




A measurement-based upstream oil and gas methane inventory for Alberta, Canada reveals higher emissions and different sources than official estimates

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Mitigation actions and regulations to meet critical 2030 methane reduction targets under the Global Methane Pledge are hampered by uncertainty in true levels of emissions and source breakdowns. Here we present a measurement-based, source-resolved, hybrid top-down/bottom-up methane inventory for conventional upstream oil and gas operations in Canada's largest oil and gas-producing province, Alberta. The derived 2021 inventory of 1337 kt/y is approximately 1.5× the official federal inventory and matches independent top-down aerial mass-balance and satellite estimates within uncertainties. Major sources are starkly different from official estimates, with venting (e.g., uncontrolled tanks, pneumatics, unlit flares) comprising almost two-thirds of emissions implying important mitigation opportunities. Derived methane intensities, while similar to U.S. basins, are approximately 4× those in neighbouring British Columbia and further reveal order-of-magnitude differences among individual anonymized companies at directly comparable facility types. This highlights the importance of independent monitoring, reporting, and verification to ensure collective success in reducing emissions.

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Strong, rapid (by 2030), and sustained reduction of global anthropogenic methane emissions is a required component of every scenario in the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report that sees humanity avoiding the most catastrophic outcomes of climate change¹. Along with 148 other countries, Canada has signed on to the Global Methane Pledge² (GMP) with a promised 30% cut in its methane emissions by 2030, led by a 75% or greater reduction in the oil and gas sector^{3,4}. There are now just six years remaining to achieve this vital goal. New regulations are under development to drive the necessary reductions, but this critical effort is hampered by official bottom-up inventories that are thought to significantly underestimate emissions, and even more critically, by a general lack of accurate data on the breakdown of sources to be mitigated.

The province of Alberta is Canada's largest producer of oil and gas resources^{5,6} and largest emitter of oil and gas sector methane, with the official inventory estimating 2.1 times the emissions of the rest of Canada combined⁷. However, multiple studies using a variety of measurement approaches have pointed to substantial underestimates in both reported emissions and official inventories for Alberta^{8–12}, such that the true magnitude of emissions from the province are likely higher. Most critically, uncertainty on the true breakdown of sources driving emissions creates a fundamental barrier to the development of effective and efficient regulations, which are needed to meet 2030 methane reduction targets¹³. At the same time, Alberta has been a leader piloting alternative fugitive emissions management plans (Alt-FEMP)¹⁴ in place of regulated manual leak detection and repair (LDAR) surveys¹⁵ but public data assessing the performance of these programs are lacking and their relative impacts on mitigation and inventories are currently unknown.

The primary objective of this work is to derive and prove a robust, source-resolved methane inventory for conventional (non-oil sands) upstream oil and gas production in Alberta, Canada. Leveraging the capabilities of high-sensitivity LiDAR-based methane detection^{16–19}, analyzed considering the condition-dependent probability of detection during multi-pass measurements^{19,20}, a measurement-based, source-resolved, hybrid top-down/bottom-up 2021 methane inventory is created. This inventory is directly compared with an independent top-down estimate created from parallel aerial mass-balance²¹ surveys and a provincial inventory derived from recent satellite measurements in western Canada²². The alignment of all three approaches demonstrates how it is possible to “close the gap” between traditional bottom-up vs. top-down approaches to produce a comprehensive source-resolved inventory that matches independent top-down measurements. A second key objective is to contrast sources in the derived hybrid inventory with those in the most recent official federal inventory. This reveals the key sources driving 2021 methane emissions, where the differences from those assumed in the official bottom-up inventory breakdown have important implications for regulations currently under development. Third, the inventory results are used to calculate methane intensities of produced hydrocarbons, enabling direct comparisons with results from a range of recent studies across North America. Finally, the inventory and detailed uncertainty analysis protocol is applied to quantify and contrast methane intensities of anonymized companies operating comparable upstream oil and gas facilities, consistent with the goals of monitoring, reporting, and verification (MRV) efforts such as the oil and gas methane partnership (OGMP 2.0)²³. This reveals order of magnitude differences among companies while demonstrating that independently verified, objectively low methane intensities can be achieved in practice.

Results and discussion

Survey overview. Two independent aerial surveys using unique measurement technologies were performed to quantify oil and gas methane emissions in Alberta during 2021. The primary, source-resolved survey deployed Bridger Photonics Inc.'s Gas Mapping LiDAR™ (GML) technology^{16,17} to complete high spatial resolution (~1–2 m) measurements of upstream oil and gas facilities and wells (i.e., sites) within five representative sub-regions of Alberta as detailed below. This survey was led by the Energy and Emissions Research Laboratory (EERL) and was specifically designed to enable creation of a hybrid, source-resolved, measurement-based methane inventory for Alberta following the detailed methodology described by Johnson et al.²⁰. A parallel region-level survey, led by the Environmental Defense Fund (EDF), deployed an aircraft from Scientific Aviation to complete aerial mass-balance flights²¹ around nine geographically distinct conventional oil and gas production regions within Alberta. These flights enabled an independent estimate of total methane emissions for comparison with the total obtained from the source-resolved inventory. Finally, a third independent total emissions estimate for comparison was derived from the satellite measurements of Shen et al.²² as further detailed below.

Figure 1 shows a map of Alberta identifying all facilities and wells that were active during one or more months of the survey period, September–November 2021. Facilities and wells were deemed active based on volumetric reporting in the public Petrinex database²⁴ (see online supplementary information (SI) for further details and ref. ²⁵ for a glossary of oil and gas terminology) and are coloured according to their inclusion in the source-resolved survey as summarized in the legend. Blue and dashed red polygons in the figure represent the five and nine regions surveyed by Bridger Photonics and Scientific Aviation, respectively. As further described in the Methods section below and in Section S1 of the SI, the facilities and wells within these regions encompassed the diversity of upstream conventional oil and gas activities in Alberta, while excluding “unconventional” mined and in situ oil sands, which were not considered.

Provincial upstream oil and gas sector methane inventory. The provincial methane inventory for the upstream oil and gas sector derived using the present source-level aerial measurement data is summarized in Fig. 2. As discussed below (and further detailed in SI Section S2 and Johnson et al.²⁰), the derived provincial inventory is parsed into four components: the measured source inventory (blue), unmeasured non-pneumatic source inventory (orange), and unmeasured source inventory for pneumatic instruments (light gray) and pneumatic pumps (dark gray). The derived 2021 Alberta conventional upstream oil and gas methane inventory is 1337 kt/y with a 95% equal tail confidence interval (95% CI; the range defined by the 2.5th and 97.5th percentile of the data, derived from the measured source inventory only) of 1142–1669 kt/y. This represents a stark 147% (126–184%) increase over the corresponding upstream emissions (S. Smyth, personal communication, April 19, 2023) from the official inventory from Environment and Climate Change Canada's National Inventory Report⁷ (ECCC) of 909 kt/y. Moreover, the 1014 kt/y contribution from measured sources on their own exceeds the total of the most recent federal estimate by more than 10%.

The observed discrepancy between the official and hybrid top-down/bottom-up, measurement-based inventories is not novel to the province of Alberta nor the measurement year. Significant discrepancies between aerial/satellite measured/estimated inventories and official bottom-up inventories or industry-reported emissions have been observed previously in sub-regions of

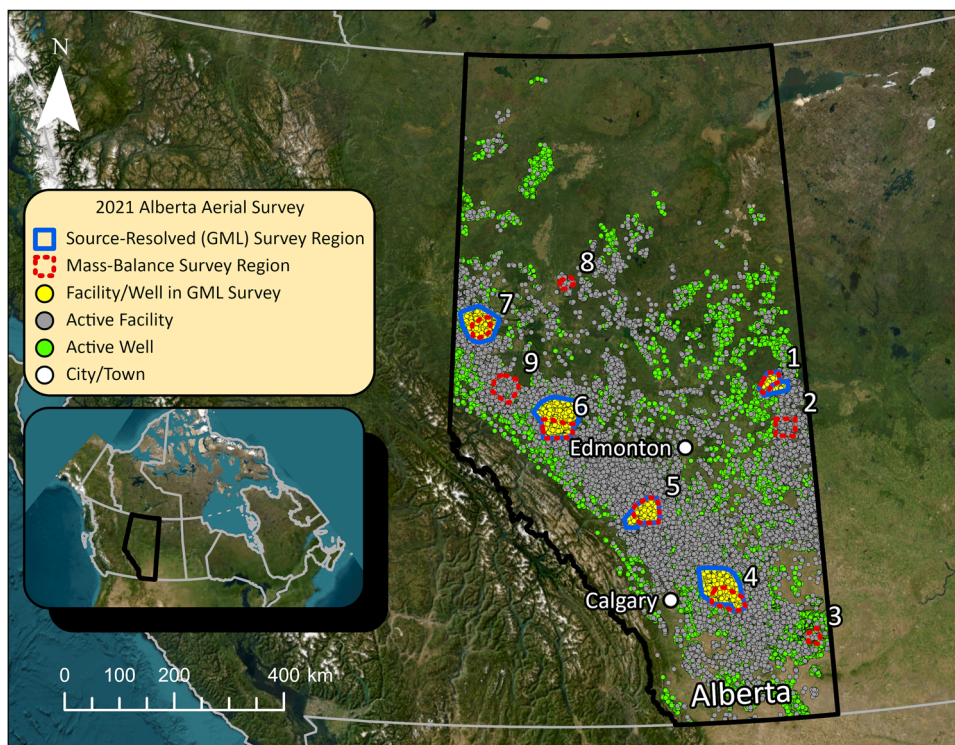


Fig. 1 Map of Alberta, Canada showing sample sites and regions overlaid on active facilities and wells during September–November 2021. Yellow dots indicate the 3469 facilities and 5592 wells within five regions (blue polygon) surveyed using Bridger Photonics GML. Dashed red polygons show mass-balance survey regions flown by Scientific Aviation.

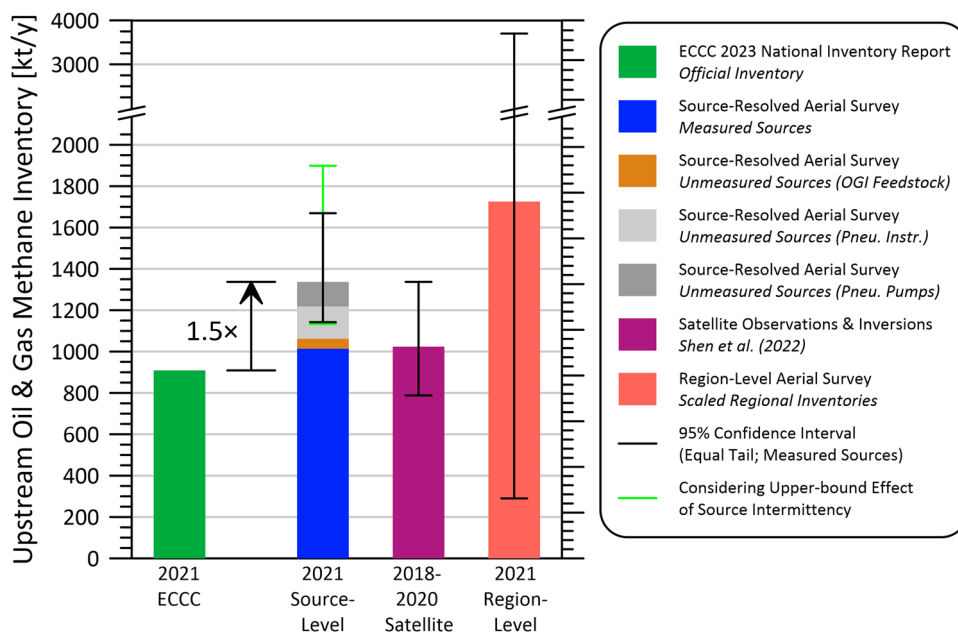


Fig. 2 Comparison of official and measurement-derived provincial methane inventories for the upstream oil and gas sector. The present hybrid measurement-based inventory is parsed by measured sources, unmeasured non-pneumatic sources, and unmeasured pneumatics and suggests provincial emissions are 1.5 times greater than the latest official inventory from Environment and Climate Change Canada⁷ (ECCC). Parallel inventory estimates for 2018–2020 using satellite measurements²² and 2021 using region-level aerial measurements (see SI Section S5) are shown for comparison. 95% CIs are shown for each estimate according to the methodologies detailed in the SI; a secondary confidence interval is shown for the present hybrid inventory (light green) that upper bounds the potential effect of source intermittency (see statistical testing and analysis in SI Section S4 and Johnson et al.²⁰).

Alberta in 2016¹², the neighbouring province of British Columbia (BC) in 2019¹⁸ and 2021²⁰, and numerous basins in the U.S.^{22,26,27}. However, the present inventory for Alberta and the 2021 inventory for BC²⁰ are unique in that approximately 76 and

78% of the inventories, respectively, are based on direct measurements at the source level. This permits robust characterization of measurement uncertainties and consideration of sample size effects²⁰ and, following manual attribution of individual

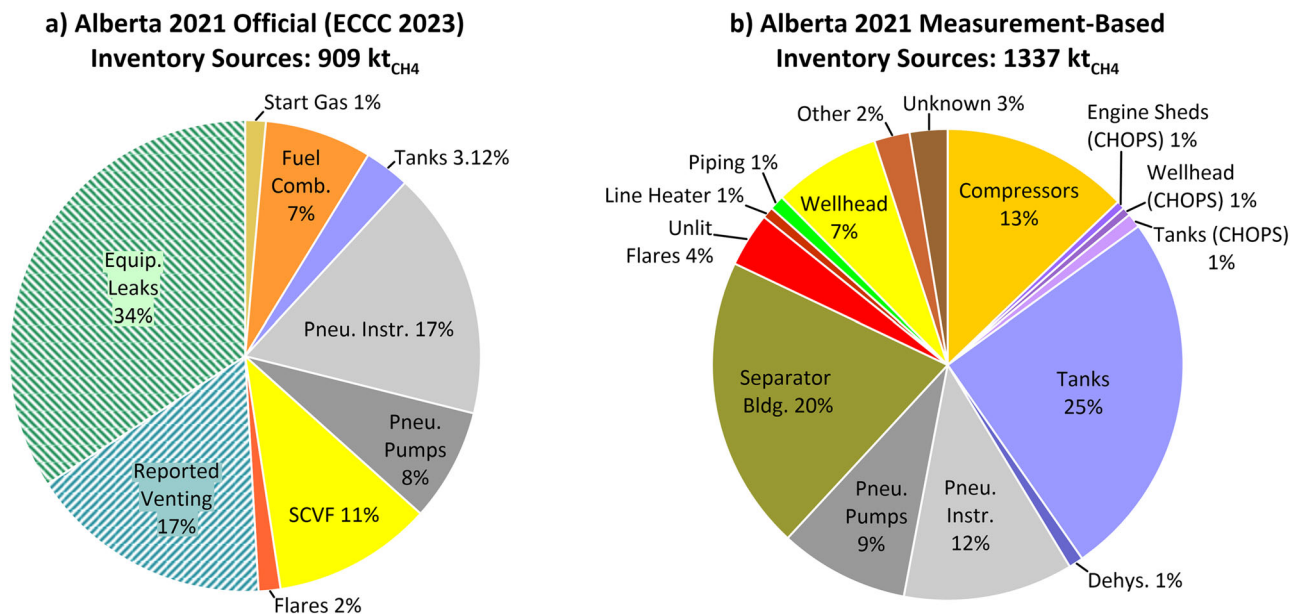


Fig. 3 Contrast between sources in the official ECCC bottom-up inventory versus the presently derived hybrid measurement-based inventory. **a** the ECCC national inventory and **(b)** the currently derived, hybrid measurement-based inventory (see also Table S6). Colours match where sources are equivalent in the two inventories. Hatched slices in the official inventory pie represent categories derived from reported data for which no further breakdown is possible. CHOPS = Cold Heavy Oil Production with Sand; SCVF = Surface Casing Vent Flow.

sources to specific equipment types, enables a detailed breakdown of the inventory by source (see below and Johnson et al.²⁸).

Figure 2 also shows how the present source-level inventory aligns with estimates derived from satellite data by Shen et al.²². Via Bayesian inverse methods, Shen et al.²² combined methane retrieval data from the Tropospheric Monitoring Instrument (TROPOMI) during May 2018 to February 2020, sector-resolved prior anthropogenic methane emissions, and chemical transport models to obtain a gridded methane emissions inventory for the continental U.S.A. and portions of Canada. Posterior Monte Carlo data provided by the authors were used to aggregate gridded data to the province of Alberta to estimate the provincial methane emissions inventory for the conventional upstream sector; these data imply annual emissions of 1024 kt/y with a 95% CI of 788–1337 kt/y. Notwithstanding the differing inventory periods and likely underestimation of satellite inventory uncertainties (see below), error bars for this satellite-based estimate significantly overlap with those of the present study suggesting that there is no statistically significant difference between the two inventory totals. Moreover, the prior emissions used to regularize satellite observations in the analysis of Shen et al.²² were sourced from Scarpelli et al.²⁹ who used 2018 data from ECCC's National Inventory Report to derive gridded methane emissions by sector for the country. This is the same source data (albeit in a different year) that underestimates the present inventory by a factor of 1.5. Thus, assuming limited TROPOMI observations (which are regularized to purposely avoid over-fitting at the cost of biasing emissions estimates towards the prior) at northern latitudes are insufficient to overpower Scarpelli et al.'s²⁹ data as a prior, it is reasonable to expect that Shen et al.'s²² inventory should be biased low, which potentially explains the differences between the nominal inventory totals plotted in the figure. Further negative bias arises due to the exclusion of satellite grid cells (49 total with a combined area of approximately 25,300 km²) containing in situ or surface mined oil sands facilities and upgraders when calculating the Shen et al.²² total. While necessary to enable comparison of conventional oil and gas inventory totals, this inherently excludes some co-located conventional facilities and

wells that would be expected to account for 1.2% of the inventory based on present measurements. In addition to the identified sources of negative bias, the plotted uncertainties in the satellite-derived provincial inventory are likely to be conservatively small since Monte Carlo-perturbation of prior emissions were limited to +50% from the Scarpelli et al.²⁹ (which is insufficient to encompass the final inventory total observed in the present study) and did not consider uncertainty in sectorial partitioning. This propensity for underestimation is further supported by the regional inventory comparison shown in Figure S5 of the SI, where in two of five regions the satellite inventory estimate is less than the measured-source component of the source-resolved inventory on its own.

The rightmost bar in Fig. 2 shows a derived emissions inventory for Alberta from the parallel region-level aerial survey (see SI Section S5). Referring to the SI, regional emission rate data were regressed to obtain energy-based methane emission factors for produced gas, condensate, (light) crude oil, and heavy oil, which were multiplied by raw provincial production to estimate the 2021 provincial inventory. The nominal result was 1726 kt/y with an estimated 95% confidence interval of 290–3700 kt/y considering measurement and regression errors. Noting the break in the vertical axis of Fig. 2, this analysis highlights the challenge of scaling region-level emissions data to a larger jurisdiction when regional uncertainties are high (see Table S10). Nevertheless, the nominal provincial total aligns with the upper bound of the present source-resolved, hybrid inventory. Thus, all three independent inventory estimates agree within uncertainty limits and support the key conclusion that actual upstream oil and gas sector methane emissions in Alberta are substantially higher than official inventory estimates.

Breakdown of inventory by source. Aggregating the nominal magnitudes of measured and bottom-up sources from the present hybrid inventory into fifteen unique emitter categories reveals the true breakdown of sources driving methane emissions in Alberta (Fig. 3b). This result is contrasted with the breakdown gleaned

from the most recent National Inventory Report⁷ (NIR) of Environment and Climate Change Canada (ECCC) (Fig. 3a), revealing important gaps in the current reporting framework. In addition to the 1.5× difference in total emissions magnitude, the stark differences in source breakdowns can be expected to hinder mitigation policy and complicate ongoing development of regulations to meet 2030 reduction targets. Most notably, the official NIR estimate is constrained by the granularity of available bottom-up reporting and emission factors, such that more than half of the inventory are coarsely attributed to “reported venting” and “equipment leaks” without further detail (see striped slices of Fig. 3a). The former reflects an aggregation of vented gas volumes reported by industry to the Alberta Energy Regulator (AER) through the Petrinex²⁴ reporting system, and adjusted using reporting to the OneStop³⁰ system. Notwithstanding that these volumes represent a coarse combination of sources that may include venting from tanks, compressor seals, or other sources, site-total volumes below 500 m³/day of whole gas do not have to be measured and instead are typically only estimated using a predetermined gas-oil-ratio (GOR) and measured volume of produced oil³¹. Worse, site-level measurement studies^{11,32,33} show that reported vent volumes tend to markedly underestimate measured totals. Similarly, the equipment leaks category in the NIR is an aggregate estimate of fugitive sources based on average counts per facility and emission factors from Clearstone³⁴.

Among directly comparable sources, the relative contribution from wellhead emissions (i.e., surface casing vent flows (SCVF) in Fig. 3a) appears to be overestimated in the ECCC inventory by approximately a factor of 1.5, although the absolute magnitudes are effectively equivalent. ECCC³⁵ estimates surface casing vent totals from well-specific emission factors that combine a gas composition map derived by Tyner and Johnson³⁶ and reported and measured events tabulated in the AER’s Vent Flow and Gas Migration Report³⁷ (i.e., onset and resolution dates and estimated flow rate). Although these latter data are notably incomplete – approximately 28% of serious and 66% of all gas vent flows since 2016 (inclusive) do not have a reported resolution as of writing and approximately 30% of all events do not have a reported flow rate – the observed agreement suggests that the missing data are likely small on an emission rate basis. More importantly, this result highlights that bottom-up inventories using direct, source-level measurements can indeed match source-resolved top-down measurements.

By contrast, the relative contribution of tank emissions (which are parsed into CHOPS – cold heavy oil production with sand – and non-CHOPS activities in Fig. 3b) appear to be underestimated by a factor of approximately 8.4× (26.3% vs. 3.1%) in the official inventory. Even if all reported venting in the NIR breakdown were attributed to tanks, absolute tank emissions of 352 kt/y in the present measurement-based inventory would still be underestimated by one half. This discrepancy is consistent with the fact that reported tank venting in Alberta is generally not measured and instead is most often based on engineering estimates and models of flashing losses from infrequently measured or modelled gas in solution (GIS)³¹. Indeed, Rutherford³⁸ suggested that underestimation of unintentional venting from tanks is one of the biggest reasons for discrepancies between the official inventory and measurements in the U.S. On a positive note, total CHOPS-related emissions from tanks, well-heads, and engine sheds are markedly lower than parallel measurements in the neighbouring province of Saskatchewan³². Ground studies could help identify particular reasons for this discrepancy, however the primary reason is surely the eighteen times lower regulated venting limits for heavy oil facilities in Alberta versus Saskatchewan^{15,39}.

The ECCC inventory does not include a specific category for unlit flares (50 kt/y in the present inventory) but does estimate flare-related methane emissions based on total reported flare volumes in Petrinex, assuming a location-dependent methane content for flared gas and a 98% combustion efficiency³⁵. Notwithstanding the potential inaccuracy of a 98% combustion efficiency for flares of complicated gas compositions in potentially turbulent crosswinds (see, for example, refs. 40–42), this inherently assumes flares are always lit. Consistent with recent studies^{18,28,43–45}, the present source-level aerial measurements detected multiple unlit flares but only rarely detected methane from lit flares. Overall, methane emissions from unlit flares were >40× that of detected inefficient lit flares in the present study. As a thought experiment, combining flare volumes reported to Petrinex in 2021 (1.15 billion m³) and an assumed methane content of flared gas were 85.2% by volume²⁰, an effective flare efficiency of approximately 92% would be required to match the measured total methane from lit and unlit flares in the present survey; this is consistent with recently estimated average effective flare efficiencies of 91.1% (95% CI: 90.2–91.8%) in three U.S. basins⁴⁶. More importantly, although unlit flares are just 3.7% of the present measurement-based inventory, they represent a mitigation potential of approximately 50 kt/y of methane that in principle should be one of the easiest and lowest cost sources to mitigate. However, given that at least 65% of the inventory contribution from unlit flares is from single-well facilities and well sites that are unlikely to be crewed, this mitigation is unlikely to be achieved without a commitment to ongoing monitoring and verification.

The large (20%) contribution of emissions associated with separators in the present inventory was somewhat unexpected, although these sources were recently found to emit 9% of methane emissions in neighboring BC²⁰. Ground investigations in BC²⁸ suggested that separator-related emissions may represent a combination of possible sources including abnormally operating pneumatic instruments and/or pumps, methane slip in catalytic heaters, and failing/emitting pressure relief valves and regulators. At crude oil wells and batteries specifically (responsible for just under one-half of aerially detected separator emissions), it is possible that emitted methane may also include intentional venting of associated gas in place of other techniques like capturing co-produced gas or combustion. Further ground analyses of separator emissions in Alberta would be helpful to discern the root causes of these aerially detected emissions and associated opportunities for mitigation.

Overall, the distribution of sources in Fig. 3b suggests that vented sources dominate conventional upstream oil and gas sector methane emissions. Assuming all non-CHOPS-related wellhead sources, all piping, and all other and unknown sources can be classed as fugitive leaks; separator emissions are split equally between vented and fugitive sources; and compressor emissions are dominated by methane slip in the exhaust²⁸; approximately 63% of methane in the inventory could be categorized as known vent sources (e.g., uncontrolled tanks, pneumatic equipment, dehydrators, CHOPS-related venting, unlit flares or vent stacks), approximately 14% as combustion-related methane slip, and approximately 24% as fugitive leaks. From a mitigation perspective, this is potentially encouraging since known vent sources in principle should be easier to address and their mitigation is more likely to result in sustained reductions in emissions. However, the significant 5.5× difference between reported venting levels and the implied venting totals in the present inventory (152 kt/y vs. 840 kt/y) highlights the need for the verification component of MRV efforts if emissions are to be accurately identified, tracked, and reduced.

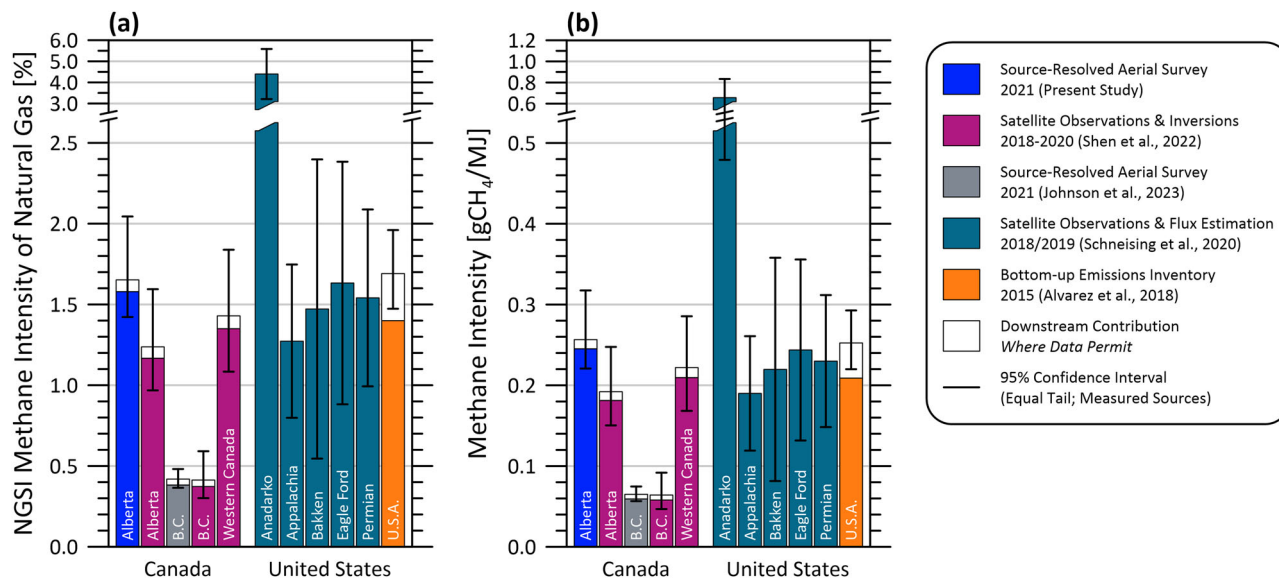


Fig. 4 Comparison of methane intensities of conventional production across North American basins^{20,22,26,27}. (a) NGSI methane intensities of natural gas [%] and (b) methane intensities [g_{CH₄}/MJ]. Where data permit, intensities show the individual contributions of upstream (coloured) and downstream (white) oil and gas sectors with uncertainties on the total sector intensity. For the Canadian provinces, downstream sector emissions were obtained from Environment and Climate Change Canada's National Inventory Report⁷. Total emissions for individual U.S. basins²⁷ are not parsed by sector.

Methane emissions intensities. To enable objective comparison of the present methane inventory with other jurisdictions, it is useful to derive methane emissions intensities of marketed products. For natural gas, one useful metric is the Natural Gas Sustainability Initiative's⁴⁷ (NGSI) emissions intensity (sometimes called leakage rate²⁷ or a loss rate, but hereinafter called NGSI methane intensity), which allocates a portion of total methane emissions to natural gas production on a produced energy-basis and calculates a characteristic leakage rate (in percent) by comparing to the amount of methane in marketed natural gas. As detailed in SI Section S3 and plotted in Fig. 4a, the present inventory results suggest the NGSI methane intensity for the conventional upstream sector in Alberta in 2021 was 1.58% (95% CI: 1.35–1.97%). After adding in downstream emissions estimated by ECC⁷, the total conventional sector NGSI methane intensity for 2021 was estimated to be 1.65% (95% CI: 1.42–2.04%). As shown in the figure, this total conventional sector NGSI methane intensity is closely aligned with nominal 2018/19 NGSI methane intensities of 1.27%–1.63% estimated²⁰ from satellite measurements²⁷ in the U.S. Appalachia, Bakken, Eagle Ford, and Permian basins, and much less than the 4.40% (95% CI: 3.21–5.58) estimated for the Anadarko basin. By contrast, the 2021 NGSI intensity for Alberta is approximately four times that of the neighboring province of BC²⁰ – upstream sector: 0.38% (95% CI: 0.33–0.44%) and total sector: 0.42% (95% CI: 0.36–0.48%). Although BC is largely a gas-producing province (90% of total production on an energy-basis), conventional operations in Alberta (i.e., excluding mined and in situ oil sands production) are comparably gas-dominant at 70% of total production on an energy-basis. Contrasting the source breakdown presented above for Alberta and that presented by Johnson et al.²⁰ for BC highlights much greater relative methane contributions of tanks and other non-compressor sources in Alberta, which further underscores the opportunities for mitigation.

The methane intensity of marketed hydrocarbon products, defined as the total mass of emitted methane per unit of total delivered energy in gCH₄/MJ, is a second important metric for assessing environmental impacts. Although closely related to the NGSI methane intensity, the two metrics differ due to jurisdiction-dependent differences in methane contents of

produced gas and energy contents of marketed gas and oil. In the present work, the methane content of produced gas was fixed to 85.2% for consistency with Johnson et al.²⁰ and energy contents of produced hydrocarbons were taken either from the Canada Energy Regulator⁴⁸ or the U.S. Energy Information Administration⁴⁹. As detailed in Section S3, the present hybrid inventory suggests that the 2021 methane intensity of energy products from Alberta's total conventional sector was 0.257 gCH₄/MJ (95% CI: 0.221–0.317). Referring to Fig. 4b, this matches within uncertainty a western Canadian estimate of 0.222 gCH₄/MJ (0.168–0.285) derived from satellite measurements of Shen et al.²², and equals a 2015 United States estimate of 0.252 gCH₄/MJ (0.220–0.293) based on the inventory of Alvarez et al.²⁶. However, this intensity is again substantially higher than the methane intensity of 0.065 gCH₄/MJ (0.057–0.075) for total sector energy products from BC in 2021²⁰. Key reasons for this difference include stronger regulations and enforcement in BC, noting that BC requires three times per year leak detection and repair (LDAR) surveys at most facilities that include direct measurement of detected leaks⁵⁰, which are further backed by transparent publishing of operator-specific LDAR data to track performance⁵¹. Additional factors likely include geologic differences in amounts of energy produced per facility and potential differences in methane intensities by general facility type (e.g., predominantly gas or oil facilities, multi-well vs. single-well facilities, etc.). As discussed in the following section, there can also be significant differences in environmental performance among operators.

Operator performance. To explore this further, Fig. 5 compares measured-source methane intensities (i.e., considering only the measured-source portion of the inventory) of companies operating three of the most common facility subtypes in Alberta: crude oil single-well batteries (subtype 311), crude-oil multi-well batteries (subtypes 321 and 322), and gas single-well batteries (subtype 351). These operator-specific intensities were calculated by running the complete measured source inventory protocol (including the analysis of intermittency effects described in SI Section S4) on the subsets of facility types operated by each company. Data are only

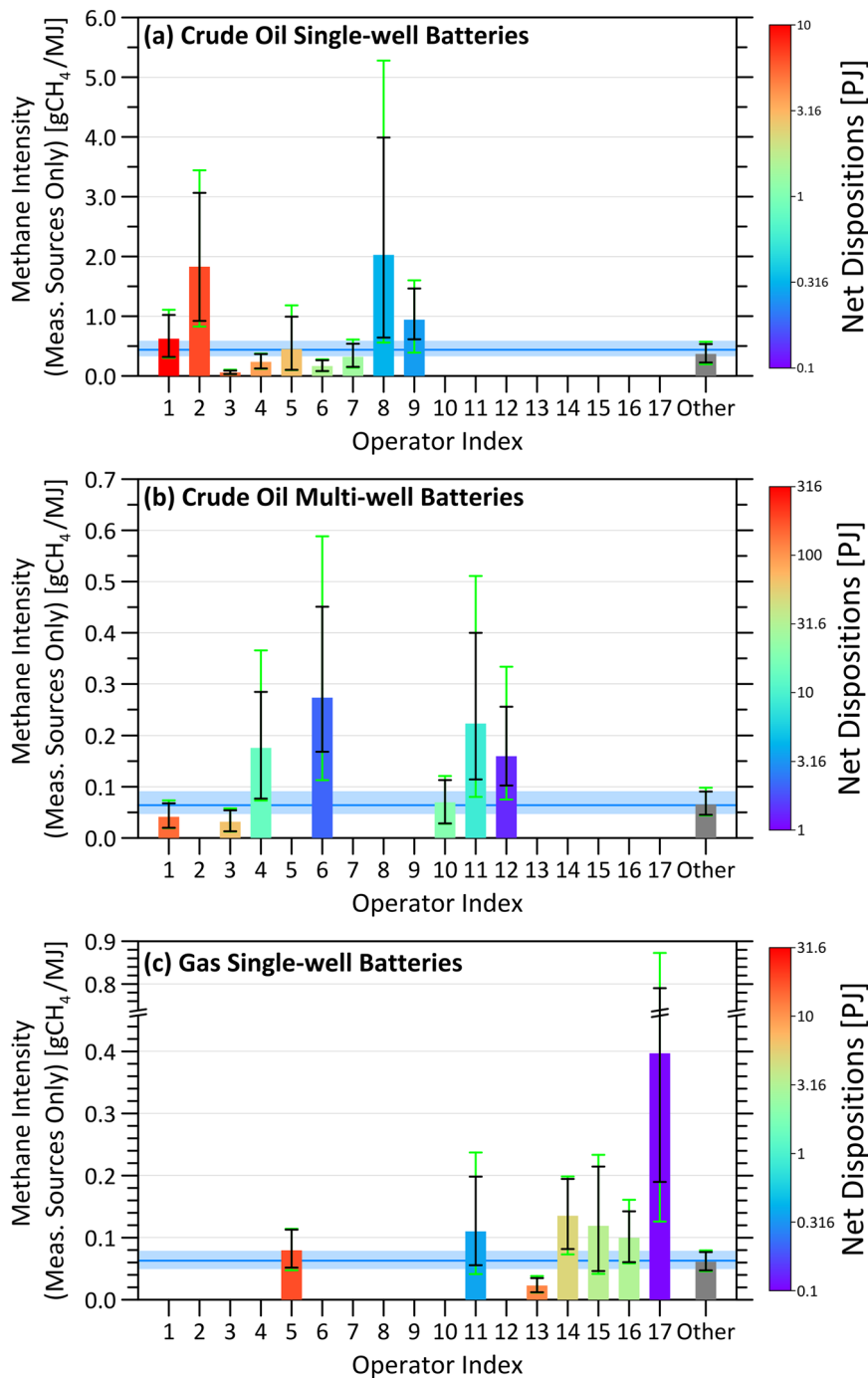


Fig. 5 Operator-specific, methane intensities (considering measured sources only) of delivered hydrocarbons for select (anonymized) operators at specific well battery types. (a) crude oil single-well batteries, **(b)** crude oil multi-well batteries, and **(c)** gas single-well batteries. Methane emissions include measured sources at both facilities and associated wells, and net dispositions of hydrocarbons are calculated from volumetric reporting data (dispositions less receipts) in the Petrinex system. The gray bar in each subplot represents all operators not explicitly plotted. 95% CIs are shown in black with the light green confidence interval upper bounding the effect of source intermittency as in Fig. 2. The horizontal blue line and band represent the mean and 95% confidence interval (including the effect of intermittency) of the relevant facility type across the entire province.

shown where the sample size of an operator’s assets was sufficient to complete the mirror-match bootstrap analysis^{52,53} to enable a robust quantification of uncertainties.

Noting the different scales on the vertical axes of Fig. 5a and b, the first important observation is that single-well oil facilities have approximately order of magnitude higher methane intensities than multi-well oil facilities. This has several potential implications for regulation and mitigation, but above all shows how

smaller single-well sites can disproportionately increase methane intensities of an operator and cannot be overlooked in the quest to reduce methane emissions. While detailed analysis of these trends is beyond the scope of this paper, reasons for this difference would include facility age (where multi-well facilities are more common for new development) and the likelihood of better mitigation infrastructure at multi-well sites (e.g., air-driven pneumatic equipment, controlled tanks, on-site combustors, etc.).

Second, by restricting the analysis to sets of identical facility subtypes, it is possible to objectively compare real-world, independently measured methane intensities of different operators. These data show that many operators are statistically smaller or larger emitters than the average and that differences in methane intensities among operators of the same facility types can exceed an order of magnitude. Referring to Fig. 5a, operators 2 and 3 produce similar, large amounts of energy (net dispositions of approximately 6 PJ) at their crude oil single-well batteries but the measured-source methane intensity of operator 2 is approximately 31 times larger than operator 3 (1.829 vs. 0.059 gCH₄/MJ). In terms of opportunity, Fig. 5 highlights achievable, independently verified methane intensities that all operators can strive toward; see, for example, operator 3 in Fig. 5a and b and operator 13 in Fig. 5c, who are producing large amounts of resources with notably lower methane intensities than many of their peers.

Finally, Fig. 5 demonstrates how high-sensitivity source-resolved measurements combined with careful analysis and rigorous consideration of uncertainties²⁰ can be used to independently quantify methane intensities of individual companies. This is a key goal of international initiatives such as the oil and gas methane partnership (OGMP 2.0)²³ as well as several private gas certification programs. The value and importance of third-party verification in these efforts is also difficult to overstate. For one of the anonymized operators in Fig. 5, the measured-source methane intensity (excluding any additional contributions from unmeasured sources and pneumatics) is 21 times greater than what is reported in their public Environmental Social Governance (ESG) report. Certainly, it is possible that much lower intensities at other producing facilities in their portfolio could lead to an overall intensity as they report. However, given the discrepancy in Fig. 2 between official inventories and top-down measurements like the present source-resolved aerial survey, it is also possible that self-reported emissions estimates used in ESG reporting are similarly underestimated. Most importantly, the disparity in measured methane intensities among operators highlights a key challenge in achieving the sector-wide methane reductions needed to meet climate targets. Success will require a collective commitment. While a few operators are clearly leading the way, their efforts risk being overshadowed by the emissions profiles of some others. This underscores the critical importance of third-party verification as part of emerging monitoring, reporting, and verification (MRV) frameworks.

Methods

Source-resolved aerial survey. The source-resolved aerial survey flights were completed during September 3 to November 10, 2021, using Bridger Photonics' GML technology. Referring to additional detail in the literature^{16,17,54,55}, the GML is an aircraft-mounted active optical sensor capable of detecting and quantifying methane abundance at spatial resolutions of approximately 1–2 m when flown at typical altitudes of 175 m above ground level (AGL). At such altitudes, the swath width of the optical sensor is approximately 100 m, which is sufficient to fully scan and quantify methane emitters at small oil and gas facilities (e.g., single-well batteries) with a single pass of the aircraft; for larger facilities, multiple passes are necessary. The measurement protocol entailed an initial flight (with one or more passes) over each site, preliminary analysis of the initial data from the pass(es) over that site, and then subsequent re-flight(s) of all sources detected during the initial flight usually 1–11 (mean of 3.58 and median of 3) days later. This process enabled insights into the persistence of each detected source and reduces quantification

error through the averaging of detections over flight passes and measurement days^{20,28}.

As detailed in Section S1.2 of the SI, the present survey was planned by EERL during spring 2021 using available January to March 2021 volumetric reporting data from the Petrinex database²⁴ to identify active facilities and wells within the province. Five survey regions were defined whose combined distribution of facility subtypes (e.g., crude oil single-well battery, sweet gas plant, gas gathering system) and well-bore fluids (e.g., crude oil, crude bitumen, and gas) were broadly representative of the province as a whole. Within each of these regions, all facilities that were active at the time of planning were included in the aerial survey subject to the availability of sufficient quality satellite imagery, which was used to manually bound the facilities' footprints and create geolocated shapefiles to guide the plane. The remaining project budget was deployed to survey as many off-site well pads as possible. In total, 3454 geographically distinct sites were surveyed, which at the time of the survey (September 3 to November 10, 2021) included 3317 active facilities and 5205 unique active wellheads, representing approximately 17.6% and 3.7% of provincial counts, respectively. An additional 152 (5.1%) shut-in facilities and 387 (3.3%) shut-in wellheads were also included in the sample and separately analyzed as further detailed in the SI.

Source attribution. During the aerial survey, Bridger detected 2087 unique methane sources. Reported GML data included high-resolution, geolocated, visual imagery for each surveyed site/polygon. Combined with facility plot plans obtained from the Alberta Energy Regulator, these data enabled the manual attribution of detected sources to specific equipment at the building scale (e.g., compressor buildings, separators, dehydrators, tanks, unlit flares, etc.). Additional provided data for each flight pass included the estimated local wind speed from Meteoblue (<http://www.meteoblue.com/>) and aircraft altitude; combined with the continuous probability of detection function for Bridger's GML derived from parallel controlled release studies¹⁹, methane sources of 1.6 and 3.2 kg/h were detectable with 50% and 90% probability at the median wind speed and aircraft altitude of the present survey. Quantification errors (95% CI) for a single observation were approximately $-69/+113\%$ ¹⁹, which reduced to an average value of $-42/+48\%$ when averaging detections over available flight passes and measurement days for each source.

Source-resolved, hybrid measurement-based inventory. The detected source data were then used to develop a measurement-based, hybrid top-down/bottom-up provincial inventory following the method of Johnson et al.²⁰. Firstly, a provincial inventory for measured/measurable sources (those detected/detectable by Bridger's GML) was derived from the survey data. Referring to the method of Johnson et al.²⁰ and SI section S2, the inventory was computed using a stratified sampling approach that first parsed detections by facility type or well-bore fluid to produce separate emissions estimates for each stratum. A Monte Carlo algorithm perturbed successfully detected/quantified emissions at the pass-level according to the quantification error model for Bridger's GML¹⁹ while also perturbing any "missed" detections (i.e., instances where a source at a specific location is detected during one or more flight passes but not in others, whether due to source intermittency or probabilistic detection) via a Bayesian analysis. This Bayesian analysis leveraged the continuous probability of detection function¹⁹ at the time of the miss and the prior knowledge that a source at this location had been detected. A mirror-match bootstrap analysis^{52,53}, nested within the MC algorithm, scaled flight pass- and measurement day-averaged detected emissions to the province; fully considering sample size effects and the finite populations of each stratum.

This measured inventory was combined with a provincial inventory of unmeasured sources, derived through a separate MC simulation²⁰. This supplemental analysis used the specific measurement conditions during the survey to simulate flights over facilities/wells with sources near or below the detection limit of Bridger's GML from prior studies. These bottom-up source data included measured or estimated source rates for non-pneumatics from a 2017 ground survey in Alberta by Clearstone Engineering³⁴, pneumatic counts from the same survey³⁴, and pneumatic emission factors from the Alberta Energy Regulator⁵⁶, and are the same data that underpin current official inventory estimates. A key distinction of this hybrid, top-down/bottom-up, measurement-based protocol is that bottom-up data only contribute to the final inventory as sources that would not have been seen in any measurement pass. As such, more than three-quarters of methane in the present inventory is directly measured. As further detailed by Johnson et al.²⁰, this procedure ultimately provides stratum-specific emission factors that are applied to the population of sites in the province to yield the unmeasured portion of the total provincial inventory parsed by pneumatic instruments, pneumatic pumps, and non-pneumatics.

Region-level aerial survey. Mass-balance measurements to estimate total emissions from the nine regions shown in Fig. 1 were completed by Scientific Aviation under the direction of EDF during September 29 to November 6, 2021. This simultaneous survey (bounded by the measurement dates of the source-resolved survey) was implemented to provide a secondary estimate of the provincial inventory using an alternative method. Briefly, referring to additional detail in the literature²¹, light aircraft-mounted instrumentation tracks local methane concentration and wind speed/direction during flight laps surrounding a geographical region of interest. These data provide a local flux of methane out of the measurement region, which, via Gauss' divergence theorem, is used to estimate methane emissions within the measurement region. Given the regional nature of this measurement, detected methane flux is a function of sources and sinks across numerous potential sectors. Detected methane flux was ultimately apportioned to upstream oil and gas activity by correcting for non-oil and gas anthropogenic and wetland methane emissions using openly available data^{29,57}. This procedure and an associated uncertainty analysis is detailed in SI Section S5.1. Computed emission rates for the nine regions were scaled to estimate a provincial inventory as detailed in SI Section S5.3 and presented above alongside results of the source-resolved inventory.

Data availability

Data to replicate Fig. 2 through Fig. 5 in the main text and Figures S2 through S5 in the supplementary information, as well as Supplementary Tables of results can be accessed via the Carleton University dataverse at <https://doi.org/10.5683/SP3/8K88G6>.

Anonymized detected emissions for each detected source in the aerial survey are also included.

Received: 23 July 2023; Accepted: 1 November 2023;

Published online: 15 November 2023

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Acknowledgements

We wish to thank Dr. Lu Shen (Peking University and Harvard University) for promptly sharing and describing gridded posterior emissions derived from satellite²². We also gratefully acknowledge helpful discussions with Steve Smyth (Environment and Climate Change Canada, ECCC) in parsing bottom-up federal inventory data to facilitate source-level comparisons. The leadership of Natural Resources Canada (NRCAN, especially Nicole MacDonald, Michael Layer, and Amin Asadollahi) under tight timelines was essential to the success of this project as was the collaborative cooperation of Bridger Photonics Inc. (especially Ben Losby, Kerry Neal, and Mike Thorpe). Finally, we appreciate the assistance of Zachary Milani and Alex Szekeres (EERL) during the initial source attribution processing, Ellen McCole (EERL) during the initial set up of the facility polygons and flight regions, and Jack Warren, Katlyn MacKay, James S. Wang, and Scott Seymour (EDF) for assistance with flight planning. This work was generously supported by the McCall MacBain Foundation, Natural Resources Canada (NRCAN, grant number EIP2-MET-001), and Natural Sciences and Engineering Research Council of Canada (NSERC, grant numbers 06632 and 522658).

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Conceptualization: D.R.T., D.X., and M.R.J.; Software, validation, data curation, and formal analysis: B.M.C., D.R.T., H.Z.L., and M.R.J.; Writing – Original Draft: B.M.C., M.R.J.; Writing – Review & Editing: All authors.

Competing interests

The authors declare no competing interests.

Additional information

Supplementary information The online version contains supplementary material available at <https://doi.org/10.1038/s43247-023-01081-0>.

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Peer review information *Communications Earth & Environment* thanks Elton Chan and the other, anonymous, reviewer(s) for their contribution to the peer review of this work. Primary Handling Editors: Clare Davis. Peer reviewer reports are available.

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