Alberta
Energy
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Upstream Petroleum Industry Emissions Report

Industry Performance for Year Ending December 31, 2020

January 2022

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ST60B-2021: Upstream Petroleum Industry Emissions Report

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Executive Summary

The Alberta Energy Regulator (AER) has published the *ST60B: Upstream Petroleum Industry Flaring and Venting Report* annually since 2001. This year, the report was revised to include fuel volumes, source-specific vent volume breakdowns, and fugitive emissions volumes, in addition to flaring and venting volumes. Given the expanded scope, the report was also renamed the *Upstream Petroleum Industry Emissions Report*.

In 2018, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* was revised to include limits to reduce methane emissions and expand the scope of methane emissions reported to the AER. As a result of the more extensive methane emission reporting requirements, this report now expands past its historic focus on solution gas to present a broader view of upstream oil and gas fuel, flare, vent, and fugitive emissions across the province.

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 OneStop.

Key statistics from 2020:

Production (from ST98: Alberta Energy Outlook)

- Crude bitumen production decreased by 3.9 per cent to 173.1 10^6 m^3.
- Crude oil production decreased 12.5 per cent to 24.6 10^6 m^3.
- Gas production decreased 4.1 per cent to 105.1 10^9 m^3.
- Solution gas production from crude oil and bitumen batteries decreased by 2.5 per cent to 22.2 10^9 m^3.

Fuel Use

- Total reported fuel use decreased by 4.3 per cent to 26.5 10^9 m^3. The decrease is likely the result of both a production decline from 2019 to 2020 and the fuel, flare, and vent definition changes that came into effect in 2020.

Flaring

- Total reported flaring increased by 21.5 per cent to 865.9 10^6 m^3. Flaring volume increase was expected because of the fuel, flare, and vent definition changes. This increase may also reflect companies meeting new venting limits in *Directive 060* by flaring, incinerating, or combusting. This was the first year the AER collected data under the new definitions and expect the magnitude of yearly change to be less substantial in subsequent years.

- Reported solution gas flaring increased by 23.5 per cent to 475.7 10^6 m^3.

Venting

- Total reported venting increased by 98.8 per cent to 347.4 10^6 m^3. Venting volume increase was expected because of the fuel, flare, and vent definition changes. This was the first year the AER collected data under the new definitions and expect the magnitude of yearly change to be less substantial in subsequent years.
- OneStop source-specific venting and fugitive emissions were both reported for the first time this year at a total volume of 547.1 10^6 m^3.
- Reported solution gas venting increased by 2.3 per cent to 147.9 10^6 m^3.

Solution Gas Conservation

- Solution gas conservation decreased to 97.2 from 97.7 per cent in 2019.

Fugitive Emissions

- Total fugitive emissions reported in OneStop were 70.1 10^6 m^3. This was the first year the AER has received comprehensive fugitive emission data required under the new methane requirements in section 8 of *Directive 060*.
- Surface casing vent flow (SCVF) and gas migration (GM) were reported at 10 246 wells, which was a decrease of 0.8 per cent. The associated fugitive emissions decreased by 2.4 per cent to 64.5 10^6 m^3.

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* (for example, crude bitumen schemes are covered, but oil sands schemes are not).

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* (*AAAQO*).

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 2020 data that was submitted on or before August 5, 2021. Annual reported data may change over time due to data amendments and compliance enforcement activities. So previous-year data reported here may differ from earlier reports.

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

1.1 Important Notes for this Year's Publication

The AER has published the *ST60B: Upstream Petroleum Industry Flaring and Venting Report* annually since 2001. This year, the report was revised to include more comprehensive methane emissions reporting and was renamed the *Upstream Petroleum Industry Emissions Report*.

Historically, this report primarily focused on solution gas, and while solution gas is still reported here, it now presents a broader view of upstream oil and gas emissions across the province. In 2018, *Directive 060* was revised to include limits and requirements to reduce methane emissions. This revision had a few important implications for this report:

1) *Changes to the fuel, flare, and vent gas definitions* resulted in significant differences in reported volumes from 2019 to 2020. As a result, comparing 2019 and 2020 Petrinex volumes in this year's report would not be an accurate reflection of the year over year trend. These differences are commented on throughout the report in more detail.
2) *An increase in the scope of emissions reported to the AER* now better reflects the state of emissions (particularly methane emissions) in the province with the inclusion of source-specific and fugitive emission reporting requirements. This increased level of granularity is now reflected throughout the report in source-specific categories.
3) *Differences in Petrinex and OneStop total vent volumes* were observed in 2020 reported data. The reasons for these differences may include operators using different emission management systems; incomplete transition of Petrinex reporting systems to adapt to the change in fuel, flare, and vent definitions; and different estimation methods used for Petrinex and OneStop.

1.2 Facility Information

For this report, volume data is presented by facility subtype. This categorization is relevant to both Petrinex and OneStop because reporting is done by facility ID, which includes a facility subtype identifier. To provide more context for the data presented in this report, it may be helpful to understand how many active facilities there were. Table 1 shows the facility subtype counts for active reporting facilities in 2019 and 2020.

Table 1. Active facility counts by subtype for 2019 and 2020

Facility subtype	2019 count	2020 count	Per cent change
Crude bitumen batteries	4 157	3 542	−15%
Crude oil batteries	8 699	8 521	−2%
Gas batteries	9 585	9 509	−1%
Gas plants	527	531	1%
Gas gathering / compressor stations	6 633	6 899	4%
Other	1 935	1 935	0%
Total	**31 536**	**30 937**	**−2%**

The "crude bitumen battery" subtype includes thermal and nonthermal bitumen-producing batteries, 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. Data from facilities associated with bitumen mining are not included in this report.

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.

2.1 Historic Petrinex Fuel Use Data – Prior to Fuel Gas Definition Change

Figure 1 shows fuel volumes over the past 10 years, as reported to Petrinex. These volumes represent the yearly total of combined monthly reported fuel volume by facility subtype.

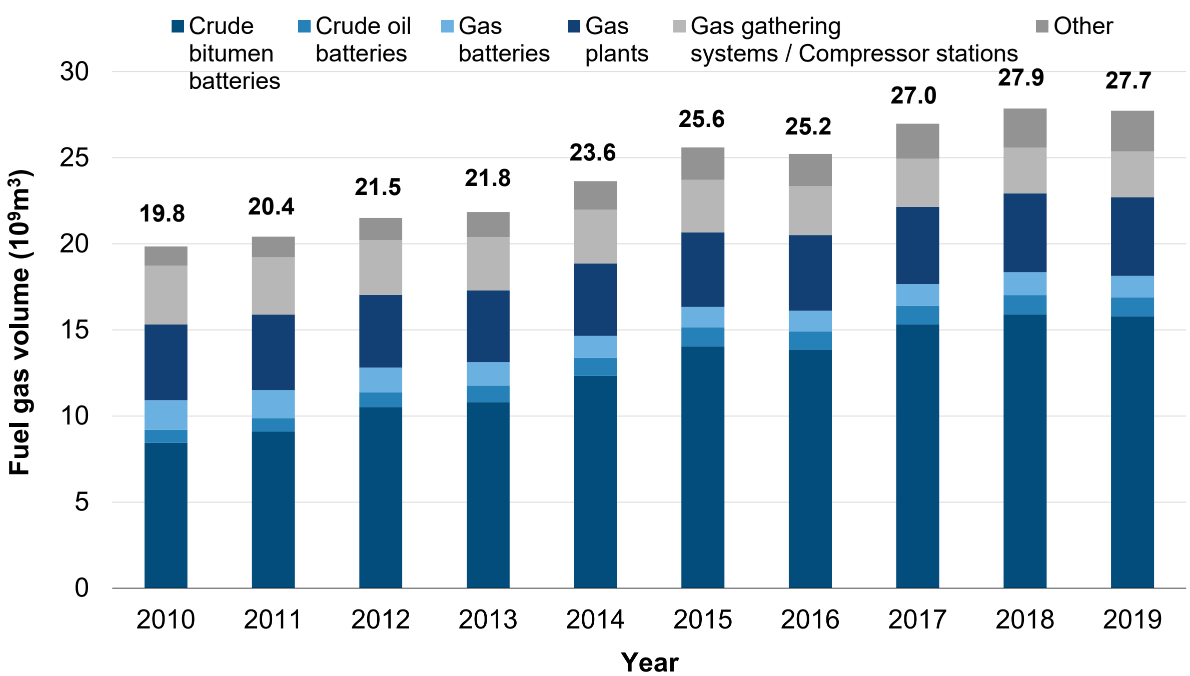


Figure 1. Fuel gas use from 2010 to 2019 reported to Petrinex by facility subtype

2.2 2020 Petrinex Fuel Use Data – After Fuel Gas Definition Change

While figure 1 shows that fuel gas use has primarily been increasing each year, in 2020, reported fuel gas use decreased to 26.5 10^9 m^3. One reason for this decrease is because of a change in the fuel gas definition within *Directive 060*. 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. Since this gas is ultimately vented to the atmosphere, we changed the definitions to now consider this as vent gas and require it to be reported as such in Petrinex. However, this is not the only contributor to the fuel gas reduction. Reported fuel volume decreased by 1189.7 10^6 m^3, while flare and vent volumes increased by 153.0 10^6 m^3 and 172.6 10^6 m^3, respectively. The fuel gas decrease is greater than the increases in flare and vent volumes combined, indicating that the lower active facility count and lesser production in 2020 were also contributing factors to a fuel gas decrease.

Figure 2 shows a breakdown of 2020 reported fuel volumes by facility subtype. Crude bitumen batteries report the highest fuel gas volumes, which is consistent with historical data.

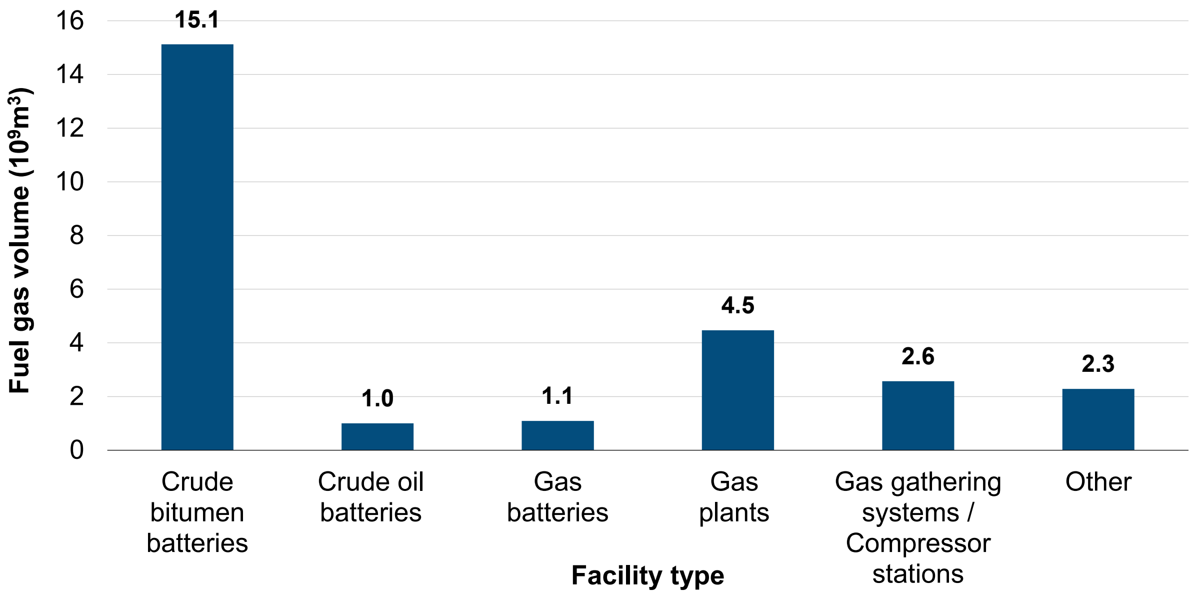


Figure 2. 2020 fuel gas use reported to Petrinex by facility subtype

3 Flaring

Flaring is the action of combusting gas in a flare or incinerator at upstream oil and gas operations. Gas that is combusted in a flare or incinerator (including an enclosed combustor), must be reported as flare gas in Petrinex; some examples include waste gas, pilot gas, dilution gas, acid gas, blanket gas, purge gas, and gas that is flared or incinerated during well completions, well unloading operations, or equipment failures, and plant upsets.

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.

A provincial flaring map can be found in appendix 1. Flaring performance rankings by operator can be found in appendix 2.

3.1 Historic Petrinex Flaring Data – Prior to Flare Gas Definition Change

Figure 3 shows flare volumes over the past 10 years, as reported to Petrinex. These volumes represent the yearly total of combined monthly reported flare volumes by facility subtype.

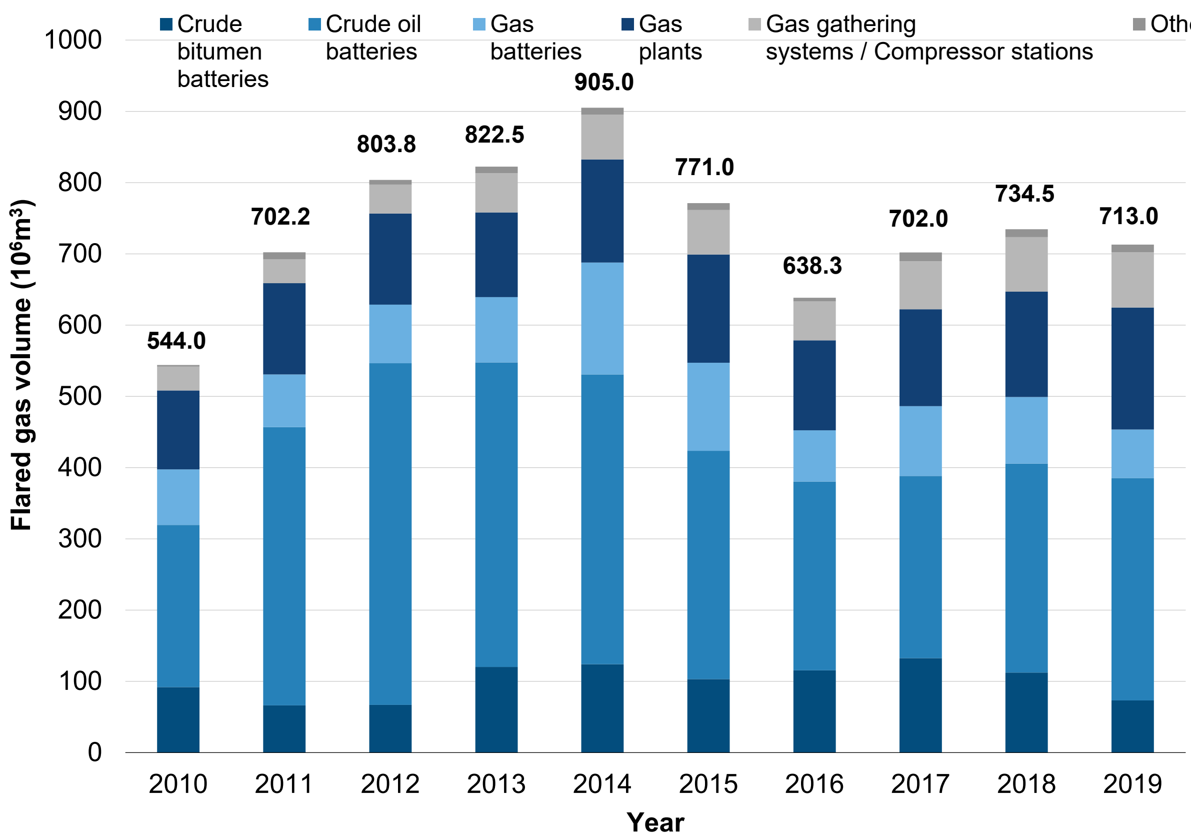


Figure 3. Flared gas from 2010 to 2019 by facility subtype

3.2 2020 Petrinex Flaring Data – After Flare Gas Definition Change

Total reported flaring in 2020 was 865.9 10^6 m^3. Flare volumes in 2020 likely increased because of both the flare gas definition change and the introduction of new methane requirements in 2020 that emphasize methane (vent gas) reductions. Certain gas volumes, such as waste gas or pilot or purge gas used during combustion activities (prevalent at crude bitumen batteries given the high associated solution gas venting potential) were previously being reported as fuel in 2019 but are now being reported as flare.

The 2020 volume increase at crude bitumen batteries, may also reflect an actual increase in flaring, as operators route more gas to combustion equipment to meet the new venting limits.

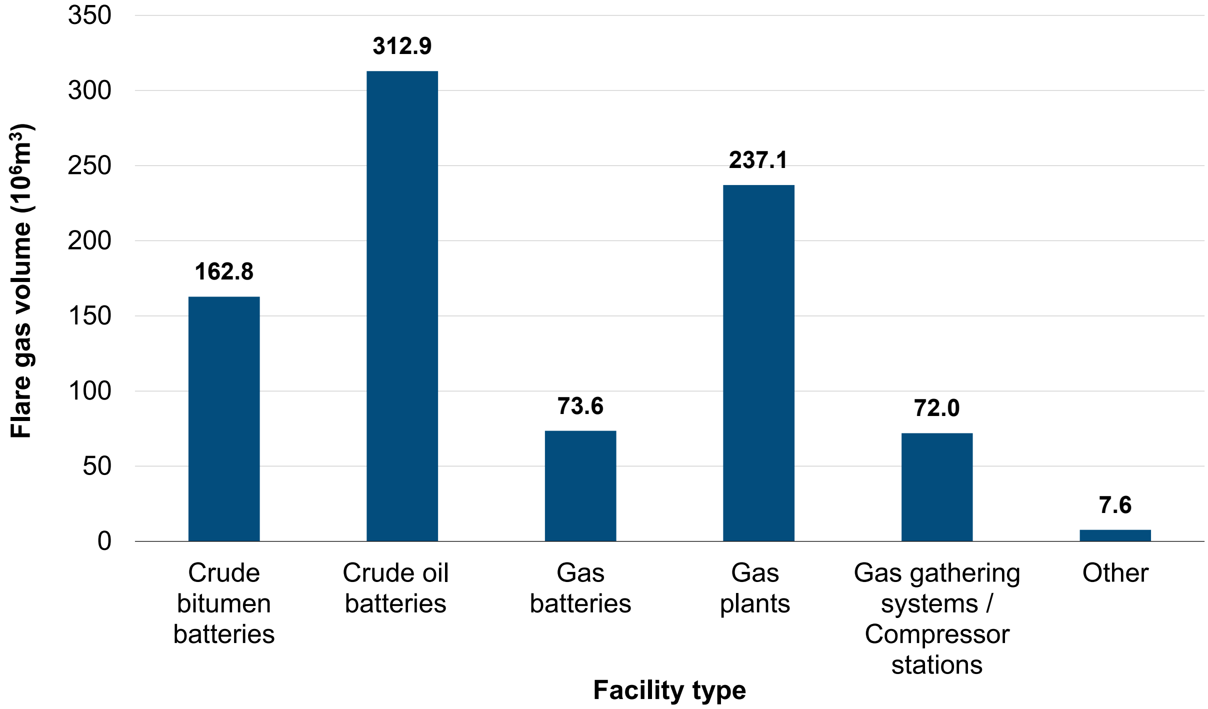


Figure 4. 2020 flare gas reported to Petrinex by facility subtype

3.3 Gas Plant Flaring

Table 2 shows the top 30 gas plants that flared in 2020 by volume and the percentage of the total gas received at each plant that is flared.

Table 2. Top 30 flaring gas plants in 2020

Gas plant	Location[a]	Operator name	Gas flared (10^6 m^3)	Gas flared as a percentage of plant gas receipts (%)
ABGP0001892	04-08-075-07W6	Ovintiv Canada ULC	10.2	0.49
ABGP0001147	11-18-074-12W6	Veresen Midstream General Partner Inc.	8.9	0.25
ABGP0001107	01-12-062-20W5	Energy Transfer Canada ULC	8.0	0.48
ABGP0001350	01-08-070-11W6	Cenovus Energy Inc.	7.3	0.49
ABGP0001084	04-11-053-18W5	Repsol Oil & Gas Canada Inc.	7.2	0.64
ABGP0150386	04-07-073-08W6	Keyera Energy Ltd.	7.1	1.97
ABGP0001901	10-11-020-01W4	Plains Midstream Canada ULC	6.7	0.07
ABGP0001060	09-27-031-04W5	AltaGas Ltd.	6.4	0.19
ABGP0001129	13-26-067-05W6	Canadian Natural Resources Limited	5.3	0.66
ABGP0149088	03-18-084-17W5	Baytex Energy Ltd.	5.2	4.42
ABGP0001004	02-05-044-01W5	Keyera Energy Ltd.	5.1	0.23
ABGP0152315	12-35-070-09W6	Tidewater Midstream and Infrastructure Ltd.	5.1	0.71
ABGP0001133	11-35-037-09W5	Keyera Energy Ltd.	5.0	0.45
ABGP0001520	06-19-073-08W6	NuVista Energy Ltd.	4.4	0.57
ABGP0001113	09-06-063-25W5	Keyera Energy Ltd.	4.3	0.22

Gas plant	Location[a]	Operator name	Gas flared (10^6 m^3)	Gas flared as a percentage of plant gas receipts (%)
ABGP0118855	08-13-063-05W6	Pembina Gas Services Ltd.	4.2	0.34
ABGP0001506	01-01-078-10W6	Canadian Natural Resources Limited	4.1	0.32
ABGP0094954	08-11-060-03W6	Pembina Gas Services Ltd.	4.0	0.17
ABGP0001134	02-04-021-04W5	Caledonian Midstream Corporation	3.9	3.23
ABGP0145129	14-28-062-20W5	Pembina Gas Services Ltd.	3.6	0.21
ABGP0001108	06-12-046-14W5	Keyera Energy Ltd.	3.4	0.27
ABGP0001037	13-13-025-05W5	Pieridae Alberta Production Ltd.	3.3	0.37
ABGP0134628	09-26-062-06W6	Pembina Gas Services Ltd.	3.1	0.26
ABGP0001144	03-15-059-18W5	Energy Transfer Canada ULC	3.1	0.18
ABGP0001056	02-20-004-30W4	Pieridae Alberta Production Ltd.	3.0	0.30
ABGP0150355	03-19-067-07W6	Keyera Energy Ltd.	2.7	0.37
ABGP0001351	04-08-069-08W6	Canadian Natural Resources Limited	2.6	0.10
ABGP0130964	15-07-060-18W5	XTO Energy Canada	2.5	0.20
ABGP0001740	04-25-062-06W6	Pembina Gas Services Ltd.	2.5	0.16
ABGP0001121	06-10-044-12W5	Keyera Energy Ltd.	2.5	0.39
Total			**144.6**	

[a] Legal Subdivision, Section, Township, Range, West of the *n*th Meridian.

3.4 Well Testing

Directive 060 requires that operators seek alternatives to well test flaring and venting. 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 is required to 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 Digital Data Submission (DDS) System and is compiled through the Compliance and Operations Management (COM) System. Given they are a unique subset of flaring, they are presented separately here.

In 2020, 488 production well tests were completed, compared with 664 tests in 2019. Flaring or venting occurred during 73 per cent of the well tests in 2020, compared with 77 per cent of the tests in 2019.

Table 3 shows that the average volume of gas flared per test in 2020 was 72.9 10^3 m^3, compared with 58.1 10^3 m^3 per test in 2019, an increase of 25.5 per cent. However, this still represents a decline in well test flare volumes compared to 2011–2018.

Table 3. Average volume of gas flared per well test and number of wells drilled by type

Year	Volume flared per well test (10^3 m^3)	Number of horizontal multistage fractured gas wells	Number of horizontal multistage fractured oil wells	Total number of wells drilled[a]
2010	63.5	350	778	8 946
2011	83.2	645	1 645	9 303
2012	102.3	530	1 839	8 143
2013	109.8	626	1 612	7 812
2014	140.6	846	1 506	7 543
2015	125.2	662	573	3 411
2016	99.9	512	419	2 638
2017	88.6	858	910	4 895
2018	83.4	599	1 004	5 095
2019	58.1	406	596	3 951
2020	72.9	411	348	2 338

[a] The total count of wells includes both development and exploratory, oil bitumen and gas wells, and both vertical and horizontal drills. Counts were obtained from *ST59: Alberta Drilling Activity Monthly Statistics*.

Historically, well testing volumes have been manually reviewed by the AER. However, given a steadying trend in the quality of the reported data, this exercise was not done this year. A detailed data review of all well testing submissions is not expected in subsequent years unless data anomalies are observed.

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 to the AER for both the protection of the environment and for meeting provincial methane emission reduction goals.

The AER collects venting data through Petrinex (monthly) and OneStop (annually). Petrinex vent gas volumes include both routine and nonroutine vent gas, while OneStop only includes routine vent gas. However, OneStop provides greater emission breakdowns by source type, as discussed and shown below.

In the 2020 data, AER observed differences in the total vent volumes reported to Petrinex and the total vent volumes reported to OneStop. While these volumes are not expected to align (Petrinex includes nonroutine venting), we would expect Petrinex total vent volumes to be greater than OneStop vent volumes, and that was not always the case. The reported Petrinex vent volume (including routine and nonroutine) in 2020 was 347.1 10^6 m^3, while the reported OneStop vent volume in 2020 was 477.0 10^6 m^3. The reasons for these differences may include operators using different emission management systems; incomplete transition of Petrinex reporting systems to adapt to the change in fuel, flare, and vent definitions; and different estimation methods used for Petrinex and OneStop.

A provincial venting map can be found in appendix 1. Venting performance rankings by operator can be found in appendix 2.

Greater detail on overall methane performance can be found in section 7 and on our [methane performance webpage](#).

4.1 Historic Petrinex Venting Data – Prior to Vent Gas Definition Change

Routine and nonroutine volumes are reported as a combined monthly volume to Petrinex. Figure 5 shows annual vent gas volumes over the past 10 years by facility subtype. In this period of time (prior to changing the vent gas definition), overall venting had been decreasing since 2014.

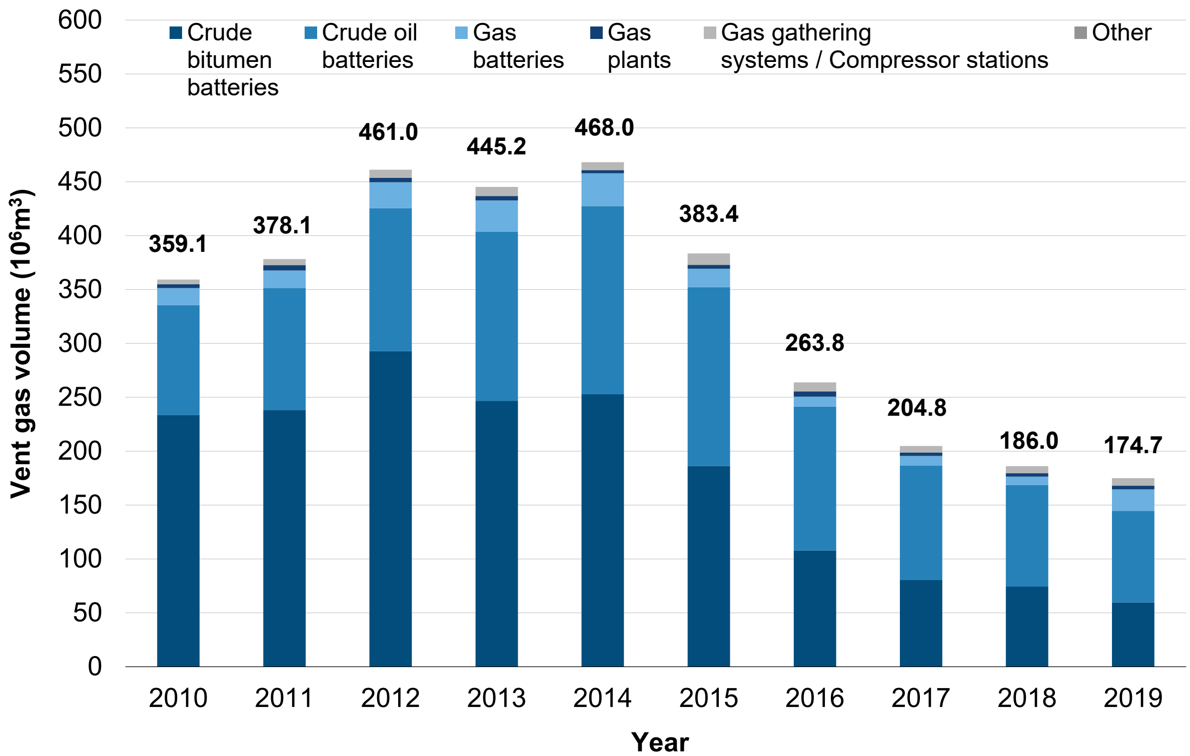


Figure 5. Vent gas from 2010 to 2019 by facility subtype reported to Petrinex

4.2 2020 Petrinex Venting Data – After Vent Gas Definition Change

In 2020, vent gas was 347.4 10^6 m^3, which is a significant increase from the volumes reported in 2019. This likely represents a shift in volume from one reporting category to another (fuel gas to vent gas). The definition for vent gas was revised as part of the methane reduction requirements. Starting in 2020, volumes that would have previously been reported as fuel gas are now being reported as vent gas. For example, the previous definition of gas used to drive a pneumatic device was fuel gas. Since this gas is ultimately vented to the atmosphere, it is reported as vent gas in Petrinex.

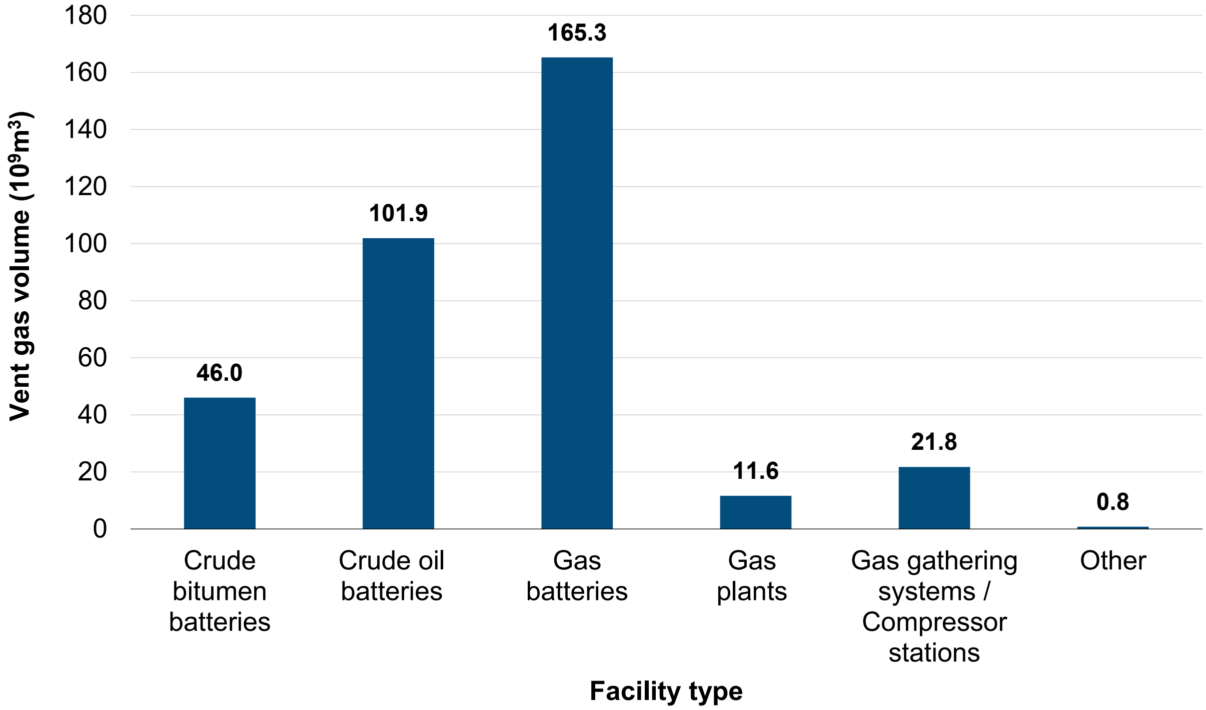


Figure 6. 2020 vent gas reported to Petrinex by facility subtype

In 2020, venting from facilities associated with gas production (batteries, compressor stations, and gas plants) increased most significantly. This is likely a result of the presence of pneumatic devices, compressors, and dehydrators at these facilities, whose associated volumes would have been reported as fuel in 2019 and were reported as vent in 2020.

4.3 OneStop Source-Specific Emissions

Volumetric data reported to the AER through OneStop, as required under *Directive 060*, provides greater detail on the source-specific contributions to the methane emission baseline. Source-specific volume breakdowns are provided in subsequent sections. In 2020, total OneStop vent volumes were 477.0 10^6 m^3. This volume includes the sources identified in table 4 but does not include nonroutine volumes. Nonroutine volumes are reported in Petrinex.

Table 4 shows data reported in 2020 broken down by source category and facility subtype; this is also visually represented in figure 7. The data below represents most of the facilities that were required to report, however, at the time of publication, there was a 90 per cent submission compliance rate.

Table 4. 2020 source-specific volumes reported to OneStop by facility subtype (10^6 m^3)

Facility subtype	Defined vent gas	Pneu-matic pumps	Pneumatic instru-ments	Recipro-cating compres-sors	Centrifugal compres-sors	Glycol dehydra-tors[a]	OneStop vent total
Crude bitumen battery	41.7	1.1	0.6	0.3	0.0	0.0	43.8
Crude oil battery	65.3	20.3	23.3	3.6	0.0	0.5	112.9
Gas battery	32.5	108.9	96.0	3.3	0.1	4.2	244.9
Gas gathering / compressor station	8.1	3.6	7.9	10.1	0.3	10.6	40.6
Gas plant	15.2	1.8	3.2	9.6	0.8	1.7	32.3
Other	1.3	0.2	0.4	0.0	0.0	0.4	2.4
Total	164.1	135.9	131.4	26.9	1.2	17.4	476.9

a Only methane mass is reported to OneStop. Glycol dehydrator volumes were converted from mass to volume for this table.

The data in figure 7 shows that gas batteries have the greatest associated vent volumes, because of the high presence of pneumatic devices at these facility subtypes. Defined vent gas (DVG) is the greatest contributing source for both crude oil and crude bitumen batteries, likely due to the presence of hydrocarbon storage tanks at these sites. As the AER continues to evaluate improvements to tank emission estimates, we may see fluctuations in these reported volumes in subsequent years.

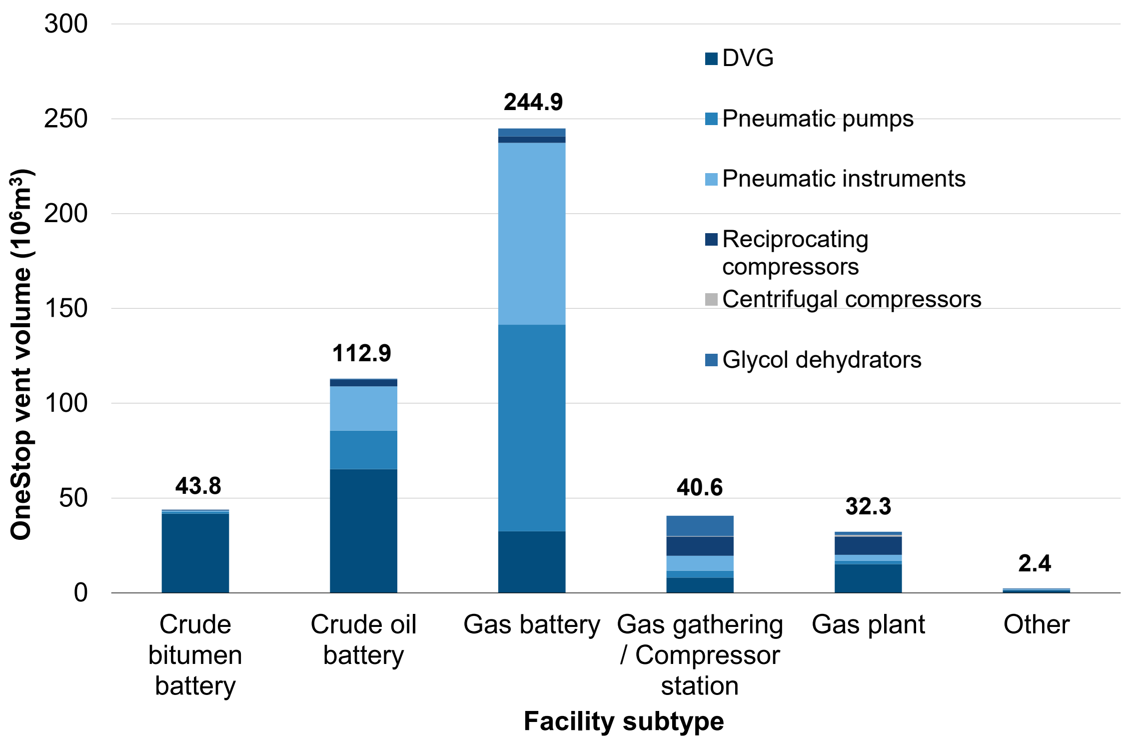


Figure 7. Reported OneStop vent volumes by source category and facility subtype

4.3.1 Defined Vent Gas

Directive 060 includes vent limits for DVG (routine vent gas, excluding gas from pneumatic devices, compressor seals, and glycol dehydrators). DVG volumes are reported annually to the AER through OneStop and should also be captured within the vent gas volumes reported monthly to Petrinex. In 2020, DVG volumes reported to OneStop were 164.1 10^6 m^3. This represents 34.4 per cent of the total vent volume reported to OneStop. Figure 8 shows a breakdown of DVG volumes by facility subtype.

The volume distribution between battery types does not vary significantly; however, crude oil batteries contribute the most DVG 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.

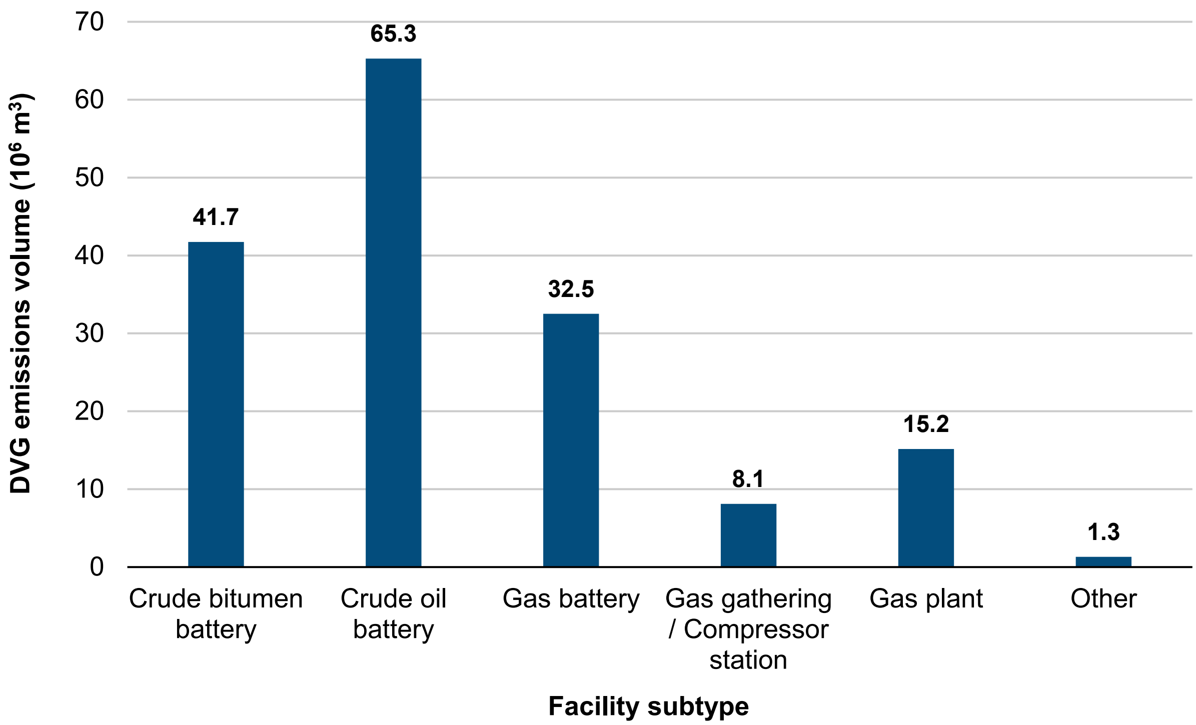


Figure 8. 2020 DVG emissions reported to OneStop by facility subtype

4.3.2 Pneumatic Devices

Directive 060 includes vent limits for both pneumatic instruments and pumps. Vent volumes from pneumatics instruments and pumps are estimated based on a comprehensive inventory and are reported annually to the AER through OneStop. These volumes should also be captured within the vent gas volumes reported monthly to Petrinex. Pneumatic device inventories are not reported to the AER, so comprehensive device counts are not available.

In 2020, pneumatic devices (instruments and pumps) vent gas volumes reported to OneStop were 267.2 10^6 m^3. This represents 56.0 per cent of the total vent volume reported to OneStop. Figure 9 shows a breakdown of pneumatic device emissions by facility subtype.

Gas batteries were the most significant contributor, with 76.6 per cent of the total pneumatic emissions. This is a result of a large number of gas batteries and a higher likelihood of gas-driven pneumatic devices at these sites.

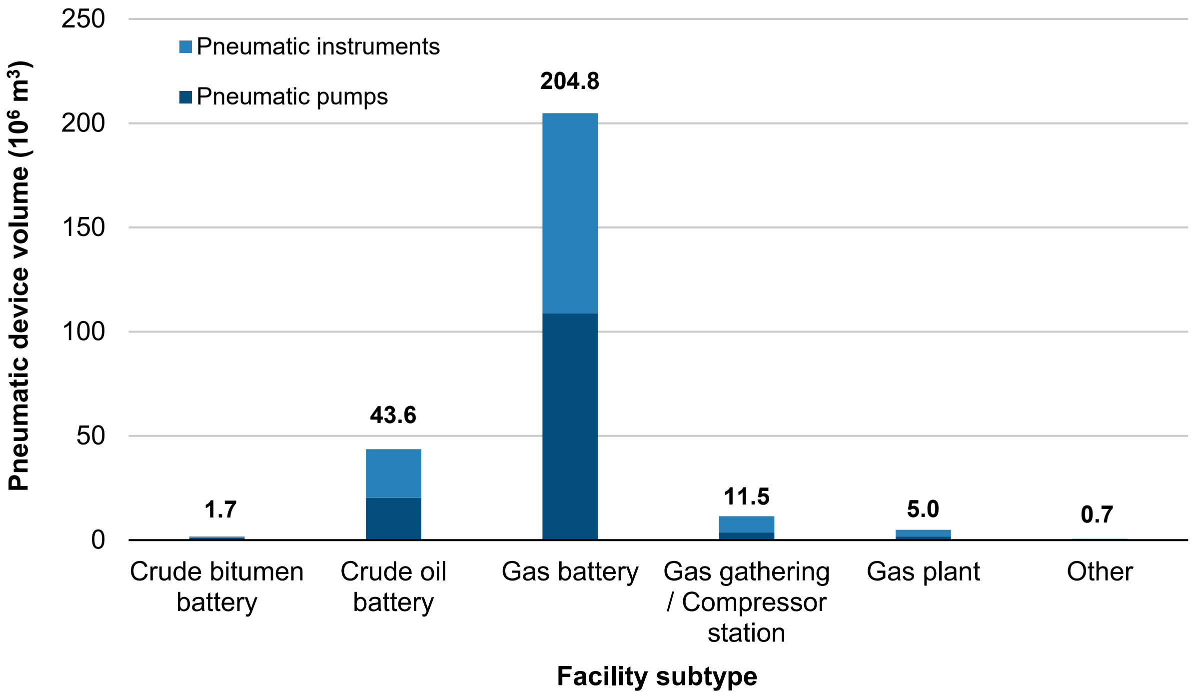


Figure 9. 2020 pneumatic device volumes reported to OneStop by facility subtype

4.3.3 Compressor Seals

Directive 060 includes testing requirements and vent limits for both reciprocating and centrifugal compressor seals. Vented volumes for this source are measured or estimated and reported annually to the AER through OneStop. These volumes should also be captured within the vent gas volumes reported monthly to Petrinex.

4.3.3.1 Compressor Inventory

Directive 060 requires annual reporting of a compressor inventory to the AER through OneStop. Compressors rated 75 kW or more and pressurized for at least 450 hours per calendar year must be reported individually. For compressors that do not meet those criteria, their associated emissions are reported as part of DVG. In 2020, there were 3433 reciprocating compressors and 202 centrifugal compressors that reported activity. This includes compressors that reported 0.0 m^3.

4.3.3.2 Compressor Seal Emissions

In 2020, reciprocating compressor seal emissions reported to OneStop were 27.0 10^6 m^3. This represents 5.7 per cent of the total vent volume reported to OneStop. Centrifugal compressor seal emissions reported to OneStop were 1.2 10^6 m^3, a small emission contributor relative to the other sources reported here, representing only 0.3 per cent of the total vent volume reported to OneStop. Figure 10 shows a breakdown of compressor emissions by facility subtype.

The most significant contributions came from gas gathering, compressor stations, and gas plants. Given that the presence of compressors is more likely at these large facility subtypes, it is reasonable that they would have the highest associated volumes.

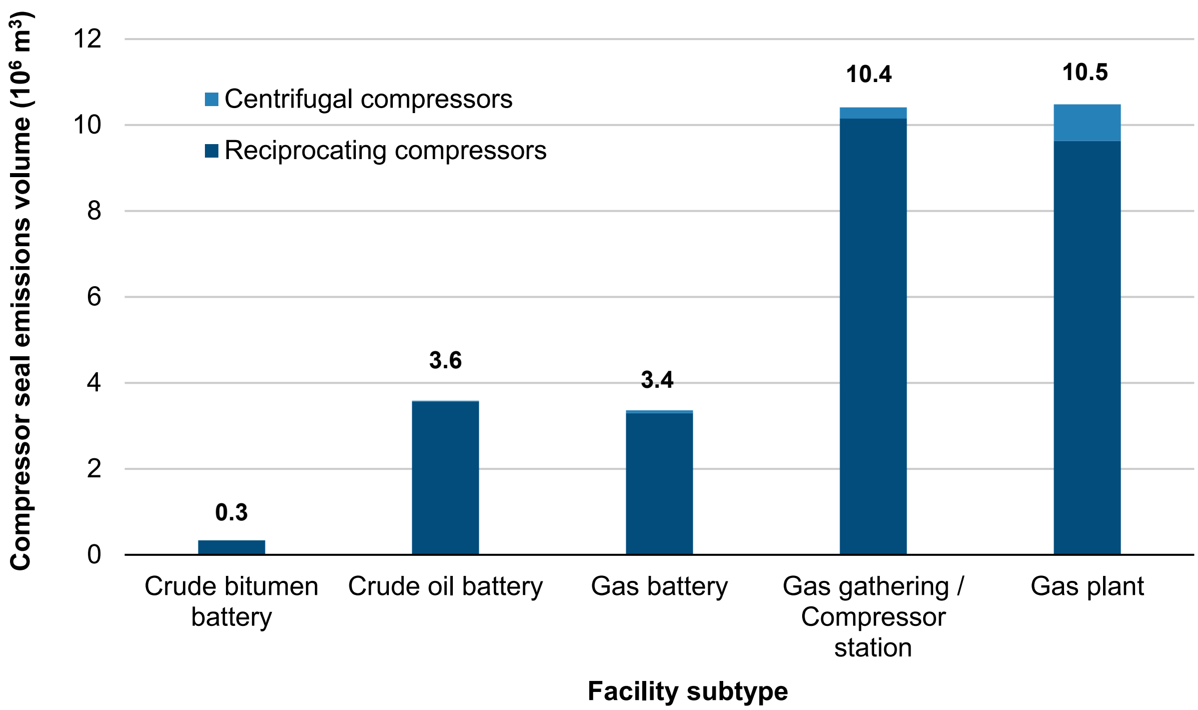


Figure 10. 2020 compressor seal emissions reported to OneStop by compressor and facility subtype

4.3.4 Glycol Dehydrators

Directive 060 includes methane 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 gas volumes reported monthly to Petrinex.

Companies also cannot exceed 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 benzene inventory form that details all their glycol dehydrators. Though benzene emissions are not managed by limits within *Directive 060*, for historical continuity benzene emissions and associated emission control data is provided in this report in appendix 3.

4.3.4.1 Glycol Dehydrator Inventory

In 2020, there were 1351 operating glycol dehydrators in Alberta. Not all dehydrators would be active for the full year but are counted in this report if they were operated at all in 2020. Table 5 below shows the counts of all operating glycol dehydrators per year over the past 11 years.

Table 5. Total count of glycol dehydrators per year (2010 to 2020)

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	1 400
2019	1 328
2020	1 266

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.

4.3.4.2 Glycol Dehydrator Emissions

The reporting requirements for glycol dehydrators differ from all other source categories in that the AER only requires the emissions mass to be reported. The data presented in this section reflect a conversion of the reported mass to volume using methane density and an 85 per cent methane concentration estimate. In 2020, glycol dehydrator emissions were calculated to be 17.4 10^6 m^3. This represents 3.6 per cent of the total vent volume reported to OneStop. Figure 11 shows a breakdown of glycol dehydrator emissions by facility subtype.

The most significant contributions came from gas gathering and compressor stations, with 61.2 per cent of total emissions.

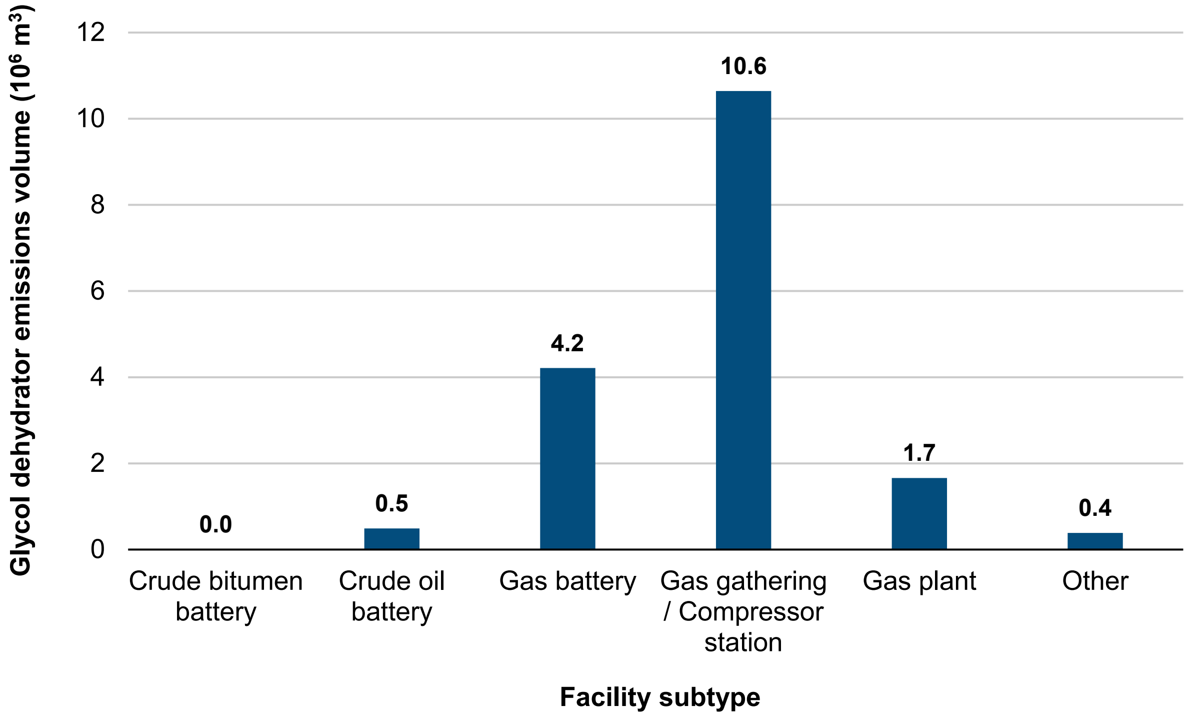


Figure 11. 2020 glycol dehydrator emissions reported to OneStop by facility

5 Fugitive Emissions

5.1 Equipment 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.

Fugitive emission requirements under *Directive 060* went into effect in 2020, and 2021 was the first year equipment fugitive emissions were reported to the AER. The year 2020 was also unique in that some requirements were temporarily suspended because of the COVID-19 pandemic. The 2020 data is therefore only a partial picture of overall fugitive emissions volumes. In 2020, fugitive emissions reported to OneStop were 70.1 10^6 m^3. Figure 12 shows a breakdown of the fugitive emissions by facility subtype.

Even though facility counts vary significantly from one facility subtype to the next (see table 1), the fugitive emission volumes are relatively consistent. This indicates that per-facility fugitive emission rates are higher for those facility types with lower facility counts.

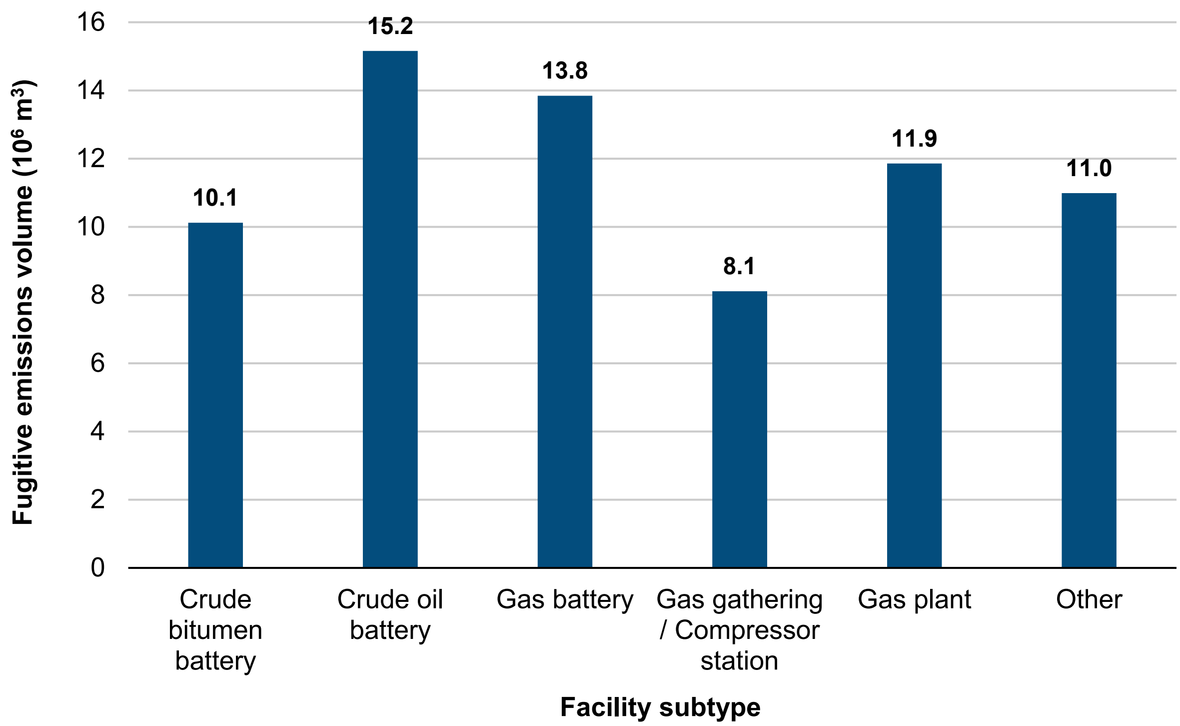


Figure 12. 2020 fugitive emission volumes reported to OneStop by facility subtype

5.2 Surface Casing Vent Flows 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* now 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.

In 2021, the AER released *Directive 087: Well Integrity Management*. It 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, SCVFs and GM, and casing failures. *Directive 087* requires companies to report emissions from SCVFs and GM. Over the years, the AER has worked with licensees to ensure proper reporting of SCVFs and GM.

Table 6 shows that in 2020, there were 10 246 unrepaired wells with SCVFs or GM that emitted a total of 65 10^6 m^3 of natural gas.

Table 6. Emissions from SCVFs and GM at unrepaired wells

Year	Number of wells with SCVFs, GM, or both	Annual natural gas emissions (10^6 m^3)
2010	8 926	95
2011	9 318	92
2012	9 563	88
2013	9 624	89
2014	9 982	84
2015	10 247	86
2016	9 972	81
2017	10 291	83
2018	10 128	65
2019	10 324	66
2020	10 246	65

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 used.
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.
Typically, the methane content of natural gas in SCVFs and GM is between 95 and 99 per cent.
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.

The age, construction, and operation of a well affect the rates of SCVFs or GM. As a result, these SCVF or GM rates differ throughout the well's life cycle. Table 7 below shows the percentage of wells with an SCVF or GM in 2020, both repaired and unrepaired, based on the status of the well. For all wells that were not abandoned, 7.6 per cent had a reported SCVF or GM.

Table 7. Percentage of wells with an SCVF, GM, or both by well status in 2020

Well status	Number of wells	Number of wells that reported SCVFs or GM	Percentage of wells with SCVFs, GM, or both (%)
New drills[a]	666	5	0.8
Active[b]	159 140	8 363	5.3
Inactive[c]	97 243	11 249	11.6
Total	**257 049**	**19 617**	**7.6**

[a] New drills are wells that have been recently drilled and for which licensees are required to test and report any SCVF or GM.

[b] Active wells are those that are currently producing or injecting and reporting volumetric activity on Petrinex.

[c] Under *Directive 013: Suspension Requirements for Wells*, inactive wells are those that have not reported any volumetric activity for either 6 or 12 months, depending on the well's risk classification. However, the number of inactive wells shown in this table also includes wells that are not covered by *Directive 013*, such as observation wells and training wells.

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 alternative 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 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 an important factor in the achievement of provincial methane emission reduction targets. Solution gas performance rankings by operator can be found in appendix 2.

6.1 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 2020, 97.2 per cent of the solution gas produced from crude oil and crude bitumen batteries was conserved, down from 97.7 per cent conservation in 2019.

Figure 13 shows total annual solution gas flared and vented volumes as well as the associated annual conservation rates. As shown in figure 5 above, vent gas volumes from crude oil batteries increased from 2019 to 2020 because of the new definitions in *Directive 060*. This results in a minor reduction in solution gas conservation, as shown in the figure below.

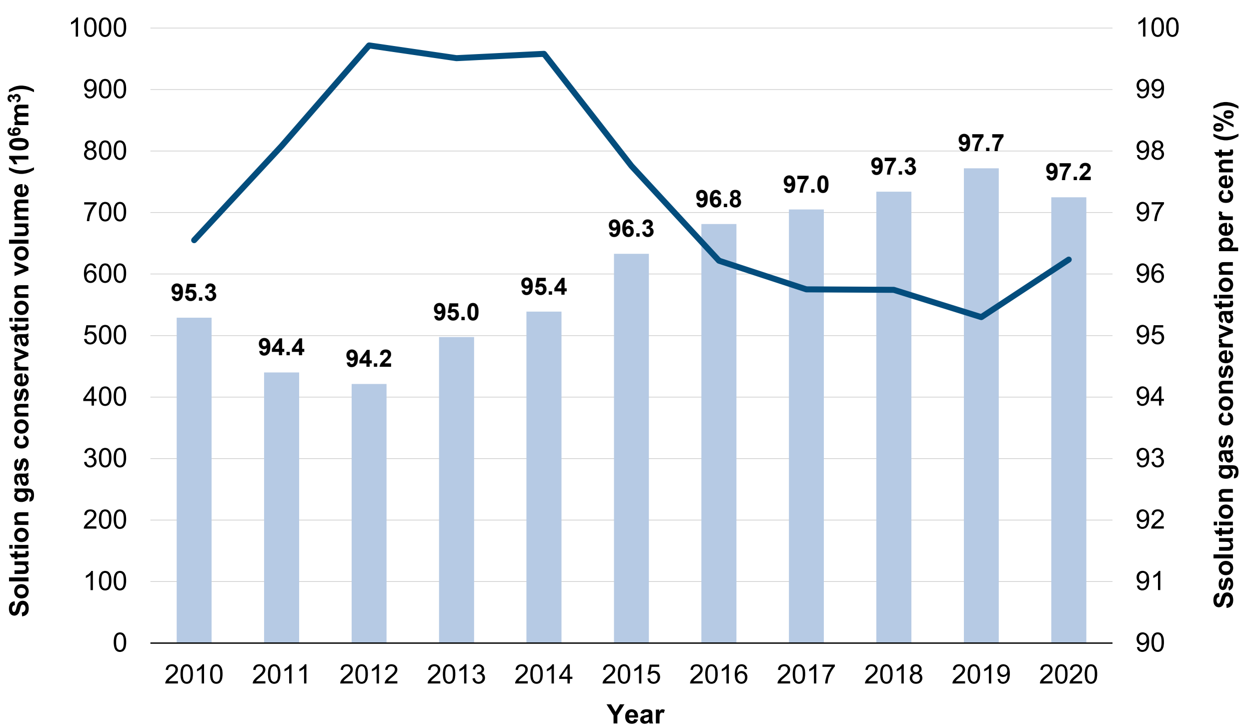


Figure 13. Solution gas conservation from 2010 to 2020 for crude oil and crude bitumen batteries

6.2 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 14 shows annual solution gas conservation 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 2020, where we see that thermal operation conservation is 96.3 per cent while nonthermal conservation is 89.1 per cent. This may be a result of the flare and vent gas definition changes impacting thermal operations more than nonthermal operations.

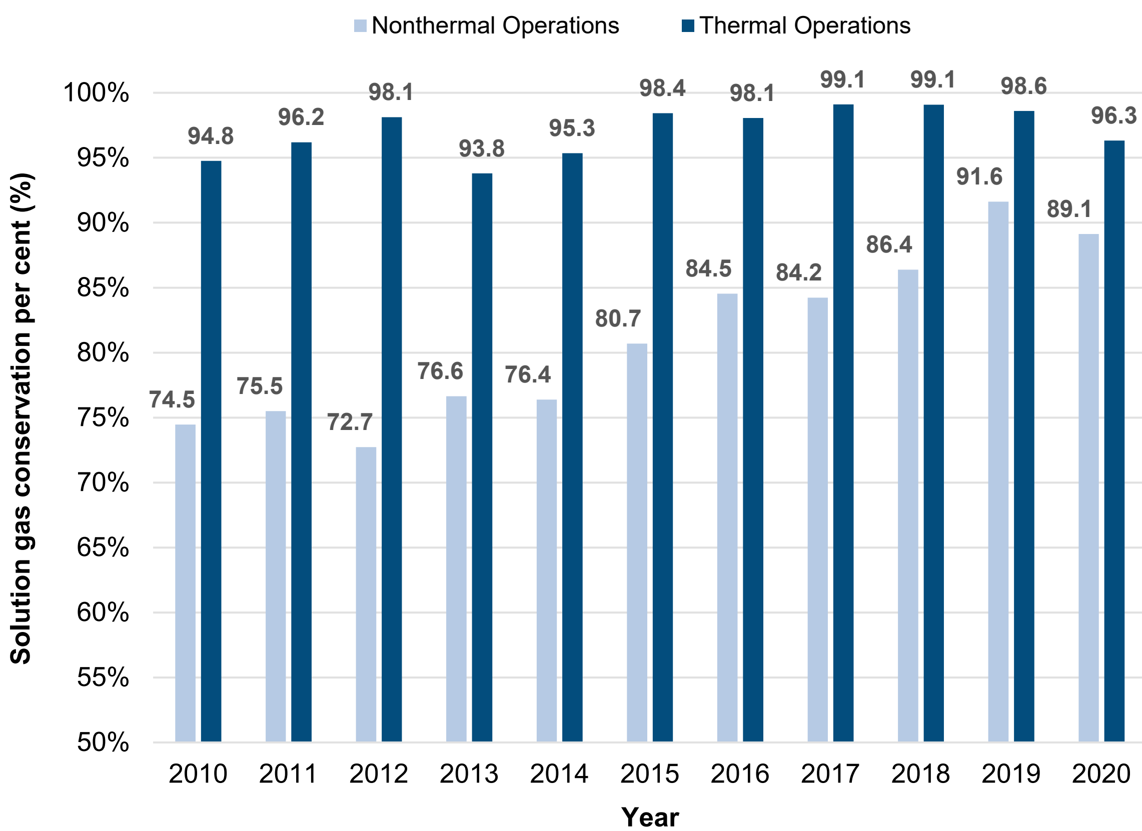


Figure 14. Solution gas conservation from 2010 to 2020 by thermal and nonthermal operations

6.3 Solution Gas Flaring

In 2020, 475.7 10^6 m^3 of solution gas was flared, which was 23.5 per cent higher than 2019 volumes (see figure 15). Flaring was 29.0 per cent below the provincial annual flaring limit of 670 10^6 m^3 set out in *Directive 060*.

The 2020 solution gas flaring increase shown above is greater than the 5 per cent decrease from 2018 to 2019, despite 793 fewer crude oil and crude bitumen batteries. The 2020 increase may be a result of the fuel, flare, vent definition changes detailed above or companies bringing venting facilities into compliance by routing vent gas to flare systems. Also, in 2020 there were new crude oil and bitumen wells that were drilled in areas with minimal existing infrastructure to tie into, leading to an increased reliance on flaring for the early stages of development.

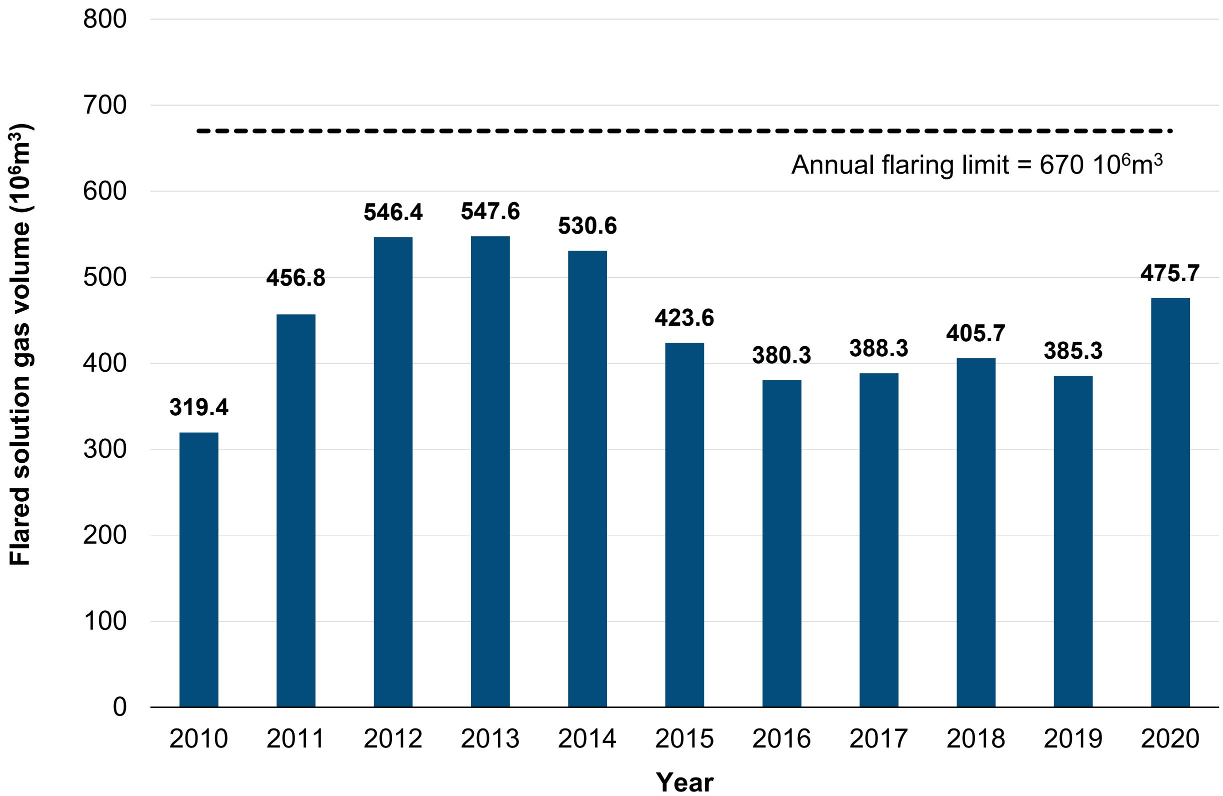


Figure 15. Solution gas flaring from 2010 to 2020 for crude oil and crude bitumen batteries

6.4 Solution Gas Venting

In 2020, 147.6 10^6 m^3 of gas was vented from crude oil and crude bitumen batteries, which was a 2.1 per cent increase from 2019. Solution gas venting was also 79.0 per cent less than the 2000 venting baseline of 704 10^6 m^3 (see figure 16).

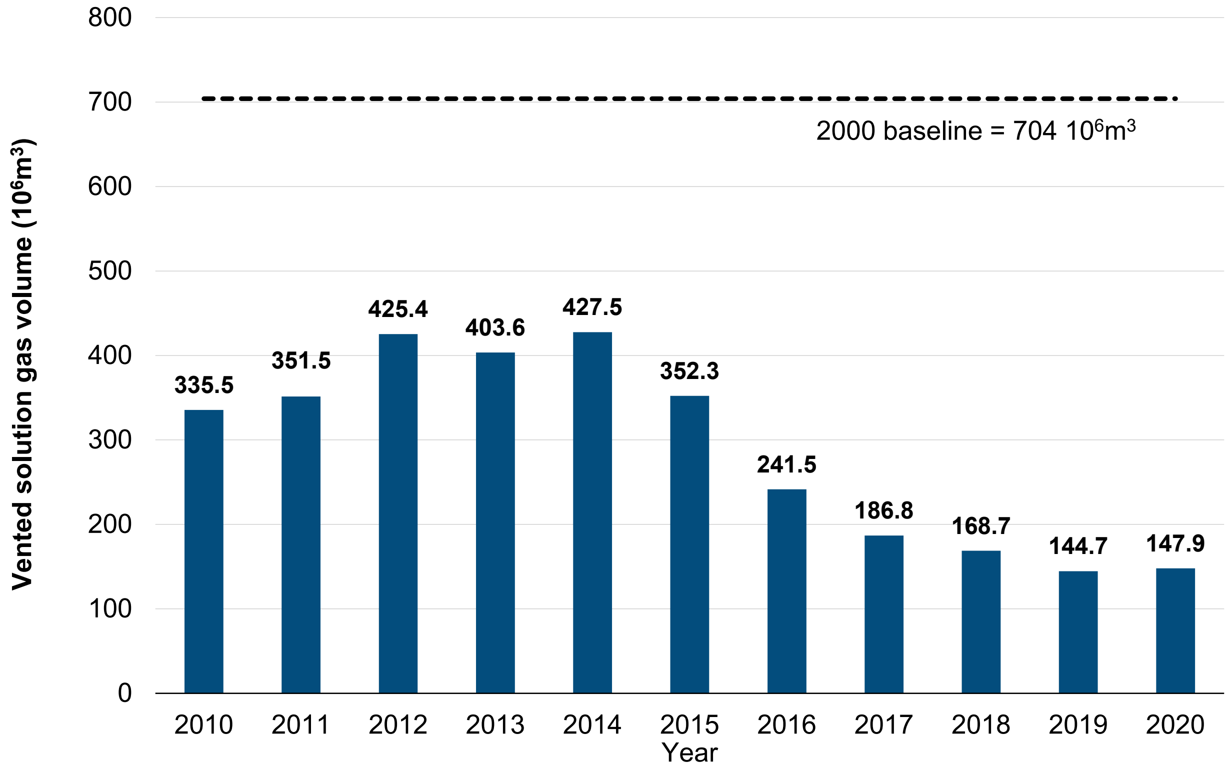


Figure 16. Solution gas venting from 2010 to 2020 for all crude oil and crude bitumen batteries

7 Methane Performance

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* 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 methane emission reduction target established by the Government of Alberta is to achieve a 45 per cent reduction in oil and gas methane emissions from a 2014 baseline by 2025. The new methane requirements have set the oil and gas industry on the path towards achieving that target. To allow for an evaluation of the emission reductions achieved to date, the AER uses a combination of reported information and emission estimates. Estimation is required for sources where reporting volumes are either incomplete (pneumatics) or are not submitted as part of the requirements (incomplete combustion). This combination of reported and estimated volumes means that the total methane emissions shown in figure 17 are greater than the reported volumes provided in the sections above.

Figure 17 shows that Alberta's oil and gas methane emissions are estimated to have been reduced by approximately 34 per cent between 2014 and 2020. Even though reported vent volumes increased in 2020 there is still a decreasing trend in methane emissions from 2014. Those volumes were still released to atmosphere in previous years (but reported as fuel gas), so are included in the total methane emissions each year.

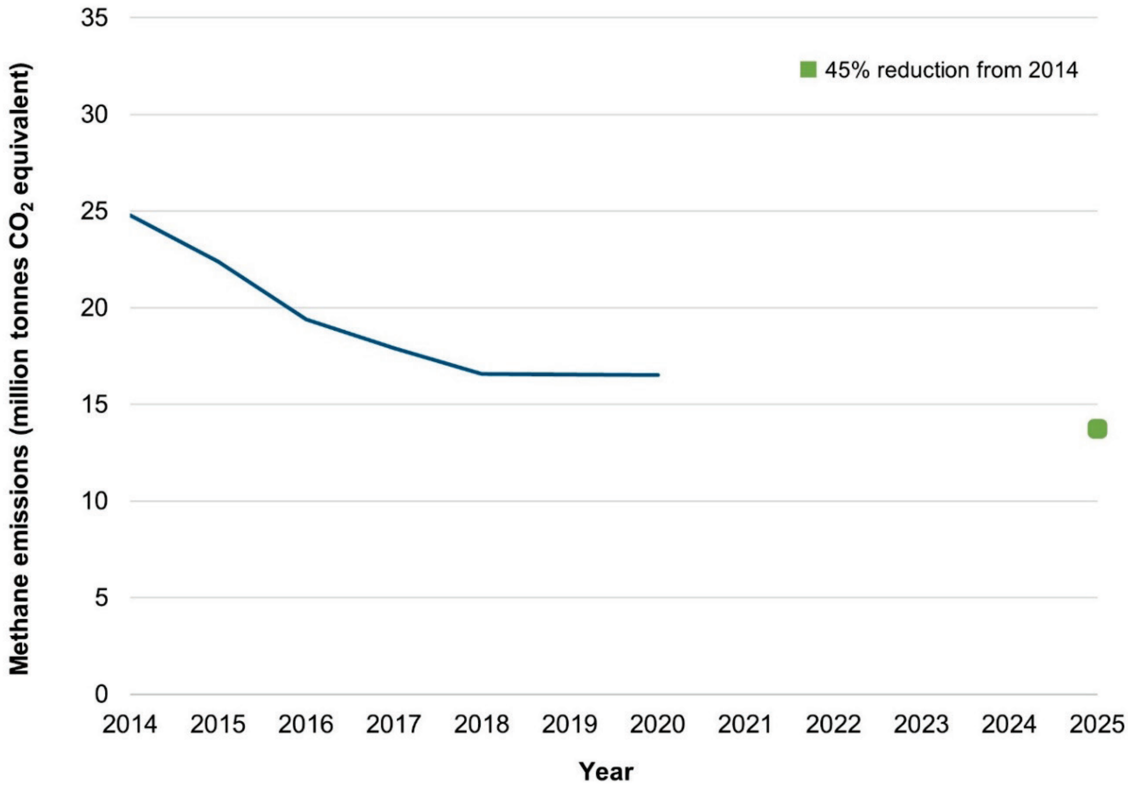


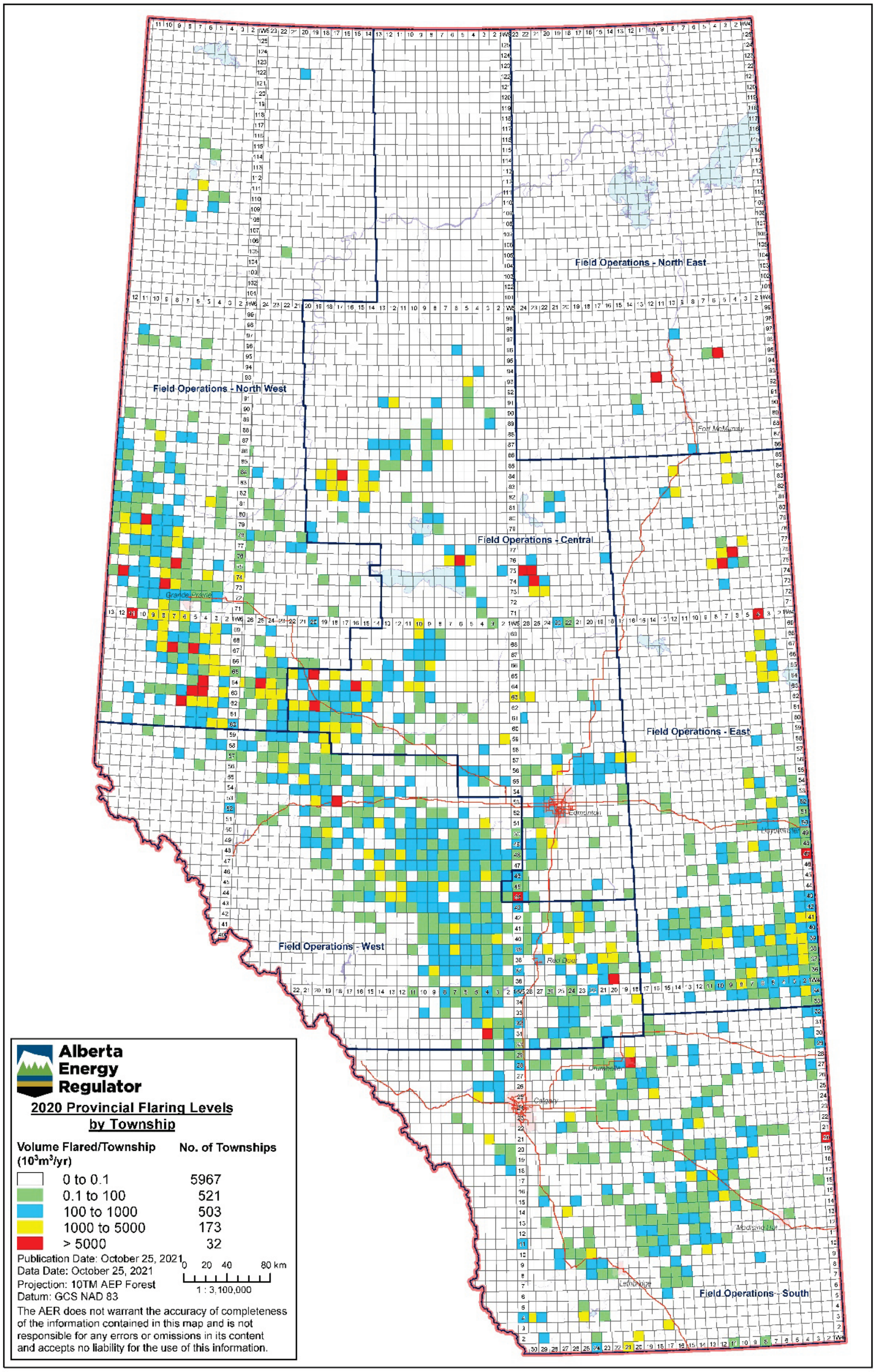
Figure 17. Methane emission reductions (2014 to 2020).

Most of the methane reductions shown here occurred prior to the *Directive 060* methane requirements coming into effect. These reductions are the result of improved industry practices and early action driven through programs like the Alberta Offset System, direct funding programs, and the new methane reduction requirements.

The estimates are reflective of the best available data at the time and may not align with emission estimates conducted by other parties. The AER will continue with compliance assurance activities and data quality assessments to improve our understanding of the emission baseline in 2014 and current methane emission levels. As data quality improves, AER will continue 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.

Additionally, the AER is committed to a regulatory review of *Directive 060* by the end of 2022. The effectiveness of the new requirements will be reviewed and adjustments made if needed.

Appendix 1 Provincial Flaring and Venting Maps



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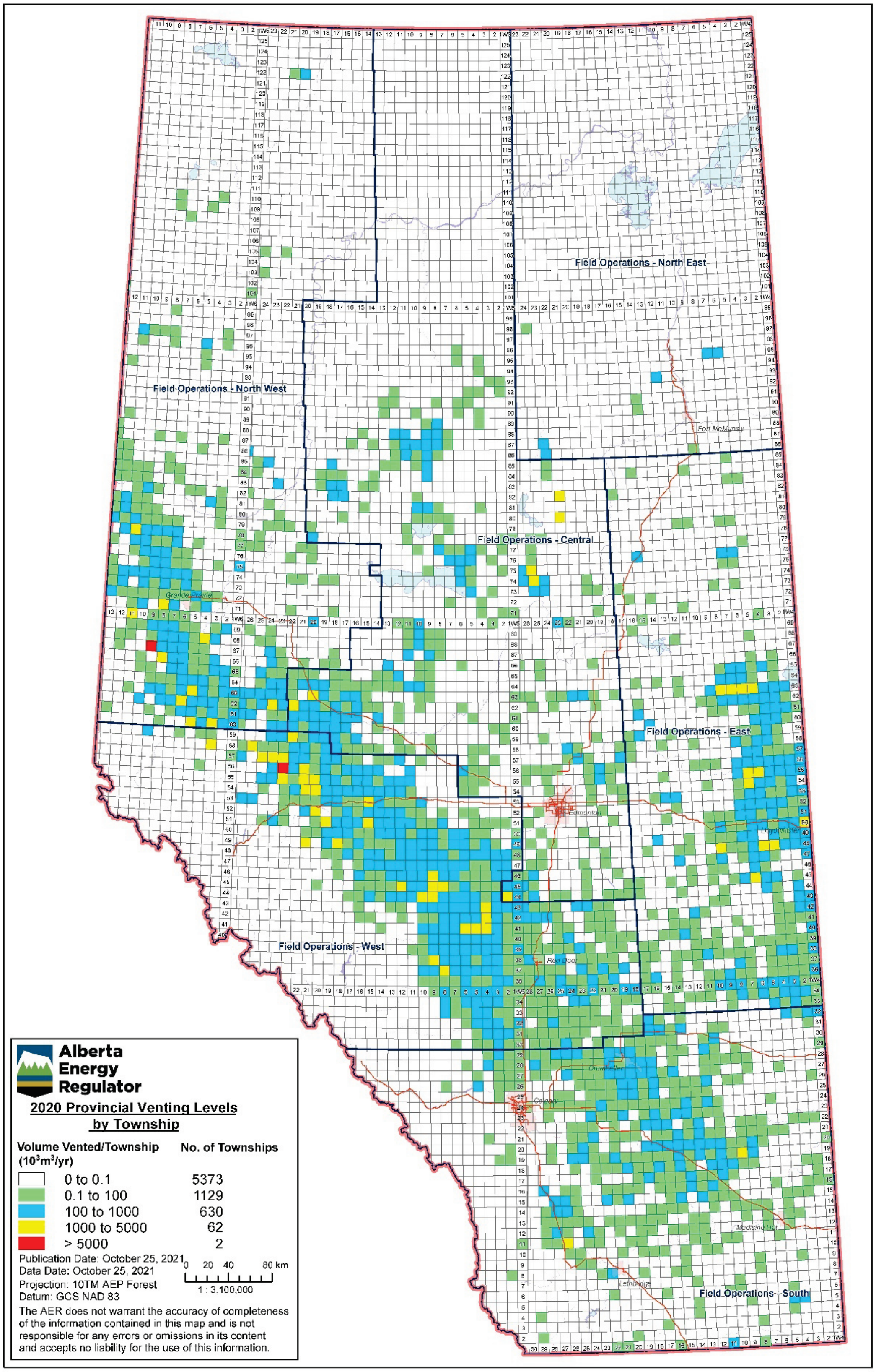

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Appendix 2 Operator Rankings

Caution is required when comparing with last year's report due to mergers, acquisitions, and divestments.

AER field centre boundaries and offices were changed in 2021. To avoid referencing old field centres and to consolidate operator ranking tables, this year's report presents operator rankings by provincial totals.

Operators with the Largest Fuel Gas Use in 2020

Run Date: August 5, 2021

Company	Fuel use (1000 m^3)	Total fuel use ranking	Total production (BoE)	Fuel use intensity (1000 m^3/BoE)	Fuel use intensity ranking
Canadian Natural Resources Limited	4 744 275	**1**	230 909 795	0.02	**12**
Cenovus Energy Inc.	3 227 324	**2**	190 341 240	0.02	**14**
Imperial Oil Resources Limited	2 228 048	**3**	56 871 684	0.04	**5**
Suncor Energy Inc.	1 578 337	**4**	81 270 706	0.02	**13**
ConocoPhillips Canada Resources Corp.	1 238 203	**5**	45 266 082	0.03	**9**
Husky Oil Operations Limited	1 135 787	**6**	47 997 024	0.02	**10**
MEG Energy Corp.	563 218	**7**	36 187 492	0.02	**16**
ARC Resources Ltd.*	453 594	**8**	63 226 924	0.01	**23**
Tourmaline Oil Corp.	419 987	**9**	94 280 582	0.00	**25**
Keyera Energy Ltd.	415 114	**10**	99 806	4.16	**1**
Pieridae Alberta Production Ltd.	369 706	**11**	4 860 712	0.08	**3**
Athabasca Oil Corporation	355 739	**12**	11 900 671	0.03	**7**
Tidewater Midstream and Infrastructure Ltd.	270 632	**13**	1 681 650	0.16	**2**
Japan Canada Oil Sands Limited	246 798	**14**	8 379 053	0.03	**8**
PetroChina Canada Ltd.	244 554	**15**	8 126 457	0.03	**6**
Ember Resources Inc.	224 752	**16**	17 978 505	0.01	**17**
CNOOC Petroleum North America ULC	219 528	**17**	12 974 443	0.02	**15**
TAQA North Ltd.	193 930	**18**	19 827 911	0.01	**19**
Torxen Energy Ltd.	189 813	**19**	21 186 756	0.01	**21**
Bonavista Energy Corporation	184 419	**20**	20 084 464	0.01	**20**
Strathcona Resources Ltd.	174 077	**21**	20 015 461	0.01	**22**
Peyto Exploration & Development Corp.	170 204	**22**	30 244 000	0.01	**24**
Connacher Oil and Gas Limited	168 032	**23**	4 161 886	0.04	**4**
Repsol Oil & Gas Canada Inc.	143 574	**24**	13 381 224	0.01	**18**
Harvest Operations Corp.	134 362	**25**	6 493 384	0.02	**11**

* ARC Resources Ltd. volumes include volumes associated with Seven Generations Energy Ltd, as these assets were acquired early 2021.

Operators with the Largest Flaring Volumes in 2020

Run Date: August 5, 2021

Company	Total flaring (1000 m^3)	Total flaring ranking	Total production (BoE)	Flaring intensity (1000 m^3/BoE)	Flaring intensity ranking
Canadian Natural Resources Limited	71 716	**1**	230 909 795	0.0003	**22**
ARC Resources Ltd.	45 913	**2**	63 226 924	0.0007	**18**
Cenovus Energy Inc.	43 466	**3**	190 341 240	0.0002	**23**
Keyera Energy Ltd.	40 008	**4**	99 806	0.4009	**1**
Deltastream Energy Corporation	33 224	**5**	3 161 649	0.0105	**4**
Suncor Energy Inc.	27 697	**6**	81 270 706	0.0003	**21**
Murphy Oil Company Ltd.	23 864	**7**	4 777 087	0.0050	**7**
Spur Petroleum Ltd.	21 342	**8**	5 259 382	0.0041	**9**
Baytex Energy Ltd.	20 983	**9**	8 746 552	0.0024	**12**
Ovintiv Canada ULC	19 949	**10**	14 550 644	0.0014	**15**
West Lake Energy Corp.	15 536	**11**	3 437 282	0.0045	**8**
Surge Energy Inc.	14 153	**12**	4 914 440	0.0029	**11**
Repsol Oil & Gas Canada Inc.	12 030	**13**	13 381 224	0.0009	**17**
Whitecap Resources Inc.	11 971	**14**	20 254 146	0.0006	**20**
North 40 Resources Ltd.	11 481	**15**	1 030 683	0.0111	**3**
Obsidian Energy Ltd.	10 812	**16**	9 235 294	0.0012	**16**
Husky Oil Operations Limited	10 569	**17**	47 997 024	0.0002	**24**
Pieridae Alberta Production Ltd.	10 311	**18**	4 860 712	0.0021	**13**
Velvet Energy Ltd.	10 308	**19**	6 574 594	0.0016	**14**
Tourmaline Oil Corp.	10 131	**20**	94 280 582	0.0001	**25**
NuVista Energy Ltd.	9 776	**21**	13 754 642	0.0007	**19**
Enhance Energy Inc.	9 611	**22**	377 536	0.0255	**2**
Rising Star Resources Ltd.	9 596	**23**	1 775 979	0.0054	**6**
Tidewater Midstream and Infrastructure Ltd.	9 557	**24**	1 681 650	0.0057	**5**
Karve Energy Inc.	9 477	**25**	2 394 451	0.0040	**10**

Operators with the Largest Venting Volumes in 2020

Run Date: August 5, 2021

Company	Total venting (1000 m^3)	Total venting ranking	Total production (BoE)	Venting intensity (1000 m^3/BoE)	Venting intensity ranking
Canadian Natural Resources Limited	75 250	**1**	230 909 795	0.0002	**20**
Cenovus Energy Inc.	23 780	**2**	190 341 240	0.0001	**24**
Bonavista Energy Corporation	18 080	**3**	20 084 464	0.0009	**5**
Husky Oil Operations Limited	15 370	**4**	47 997 024	0.0003	**15**
Tourmaline Oil Corp.	13 090	**5**	94 280 582	0.0001	**23**
Repsol Oil & Gas Canada Inc.	11 850	**6**	13 381 224	0.0009	**6**
Peyto Exploration & Development Corp.	10 490	**7**	30 244 000	0.0003	**13**
Torxen Energy Ltd.	6 690	**8**	21 186 756	0.0016	**2**
Deltastream Energy Corporation	5 190	**9**	3 161 649	0.0003	**16**
Obsidian Energy Ltd.	4 880	**10**	9 235 294	0.0016	**1**
Whitecap Resources Inc.	4 690	**11**	20 254 146	0.0008	**7**
Harvest Operations Corp.	4 350	**12**	6 493 384	0.0005	**10**
ARC Resources Ltd.	4 240	**13**	63 226 924	0.0002	**18**
Ovintiv Canada ULC	4 200	**14**	14 550 644	0.0007	**8**
Tamarack Acquisition Corp.	4 140	**15**	10 874 455	0.0001	**25**
Paramount Resources Ltd.	4 140	**16**	17 888 772	0.0003	**17**
TAQA North Ltd.	4 130	**17**	19 827 911	0.0004	**12**
Cardinal Energy Ltd.	3 910	**18**	4 884 127	0.0002	**19**
Westbrick Energy Ltd.	3 540	**19**	12 092 361	0.0002	**21**
Yangarra Resources Corp.	3 430	**20**	3 654 441	0.0004	**11**
Ember Resources Inc.	3 330	**21**	17 978 505	0.0009	**4**
Velvet Energy Ltd.	3 290	**22**	6 574 594	0.0002	**22**
Karve Energy Inc.	3 280	**23**	2 394 451	0.0003	**14**
Spur Petroleum Ltd.	2 930	**24**	5 259 382	0.0014	**3**
Birchcliff Energy Ltd.	2 670	**25**	25 937 044	0.0006	**9**

Operator Rankings: Solution Gas Conservation

The AER has ranked companies based on volumes from operated crude oil and crude bitumen batteries of (1) solution gas production, (2) vented solution gas, and (3) GHG emissions from solution gas flaring and venting.

In this section, all crude oil and crude bitumen batteries have been included except for batteries that had an experimental well reporting fluid production in a month. The information on experimental wells remains confidential. This exclusion of data from experimental wells is the reason for variances between the values in the preceding sections of this report and the values contained in the ranking tables in this section. 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.

Greenhouse gas (GHG) emissions are expressed in tonnes of carbon dioxide equivalent (tCO_2e).[1] The GHG emission factors used to quantify emissions from flaring and venting vary depending on the type of production as set out below:[2]

- Gas production:
  - Vented gas GHG emission factor = 15.4 tCO_2e per thousand cubic metres (10^3 m^3) of gas
  - Flared gas GHG emission factor[3] = 2.7 tCO_2e per 10^3 m^3 of gas
- Crude oil:
  - Vented gas GHG emission factor = 12.5 tCO_2e per thousand cubic metres (10^3 m^3) of gas
  - Flared gas GHG emission factor = 2.9 tCO_2e per 10^3 m^3 of gas
- Crude bitumen
  - Vented gas GHG emission factor = 16.3 tCO_2e per 10^3 m^3 of gas
  - Flared gas GHG emission factor = 2.6 tCO_2e per 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 25 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).

[2] Speciation profiles for gas, oil and bitumen production can be found within Table 2 and Table 4 in *2018 Alberta Upstream Oil & Gas Methane Emissions Inventory and Methodology* report by Clearstone Engineering Ltd., April 22, 2019, https://static.aer.ca/prd/documents/ab-uog-emissions-inventory-methodology.pdf

[3] Flaring is assumed to have a 95 per cent conversion efficiency.

Operators with the Highest Solution Gas Conservation Rates in 2020 (Crude Oil and Crude Bitumen Batteries)
Run Date: August 5, 2021

Company	2020 solution gas production (1000 m^3)	2020 solution gas conservation rate (%)	2019 solution gas production (1000 m^3)	2019 solution gas conservation rate (%)	2019 to 2020 per cent change
Petrus Resources Corp.	147 976	99.7	164 904	99.9	−0.21
Birchcliff Energy Ltd.	961 786	99.7	778 929	99.9	−0.16
ARC Resources Ltd.	615 256	99.7	612 635	99.7	−0.01
Tourmaline Oil Corp.	734 789	99.7	868 904	99.6	0.05
Hammerhead Resources Inc.	1 236 076	99.6	1 175 698	99.7	−0.03
Kelt Exploration Ltd.	377 046	99.5	370 463	99.6	−0.14
Torxen Energy Ltd.	787 586	99.4	703 449	99.2	0.20
MEG Energy Corp.	430 401	99.3	448 107	99.8	−0.46
Boulder Energy Ltd.	203 523	99.3	184 856	99.7	−0.42
Journey Energy Inc.	214 166	99.1	236 088	98.6	0.56
Yangarra Resources Corp.	377 505	99.1	428 253	99.5	−0.46
ORLEN Upstream Canada Ltd.	293 440	99.0	239 048	98.5	0.54
Bonterra Energy Corp.	248 338	99.0	259 066	99.0	−0.07
Whitecap Resources Inc.	1 262 719	98.8	1 219 409	98.9	−0.05
Velvet Energy Ltd.	674 098	98.8	689 285	98.2	0.63
Tamarack Acquisition Corp.	555 865	98.8	555 145	98.0	0.78
Long Run Exploration Ltd.	143 123	98.7	193 847	98.7	−0.02
TAQA North Ltd.	305 892	98.7	301 697	98.6	0.06
Husky Oil Operations Limited	1 278 682	98.6	1 443 920	98.8	−0.17
Bonavista Energy Corporation	153 738	98.3	167 686	98.9	−0.57
Ridgeback Resources Inc.	298 561	98.2	292 567	98.8	−0.62
Paramount Resources Ltd.	203 446	98.2	299 011	99.1	−0.95
Imperial Oil Resources Limited	422 615	98.2	441 939	99.2	−1.05
Obsidian Energy Ltd.	499 719	97.4	468 120	98.6	−1.19
Cenovus Energy Inc.	1 259 427	97.1	957 657	97.6	−0.51

Note: Operators currently under active investigation related to the information presented in this table have been removed.

Operators with the Largest Solution Gas Venting Volumes in 2020 (Crude Oil and Crude Bitumen Batteries)

Run Date: August 5, 2021

Company	Solution gas vented (1000 m^3)
Canadian Natural Resources Limited	38 646
Husky Oil Operations Limited	12 163
Deltastream Energy Corporation	5 187
Cenovus Energy Inc.	4 219
Obsidian Energy Ltd.	3 938
Whitecap Resources Inc.	3 877
Cardinal Energy Ltd.	3 699
Tamarack Acquisition Corp.	2 970
Yangarra Resources Corp.	2 838
Karve Energy Inc.	2 836
Torxen Energy Ltd.	2 601
Spur Petroleum Ltd.	2 536
Prairie Provident Resources Canada Ltd.	2 309
Gear Energy Ltd.	2 221
TAQA North Ltd.	2 115
West Lake Energy Corp.	1 757
Harvest Operations Corp.	1 441
Baytex Energy Ltd.	1 306
ARC Resources Ltd.	1 233
InPlay Oil Corp.	1 139
Grizzly Resources Ltd.	1 019
Crew Energy Inc.	1 015
Repsol Oil & Gas Canada Inc.	1 012
Surge Energy Inc.	832
Ipc Canada Ltd.	802

Operators with the Largest Solution Gas GHG Emissions in 2020 (Crude Oil and Crude Bitumen Batteries)
Run Date: August 5, 2021

Company	Solution gas flared from crude oil batteries ($1000\ m^3$)	Solution gas flared from crude bitumen batteries ($1000\ m^3$)	Solution gas vented from crude oil batteries ($1000\ m^3$)	Solution gas vented from crude bitumen batteries ($1000\ m^3$)	GHG emissions (tCO_2e)
Canadian Natural Resources Limited	21 115	20 008	7 184	31 461	715 876
Husky Oil Operations Limited	3 673	1 583	8 908	3 254	179 167
Deltastream Energy Corporation	2 319	30 632	868	4 320	167 624
Cenovus Energy Inc.	1 724	30 338	2 827	1 392	141 908
Spur Petroleum Ltd.	16 662	4 680	1 246	1 290	97 089
Whitecap Resources Inc.	11 198	0	3 871	6	80 955
Suncor Energy Inc.	0	27 697	0	305	76 981
Obsidian Energy Ltd.	695	8 210	3 164	774	75 527
West Lake Energy Corp.	15 358	39	1 438	319	67 807
Karve Energy Inc.	9 360	0	2 836	0	62 598
Cardinal Energy Ltd.	5 413	0	3 699	0	61 937
Baytex Energy Ltd.	2 589	9 439	703	603	50 659
Surge Energy Inc.	13 412	0	832	0	49 300
Tamarack Acquisition Corp.	3 783	0	2 970	0	48 101
North 40 Resources Ltd.	11 481	0	1 093	0	46 960
Murphy Oil Company Ltd.	14 694	0	153	0	44 522
Torxen Energy Ltd.	2 104	0	2 596	5	38 633
Gear Energy Ltd.	878	1 435	1 869	352	35 378
Enhance Energy Inc.	9 570	0	88	135	31 053
Longshore Resources Ltd.	5 709	0	963	0	28 590
Hammerhead Resources Inc.	2 727	0	1 640	0	28 406
Velvet Energy Ltd.	7 674	0	474	0	28 180
Rising Star Resources Ltd.	9 596	0	16	0	28 022
Harvest Operations Corp.	1 822	1 663	1 387	54	27 826
Crescent Point Energy Corp.	6 620	0	497	0	25 413

Appendix 3 Glycol Dehydrator Benzene Emissions Data

Year	Number of dehydrators[a]	Volume of gas processed (10^6 m^3)	Benzene emissions before controls (tonnes)	Benzene emissions after controls (tonnes)	Overall control efficiency (%)[b]
2008	2 396	159 417	3 011	1 248	58.6
2009	2 236	153 323	2 750	1 093	60.3
2010	2 107	134 681	2 365	989	58.2
2011	2 006	137 790	2 286	849	62.9
2012	1 985	148 334	2 228	794	64.4
2013	1 905	142 110	2 757	777	71.8
2014	1 886	146 036	2 640	746	71.7
2015	1 778	153 486	2 376	609	74.4
2016	1 646	151 825	2 307	501	78.3
2017	1 528	152 397	2 008	399	80.1
2018	1 400	170 768	1 996	285	85.7
2019	1 328	165 667	1 959	258	86.8
2020	1 351	154 640	1 891	218	88.5

Note: Benzene amounts have been rounded to the nearest tonne.

[a] 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.

[b] The control efficiency is the total benzene emissions before controls minus the total benzene emissions after controls divided by the total benzene emissions before controls multiplied by 100.