

Variation in Methane Emission Rates from Well Pads in Four Oil and Gas Basins with Contrasting Production Volumes and Compositions

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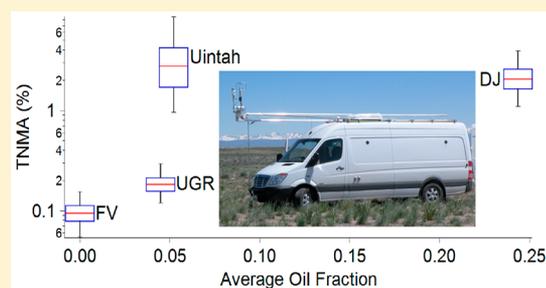
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Supporting Information

ABSTRACT: Atmospheric methane emissions from active natural gas production sites in normal operation were quantified using an inverse Gaussian method (EPA's OTM 33a) in four major U.S. basins/plays: Upper Green River (UGR, Wyoming), Denver-Julesburg (DJ, Colorado), Uintah (Utah), and Fayetteville (FV, Arkansas). In DJ, Uintah, and FV, 72–83% of total measured emissions were from 20% of the well pads, while in UGR the highest 20% of emitting well pads only contributed 54% of total emissions. The total mass of methane emitted as a percent of gross methane produced, termed throughput-normalized methane average (TNMA) and determined by bootstrapping measurements from each basin, varied widely between basins and was (95% CI): 0.09% (0.05–0.15%) in FV, 0.18% (0.12–0.29%) in UGR, 2.1% (1.1–3.9%) in DJ, and 2.8% (1.0–8.6%) in Uintah. Overall, wet-gas basins (UGR, DJ, Uintah) had higher TNMA emissions than the dry-gas FV at all ranges of production per well pad. Among wet basins, TNMA emissions had a strong negative correlation with average gas production per well pad, suggesting that consolidation of operations onto single pads may reduce normalized emissions (average number of wells per pad is 5.3 in UGR versus 1.3 in Uintah and 2.8 in DJ).



INTRODUCTION

The natural gas and petroleum industry was estimated to be the primary source of anthropogenic methane emissions in the United States in 2014.¹ Natural gas, which produces roughly half as much carbon dioxide as coal when burned in a modern power plant,² has been proposed as a less carbon intensive energy source. However, methane has a 20-year global warming potential approximately 86 times greater than carbon dioxide.³ Previous studies have found that the immediate climate benefit of switching power production from coal to natural gas is lost if more than a few percent of methane produced is emitted to the atmosphere, including all emissions from well head to consumer.^{4,5} Top-down (direct measurement) assessments indicate that the Environmental Protection Agency's Greenhouse Gas Inventory (EPA GHGI) routinely underestimates actual emissions and is approximately a factor of 1.5 low nationally for all methane emissions and up to a factor of 3–5 low regionally for methane emissions from the oil and natural gas sector.⁶ Discrepancies between top-down and inventory estimates could result from incorrect assumptions about equipment activity counts, outdated or incorrect emission factors, errors in attribution of biogenic and thermogenic emissions, or difficulty in accounting for the spatial and temporal variations throughout the natural gas network.⁷

Studies have been performed throughout the natural gas chain over varying spatial scales in an effort to reconcile methane emission estimates between inventories and atmospheric measurements.^{8–21} This study focuses on direct measurements of methane emissions from production sites.

Large variations in atmospheric methane emissions from active oil and gas operations have been observed in various oil and gas producing regions of the country,^{6,7} but the cause of these variations remains uncertain, making accurate inventory estimates and implementation of effective control strategies difficult. In this study, methane emissions from active production sites (well pads) were quantified in four major U.S. oil and gas basins: (1) Jonah and Pinedale Anticline Fields of the Upper Green River (UGR) basin in southwestern Wyoming, (2) Wattenberg Field in the Denver-Julesburg (DJ) basin in northeastern Colorado, (3) Greater Natural Buttes Field in the Uintah basin in northeastern Utah, and (4) Fayetteville (FV) gas play in the eastern Arkoma basin in north-central Arkansas. The number of producing wells in each study

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area was approximately 6000, 16 000, 7000, and 5500,^{22,23} respectively. Emissions were quantified using the EPA's Other Test Method (OTM) 33a in all four basins. OTM 33a is an inverse Gaussian method in which measurements of methane concentration and 3D winds are made 20–200 m downwind of a known emission source and Gaussian plume dispersion parameters are empirically determined based on atmospheric conditions to derive a mass flux.²⁵ OTM 33A was selected for this study due to the relatively quick sampling times (approximately 20 min) and because no site access is required (only access to adjacent roadways). The basins studied range from wet gas basins that produce significant amounts of oil (DJ, Uintah, UGR) to dry basins that produce virtually none (FV). This paper explores the relationship between atmospheric methane emissions from well pads and the amount of natural gas, oil, and water produced at those well pads.

MATERIALS AND METHODS

Measurements performed in DJ and FV were part of a larger effort under the Research Partnership to Secure Energy for America (RPSEA), measurements in Uintah were part of the Joint Air and Ground Uintah basin Air emissions Reconciliation (JAGUAR 2015) campaign and UGR measurements were part of an independent field campaign. All projects focused on reconciling top-down and bottom-up estimates of methane emissions. 51 valid measurements were taken in UGR in 2014/2015, 16 in DJ in 2014, 30 in Uintah in 2015, and 53 in FV in 2015 (Supporting Information, SI, Table S1). Measurements were valid if they met all data quality criteria described below and in SI section 1.4. Although there is a data quality criterion for low methane enhancement, measurements were never excluded based on low methane levels alone because this would bias the data set. Instead, these measurements were included, but it must be recognized that emission rates below the OTM 33a limit of detection (LOD = 0.036 kg/h) can only be said with certainty to be below the LOD; this occurred 5 times. Each measurement was for one well pad, however well pads often received products from multiple wellheads. In Uintah, 6 of 30 measured well pads were distinctly classified as oil wells by the Utah Division of Oil, Gas and Mining (classification is primarily dependent on the reservoir the well is producing from) and calculations for Uintah are broken into separate groups for gas versus oil wells. To increase the size of the data set in DJ, where only 16 successful measurements were made due to unfavorable meteorological conditions, 68 measurements collected using the same OTM 33a method during similar time periods to this study and published in Brantley et al.¹⁵ were provided by Dr. Brantley to supplement the data set. Details related to this added data are in SI Section 1.6. Briefly, the median and 95% confidence intervals of throughput-normalized methane average emissions in the DJ was 0.99% (0.34–3.50%) for the 2010 Brantley data, 2.70% (1.24–5.97%) for the 2011 Brantley data, and 2.59% (1.15–5.90%) for the 2014 data from the current study (SI Figure S4). In the UGR, DJ and Uintah basins there was no site access and all measurements were performed from public roads. In FV, there was site access with a company escort and measurements were performed either on the well pad or on access roads. Site access in FV was critical because dense forest made measurements from nearby roads difficult with OTM 33a.

All measurements described in this paper, other than those provided by Brantley et al.¹⁵ were made from the University of Wyoming Mobile Laboratory utilizing the EPA's Other Test

Method (OTM) 33a. In UGR, Uintah, and DJ, a starting location within the basin was chosen randomly each day, then measurement sites were selected based on favorable wind direction and road location beginning at this location and driving progressively farther away. In FV, geographically proximate sites were grouped into clusters prior to the field campaign. Each day sites with favorable wind and road locations were selected from within a cluster randomly selected for measurement.

This study focuses on emissions from well pads in normal operation to determine the average emissions in each basin and attempt to understand differences between the basins. Sites visibly being serviced were not included in the final data set (e.g., water unloading truck or maintenance personnel on site), but episodic events (e.g., flash emissions, automated liquid unloadings) and failed components (e.g., thief hatch stuck open, malfunctioning pressure relief valves) may have been captured during a measurement. Industry cooperation in FV provided information on well pad operations including episodic emissions (e.g., three automatic plunger lift operations), but episodic events were unknown in the other basins and were not separated from any of the data sets. One event in FV was excluded because it did not adhere to the random sampling approach of these studies; a manual unloading (MU) that was identified as a large emission by aircraft and then purposefully visited. The estimated emission rate for the manual unloading, which has been identified as a large potential emission source in previous studies,^{7,24} was 68.3 kg/h (53.3–95.0 kg/h, 95% CI), accounting for 59% of the total mass emissions measured in FV. However, emissions from this manual unloading were likely underestimated by the OTM method due to the high vertical velocity of the plume.

Duplicate measurements of the same site were occasionally performed (SI section 5.0). To prevent statistical bias, if multiple measurements of the same site were valid, then a single measurement was chosen using a random number generator.

Mobile Laboratory, Methane, and Meteorology Measurements. The University of Wyoming Department of Atmospheric Science Mobile Laboratory is built on a Freightliner Sprinter Van (SI Figure S1). Onboard batteries allowed OTM 33a measurements to be made with the engine off, avoiding interference from vehicle exhaust. However, in FV, air conditioning often required that the vehicle engine run during measurements, in which case a ~6 m hose was attached to the tailpipe to release vehicle emissions downwind. A mast that holds the air inlet, a 3D sonic anemometer, and a 2D compact weather station extends to the front bumper of the vehicle and is 13 feet above the ground, minimizing flow perturbations from the ground or van. The inlet, weather station, and sonic anemometer were rotated to point directly into the wind to avoid one instrument being in the wake of another. Air was pulled through the inlet then through 23 feet of 1/4 in. Teflon tubing at approximately 7 LPM to a Picarro Cavity Ring-Down Spectrometer (CRDS, Model G2204) modified by Picarro Inc. to measure dry methane mixing ratio every 0.5 s. The calibration of the Picarro CRDS was verified by sampling a NIST traceable ($\pm 1\%$) methane in ultrapure air mixture with a methane concentration of 2.576 ppm. The Picarro CRDS was always within ± 6 ppb of the NIST traceable standard with a precision of 2 ppb in 5 s.

Converting Mixing Ratios into Mass Emission Rates. OTM 33a is described in detail in Brantley et al. and in the

EPA's method documentation.^{15,25} The OTM 33a method uses the concept that if dry methane mixing ratio, wind speed, and wind direction are measured at high frequency (2 Hz) at a point 20–200 m downwind of an emission source for a sufficient period of time (~20 min), a plot of averaged methane mixing ratio enhancement versus wind direction will form a Gaussian curve. The lower detection limit for this method reported by Brantley et al.¹⁵ is 0.01 g/s (0.036 kg/h). In this study, 5 measured well pads had emissions below the detection limit, all in FV. During this study, measurements were made 20 to 200 m downwind of a source with wind speeds ranging between 1 and 10 m per second. The average distance to potential emitting sources on a well pad was estimated with a laser range finder and, when possible, an infrared camera (FLIR GF300) was employed to pinpoint source location(s). The average measurement distance to source ($\pm 1\sigma$) was 83.5 ± 43.4 , 111.5 ± 44.7 , 74.75 ± 40.4 , and 46 ± 24.0 m in UGR, Uintah, DJ, and FV respectively. High-frequency (~2 Hz) wind and dry methane mixing ratio measurements were collected from a stationary point over a period of approximately 20 min to provide sufficient averages. Horizontal and vertical standard deviations of wind direction are averaged over the entire measurement period to estimate Pasquill-Gifford dispersion parameters.²⁶ The estimated dispersion parameters, along with distance from the source, and peak concentration observed in the Gaussian fit of methane enhancement versus wind direction allow conversion of mixing ratio measurements to mass emission rate (SI section 1.3), which is assumed to be from a single collective point source (i.e., all emissions from a well pad mixed into a single plume). The measured plume width can be compared to modeled horizontal dispersion to give confidence in model accuracy. Data quality flags arise during postprocessing if the model is not valid for measured wind speeds, turbulence, or if the observed plume shape cannot be accurately simulated with a Gaussian curve (see SI section 1.4). The percentage of total measurements that exceeded the data quality flag threshold, and were considered invalid, are 30% in Uintah, 33% in DJ, 24% in FV, and 30% in UGR, suggesting that OTM 33a has a fairly uniform ~70% success rate across a wide range of conditions.

Transect Analysis and Site Selection. Before stationary OTM 33a measurements were performed, several transects downwind of a site were made to locate the approximate center of the methane plume. When possible, transects were also performed upwind to verify that there were no methane sources upwind. Transect profiles of methane enhancements were analyzed to confirm that emissions, potentially from multiple sources on the well pad, had mixed into a single plume.

In FV, drives around all equipment on a well pad were used as part of that campaign's collaborative screening process to

quickly identify emission sources. Well pads where detected enhancements (within a few meters of the equipment) never exceeded 0.05 ppm were recorded as "zero based on transect," or 0 BOT, which occurred 12 times, and no OTM measurement was performed at that well pad. Since well pad access was not available in the other basins, sites were not identified as zero emitters based on transect alone. However, in the other three basins, we never performed an off-site transect where we were clearly positioned downwind of a well pad and observed zero enhancement, FV was the first basin in which we observed zero or near-zero emitters with any frequency.

Controlled Releases to Validate OTM 33a. To assess the accuracy of the OTM 33a method as implemented in this study, 23 controlled methane releases were performed. Controlled releases, with methane emissions regulated by a mass flow controller, were performed in collaboration with Colorado State University researchers²⁷ at the Christman Air Field in Fort Collins, Colorado. Controlled releases occurred over three different days at distances of 30 to 175 m, wind speeds of 2 to 10 m/s, and methane release rates of 0.11 to 2.02 kg/h, with no obstructions between release and measurement points. SI section 1.5 details these releases along with an additional 90 controlled releases performed by Brantley et al.¹⁵ The fractional error between OTM 33a and the controlled release rate can be fit to a Gaussian (SI Figure S3) with a 2σ width of $\pm 56\%$ of the known emission rate. The 1σ error ($\pm 28\%$) of the known emission rate is similar to the error estimated by Brantley et al.¹⁵ for this method (they reported 70% of OTM 33a measurements were within $\pm 30\%$ of the actual release rate). Controlled release results from the current study suggest that OTM 33a may have a 10% low bias, however, Brantley et al.¹⁵ saw no bias. Due to the ambiguity related to measurement bias, no correction was applied to the current data set. It is important to note that while the technique may have a low bias, this bias is not expected to vary between basins.

Throughput-Normalized Methane Emissions. The term throughput-normalized methane (TNM) emission is defined here as the percent of gross methane produced that was emitted to the atmosphere per well pad:

$$\text{TNM}(\%) = \frac{\text{measured methane emission rate} \left(\frac{\text{kg}}{\text{h}} \right)}{\text{gross methane produced} \left(\frac{\text{kg}}{\text{h}} \right)} \times 100 \quad (1)$$

where gross methane produced is calculated using operator-reported gross gas production in thousands of cubic feet (mcf) per month and converted to gross methane production in kilograms per hour by the following:

$$\text{GMP} \left(\frac{\text{kg}}{\text{h}} \right) = \text{GP} \left(\frac{\text{mcf}}{\text{mo}} \right) \times \left[\frac{\left(1000 \frac{\text{ft}^3}{\text{mcf}} \right) \times \left(1.19804 \frac{\text{mol gas}}{\text{ft}^3} \right) \times \left(xx \frac{\text{mol CH}_4}{\text{mol gas}} \right) \times \left(0.01604 \frac{\text{kg}}{\text{mol CH}_4} \right)}{(\# \text{days}/\text{mo}) \times (24 \text{h}/\text{day})} \right] \quad (2)$$

where GMP is the gross methane produced and GP is the gas produced. Monthly gas production rates were obtained from each basin's respective oil and gas commission online inventory.^{28–31} Production data for several well pads in FV was also provided by cooperating companies. The number of days per month is the number of days the well was producing

for the particular month when the measurement was made. In UGR and FV, methane mole fractions of gas by volume were provided by the respective oil and gas commission reporting inventory for measured wells.^{29,31} Average methane mole percent of gas varied little in UGR and FV and was 92% and 97%, respectively. Mole percent of methane was more variable

in Uintah and DJ. A range of 85–95% was used for Uintah, reported by Zhang et al.³² for the Natural Buttes Field. The methane content used for DJ was from a sample of random wells in Weld County where mole percent of methane ranged from 70–85%. Due to variability in gas composition in Uintah and DJ, variability was included in the measurement uncertainty for those basins. However, using the whole range of mole percent or a single average value has negligible effect on final bootstrapped results. Monthly oil (bbl) and water (bbl) production rates used in this study were also obtained from each basin's respective oil and gas inventory.

Oil and Water Fraction. For each basin, oil and water production were compared to gross gas production for the wells measured to investigate whether the fraction of liquids produced, and consequently the amount of processing needed before the gas could be sent to the pipeline, had an effect on the magnitude of methane emissions. To roughly represent the fraction of energy production from oil, gas production was represented by barrels of oil equivalent (BOE) and a ratio, which we call the oil fraction, was generated:

$$\frac{\sum OP\left(\frac{\text{bbl}}{\text{d}}\right)}{\sum \text{totalBOE}\left(\frac{\text{bbl}}{\text{d}}\right)} = \frac{\sum OP\left(\frac{\text{bbl}}{\text{d}}\right)}{\sum \left[OP\left(\frac{\text{bbl}}{\text{d}}\right) + \text{OEGP}\left(\frac{\text{bbl}}{\text{d}}\right)\right]} \quad (3)$$

where OP is oil production and OEGP is oil equivalent of gas production. BOE is often used to quantify combined yield of oil and gas as one unit of energy. BOE for gas produced was computed in all basins using the Society of Petroleum Engineer's conversion ratio of 1 BOE = 5.8 mcf of gas.³³

Water fraction was similarly calculated as follows:

$$\frac{\sum WP\left(\frac{\text{bbl}}{\text{d}}\right)}{\sum \text{totalBOE}\left(\frac{\text{bbl}}{\text{d}}\right)} = \frac{\sum WP\left(\frac{\text{bbl}}{\text{d}}\right)}{\sum \left[OP\left(\frac{\text{bbl}}{\text{d}}\right) + \text{OEGP}\left(\frac{\text{bbl}}{\text{d}}\right)\right]} \quad (4)$$

where WP is water production, OP is oil production, and OEGP is oil equivalent of gas production.

Throughput-, Energy-, and Natural Gas-Normalized Methane Average Emissions. The throughput-normalized methane average (TNMA) emissions for a basin were computed by summing emissions and production from all well pads measured in each basin, and represents the basin-average emissions from well pads. We define the TNMA as follows:

$$\text{TNMA}(\%) = \frac{\sum \text{MMER}\left(\frac{\text{kg}}{\text{h}}\right)}{\sum \text{GMP}\left(\frac{\text{kg}}{\text{h}}\right)} \times 100 \quad (5)$$

where MMER is the measured methane emission rate and GMP is the gross methane produced. Natural gas-normalized methane average (NGNMA) emissions are calculated in a similar way as TNMA except with gross natural gas produced in the denominator (SI section 2.0). Many of the well pads measured also had oil production. For wells with significant oil production we propose a metric that presents methane emissions as a fraction of total energy produced, or energy-normalized methane average (ENMA) emissions. Measured methane emissions were converted to a unit of energy by using a conversion unit of 1×10^6 Btu per mcf of methane.³⁴ Equivalent energy production (combined energy content from gas and oil) was converted to total Btu by using the conversion

unit 5.8×10^6 Btu per barrel of oil and 1×10^6 Btu per mcf of gas.³⁵ ENMA is then calculated as follows:

$$\text{ENMA}(\%) = \frac{\sum \text{MEER}\left(\frac{\text{Btu}}{\text{d}}\right)}{\sum \text{EEP}\left(\frac{\text{Btu}}{\text{d}}\right)} \times 100 \quad (6)$$

where MEER is the measured energy emission rate and EEP is the equivalent energy production.

Statistical Bootstrapping. To account for uncertainty caused by the fact that measured wells may not fully represent the distribution of emissions in a given basin, bootstrapped estimates of TNMA, ENMA, and NGNMA emissions for an entire basin were made. First the measurement error in individual OTM 33a estimates of mass emission rate was simulated by generating two normal distributions around the measured mass emission. For the positive error we use a normal distribution with sigma of 39% and for the negative error we use sigma of 22% (+39%/−22%). The need to have a different sigma for positive and negative error estimates arises from the fact that we observe a Gaussian distribution with 28% error (relative to the known release rate) during controlled releases, which becomes unequal when referenced to a measurement instead of the known release rate. Then, 100 000 points were pulled from this Gaussian distribution for each measurement, these 100 000 points can be thought of as best estimates with measurement error added in. Next, the number of measurements from a given basin (30 to 84), which now include simulated experimental error, were bootstrapped 100 000 times.³⁶ Lastly, the sum of each bootstrapped sample was divided by the sum of gross methane or energy production from the wells in that bootstrap sample to generate a distribution of throughput or energy-normalized methane averages. Uncertainty in basin-wide extrapolation is dominated by between-pad variability compared to OTM 33a error.

Two-Sample Kolmogorov–Smirnov Test. The two-sample Kolmogorov–Smirnov (KS) test is similar to the Student *t* test but does not assume a Gaussian distribution. The KS test is used in this study to verify whether two observed cumulative distributions are from different underlying distributions at a given confidence level (i.e., statistically different from one another), as well as to test whether one cumulative distribution is larger or smaller than another.

RESULTS AND DISCUSSION

Methane Emissions from Individual Well Pads. Figure 1a shows rank-ordered throughput-normalized methane (TNM) emissions for individual well pads in each basin. Overall, TNM emissions are highest in Uintah and DJ and decrease successively to UGR and FV. Several of the well pads with the highest TNM emissions in Uintah are oil wells (see next section). Figure 1b is rank-ordered by methane mass emissions and shows that for well pads in FV, Uintah, and DJ, the 20% of well pads with the highest mass emissions accounted for 72–83% of total methane emissions to the atmosphere. Skewed distributions of this type, where relatively few well pads account for the majority of overall emissions, have been documented in other basins including the Marcellus Shale, Barnett Shale, and the Four Corners region.^{4,37–39} UGR has a less skewed distribution, with the top 20% of mass emitters only accounting for slightly over half (54%) of total methane mass emissions.

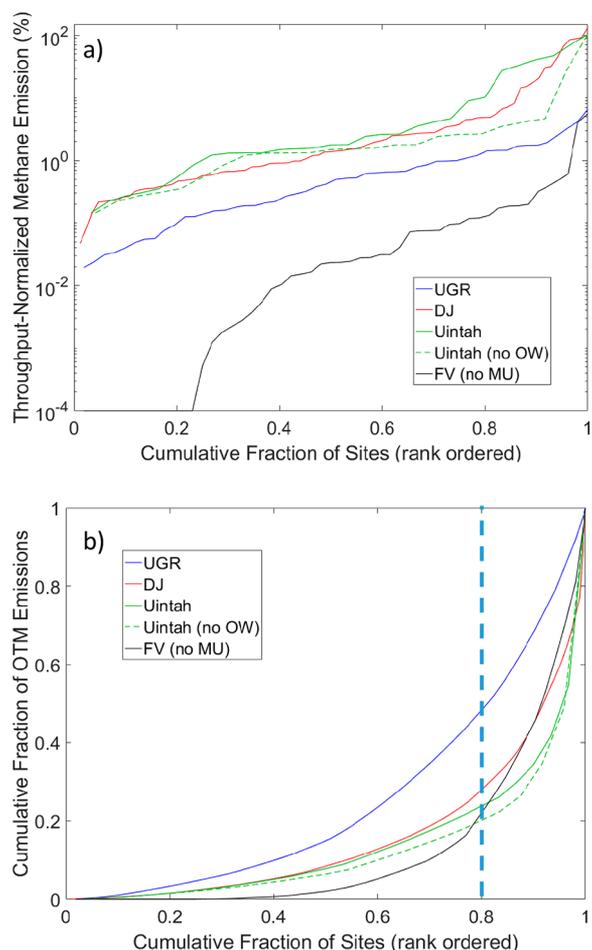


Figure 1. a) Throughput-normalized emissions at each well pad vs cumulative fraction of sites (rank ordered by throughput-normalized methane emissions) b) cumulative fraction of total mass emissions vs the cumulative fraction of sites (rank ordered by absolute emissions). “No OW” signifies that no oil wells were included in the calculations, and “no MU” signifies that the manual unloading was not included.

Basin-Average Methane Emissions from Well Pads.

Probability distribution functions (PDF) generated from bootstrapped results are given in Figure 2. Table 1 summarizes some key numerical results from Figure 2, namely: throughput-normalized methane average (TNMA), energy-normalized methane average (ENMA), natural-gas-normalized methane average (NGNMA, not shown in Figure 2), and mass emission rate (kg/h) with 95% confidence intervals. While the percentages in Table 1 shift depending on the normalization chosen, Figure 2a,b show that the large differences between basins remain independent of normalization. The one exception is that ENMA emissions for oil wells in Uintah are much lower than TNMA emissions, suggesting that ENMA may be a more appropriate metric for wells that produce a majority of their energy in the form of oil, since low gas production at these sites biases their TNMA emissions high. Notably, the average methane mass emissions from Uintah oil well pads are statistically similar to methane mass emissions from natural gas well pads in other basins (Figure 2c) demonstrating that methane emissions from oil wells that coproduce natural gas are non-negligible. However, because Uintah was the only basin where distinctly oil well pads with an oil derrick on-site were measured, they are shown as a separate

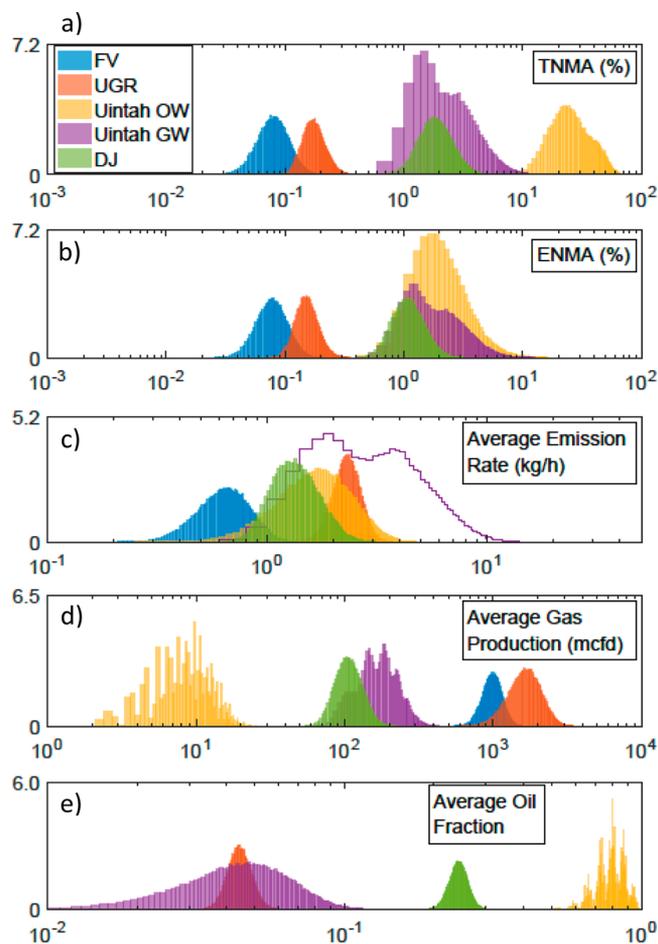


Figure 2. Probability density functions (PDF) for a) throughput-normalized methane average (%), b) energy-normalized methane average (%), c) average methane emission rate (kg/h) per well pad, d) average gas production per well pad (thousand standard cubic feet per day, mcf/d), and e) average oil fraction per well pad. All y-axes are percent of total counts. In panel (c) the PDF for Uintah gas wells (GW) is transparent to make other basins visible.

distribution here and are not included in subsequent plots or sections. Since it requires the fewest assumptions to calculate, and for consistency with previous studies, TNMA will be used for the remainder of this paper. Importantly, for natural gas wells, which are the focus for the remainder of the paper, the conclusions drawn for TNMA also apply for NGNMA and ENMA.

UGR and FV have the smallest median TNMA emissions (0.18% and 0.09%, respectively, Figure 2a, Table 1) and are similar to the median of 0.13% reported by Omara et al.³⁷ for unconventional gas well pads in the Marcellus region. Because site access in the FV allowed us to determine that well pads had zero emissions based on transect alone (0 BOT, see Materials and Methods), we calculated the FV TNMA without these measurements included and found that it was 0.10% (0.06% – 0.18%, 95% CI), which is negligibly different from the 0.09% calculated including these sites. Accordingly, the 0 BOT measurements were included in all further analysis. TNMA emissions in Uintah and DJ are an order of magnitude higher (2.8% and 2.1%, respectively) and are similar to the median TNMA emissions reported by Lan et al.¹⁴ for production sites measured in the Barnett Shale (2.1%). One very large emitter (46.5 kg/h of methane) was measured in Uintah. Without this

Table 1. Median and 95% Confidence Interval of Throughput-Normalized Methane Average (TNMA), Energy-Normalized Methane Average (ENMA), Natural Gas-Normalized Methane Average (NGNMA), and Average Methane Mass Emission Rate^a

	median TNMA, % (95% CI)	median ENMA, % (95% CI)	median NGNMA, % (95% CI)	median mass emission rate, kg/h (95% CI)
Uintah–Gas Wells	2.8 (1.0–8.6)	2.3 (0.81–7.1)	2.4 (0.86–7.7)	3.7 (1.2–9.1)
Uintah–Oil Wells	29 (14–56)	2.5 (0.92–8.7)	26 (12–51)	1.9 (0.8–3.5)
DJ	2.1 (1.1–3.9)	1.2 (0.65–2.2)	1.6 (0.85–3.0)	1.4 (0.88–2.3)
UGR	0.18 (0.12–0.29)	0.16 (0.10–0.26)	0.17 (0.11–0.27)	2.3 (1.7–3.1)
FV (no MU)	0.09 (0.05–0.15)	0.08 (0.05–0.15)	0.08 (0.05–0.15)	0.68 (0.38–1.1)

^a“No MU” signifies that the manual unloading was not included.

large-emitter, Uintah’s TNMA is 1.50% (0.60% – 3.97%, 95% CI) emphasizing the importance of rare, large-emitting sites. Several previous studies have stressed the importance of including “super-emitters” when estimating basin-wide emission profiles,^{19,39–41} so this data point is included in all subsequent calculations.

Average methane mass emissions per well pad (Figure 2c) were similar between basins despite large differences in average gas production (Figure 2d) between the basins. However, mass emissions in FV are significantly less than in the other three basins, with KS tests accepting the null hypothesis that emissions in FV are less than the other three basins at the 5% significance level. KS tests also reveal that average mass emissions in DJ are less than those from natural gas wells in UGR and Uintah.

Differences between mass emissions per well pad and TNMA emissions are driven by average well pad gas production (Figure 2d). FV well pads have large average gas production (1013 thousand cubic feet per day, mcf/d) and the lowest mass emissions per well pad, resulting in the lowest TNMA emissions. The situation is different for the wet basins where median gas production per well pad in UGR (1744 mcf/d) is a factor of 15 larger than in DJ (111 mcf/d) and a factor of 10 larger than in Uintah (183 mcf/d), resulting in much smaller TNMA emissions in UGR even though average mass emissions are higher in UGR than in DJ and comparable to Uintah.

Overall, basins with oil production (DJ, Uintah, UGR) have well pads with higher TNMA and methane mass emissions than the dry FV. This may be the result of the different equipment (e.g., no oil/condensate tanks in FV⁴²) and processing needed to separate wet gas at the well pad as opposed to dry gas, i.e., the amount of liquids handling required,⁴¹ but future work is needed to understand this relationship. Additionally, UGR has significantly lower TNMA emissions than the other two wet basins. This may partially be the result of higher reservoir pressure in UGR (resulting in a lower need for liquid unloadings), but appears to be most strongly driven by the higher average gas production per well pad. The average number of wells per pad in UGR is 5.3 versus 1.3 in Uintah and 2.8 in DJ (based on the 16 DJ measurements we performed), suggesting that consolidation of wells onto centralized well pads may be an effective way to decrease normalized emissions per pad. Again, further study is needed, but the effect of coproduction of oil and water are explored in the next section.

Variation In Basin-Average Methane Emissions from Well Pads with Basin-Average Oil and Water Production. Figure 2e shows the distributions of oil fraction for each basin, and Figure 3a shows bootstrapped TNMA emissions versus median bootstrapped oil fraction for each basin. Central estimates of oil fraction in the basins range from zero in FV to ~25% in DJ, one of the top 5 US basins for proven oil reserves.⁴³ Table 2 shows calculated oil fraction and this same

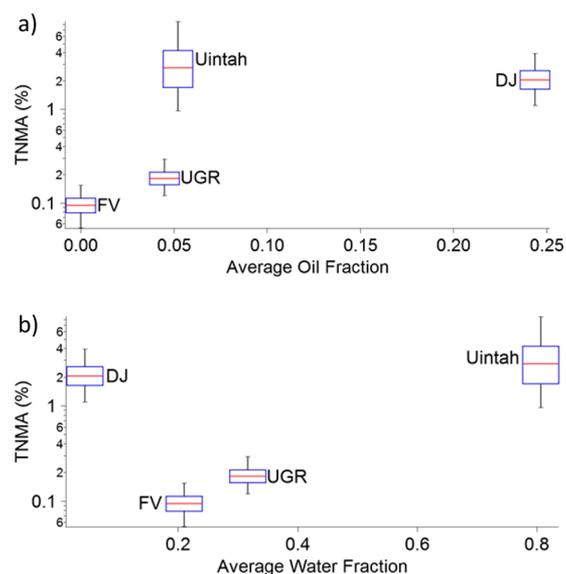


Figure 3. Box plots of the bootstrapped throughput-normalized methane average emissions for each basin, sorted by a) basin average oil fraction, and b) basin average water fraction. On each box the central line represents the median, the edges of the box are the 25th and 75th percentiles, and the whiskers are the 95% CI. For the UGR, DJ, Uintah, and FV the bootstrap calculations were based on: $n = 51, 84, 30,$ and $53,$ actual well-pad measurements, respectively.

fraction represented as the oil to gas ratio allowing us to compare our estimates of oil fraction (or equivalently oil-gas ratio) to the range of oil-gas ratios reported by the USGS.^{44–46} We find the estimates to be similar for all basins except Uintah, where measured wells produce more oil than the reported range. These results demonstrate that measured wells are fairly representative of wells in the entire basin, but that the exact oil–gas ratio can vary significantly depending on the exact subset of wells measured. Figure 3a again shows that higher TNMA emissions were observed from the three wet-gas producing basins than in the dry-gas FV, confirmed by KS tests accepting the null hypothesis that emissions are smaller in FV than the other basins at the 5% significance level.

TNMA emissions between the oil producing basins show large variation. To further investigate, basin TNMA emissions were compared to water fraction (Figure 3b). A similar rank of basin wetness was found as for oil fraction, except for DJ, which has the lowest water fraction of all basins. These results are consistent with a USGS report for the Wattenberg field in DJ⁴⁵ that reported low water production rates for 128 sampled wells, with half of the wells reporting no water production and the other half averaging less than 1 bbl/day. With the DJ results included, there is little correlation between TNMA emissions and water production.

Table 2. Oil Fraction (Derived from Wells Measured in This Study), Median Oil–Gas Ratio (Derived from Wells in This Study), and Oil–Gas Ratios from the USGS

	FV	UGR (Pinedale and Jonah Fields)	Uintah Gas Wells (Greater Natural Buttes Field)	DJ (Wattenberg Field)
95% CI of oil fraction (this study)	0	0.04–0.05	0.02–0.09	0.21–0.28
median oil-gas ratio (bbl/mmcf) from this study (95% CI)	0	8.2 (6.8–10.1)	11.2 (3.9–22.4)	73.5 (55.2–98.9)
USGS oil-gas ratio (bbl/mmcf) ^a	N/A (0)	7–18	1–5	18–760

^aSee refs44–46.

Intra-Basin Variation in Methane Emissions from Well Pads with Gas, Oil, and Water Production. Figure 2 shows that the highest TNMA emissions were observed in oil producing basins with relatively small gas production per well pad (Uintah and DJ). To determine if high TNMA emissions were a feature of the basin or a feature of individual wells, bootstrapped TNMA emissions were estimated over binned ranges of well pad gas production, as shown in Figure 4a. While

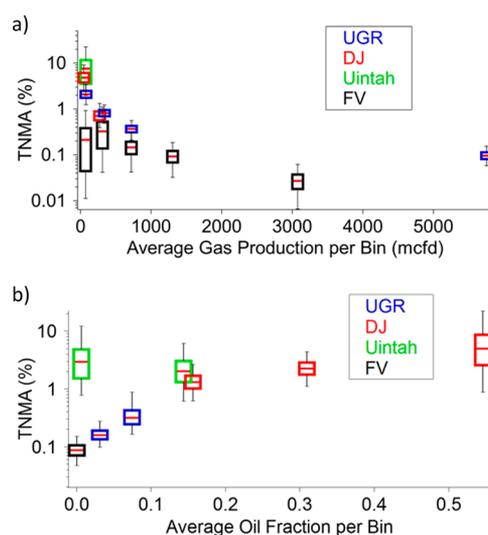


Figure 4. a) Box plots of bootstrapped throughput-normalized methane average (TNMA) emissions for each basin, binned a) by gas production (bin edges (mcf/d) are 150, 500, 1500, 2000), and b) binned by oil fraction (bin edges are 0.05, 0.25, 0.4). A basin was only included in a bin if it had at least 8 measurements in that bin. On each box the central line represents the median, the edges of the box are the 25th and 75th percentiles, and the whiskers are the 95% CI. The number of measurements on which the bootstrap calculations were based for each gas production bin are UGR – 16, 11, 8, 0, 13; DJ – 68, 13, 0, 0, 0; Uintah – 17, 0, 0, 0, 0; FV – 11, 11, 11, 10, 9. For each oil fraction bin: UGR – 35, 16, 0, 0; DJ – 0, 43, 23, 12; Uintah – 16, 8, 0; FV – 52, 0, 0, 0.

basin-average TNMA emissions in UGR are an order of magnitude lower than the other oil producing basins, well pads with low gas production (<500 mcf/d) in UGR have similar TNMA emissions to well pads with low gas production in DJ and Uintah. These results show that low overall TNMA emissions in UGR are the result of well pads with large gas production, not the result of significantly different behavior on well pads of similar size in the different wet gas basins. Well pads in FV, which does not produce oil, have lower TNMA emissions than wells in the oil producing basins at all levels of gas production. At higher gas productions (>2000 mcf/d) TNMA emissions in UGR approach those in FV with median TNMA emission of 0.09% in UGR and 0.03% in FV.

Figure 4b shows TNMA emissions versus binned oil fraction and reveals that well pads in UGR and FV have lower TNMA emissions even when compared to the lowest oil producing wells in DJ and Uintah. While TNMA emissions increase with oil fraction in UGR (confirmed by KS test at the 5% significance level), Uintah and DJ show no significant change of TNMA emissions with increasing oil production. There was also little correlation between TNMA emissions and water fraction (SI Figure S5).

Well Pad Emissions as a Fraction of Total Basin-Wide Emissions.

If the well pads measured in this study are representative of well pads basin-wide, then bootstrapped well pad TNMA emissions from this study can be directly compared to basin-wide throughput-normalized emissions from previous aircraft studies to determine the fraction of total emissions contributed by well pads in normal operation. The uncertainty in basin-level emissions was bootstrapped using the aircraft studies' reported mean with 1-sigma errors incorporated, analogous to the bootstrapping method used for TNMA emissions. Karion et al.⁹ estimated methane emissions from oil and gas (O&G) operations in Uintah County to be 6.2–11.7% (1 σ) of gross production in the Uintah basin in 2012. Using the bootstrapped quotient of TNMA emissions for Uintah O&G well pads from our study (also measured in the Uintah County portion of the basin) and the Karion result, well pads account for 36% (19–70%, 1 σ) of total basin-wide emissions. Basin-wide methane emissions from O&G operations in Weld County in the DJ basin were estimated to be 2.6–5.6% (1 σ) of production in 2012 by Petron et al.⁸ which, when combined with the current study, results in well pads accounting for 52% (32–90%, 1 σ) of basin-wide emissions. Well pads in FV, excluding the manual unloading, contribute a smaller portion of basin-wide emissions. Peischl et al.¹⁰ estimated basin-wide emissions for the Fayetteville in 2013 to be 1.0–2.8% of production, which results in well pads accounting for 5% (3–9%, 1 σ) of basin-wide emissions. Basin-wide results for UGR will be presented in a forthcoming publication focused on airborne measurements of flux from UGR. In all cases, our measurements were taken 2–3 years after the aircraft estimates and, although production changed very little (<10%), exploration activity decreased during the intervening years. The fractions presented here illustrate that emissions from well pads in normal operation are important contributors to basin-scale emissions in Uintah and DJ, but are less important in FV. However, episodic emissions in FV, such as manual and automatic liquid unloadings, have been shown to be a large source of methane emissions in FV, as discussed in the methodology section, and were likely undersampled in this study.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.7b00571.

Details of the measurements performed and data used in this manuscript; further description of the OTM 33a measurement method, data quality indicators, and controlled test releases; and an explanation of how natural gas-normalized emissions were calculated (PDF)

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Notes

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