Methane emissions from conventional and unconventional oil and gas production sites in southeastern Saskatchewan, Canada

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Abstract

Energy development in southeastern Saskatchewan, Canada, is unique because conventional and unconventional oil and gas production is co-located. Mobile surveys are ideal for understanding emissions in this area because the overlap of production makes it difficult for airborne or satellite-based methods to differentiate emissions from each type of infrastructure. In this study, we conducted truck-based mobile surveys in the unconventional Canadian Bakken and conventional Weyburn-Midale fields to enumerate and attribute individual methane plumes, estimate methane (CH₄) emission rates, and compare emission vectors. We sampled downwind of 645 conventional and 289 unconventional sites, covering over 4500 km of public roads. We found that 28% of surveyed conventional sites were emitting, compared to 32% of surveyed unconventional sites. Mean emissions intensities in each development were 20 m³CH₄/day per conventional site and 59 m³CH₄/day per unconventional site. Emissions intensities in southeastern Saskatchewan fall on the lower range of other emissions estimates from developments in the US and Canada.

Introduction

The volume of methane (CH₄) vented, flared, and leaked from oil and natural gas production is important to quantify because it represents wasted potential energy and contributes directly to greenhouse warming. Methane has an estimated global warming potential of ~25 over 100 years (US Environmental Protection Agency US EPA 2017). Recently, researchers have worked to quantify CH₄ emissions from the oil and gas sector using aircraft (e.g. Peischl et al. 2016, Peischl et al. 2018), and also facility-level inspections (Allen et al. 2013, GreenPath Energy Ltd 2016). This work has established that CH₄ inventory estimates for North American developments are sometimes accurate (Karion et al. 2015, Peischl et al. 2015), and sometimes underestimated (Pétron et al. 2012, Karion et al. 2013, Peischl et al. 2013, Brandt et al. 2014, Pétron et al. 2014, Atherton et al. 2017, Zavala-Araiza et al. 2018). On a global basis, the change in CH₄ isotopes over time suggests that CH₄ inventories are underestimated by 20 to 60 percent (Schwietzke et al. 2016). Sources with uncharacteristically large emissions (super-emitters) are a potential source for the discrepancy between estimated inventories and measured volumes (Karion et al. 2013). These super-emitters often represent a small fraction of emitters, but account for a large fraction of the total measured emissions, attributing to heavy-tailed emissions distributions (Brandt et al. 2016a, Alvarez et al. 2018).

Some studies have attributed recent increases in atmospheric CH₄ to the boom in unconventional petroleum production from low-permeability reservoirs (Schneising et al. 2014). Though some emissions are associated with the process of hydraulic fracturing (Howarth 2015), the period of increased emissions during flowback is short, and there is little evidence to suggest that unconventional developments have greater lifetime emissions than conventional developments. Increases in emission footprints may simply be the result of more oil and gas production activity. Methane emissions from hydrocarbon development in North America have fallen in the past decade (Schwietzke et al. 2016), indicating that new developments emit less as a proportion of
production because of better infrastructure and practice. However, direct comparative studies are difficult because unconventional and older, conventional developments are rarely co-located.

The Bakken formation is a low-permeability oil-rich formation that extends from southeastern Saskatchewan, Canada to North Dakota, US. In Saskatchewan, the Bakken formation exists alongside conventional oil production from the shallower Weyburn-Midale and Frobisher formations. This area is an excellent region to compare CH$_4$ emissions from different production styles because unconventional and conventional developments are co-located in a relatively accessible landscape (Bakken located to the east, and Weyburn-Midale to the west). They are also serviced by many of the same companies, and have similar aboveground infrastructure. In addition, emission inventories for the US portion of the Bakken are uncertain, and estimates vary by nearly 10-fold. For example, airborne campaigns by Peischl et al (2016) over the US Bakken found that the average CH$_4$ emission rates exceeded EPA estimates by 5–8 times, but were 4 times lower than satellite-generated estimates by Schneising et al (2014) for the US and Canadian Bakken. Peischl et al (2018) found that CH$_4$ emissions attributed to O&G operations in the Bakken region were constant between May 2014 (Peischl et al 2016) and April 2015, where emissions were calculated to be 26.5 ± 6.5 tonnes CH$_4$/hr and 28 ± 7 tonnes CH$_4$/hr, respectively. Furthermore, facility-level contributions cannot be quantified from airborne measurements, making recommendations for improving best practice difficult.

In this study, we used extensive and replicated truck-based survey campaigns in the unconventional Canadian Bakken and conventional Weyburn-Midale fields to enumerate and attribute individual CH$_4$ plumes, estimate emission rates, and compare emission vectors. To our knowledge this is the first direct comparison study between co-located conventional and unconventional oil and gas developments.

**Methods**

Our study focused on a 20 000 km$^2$ area of southeastern Saskatchewan, centered near the town of Midale (figure 1). The area of interest contains more than 30 000 pieces of oil and gas infrastructure, and has been exploited for oil and gas production since the 1960s (Brown et al 2017).

We conducted mobile surveys on eight pre-planned routes: five through areas dominated by conventional development, and three through areas dominated by unconventional development. In addition, a control route was surveyed in August 2015, located in a region with minimal infrastructure to determine the probability of detecting false positives. We surveyed each of the routes 2–4 times.

We sorted infrastructure (including active and suspended wells, storage tanks, and production facilities) to the wellpad-scale by combining those within 90 m of each other. We categorized these sites as either unconventional (Bakken and Torquay) or conventional (Weyburn-Midale, Frobisher, Alida, etc). In total, there were 14 167 pieces of infrastructure grouped to 9910 sites. 7308 (73.74%) of the sites were conventional and 2602 (26.26%) were unconventional. Our separation of conventional and unconventional development is based on the geologic formation from which the oil and / or gas is extracted. Therefore, the extractive methods employed by oil and gas companies in our two groups are not necessarily different (e.g. hydraulic fracturing occurs in both), but our method of separation does capture the difference between conventional and tight resource development. A total of 28 surveys took place between October and November 2015. During conventional surveys, we sampled 645 sites over 2824 km, and during unconventional surveys, we sampled 289 sites over 1681 km. Sites were considered sampled when they met the criteria of being upwind and within 325 m of the mobile survey truck on at least two passes.
The truck was equipped with a high volume (7 LPM) air pump, which brought air from an inlet at 1 m height through 6 mm outer-diameter Vinyl-Flex PVC to spectroscopic trace gas analyzers in the bed of the truck. The gas analyzers included a Picarro G2201-i which measured CO₂, CH₄, δ¹³C, and H₂O, and a Teledyne T101 UV Fluorescence analyzer which measured H₂S. Control surveys were conducted using an LGR Ultraportable Greenhouse Gas Analyzer in place of the Picarro G2201-i, and Picarro G2201-i data were filtered to be within the minimum detection limit of the LGR UGGA. Climate data were collected from hourly historical weather archives from Environment and Climate Change Canada stations in Weyburn and Estevan, SK (Environment and Climate Change Canada ECCC 2015). Gas measurements and geolocations from a Garmin GPS were collected at 1 Hz while driving. Since the analyzer pumps into the cavity continually, measured mixing ratios are instantaneous values, but represent line-integrated averages for segments of roughly 8 m–19 m given our typical transit speed of 30–70 kmh⁻¹. Gas measurements were corrected for lag times between the intake filter and the gas analyzers.

The survey data was analyzed to isolate CH₄-rich plumes from the varying ambient atmospheric levels using ratios of super-ambient (or ‘excess’, denoted by ‘e’) CO₂ and CH₄ (eCO₂:eCH₄). The gas ratio approach has been used previously by Atherton et al (2017), Williams et al (2018), and O’Connell et al (2019), though the most complete explanation is presented in Hurry et al (2016). Ambient atmospheric CO₂ and CH₄ vary spatiotemporally due to factors such as atmospheric stability, land-use types, and topography. The approach separates oilfield emissions from combustion sources, or natural anomalies that might be present in depressions or in treed areas where atmospheric mixing is poor. Oilfield sources will have significant eCH₄ relative to eCO₂, because methane is a major component of oilfield emissions relative to CO₂. Oilfield emissions therefore push the eCO₂:eCH₄ ratio to a numerically low value (large denominator). Conversely, the ratio of eCO₂ to eCH₄ is generally unchanged from that of the local atmosphere in areas of natural pooling, because ecosystem-emitted gases collect in natural proportion to one another, meaning the natural ratio is unaltered. To account for these natural variations, the method considers the minimum value of each gas within a moving time window to be representative of background levels for that part of the survey. The size of the window is optimized for each survey to account for the respective level of variance (Atherton et al 2017).

We used kernel density plots of eCO₂:eCH₄ from aggregated survey data to determine the target excess ratio for oilfield plume detection as in Atherton et al (2017). The selected target ratio for emissions from conventional and unconventional developments was eCO₂:eCH₄ < 135. Sites were determined to be emitting when CH₄-enriched plumes (eCO₂:eCH₄ < 135) lasting > 2 s were located downwind and within 325 m of a site. The site had to be emitting on >50% of at least two survey passes, which indicated that these plumes were persistent/continuous emitters, and that plumes were present at the same location on multiple days. In our study, we used a maximum detection distance of 325 m because it was the typical distance of sites from public roads, and also allowed our attribution process to exclude more distant sources that were less likely to explain the detected emissions.

We used a point-source Gaussian Dispersion Model (GDM) (Bosanquet and Pearson 1936, Sutton 1953, Pasquill 1974, Stern 1976, De Visscher 2013) to estimate CH₄ emission rates. Other transect-based mobile dispersion studies (Rella et al 2015, Yacovitch et al 2015, Caulton et al 2017) often integrate observed concentration enhancements across the entire width of the plume. The integration method is suitable so long as certain conditions can be satisfied, such as the emission source height being within range of the sampling inlet height, signal to noise from the background is sufficient to fully resolve the plume edges, and the transect is perpendicular downwind of the plume. The plume centreline GDM approach used in this study is a useful alternative when such conditions can’t be guaranteed (O’Connell et al 2019, S3.2). The GDM closely resembled the ‘screening’ method described in the Saskatchewan Air Quality Modeling Guideline (Saskatchewan Ministry of Environment 2012). We estimated emission rates for fixed-rate single sources using the 2D CH₄ enhancement at the plume centerline (maximum eCH₄ measurement in plume, corrected for dilution caused by short plume exposure times), the estimated emission release height(s), the distance to the source, and estimates of Pasquill atmospheric stability using local meteorological data, with downwind sigma values based on Turner (1994) emission rate estimates. Volumetric CH₄ emission rates in m³/day were calculated under conditions of 15 °C and 1 atm. We determined Pasquill-Gifford stability classes (Pasquill 1961) from ECCC archives on atmospheric cloudiness. Equations that fit the Pasquill-Gifford curves (Turner 1970) were used to calculate the dispersion parameters. Volumetric CH₄ emission rates presented in this study were the average of 1–12 downwind plume transects, depending on the site. We also estimated an emissions rate Minimum Detection Limit (MDL) for the campaign by taking the 5th percentile of maximum eCH₄ for attributed plumes (0.01 ppm) and inputting it into the dispersion model, giving an estimate of the smallest emission rate we could have detected at each site under the respective meteorological conditions.
Uncertainty

There are three distinct sources of uncertainty associated with using mobile surveying to characterize oil and gas emissions: (1) isolating methane plumes associated with oil and gas infrastructure, (2) attributing the methane plumes to the correct source upwind, and (3) estimating emission rates.

To establish that we were isolating oil and gas methane plumes correctly, we collected 17 187 geo-located wind and gas measurements along a control route in an area of minimal oil and gas development, of which only 306 were considered methane-rich and anomalous (eCO₂:eCH₄ < 135). Most of the false positives were located randomly and observed once. Because these plumes were not observed repeatedly in the same location, they would not be classified as CH₄ emissions by our criteria. Some plumes, however, were clearly sourced from infrastructure that produces similar emissions as oil and gas operations (e.g. gas stations). In a similar study, Atherton et al (2017) showed with extensive control routes that the eCH₄:eCO₂ approach virtually eliminated false positives in regional campaigns. Overall, our control route surveys indicated that the likelihood of false positives is very low.

Our confidence in CH₄ plume attribution is directly correlated with the spatial density of oil and gas sites, as well as the spatial overlap of conventional and unconventional production. Geospatial uncertainties affect our understanding of source type, because plumes originating from further upwind may be inaccurately attributed to an oil and gas site closer to the point of measurement. To account for this possibility, we approximated attribution confidence as 1/n (where n is the total number of sites upwind and within 325 m of the location at which the plume was detected). For plumes that were attributed to conventional sites, 89% of the sites that were upwind and within 325 m were also conventional. For plumes that were attributed to unconventional sites, 35% of sites upwind and within 325 m were also unconventional, so a greater possibility exists of mis-attributing plumes to unconventional sites. We are therefore more confident that we correctly attributed plumes originating from conventional sites. However, we sampled downwind of sites up to 12 times, from multiple angles, to increase our confidence that we attributed plumes to the correct source type. Our mean estimated geospatial attribution confidence was 67%.

O’Connell et al (2019) covers an extensive Supplement on CH₄ emission rate uncertainty using the same transect-based technique as this study. The supplement describes results from empirical controlled release experiments performed over 5 days involving ~120 downwind measurements under environmental conditions representative of our study environment, and across atmospheric stability classes C and D. O’Connell et al (2019) presents a full uncertainty profile, but in general the Standard Error for CH₄ emission rates were found to be ~63%. O’Connell et al (2019) noted a slight upward bias (+30%) for mean rates measured by 3 passes, in bootstrapped analysis of the entire study distribution, because on very rare occasions the technique overestimated emissions by as much as 200%–300% which had a large effect on the mean. For individual measurements, however, the probability of upwards bias is unlikely, because on about two-thirds of the measurements, rates were actually underestimated slightly. Emission rate estimation errors have been addressed in other transect-based studies (Day et al 2014, Feitz et al 2018), showing that replicated estimates are generally within 60% of the actual release rate, though individual estimates can vary by 200%. Other dispersion-based studies have documented similar levels of uncertainty on individual measurements (Brantley et al 2014) involving temporal replication over 20 min. These uncertainties seem large, but are modest relative to the range in emission rates observed in an oilfield, where the largest sources can emit >100 000% that of the smallest.

Sensitivity tests with the Gaussian model show that the largest source of uncertainty in our dispersion modelling was not centerline mixing ratio, but emission source height. In this study it was not possible to identify the specific emitting source on each pad, nor did we have access to probabilistic data that would allow us to assume an emission height. Therefore, we calculated volumetric emission rates for each possible source height present at each site, and reported the mean rate. Error bars in figure 2 represent the range of emission rates for each site due to the range in emission source heights. For uncertainties on development-wide emission rate estimates, we used the process described in Zavala-Araiza (2018), which involves bootstrap resampling to calculate a 95% confidence interval for the mean. Our method departed in only one aspect, as we did not adjust the distribution of field measurements using a bottom-up calibration distribution, because one was not available for this regional study.

Results and discussion

Ambient air characteristics

In total, 228 135 geo-located multi-datapoints were recorded on the survey routes, and we sampled downwind of 982 sites a minimum two times. The mean ambient CH₄ measurement was 1.96 ppm (σ = 0.19 ppm,
n = 228 (135) on the survey routes, and 1.89 ppm on the control route (σ = 0.01 ppm, n = 17 187). Overall, ambient values on survey routes were slightly elevated in CH4, CO2, and H2S compared to the control routes.

Ambient values collected on mobile campaigns provide a regional snapshot of air quality. In our survey area, mean CH4 measurements were not appreciably higher than the reported annual global mean in 2015 of 1.83 ppm CH4 (Dlugokencky 2017). Ambient CH4 in the Midale/Bakken region was similar to those recorded in another mobile study within the British Columbia Montney shale gas formation, at 1.897 ppm, σ = 0.084 ppm (Atherton et al 2017). In the Denver-Julesburg Basin, which contains 54 000 oil and gas wells in a 60 000 km² region (Sherwood et al 2016), mobile surveys documented CH4 levels between 1.80 ppm and 1.84 ppm (Petron et al 2012). In the Barnett Shale development (15 000 shale gas wells in a 13 000 km² region), ambient CH4 has been documented to be as high as 11.99 ppm (Rich et al 2014).

Emission frequency

A higher percentage of unconventional sites were found to be emitting than conventional sites, though we sampled more conventional sites overall. We found that 28% (n = 179) of sampled conventional sites were emitting, compared to 32% (n = 93) of unconventional sites. Sites were considered emitting when CH4-enriched plumes lasting >2 s were located downwind and within 325 m of a site on >50% of at least two survey passes. We detected CH4-enriched plumes every time we sampled downwind of 19% of conventional (n = 122) and unconventional (n = 55) sites, which suggests that these emissions were consistent (rather than episodic) emitters. Emission detections are limited by wind direction on the day of surveying, as well as accessibility due to public road networks. Depending on our distance to the source, it is also possible that we could not detect emissions originating from tall sources (such as flares). We repeated surveys on multiple days to account for varying wind directions, but some emission sources might have been missed and therefore our emission frequencies are potentially somewhat higher than reported above. During our campaigns, unconventional and conventional sites were sampled at a mean distance of 165 m and 228 m, respectively.

Emission frequencies vary significantly across studies, and between developments. In an optical gas imaging (OGI) study by GreenPath Energy Ltd (2016), 11.3% of infrastructure (n = 62) in Medicine Hat, AB was found to be emitting. Mobile surveys in the Montney shale gas region found 34.5% of wells and 32% of facilities to be emitting (Atherton et al 2017). OGI surveys in CHOPS (cold heavy oil production with sand) regions in Bonnyville, AB found 56.9% of 395 surveyed wells and/or facilities to be emitting, 99% of which were from venting-related sources (GreenPath Energy Ltd 2016). In the North Dakota Bakken (unconventional oil), OGI helicopter surveys found that 9% of battery vents (n = 170), 84% of battery hatches (n = 61), and 13.8% of wellpads (n = 94) had associated emissions, the highest emission frequency of all seven basins surveyed (Lyon et al 2016). However, it should be noted that OGI cameras used at that distance are well suited only for observing...
Table 1. Surveyed infrastructure types, the number of times each infrastructure type was sampled downwind, and the fraction of emitting sites containing each infrastructure type. In the survey region there were 9910 sites—7308 classified as conventional and 2602 unconventional. Of those, we sampled 645 conventional and 289 unconventional sites.

| Infrastructure type | Sampled (N) | Fraction of emitting sites containing each infrastructure type |
|---------------------|-------------|-------------------------------------------------------------|
| **Unconventional**   |             |                                                             |
| Oil Well             | 1317        | 88%                                                         |
| Battery              | 246         | 16%                                                         |
| Satellite            | 100         | 8%                                                          |
| Suspended Oil Well   | 83          | 10%                                                         |
| Injection Plant      | 38          | 2%                                                          |
| Terminals            | 10          | 1%                                                          |
| **Conventional**     |             |                                                             |
| Oil Well             | 1693        | 25%                                                         |
| Suspended Oil Well   | 589         | 26%                                                         |
| Battery              | 515         | 61%                                                         |
| Satellite            | 152         | 7%                                                          |
| Injection Plant      | 138         | 6%                                                          |
| Gas Injector         | 106         | 4%                                                          |

gross leaks. Since an OGI camera is a qualitative detection technique, we can expect to see lower emission frequencies reported than with mobile-based techniques, which have a lower MDL than OGI.

**Site characteristics**

Surveyed sites were host to a variety of infrastructural types, including oil wells, satellites, and batteries. Overall, emitting unconventional sites had slightly more infrastructure per site ($\mu = 1.60$, $\sigma = 0.89$) than emitting conventional sites ($\mu = 1.40$, $\sigma = 0.65$) (table 1).

Of the 93 emitting unconventional sites, 88% included wells, and 22 had $>1$ well ($\mu = 1.18$, $\sigma = 0.74$). Multi-well sites are common in this region and also the North Dakota Bakken, where multiple horizontal wells on the same pad increase the economic potential of unconventional oil (Shrestha et al. 2017). At the well, emissions may originate from fugitive or vented sources at the wellhead stuffing box, or via surface casing vent flow (Lackey et al. 2017).

Storage tank batteries were present at 61% of emitting conventional sites, whereas only 16% of emitting unconventional sites had batteries. This suggests that in the conventional area, batteries were more likely to be an emissions vector. Other studies have shown significant emissions from tank batteries as well (Brantley et al. 2014, Mitchell et al. 2015). A helicopter-based OGI study by Lyon et al. (2016) showed 93% of emissions detected in the Bakken were attributed to tank vents or hatches.

**Emissions rates**

The mean emission rate from emitting unconventional sites in our survey area was 184 m$^3$/CH$_4$/day (95% CI: 12.2–354.3, $\sigma = 845$, range = 1–7815, 75th percentile = 69.0), with a mean MDL of 10 m$^3$/CH$_4$/day.

Conventional sites were not only emitting less frequently than unconventional sites, but emitting sites also had lower mean emission rates of 74 m$^3$/CH$_4$/day (95% CI: 57.8–89.9, $\sigma = 110$ m$^3$/CH$_4$/day, range = 2–765, 75th percentile = 75.6), with a mean MDL of 10.6 m$^3$/CH$_4$/day.

We calculated a mean emission intensity value per site by averaging the total CH$_4$ emission rate across all the sites in the development based on the emission frequency, factoring in the sites that weren’t emitting (above our MDL). The mean emission intensity was 59 m$^3$/CH$_4$/day per site (mean range = 53–66) for unconventional sites, and 20 m$^3$/CH$_4$/day per site (mean range = 14–30) for conventional sites. For comparison, if we assume that the airborne study by Peischl et al. (2018) measured emissions from ~10 000 Bakken wells (North Dakota Department of Mineral Resources ND DMR 2016), the emissions intensities from the North Dakota Bakken were ~99 $\pm$ 25 m$^3$/CH$_4$/day per well in 2015, increasing slightly, but not significantly from 2014 where emissions intensities were ~93 $\pm$ 23 m$^3$/CH$_4$/day per well (Peischl et al. 2016). We expect that ground-based emission rate estimates would be lower than airborne estimates for a number of reasons, including: emissions from high or buoyant sources (e.g. flares) may reach the ground beyond our on-road detection distances, some emissions may fall below our MDL, not all possible infrastructural emission sources were targeted during the study (e.g. pipelines, risers, abandoned wells), and episodic emissions from service events would not be fully included in our inventory.

Conventional and unconventional emission rates are shown in figure 2. Emissions from conventional sites were less extreme than those from unconventional sites, but none surpassed the current Saskatchewan flaring and venting allowance of 900 m$^3$ day$^{-1}$ (Government of Saskatchewan 2015b). Recently released Canadian Federal regulations require that, as of 2023, facility production venting must be reduced below ~41 m$^3$/CH$_4$/day (1250 m$^3$/CH$_4$/month, 15 000 m$^3$/CH$_4$/year) (Environment and Climate Change Canada ECCC 2018).
Table 2. Range of emissions estimates and intensities from developments in the US and Canada. Emissions were calculated by adjusting the rate reported to m³CH₄ (CH₄ density at 15 °C, 1 atm = 0.678 kg m⁻³), and dividing by the estimated number of well sites surveyed in each study.

| Development                        | Method     | Estimated well sites | Rate reported       | Estimated emissions intensity per well (m³CH₄/day) |
|-----------------------------------|------------|----------------------|---------------------|--------------------------------------------------|
| Conventional/Weyburn-Midale       | Truck      | 7308                 | —                   | 20                                               |
| Unconventional/Bakken             | Truck      | 2602                 | —                   | 59                                               |
| Denver-Julesburg Basin (Pétron et al 2014) | Airborne   | 24 000               | 26.0 ± 6.8 tCH₄/h | 38 ± 10                                           |
| Red Deer (Johnson et al 2017)     | Airborne   | 2053                 | 3.05 ± 1.1 tCH₄/h  | 40 ± 15                                           |
| Montney (Atherton et al 2017)     | Truck      | 5294                 | 111 800 tCH₄/yr    | 85                                               |
| Bakken (Peischl et al 2016)       | Airborne   | 10 000               | 26.5 ± 6.5 × 10³ kgCH₄/h | 93 ± 23                                           |
| Bakken (Peischl et al 2018)       | Airborne   | 10 000               | 28 ± 7 × 10³ kgCH₄/h | 99 ± 25                                           |
| Marcellus (Barkley et al 2017)    | Airborne   | 7000                 | 20 MgCH₄/h         | 101                                              |
| Barnett (Karion et al 2015)       | Airborne   | 16 100               | 60 ± 11 × 10³ kgCH₄/h | 132 ± 24                                         |
| Uintah (Karion et al 2013)        | Airborne   | 5800                 | 55 ± 15 × 10³ kgCH₄/h | 336 ± 92                                         |
| Lloydminster (Johnson et al 2017) | Airborne   | 2532                 | 24.5 ± 5.9 tCH₄/h  | 343 ± 82                                         |
In this study, emissions fall on the lower range of estimates from other developments in the US and Canada (table 2). We would expect emissions in the southeastern Saskatchewan region (tight/light oil) to fall between those of natural gas developments (e.g. Red Deer), which are driven to conserve natural gas, and heavy oil developments (e.g. Lloydminster), which are associated with large emissions (Johnson et al 2017). However, conventional developments in the region have the lowest calculated emissions intensities across developments in North America, suggesting that differences in total emissions may be driven by a number of factors, such as differences in reservoir composition, regulation, age of the development and infrastructure, operator size and best practice, and field unitization.

**Interpretations**

Using the same method as O’Connell et al (2019) to assess the distribution of site-level emissions rates in conventional and unconventional developments, we found that the emissions can be described using lognormal statistics, as previously observed by Zavala-Araiza et al (2015) and Zavala-Araiza et al (2018). As expected with lognormal distributions, a Lorenz curve shows that a small percent of sites is responsible for a large percentage of measured emissions (figure 3). Both developments were characterized by a moderately heavy-tailed emissions distribution, in which 28.36% and 49.28% of cumulative emissions in conventional and unconventional developments, respectively, originated from 20% of emitting sites. Distributions of measured emissions from production sites in other bottom up studies are invariably heavy-tailed, with large emission rates measured at a small subset of sites at any single point in time (Alvarez et al 2018). Brandt et al (2016a) found that by analyzing ~15 000 measurements from 18 prior studies, all available natural gas leakage datasets were statistically heavy-tailed. The small fraction of leaking sources often account for a large fraction of the total volume of leakages and represent profitable ‘low-hanging fruit’ for methane reduction efforts. Past regulatory action in southeastern Saskatchewan has lead to flaring and venting restrictions in Glen Ewen/Oxbow, SK, beginning January 1, 2015 (Government of Saskatchewan 2014) and understanding that emissions have a heavy-tailed distribution is important factor for mitigation efforts.

The Weyburn-Midale and Bakken formations have differing reservoir gas compositions, which may explain some of differences in emissions intensities between conventional and unconventional developments. The composition of the Weyburn-Midale formation (unconventional) is 43.8 mol% CH₄, 4.0 mol% CO₂ (Emberley et al 2004), and 1.3 mol% H₂S (Cantucci et al 2009). The average composition of the Bakken formation (conventional) is 47.1 mol% CH₄, 1.2 mol% CO₂, and 0.18 mol% H₂S (Brandt et al 2016b).
The Weyburn-Midale formation has an H2S content 7 times greater than that of the Bakken, which may well lead to increased scrutiny and management—and reduced methane emissions. H2S is a toxic gas with a strong olfactory component. The maximum H2S measurement recorded in all surveys was 132 ppb. In the southeastern Saskatchewan region, H2S emissions have come under scrutiny from the public due to safety concerns and odour complaints (Leo 2015). It is possible that mitigation efforts following Directive S-10 (Government of Saskatchewan 2015b) have yielded positive impact, particularly within the H2S-rich Weyburn-Midale region.

Development style may have an impact on emissions frequency and severity. In the conventional development of our study area, two operators own pipelined enhanced oil recovery (EOR) projects. One of these is the extensively studied Weyburn-Midale field. These fields have closed-loop systems, where all wells are tied into pipelines, and the produced fluids are transported directly to a central facility. After separation at the facility, some associated gases and fluids are re-injected into the reservoir. In comparison, regular operations store produced fluids in tank batteries before being transported by trucks to processing facilities. Emissions from the two operators using this process were markedly lower than the rest of the study area, which would be expected because this form of production eliminates known sources of emissions. For example, the Weyburn–Midale field design eliminated the need for 115 tank batteries (Scott 1966). In North Dakota, where non-pipelined oil and gas operations evolved rapidly, 56% of Bakken crude oil is transported by truck and 44% is transported by pipeline (Shrestha et al 2017). We could not find similar statistics for Saskatchewan.

Since we had good information on the age of infrastructure in the Bakken region, we used linear regression to examine the impact of operator size on emissions. It initially appeared that larger operator size (derived from the total sites operated in the region) was a predictor of higher operator-specific emissions intensity ($R^2 = 0.30$, p-value = 0.004). However, the strength of the regression seemed dependent on one outlier, which was the largest and most intensely emitting operator. After removing the outlier, there was no relationship between operator size and emissions intensity ($R^2 = 0.0015$, p-value = 0.85). In terms of infrastructure age, the conventional Weyburn-Midale development has been exploited for nearly 50 years longer than the Bakken. For this older infrastructure, we lacked accurate age data and were unable to conduct similar analysis.

We estimated the atmospheric %CH4 loss from conventional and unconventional developments using the method described by Peischl et al (2016). This represents the fraction of produced gas that is not recovered, and lost to the air. The CH4 extraction rate was derived using the mean CH4 abundance in conventionally (43.8 mol% CH4) and unconventionally (47.1 mol% CH4) produced gas (Emberley et al 2004, Brandt et al 2016b), and the gas production volume from Saskatchewan Ministry of Economy monthly oil production reports (Government of Saskatchewan 2015a). The estimated CH4 loss from conventional development was calculated at 13%, while the unconventional development is slightly higher at 14%. Southeastern Saskatchewan has apparently higher % losses than other developments, regardless of the type of production (oil versus gas). In the US Bakken region (mainly tight-oil), the loss rate was calculated as 6.3 ± 2.1% in 2014 (Peischl et al 2016) and 5.4 ± 2.0% in 2015 (Peischl et al 2018), based on in situ airborne data. Studies in the DJ Basin (mainly tight sand and shale-oil) found loss rates of 4.1 ± 1.5% (Pétron et al 2014), and a mass-balance flight over the Uintah Basin (mainly tight sand and shale-gas) found loss rates of 8.9 ± 2.8% (Karion et al 2013).

**Conclusions**

This study presents CH4 emissions intensities estimates for conventional (Weyburn-Midale) and unconventional (Bakken) developments in southeastern Saskatchewan. Our results showed that unconventional sites in southeastern Saskatchewan emit about as often as nearby conventional sites, but with somewhat greater severity that could stem from a variety of factors. In these co-located developments, differences in emissions intensities may be explained by differences in reservoir composition, indirect mitigation of CH4 emissions through H2S management practices at conventional sites, and the unitization of oil and gas production fields. Although the region has a relatively low per-site emission rate, the %CH4 loss was higher than comparable developments. Of course, if more gas were recovered, emissions of H2S, and other air contaminants would also be proportionately reduced.

Future CH4 emission monitoring and mitigation strategies will need to focus on measuring and understanding emission sources. Future work should focus on emissions over the lifespan of infrastructure, including during the drilling process. Also, this study only focused on persistent emitters, and it should be noted that there are many episodic emissions from service events that should be quantified in addition to our estimates. Future work may also focus on the correlation between H2S and fugitive CH4 emissions in sour fields, and whether H2S mitigation strategies also lead to CH4 emission reductions.
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