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Article

Highly Uncertain Methane Leakage from Oil and Gas Wells in Canada Despite Measurement and Reporting

Scott P. Seymour,* Donglai Xie, and Mary Kang

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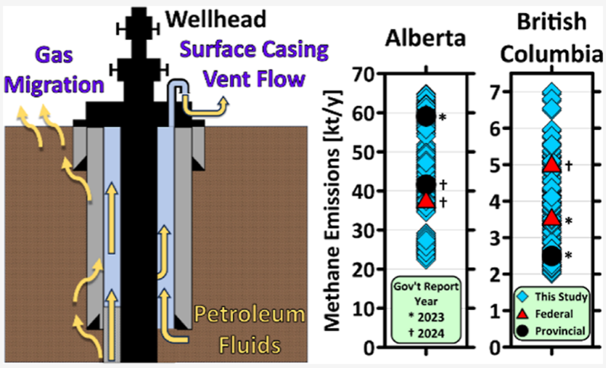
ABSTRACT: Leakage of fluids from oil and gas wells is a source of the key greenhouse gas methane, and presents environmental risks, including groundwater contamination. A loss of well integrity can result in fluid leakage into the annular space between subsequent well casings (which is often vented to the atmosphere) or into the surrounding subsurface. In Canada, industry reporting on well integrity is often incomplete, leading government inventories to disagree on emission magnitudes. In this study, we model wellbore methane emissions using industry data in British Columbia and Alberta, Canada, finding that differing model assumptions to handle unclear/missing data have a strong influence on estimated emissions. Considering estimates derived from industry reporting and from independent measurement, wellbore emissions in the two provinces range anywhere from 23 to 176 kt of methane, representing 1.7−11.4% of their upstream sector methane emissions. Further, finding over 130 examples of measured leaks seemingly missing from industry reporting, we conclude that wellbore emissions, groundwater contamination, and broader environmental risks are underestimated. We provide recommendations to improve well integrity tracking through data quality assurance measures and increased testing. Finally, we find that ongoing optical gas imaging camera surveys could be an effective tool to augment wellbore testing requirements to minimize industry burden.



1. INTRODUCTION

Methane (CH_4) is a potent greenhouse gas, and reducing emissions—particularly from the oil and gas industry—will play a key role in limiting climate warming.[1,2] Global methane levels continue to rise,[3,4] and while anthropogenic methane mitigation continues to garner international attention,[5] development and implementation of mitigation regulations has been hampered by a poor understanding of emission levels and source distributions.[6] Simple calculations or infrequent measurement can lead to considerable uncertainty—and often underestimation—for many emission sources. While recent work has shed new light on emissions from on-site compressors, liquid storage tanks, and heavy oil production,[7−13] wellbore leakage remains understudied.

Leakage from petroleum wellbores can result in both methane emissions and groundwater contamination;[14−17] long-term wellbore leakage issues could also negatively impact any co-located geologic storage of carbon dioxide or hydrogen.[16] Petroleum fluids (most often gas) can leak into the well from surrounding formations, or they can escape from within the inner well casing/tubing, becoming trapped in the annular space between well casings. In Canada, fluids entering this space are intentionally vented at the surface to protect groundwater, resulting in surface casing vent flow (SCVF).[18−21] SCVF is not particular to Canada, but many other jurisdictions (e.g., United States, China)[22−25] opt to keep the fluids sealed in the surface casing. While this may reduce methane emissions to the atmosphere, it can increase the risk of well blowouts and/or groundwater contamination.[14,23,26] Fluids may also escape the well entirely, traveling through the surrounding subsurface, referred to as "gas migration" (GM).[27,28] While GM generally emits much less methane than SCVF, this intrusion of petroleum fluids into the subsurface can pose a risk to groundwater.

In Canada, the provinces of Alberta and British Columbia (B.C.)—together representing 82 and 98% of national crude oil and natural gas production, respectively,[29] —have required industry testing and reporting of well integrity in some form since the 1990s,[30,31] resulting in some of the largest data sets in the world to track wellbore integrity and associated emissions.[32] However, these reported data were not designed for methane emission estimation and are notably incomplete,[31,33] requiring governments to apply assumptions to derive methane emission estimates.[34,35] Interestingly, differing

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assumptions between governmental bodies—implying different understandings about underlying mechanisms—have led to methane estimates that fundamentally disagree in magnitude and trend despite being derived from the same data sets (Figure 1). Recent measurement-based inventories suggest that such leakage represents ~7% of upstream oil and gas methane in Canada.[10,11,13]

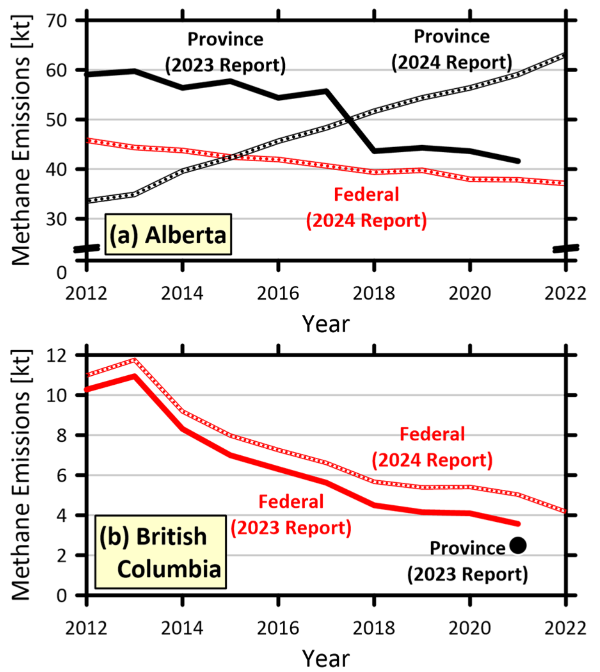

Figure 1. Estimated SCVF/GM methane in (a) Alberta and (b) B.C. according to Canadian federal and provincial governments, illustrating the stark disagreement in trend and magnitude between them despite coming from the same underlying industry data. While Alberta SCVF/GM calculation methodology reportedly changed between 2023 and 2024, the differences between 2023 and 2024 federal estimates for B.C. are apparently due to retroactive changes to the province's industry data.

In this study, we tested the sensitivity of methane emission magnitudes derived from industry reports of wellbore leakage (SCVF/GM) in Alberta and British Columbia, Canada. Unfortunately, other producing regions in Canada could not be included because of a lack of similar SCVF/GM data. Nevertheless, by recreating these estimates under a range of possible model assumptions, we identified the key uncertain terms in quantifying SCVF/GM methane from these data. We compared these data at well and province levels to available measurement data and provide recommendations on how to improve the monitoring and quantification of SCVF/GM methane in Canada. Finally, we discuss how Canada's proposed methane regulations[36,37] might impact these sources if/when they are implemented in 2027. Our results highlight the challenges of using industry-reported data focusing on well integrity, not emissions, to quantify methane leakage; instead, reporting protocols are needed that are catered toward methane emission quantification.

2. METHODS

2.1. Regulatory Background. Wellbore leakage (SCVF/GM) is a complex process with many possible, yet poorly understood, drivers.[38,39] For example, poor curing/installation of wellbore cement can result in permanent fluid transmission pathways for SCVF/GM;[27,40−45] production type, geography, and geology may influence emissions;[33,46−50] and well casing/cement degradation can result in issues that develop over time.[14,42] GM study is further complicated since gas may not be emitted uniformly around a wellhead, if at all.[50−52] Perhaps because of these complexities, well integrity tracking in Canada has largely relied on periodic testing.

For SCVF, emission testing is generally required after initial drilling and/or fracturing operations, and again at well abandonment.[19,53] Such tests may be as simple as the recommended "bubble test" in which a hose connected to the surface casing vent line is inserted in water—if bubbles are produced over a 10 min period, an SCVF is considered present (reportedly detecting flows of 0.003 m^3/d or greater[54]). Detected SCVFs must have their flow rates and shut-in pressures measured and reported, with equipment being selected "based on previous observations indicating what flow rate and pressure range can be expected".[53] Interestingly, no duration requirements are prescribed for flow rate measurements despite observations of fluctuating emission rates.[23,26,55] An SCVF is considered "serious" if one of multiple factors are true, e.g., gas flow rates exceeding 300 m^3/d in Alberta (100 m^3/d in B.C.), the emission contains H_2S gas, liquids, etc. Serious SCVFs must be repaired immediately (90 days in Alberta).[19,53] "Non-serious" SCVFs, on the

Table 1. Assumptions Needed to Estimate Start and End Dates for SCVF/GM Events Following Federal Methods,[35] Noting the Occurrence Rate for Each Scenario

Province	Reported Date Scenario	Serious Events	Non-serious Events	Occurrence by Province [%]
Alberta	Report < Resolution	Start: 90 days before report date End: resolution date	Start: finished drill date End: resolution or abandonment (whichever is first)	44
	Report = Resolution			13
	Report > Resolution	Start: 90 days before resolution End: report date		12
	No Resolution	Start: report date End: 90 days after report	Start: finished drill date End: continues to present	31
British Columbia	Report < Finished Drill Date	Start: report date End: resolution date*	Start: finished drill date End: abandonment or resolution date; if neither exist, continues to present	0.2
	Well is Abandoned at Report Date	Start: abandoned date End: resolution date*		0.5
	All Other	Start: finished drill date End: resolution date*		99

[a]Resolution dates for B.C. are subsequent well tests where the flow rate is zero and/or noted as "no emission"; if subsequent tests are not reported for an emission, emission durations follow the assumptions of Alberta: 90 days if serious, continues to present otherwise.

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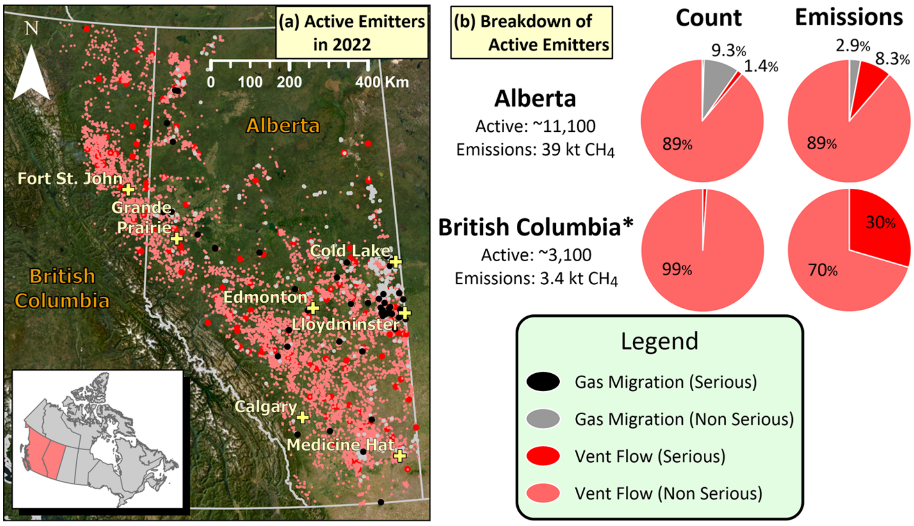

Figure 2. Active SCVF/GM emissions in 2022 by (a) location and (b) broken down by type/severity in each province. While SCVFs occur throughout the industry, GM appears focused around Lloydminster and Cold Lake, although this may be the result of enhanced testing requirements in those regions. *B.C. does not publish similar GM occurrence data, so it is not included here. Credit: satellite imagery from Earthstar Geographics, powered by ESRI, and inset context map adapted from the Government of Canada.[73]

other hand, generally require annual follow-up tests for 5 or 6 years (B.C. and Alberta, respectively), but their repair can be deferred to the time of well abandonment. Before abandonment, SCVF tests are again conducted, and any leaks must be repaired.[56,57]

For GM, testing after well drilling and/or abandonment is generally only required for wells in the Lloydminster/Cold Lake heavy oil region of Alberta,[57] following findings of higher occurrence rates there.[58,59] Otherwise, testing is required only if signs/symptoms of GM have been observed, such as bubbles in ponded water, stressed vegetation, or the presence of odors or gases "not attributable to another source".[19] If surface testing suggests that GM may be present, in-soil samples are taken in a cross-pattern up to 6 m around a well;[53,57] however, testing methods and their results can apparently vary significantly.[60,61] GM is classified as "serious" where the emissions pose safety hazards, when a well has already been abandoned, or when groundwater wells are in the vicinity; otherwise, they are considered "non-serious". Like SCVFs, serious emissions require immediate repair, while the nonserious ones may be deferred to the time of abandonment.

2.2. Baseline SCVF/GM Emission Estimates. Baseline SCVF/GM methane emissions were calculated using federal government assumptions and data sources[35] implemented in R and described briefly below; additional methodological details are available in Supporting Information Sect. S1. Industry-reported SCVF/GM data were accessed from provincial databases,[62,63] which included reporting dates, well identifying information, and emission details (type, severity, flow rate, etc.). Like the federal inventory, we supplemented these data with well status information,[64−67] location data,[68,69] and composition data.[35,70] For both provincial databases, only entries reporting "gas" emissions and those missing a defined fluid type were considered to be emitting methane.[71] Importantly, while Alberta only requires the initial SCVF/GM test to be reported (if one is found), B.C. requires reporting of all measurements, including when no SCVF/GM is observed.[19]

The reported data sometimes include incomplete/unclear information such as *repair* dates *before report* dates, or missing flow rates. Start and end dates of each emission were established following Table 1 based on federal inventory assumptions. For entries with a missing flow rate (blank or zero), the federal inventory calculates and applies average emission factors, which we estimated to be 19−20 m^3/d (see Supporting Information Sect. S3.2). In Alberta, where 42% of entries had no flow rate and another 14% had a zero flow rate, average flow rate factors were calculated from reported flow rates grouped by type (SCVF or GM), severity (serious, nonserious), and administrative region;[68] in B.C., where flow rates were missing in 13% or zero-valued in 7% of entries, average factors were calculated by severity groups only and were applied only to blank flow rates (zero-valued rates were assumed to represent repairs; see Table 1). The emitting wells were also categorized by status (i.e., active or nonproducing, the latter including suspended/shut-in and abandoned) using available data.[64−67] Finally, because emissions are reported volumetrically, SCVF/GM gas compositions for Alberta were assumed from average composition maps;[70] in B.C., a single composition was assumed (~88% methane by volume) consistent with the federal inventory.[35]

2.3. Alternate SCVF/GM Estimates. The federal SCVF/GM emission model differs from those made by the provincial governments. For example, where the federal estimate assigns average flow rates when missing, the Alberta government assumes a flow rate of 300 m^3/d for serious SCVF, and that all other emissions are small, applying a factor of 1 m^3/d.[72] Unfortunately, most provincial model assumptions remain unpublished, but the significant differences between government estimates (Figure 1) suggests other differences exist. To understand the impact that differing assumptions have on SCVF/GM methane estimates, we recalculated emissions for both provinces under a range of model assumptions, addressing the following unknowns (see Supporting Information Sect. S1 for details):

1. **Missing or zero-valued flow rates:** average, near-zero,[71] or some combination[72] of these emission factors can be applied when reported rates are missing or zero-valued;
2. **Unknown gas composition:** in Alberta, federal assumptions use production formation gas compositions[70] (averaging methane content of ~90% by volume), whereas the Alberta government assumes a methane content of 95−99% by volume,[72] suggesting different assumed origins of the gas;
3. **Missing repair dates (serious):** while serious emissions must be repaired immediately, a number of SCVF/GM reports have no repair dates for many months or years after being reported; the federal assumption is that these are repaired within the 90-day required period[53] but it is unclear whether repairs have truly occurred;
4. **Unknown start dates (serious and nonserious):** start dates of SCVF/GM are highly uncertain because of minimal monitoring/testing requirements; such emissions could have started as early as the well's drill date or as late as the reporting date, which can be years apart;
5. **Events that reportedly "die out":** emissions that reportedly die out are assumed to emit their reported flow rate until the

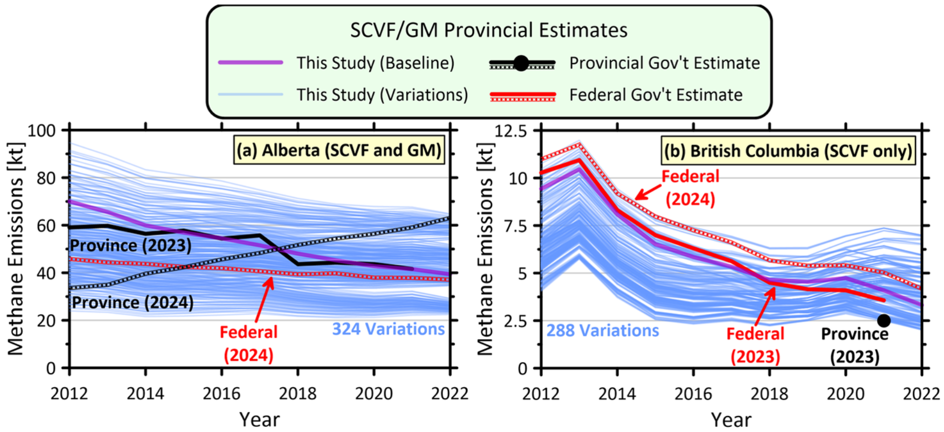

Figure 3. Possible SCVF/GM estimates for (a) Alberta and (b) B.C. using a variety of possible model assumptions (Sect. 2.3) to address uncertain event start/end dates, missing flow rates, unknown gas composition, etc. The baseline estimate was derived using federal model assumptions. These are plotted against government estimates for each province.

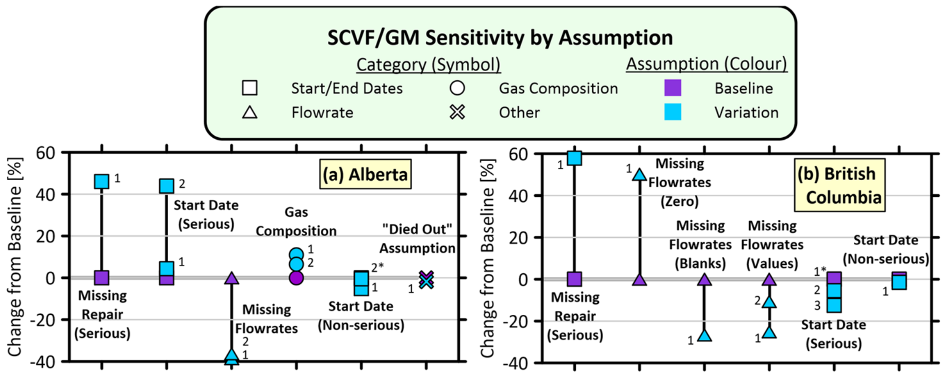

Figure 4. Relative change from baseline estimate (purple) under different assumptions (light blue) in (a) Alberta and (b) B.C., ranked left to right in terms of magnitude. Alternate assumptions are numbered to correspond with assumption descriptions in Tables S2 and S3. *Noted alternate assumptions are effectively equal to the baseline.

die-out date; however, it is possible that the emission decreased over time toward that date.

Multiple assumptions were tested for each of the above unknowns. Provincial SCVF/GM methane emissions were recalculated from the baseline inventory in R for the 324 and 288 unique combinations of these alternate assumptions for Alberta and B.C., respectively. We calculated annual emission levels for 2012−2022 since data in 2011 and earlier fell under different testing/reporting requirements.[30,31]

3. RESULTS

3.1. Wellbore Leakage in Canada. Our baseline estimates of SCVF/GM methane (Figure 2) show that most reported emissions are from nonserious SCVF (89% of emissions in Alberta and 70% in B.C.), meaning that cutting methane emissions from these sources must focus on mitigating nonserious SCVFs. In 2022, Alberta had nearly ∼11,100 unique wells with reported emissions, releasing ∼39 kt of methane. In B.C., ∼3100 SCVFs were emitting in 2022, releasing an estimated 3.4 kt of methane. Roughly 70% of the emissions in both provinces are from active wells, and more detailed breakdowns of these emitters by type and region are available in Supporting Information Sect. S2. More generally, the available data suggests that Alberta has observed SCVF at ∼2.8% of all wells (reports with nonblank, nonzero flow rates), whereas B.C. has SCVF at 12% of wells; these reported occurrence rates fall within the ranges observed in the United States.[32] While differences in geology and/or production methods could explain the differences in occurrence rates, it may also be due to different reporting requirements (e.g., B.C.'s requiring SCVF testing during the life of a well). When including blank and/or zero-valued flow rates, Alberta has SCVF reports for 5.5% of all wells; B.C. has reports for 15.2%.

While it appears in Figure 2 that GM is most prevalent in the heavy oil regions of Cold Lake and Lloydminster, Alberta, it is important to remember that these are the only regions where more frequent GM testing is required.[57] GM makes up a small percentage of reported wellbore methane emissions in Alberta (∼3%), but it poses groundwater contamination risks, and minimal testing requirements outside of Cold Lake/Lloydminster may allow for many to go undetected.[31] In Alberta, there are GM reports on 0.8% of all wells (in B.C., GM reportedly has occurred at 0.6% of wells,[48] but similarly detailed data are not available and are not included in this study). These rates fall below the 1.5% occurrence rates of GM in the United States,[32] but again, testing/monitoring requirements vary.

3.2. Provincial Methane Emission Sensitivity. By recalculating SCVF/GM methane emissions using all possible combinations of alternate model assumptions (Sect. 2.3), we found that SCVF/GM estimates can vary significantly from the baseline estimate derived using federal assumptions (Figure 3). In Alberta in 2022, methane estimates ranged from 22 to 65 kt (−43 to +65% from the baseline); in B.C., estimates ranged from 2 to 7 kt (−39 to +111% from the baseline). Unfortunately, it is difficult to make direct performance

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comparisons between provinces since the modeling assumptions are not directly comparable. Interestingly, while our estimates generally resemble the magnitude and trends estimated by the different governments, we were unable to recreate the steeply increasing trend of SCVF/GM emissions in Alberta using their 2024 assumptions. This suggests that other key assumptions remain unreported and thus our model likely underestimates the possible spread of SCVF/GM methane estimates. It is also worth noting that the difference between subsequent federal government estimates in B.C. in Figure 3 is reportedly not caused by a change in methodology but may instead be due to retroactive changes to the provincial data.

Alternate SCVF/GM model assumptions in both provinces had a strong impact on the annual emission estimates for the following (Figure 4): missing repair dates, missing/zero-valued flow rates, and unclear start dates. In Alberta, changes to these assumptions induced a relative change of +46, +44, and −39%, respectively, from the baseline; in B.C., similar alternate assumptions induced relative changes of +58, +50, and −13%, respectively. Missing repairs for serious SCVF/GM emitters had an outsized impact on provincial methane estimates despite representing only 0.7% of emitting wells in Alberta (0.1% in B.C.) because serious SCVFs are often the largest emitters. For SCVF/GM with missing/zero-valued flow rates, their different treatments had a large impact because the average applied flow rate (∼19−20 m^3/d in both provinces) was much greater than Alberta's 2023 assumed flow rate of 1 m^3/d and because many reports were missing a flow rate (∼40% of SCVF/GM in Alberta in 2022; only 8% in B.C.; Figure S3 of the Supporting Information). Finally, the different assumptions for emission start date (particularly for serious SCVF) had a considerable impact on total emissions because there can be months- or even years-long gaps between the reported date and the well's last required test date. Other differences in model assumptions (i.e., gas composition, "died out", and nonserious start dates) had impacts on emission magnitudes, but to a much lesser extent. See Supporting Information Sect. S3 for more details.

3.3. Evaluating Model Assumptions. In principle, many of the uncertain factors in quantifying SCVF/GM emissions from the reported data can be evaluated with field measurements. For example, wells missing reported repair action could be investigated for continuing flow, gas compositions could be measured, wells with missing flow rates can be tested, etc. In the current absence of such data, we compared industry-reported SCVF data with static chamber measurements in Alberta by Bowman et al.[74] and to measurements performed by a confidential oilfield service company (hereafter "OSC"). Bowman et al. measured emissions from 115 surface casing vents at nonproducing wells in Alberta in 2022 and the OSC shared data from over 3100 tests of wells in Alberta and B.C. dating back nearly a decade (see Supporting Information Sect. S4 for more details).

At wells with industry-reported SCVFs that had missing or zero-valued flow rates, measurement data suggests that emissions are higher than the often assumed 1 m^3/d but perhaps lower than the average factor derived from the federal method (∼19−20 m^3/d). Bowman et al. measured an average flow rate of 6 m^3/d (9 wells) and the OSC measured ∼4 m^3/d (100 wells). Unfortunately, it is not possible to recommend a more appropriate average emission rate because these measurements were taken at different points in time relative to when industry reported these SCVFs to the province, and emissions could have changed over time,[15,23,51,55,75,76] with even the Alberta Energy Regulator suggesting that flow rates "can fluctuate significantly over a period of time".[71] Concerningly, of the sites found to have SCVF by the OSC, over 12% were reported by site operators without a flow rate.

We also found evidence that SCVFs are entirely missing from the provincial databases, suggesting that well integrity issues and resulting emissions are underestimated. Half of the 34 SCVFs observed by Bowman et al. in Alberta did not have corresponding industry reporting, and another 2 SCVFs were found emitting that had *reportedly* died out years prior, suggesting that the provinces should not allow SCVF monitoring to end when the flow dies out as is currently the case.[53] From the OSC, 11% of wells found to be emitting (nearly 120) were entirely missing from provincial reporting in Alberta and B.C. These findings suggest that even when SCVFs are detected, they are not always reported to provincial authorities.

Finally, SCVF/GM emissions are known to vary over time, but because of a lack of follow-up measurements in the databases, the inventory model must extrapolate reported flow rates over long periods. While it was not possible to directly evaluate the impact of temporal variability, we found that between the two provinces, Alberta is likely much more susceptible to its impacts. Inspecting the age of SCVF/GM reports informing the 2022 inventory, we found that more than 71% of Alberta's emissions were extrapolated from reports older than 5 years. By comparison, only 19% of emissions in B.C. came from reports 5 years or older (see Supporting Information Sect. S5).

Unfortunately, it was not possible to directly test other assumptions. It remains unclear how far back in time is appropriate to extrapolate detected emissions beyond the first reported date. While the federal assumptions (Table 1) often assume that the emission starts at the well's drill date (earliest possible), discussions with provincial regulators suggest that they assume that emissions start at the reported date (latest possible), the latter assuming a negligible amount of time between SCVF/GM initiation and detection. These differing assumptions mean that the inferred lifetime of a SCVF/GM event can differ by years or even decades between the inventories.

Ultimately, the uncertain lifetimes, poorly characterized temporal variability, and reporting incompleteness of SCVF/GM are likely to hamper efforts to quantify methane emissions and prioritize them for mitigation under proposed federal methane regulations.[36,37] Even if current testing/reporting requirements were strictly followed, the minimal testing—particularly for GM—could mean that well integrity issues can remain undetected. Although an increase in SCVF/GM testing frequency may be the most effective approach, we tested the possibility of using other, ongoing measurement/monitoring efforts to augment current monitoring requirements.

3.4. Leveraging Ongoing Measurement/Monitoring Efforts. Perhaps acknowledging the possibility of undetected/unreported SCVFs in Alberta, the provincial regulator has suggested that on-site fugitive surveys (sometimes called "leak detection and repair" surveys; LDAR) would increase SCVF detection and reporting.[71] However, SCVF/GM reporting in Alberta in 2022 was on-par with pre-LDAR levels (2019; in B.C. at least, SCVF reporting had increased by 54% from 2019 levels). While the use of optical gas imaging (OGI) cameras or

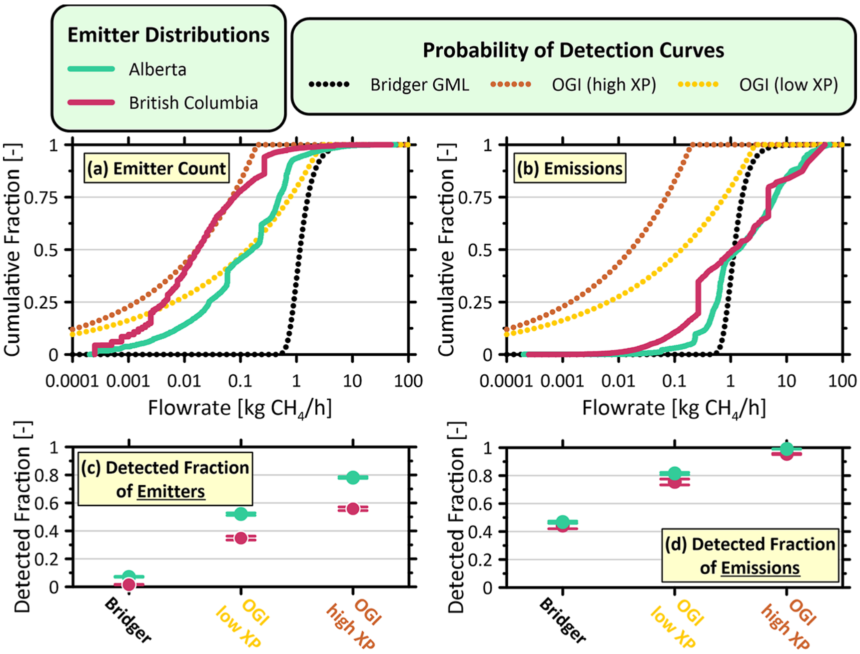

Figure 5. Cumulative distribution of (a) SCVF emitter count and (b) SCVF emissions in comparison with POD curves for the Bridger Photonics aerial system[82] and high- and low-experience (XP) OGI camera surveys.[81] Panels (c,d) show the expected detected fraction of SCVFs and SCVF methane, respectively, in Alberta and B.C. Error bars show the 2.5 and 97.5 percentile of Monte Carlo results.

other instruments may have nevertheless increased SCVF detection, this is only true where such surveys are required and actually performed.[77,78] In Alberta, for example, such comprehensive surveys are only required for wells colocated with central batteries,[79] and data from Seymour et al.[80] suggests that roughly two-thirds of wells are exempt from fugitive surveys, requiring only cursory annual screenings. Nevertheless, we evaluated whether comprehensive emission surveys could be an effective tool in augmenting current SCVF testing requirements.

We estimated the fraction of SCVF emitters (and emissions) detectable by OGI cameras and aerial surveying techniques using a simple Monte Carlo simulation (Figure 5). Using probability of detection (POD) curves for each technology,[81,82] we calculated the POD for each SCVF active in each province in 2022. Imagining that each technology surveyed all emitting wells, we randomly drew a detect/nondetect outcome for each emitter based on its POD. This allows us to determine a plausible province-level survey result for each technology. Since any annual survey would yield a different set of detects and nondetects, we repeated this simulation 50,000 times for each technology to characterize the variability in detection results. Emitter distributions and POD curves are shown in Figure 5a,b, and Monte Carlo results are shown in Figure 5c,d.

We found that OGI cameras are somewhat effective at detecting SCVFs. Referring to Figure 5c and d, lower experience OGI camera surveyors could observe 52 ± 0.9% of SCVFs in Alberta, representing 81 ± 0.8% of SCVF methane emissions; in B.C., 35% of emitters would be detected, representing 76% of emissions (the fractions are lower for B.C. because of lower average emission rates). Meanwhile, higher experience OGI surveyors in Alberta might detect 78 ± 0.6% of emitters and 99 ± 0.06% of emissions (56% of emitters and 95% of emissions in B.C.). Although this suggests that OGI surveys may be effective at supplementing current SCVF test requirements, the detection probabilities for OGI cameras are highly uncertain. Zimmerle et al.[81] noted that the field evaluations of OGI effectiveness were conducted in a competitive environment which may have encouraged higher than normal detection rates. In the experiments by Zimmerle et al., the emission source locations were not known to surveyors. If, instead, OGI surveyors were required to explicitly inspect and report on emissions from the surface casing vent line, we might expect detection probabilities to be limited only by camera performance and not the surveyor's experience level. Rerunning the Monte Carlo simulation with camera-limited POD curves from Ravikumar et al.[83] (Supporting Information Sect. S6), we found that SCVF detection rates could be as high as 91% of emitters, observing >99.9% of emissions. Although this represents only a marginal increase in detected methane relative to the high experience surveyors, there is still a meaningful increase in the detected number of SCVFs, which would still be worthwhile since SCVF is often an indicator of GM[32,48] or other well integrity issues that risk contaminating groundwater.[84]

We also tested the performance of Bridger Photonics' Gas Mapping LiDAR, an aircraft-based remote sensing system that quantifies observed plume emissions.[85,86] The use of this technology has proliferated in Canada to quantify upstream oil and gas methane emissions[10,11,13,87] and has been supported by federal and provincial Canadian governments. Using POD curves from Conrad et al.[82] (175-m altitude, 3-m/s wind speed), we found that only the largest 7% of emitters, representing 47% of methane emissions, are expected to be detected in Alberta (<2% of emitters and 44% of emissions in B.C.). This is perhaps sufficient in terms of aerial SCVF methane detection, but it leaves the majority of possible well integrity issues undetected. Clearly, this aerial detection system cannot entirely replace more close-range methods. And while Conrad et al.[82] provided POD curves for other aerial technologies, they were much less adept at measuring

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SCVFs, observing only the top 1% of emitters (12% of emissions).

This technology comparison is not exhaustive. In another example of potential surveying technologies, the B.C. Energy Regulator has partnered with a helicopter-based survey company to detect methane coming from nonproducing wells,[88] which may have a detection limit below 0.15 kg/h.[89] However, robust POD data are not yet available. Unfortunately, the above analysis only considered SCVF emissions; GM are much more difficult to detect with cameras or aerial remote sensing since they are a distributed source of much lower flow rates. It has been suggested previously that GM testing requirements also need improvement considering that inconsistent industry test methods reportedly result in different observed GM occurrence rates.[60,61]

3.5. Measurement Comparison. Finally, we compared our industry-derived SCVF/GM methane emission estimates with published measurement studies at the province level (Figure 6), finding a widespread of emission estimates. The figure includes Bridger Photonics-based, hybrid inventories in Alberta and B.C.,[10,11,87] static chamber measurements of Bowman et al.[74] in Alberta, "bag sampling" in B.C.,[55] and Hi-Flow sampling in Alberta[90] and B.C.[91] Importantly, we segmented these estimates by well activity status (active, nonproducing) since many of the above studies similarly segmented their results.

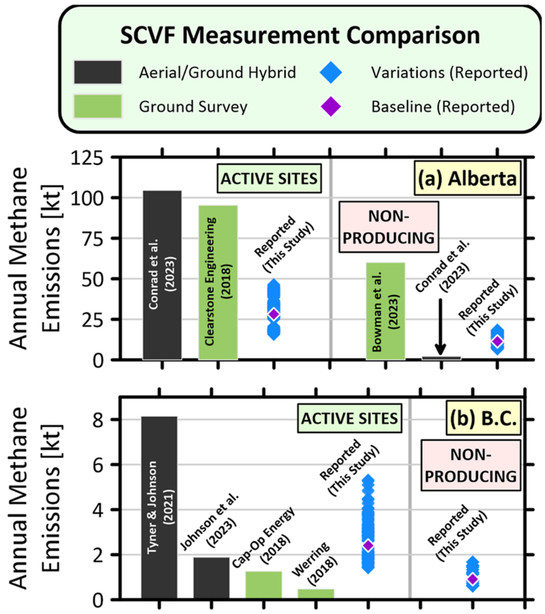

Figure 6. Comparison in (a) Alberta and (b) B.C. of measured SCVF methane emissions to industry-reporting derived estimates from the present study. While the comparison suggests that SCVF methane is underestimated at active sites in Alberta; conflicting findings are found in other groups.

Figure 6 suggests that SCVF methane may be underestimated at active sites in Alberta. The aerial/ground-survey hybrid inventory of Conrad et al.[10] reported ∼105 kt of annual methane emissions from active wellheads, which is more than double our highest estimate from industry reporting. However, the aerial attribution of emissions cannot distinguish between SCVF and other wellhead emissions (e.g., from leaking flanges or disconnected lines), meaning that non-SCVFs may be included in this count. Since the aerial LiDAR measurements by Bridger Photonics are likely to miss more than half the SCVF methane (see Sect. 3.4), it is also possible that much of the wellhead emissions are instead part of the aerially unmeasured sources which are estimated from ground survey data.[90] These ground survey data, from Clearstone Engineering, can also be used to independently estimate SCVF emissions and are included separately in Figure 6. From their observed leak frequency and emission rates (from a sample of 440 wells) combined with active well counts,[10] methane emissions of 93 kt were estimated.

At nonproducing sites in Alberta, there are conflicting estimates of SCVF emissions. The aerial survey of Conrad et al.[10] found only 2 kt of wellhead methane emissions (less than a third of our lowest estimate from industry-reported emissions). Underestimation from these aerial measurements is perhaps unsurprising since their survey largely focused on active infrastructure and because the available ground survey data explicitly excluded nonproducing sites.[90] By comparison, static chamber measurements by Bowman et al.[74] estimated inactive well SCVFs to be emitting ∼60 kt of methane annually (more than 3 times our maximum estimate from reported data), although their study was of a fairly limited size (115 wells) and could lack representativeness.

In B.C., the most recent aerial measurements at active sites by Johnson et al.[11] fall within the range of SCVF estimates we derived from industry reporting, suggesting that these emissions may be better reported than in Alberta. Interestingly, a previous aerial/hybrid survey of B.C. by Tyner and Johnson[87] suggested emissions of ∼8 kt (∼54% higher than our maximum estimate). While this latter study did not explicitly break out emissions by (in)active status, it is assumed that the majority of emissions were observed at active sites because of their focus on active infrastructure and since the incorporated ground survey data again did not include inactive sites.[91] Estimating SCVF emissions at active sites directly from the ground survey data (Cap-Op Energy; 244 wells),[91] the ∼1.3 kt of methane estimate falls just below our industry-derived estimates. Interestingly, emission factors from another study by Werring (81 wells)[55] suggested less than half as many emissions; however, this may again be an issue of limited sample size.

Considering all possible estimates of SCVF/GM methane in both provinces in Figure 6, annual estimates range from 22 and 166 kt of methane in Alberta (between 1 and 10 kt in B.C.). Combining these with measurement-based inventory estimates in both provinces,[10,11] SCVF/GM methane could represent between 1.8 and 11.9% of Alberta's emissions (0.8−6.4% in B.C.). This large range illustrates the difficulty in prioritizing such an uncertain emission source. When compared with other methane sources in the provinces' upstream sectors, SCVF/GM would rank anywhere from fifth to 10th largest source (following at least tanks, compressors, separators, and pneumatic devices). Ultimately, larger scale ground-level measurements are needed to better constrain SCVF (and likely GM) methane emissions despite these provinces having some of the more stringent monitoring requirements in Canada, if not more broadly.

4. IMPLICATIONS AND RECOMMENDATIONS

Canada has committed to a 75% reduction in oil and gas methane by 2030,[92] with proposed rules targeting all sources of venting expected to be phased-in starting in 2027.[36,37] While these regulations are not expected to directly impact GM emissions, site operators would have to prevent SCVFs with flow rates above 5 m^3/d (∼0.13 kg/h, assuming 90% methane by volume). The federal regulatory impact assessment assumes that combustors/incinerators would be used for flow rates up to 100 m^3/d, and higher flow rate SCVF gas would be conserved with the installation of a compressor. This 5-m^3/d threshold could result in the mitigation of ∼89% of SCVF methane in Alberta (92% in B.C.; see Figure 5) but will only truly be possible if all SCVFs are detected and reported. Even once detected, uncertain temporal variation (including duration) of SCVFs could make it difficult for site operators to choose the most appropriate mitigation strategy for engineering and/or cost-effectiveness reasons. Operators *could* instead consider the immediate repair of SCVF (these SCVFs would have to be repaired at abandonment anyway); however, repair costs are reportedly highly variable,[58] and repairs often require intentionally perforating the well casing and cement,[93−95] possibly introducing new well integrity issues.[14] These unknowns about repair have previously resulted in operators leaving wells in an inactive, nonabandoned state to avoid final repair costs,[96,97] and it is unclear whether the proposed federal regulations would encourage more wellbore repairs or more deferrals.

However, before economic evaluations of SCVF/GM mitigation/repair can be conducted, it is necessary to better understand their occurrence rates, emission magnitudes, duration, and temporal variability. Fortunately, Alberta and B.C. can build off existing SCVF/GM monitoring requirements to improve well integrity tracking and better estimate methane emissions. We recommend a combination of data QA/QC measures and increased testing requirements, namely:

4.1. QA/QC Improvements.

- Prevent reporting of zero-valued and/or blank flow rates (unless specific use cases are defined);
- Verify the status of serious SCVF/GM where required repairs have not been reported; and
- Require **reporting on all SCVF/GM testing (even when zero)** to better understand when SCVF/GM begin and to build a time series of emission rates;

4.2. Increase Testing.

- Increase testing frequency of SCVF/GM (both producing and nonproducing); this will help find missing emitters and will reduce uncertainty on emission start dates; this includes increasing testing on emitters that had seemingly "died out" since they have been observed to continue emitting;
- Increase testing requirements for GM; limited testing requirements are likely to miss instances of GM;

4.3. Leverage Fugitive Emission Surveys.

- Industry testing burden could be reduced by finding efficiencies with ongoing OGI camera (or similar) surveys.

Wellbore leakage methane emissions and occurrence rates in Alberta and British Columbia, Canada, are highly uncertain; however, it is important to remember that other jurisdictions may lack the same level of testing and reporting requirements. Neighboring Saskatchewan, for example, has fewer monitoring requirements for these sources[98] and does not have a similar reporting database.

■ ASSOCIATED CONTENT

Data Availability Statement

Data were accessed from the publicly available provincial databases of Alberta Energy Regulator (https://www1.aer.ca/productcatalogue/365.html) and British Columbia Energy Regulator (https://www.bc-er.ca/data-reports/data-centre/; BCOGC-2883).

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.energyfuels.4c00908.

Information on model assumptions, baseline emitter counts and emissions data, model sensitivity results, comparisons with measurement data, temporal variability, and POD findings (PDF)

■ AUTHOR INFORMATION

Corresponding Author

Scott P. Seymour − *Department of Civil Engineering, McGill University, Montreal, Quebec H3A 0G4, Canada; Environmental Defense Fund, Montreal, Quebec H3K 1R1, Canada;* orcid.org/0000-0002-9272-4596; Email: sseymour@edf.org

Authors

Donglai Xie − *Environmental Defense Fund, Montreal, Quebec H3K 1R1, Canada*

Mary Kang − *Department of Civil Engineering, McGill University, Montreal, Quebec H3A 0G4, Canada;* orcid.org/0000-0001-9142-384X

Complete contact information is available at: https://pubs.acs.org/10.1021/acs.energyfuels.4c00908

Author Contributions

S.P.S., D.X., and M.K. contributed to the conception and design. S.P.S., D.X., and M.K. contributed to analysis and interpretation of data. S.P.S., D.X., and M.K. drafted/revised the article. S.P.S, D.X., and M.K. approved the submitted version for publication.

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Notes

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