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RESEARCH ARTICLE

Sources and reliability of reported methane reductions from the oil and gas industry in Alberta, Canada

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Since committing to a 40%–45% reduction in methane emissions from the oil and gas industry in Canada by 2025, relative to 2012 levels, the federal government has reported significant emission reductions from the industry in its largest producing province, Alberta. At the same time, multiple measurement studies have shown that the industry's emissions in Canada's national greenhouse gas inventory are underreported, generally by a factor of 1.5 to 2. To better understand the source and reliability of claimed emission reductions, we developed an upstream oil and gas (UOG) methane emissions inventory model for the province of Alberta, 2011–2021, following government methodologies. The model revealed that historically only approximately 28% of Alberta's UOG methane emissions are based on reported data, and although more comprehensive reporting was enforced in 2020, further analysis suggests that this reporting shift could represent a significant fraction of the *apparent* emission reductions since 2012. Reviewing the data and modeling assumptions underlying the inventory estimate revealed significant uncertainty in not only modeled emission sources but also in the operator-reported data. These findings imply that the reported emission trends since 2012 are highly uncertain, and even future emission factor updates might not improve the reliability in reported trends of emission reduction. This poses a significant problem for the validation of the stated 40%–45% reduction from 2012 levels. To improve the representativeness of both annual inventory magnitudes and the emission trends for the upstream sector in Alberta, we make recommendations to the Canadian federal and Alberta provincial governments.

Keywords: Methane inventory, Alberta, Canada, Upstream oil and gas, Methane regulations, Flaring, Venting

1. Introduction

The Government of Canada has committed to reducing methane (CH_4) emissions from the oil and gas sector by 40%–45% below 2012 levels by 2025 and, more recently, by 75% in 2030 (Environment and Climate Change Canada [ECCC], 2020; 2021). The mitigation of this climate warming pollutant with relatively short atmospheric lifetime (Forster et al., 2021; Gulev et al., 2021) represents a key opportunity to limit climate impacts in the near term and will play an important role in limiting overall warming to less than 2°C (Intergovernmental Panel on Climate Change [IPCC], 2018; Ocko et al., 2021). After reaching equivalency agreements with the federal government, the provinces of Alberta, British Columbia, and Saskatchewan (Government of Canada, 2020a; 2020b; 2020c) enacted methane reduction regulations for their respective upstream oil and gas (UOG) sectors, each going into effect on January 1, 2020. In the latest National Inventory Report—Canada's annual multisectoral greenhouse gas emissions inventory—the Government of Canada reported an approximately 47% reduction in oil and gas sector methane emissions in Alberta since 2012 (ECCC, 2022a). The Government of Alberta (2022) similarly reported a 34% reduction for its UOG since 2014 using a similar inventory methodology. If true, these reductions represent significant progress toward Canada's reduction targets, especially since Alberta's entire oil and gas sector represents 57% of national oil and gas methane emissions and 27% of national total methane emissions.

Despite these significant reported reductions, a growing number of measurement studies have shown that methane emissions are underestimated/underreported in Canada. Satellite inversions and flux towers have shown that oil and gas sector emissions as a whole are underestimated (e.g., Chan et al., 2020; Maasakkers et al., 2021; Lu et al., 2022; Shen et al., 2022), and more targeted studies have shown this issue to be widespread throughout the industry. Regional aircraft measurements (Johnson et al., 2017; Baray et al., 2018), truck-based measurements (Atherton et al., 2017; Zavala-Araiza et al., 2018; MacKay et al., 2021), site-level aircraft (Tyner and Johnson, 2021), and tracer flux ratio measurements (Roscioli et al., 2018) have shown that emissions are higher than estimated by the

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federal government, across different production methods (e.g., heavy oil, gas, mined oil sands) and provincial jurisdictions. The gap between modeled inventories and measurement-based estimates in the UOG, generally a factor of 1.5–2 between them, leaves significant uncertainty around the causes of underestimation and the reliability of the claimed reduction trends.

To better understand the source(s) of these claimed emission reductions and how, or if, these claims should be considered reliable, we developed and analyzed a detailed methane inventory model for Alberta's UOG sector, deriving annual estimates from 2011 to 2021. The presented model, based on federal government methodologies, allowed for site- and source-specific emissions to be calculated, whereas published federal inventory data only delineate emissions from flaring, venting, and generic "oil" and "gas" sector emissions. Furthermore, we attempt to handle known reporting inconsistencies in the inventory and show how this is a likely contributor to *apparent* emissions reductions in the model. We also augmented the model with updated emission factors derived from published measurement campaigns to illustrate the relative impacts of different source types. Finally, we reviewed the underlying data and assumptions of the federal UOG methane inventory for Alberta and identify additional sources of uncertainty, including performance assumptions (e.g., unlit flares) and apparent reporting noncompliance, both supported by a helicopter-based survey commissioned by the authors (see Section 4 and SM Section S5).

2. Inventory model methods

2.1. Inventory model overview

The federal inventory model used in Alberta is based on a bottom-up IPCC Tier 3 approach developed by ECCC (2022a) and Clearstone Engineering Ltd. (2014a; 2018; 2019a). The model is structured around monthly operator-reported activity data, which oil and gas operators upload to the Petrinex (2021) reporting system, a production and royalties database governed by Canada's western provinces and industry groups. These data sets include oil and gas production volumes, product dispositions and receipts, and flared, vented, and natural gas fuel use volumes. The federal inventory model includes both these reported emissions data and estimates of historically unreported emissions, the latter being derived by Clearstone Engineering Ltd. (2014b) and is also available in the supplemental information in Johnson and Tyner (2020), where it is delineated conveniently by facility types.

Following the same methodologies, we used operator-reported data (2017–2021 accessed from Petrinex, 2021; 2011–2016 provided in a personal communication from L Pacholko, Alberta Energy Regulator [AER], to SP Seymour, Environmental Defense Fund [EDF], 21 January, 2022) as the basis to develop an in-house UOG methane emissions model for Alberta from 2011 to 2021. **Table 1** summarizes each emission category and their calculation methods described in the following subsections. The upstream sector encompasses production, disposal and waste treatment, and natural gas processing. Consistent with upstream models by Clearstone Engineering Ltd. (2019a) and Johnson and Tyner (2020), we excluded transmission, distribution, and refining emissions, which represents approximately 4% of Alberta's total oil and gas industry methane. Importantly, this model also excluded mined oil sands and upgrading emissions, representing another 19% of Alberta's oil and gas methane, since these are excluded from the 40% to 45% methane reduction commitment for the industry.

2.1.1. Active infrastructure and gas composition

Active wells and facilities were defined as any sites that produced gas or oil; reported flaring, venting, or fuel use; or had gas receipts or dispositions (see SM Section S1.1 for a summary of active sites and produced energy by type). Active wells were combined with AER well data files (AER, 2021a; 2021b) to track production methods and well locations; facility locations were determined from the provincial Dominion Land Survey data in the Petrinex entries (AER, 2020a). Additionally, surface casing vent flow (SCVF) and gas migration (GM) emissions were estimated using reported SCVF/GM data (AER, 2022a), and any reported events without flowrate estimates were augmented with average emission factors calculated from reported flowrates following ECCC (2022a) methods. Abandoned well emissions were also included following ECCC methods, which combined emission factors (Townsend-small et al., 2016) with documented abandoned and suspended wells (AER, 2021a). Site gas compositions were derived from Tyner and Johnson (2020), which took over 400,000 individual well gas samples to produce a gas composition map of Alberta (see Section S1.2 of SM).

2.1.2. Reported emissions

Monthly flared, vented, and fuel use produced gas volumes were aggregated to each reporting well or facility, but performance assumptions were necessary to convert flared and fuel use volumes into mass of emitted methane. Flaring emissions were calculated knowing the site gas composition and assuming a "combustion efficiency" of 98% consistent with federal inventory estimates (ECCC, 2022b). For gas volumes used in fired equipment (e.g., power generation, heating, compressors), methane emissions were calculated using fractions of fuel burned by different equipment types from Johnson and Tyner (2020), average fuel heating values, and emission factors for reciprocating engines, turbines, and heaters/boilers from the U.S. Environmental Protection Agency (U.S. EPA, 2000), as used in the ECCC inventory (Clearstone Engineering Ltd., 2014a).

2.1.3. Estimated emissions for unreported sources

Historically unreported emission sources, such as storage losses, pneumatics, fugitives, or compressor seal vents, were estimated for 2011 in Alberta by Clearstone Engineering (2014b) for inclusion in the Canadian national inventory. Since this work only provided estimates for 2011, ECCC extrapolates these data to subsequent years by scaling by each inventoried year's production volumes or active site counts (Clearstone Engineering Ltd., 2014a;

Table 1. Overview of Alberta upstream oil and gas inventory emission categories and their data sources

Category	Emission Type	Methane Quantification	Primary Data Source
Operator reported	Vent	– Site gas composition[a]	Data for 2017–2021 from Petrinex (2021). Data for 2011–2016 accessed from Alberta Energy Regulator (AER)
	Flare	– Site gas composition[a] – Assumed 98% efficiency[b]	
	Fuel use	– Typical engine type and average fuel heating value by site type[c] – Engine emission factors[c]	
	Surface casing vent flow/gas migration	– Site gas composition[a] – Flow rate (if missing)[d]	Well vent flow/gas migration report (AER, 2022a)
Estimated emissions	Storage losses (Un)loading Glycol dehydrators Compressor starts	– Scaled from 2012 baseline estimate by production volume to each year (ECCC, 2022b)	Original estimates from Clearstone Engineering Ltd. (2014a; 2018; 2019a) were compiled by Johnson and Tyner (2020) to include any missing facility types
	Fugitives Compressor seals	– Scaled from 2012 baseline estimate by site counts to each year (ECCC, 2022b)	
	Pneumatic controllers Pneumatic pumps Pneumatic instruments	– Site gas composition[a] – Average vent rates (SM Section 1.3)	Bottom-up pneumatic count data compiled by Johnson and Tyner (2020)
	Abandoned wells	– Apply emission factors to abandoned wells	ST37: List of wells in Alberta (AER, 2021a)

[a]Gas compositions derived from Tyner and Johnson (2020), described in SM Section S1.2.

[b]Typical flare efficiency assumed following Clearstone Engineering Ltd. (2014b) and ECCC (2022b).

[c]From Johnson and Tyner (2020), built from Clearstone Engineering Ltd. (2019a) counts and U.S. Environmental Protection Agency (2000) emission factors.

[d]Unknown/unreported flow rates follow ECCC (2022b) estimation method for severity classes.

ECCC, 2022b). These same 2011 Clearstone Engineering emissions data were more recently compiled by site type in the supplemental information of Johnson and Tyner (2020) and were more easily included in our model for each year after the necessary scaling was applied. Compressor seals and fugitives were scaled by site counts (a surrogate for equipment counts), while storage losses, (un)loading, compressor starts, and dehydrator emissions were scaled by produced oil/gas volumes. **Table 1** provides source data and scaling method details for each emission type.

Pneumatic emissions were estimated separately using a bottom-up inventory of pneumatic instrument counts by site type in Johnson and Tyner (2020), which was adapted from Clearstone Engineering Ltd. (2018) counts, and also leveraged gas compositions and average vent rates (see SM Section S1.3 for additional details).

2.1.4. Regulatory updates

Among the numerous requirements set out in Directive 060, Alberta's UOG methane reduction regulations were two requirements that necessitated updates to the inventory model: (1) a shift from modeled emissions to reported and (2) leak detection and repair (LDAR) surveys.

Starting in 2020, Directive 060 required oil and gas operators in Alberta to report nearly all sources of venting, flaring, and fuel use (Petrinex, 2019; AER, 2021c). Before 2020, only direct venting of gas was reported, whereas operators must now report all indirect venting from sources, such as compressor seals, pneumatics, or storage losses. Similar to ECCC's methodology, we therefore did not require scaled emission estimates (Section 2.1.3) for such categories in 2020 or 2021.

At the same time, Directive 060 required operators to conduct annual or triannual LDAR surveys at certain site types to mitigate fugitive emissions. The impact of LDAR at applicable sites was modeled following Johnson and Tyner (2020) who applied simulated emission reduction factors from Ravikumar and Brandt (2017) to each site's modeled fugitive emissions (see SM Section 1.4 for more details on LDAR applicability and survey frequencies). The fugitive emission reduction factors interpolated from Ravikumar and Brandt (2017) by Johnson and Tyner (2020)—roughly 40% and 68% reductions for annual and triannual surveys, respectively—considered detection limits of the common optical gas imaging (OGI) camera approach.

2.2. Reporting inconsistency model update

The shift in inventoried emissions from modeled to operator-reported, beginning in 2020 (see Section 2.1.4), created an inconsistency between years. Previously, ECCC modeled emissions from storage losses, pneumatics, dehydrators, and so on and scaled them to each year by production volume or site counts (see Section 2.1.3). Now, however, operators must report these emissions to Petrinex and a parallel, nonpublic database called OneStop (AER, 2020b). Importantly, these new reported data are aggregated in Petrinex under a generic "vent" category without any way to disaggregate them. Since limited data were available to ECCC to validate these new reports, the data simply replaced the previous estimates.

Since the publication of ECCC's 2020 inventory, however, two reports have been published by the Alberta government from the separate OneStop database, which broadly disaggregated vented emission sources (AER, 2022b; Government of Alberta, 2022). Using these reports, we downscaled the total reported venting in Petrinex to represent only direct venting and allowed the ECCC estimates of indirect venting apply consistently across all inventoried years. Any observed differences between this modeling approach and the typical inventory estimates in Section 2.1 could then be attributed to the shift in reporting requirements. This downscaling factor (34%) was the fraction of direct vented emissions relative to all reported venting emissions in Alberta, according to OneStop database (Government of Alberta, 2022). We selected this downscaling factor because it was the closest match to expected direct venting reduction modeled for 2020 from 2019 data and would also report the most conservative discrepancy with the original model in Section 2.1 (see SM Section S1.5 for more details on the scaling options considered).

This updated model was also adapted to reflect expected reductions in pneumatic emissions following future venting limits for the instruments under Alberta's new regulations. Directive 060 outlines new venting limits for existing pneumatic instruments beginning in 2023, and toward compliance with this requirement, operators have been converting instruments to low- or no-bleed alternatives. Pneumatic conversion counts were provided in a personal communication (H Carmichael, Director of Strategic Climate Policy, Government of Alberta, to SP Seymour, EDF, 02 February, 2022). Converted instrument counts and low-bleed emission factors were used to discount the original bottom-up pneumatics estimate described in Section 2.1.3 (see SM Section 1.3 for more detail).

2.3. Measurement-based update to model

As mentioned, several top-down measurement studies have found that UOG methane emissions are higher than reported. It is possible for regulators or government to leverage published measurement studies to update emission factors to close the gap between top-down measurements and bottom-up inventories. To better understand how this might impact the current inventory model, we updated select emission factors from published studies in Canada and re-ran our model from Section 2.2 to assess the impact of these changes. Updates included venting from cold heavy oil production with sand (CHOPS) wells, abandoned wells, fired equipment, and unlit/malfunctioning flares, although this list should not be considered exhaustive nor necessarily representative of current emissions. **Table 2** summarizes the impact each update had on the model, and the inclusion of each update is discussed in greater detail in SM Section S4.

3. Inventory model results

3.1. Inventory model (following government methods)

Closely following federal government methodologies, we produced methane emission estimates for Alberta' UOG sector for 2011 to 2021, shown in **Figure 1**. This model exhibits a 58% emissions reduction between 2020 (the most recent inventoried year) and 2012, the federal baseline year. By comparison, ECCC (2022a) reported a 47% emissions reduction, which is less drastic a reduction since their estimate includes downstream emission sources, such as refineries, upgraders, and so on (see Section 2.1), which are expected to be more stable considering new regulations do not apply to them.

Figure 1 shows that reported venting emissions have decreased significantly since 2014, and in 2020, an overall vent gas (OVG) limit went into effect, which should further limit sites to a maximum venting of 15,000 m^3/month of gas or 9,000 kg/month of methane (AER, 2021c). Instead, venting in 2020 appeared to increase by 94% (and flaring by 38%), which is likely caused by the new reporting requirements to include indirect venting sources (e.g., pneumatics, storage losses, compressor seals and starts) previously estimated by ECCC.

If the apparent reductions reported by this model (and those reported by ECCC) are valid, this implies that the province has already reached its 45% reduction target. However, the combination of new venting limits, reporting changes, and a significant drop in production in 2020 (the last one due in part to the COVID-19 pandemic; Canada Energy Regulator, 2020) makes any progress difficult to confirm. We therefore attempted to resolve this reporting change by scaling down reported venting emissions to represent only direct venting and applied ECCC emission estimates (Section 2.1.3) to represent indirect venting in 2020 and 2021, which is shown in the following section.

3.2. Inventory model (handling reporting inconsistency)

Figure 2 shows the 2011–2021 Alberta methane inventory using the updated methodologies (Section 2.2) to account for the change in reporting requirements in

Table 2. Selected measurement-based updates to Alberta inventory

Emission Type	Original Assumption	Proposed Assumption	Rescaling Justification and Sources	Emission Increase (%)	Emission Increase (kt CH_4)
Flaring	98% efficiency	~96% efficiency	New average efficiency assumes a 2% unlit flare and 2% malfunction fraction (90% efficient; EDF, 2021b). Fractions were less than half the rates from other studies (EDF, 2021a)	133	16
Cold heavy oil production with sand (CHOPS) well venting	Use reported venting	Add excess emissions	Excess emissions detected by Johnson et al. (2017) in CHOPS-dominant Lloydminster. Add excess venting to CHOPS wells based on produced volumes, and excluding Directive 084 areas (equal to +56 kg CH_4 per m^3 oil)[a,b]	1,549	415
Abandoned wells	EF from Townsend-small et al. (2016)	Increase EF by 2.5×	Increased EF based on Williams et al. (2021) to account for updated EFs and uncounted abandoned wells	150	13
Fired equipment	Rich-burn engine EF	Assume 10% lean-burn engines	Excess emissions reported by Tyner and Johnson (2021) from fired equipment that suggest lean-burning engines are present in Alberta. Assume 10% of reciprocating engines have lean-burn EF	50	14
			Total increase in 2020 inventoried emissions	**+74%**	**+458 kt**

EF = emission factor.

[a]The excess venting emissions from Lloydminster CHOPS were not expected to be observed in Directive 084 areas (Lavoie et al., 2021).

[b]Added emissions were attributed to storage loss because tank loss is not monitored during gas–oil ratio tests (Alberta Energy Regulator, 2018a) and may be a significant source of excess emissions.

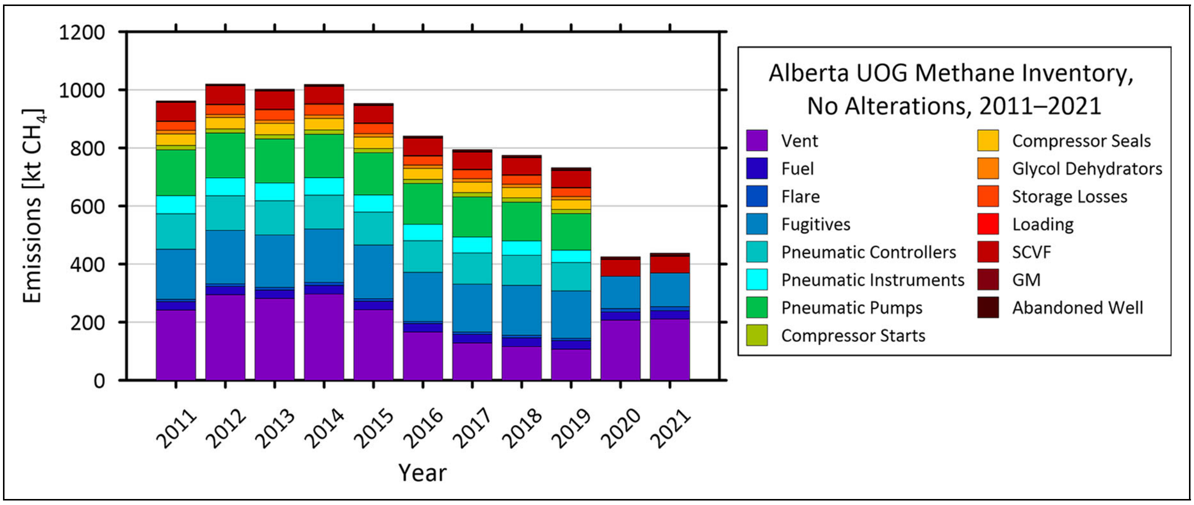

Figure 1. Alberta Upstream Oil and Gas Methane Inventory, 2011–2021. The Alberta methane inventory model for 2011 to 2021, closely following federal government data sources and methodologies, shows an apparent emission reduction of approximately 58% between 2012 and 2020. However, changes by source type are obscured by a change in reporting in 2020. Previously modeled emissions from pneumatics, compressors, dehydrators, storage, and loading/unloading had to be reported to "vent" or "flare" categories by oil and gas operators.

2020. This model approach exhibits a 45% (38%) increase in inventoried emissions for 2020 (2021) compared to the original methodology of **Figure 1**. This method also exhibits a 39% emissions reduction between 2020 and 2012, compared to the 47% reduction reported for Alberta in the federal inventory (ECCC, 2022c) and the

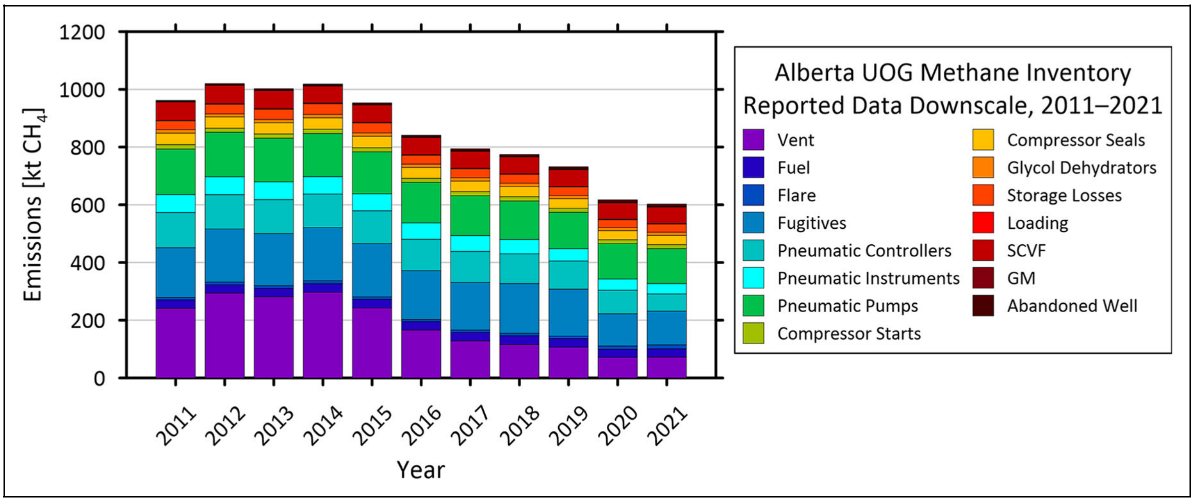

Figure 2. Alberta Upstream Oil and Gas Methane Inventory, 2011–2021, accounting for the reporting inconsistency in 2020. To account for the reporting shift in **Figure 1**, reported venting emissions were downscaled by 34% to represent only direct venting and the models for indirect venting (i.e., from pneumatics, compressors, and so on), which were typically applied to 2011–2019 years were extended to 2020/2021. This modification increased inventory estimates for 2020 and 2021 by 45% and 38%, respectively, and suggests that emission reductions since 2012 might be 39% instead of the 58% in **Figure 1**.

58% reduction in **Figure 1**. It should be reiterated that the necessary downscaling approach described in Section 2.2 to avoid the usage of seemingly underreported venting emissions is an approximation of direct venting. It is possible that the typical ECCC emission estimates could not capture changes in emissions due to the COVID-19 pandemic; however, this appears unlikely since production largely returned in 2021 (SM Section S1.1) while reported emissions remained stable (**Figure 1**).

The significant difference between the model with and without reporting inconsistency correction suggests that a significant fraction of emission reductions since 2012 are attributable to the inconsistency itself (an overall 19% emission reduction since 2012 or roughly a third of apparent reductions). Future measurement campaigns will hopefully confirm that this reporting change is responsible for a widened gap between the inventory and measurements, that is, new measurements finding emissions in excess of the well-established 1.5–2 factor above the inventory.

This updated model also has the benefit of maintaining separate emission estimates by source type, which were aggregated into contributions from modeled regulatory impact, reported data, and from estimated sources. **Figure 3** shows the breakdown of emissions by type. Reductions in reported emission sources (57% of reductions) were driven largely by venting. Reductions from historically unreported (modeled) emission sources (28% of reductions) were mostly from sources scaled by site counts (following a general contraction in site counts; see SM Section S1.1); volume-scaled emissions also decreased but to a much lesser degree. Reductions gained through modeled LDAR made up another 10% and conversions of pneumatic instruments from high- to low-bleed devices constituted 6% of the reductions. This breakdown shows that while roughly two-thirds of the apparent emission reductions can be attributed to reported data (mostly venting and reported pneumatic conversions), the remaining third depends on the reductions from estimated sources and modeled LDAR impact. Section 4 reviews the methodologies underlying each of these reduction categories to assess the reliability of the claimed reduction in emissions.

3.3. Measurement-updated inventory model

Updating emission factors for 4 selected emission types using published measurement data (see **Table 2**) increased each inventoried year's emissions by factors between 1.6 and 1.8. Interestingly, the decrease in emissions since 2012 was essentially unchanged from Section 3.2 (approximately 36%). **Figure 4** shows the updated inventory estimate.

Comparing these results with those of Section 3.2, we see that the emission factor updates have caused the inventory estimate to increase to within 1.5–2 times, consistent with previous measurement studies. Although this would represent an improvement to the inventory in terms of annual quantification, it relies more significantly on emission factors and scaled emissions (81% of the inventory in **Figure 4** from 71% in **Figure 1**). This has implications for monitoring emission trends: *By updating emission factors to close the measurement-inventory gap, the inventory more heavily relies upon static emission factors and/or performance factors.*

Undoubtedly, updated emission factors helped to close the gap between top-down measurement and the bottom-up inventory; however, the increased reliance on estimated emissions may not reflect true emissions if they are not updated regularly. Single snapshot updates of emission factors fix the assumed performance of, for example, unlit flares, which might change as targeted regulations attempt to resolve this issue. These snapshot updates also hold fixed the assumed industry

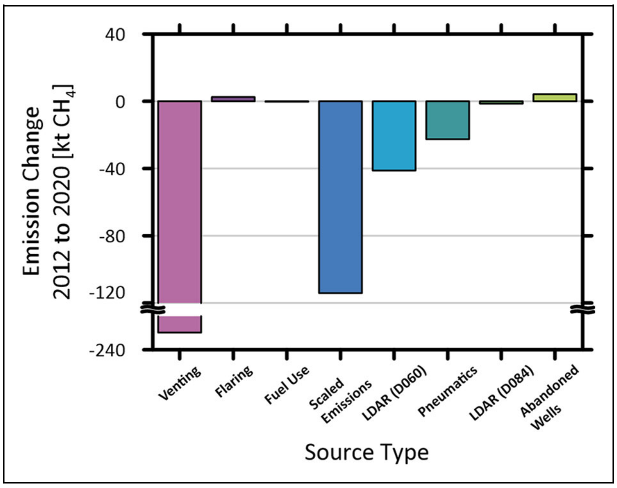

Figure 3. Emission reductions between 2012 and 2020 for the downscaled inventory model by source type. The emission reductions in the downscaled inventory model of **Figure 2** show that reductions in reported emissions (venting, flaring, and fuel use) are approximately 57% of the reductions, while reductions from scaled emissions (storage losses, pneumatics, compressors, etc.) contribute approximately 28%, from leak detection and repair (LDAR) 10%, and from pneumatic conversions 6%.

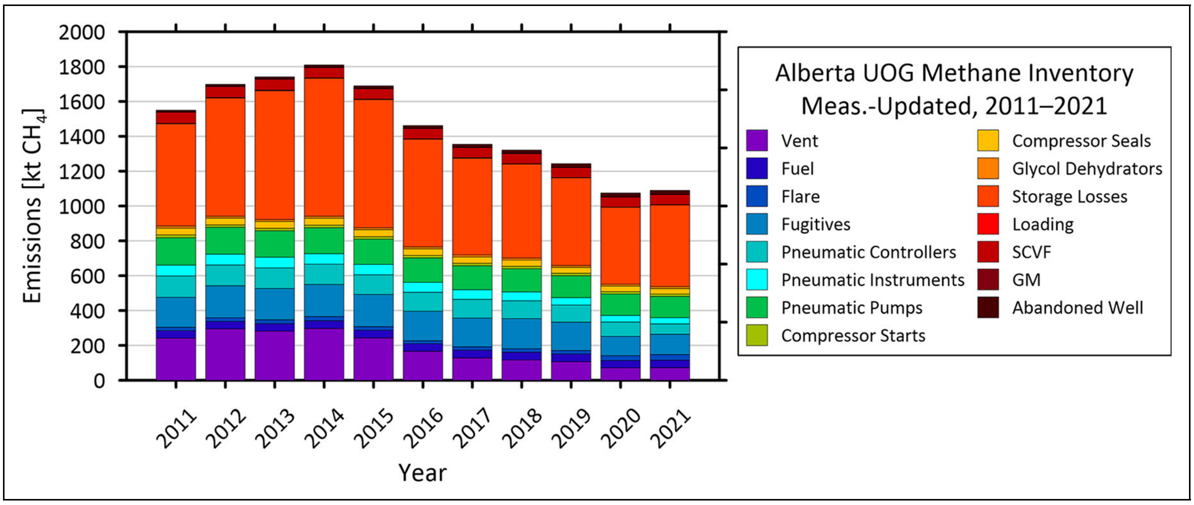

Figure 4. Measurement-updated methane inventory for Alberta, 2011–2021. By updating emission factors for cold heavy oil production with sand wells, abandoned wells, unlit/malfunctioning flares, and poorly maintained fired equipment, the inventory estimate for each year increased by a factor of between 1.6 and 1.8. However, the reduction between 2012 and 2020 only reduced from 39% to 36%. Although updated emission factors increased the inventory to close the gap with top-down measurements, it also increases the reliance on estimated emissions/emission factors, which would need frequent updating to maintain relevance.

infrastructure. By updating equipment counts infrequently and applying them to each inventoried year, any shifts in active equipment types are neglected. Of the updated emissions, the largest increase was observed for CHOPS wells; however, these measurements were conducted in 2016 and may hold little relevance now.

On the other hand, there is reason to believe that reliance on out-of-date emission factors could be resolved if new requirements for oil and gas operator reporting yield accurate emissions. We review the reliability of different inventory data sources and assumptions in Section 4, including operator-reported data in Section 4.1, and find significant uncertainties with both estimated and operator-reported emissions.

4. Review of reductions by category

In this section, we discuss the reliability of emission reductions from each of the main reduction categories discussed in Section 3.2, namely, reported data, estimated/scaled emissions, LDAR impact, and pneumatic conversions. Sources of uncertainty and issues impacting annual emission trends are highlighted.

4.1. Reported data

Reductions in reported data make up more than half of the overall emission decreases between 2012 and 2020 in the presented model of Section 3.2 after accounting for reporting inconsistencies. Although it might be assumed that this category is the most reliable—it comes directly from operators at the site level and is reported monthly—the reported emissions may in fact be estimated (i.e., not measured/metered; AER, 2021a). Additionally, full reporting compliance is necessarily assumed, and performance assumptions are required to convert flared and fuel use volumes into mass emissions of methane.

4.1.1. Emission estimation by operators

For gas and crude oil wells and facilities, any site with <500 m^3/day of fuel use or flare/vent emissions may estimate these volumes using typical manufacturer gas consumption rates for fired equipment or from a minimum 1-h metering test of the gas stream and assuming constant flow rates thereafter (AER, 2018a). In 2020, for example, >99% of wells and >90% of facilities reporting any flared and vented volumes were exempted from metering their emitted gas. Most notably uncertain, however, is gas production at cold heavy oil sites.

CHOPS wells use much of their (reported) produced gas as fuel and often do not have the infrastructure to conserve the gas, implying that any excess produced gas is likely to be vented. However, CHOPS wells are not required to meter their gas production unless it exceeds 2,000 m^3/day (AER, 2018a), such that 93% of sites in 2020 were eligible to use estimation methods. The most common estimation method assumes a stable volumetric relationship between gas and oil allowing a gas–oil ratio (GOR) to be derived from a 24-h measurement; the vast majority of which are updated annually or every 3 years (AER, 2018a). However, measurements from these same cold heavy oil regions have shown significantly higher emissions than suggested by the inventory (Chan et al., 2020; MacKay et al., 2021), and in particular, studies by Johnson et al. (2017) and Roscioli et al. (2018) have suggested uncertainties in GOR to be a likely cause of underestimation. Possibly confirming these suggestions, GOR measurements conducted by Peachey (2004) show that GOR may vary "wildly" between tests and there have been inconsistencies in derived values between different operators. Tank vents are a likely point of emission for underestimated GOR/gas production since they are often not monitored during GOR testing (AER, 2018a). Any excess gas production would likely be vented to atmosphere without a report since it is not actively measured.

4.1.2. Methane destruction performance assumptions

Reported emissions from Petrinex are quoted in terms of dispensed volumes, not in terms of resulting emissions, which requires assumptions to be made about the gas destruction "efficiency" of flares and fired equipment (e.g., boilers, reciprocating engines).

Flares are assumed to combust 98% of the inlet gas in the federal government inventory (Clearstone Engineering Ltd., 2014a; ECCC, 2022b). However, multiple surveys in the United States and Canada have found significant emissions from unlit flares and/or malfunctioning flares emitting uncombusted gas (EDF, 2021a; Tyner and Johnson, 2021). Indeed, as part of the present study, we conducted a helicopter-based OGI camera survey near Grande Prairie, Alberta, in 2021 and found 0.3% of flares to be unlit. Although this unlit fraction may be conservatively low due to winter temperatures (Lyman et al., 2019; see SM Section S5 for more details), the study shows that emissions from flaring are underestimated since all flares are assumed to be properly lit.

Performance assumptions were also necessary for fired equipment. The ECCC inventory assumes a rich-burning emission factor for fired equipment. However, aerial LiDAR measurements in British Columbia (Tyner and Johnson, 2021) found methane emissions from compressor exhaust to be much higher than from studies in the United States (Vaughn et al., 2019; Zimmerle et al., 2020b) and suggested that the assumption of rich-burning engines may not be accurate. Lean-burning engines may be used by operators to suppress the formation of oxides of nitrogen (NO_x) to comply with federal regulations (Government of Canada, 2016), but this also has the effect of decreasing methane destruction efficiency by approximately 5 times (Clearstone Engineering Ltd., 2019a). Although unlit flares and highly emitting engines suggest that emissions magnitudes are underestimated, these sources are likely to have persisted throughout many inventoried years and would not necessarily impact temporal emission trends.

4.1.3. Reporting noncompliance

Any evidence of reporting noncompliance would severely undercut the credibility of claimed emission reductions from reported data. The inventory does not account for reporting noncompliance and the helicopter survey conducted by the authors (see SM Section S5) found lit flares at approximately 16% of their 284 unique sites for which no flaring activity was reported (minimum reporting volume was >49 m^3 in a month; AER, 2020c). It was possible that the observed flaring was reported at an off-site facility, but if true, this misallocation would still constitute noncompliance (AER, 2021d). This nonreporting fraction implies that flaring emissions could be underreported by approximately 16%.

The apparent reporting noncompliance observed in the helicopter survey may have been due to reporting changes in 2020. Alberta operators were required to report new emission categories to Petrinex (Section 2.2) and to a nonpublic, parallel database called OneStop. Reports from the AER and Government of Alberta (AER, 2022b; Government of Alberta, 2022) found that the OneStop database had 37% more reported emissions than Petrinex, despite Petrinex being expected to have higher reported emissions. It is difficult to determine why Petrinex data appear underreported, especially since even OneStop underestimates emissions relative to the modeled approach (see SM Section S2), but this suggests that emission trends have become more uncertain since 2020.

Although it is not possible to assign a specific uncertainty to the reported data, the issues of performance assumptions, CHOPS GOR, and assumed operator compliance are all likely to bias the inventory low. However, since estimation methods are largely unchanged across the inventoried years and assuming that unlit flares and

Table 3. Rescaling exercise for select estimated emission sources in the Alberta upstream methane emissions model and relative and absolute emission increases for the 2020 inventoried year

Emission Type	Original Scaling	Proposed Scaling	Rescaling Justification	Emission Increase (%)	Emission Increase (kt CH_4)
Storage losses	Oil/gas volumes	Produced oil/ condensate volume	Losses from liquid hydrocarbon storage tanks proportional to tank liquid volumes/throughput (Clearstone Engineering Ltd., 2014a)	77	22
Compressor seals	Site counts	Produced gas volume	Losses from compressors to increase with heightened service times to transmit more produced gas (AER, 2018b)	36	11
Fugitives	Site counts	Produced gas volume	Fugitive emission increases with longer time-in-service from increased production	6	16
Pneumatic-level controllers	Site counts	Produced liquids (water, oil, condensate)[a]	Controller actuation related to liquid levels (D'Antoni, 2018; Spartan Controls, 2018)	79	65
Glycol dehydrators	Oil/gas volumes	Produced gas volume	Emissions cited per unit produced gas (Clearstone Engineering Ltd., 2014a)	1	0.1
			Total increase in 2020 inventoried emissions	**+12%**	**+114 kt**

[a]Produced water volumes were also available from the Petrinex activity data.

poor engine combustion have similarly persisted, these are unlikely to introduce changes to annual emission trends (seemingly confirmed by the similar reductions in Sections 3.2 and 3.3). The reporting inconsistencies that seemingly began in 2020, on the other hand, are likely to have a negative impact on the apparent emission trends since they do not similarly apply to the baseline year.

4.2. Scaled emissions

In any given inventoried year, emissions estimated in—and scaled up from—a baseline year constitute approximately 71% of the total pre-2020 inventory. For the emission sources scaled by volume, each broad production type (e.g., crude oil, gas, cold heavy oil, thermal heavy oil) was scaled by its primary production fluid.

These estimates rely on the assumption that their underlying emission factors are well-characterized. However, multiple studies have shown that many oil and gas systems follow extremely heavy-tailed distributions (Rella et al., 2015; Brandt et al., 2016; Zavala-Araiza et al., 2017), and if component-level emission factors were not derived from a sufficiently large sample, the resulting factor is unlikely to properly characterize the heavy tail. It is unclear whether underlying measurements were of sufficient quantity, but if not, the likely outcome is an underestimate of average emissions. For pneumatic-level controllers, at least, such behavior has been reported where "level controllers remaining in transient vent state can be reset" (Spartan Controls, 2018)—although fewer than 10 such instances of abnormal emissions were observed in the study. By contrast, emissions from glycol dehydrators were based on simulation (Clearstone Engineering Ltd., 2014a) and might not include any emissions stemming from abnormal processes.

Additionally, the linear scaling of estimates from a reference year by broad production volumes or site counts (a proxy for equipment counts) remains an untested assumption. Simulations by Cardoso-Saldaña and Allen (2020) show that leaks and emissions from pneumatics may remain constant even when production decreases, suggesting that a production scaling is not necessarily appropriate.

Even assuming that scaling is possible, the scaling factors employed in the inventory are not necessarily the most appropriate for each emission source (e.g., gas production scaling liquid storage tank losses). We therefore reviewed the underlying emission factors and, where applicable, identified alternate scaling approaches using volumetric data germane to the emission type. We applied these alternate scaling methods to the inventory model of Section 3.2 and summarize their impact on the 2020 inventory in **Table 3** (justification for the alternate scaling is provided in SM Section S3).

Scaling the estimated emissions using more appropriate alternative factors increased each category and resulted in an increased inventory total by as much as 18% for each year. In 2020, the alternate scaling increased the inventory by 12% and suppressed apparent emission reductions since 2012 to 31% from 39% in **Figure 1**. This rescaling exercise shows that slight changes in the scaling assumptions can drastically change the emissions. Regardless of the scaling factor choice, the linear scaling makes implicit assumptions about the industry.

Relying on site counts and broad production volumes for scaling necessarily assumes that the distribution of production by site types remains constant. Theoretically, all single well batteries could be converted to multiwell batteries and identical emissions would be estimated for a count-scaled emission source despite the considerable infrastructure differences; similarly, the same produced volume would result in an identical emission from any number of sites when applied to volume-scaled sources. Although the distribution of site types was likely captured in the original surveys (e.g., Clearstone Engineering Ltd., 2018), they assume a static distribution (cross-section) of sites when extrapolated to other years.

4.3. LDAR reductions

The reduction of fugitive emissions through LDAR surveys was modeled by applying time-averaged emission reduction factors for the required annual or triannual LDAR surveys. Fugitive reduction factors were applied to modeled fugitive emission magnitudes, so the accuracy of LDAR impact depended on both the reduction factors and the modeled fugitive totals—the LDAR modeling also assumed full compliance. These considerations are discussed below.

4.3.1. Modeled LDAR effectiveness

The presented model applied simulated fugitive reduction factors to each site's modeled fugitive total. However, more recent studies have shown real-world detection limits of OGI cameras to be roughly an order of magnitude larger than previously reported (Ravikumar et al., 2018; Zimmerle et al., 2020a), suggesting the effectiveness of LDAR surveys may be overstated. Additionally, any LDAR survey effectiveness would be reduced when conducted in cold winter conditions where camera sensitivity is further reduced (Lyman et al., 2019). Finally, LDAR by the common OGI camera may be even less effective in situations where fugitives are in difficult to reach areas, such as tank tops, flare stacks, or building tops (Ravikumar et al., 2018). Indeed, Tyner and Johnson (2021) reported that aerial measurements found 18 times more methane emissions than an OGI survey at the same sites in British Columbia. The largest emitters in the aerial survey (compressor exhaust, unlit flares, and storage tanks) would all be difficult for ground-based OGI teams to quantify.

4.3.2. Modeled fugitive emissions

The LDAR model also assumes fugitive emission magnitudes are well-characterized. The fugitive total originally developed by Clearstone Engineering Ltd. (2014b) was derived following U.S. EPA (1995) methodology, which estimates fugitive leaks using component counts and average measured emission factors (which may be underestimated; see Section 4.2). However, this method only considers component leaks (e.g., wear, poor design, or improper installation of seals, connectors) and is likely to neglect abnormal equipment operation that leads to unintended emissions (Clearstone Engineering Ltd., 2014c). For example, stuck dump valves leading to gas carry-through into storage tanks (Clearstone Engineering Ltd., 2019b), unlit flares, exhaust from poorly operating engines, or vapor recovery unit malfunctions can all lead to significant emissions that are not considered in a component-level survey since this method does not measure emissions from intentional exhaust/vent points. Nevertheless, the definitions of "fugitives" in the province would still consider these fugitives (AER, 2020c). The omission of these sources in the model could explain why the reported fugitive emissions in OneStop were roughly equal to modeled fugitives in a year, where LDAR requirements were heavily curtailed (AER, 2020d; see SM Section S2).

4.3.3. LDAR compliance rates

Full compliance is also assumed in the LDAR model. However, the neighboring province of British Columbia found approximately 45% of LDAR surveys to have not been completed in 2020 (BC Oil and Gas Commission, 2021). They also found more than 2,000 leaks that were not repaired on time, suggesting that even when detected, the emissions persisted for longer than the simulated reduction factors may have assumed.

Although the implementation of LDAR will reduce methane emissions, the magnitude of these reductions remains highly uncertain. As discussed, modeled fugitive totals may be significantly underestimated and the effectiveness of OGI-based LDAR may be overstated. Since LDAR requirements only began in 2020, any mischaracterization of fugitive magnitudes or LDAR impact would also negatively impact annual emission trends since they do not apply to the 2012 baseline—if modeled LDAR effectiveness is indeed overstated, then the inventory would further underestimate real-world emissions.

4.4. Pneumatic conversions

Reductions associated with pneumatic conversions are expected to be relatively well-characterized compared to other reduction categories. Emission totals were calculated using estimated instrument counts and measured emission factors, and reported counts of converted instruments (and their respective emission factors) were used to discount the total. Compared to other reporting categories, the modeled emissions from pneumatics compared favorably with operator-reported pneumatics total in the nonpublic OneStop database (reported data were approximately 70%–80% of modeled total; see SM Section S2). The largest remaining uncertainty in this emission category is assumed to be any undercharacterization of abnormally operating pneumatic devices (e.g., Spartan Controls, 2018; Luck et al., 2019).

5. Discussion and recommendations

The Government of Canada has reported an approximately 47% reduction in methane emissions from the entire oil and gas industry in Alberta since 2012 (ECCC, 2022c; Government of Alberta, 2022). Following methodologies consistent with the Government of Canada and its consultants, we developed an inventory model for Alberta's UOG sector and found an apparent reduction in emissions of 58% (Section 3.1). This model closely followed the federal government methodology, but we also presented subsequent variations on this model to

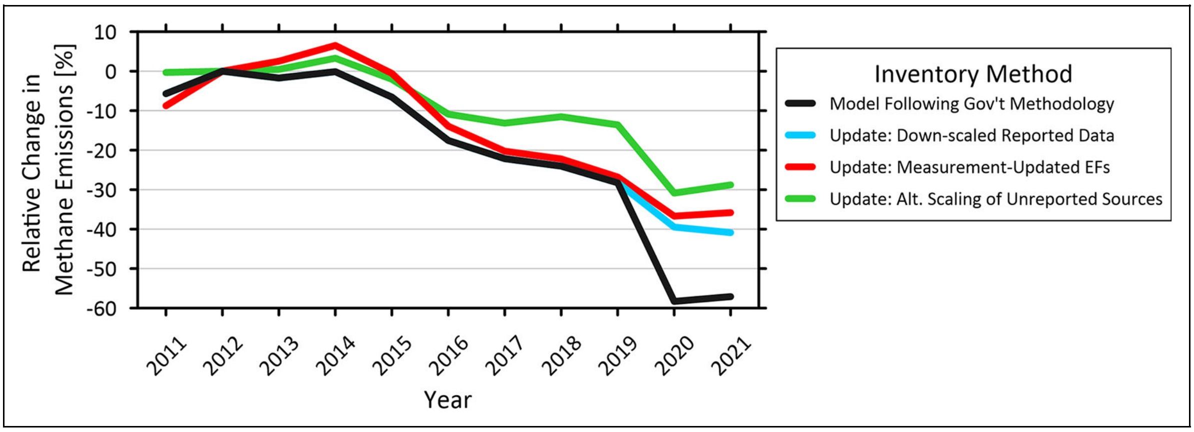

Figure 5. Relative reductions in annual inventoried methane emissions from different model variations. The relative change in annual methane emissions since 2012 for the original inventory model (Section 2.1) and subsequent model variations to account for reporting inconsistencies (down-scale), underestimated emission factors, and alternate scaling/extrapolation assumptions (Sections 2.2, 2.3, and 4.2, respectively). This shows that slight changes to the model could result in apparent emission reductions of between 30% and 58% since 2012. (Note that the government method and down-scaled models are equivalent for 2011–2019, only diverging after a change in reporting requirements in 2020.)

1. resolve a reporting inconsistency through down-scaling and reapplying ECCC modeled emissions (Section 3.2),
2. update select emission factors from published measurement data (Section 3.3), and
3. utilize more relevant scaling factors when estimating historically unreported emissions (Section 4.2).

The model variations indicated that (1) reporting inconsistencies/underreporting may have contributed significantly to *apparent* emission reductions (and were seemingly confirmed by helicopter survey; SM Section S5), (2) updating emission factors may improve inventory magnitudes but only if they are updated to maintain relevance, and (3) slight modifications to the scaling assumptions yield different annual inventory estimates. Although these model variations are not necessarily more accurate than the federal government methodology, they illustrate that slight changes to the methodology produce different conclusions. **Figure 5** displays the relative change in annual emissions for each model variation and shows a significant spread in apparent reductions since 2012. Between 2012 and 2020, the different model variations suggest emission reductions between 30% and 58%. (Note, however, that the emission factor-updated and alternative scaling variations were produced by applying new assumptions to the down-scaled inventory estimate and are thus not entirely independent from the down-scaled estimate.)

The review of emission estimation methodologies in our inventory model shows where emission magnitudes are likely underestimated, but it also illustrates the significant uncertainty in emission trends since 2012, which makes the achievement of a 40%–45% reduction in emissions difficult to verify.

5.1. Recommendations

Toward a more certain methane inventory for the UOG industry, we recommend the adoption of the 4 following considerations at the provincial and/or federal level.

5.1.1. Measurement-based inventory

Jurisdictions seeking to reduce the uncertainty of their oil and gas methane inventory should develop inventories based on direct source-level measurements conducted at regular intervals. Current inventories often rely on limited measurements focused on only one emission source and are not regularly updated. By contrast, direct measurements of all on-site sources could build an inventory based on up-to-date emissions, and survey repetition would identify emission trends related to aging equipment, equipment retrofits, new venting limits, and so on, although repetition frequency will be technology dependent. For this approach to be effective, sampling would need to be representative of the entire population of site/equipment types, and sufficient sampling would be required to properly characterize heavy-tailed emission distributions.

The recent use of aerial Gas Mapping LiDAR (GML) technology to detect and quantify equipment-level emissions (Johnson et al., 2021) has proven quite promising for these purposes. Importantly, this technology is capable of observing not only typical operation but irregular emission events that are otherwise only included under a generic fugitive category or omitted entirely in the inventory (Tyner and Johnson, 2021). In the case of GML, not all emissions are large enough to be detected (pneumatics), but supplementing with ground-based techniques could help cover the gap. GML surveys could also be used as an advanced screening method and would allow ground-based follow-up surveys of highly emitting sites to identify root causes and suggest repairs/resolution (Fox et al., 2019)—this would also provide regulators with invaluable data on which to develop effective regulations. Such measurement-based inventories could be readily validated by comparison with larger scale methods, such as aerial mass balance (regional) measurements (e.g., Johnson et al., 2017; Baray et al., 2018). Comparisons would either demonstrate agreement or would direct additional measurements toward regions that appear to be poorly characterized. In addition to GML or similar measurements, long-term detection methods, such as satellites or continuous monitoring towers, would be required to identify highly infrequent large emissions (e.g., pipeline ruptures) and help monitor trends.

5.1.2. Improved fugitive classification

We recommend that the estimated fugitive category (and LDAR model) be replaced by reported fugitive emissions observed through LDAR surveys. As previously mentioned, Alberta oil and gas operators began reporting their detected fugitive emissions to the OneStop (nonpublic) database in 2020 and these could replace the dual-modeling approach currently used to estimate fugitives (modeled fugitives and modeled LDAR). These data should be made public and disaggregated by equipment type to again allow for the identification of the most highly emitting and/or most often malfunctioning equipment, permitting the development of targeted regulation. However, the inclusion of new operator-reported data would only be feasible if there is full reporting compliance and accurate quantification methods.

5.1.3. Improved reporting and validation

Despite the recommendation of a measurement-based inventory, operator reported data remain invaluable to the current inventory and may still prove useful provided they are either measured or estimated accurately. These data capture nonroutine events, which may not be captured by intermittent surveys and instead offer site-level, monthly granularity. If operator-reported emissions could be periodically validated (and penalties imposed for poor estimation), operators would be incentivized to improve the accuracy of their reports, which would improve confidence in the data. The Government of Alberta (2022) has previously conducted site-level aircraft measurements to ensure compliance with venting limits, but this enforcement practice should be extended to the validation of reported data. This would assist in identifying reporting noncompliance and may also identify emission estimation practices in need of updating (e.g., GOR methods).

5.1.4. Static emission reduction target

Finally, considering the uncertain emission magnitudes of each inventoried year, the target of a 40%–45% reduction in emissions since 2012 is difficult to define. If the federal government revised their 2012 estimate to account for the previously mentioned 1.5–2 times gap with top-down measurement, then the 40%–45% reduction target would permit higher emissions in 2025. We therefore recommend that the Government of Canada explicitly state that the reduction targets are relative to the *currently estimated* 2012 methane emissions. Thus, any future updates to increase annual emission estimates would spur more aggressive reductions to meet the 40%–45% target.

6. Conclusion

Although issues with emission trends have been observed in countries using IPCC Tier 1 methods, such as Mexico and Romania (Government of Romania, 2020; Zavala-Araiza et al., 2021), the present analysis shows that reporting inconsistencies and uncertain emission estimation methods in Tier 3 inventory models may also produce highly uncertain emission magnitudes and trends, obscuring the magnitude of emission reductions. Our inventory model showed significant apparent emission reductions for Alberta; however, model updates show that a reporting inconsistency may have contributed significantly to apparent emission reductions, and a review of the underlying model data shows considerable uncertainty in most emission categories. These uncertainties help to explain the significant gap between top-down measurements and the bottom-up inventory, but more importantly, they cast doubt over the feasibility of quantifying a 40%–45% emission reduction from 2012, as committed to by the Government of Canada. Since the inventory methods cannot be applied uniformly through each inventoried year, the emission reduction since 2012 is highly uncertain.

To resolve these inventory uncertainties, we proposed that the Alberta and/or Canadian governments (1) adopt a measurement-based inventory that is updated regularly, (2) leverage reported fugitive emissions data, (3) improve reported data accuracy and conduct validation measurements, and (4) set a static emissions target. A measurement-based inventory would allow for the tracking of emissions annually and would remove the highly uncertain methods currently employed. Adding reported fugitives to the inventory could help resolve issues of modeled fugitive emissions and would assist regulators in understanding the most significant contributors to abnormal operating emissions. An improvement in operator reporting requirements and a validation of those data by independent measurement would lend more confidence to the emission magnitudes included in the inventory. Finally, setting reduction targets relative to the *currently estimated* 2012 inventory would limit any upward revisions to the estimate, meaning that as the federal inventory is improved in accuracy, more aggressive mitigation will be required to meet Canada's methane emission targets.

Data accessibility statement

Data were accessed through publicly available databases and cited reports. Operator-reported data (Conventional Volumetric Data) can be downloaded from the Petrinex database (https://www.petrinex.ca/PD/Pages/APD.aspx; 2017–2021) and by contacting the Alberta Energy Regulator Information Request desk (informationrequest@aer.ca; 2011–2016).

Supplemental files

The supplemental files for this article can be found as follows:

Supplemental information is provided as an attached document, Text S1, in PDF format.

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Competing interests

The authors declare that they have no known competing interests.

Author contributions

Contributed to the conception and design: SPS, DX, HZL, KM.

Contributed to analysis and interpretation of data: SPS, DX.

Drafted and/or revised the article: SPS, DX, HZL, KM.

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