

<https://doi.org/10.1038/s43247-024-01728-6>

Hybrid bottom-up and top-down framework resolves discrepancies in Canada's oil and gas methane inventories



Elton Chan ¹✉, Felix Vogel ¹✉, Steve Smyth ², Owen Barrigar ², Misa Ishizawa ¹, Jinwoong Kim ³, Michael Neish ¹, Douglas Chan ¹ & Douglas E. J. Worthy¹

Estimating accurate oil and gas methane emissions has been a global challenge, highlighted by a twofold discrepancy between atmospheric measurement-based estimates and emission inventories. The principle of continuous improvement in Canada's National Inventory Report has led to an unstable baseline in recent years for tracking emission reduction progress. The gaps between previous inventory estimates and inversions exceeded 60%. Here we show that incorporating new source-resolved information derived from low-altitude aerial survey data has narrowed this gap by 80%, reducing the discrepancy to 10% for the 2010–2014 baseline. This study proposes a hybrid emission reporting framework, complemented by an ensemble inversion top-down method using continuous tower-based atmospheric measurements, to establish a stable baseline and provide independent verification. As the 2030 target year for emission reduction approaches, we report a significant 27% decline (19%–34%) in inverse oil and gas methane emissions from 2010 to 2022 in Alberta and Saskatchewan, Canada, and a 41% decline (26%–56%) as calculated using the 2024 official inventory.

Over the last two decades, numerous observational studies worldwide have consistently found methane emissions from the oil and natural gas sector to be 1.5 to 2 times higher than figures reported in national inventories^{1–10}. Recent findings have revealed underestimations in fugitive methane emissions from oil production, implying that oil production sites may be less able or motivated to both capture and accurately quantify associated gases that are not sold but are traditionally disposed of through flaring or venting¹¹. A number of reports have pinpointed the source of these underestimated emissions to unintentional leaks from liquid storage tanks and other equipment^{12,13}. Some research suggests that the discrepancy arises from unreliable data reported by operators, which is subsequently used in inventory calculations. This unreliable data source can lead to significant inaccuracies in emission estimates^{14–18}. Furthermore, the presence of super-emitters poses a significant challenge in accurately representing the magnitude of emissions in official inventories^{8,19–21}. Methane emission factors, which are developed for inventory calculations and often based on limited samples of field data²², may not represent the full range of potential emission sources in the oil and gas sector, especially when applied across broad regions. Using methane emission factors often does not accurately capture the impact of super-emitters, which tend to be rare, intermittent and localized.

To mitigate key methane emission sources in the upstream oil and gas sector, Canada designed and implemented regulations^{23–25}. These sources include fugitive equipment leaks, production venting, and venting from pneumatic devices, compressors, and well completions. From 2000 to 2014, the oil and gas industry continued to grow substantially in Canada, but fugitive methane emissions did not increase at the same rate. This was due to the combined effect of improved inspection and maintenance programs, better industry practices, technological improvements, and initiatives by provincial regulators²⁶. Initial federal regulatory requirements took effect in January 2020, with additional provisions being phased in over the following years. Additionally, during the COP28 UN Climate Change Conference, Canada announced proposed regulatory amendments to fulfill its climate commitment²⁷. Since 2020, the Provincial Governments of Alberta (AB), Saskatchewan (SK), and British Columbia (BC), have also implemented their own methane regulations. These provincial regulations aim to achieve methane emission reductions that are equivalent to or greater than those mandated by federal regulations^{28,29}. Both federal and provincial regulations aim to achieve a 40–45% reduction in methane emissions from the oil and gas sector relative to 2012 levels by 2025. Work is ongoing to enhance these regulations with the further goal of achieving a minimum reduction of 75%

¹Climate Research Division, Environment and Climate Change Canada, Toronto, Ontario, Canada. ²Pollutant Inventories and Reporting Division, Environment and Climate Change Canada, Gatineau, Québec, Canada. ³Meteorological Research Division, Environment and Climate Change Canada, Dorval, Québec, Canada.

✉ e-mail: elton.chan@ec.gc.ca; felix.vogel@ec.gc.ca

by 2030^{23,25} in alignment with the Global Methane Pledge. In summary, the oil and gas sector in Canada is undergoing significant changes in management practices and technologies, largely driven by the implementation of current and impending regulations. Without the ability to reliably track methane emission changes, ambitious reduction targets and pledges risk being seen as futile.

While updates to the National Inventory Report (NIR) methodologies can align with measurement-based estimates for the historical period, the need for further inventory improvements remains critical. Continued atmospheric monitoring of emission trends is essential to accurately capture future emission changes, especially considering the significant methane reductions expected over the next decade.

Aims and scope of this study

- Analyze Alberta and Saskatchewan collectively, as they accounted for over 86% of Canada's oil and gas methane emissions from 2010 to 2022.
- Discuss the official methane emission inventories for the 2021–2023 NIRs, highlighting the remaining challenges.
- Demonstrate the discrepancy between inventory and measurement-based estimates, emphasizing the need for improved tracking of emission changes to ensure greater consistency and transparency. This discrepancy has driven significant improvements in the 2024 NIR. Discuss the major methodological advancements in the 2024 inventory.
- Examine the long-term variations in oil and gas emission estimates over the past decade and discuss the implications of forthcoming regulations.
- Calculate 5-year average emissions for 2010–2014 and 2015–2019 using ground-based atmospheric data and inverse modeling, and synthesize these with inventory data to establish a robust baseline. The 5-year average from 2010 to 2014 is used as a proxy for 2012, which is key to measuring regulatory effectiveness in achieving the oil and gas sector's 2025 and 2030 methane reduction targets.

Recent inventory updates and identified potential for further improvements

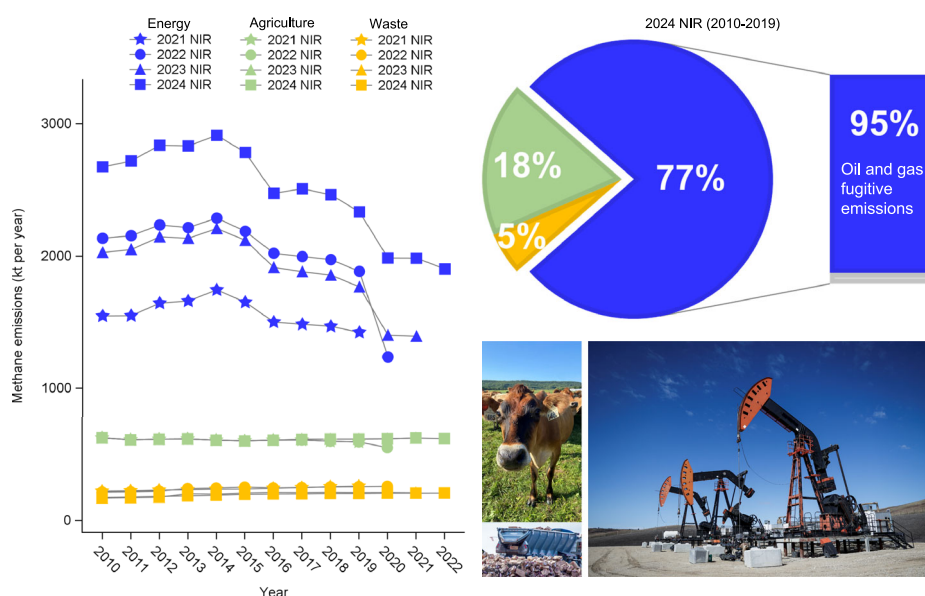
Figure 1 shows the evolution of the annually reported anthropogenic emissions of methane in Canada's greenhouse gas inventory for AB and SK. The magnitudes, inter-annual variations, and long-term trends in these inventory editions are notably uncertain, especially regarding emissions from the energy sector. In 2022, over 90% of methane emissions from the oil

and gas sector in the two provinces considered in this paper are contributed by the upstream oil and gas sector (Supplementary Table 1). A recent study has also demonstrated that the upstream sector dominates emissions from the oil and gas industry in AB and SK³⁰. For the years 2010–2019, the 2023 NIR indicated that, on average, 71% of anthropogenic methane emissions originated from the energy sector. It is noteworthy that this contribution has been revised to 77% in 2024 NIR with improvements in accounting for fugitive sources and may further change in future inventory editions. As shown in the pie chart in Fig. 1, fugitive oil and gas methane emissions³¹, which include flaring, venting, and other unintentional releases, constituted ~95% of the emissions from the energy sector. The agriculture sector was responsible for 18% (revised from 22%), while the waste sector for 5% (revised from 7%). Updates to data and methodologies can result in upward or downward revisions to emission estimates. For more details regarding the 2022, 2023 inventories, see Supplementary Method 1.

Figure 2 illustrates the contributions of different calculation methods used to estimate methane emissions from the oil and gas sector in the 2023 and 2024 NIRs, which is included in the energy sector, as shown in Fig. 1. It highlights that modeling plays an important role in AB's energy emission calculations, while direct estimation is the predominant contributor for SK. Modeled emissions are estimated based on component-level emission factors and other source specific parameters, and directly estimated emissions are based on volumetric data reported by facilities to the Petrinex reporting system³². In the 2022 NIR (Supplementary Fig. 1), a significant drop was reported in the emissions using the modeled method for both AB and SK in 2020. This decline is attributed to three main events in 2020: regulatory implementations, the COVID-19 global pandemic, and changes in provincial reporting requirements. The assumed impact of Canada's methane regulations influenced the assumptions underlying the reduced emission factors used to model emission reductions, while changes to provincial reporting requirements introduced a methodological inconsistency between pre-2020 and post-2020 industry reported data. These two issues consequently led to a high degree of uncertainty regarding the significant drop in 2020 as presented in the 2022 NIR.

Given the challenges encountered during the compilation of the 2022 NIR (Supplementary Method 1) and the methodological inconsistencies introduced as result of the changes to provincial requirements for reporting fuel, flare, and vent gas volumes, the 2023 NIR made use of data from the Alberta Energy Regulators' OneStop reporting system³³. OneStop requires operators to report vent volumes delineated by pneumatic pumps and instruments, compressor seals, glycol dehydrators, fugitive leaks, and

Fig. 1 | Recent inventories of the three main anthropogenic methane sources in Alberta and Saskatchewan. The recent changes are primarily due to revised methods for calculating fugitive emissions in the energy sector. Sectoral emissions are categorized as follows: energy (blue), agriculture (green), and waste management (yellow). Each inventory edition includes data up to two years before its release; for instance, the 2024 NIR includes data up to 2022. Methodological changes are applied retroactively, updating all yearly emission estimates back to 1990. The pie chart data cover the years 2010 to 2019, based on the 2024 NIR. Pumpjacks extract oil and associated gas near northwest of Calgary, Alberta. Pumpjacks and landfill photos by Jeff McIntosh. Livestock photo by Meghan Flood/Environment and Climate Change Canada.



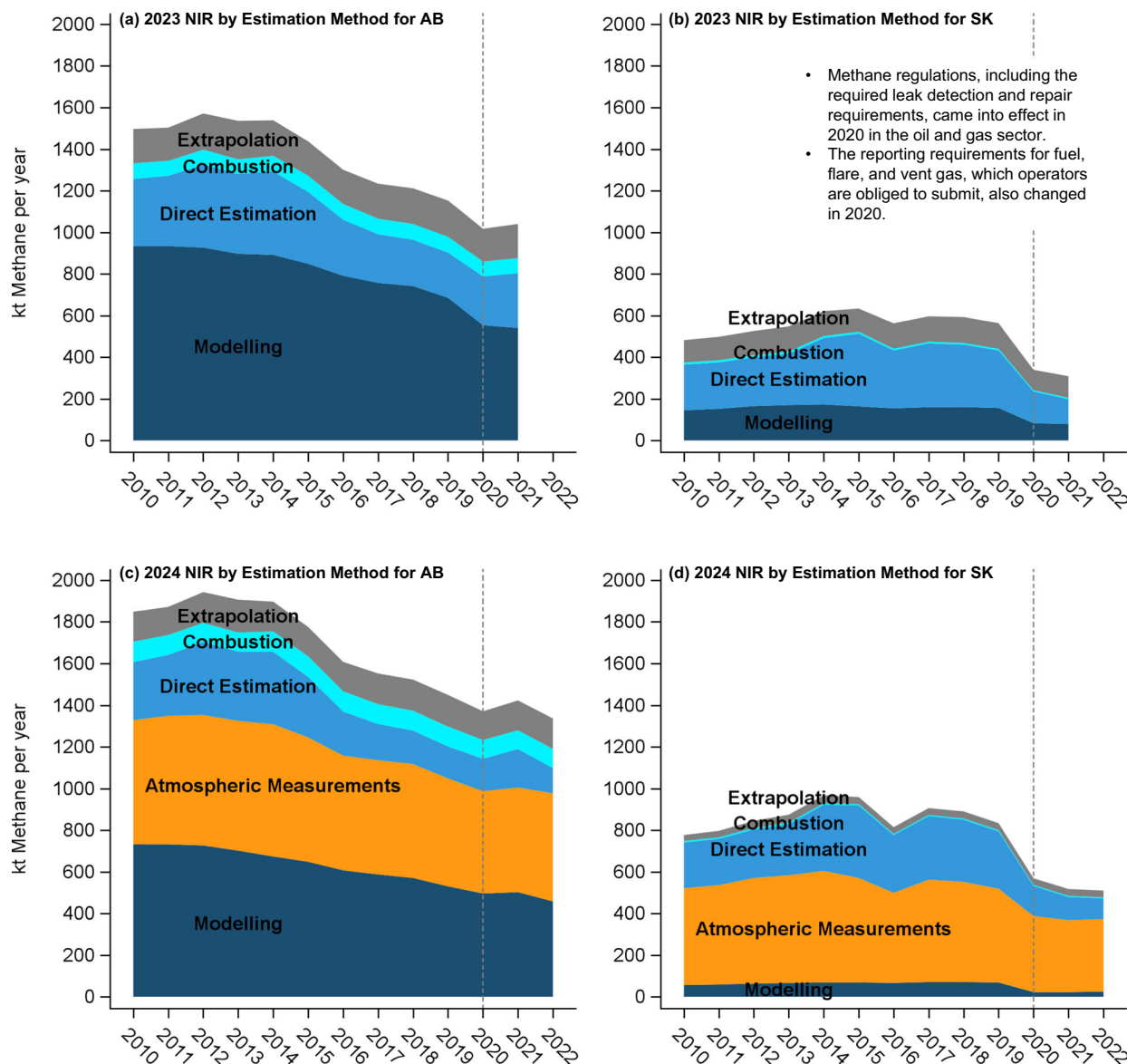


Fig. 2 | Contributions to total methane emissions from Alberta and Saskatchewan's oil and gas sectors by estimation method. **a** Alberta oil and gas inventory from 2023 NIR, **b** Saskatchewan oil and gas inventory from 2023 NIR, **c** Alberta oil and gas inventory from 2024 NIR and **d** Saskatchewan oil and gas inventory from 2024 NIR. Components include: 1) Extrapolation: includes emission estimates for sources taken from detailed inventory studies compiled by Clearstone Engineering Ltd. for the years 2000, 2005, and 2011 and extrapolated for the years without detailed inventory data based on changes in various activity data. 2) Combustion modeling: for natural gas combustion, facility reported fuel gas volumes are multiplied by consumption-weighted, technology specific CH_4 emission factors. Fuel consumption volumes for other fuels (e.g., diesel, propane, gasoline, etc.) are multiplied by fuel specific CH_4 emission factors. 3) Direct Estimation: includes emission

sources that are estimated directly by Environment and Climate Change Canada (ECCC) using facility reported volumetric data and detailed gas composition data. 4) Modeling: includes emission sources that are modeled by ECCC based on annual facility counts, average number of components per facility, component-level emission factors and gas composition data. 5) Atmospheric Measurements: source-resolved emission inventories for AB (2021) and SK (2020 and 2021) by Energy and Emissions Research Laboratory (EERL) derived using aerial survey data are used as the basis to estimate emissions from storage tanks, compressor buildings, unlit flares, engine sheds in AB and SK, and wellheads in SK. As shown by the dashed lines, the large drop in 2020 is the result of regulatory implementations, the COVID-19 pandemic, and changes in industry reporting requirements.

defined vent gas. The data were used to break down the total vent volumes reported to Petrinex, extract the pneumatics portion from the operator-reported vent volume data, and recompute emissions for both 2020 and 2021 using the modeling method for pneumatics consistent with the rest of the time series. This led to an upward revision of methane emissions in Alberta for 2020 between the 2022 and 2023 NIRs, as shown in Fig. 1 and Supplementary Fig. 1. The drop of the oil and gas methane emissions from 2019 to 2020 was reduced from 34% in the 2022 NIR to 21% in the 2023 NIR. Additionally, the recently implemented regulations in 2020 have required assumptions to be made regarding their impact on reducing

emissions as reflected in the modeling method for the 2022 and 2023 NIRs. These assumptions may not accurately reflect actual emissions. Therefore, the depicted significant drop of 364 kt/yr (21%) in total emissions from the oil and gas sector from 2019 to 2020, as shown in Fig. 1, should be interpreted with caution. In summary, the 2023 NIR revisited and adjusted these assumptions accordingly with refinements to the estimation methods, as explained above. Therefore, we discussed the challenges in the 2021 and 2022 NIRs at the beginning of the manuscript to provide context, but focused primarily on the more recent 2023 and 2024 NIRs for the subsequent analyses.

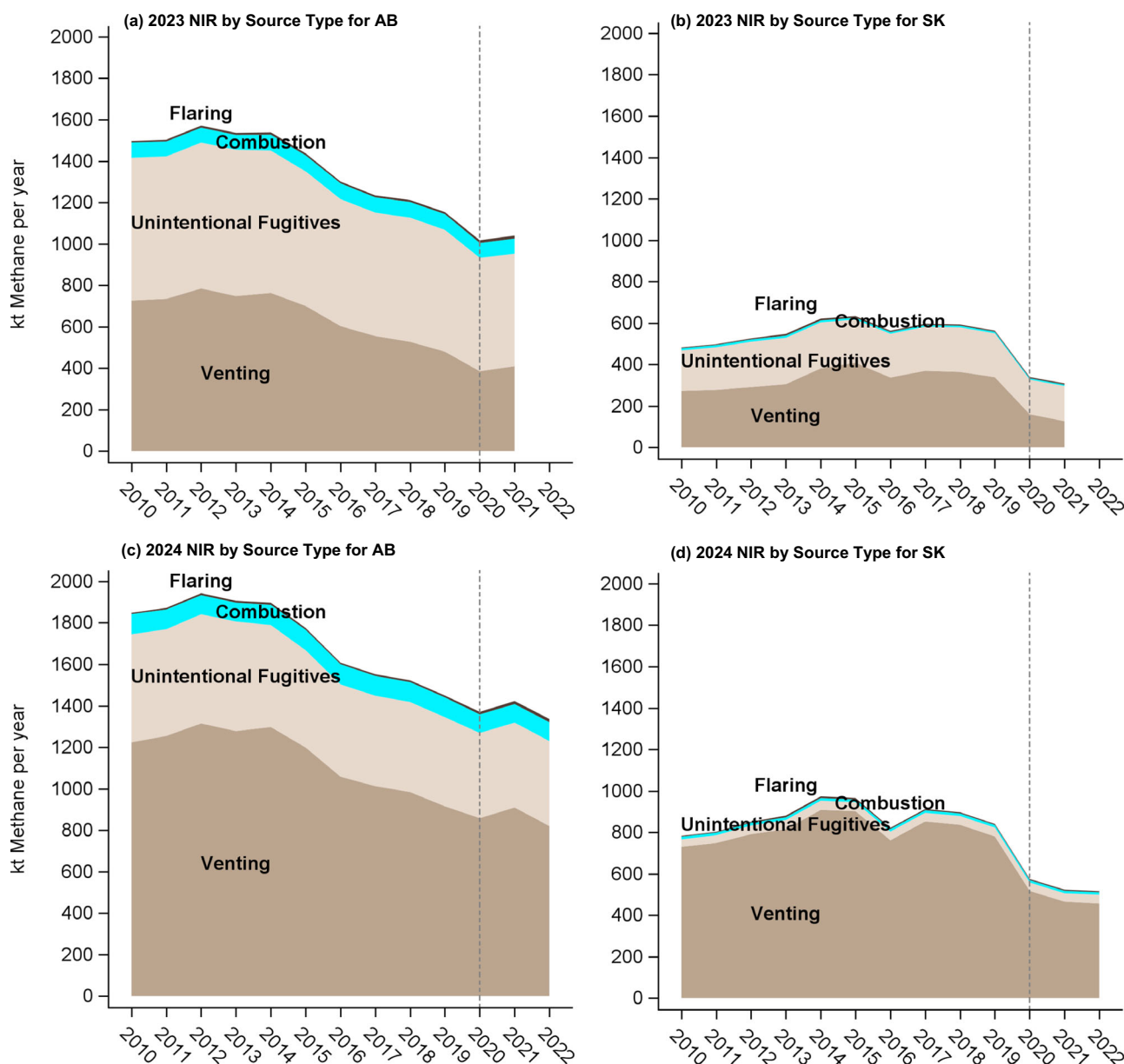


Fig. 3 | Contributions to total methane emissions from Alberta and Saskatchewan's oil and gas sectors by source type. a Alberta oil and gas inventory from 2023 NIR, **b** Saskatchewan oil and gas inventory from 2023 NIR, **c** Alberta oil and gas inventory from 2024 NIR and **d** Saskatchewan oil and gas inventory from 2024 NIR.

Figure 2a illustrates the contribution of methane emissions in AB according to the estimation methods used in the 2023 NIR. The primary methods include modeling, direct estimation, combustion modeling, and extrapolation. The majority of methane emissions were calculated using modeling and direct estimation, with smaller contributions from combustion modeling and extrapolation. Figure 2b shows the estimation methods used in SK as reported in the 2023 NIR. Similar to AB, modeling and direct estimation were the dominant methods, with extrapolation and combustion contributing to a lesser extent. The figure also notes the impact of methane regulations, including leak detection and repair requirements, which came into effect in 2020, as well as changes in reporting requirements for fuel, flare, and vent gas.

In Fig. 2c, the 2024 NIR for AB is depicted, illustrating a shift in estimation methods compared to the 2023 NIR. See Supplementary Table 2 for details on the 2023 NIR, and Supplementary Tables 3–5 for changes in the 2024 NIR. The introduction of low-altitude aircraft-based atmospheric measurements as a new estimation method is particularly significant, contributing notably to the overall methane emissions reported in the inventory. While the modeling method continues to play a major role, the

addition of atmospheric measurements has reduced the reliance on traditional approaches to estimating emission factors. The contribution of the direct estimation method has also decreased. Figure 2d presents the estimation methods used in SK as reported in the 2024 NIR. Similar to AB, there is a reduced reliance on modeling, direct estimation, combustion, and extrapolation methods. Specifically, source-resolved methane emission inventories, derived from aircraft atmospheric measurements, were used as the basis for estimating emissions from storage tanks, compressor buildings, unlit flares, and engine sheds in both AB and SK, as well as from wellheads in SK. It is important to note that the new emission factors are specific to the years 2020 (SK) and 2021 (AB and SK), utilizing aerial survey data to refine the emission factors used in the inventory. Extrapolation for earlier periods was conducted using activity data, volumetric data, and facility and well population data. For more details, refer to the equations provided in the 2024 NIR Annex 3.2, Section 3.2.2.1.5³⁴.

Figure 3a presents the contribution of methane emissions in AB according to source type as reported in the 2023 NIR. The major sources include venting, unintentional fugitives, combustion, and flaring. Venting is

the dominant source of methane emissions, followed by unintentional fugitives. Combustion and flaring contribute to a lesser extent, indicating that venting and fugitive emissions are the primary targets for emission reduction strategies in AB. Figure 3b displays the methane emissions by source type in SK as reported in the 2023 NIR. Venting remains the largest contributor to methane emissions, followed by unintentional fugitives, combustion, and flaring. The pattern is similar to AB, though the overall scale of emissions is lower in SK. The distribution of sources suggests that similar mitigation strategies may be applicable across both provinces.

Figure 3c shows the 2024 NIR data for AB, with updated source type information. The inclusion of aircraft atmospheric measurements and refined methodologies has led to adjustments in the emissions reported in the inventory. While venting continues to be the largest source of methane, there is a slight decrease in unintentional fugitives as unintentional fugitives from sources now estimated based on atmospheric measurements, where all sources are included in venting, were removed from the inventory to avoid double-counting. Figure 3d presents the 2024 NIR data for SK, illustrating changes in methane emissions by source type following the inclusion of new atmospheric measurements. Similar to AB, venting remains the dominant source, with slight adjustments in the estimates for unintentional fugitives, combustion, and flaring.

The estimation methods and associated sub-sources for the 2023 and 2024 NIRs can be found in Supplementary Tables 2 and 3. Additionally, Supplementary Tables 4 and 5 highlight the sub-sources with emission data for which new emission factors have been developed for the 2024 NIR based on aerial surveys.

Results and discussion

Synthesizing inverse estimates and inventory data

Compared to previous work⁹, our results in this study demonstrate that the inverse emission estimates are robust, despite being derived from different

model inputs and setups (Supplementary Method 3). The two studies have yielded 5-year mean estimates in agreement for the same time period. The long-term ground-based tower atmospheric observations and ensemble inverse modeling method provide a static baseline for historical emissions. In contrast, emissions reported in the NIR can vary significantly from one edition to the next, reflecting annual updates and methodological improvements to incorporate the latest scientific information and activity data.

Figure 4 shows a reduction in the gap of annual total anthropogenic methane emissions between ensemble inverse estimates and inventory reported emissions in the 2023 NIR edition (blue horizontal bar), at 26%. This improvement is compared to the 36% difference found in the 2021 NIR (black horizontal bar). This gap reduction is primarily attributed to revised calculations of fugitive emissions from the upstream oil and gas sector. Despite this improvement, a substantial discrepancy of 1 Mt/year (3.9 minus 2.9 Mt) of methane in AB and SK remains. For context, using a 100-year time horizon, emitting 1 Mt of methane per year has a similar impact on climate change as the annual carbon dioxide emissions from ~5 million passenger vehicles.

To further improve the accuracy of the inventory, Canada's official inventory incorporates atmospheric data from low-altitude aerial surveys into its estimations in 2024 NIR as described in the Materials and Methods section. This methodology integrates information from operator self-reporting, inventory activity-based modeling, and atmospheric data. Complementing traditional inventory methods, aerial measurements at the facility and component levels offer detailed snapshots of emission factors and activities across sub-regions, thereby enabling timely updates in the NIR. Inverse modeling, coupled with continuous ground-based tower atmospheric data not utilized in inventory calculations, provides regional-scale methane total emission estimates. This independent data source is essential in capturing a wide range of emission sources, serving as a regional

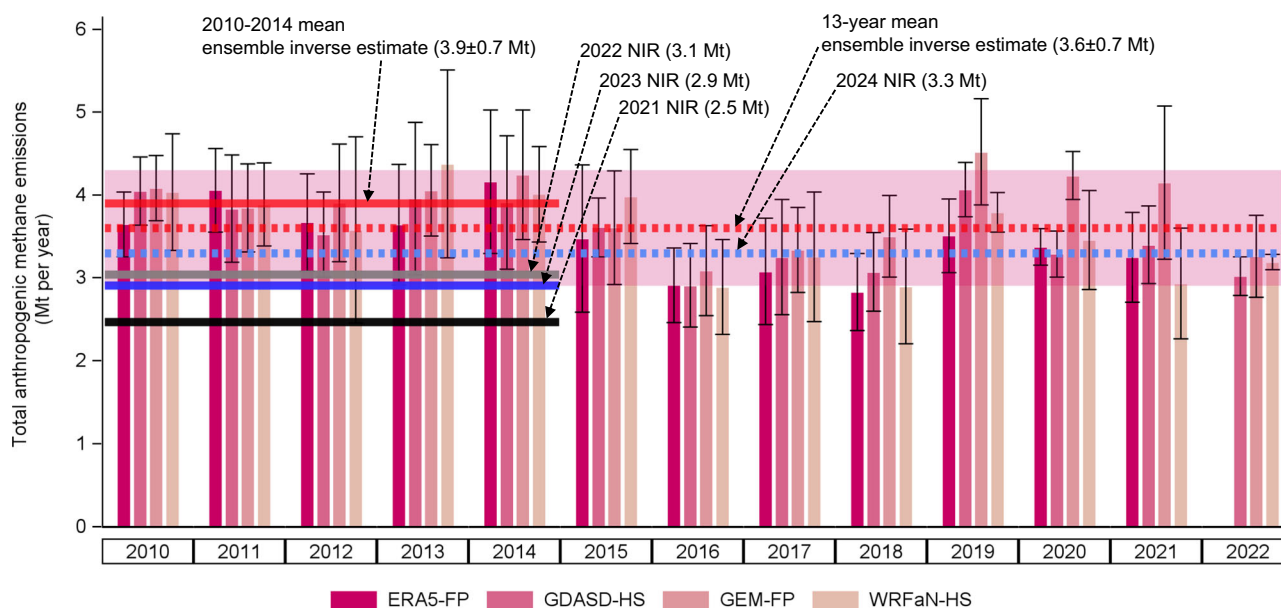


Fig. 4 | Reduced gap of the annual total anthropogenic methane of ensemble inverse estimates and inventory emissions in Alberta and Saskatchewan; however, a significant discrepancy persisted prior to the 2024 NIR major methodological updates. The inverse estimates for the four atmospheric transport models are shown here. Average results incorporating the three prior emission scenario inputs, two inversion methods and two cold periods of Nov–Dec and Jan–Mar are shown using the 7-sub-region inversion setup. 0.2 Mt of wetland emissions have been subtracted. The error bars show the ± 1 standard deviation (STD) of ensemble estimates by transport model and by year. The red horizontal line shows the 5-year average of 2010–2014 for the ensemble inverse methane estimates. The light pink shaded band shows the ± 1 STD of the ensemble results over the 2010–2022 period. The 5-year average of inventory emissions for the 2023, 2022 and 2021 NIRs are

shown as blue, gray and black horizontal bars respectively. The red and blue dashed lines show the 2010–2022 averages for the inverse and 2024 NIR methane emission estimates. ERA5-FP: The ERA5 reanalysis meteorological data from the European Centre for Medium-range Weather Forecasts driving the FLEXPART dispersion model. GDASD-HS: the Global Data Assimilation System data from the National Weather Service's National Centers for Environmental Prediction driving the US. NOAA's HYSPLIT dispersion model. GEM-FP: the global environmental multi-scale model from ECCO driving the FLEXPART dispersion model. WRFa-N-HS: the Advanced Research Weather Research and Forecasting time-averaged meteorological data driving the US. NOAA's HYSPLIT dispersion model. For details, see Supplementary Method 3.1.

constraint over extended periods. Our hybrid framework not only ensures historical consistency but also enhances the quality assurance of emission estimates in the inventory by leveraging the strengths of various complementary data sources, thereby improving our capability in assessing the effectiveness of mitigation measures. Note that this major methodological update in that 2024 NIR notably improves the accounting of historically under-reported sources, such as storage tanks, unlit flares, and compressors.

Drivers for oil and gas methane emissions variations

As detailed in Supplementary Method 4, the discrepancy between our inverse measurement-based emission estimates is not attributable to agricultural and waste emissions in AB and SK. Nonetheless, to account for the uncertainties associated with these two sources, we conducted a Monte Carlo (MC) analysis with 1000 samples annually per ensemble member as explained in the “Materials and Methods” section. The annual total anthropogenic inverse estimates were used to calculate the oil and gas methane emissions.

Historically, oil and gas production activity data have played a limited role in estimating methane emissions within the inventory. In the context of Canada’s methane national inventory, this data is not directly used for estimating methane emissions. Rather, it aids in the scaling of comprehensive emission inventories to specific years and enables backcasting to periods where detailed inventories are not available (i.e., extrapolation method shown in Fig. 2). Details on backcasting can be found in the official inventory report³⁴. Moreover, production data is selectively employed to scale only certain emission sources, namely glycol dehydrators, storage losses (including breathing and working losses from storage tanks), and the loading/unloading of liquids from truck and rail tankers. In 2021, sub-sources estimated using the extrapolation method, based on production data, accounted for 8–9% of total CH₄ emissions in Alberta and Saskatchewan. It is important to note that other sources were extrapolated using various activity data, including the number of wells drilled, the number of active wells, and flare and vent volumes. In fact, intentional venting is a primary source of methane, including from uncontrolled tanks, pneumatics, compressor seals, dehydrator off-gas, and other processes designed to vent

routinely or during non-routine events. While some of these emissions are related to production activity and would be captured in operator-reported volumetric data, unintentional venting from malfunctioning equipment and unlit flares also contribute significantly to overall emissions, as demonstrated in the referenced aerial survey studies in Canada. Such sources are difficult to characterize from reported data alone and can only be reliably detected and quantified when facility sites are surveyed frequently. Additionally, combustion slip and various fugitive releases from compressor buildings, wellheads, separators, and engine sheds have been shown to account for significant methane emissions^{16,21,35,36}.

As explained earlier and shown in Fig. 5a, production volumes are not reliable proxies for estimating emissions. The significant shifts depicted in the figure correlate with major global events: a marked decline in oil production from 2014 to 2016, a rebound between 2018 and 2019, and the lockdown during 2020–2021. However, pinpointing specific causes for the year-over-year variations in methane emissions remains a challenge. This difficulty arises due to overlapping regulatory changes introduced in 2020 and ongoing modifications in industry practices and reporting guidelines. These overlapping factors make it difficult to directly attribute these shifts to a single cause.

It is noteworthy that a divergence between production and emission estimates emerged in 2020, coinciding with the implementation of methane regulations in the upstream oil and gas (UOG) sector, as detailed in the previous inventory section. Projections suggest that Canada may reach an all-time high in oil production by 2024, potentially exceeding that of the United States³⁷. This potential increase in production could result in a widening deviation between production and emissions, especially if emission intensity continues to decrease. Should methane emissions from the oil and gas sector decrease in spite of the spike in oil production, it would underscore the effectiveness of the recently implemented methane regulations targeted on fugitive sources.

While a statistically significant decline of 27% (with a 95% Confidence Interval [CI] of 19%–34%) in oil and gas emissions was observed from 2010 to 2022 in AB and SK, Canada (Fig. 5a), likely due to the effects of oil and gas regulations implemented in the last decade, caution in interpreting the exact

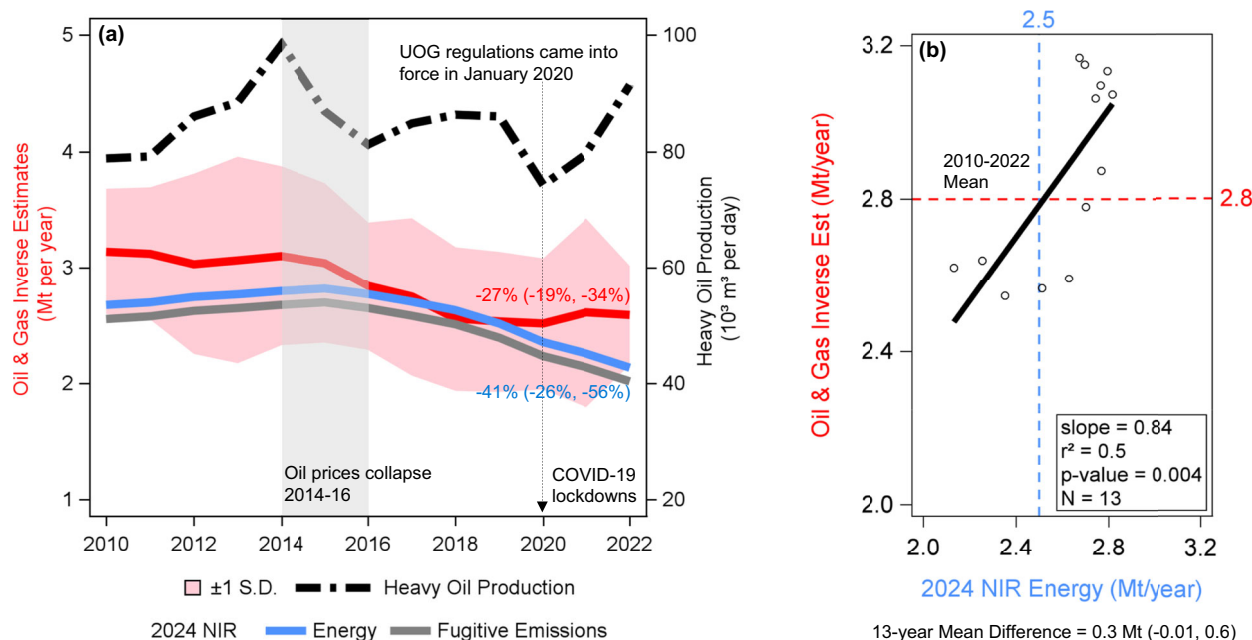


Fig. 5 | Annual total oil and gas methane emissions estimates and annual daily average conventional oil production in Alberta and Saskatchewan. a Results were averaged over the 4 transport models, 3 prior emissions, 2 inversion methods and 2 cold periods of Nov–Dec and Jan–Mar shown as the solid red curve. The light pink shaded band shows the ±1 standard deviation (STD) of the 48,000 ensemble results for individual years except for 2022. Five-year moving averages of the ensemble

means and the 2024 NIR data are shown. The dashed black curve shows the annual daily average of the total conventional heavy oil production volumes. In Canada, the first requirements of the methane regulations for the upstream oil and gas (UOG) sector took effect in 2020. **b** correlation analysis of the inverse estimates and 2024 NIR data for the energy sector.

magnitude of this decline is warranted. This caution arises from the increased amount of invalidated measurement data in the inverse emission estimations for the years 2020–2021, considerably impacted by the COVID-19 lockdowns. Similarly, a statistically significant decline of 41% (with a 95% Confidence Interval [CI] of 26%–56%) in oil and gas emissions was estimated from 2010 to 2022 in AB and SK using the 2024 NIR data. As shown in Fig. 5b, the correlation between the inverse estimates and the 2024 NIR estimates for the energy sector (primarily upstream oil and gas) from 2010 to 2022 was analyzed, yielding a correlation coefficient (r^2) of 0.5. The slope of the linear regression line is 0.84, indicating a moderate positive relationship between the two independent datasets. A mean difference of 0.3 Mt was calculated between the inverse and NIR estimates; however, this difference was not statistically significant, as the confidence interval for the mean difference ranged from -0.01 to 0.6 Mt, indicating that the discrepancy is minimal for this historical 13-year period. However, we emphasize that continued atmospheric monitoring and data collection over the next decade are critical to confirm that the emission targets are being met.

Tracking oil and gas methane emissions consistently and transparently

In Fig. 6, the NIR 5-year average annual emission rates from the Energy sector are depicted as blue, gray and black bars, while ground-based tower atmospheric inverse estimates are depicted in red. Note that the difference between the 2022 NIR and the 2023 NIR is less than 100 kt for the 2010–2019 period. The 2023 NIR indicates an average annual emission rate from the energy sector of 2.1 Mt CH_4 for the 2010–2014 period and 1.9 Mt CH_4 for 2015–2019. In contrast, the 2024 NIR shows higher average annual emission rates, with 2.8 Mt CH_4 for 2010–2014 and 2.5 Mt CH_4 for 2015–2019. Atmospheric inverse estimates from the Energy sector reveal emission rates of 3.1 Mt CH_4 and 2.6 Mt CH_4 for these respective 5-year intervals. The 5-year annual mean (2010–2014) inverse emission estimate for AB and SK is ~ 1.5 times ($=3.1$ Mt/ 2.1 Mt) higher than the 2023 NIR emission rate for the same period. Notably, this ratio was reduced in the 2023 NIR compared to the 2021 NIR, where it was 1.9 times.

Incorporating an additional 0.7 Mt per year for 2010–2014, based on the 2024 NIR emission data, as shown by the light blue bars in Fig. 6 (2024 NIR Improvements), further narrows the gap between inverse emission estimates and the inventory to ~ 1.1 times (or 10%). This reduced difference now falls within our ensemble results' uncertainty range of 23% ($=0.7$ Mt/ 3.1 Mt). Similarly, the energy sector emissions have been adjusted upward by an additional 0.6 Mt per year for the 2015–2019 period, bringing latest inventory estimates more in line with the inverse estimates of 2.6 Mt. As mentioned earlier, Alberta and Saskatchewan collectively accounted for over 86% of Canada's oil and gas methane emissions on average from 2010 to 2022. This means that if the accuracy of methane emissions reporting from the oil and gas sector (primarily upstream sources) is improved, and the industry successfully addresses methane emissions in this sector within these two provinces alone, Canada will effectively mitigate its oil and gas methane emission challenge on a national scale.

Conclusions

We have demonstrated how independent measurements continue to improve official inventories in Canada. The new hybrid framework described in this paper can ensure consistency in historical emission data and enhance Canada's capability to track emission changes in response to current and impending regulations. Canada is a pioneer in incorporating atmospheric measurements from low-altitude aerial surveys to enhance the accuracy of its national oil and gas inventory with source-level details^{16,21,35,36,38,39}. By utilizing continuous, long-term systematic measurements from ground-based towers, coupled with ensemble inverse modeling to account for uncertainties, we can independently ensure the accuracy of regional-level annual oil and gas emission estimates⁹. Our effort aligns with the 2019 Refinement of the 2006 IPCC guidelines, which advocate for integrating atmospheric measurements^{40,41}, and also corresponds with the guiding principles of the World Meteorological Organization's Integrated Global Greenhouse Gas Information System (IG³IS), employing a unified approach that combines atmospheric measurements with inventory data. Furthermore, with the potential establishment of international emissions trading under Article 6 of the Paris Agreement⁴², the verification of emissions will become increasingly important.

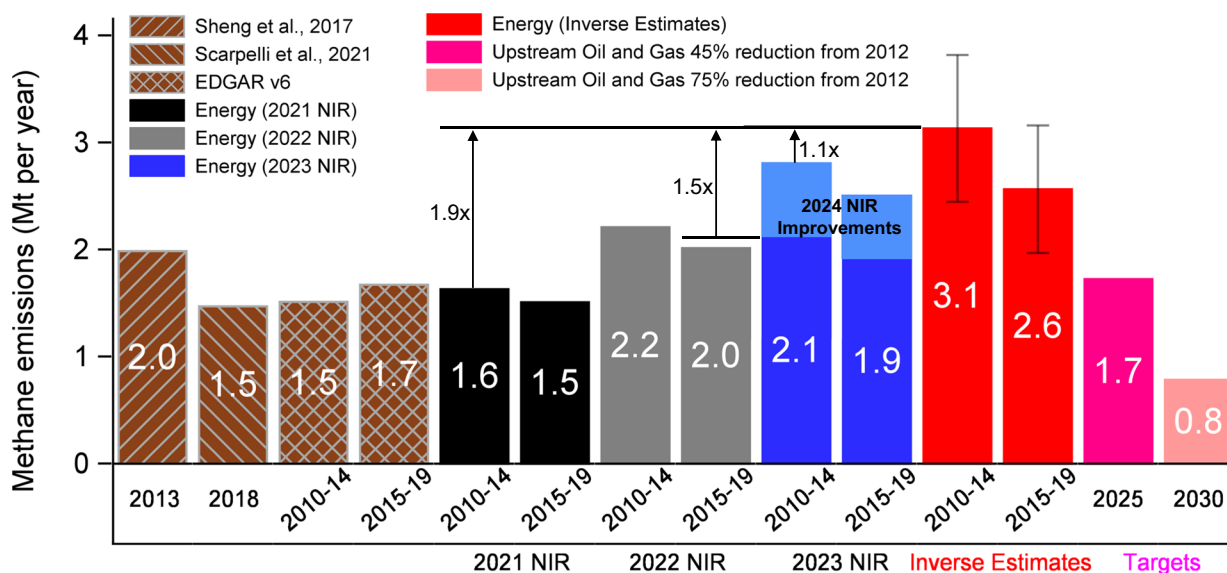


Fig. 6 | Reconciling the methane emission reporting gap in the oil and gas sector of Alberta and Saskatchewan for tracking changes in emissions. This figure illustrates improvements due to major methodological changes for the 2024 oil and gas methane inventory in Canada and the projections (light pink bars) of the ensemble inverse estimates fulfilling the reduction targets by 2025 and 2030. These projections are compared against the 2010–2014 inverse emission baseline, calculated at 3.1 Mt/year. Error bars indicate ± 1 standard deviation of the 5-year mean inverse estimates. The 2024 methodological refinements significantly reduce the gap

between inverse emission estimates and inventory data, shown as upward adjustments in light blue. The figure compares the 5-year mean energy-related methane emissions, primarily from the oil and gas sector, as reported in the 2021 (black), 2022 (gray), and 2023 (blue) NIRs with inverse estimates. The red bars represent emissions based on tower measurement-based inverse estimates. The three spatial distributions of prior emissions used in the ensemble inversions are shown in brown^{47–49}.

The oil and gas industry expects reductions to be reflected in official estimates. However, modeling expected reductions in the inventory is risky without a measurement-based framework for verification. While self-reporting from the industry remains a key source of information, complete reliance on it presents risks for inventory compilers when modeling fugitive methane sources that are not always captured reliably in reported data. Our hybrid framework helps verify industry self-reported emissions and reduction claims. It can also reflect both the efficacy of the government's policy and the collective actions taken by the industry, whether voluntary or mandated by regulations.

Initiating dialog between inventory experts and atmospheric scientists, and fostering long-term collaboration, is crucial to addressing further discrepancies in emission data. Therefore, this paper holds the potential to contribute to the efforts of over 150 nations committed to the Global Methane Pledge, aiming to reduce methane emissions by 2030. Achieving the collective reduction target critically depends on the accuracy of national emission inventories.

Materials and methods

Canada's hybrid oil and gas methane inventories

Recent work by the Energy and Emissions Research Laboratory (EERL) at Carleton University revealed the potential of using Gas Mapping LiDAR (GML) mounted to low altitude flying aircraft to measure methane releases at oil and gas facilities and subsequently used those measurements to produce measurement-based hybrid methane emission inventories^{16,21,35,36,38,39}. EERL conducted measurement campaigns involving thousands of facilities spread across Canada's major oil and gas producing regions in AB, SK, and BC. Combining the GML quantified emission rates, high-resolution visual images of each surveyed site and facility plot plans obtained from Provincial regulators allows for the manual identification of detected sources such as tanks, unlit flares, and compressor buildings. Because of the resolution of aerial GML and the number of facilities surveyed, the measurement-based methane inventories produced by EERL provide robust source-resolved emissions estimates for the various facility configurations in these provinces. Specifically, EERL presents estimates by facility subtype, grouped where necessary, as defined in the Petrinex reporting system³².

Emission factors for specific sources from the EERL measurement-based inventories that may not be currently well characterized in Canada's NIR (i.e., storage tanks, engine sheds, compressor buildings and unlit flares/combustors) are used to improve 2024 NIR estimates for AB and SK (Supplementary Tables 3–5). Since emissions from storage tanks are already included in the NIR, previously estimated emissions from tanks need to be removed to eliminate any double counting. Similarly, EERL's estimates for compressor buildings, including both combustion and fugitive emissions, require careful consideration to avoid redundancy.

Aerial GML surveys are available for AB in 2021, and for SK in 2020 and 2021, meaning the results are directly applicable to those years. To form a complete time series for the aforementioned sources, existing facility and well populations for non-measured years are multiplied by measurement-based facility/well-site methane emission factors. Alternatively, activity data such as oil production, gas production, or reported volumetric data can be used to extrapolate measurement-based methane estimates for non-measured years.

Ensemble inversion method

A regional Bayesian inversion model was used to estimate methane emissions for AB and SK. Bayesian inversion modeling begins with an initial estimate of the spatial emission (prior emissions from existing inventory database) as inputs to an atmospheric transport model to simulate a methane data record. The modeled data are compared to observations to calculate model-observation differences. These differences are then processed by an optimization procedure to estimate the emissions (posterior emissions) that would yield the best match to the observations.

The main components of the inverse modeling method are ground-based tower atmospheric measurements (Supplementary Method 2), atmospheric transport model (Supplementary Method 3.1), boundary

conditions (Supplementary Method 3.2), prior emissions (Supplementary Method 3.3), Bayesian optimization procedure (Supplementary Method 3.4), data selection (Supplementary Method 3.5), inversion region definition (Supplementary Method 3.6). An ensemble has been created to calculate multiple inverse emission estimates using different transport models, different prior emissions, different optimization procedures and region definition setups to provide a more inclusive estimate of the uncertainties in the results.

Compared to our previous eight-year inversion study⁹, which relied on 2 atmospheric transport models, our current research spans 13 years, assessing 9 transport models with core results derived from 4. This study expands upon the previous one by incorporating an additional optimization method and applying multiple techniques to estimate boundary conditions. To further evaluate the inversion results, Supplementary Method 5 provides an analysis of the model performance. Supplementary Method 6 presents emission estimate validations, and Supplementary Method 7 details the availability of ground-based tower measurement data for the inversions. Additionally, we conducted a more comprehensive robustness analysis of the emission estimates using three spatial definitions for the inversions to calculate scaling factors (see Supplementary Method 8).

Inverse estimates of annual total anthropogenic methane emissions

Canada's NIR annually reports greenhouse gas emissions. Given the minor seasonal fluctuations in emission estimates, it is reasonable to average the annual inverse estimates using measurement data from cold months of January–March and November–December to align with the timeframe of the NIR. The methane contribution from natural sources (mainly wetlands) for the 5-month period in these mid-latitude western regions in Canada was negligible (Supplementary Method 4). In the oil and gas sector, the most significant seasonal variation could arise from the use of chemical injection pumps in winter to prevent hydrate formation. Reports prepared for the Alberta Energy Regulator indicated that these pumps were used in roughly half of the wells, resulting in a slight winter bias increase of 0.12 Mt CH₄ per year⁴³. Monthly oil and gas production volumes tend to remain consistent throughout the year^{44,45}. In agriculture, there might be a slight decrease in emissions during winter due to a 10% reduction in cattle populations compared to summer⁴⁶. Since the emissions from waste are minimal, the impact of the seasonal variations would also be negligible. To summarize, the impact of any seasonal biases is considerably small when considered in the context of the broader multi-year averages and the overall uncertainties associated with the core findings of inverse modeling results.

Monte Carlo simulations to derive oil and gas inverse emission estimates

Forty-eight ensemble estimates of inverse annual total anthropogenic emissions were calculated with 3 prior emissions, 2 cold periods, 2 inversion methods, and 4 transport models except for 2022 in that only 3 transport models were available. A MC analysis with 1000 simulations was used to derive oil and gas emissions from the inverse annual total anthropogenic emissions. This analysis propagated uncertainties in prior emissions, atmospheric transport, optimization methods, and varying cold periods within the inversions. As a result, we derived 48,000 oil and gas emission estimates annually by deducting emissions from agriculture (livestock) and waste (landfills) from the total inverse anthropogenic estimates. We subtracted different combinations of agricultural and waste emissions through the MC simulations, using a normal distribution with means based on NIR data for agriculture and waste emissions, and standard deviations representing uncertainties of 25% and 100%, respectively. The overall uncertainty for the 2010–2014 average oil and gas emission estimates has increased marginally, from 0.7 Mt/year to 0.73 Mt/year (± 1 STD), as a result of this MC analysis. This indicates that the uncertainty bands shown in Fig. 5, which aggregate the individual uncertainties from the mentioned inverse model components, remain essentially consistent following the MC simulations.

Data availability

The Canada's NIR emission data files used in this manuscript are available from <https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory?lang=en>, and ERA5 data from <https://confluence.ecmwf.int/display/CKB/How+to+download+ERA5> and <https://cds.climate.copernicus.eu>. Tower-based atmospheric inversion estimates are available from <https://github.com/Elton-Ch/hybrid-inventory/>. The tower-based atmospheric measurement data used in the inversions are available from <https://gaw.kishou.go.jp/>.

Code availability

SAS- and Fortran-language scripts used for inversions are available from Github: <https://github.com/Elton-Ch/hybrid-inventory/>, the FLEXPART model from <https://www.flexpart.eu/>, and the HYSPLIT model from <https://www.ready.noaa.gov/HYSPLIT.php>.

Received: 24 April 2024; Accepted: 24 September 2024;

Published online: 07 October 2024

References

- Katzenstein, A. S., Doezeema, L. A., Simpson, I. J., Blake, D. R. & Rowland, F. S. Extensive regional atmospheric hydrocarbon pollution in the southwestern United States. *Proc. Natl. Acad. Sci. USA* **100**, 11975–11979 (2003).
- Allen, D. T. et al. Measurements of methane emissions at natural gas production sites in the United States. *Proc. Natl. Acad. Sci. USA* **110**, 17768–17773 (2013).
- Miller, S. M. et al. Anthropogenic emissions of methane in the United States. *Proc. Natl. Acad. Sci. USA* **110**, 20018–20022 (2013).
- Brandt, A. R. et al. Methane leaks from North American natural gas systems. *Science* **343**, 733–735 (2014).
- Pétron, G. et al. A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin. *J. Geophys. Res.* **119**, 6836–6852 (2014).
- Barkley, Z. R. et al. Forward modeling and optimization of methane emissions in the south central United States using aircraft transects across frontal boundaries. *Geophys. Res. Lett.* **46**, 13564–13573 (2019).
- O'Connell, E. et al. Methane emissions from contrasting production regions within Alberta, Canada: implications under incoming federal methane regulations. *Elementa* **7**, 3 (2019).
- Johnson, M. R., Tyner, D. R., Conley, S., Schwietzke, S. & Zavala-Araiza, D. Comparisons of airborne measurements and inventory estimates of methane emissions in the Alberta upstream oil and gas sector. *Environ. Sci. Technol.* **51**, 13008–13017 (2017).
- Chan, E. et al. Eight-year estimates of methane emissions from oil and gas operations in western Canada are nearly twice those reported in inventories. *Environ. Sci. Technol.* **54**, 14899–14909 (2020).
- Deng, Z. et al. Comparing national greenhouse gas budgets reported in UNFCCC inventories against atmospheric inversions. *Earth Syst. Sci. Data* **14**, 1639–1675 (2022).
- Gorchov Negron, A. M. et al. Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production. *Proc. Natl. Acad. Sci. USA* **120**, e2215275120 (2023).
- Rutherford, J. S. et al. Closing the methane gap in US oil and natural gas production emissions inventories. *Nat. Commun.* **12**, 1–12 (2021).
- Johnson, D. et al. Methane emissions from oil and gas production sites and their storage tanks in West Virginia. *Atmos. Environ.* **X** **16**, 100193 (2022).
- Alvarez, R. A. et al. Assessment of methane emissions from the U.S. oil and gas supply chain. *Science* **361**, 186 LP–186188 (2018).
- Seymour, S. P., Xie, D., Li, H. Z. & MacKay, K. Sources and reliability of reported methane reductions from the oil and gas industry in Alberta, Canada. *Elementa* **10**, 00073 (2022).
- Festa-Bianchet, S. A., Tyner, D. R., Seymour, S. P. & Johnson, M. R. Methane venting at cold heavy oil production with sand (CHOPS) facilities is significantly underreported and led by high-emitting wells with low or negative value. *Environ. Sci. Technol.* **57**, 3021–3030 (2023).
- Seymour, S. P., Li, H., MacKay, K., Kang, M. & Xie, D. Saskatchewan's oil and gas methane: how have underestimated emissions in Canada impacted progress toward 2025 climate goals? *Environ. Res. Lett.* **18**, 084004 (2023).
- Hmiel, B. et al. Empirical quantification of methane emission intensity from oil and gas producers in the Permian basin. *Environ. Res. Lett.* **18**, 024029 (2023).
- Duren, R. M. et al. California's methane super-emitters. *Nature* **575**, 180–184 (2019).
- Lauvaux, T. et al. Global assessment of oil and gas methane ultra-emitters. *Science* **375**, 80 (2022).
- Tyner, D. R. & Johnson, M. R. Where the methane is—insights from novel airborne LiDAR measurements combined with ground survey data. *Environ. Sci. Technol.* **55**, 9773–9783 (2021).
- Environment and Climate Change Canada. National Inventory Report: Greenhouse Gas Sources and Sinks in Canada. National Inventory Report 1990–2021: Greenhouse Gas Sources And Sinks In Canada (Government of Canada, 2023).
- Environment and Climate Change Canada. Technical Backgrounder: Federal methane regulations for the upstream oil and gas sector - Canada.ca. (2018).
- Environment and Climate Change Canada. *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*. (2018).
- Environment and Climate Change Canada. *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds*. *Sor/2018-66* (2018).
- Environment and Climate Change Canada. *National Inventory Report: Greenhouse gas sources and sinks in Canada, Section 2.3.1.3* (2023).
- Government of Canada. Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) Unofficial Version. Available at: [https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/81000-2-5163-CGI-Unofficial Version Non Officielle.pdf](https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/81000-2-5163-CGI-Unofficial%20Version%20Non%20Officielle.pdf). (Accessed: 11th December 2023) (2023).
- Government of Alberta. Reducing methane emissions | Alberta.ca. Available at: <https://www.alberta.ca/climate-methane-emissions.aspx> (Accessed: 28th June 2019) (2016).
- Government of Saskatchewan. Saskatchewan Enacts Regulations With Goal To Reduce Methane Emissions By 4.5 Million Tonnes Annually | News and Media | Government of Saskatchewan. Available at: <https://www.saskatchewan.ca/government/news-and-media/2019/january/23/methane-action-plan> (Accessed: 28th June 2019) (2019).
- MacKay, K., Seymour, S. P., Li, H. Z., Zavala-Araiza, D. & Xie, D. A Comprehensive integration and synthesis of methane emissions from Canada's oil and gas value chain. *Environ. Sci. Technol.* <https://doi.org/10.1021/acs.est.4c03651> (2024).
- Eggleston, S., Goodwin, J., Irving, W., Penman, J. & Woodfield, M. IPCC Guidelines for National Greenhouse Gas Inventories. *Vol 1*, Available at: <https://www.ipcc-nggip.iges.or.jp/public/2006gl/vol1.html> (Accessed: 12th December 2023) (2006).
- Petrinex. Available at: <https://www.petrinex.ca/overview/Pages/Overview.aspx> (Accessed: 24th October 2023).
- OneStop | Alberta Energy Regulator. Available at: <https://www.aer.ca/regulating-development/project-application/onestop> (Accessed: 27th October 2023).
- Environment and Climate Change Canada. National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, Part 2, Annex 3.2. Available at: <https://publications.gc.ca/site/eng/9.506002/publication.html>, En81-4-2022-2-eng.pdf. (Accessed: 9th August 2024) (2024).
- Johnson, M. R., Tyner, D. R. & Conrad, B. M. Origins of oil and gas sector methane emissions: on-site investigations of aerial measured sources. *Environ. Sci. Technol.* **57**, 2484–2494 (2023).

36. Conrad, B. M., Tyner, D. R., Li, H., Xie, D. & Johnson, M. R. Measurement-based methane inventory for upstream oil and gas production in Alberta, Canada reveals higher emissions and starkly different sources than official estimates. *Commun. Earth Environ.* (2023).
37. Canadian oil output to hit new heights within two years, report says | CBC News. Available at: <https://www.cbc.ca/news/canada/calgary/trans-mountain-pipeline-deloitte-canada-report-1.6987896> (Accessed: 27th October 2023).
38. Office of the Auditor General of Canada. Reports of the Commissioner of the Environment and Sustainable Development to the Parliament of Canada Emission Reductions Through Greenhouse Gas Regulations—Environment and Climate Change Canada Independent Auditor's Report | 2023. Report 5, Section 5.78. Available at: https://www.oag-bvg.gc.ca/internet/docs/parl_cesd_202304_05_e.pdf. (Accessed: 14th December 2023) (2023).
39. Johnson, M. R., Tyner, D. R. & Szekeres, A. J. Blinded evaluation of airborne methane source detection using Bridger Photonics LiDAR. *Remote Sens. Environ.* **259**, 112418 (2021).
40. IPCC. 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories—IPCC. Available at: <https://www.ipcc.ch/report/2019-refinement-to-the-2006-ipcc-guidelines-for-national-greenhouse-gas-inventories/>. (Accessed: 19th September 2023) (2019).
41. IPCC. IPCC Expert Meeting on Use of Atmospheric Observation Data in Emission Inventories Task Force on National Greenhouse Gas Inventories. Available at: <https://www.ipcc-nggip.iges.or.jp>. (Accessed: 18th September 2023) (2022).
42. UNFCCC. The Paris Agreement | UNFCCC. Available at: <https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement>. (Accessed: 1st April 2020).
43. Clearstone Eng. Ltd. *Inventory of Atmospheric Emissions from Heavy Oil Production Facilities in the Three Creeks Area*. (2015).
44. National Energy Board. Marketable natural gas production in Canada. Available at: <http://www.neb-one.gc.ca/clf-nsi/rnrgynfmrtn/sttstc/mrktblntrlgspdrctn/mrktblntrlgspdrctn-eng.html>. (Accessed: 3rd September 2019) (2012).
45. Budgell, P. Estimated Production of Canadian Crude Oil and Equivalent. *National Energy Board*. Available at: <https://www.neb-one.gc.ca/nrg/sttstc/crdlndpdr/mrpdct/stt/stmtdprdrctn-eng.html#>. (Accessed: 3rd September 2019) (2015).
46. Statistics Canada, Government of Canada. CANSIM—003-0032—Number of cattle, by class and farm type. Available at: <http://www5.statcan.gc.ca/cansim/a05?lang=eng&id=0030032&pattern=0030032&searchTypeByValue=1&p2=35> (Accessed: 3rd September 2019) (2014).
47. Sheng, J. X. et al. A high-resolution ($0.1^\circ \times 0.1^\circ$) inventory of methane emissions from Canadian and Mexican oil and gas systems. *Atmos. Environ.* **158**, 211–215 (2017).
48. Scarpelli, T. R., Jacob, D. J., Moran, M., Reuland, F. & Gordon, D. A gridded inventory of Canada's anthropogenic methane emissions. *Environ. Res. Lett.* **17**, 014007 (2021).
49. Crippa, M. et al. EDGAR v6.0 Greenhouse Gas Emissions. European Commission, Joint Research Centre (JRC) [Dataset] PID. Available at: <http://data.europa.eu/89h/97a67d67-c62e-4826-b873-9d972c4f670b> (2021).

Acknowledgements

The authors extend their gratitude to Robert Kessler and Lauriant Giroux for their decades-long commitment to maintaining the Environment and Climate Change Canada (ECCC) greenhouse gas monitoring network and to Larry Flanagan at the University of Lethbridge for providing operational support of our program at their observational site. We also thank Dr. Andy Delcloo from the Royal Meteorological Institute of Belgium for his expertise

with the ECMWF-FLEXPART model simulations. Special thanks to Dr. Chris Loughner from the Atmospheric Sciences Modelling Division, NOAA Air Resources Laboratory, for his guidance with the HYSPLIT model simulations. We appreciate the support of the CarbonTracker Lagrange (CT-L) program team at NOAA and the NASA's Arctic Boreal Vulnerability Experiment (ABOVE) project for providing the WRF-STILT footprint data. Additionally, we appreciate valuable comments on the manuscript by Drs. John Liggio and Ralf Staebler of ECCC. We are grateful for the insights provided by Dr. Greg Flato and Mr. Lindsay Pratt to significantly improve the manuscript.

Author contributions

E.C. designed the project, conducted atmospheric simulations, inverse modeling, statistical analyses, and produced the figures. E.C. and F.V. developed the project scope. E.C., F.V., S.S., and O.B. co-wrote the paper. S.S. and O.B. compiled and refined the national oil and gas methane inventories. M.I. developed the cost function minimization method and extracted boundary conditions for the inverse models. J.K. ran the GEM model and provided the meteorological data to drive the FLEXPART model. M.N. automated the HYSPLIT model simulations. D.C. contributed to the inversion setups and interpretation of the results. D.W. managed the ground-based greenhouse gas measurement network and performed data quality control. All authors participated in project discussions, edited the manuscript, and approved the final version.

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/s43247-024-01728-6>.

Correspondence and requests for materials should be addressed to Elton Chan or Felix Vogel.

Peer review information *Communications Earth & Environment* thanks Kushal Tibrewal and Luke Dubey for their contribution to the peer review of this work. Primary Handling Editors: Alice Drinkwater. A peer review file is available.

Reprints and permissions information is available at <http://www.nature.com/reprints>

Publisher's note Springer Nature remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

Open Access This article is licensed under a Creative Commons Attribution 4.0 International License, which permits use, sharing, adaptation, distribution and reproduction in any medium or format, as long as you give appropriate credit to the original author(s) and the source, provide a link to the Creative Commons licence, and indicate if changes were made. The images or other third party material in this article are included in the article's Creative Commons licence, unless indicated otherwise in a credit line to the material. If material is not included in the article's Creative Commons licence and your intended use is not permitted by statutory regulation or exceeds the permitted use, you will need to obtain permission directly from the copyright holder. To view a copy of this licence, visit <http://creativecommons.org/licenses/by/4.0/>.

© Crown 2024