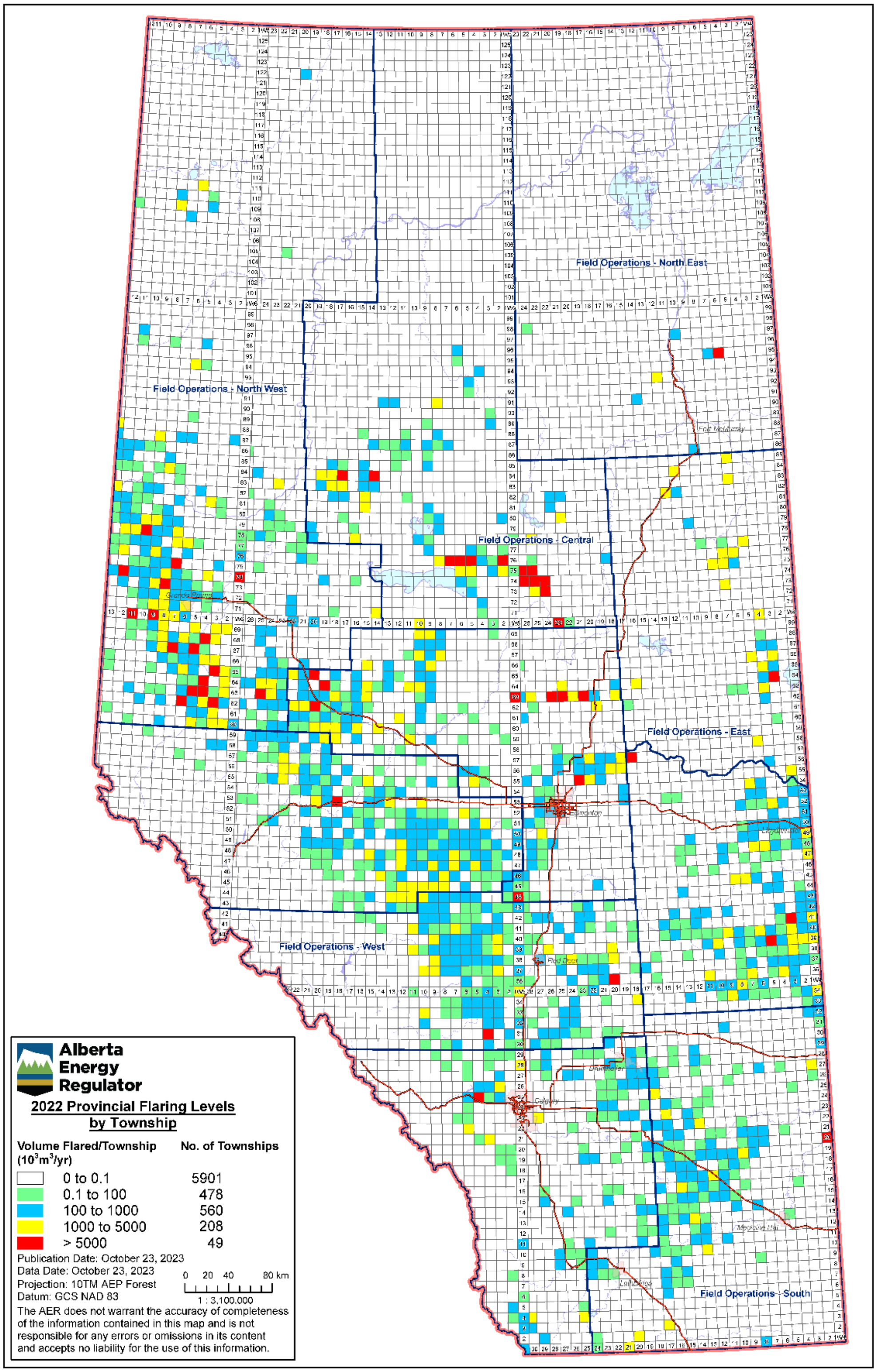


Figure 19. Methane emission reductions, 2014–2022 (reported & estimated emissions)

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 approximately 45 per cent between 2014 and 2022.

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. The AER will evaluate the emission reductions annually, as part of this publication.

Appendix 1 Provincial Flaring and Venting Maps



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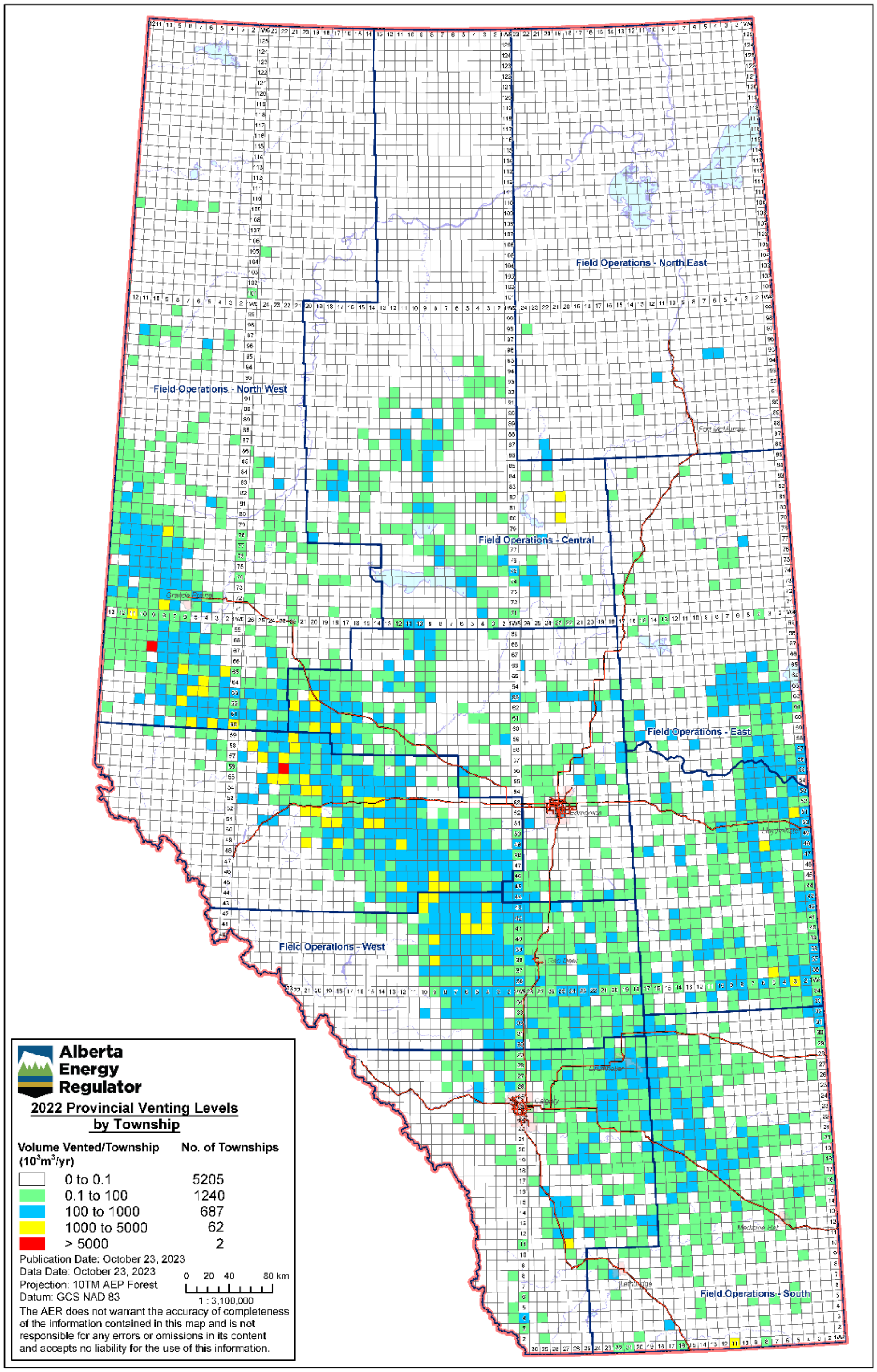

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Appendix 2 Operator Rankings

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 the oil sands assets from the rest. Rankings are based on data as of August 8, 2023.

Venting

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Cenovus Energy Inc.	337 600	1	197 520 466	0.0017	0.0026	−0.0009
Suncor Energy Inc.	334 600	2	93 828 924	0.0036	0.0048	−0.0012
Canadian Natural Resources Limited	185 400	3	140 635 854	0.0013	0.0005	0.0008
MEG Energy Corp.	147 800	4	38 708 629	0.0038	0.0087	−0.0049
Imperial Oil Resources Limited	109 100	5	59 103 669	0.0018	0.0018	0.0000
ConocoPhillips Canada Resources Corp.	102 600	6	58 303 863	0.0018	0.0014	0.0004
Harvest Operations Corp.	43 500	7	3 267 152	0.0133	0.0123	0.0010
Everest Canadian Resources Corp.	30 500	8	689 388	0.0442	0.0456	−0.0013
CNOOC Petroleum North America ULC	25 600	9	19 323 361	0.0013	0.0068	−0.0055
Athabasca Oil Corporation	24 800	10	11 769 434	0.0021	0.0017	0.0005
Strathcona Resources Ltd.	14 700	11	20 410 576	0.0007	0.0016	−0.0009
PetroChina Canada Ltd.	3 600	12	4 475 295	0.0008	0.0012	−0.0004

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	63 932 800	1	98 510 802	0.65	0.75	−13.76
Cenovus Energy Inc.	27 028 600	2	52 780 207	0.51	0.65	−21.20
Tourmaline Oil Corp.	26 837 700	3	98 081 471	0.27	0.27	−0.16
Bonavista Energy Corporation	14 364 200	4	19 147 356	0.75	0.90	−16.47
Repsol Oil & Gas Canada Inc.	8 996 700	5	8 173 752	1.10	1.17	−5.97
TAQA North Ltd.	8 887 700	6	22 488 427	0.40	0.34	16.16
Westbrick Energy Ltd.	8 496 100	7	19 407 836	0.44	0.59	−25.23
Paramount Resources Ltd.	7 812 400	8	22 265 676	0.35	0.38	−6.72
Torxen Energy Ltd.	7 057 400	9	22 889 466	0.31	0.31	−1.27
Peyto Exploration & Development Corp.	6 528 300	10	38 882 384	0.17	0.25	−33.30
Tamarack Valley Energy Ltd.	6 524 600	11	18 421 462	0.35	0.49	−27.18
Spartan Delta Corp.	6 005 900	12	14 684 230	0.41	0.44	−8.00
HWN Energy Ltd.	5 341 600	13	5 224 742	1.02	0.95	7.24
Whitecap Resources Inc.	5 149 300	14	21 106 272	0.24	0.26	−7.54
Obsidian Energy Ltd.	4 584 300	15	7 836 038	0.59	0.70	−16.52

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
ARC Resources Ltd.	4 559 800	16	60 941 353	0.07	0.10	−21.91
I3 Energy Canada Ltd.	4 389 200	17	5 454 577	0.80	1.05	−23.65
Cardinal Energy Ltd.	3 959 900	18	5 819 020	0.68	0.78	−12.51
Ember Resources Inc.	3 826 600	19	16 476 978	0.23	0.25	−7.52
Vermilion Energy Inc.	3 664 100	20	8 824 555	0.42	0.27	53.45
Saturn Oil & Gas Inc.	3 347 300	21	4 243 245	0.79	0.27	197.38
Strathcona Resources Ltd.	3 171 800	22	11 116 143	0.29	0.28	0.64
Harvest Operations Corp.	3 004 700	23	3 194 334	0.94	0.93	0.69
Battle River Energy Ltd.	2 777 000	24	1 395 416	1.99	0.28	609.32
Crescent Point Energy Corp.	2 766 500	25	19 623 411	0.14	0.14	3.07

Combined

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	64 190 500	1	239 146 656	0.27	0.29	−7.16
Cenovus Energy Inc.	27 375 000	2	250 300 674	0.11	0.14	−20.86
Tourmaline Oil Corp.	26 837 700	3	98 081 471	0.27	0.27	−0.16
Bonavista Energy Corporation	14 364 200	4	19 147 356	0.75	0.90	−16.47
Repsol Oil & Gas Canada Inc.	8 996 700	5	8 173 752	1.10	1.17	−5.97
TAQA North Ltd.	8 887 700	6	22 488 427	0.40	0.34	16.16
Westbrick Energy Ltd.	8 496 100	7	19 407 836	0.44	0.59	−25.23
Paramount Resources Ltd.	7 812 400	8	22 265 676	0.35	0.38	−6.72
Torxen Energy Ltd.	7 057 400	9	22 889 466	0.31	0.31	−1.27
Peyto Exploration & Development Corp.	6 528 300	10	38 882 384	0.17	0.25	−33.30
Tamarack Valley Energy Ltd.	6 524 600	11	23 110 536	0.28	0.39	−27.13
Spartan Delta Corp.	6 005 900	12	14 684 230	0.41	0.44	−8.00
HWN Energy Ltd.	5 341 600	13	5 224 742	1.02	0.95	7.24
Whitecap Resources Inc.	5 149 300	14	21 106 272	0.24	0.26	−7.54
Obsidian Energy Ltd.	4 584 300	15	10 194 072	0.45	0.55	−18.91
ARC Resources Ltd.	4 559 800	16	60 941 353	0.07	0.10	−21.91
I3 Energy Canada Ltd.	4 389 200	17	5 454 577	0.80	1.05	−23.65
Cardinal Energy Ltd.	3 959 900	18	5 819 020	0.68	0.78	−12.51
Ember Resources Inc.	3 826 600	19	16 476 978	0.23	0.25	−7.52
Vermilion Energy Inc.	3 664 100	20	8 824 555	0.42	0.27	53.45
Saturn Oil & Gas Inc.	3 347 300	21	4 243 245	0.79	0.27	197.38
Strathcona Resources Ltd.	3 186 500	22	31 526 719	0.10	0.09	10.62
Harvest Operations Corp.	3 048 200	23	6 461 486	0.47	0.46	3.16
Battle River Energy Ltd.	2 777 000	24	1 395 416	1.99	0.28	609.32
Crescent Point Energy Corp.	2 766 500	25	19 623 411	0.14	0.14	3.07

Flaring

Oil Sands Assets

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Suncor Energy Inc.	27 786 600	1	93 828 924	0.2961	0.3075	−0.0113
Canadian Natural Resources Limited	11 527 100	2	140 635 854	0.0820	0.1160	−0.0340
Imperial Oil Resources Limited	8 452 100	3	59 103 669	0.1430	0.0798	0.0632
Strathcona Resources Ltd.	6 558 400	4	20 410 576	0.3213	0.1525	0.1688
Cenovus Energy Inc.	6 097 200	5	197 520 466	0.0309	0.0595	−0.0287
MEG Energy Corp.	4 457 800	6	38 708 629	0.1152	0.1086	0.0066
Greenfire Resources Operating Corporation	3 951 800	7	10 597 035	0.3729	0.3728	0.0001
Connacher Oil and Gas Limited	2 299 200	8	5 652 186	0.4068	0.5597	−0.1529
ConocoPhillips Canada Resources Corp.	2 290 100	9	58 303 863	0.0393	0.0271	0.0122
CNOOC Petroleum North America ULC	1 669 100	10	19 323 361	0.0864	0.0745	0.0119
Harvest Operations Corp.	1 451 600	11	3 267 152	0.4443	0.4376	0.0067
Athabasca Oil Corporation	514 600	12	11 769 434	0.0437	0.0421	0.0016
Everest Canadian Resources Corp.	324 500	13	689 388	0.4707	0.3677	0.1030
PetroChina Canada Ltd.	100	14	4 475 295	0.0000	0.0002	−0.0001

Non-Oil-Sands Assets

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Tamarack Valley Energy Ltd.	127 666 500	1	18 421 462	6.93	6.65	4.24
Canadian Natural Resources Limited	70 427 600	2	98 510 802	0.71	0.83	−14.31
ARC Resources Ltd.	51 776 700	3	60 941 353	0.85	0.93	−8.44
Spur Petroleum Ltd.	51 513 200	4	6 651 186	7.74	11.07	−30.03
Baytex Energy Ltd.	37 464 200	5	4 919 618	7.62	8.00	−4.81
Headwater Exploration Inc.	32 527 000	6	827 010	39.33	87.83	−55.22
Cenovus Energy Inc.	31 103 300	7	52 780 207	0.59	0.55	8.02
Obsidian Energy Ltd.	21 454 500	8	7 836 038	2.74	2.66	2.76
Pieridae Alberta Production Ltd.	20 603 300	9	4 606 304	4.47	2.63	69.99
Tourmaline Oil Corp.	18 934 000	10	98 081 471	0.19	0.25	−21.85
Ovintiv Canada ULC	17 867 200	11	20 991 740	0.85	0.77	10.69
Surge Energy Inc.	16 666 700	12	5 768 171	2.89	2.05	41.23
Murphy Oil Company Ltd.	16 441 600	13	3 220 396	5.11	5.19	−1.58
West Lake Energy Corp.	16 313 100	14	3 845 806	4.24	4.81	−11.82
Crescent Point Energy Corp.	16 281 800	15	19 623 411	0.83	1.03	−19.06
Paramount Resources Ltd.	12 805 400	16	22 265 676	0.58	0.60	−3.61
TAQA North Ltd.	11 962 100	17	22 488 427	0.53	0.37	42.03
Tidewater Midstream and Infrastructure Ltd.	11 850 000	18	869 058	13.64	9.25	47.35
NuVista Energy Ltd.	11 023 800	19	17 987 763	0.61	0.66	−7.54
Hammerhead Resources ULC	10 691 300	20	11 335 990	0.94	0.98	−3.81

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Peyto Exploration & Development Corp.	9 963 700	21	38 882 384	0.26	0.21	23.65
North 40 Resources Ltd.	9 206 700	22	1 613 402	5.71	12.10	−52.85
Enhance Energy Inc.	9 179 800	23	3 665 588	2.50	2.93	−14.49
Westbrick Energy Ltd.	9 019 500	24	19 407 836	0.46	0.10	371.64
Repsol Oil & Gas Canada Inc.	8 808 200	25	8 173 752	1.08	1.05	2.60

Combined

Company	Volume (m^3)	Ran k	Total production (BoE)	Intensity	Previous year intensity	% change
Tamarack Valley Energy Ltd.	127 666 500	1	23 110 536	5.52	5.30	4.33
Canadian Natural Resources Limited	81 954 700	2	239 146 656	0.34	0.39	−12.42
ARC Resources Ltd.	51 776 700	3	60 941 353	0.85	0.93	−8.44
Spur Petroleum Ltd.	51 513 200	4	11 498 177	4.48	5.48	−18.27
Baytex Energy Ltd.	37 464 200	5	13 115 938	2.86	3.79	−24.68
Cenovus Energy Inc.	37 200 500	6	250 300 674	0.15	0.16	−7.89
Headwater Exploration Inc.	32 527 000	7	5 261 286	6.18	7.36	−16.04
Suncor Energy Inc.	27 786 600	8	94 107 964	0.30	0.31	−3.64
Obsidian Energy Ltd.	21 454 500	9	10 194 072	2.10	2.11	−0.18
Pieridae Alberta Production Ltd.	20 603 300	10	4 606 304	4.47	2.63	69.99
Tourmaline Oil Corp.	18 934 000	11	98 081 471	0.19	0.25	−21.85
Ovintiv Canada ULC	17 867 200	12	20 991 740	0.85	0.77	10.69
Surge Energy Inc.	16 666 700	13	5 768 171	2.89	2.05	41.23
Murphy Oil Company Ltd.	16 441 600	14	3 220 396	5.11	5.19	−1.58
West Lake Energy Corp.	16 313 100	15	3 962 861	4.12	4.67	−11.89
Crescent Point Energy Corp.	16 281 800	16	19 623 411	0.83	1.03	−19.06
Strathcona Resources Ltd.	14 827 500	17	31 526 719	0.47	0.33	41.02
Paramount Resources Ltd.	12 805 400	18	22 265 676	0.58	0.60	−3.61
TAQA North Ltd.	11 962 100	19	22 488 427	0.53	0.37	42.03
Tidewater Midstream and Infrastructure Ltd.	11 850 000	20	869 058	13.64	9.25	47.35
NuVista Energy Ltd.	11 023 800	21	17 987 763	0.61	0.66	−7.54
Hammerhead Resources ULC	10 691 300	22	11 335 990	0.94	0.98	−3.81
Peyto Exploration & Development Corp.	9 963 700	23	38 882 384	0.26	0.21	23.65
North 40 Resources Ltd.	9 206 700	24	1 613 402	5.71	12.10	−52.85
Enhance Energy Inc.	9 179 800	25	3 665 588	2.50	2.93	−14.49

Fuel Use

Oil Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	Absolute change
Cenovus Energy Inc.	3 660 759 600	1	197 520 466	18.53	18.97	−0.4370
Canadian Natural Resources Limited	3 445 535 400	2	140 635 854	24.50	23.87	0.6334
Imperial Oil Resources Limited	2 363 391 900	3	59 103 669	39.99	40.64	−0.6515
Suncor Energy Inc.	1 827 400 000	4	93 828 924	19.48	19.00	0.4734
ConocoPhillips Canada Resources Corp.	1 419 096 300	5	58 303 863	24.34	25.74	−1.4028
Strathcona Resources Ltd.	864 640 600	6	20 410 576	42.36	38.17	4.1903
MEG Energy Corp.	669 609 800	7	38 708 629	17.30	17.68	−0.3767
CNOOC Petroleum North America ULC	381 994 200	8	19 323 361	19.77	20.33	−0.5592
Athabasca Oil Corporation	349 988 000	9	11 769 434	29.74	32.76	−3.0208
Greenfire Resources Operating Corporation	306 467 600	10	10 597 035	28.92	30.70	−1.7784
PetroChina Canada Ltd.	254 141 200	11	4 475 295	56.79	50.46	6.3311
Connacher Oil and Gas Limited	208 633 700	12	5 652 186	36.91	39.33	−2.4195
Harvest Operations Corp.	93 828 400	13	3 267 152	28.72	29.21	−0.4877
Everest Canadian Resources Corp.	81 831 700	14	689 388	118.70	145.97	−27.2659
Ipc Canada Ltd.	9 826 800	15	478 954	20.52	19.44	1.0821

Non-Oil-Sands Assets

Company	Volume (m^3)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	1 436 090 200	1	98 510 802	14.58	16.39	−11.04
Tourmaline Oil Corp.	507 441 100	2	98 081 471	5.17	5.14	0.70
ARC Resources Ltd.	432 058 900	3	60 941 353	7.09	7.17	−1.08
Cenovus Energy Inc.	374 432 900	4	52 780 207	7.09	7.52	−5.64
Pieridae Alberta Production Ltd.	335 124 800	5	4 606 304	72.75	64.45	12.88
Tidewater Midstream and Infrastructure Ltd.	258 650 700	6	869 058	297.62	246.29	20.84
Ember Resources Inc.	215 084 500	7	16 476 978	13.05	12.96	0.73
Peyto Exploration & Development Corp.	206 083 400	8	38 882 384	5.30	5.59	−5.12
Torxen Energy Ltd.	177 370 000	9	22 889 466	7.75	7.86	−1.43
Bonavista Energy Corporation	169 374 000	10	19 147 356	8.85	8.92	−0.78
TAQA North Ltd.	142 780 600	11	22 488 427	6.35	7.67	−17.25
Baytex Energy Ltd.	135 634 700	12	4 919 618	27.57	30.22	−8.75
Birchcliff Energy Ltd.	132 654 700	13	26 357 890	5.03	4.92	2.34
Repsol Oil & Gas Canada Inc.	125 807 300	14	8 173 752	15.39	13.69	12.46
Advantage Energy Ltd.	122 574 100	15	22 416 778	5.47	5.81	−5.91

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Ipc Canada Ltd.	110 637 800	16	12 531 864	8.83	8.84	−0.14
Whitecap Resources Inc.	110 146 300	17	21 106 272	5.22	6.03	−13.45
Spartan Delta Corp.	106 005 300	18	14 684 230	7.22	7.02	2.83
Tamarack Valley Energy Ltd.	105 920 200	19	18 421 462	5.75	5.90	−2.50
Pine Cliff Energy Ltd.	100 667 500	20	7 292 938	13.80	14.60	−5.46
NuVista Energy Ltd.	94 913 300	21	17 987 763	5.28	5.97	−11.65
Lynx Energy ULC	94 161 900	22	7 131 868	13.20	12.84	2.82
Paramount Resources Ltd.	90 910 700	23	22 265 676	4.08	4.27	−4.49
Obsidian Energy Ltd.	88 027 100	24	7 836 038	11.23	11.43	−1.74
Ovintiv Canada ULC	81 634 600	25	20 991 740	3.89	4.20	−7.44

Combined

Company	Volume (m³)	Rank	Total production (BoE)	Intensity	Previous year intensity	% change
Canadian Natural Resources Limited	4 881 625 600	1	239 146 656	20.41	21.00	−2.79
Cenovus Energy Inc.	4 035 192 500	2	250 300 674	16.12	16.57	−2.72
Imperial Oil Resources Limited	2 363 391 900	3	61 867 563	38.20	38.80	−1.55
Suncor Energy Inc.	1 827 400 000	4	94 107 964	19.42	18.94	2.54
ConocoPhillips Canada Resources Corp.	1 419 096 300	5	58 788 614	24.14	25.54	−5.49
Strathcona Resources Ltd.	905 159 700	6	31 526 719	28.71	27.22	5.46
MEG Energy Corp.	669 610 600	7	42 107 793	15.90	16.11	−1.26
Tourmaline Oil Corp.	507 441 100	8	98 081 471	5.17	5.14	0.70
ARC Resources Ltd.	432 058 900	9	60 941 353	7.09	7.17	−1.08
Athabasca Oil Corporation	386 524 100	10	13 601 242	28.42	29.68	−4.25
CNOOC Petroleum North America ULC	381 994 200	11	19 492 215	19.60	20.15	−2.75
Pieridae Alberta Production Ltd.	335 124 800	12	4 606 304	72.75	64.45	12.88
Greenfire Resources Operating Corporation	306 467 600	13	10 698 220	28.65	30.28	−5.40
Tidewater Midstream and Infrastructure Ltd.	258 650 700	14	869 058	297.62	246.29	20.84
PetroChina Canada Ltd.	254 141 200	15	8 044 418	31.59	29.60	6.74
Ember Resources Inc.	215 084 500	16	16 476 978	13.05	12.96	0.73
Connacher Oil and Gas Limited	208 633 700	17	5 908 042	35.31	37.96	−6.97
Peyto Exploration & Development Corp.	206 083 400	18	38 882 384	5.30	5.59	−5.12
Torxen Energy Ltd.	177 370 000	19	22 889 466	7.75	7.86	−1.43
Bonavista Energy Corporation	169 374 000	20	19 147 356	8.85	8.92	−0.78
TAQA North Ltd.	142 780 600	21	22 488 427	6.35	7.67	−17.25
Baytex Energy Ltd.	135 634 700	22	13 115 938	10.34	14.32	−27.81
Harvest Operations Corp.	135 188 500	23	6 461 486	20.92	21.14	−1.03
Birchcliff Energy Ltd.	132 654 700	24	26 357 890	5.03	4.92	2.34
Repsol Oil & Gas Canada Inc.	125 807 300	25	8 173 752	15.39	13.69	12.46

Total Solution Gas Emitted (tCO_2e)

The AER has ranked companies based on 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 percent flare conversion efficiency and 85 percent 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 meters ($10^3\ m^3$) of gas
- Vented gas GHG emission factor: 16.1 tCO_2e per thousand cubic meters ($10^3\ m^3$) 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	0.51	1	40.22	25.73
Tamarack Valley Energy Ltd.	0.36	2	119.88	5.06
Cenovus Energy Inc.	0.15	3	19.30	6.61
Spur Petroleum Ltd.	0.13	4	51.36	0.56
Headwater Exploration Inc.	0.08	5	32.53	0.60
Obsidian Energy Ltd.	0.08	6	9.14	3.53
Whitecap Resources Inc.	0.07	7	4.81	3.76
Cardinal Energy Ltd.	0.07	8	7.00	3.42
Suncor Energy Inc.	0.07	9	27.79	0.33
Saturn Oil & Gas Inc.	0.06	10	4.58	3.33
Surge Energy Inc.	0.06	11	14.92	1.62
West Lake Energy Corp.	0.05	12	16.31	0.75
Karve Energy Inc.	0.05	13	5.02	2.32
North 40 Resources Ltd.	0.04	14	9.21	1.37
Crescent Point Energy Corp.	0.04	15	13.54	0.68
Strathcona Resources Ltd.	0.04	16	7.23	1.31
Tourmaline Oil Corp.	0.04	17	7.83	1.09
Baytex Energy Ltd.	0.04	18	10.36	0.70
Rubellite Energy Inc.	0.03	19	7.98	0.93
Ipc Canada Ltd.	0.03	20	7.13	1.01
Murphy Oil Company Ltd.	0.03	21	9.78	0.23
Canamax Energy Ltd.	0.02	22	7.24	0.47
Imperial Oil Resources Limited	0.02	23	8.45	0.26
Enhance Energy Inc.	0.02	24	9.13	0.05
Rockeast Energy Corp.	0.02	25	7.37	0.01

Total Methane Emissions

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

Company	Volume emitted ($MtCO_2e$)	Rank
Canadian Natural Resources Limited	1.25	1
Cenovus Energy Inc.	0.56	2
Tourmaline Oil Corp.	0.40	3
Bonavista Energy Corporation	0.20	4
TAQA North Ltd.	0.16	5
Westbrick Energy Ltd.	0.14	6
Paramount Resources Limited	0.13	7
Torxen Energy Ltd.	0.12	8
Crescent Point Energy Corp.	0.11	9
Whitecap Resources Inc.	0.11	10
Repsol Oil & Gas Canada Inc.	0.11	11
Peyto Exploration & Development Corp.	0.10	12
Spartan Delta Corp.	0.10	13
Tamarack Valley Energy Ltd.	0.09	14
Obsidian Energy Ltd.	0.09	15
ARC Resources Ltd.	0.08	16
I3 Energy Canada Ltd.	0.08	17
HWN Energy Ltd.	0.08	18
Long Run Exploration Ltd.	0.08	19
Vermillion Energy Inc.	0.07	20
Cardinal Energy Ltd.	0.07	21
Ember Resources Inc.	0.06	22
Lynx Energy ULC	0.06	23
Harvest Operations Corp.	0.06	24
Surge Energy Inc.	0.05	25