Aerial and Ground-Based Optical Gas Imaging Survey of Uinta Basin Oil and Gas Wells

Seth N. Lyman
Utah State University, seth.lyman@usu.edu

Trang Tran
Utah State University, trang.tran@usu.edu

Marc L. Mansfield
Utah State University, marc.mansfield@usu.edu

Arvind P. Ravikumar
Harrisburg University of Science and Technology

Follow this and additional works at: https://digitalcommons.usu.edu/bingham

Part of the Biochemistry, Biophysics, and Structural Biology Commons, and the Chemistry Commons

Recommended Citation
Lyman, S.N., Tran, T., Mansfield, M.L. and Ravikumar, A.P., 2019. Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells. Elem Sci Anth, 7(1), p.43. http://doi.org/10.1525/elementa.381

This Article is brought to you for free and open access by the Research Centers at DigitalCommons@USU. It has been accepted for inclusion in Bingham Research Center by an authorized administrator of DigitalCommons@USU. For more information, please contact digitalcommons@usu.edu.
RESEARCH ARTICLE

Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells

Seth N. Lyman*†, Trang Tran* marc L. Mansfield* † and Arvind P. Ravikumar‡

We deployed a helicopter with an infrared optical gas imaging camera to detect hydrocarbon emissions from 3,428 oil and gas facilities (including 3,225 producing oil and gas well pads) in Utah’s Uinta Basin during winter and spring 2018. We also surveyed 419 of the same well pads from the ground. Winter conditions led to poor contrast between emission plumes and the ground, leading to a detection limit for the aerial survey that was between two and six times worse than a previous summertime survey. Because the ground survey was able to use the camera’s high-sensitivity mode, the rate of detected emission plumes was much higher in the ground survey (31% of all surveyed well pads) relative to the aerial survey (0.5%), but colder air temperatures appeared to impair plume detection in the ground survey as well. The aerial survey cost less per facility visited, but the ground survey cost less per emission plume detected.

Well pads with detected emissions during the ground and aerial surveys had higher oil and gas production, were younger, were more likely to be oil well pads, and had more liquid storage tanks per pad relative to the entire surveyed population. The majority of observed emission plumes were from liquid storage tanks (75.9% of all observed plumes), including emissions from pressure relief valves and thief hatches on the tank or from piping that connects to the tank. Well pads with control devices to reduce emissions from tanks (combustors or vapor recovery units) were more likely to have detected emissions. This finding does not imply that the control devices themselves were not functioning properly. Instead, gas was escaping into the atmosphere before it reached control devices. Pads with control devices tended to be newer and have higher oil and gas production, which probably explains their higher rate of detected emissions.

Keywords: Oil and gas; Optical gas imaging; Hydrocarbons; Emissions; FLIR GF320; Infrared camera

Introduction

Many recent studies have highlighted the impact of hydrocarbon emissions from the oil and gas industry on air quality and climate (Balcombe et al., 2018; Field et al., 2014). Basin-scale (Foster et al., 2017; Robertson et al., 2017; Schwietzke et al., 2017) and nation-scale (Bruhwiler et al., 2017; Miller et al., 2013; Omara et al., 2018) studies have improved understanding of the importance of oil and gas-related emissions. Millions of components at oil and gas sites are potential leak sources (Epperson et al., 2007; Schwietzke et al., 2018). Optical gas imaging cameras have emerged as a valuable tool to fill this need (Safitri et al., 2011).

Optical gas imaging cameras visualize a narrow band of the infrared spectrum in which methane and other hydrocarbons are absorptive (between 3 and 4 μm, depending on the make and model of the camera), allowing users to visualize hydrocarbon emission plumes that are invisible to the unaided eye. These cameras allow users to quickly and definitively locate natural gas emissions from oil and gas industry facilities and equipment. Use of these cameras within the oil and gas industry is widespread. U.S. Environmental Protection Agency (U.S. EPA) regulations require leak detection and repair at many oil and gas wells in the United States (CFR, 2016) and they allow operators to use optical gas imaging for this purpose. Government agencies also use optical gas imaging cameras for regulatory compliance inspections. Scientific studies have shown the utility of optical gas imaging technology (Brantley et al., 2015; Lyon et al., 2016; Subramanian et al., 2015; Thoma et al., 2017) and have highlighted challenges to their use. This technology is qualitative, and the minimum detectable emission rate of optical gas imaging cameras is variable. Ultimately, the detectable emission rate depends on the amount of contrast in the camera image between the plume and the background behind the plume. Factors that influence contrast between the plume and the background include plume conditions (plume temperature, density and composition), the conditions of the background (temperature,
Two previous optical gas imaging surveys of emissions from oil and gas production facilities have been conducted in Utah’s Uinta Basin. The first was a helicopter-based survey conducted during summer 2014 by Lyon et al. (2016). Lyon et al. surveyed 1389 well pads over nine days and detected emissions from 6.6% of surveyed pads. Relative to the entire surveyed population, pads with detected emissions were newer, higher producing and more likely to be oil well pads. Almost all of the emissions observed by Lyon et al. were from liquid storage tanks. The second previous survey was a ground-based survey conducted during summer and fall 2016 by Mansfield et al. (2017). They surveyed 454 well pads from the ground at the edge of well pads and detected emissions from 39% of pads surveyed. All of the well pads surveyed by Mansfield et al. were oil well pads, all were constructed within the previous few years, and all had control devices installed to reduce emissions from liquid storage tanks. As with the Lyon et al. study, the majority of observed emissions in the Mansfield et al. study were from liquid storage tanks.

Here we present the results of simultaneous aerial and ground-based optical gas imaging surveys conducted in winter and spring 2018 using methods similar to Lyon et al. (2016) and Mansfield et al. (2017), respectively. We compare the results from aerial and ground-based survey platforms, make comparisons among all the optical gas imaging surveys that have been conducted in the Uinta Basin, and investigate the impacts of meteorological and surface conditions, well pad properties, pad ownership, and other factors on the frequency and qualitative size of detected emissions.

**Methods**

This study included an aerial optical gas imaging survey and two ground-based surveys of oil and gas wells in the Uinta Basin. Table 1 provides a summary of data collected in this study and in previous optical gas imaging surveys that have been carried out in the Uinta Basin.

### Table 1: Summary of optical gas imaging surveys that have been conducted in the Uinta Basin. DOI: https://doi.org/10.1525/elementa.381.t1

| Survey Type                          | Time period         | Camera       | Type                        | Facilities surveyed | Producing well pads surveyed | Notes                      |
|-------------------------------------|---------------------|--------------|-----------------------------|---------------------|-----------------------------|----------------------------|
| Aerial survey                       | Feb–Mar 2018        | FLIR GF320   | Aerial                      | 3,428               | 3,428                       |                            |
| Winter ground survey (this study)   | Feb–Mar 2018        | FLIR GF320   | Ground (at edge of pad)     | 109                 | 109                         | Synchronized with aerial   |
| Spring ground survey (this study)   | Apr–May 2018        | FLIR GF320   | Ground (at edge of pad)     | 310                 | 310                         |                            |
survey had been conducted, though the helicopter only operated during February and March. The ground crew only surveyed oil and gas well pads.

The ground crew surveyed from the edge of each well pad at the pad’s access road. They used a tripod or the vehicle to stabilize the camera and spent several minutes at each pad scanning for emissions, including in the camera’s auto-mode and high-sensitivity mode. If the ground survey crew detected emissions from any source, they recorded a video of the emissions. They made a qualitative determination of whether the observed emission plume was small, medium, or large and recorded how many distinct emission sources they observed and the observed source of the emissions. As with the aerial survey, plume size determinations were subjective and are expected to have been influenced by plume, background, and meteorological conditions.

At every well pad they surveyed, whether emissions were observed or not, the survey crew recorded their distance from the well pad’s liquid storage tanks as determined by a rangefinder. They also recorded the number of liquid storage tanks at each well pad, the type of background that was behind the plume, and whether it was sunny. Meteorological instrumentation that measured temperature, humidity, barometric pressure, wind speed and direction, and solar radiation (spring survey only for solar radiation) was mounted to the top of the survey crew’s vehicle. We calibrated meteorological instrumentation against NIST-traceable standards within the prior 12 months. The ground survey crew was not able to conduct surveys at pads where workovers or other maintenance activities were occurring because doing so would block the entrance of the pad, constituting a safety risk. Thus, we excluded these pads from the ground survey.

Industry involvement
We provided oil and gas companies whose facilities we surveyed with survey results within about 24 hours of the survey, and we provided videos as soon as we were able. After we sent videos and other final survey information, we asked companies at whose facilities emissions were observed or not, the survey crew viewed propane emissions at 50 m above ground. The helicopter crew viewed propane emissions at 50 m above ground on the first release day, and at 75 m on subsequent days.

Detection limit modeling
We used the method of Ravikumar et al. (2016) (also see Ravikumar and Brandt (2017) and Ravikumar et al. (2018)) to model the relationship between apparent ground temperature and detection limits during the aerial survey and for the period of the Lyon et al. (2016) study. The Ravikumar model uses measured meteorological conditions and surface properties to simulate radiance from the plume and the background. The model takes into account plume composition, emission size distribution, and distance from the plume, and the model has been validated against actual emission measurements (Ravikumar et al., 2016).

Cost calculations
Aerial survey costs used in this work are actual costs, rounded to the nearest $5,000. We separated helicopter mobilization costs from other costs since mobilization costs will vary depending on the helicopter’s origin and destination, while other aerial survey costs are likely to be consistent regardless of the survey location. We assumed ground survey costs to include an hourly camera operator rate of $84.78 (ICF, 2016), as well as a $10,000 per-year maintenance and depreciation cost for the optical gas imaging camera (spread over 180 days of use per year) and 16 km driven per well pad (our ground crew’s average actual travel distance) at a rate of $0.70 per mile (our ground crew’s actual cost). We assumed an operator could survey 17.4 well pads per 8-h day, which was the average rate of our survey crew.

Data access, processing, and analysis
We obtained oil and gas facility information from the Utah Division of Oil, Gas and Mining (UDOGM, 2018). The aerial survey crew only recorded survey locations when emissions were detected, so we followed the method of Lyon et al. (2016) to produce a dataset of all the well pads within the survey area. We excluded pads that were not producing (using February 2018 production data) and we aggregated well information to the pad level (based on proximity of well heads to one another) since wells on multiple-well pads with shared equipment were counted as a single facility by the aerial survey crew. Pads with tanks with emissions controls (combustors or vapor recovery units) were identified based on the 2014 Utah air agencies oil and gas emissions inventory (UDAQ, 2018b), information received from well pad operators, and the ground survey crew’s notes. We used the ground survey crew’s counts of the number of tanks per pad for analyses of ground survey results, and we used the 2014 inventory
data to obtain the number of tanks for the pads in the aerial survey. The inventory listed slightly fewer tanks per pad than the ground survey crew found (−0.1 (−0.3, 0.1) fewer tanks were listed in the inventory), which could have been due to counting errors or changes in well pad configurations between the 2014 inventory data collection and our 2018 survey. We calculated well pad age as the number of months since the well(s) were completed at the pad.

We use units from the International System of Units, except in the case of oil and gas production data. For gas production, we use MCF, which is 1,000 feet³ (28.3 m³) of natural gas at 15.6°C and 101.3 kPa. For oil production, we use bbl (barrels), which is equivalent to 159 L.

In addition to the meteorological data collected for the ground survey, we used data from the Vernal airport to compare meteorological conditions during this study to those during the Lyon et al. (2016) survey, and for detection limit modeling. The Vernal airport is 64 km northeast of the geographic center of the survey areas. The survey areas spanned 147 km east to west and 78 km north to south. We obtained Vernal airport data from the National Climatic Data Center (NCDC, 2018). We used the MODIS Terra 500 m snow cover dataset (MODIS, 2018) to determine average percent snow cover for each survey area on each day of the aerial survey. For days during which a survey area had less than 50% data coverage in the MODIS dataset, we assumed that (1) the snow cover on the missed day was the average of the days before and after, or (2) the daily rate of change in snow cover in that area was the same as other survey areas with similar percent snow cover (if data coverage was less than 50% for two or more consecutive days).

We show average values as average (lower 90% confidence limit, upper 90% confidence limit) throughout the text. We calculated bootstrapped confidence intervals using the SciPy module in Python (with scikit-bootstrap). We give correlation results as r² values, and we calculated these and related p values using the Spearman rank correlation method, following Zar (2005). We used a 95% confidence threshold in the Monte Carlo analysis (see below).

In general, correlations of meteorological and well pad variables with detected emissions were poor, showing that the presence or absence of emission plumes was driven mostly by variables our study did not capture. This is a common finding for emissions datasets (Lyman et al., 2017; Lyon et al., 2016). Factors like well design, operator activities, and equipment malfunctions likely largely determine the frequency and severity of emission plumes, and these factors our study design could not adequately account for. The analyses below mostly utilize data that have been averaged into bins (i.e., well pads with detected emissions compared to those without, data grouped by ambient temperature, etc.), since binning of data reduces the effects of outliers and improves statistical power (as many others have shown, for example Lyon et al. (2016), Schwietzke et al. (2017), Allen et al. (2015), and Edwards et al. (1994)).

We calculated two metrics to characterize the statistics of observed emissions during the winter and spring ground surveys. These were (1) the number of observed emission plumes per well pad, and (2) a “severity score,” intended to convey the qualitative size of emissions as observed by the survey crew. For the severity score, we assigned a value of 1 for plumes categorized as small, 2 for medium, and 3 for large. An average value was calculated for each well pad at which at least one emission is observed.

Monte Carlo analysis of company performance

We used a Monte Carlo analysis to determine whether emission plume detection results for individual companies were statistically significantly different from the mean for the entire dataset (Besag, 1992). For this analysis, M is the number of well pads in the entire dataset that belong to company X. The average emission detection result (i.e., plumes per pad or severity score) for company X is mₓ. We generated a large number (10⁶) of independent, random subsets of the results for the entire dataset, each subset containing M well pads. The result for each random subset is mₓ and p is the fraction of the time that mₓ is less than mₓ–p, then, is the probability that a random selection of M well pads has a lower emission detection result than the M well pads belonging to company X. Therefore, p values near zero and one, respectively, mean that company X has a lower or higher result than the entire dataset, respectively. We use a threshold of 95% to define statistical significance for this analysis, so p less than 0.05 represents statistically significantly better performance for company X, while p greater than 0.95 implies statistically significantly poorer performance, while any p between 0.05 and 0.95 is not strong evidence either way.

Results

Controlled propane releases

The ability of the aerial survey crew to clearly detect the controlled propane plumes was not dependent on the emission rate. The 5.04 g s⁻¹ plume was less consistently visible than the 1.89 g s⁻¹ plume, in spite of being more than twice as large, perhaps because of the difference in helicopter height (75 versus 50 m) or the difference in meteorological conditions (more complete snow cover for the 1.89 g s⁻¹ plume). The 3.49 g s⁻¹ plume was the most clearly detectable from the helicopter. All of the propane plumes were clearly detectable with the ground camera (at a distance of 50 m) for all of the propane releases, including a plume generated at 0.14 g s⁻¹ for the ground camera only.

Ravikumar et al. (2018) found median detection limits for a GF320 camera of 0.005, 0.014, 0.036, and 0.042 g s⁻¹ of methane at measurement distances of 6, 9, 12, and 15 m, respectively, in a summertime ground-based field study in Colorado. Extrapolating their data to a distance of 50 m, we calculate an expected median detection limit of 0.20 g s⁻¹ of methane. Optical gas imaging cameras are 3.4 times more sensitive to propane than to methane (Providence, 2019), so we estimate the Ravikumar et al. (2018) 50 m detection limit for propane to be 0.06 g s⁻¹, in the same range as the 0.14 g s⁻¹ lowest release rate in this study.

These tests showed that the detection limit for the ground-based camera was at least ten times better than that for the aerial camera, even though we used the same...
model of camera in both cases. The reason for this difference was likely because the ground-based camera was mounted on a stationary tripod and operated in high sensitivity mode, while the helicopter-based camera could only operate in auto mode because of its constant movement. The background behind the plume was the ground for both cameras, and the distance from the plume was similar. Table S-1 provides detailed information about each propane release, and optical gas imaging videos of propane releases are also available (see data accessibility statement).

Survey overview
Of the 3,428 oil and gas facilities in the aerial survey, the survey crew only detected emission plumes at 16 (0.5%), all of which were producing oil and gas well pads (they surveyed 3,225 producing well pads). In contrast, emissions were detectable at 129 of the 419 well pads visited during the winter and spring ground surveys (31%). A total of 198 emission plumes, or 0.47 plumes per pad, were observed in the ground surveys (some pads had none, and others had multiple detected emission plumes). Example videos are available (see data accessibility statement).

The aerial crew surveyed wells belonging to twenty companies, but only eleven of those companies had wells included in the ground survey. The ground survey included every well at which the aerial crew detected emissions. Seven out of these eleven companies responded to our request for information about observations in the aerial and ground surveys. Of the four that did not respond, two had recently sold their assets in the Uinta Basin to another party, but the new ownership information was not available at the time of the survey. We received responses for 81% of the well pads at which we observed emissions in the aerial survey and 90% of the well pads at which we observed emissions in the ground survey.

Impacts of meteorology, background, and distance
Aerial survey
Average conditions were calm, cold, and clear during the aerial survey, with daytime wind speed of 1.4 (1.2, 1.5) m s\(^{-1}\), daytime temperature of –2.6 (–4.6, –0.6)\(^\circ\)C, and skies that were reported as clear for 92 (85, 97)% of daytime hours on survey days. Wind speeds ranged between 0 and 4.0 m s\(^{-1}\). Daytime average temperatures varied between –9.1 and 2.6\(^\circ\)C. Average hourly visibility was greater than 10 km on all survey days. Average snow cover was 0.5 (0.0, 1.5)% in surveyed areas on survey days, and ranged between 0 and 8%. The number of emission plumes detected per pad on each aerial survey day was not correlated with daily meteorological conditions.

Ground surveys
We conducted the winter ground survey on the same days as the aerial survey, so the conditions were the same for both surveys. During the spring ground survey, wind speed at survey locations, temperature at survey locations, and percent of survey locations where it was reported to be sunny were 3.0 (2.8, 3.2) m s\(^{-1}\), 18.0 (17.4, 18.7)\(^\circ\)C, and 70%, respectively. No snow cover existed during the spring ground survey. In the ground survey, fewer emission plumes were detected per pad at lower temperatures (Figure 1), though the large confidence intervals show that they dataset is noisy and the trend is not statistically significant. Cold ambient temperature leads to poorer contrast between the plume and the background (Ravikumar et al., 2016). Fox et al. (2017) and Fox et al. (2019) discussed the problem of poor optical gas imaging detection during winter months due to cold temperatures. More plumes were detected per pad at the lowest wind speeds, likely because of decreased plume dilution (Ravikumar and Brandt, 2017), though this trend was inconsistent across the range of observed wind speeds.

Figure 1: Average number of detected plumes per pad in the ground survey, binned by wind speed and temperature. Temperature was binned in 5°C increments, and wind speed was binned in increments of 1 m s\(^{-1}\). Whiskers show 90% confidence intervals. DOI: https://doi.org/10.1525/elementa.381.f1
Sunny conditions in the ground survey yielded more detected emissions than cloudy conditions (0.63 (0.50, 0.76) and 0.41 (0.27, 0.58) plumes detected per pad in sunny and cloudy conditions, respectively). Sunny conditions allow for more surface heating, creating better contrast between the plume and the background if the ground is used as a background. Clear sky conditions also provide better contrast if the sky is used as a background (Ravikumar et al., 2016). No statistically significant differences in plume detection existed for different backgrounds behind plumes.

It is possible that we detected fewer emission plumes during colder and/or cloudier conditions because of differences in well pad operations that led to fewer actual plumes under these conditions, rather than because of differences in camera detection. There was, however, no correlation of oil or gas production rates with ambient temperature or cloudiness at the wells we visited (maximum \( r^2 \) was 0.05), and no relationship between oil or gas production rates and season (\( r^2 = 0.01, p = 0.79 \) for oil; \( r^2 = 0.12, p = 0.26 \) for gas; calculated from average monthly production data for all Utah wells between 2015 and February 2018).

The fraction of well pads with no observable emissions in the ground survey increased from 41% to 76% as the observation distance increased from 16 m to over 100 m, and the fraction of small and medium plumes decreased. All plumes detected at distances over 100 m were in the large-size class. Detection limits have been shown to be related to observation distance in other studies (Ravikumar et al., 2016).

Sources of observed emissions

Aerial survey

All but one of the 16 detected emission plumes in the aerial survey originated from liquid storage tanks. At five of the pads, detected emissions were due to intermittent activities, including liquids unloading and activities related to a well workover. Repairs that operators reported in response to the aerial survey were routine tasks, including closing valves or hatches and making adjustments to control devices. About two months after the aerial survey, the ground survey crew visited all but one of the pads at which the aerial survey detected emissions, and they observed emissions at 13 of 15 pads visited, including all the pads at which repairs were reported. Of the 11 pads at which detected emissions were not due to liquids unloading or maintenance activities, six showed the same source of emissions in both the aerial and ground surveys. Table S-2 presents details about each well pad at which the crew detected emissions in the aerial survey, including findings from the follow-up ground survey at the same pads.

Ground survey

Table 2 shows emission sources at the well pads where emission plumes were detected. For the entire dataset, thief hatches, pressure relief valves and tank vent pipes comprised the majority of emission sources (75.9% of all observed plumes), with emissions of all three qualitative sizes detected. Official inventories show that liquid storage tanks are important sources of hydrocarbon emissions (Pétron et al., 2014), and component-level studies have highlighted tank emissions as significant (Brantley et al., 2015; Hendler et al., 2009).

Pads with emission controls on tanks had a similar source distribution to the entire dataset (i.e., most emissions were not from the control devices themselves, but from tank hatches, vents, or piping upstream of the control devices), but they tended to have a larger percentage of plumes qualitatively categorized as large, perhaps because pads with controlled tanks tend to have higher production rates (see discussion below).

Companies reported that they made repairs in response to this study at 56 well pads (43% of all pads with observed emissions). At 34% of the pads for which we received responses, companies indicated that observed emissions

Table 2: Sources and qualitative sizes of observed emissions for the entire dataset and well pads with emissions controls on tanks. S, M, and L indicate emission plumes that were qualitatively categorized as small, medium, and large, respectively. DOI: https://doi.org/10.1525/elementa.381.t2

| Source                  | Entire ground survey dataset | Pads with controlled tanks |
|-------------------------|------------------------------|-----------------------------|
|                         | S   | M   | L   | TOTAL | %     | S   | M   | L   | TOTAL | %     |
| Thief hatch             | 19  | 27  | 13  | 59    | 30.3% | 3   | 11  | 11  | 25    | 26.6% |
| Pressure relief valve   | 24  | 18  | 13  | 55    | 28.2% | 13  | 9   | 10  | 32    | 34.0% |
| Tank vent pipe          | 18  | 7   | 9   | 34    | 17.4% | 4   | 5   | 8   | 17    | 18.1% |
| Combustor               | 3   | 1   | 2   | 6     | 3.1%  | 3   | 1   | 2   | 6     | 6.4%  |
| Flare stack             | 1   | 5   | 1   | 7     | 3.6%  | 0   | 2   | 1   | 3     | 3.2%  |
| Unidentified source     | 2   | 2   | 0   | 4     | 2.1%  | 1   | 2   | 0   | 3     | 3.2%  |
| Underground pipe        | 0   | 1   | 0   | 1     | 0.5%  | 0   | 0   | 0   | 0     | 0.0%  |
| Dehydrator              | 4   | 13  | 3   | 20    | 10.3% | 1   | 3   | 2   | 6     | 6.4%  |
| Chemical pump           | 0   | 1   | 0   | 1     | 0.5%  | 0   | 0   | 0   | 0     | 0.0%  |
| Well head               | 4   | 1   | 3   | 9     | 4.6%  | 2   | 0   | 0   | 2     | 2.1%  |
| TOTAL                   | 75  | 76  | 44  | 195   | 100.0%| 27  | 33  | 34  | 94    | 100.0%|
from tanks were part of normal operations (i.e., the tanks were uncontrolled), and thus repairs were not needed. Operators completed repairs within 43 (34, 52) days of the ground survey date. Table 3 shows repair categories, the number of repairs made, and costs incurred for repairs.

**Results by company**

Table 4 provides anonymized company-level information about the results of the aerial and ground surveys. The frequency and average qualitative size (i.e., severity score) of detected emission plumes varied widely among companies whose well pads we surveyed in this study. All operators that responded to the survey reported that they had a leak detection and repair program for well pads in the Uinta Basin, but no clear relationship existed between inspection frequency and plume detection frequency or severity in Table 4.

Pads with emissions controls on tanks had a higher number of detected plumes per pad and a worse severity score than the entire dataset, and these differences were statistically significant (Monte Carlo test; see methods for more information). This shows that well pads with emission controls on tanks are more likely to (1) have detectable emissions from tanks and (2) have qualitatively larger emission plumes than the dataset as a whole. We discuss possible reasons for this below.

**Well pad properties**

Table 5 shows a comparison of the properties of all surveyed producing well pads and the pads at which we detected emissions. Compared to the entire population of surveyed pads, pads with detected emissions were higher-producing (as shown by Brantley et al. (2015)), were younger (as shown by Lyon et al. (2016)), and had more tanks per pad.

### Table 3: Number and cost of repairs reported by operators. DOI: https://doi.org/10.1525/elementa.381.t3

| Repair category                  | Number of repairs made | Cost of repairs |
|----------------------------------|------------------------|-----------------|
| Hatch maintenance                | 26                     | $308 ($199, $446) |
| Piping repair                    | 8                      | $127 ($28, $238) |
| Combustor maintenance            | 7                      | $119 ($43, $241) |
| Pressure relief valve repair     | 7                      | No data         |
| Hatch replacement                | 6                      | $3,872 ($2,829, $5,046) |
| Regulator replacement            | 1                      | No data         |

### Table 4: Average frequency and qualitative severity of detected emission plumes by company. DOI: https://doi.org/10.1525/elementa.381.t4

| Company | Pads surveyed | LDAR frequency | Entire ground survey dataset | Pads with controlled tanks |
|---------|---------------|----------------|-------------------------------|-----------------------------|
| A       | 16            | No data        | 0.63 2.5                      | 0.83 2.4                    |
| B       | 121           | Semiannual/none| 0.41 2.2                      | 0.44 2.4                    |
| C       | 58            | No data        | – –                           | – –                         |
| D       | 21            | No data        | 0.31 2.3                      | 0.36 2.3                    |
| E       | 227           | None           | 0.91 1.9                      | 1.47 2.0                    |
| F       | 474           | Semiannual     | **0.30** 1.6                  | **0.13** 1.0                |
| G       | 581           | Annual         | 0.66 1.7                      | 1.43 1.8                    |
| H       | 755           | Annual/monthly | **0.20** 2.0                  | **0.25** 2.3                |
| I       | 7             | No data        | 0.25 2.0                      | 0.33 2.0                    |
| J       | 65            | Semiannual     | 1.00 2.0                      | 1.00 2.0                    |
| K       | 248           | No data        | **0.17** 1.0                  | **0.00** 0.0                |
| L       | 75            | No data        | 1.00 1.0                      | 1.00 1.0                    |
| Average |               |                | **0.47** 1.8                  | 0.72 1.9                    |

Values in bold indicate that the company’s performance for a given metric is better than the group, as determined by a Monte Carlo analysis of statistical significance, and values in italic indicate that a company underperformed the group. LDAR (leak detection and repair) frequency is also shown and indicates the frequency at which companies reported they inspect for leaks at the well pads in the survey.
We detected emissions from 13% of the pads with tank emissions controls, compared to 21% of the pads with detectable emissions detected in the same aerial survey. Although the aerial survey detected more emissions than the ground survey, we estimate that the ground survey detected a lower percentage of the pads with detectable emissions than we detected in the aerial survey. This could be due to the fact that the ground survey was conducted during the summer months, while the aerial survey was conducted during the winter months. The summer months tend to have higher wind speeds and temperatures, which can affect the detection of emissions.

In addition, the ground survey used a smaller detection limit than the aerial survey, which resulted in fewer detections. Therefore, it is possible that the ground survey underestimated the number of pads with detectable emissions.

Table 6 shows a cost breakdown for the aerial and ground surveys (the aerial survey also included about $10,000 in mobilization and demobilization costs that are excluded from Table 6 because mobilization costs can be expected to vary depending on the origin and destination of the helicopter). The aerial survey was able to visit more well pads in a much shorter period, so the cost per facility surveyed was lower for the aerial survey than for the ground survey. The poorer detection limit of the aerial survey led to a much higher cost per detected emission plume, however. Since we expect detection limits for the aerial survey to be better in summer, Table 6 also shows the cost per detection with the assumption of a 6.6% detection rate, which was the rate during the summertime Lyon et al. (2016) study.

Schwietzke et al. (2018) compared the cost per methane emissions avoided for ground optical gas imaging versus two different aerial emissions detection methods. When Schwietzke et al. assumed all aerial emissions detected were repairable, except cases of methane slip and maintenance events, they found that their ground-based survey was much more expensive per amount of methane reduced than the two aerial detection methods used. Since we made no attempt to quantify emissions, our study is not directly comparable with Schwietzke et al. We expect that the emission plumes detected in the aerial survey were, on average, much larger than in the ground survey, so if we were able to calculate cost per mass of hydrocarbon emissions reduced, rather than the cost per emission plume detected, Table 6 might look very different, and our findings might be more similar to those of Schwietzke et al. Companies that responded to our requests for information...
our survey did not include the cost of any leak quantification equipment.

Our ground survey method was very different from Schwietzke et al. (2018), which may also have caused some of the difference between the two studies. Because we conducted our survey from the edge of the pad, and because we did not attempt to quantify emission rates, we were able to visit 2.1 facilities per hour, while the Schwietzke et al. ground crew was able to visit only 1.0 facilities per hour. Also, we used the same source (ICF, 2016) to calculate a total hourly cost (labor, mileage, and equipment) of only $107, compared to their $142, since our survey did not include the cost of any leak quantification equipment.

Comparison with other Uintah Basin surveys

Comparison with Mansfield et al.
The ground-based portion of our study and the Mansfield et al. (2017) ground survey of oil well pads with control devices on tanks both showed that a high percentage of pads with tank controls have detectable emissions (47 versus 40%, respectively) and that most emissions were from liquid storage tanks (75.9 versus 82.6%). Both studies also showed an increased likelihood of detected emissions and emission plumes categorized as large from pads with higher oil and gas production. In controlled propane releases conducted by Mansfield et al., the emission plume was not consistently detectable from a 50 m distance at 0.3 g s\(^{-1}\), whereas in this work we could clearly detect a propane emission of 0.14 g s\(^{-1}\). The propane source was identical in both studies, but Mansfield et al. used an OpGal EyeCGas camera, rather than the FLIR GF320 camera used in this work.

Well pads owned by some of the companies shown in Table 4 were also surveyed by Mansfield et al. (2017), and we surveyed 53 of those pads in the current study. Comparing pads with controlled tanks in this study to the Mansfield et al. results, companies A and E increased from 0.27 to 0.83 and 0.55 to 1.47 plumes per pad, respectively, over the 1.5 years between the two studies. Company F improved, changing from 0.60 to 0.13 plumes per pad and from a severity score of 2.2 to 1.0. Companies B and D were similar in both studies. We compared the average pad age and oil production rates for the pads with controlled tanks in this study to the Mansfield et al. results, but we did not find any consistent relationships between these parameters and changes in plume size or detection rates.

Table 6: Aerial and ground survey costs. DOI: https://doi.org/10.1525/elementa.381.t6

|                             | Aerial survey | Ground survey |
|-----------------------------|--------------|---------------|
| Survey cost                 | $75,000      | $21,000       |
| Survey days                 | 10           | 24            |
| Facilities surveyed         | 3,428        | 417           |
| Facilities surveyed with detected emissions | 16         | 129           |
| Facilities surveyed per day | 343          | 17            |
| Survey cost per day         | $7,500       | $900          |
| Cost per facility surveyed  | $22          | $50           |
| Cost per facility with detected emissions | $4,690 | $160 |
| Cost per facility with detected emissions (assuming Lyon et al. (2016) detection rate) | $330 | – |

Comparison with Lyon et al.

Emission plumes were detected at a much lower percentage of oil and gas facilities in the aerial portion of the current study (0.5%) relative to the Uinta Basin portion of the study performed by Lyon et al. (2016) (6.6%). Both aerial surveys were conducted by the same company with the same camera and camera operator, with the same camera settings, and the helicopter flew at the same height above ground in both studies.
Englander et al. (2018) returned to the Bakken oil field in North Dakota and conducted an aerial infrared camera survey one year after the survey conducted there by Lyon et al. (2016). Both surveys were conducted in September. For pads that were surveyed in both years, Englander et al. found a similar percentage of detected emissions (11.1% versus 10.8%). Further, they showed that pads with detected emissions in the first study were likely to be emitting in the second study. We, on the other hand, did not detect emissions at any of the 652 pads in our survey that were also part of the Lyon et al. survey, even though Lyon et al. detected emissions at 47% (7%) of those pads. Unlike the Englander et al. study, our study occurred four years after the original Lyon et al. study, allowing for significant changes in the industry to occur. Also, our study occurred in a different season (February-March versus July), resulting in poorer detection limits.

The surveyed well pad population in this study was 34% older, produced 34% less oil, and produced 26% less of its energy from oil (determined using the method presented by Lyon et al. (2016)) relative to the survey conducted by Lyon et al. All of these well pad properties were associated in both studies with a decreased likelihood of emissions that were detectable from the helicopter. Also, industry practices and regulations are changing, which could lead to lower per-pad emissions (EPA, 2018; Lamb et al., 2015; UDAQ, 2018a).

Wind speed (1.4 (1.2, 1.5) versus 1.5 (1.2, 1.9) m s⁻¹, respectively) and cloudiness (clear skies 92 (85, 97) versus 89 (70, 95)% of survey hours) were similar during this study and the Uinta Basin portion of the Lyon et al. study. Snow cover was not present when the Lyon et al. study was conducted but was very low during this study as well. The most significant meteorological difference between the two studies was temperature (−2.6 (−4.6, −0.6) versus 21.4 (20.6, 22.4)°C in this study and Lyon et al., respectively).

Lower temperature and decreased solar insolation are associated with poorer detection by infrared optical gas imaging cameras (Ravikumar and Brandt, 2017; Ravikumar et al., 2016), and this could account for much of the difference in detection between the two studies. We used the Ravikumar model of plume detectability to explore the extent to which meteorological conditions may have impacted the results of the two studies. For the aerial survey, the background behind the plume was always the ground, so the detection limit was determined by the contrast between the apparent plume temperature (a measure of the amount of infrared energy emitted by and reflected from the plume in the camera’s bandwidth of 3.2 to 3.4 μm) and the apparent ground temperature.

Figure 2 shows the relationship between the modeled minimum methane detection limits of the infrared camera and the apparent temperature difference for the meteorological conditions of the two studies. Since we did not record the apparent ground temperature during the studies, it is impossible to know the actual detection limits with certainty. Typically, summers experience higher differences in apparent temperature compared to winter due to higher solar insolation. If we assume an apparent temperature difference of 20°C in the summer (Lyon et al.) and 10°C in the winter (this study), the minimum detection limits during this study would be higher than those experienced by Lyon et al. in the summer by 3–4 times, which explains at least a portion of the observed lower plume detection rate in this study compared Lyon et al.

Controlled hydrocarbon releases provide another way to compare detection limits in the two studies. In this study, the propane plume was marginally detectable somewhere between 1.89 and 5.04 g s⁻¹. Lyon et al. (2016) reported that a methane emission plume of 3 g s⁻¹ was marginally detectable. Since infrared camera detection limits for propane are 3.4 times lower (i.e., better) than for methane, we can assume a methane detection limit in our study in the range of 6 to 17 g s⁻¹, between 2.1 and 5.7 times worse than the detection limits reported by Lyon et al.

![Figure 2](https://doi.org/10.1525/elementa.381.f2)
Implications

This study has two main implications. First, because optical gas imaging cameras perform relatively poorly in winter, oil and gas facilities at which they are used for leak detection likely have higher overall leak rates in winter compared to summer (since it is likely that more leaks go undetected, and therefore unrepaired, in winter). Use of alternative detection techniques that are not affected by temperature (e.g., handheld natural gas detectors) as a supplement to optical gas imaging may improve wintertime leak detection and repair programs. Though our ground survey was conducted further from potential emission sources than typical on-pad leak detection programs, modeling studies have shown that low temperature likely impacts optical gas imaging detection generally (Fox et al., 2017; Ravikumar et al., 2016).

Secondly, systems to control emissions from liquid storage tanks often do not achieve their intended purpose. We only rarely observed emissions from combustors or vapor recovery units, but we frequently observed emissions from tank infrastructure upstream of these control devices, indicating that a portion of gas in storage tanks escaped before reaching control devices. Our finding that pads with tank emission controls were more likely to have detected emission plumes than the overall study population implies that malfunctioning tank emission control systems are very common. The U.S. EPA released a compliance alert that discusses this problem and its potential causes, which include (1) pressure and/or flow within tanks and associated valves and piping that exceeds the equipment’s capacity, (2) accumulation of liquids that block gas flow in piping, and (3) malfunctioning or improperly maintained pressure relief devices (EPA, 2015). Changes to design and maintenance practices may lead to a reduction in lost gas from emission control systems.

Supplemental files

The supplemental files for this article can be found as follows:

- Table S-1. Information about controlled propane releases conducted to determine detectable emission rates. [Page 2]. DOI: https://doi.org/10.1525/elementa.381.s1
- Table S-2. Information about each well pad at which emissions were detected in the aerial survey. Size is a qualitative determination made by the camera operator. [Page 3]. DOI: https://doi.org/10.1525/elementa.381.s1
- Supplemental material. Example survey videos and anonymized datasets. DOI: https://doi.org/10.1525/elementa.381.s2

Acknowledgements

This work was carried out in cooperation with and under direction from the Ute Indian Tribe and the funding agencies. Personnel employed with these organizations, as well as David Lyon of the Environmental Defense Fund, provided helpful comments and assistance. We are grateful to the many oil and gas companies who partici- pated in this project by providing information about the emissions we observed and by providing comments on drafts of this document. We acknowledge the efforts of Colleen Jones, Trevor O’Neil, Randy Anderson (of Utah State University), and Lexie Wilson (of the Utah Division of Air Quality), who completed the fieldwork for the ground surveys. We are grateful to the Utah Division of Air Quality for providing the FLIR GF320 camera used in the ground survey.

Funding information

The U.S. Bureau of Land Management, the Utah Legislature, the Utah Division of Air Quality, and the U.S. Environmental Protection Agency funded this project.

Competing interests

The authors have no competing interests to declare.

Author contributions

All authors contributed to study conception, design, and article drafting and revisions. MLM conducted the Monte Carlo analysis. APR carried out the detection limit modeling. TT and SNL led other data analyses with contributions from the other authors.

References

Allen, DT, Sullivan, DW, Zavala-Araíza, D, Pacsi, AP, Harrison, M, Keen, K, Fraser, MP, Hill, AD, Lamb, BK, Sawyer, RF and Seinfeld, JH. 2015. Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings. Environ. Sci. Technol. 49(1): 641–648. DOI: https://doi.org/10.1021/acs.est.4b05016

Balcombe, P, Brandon, N and Hawkes, A. 2018. Characterising the distribution of methane and carbon dioxide emissions from the natural gas supply chain. J. Clean. Prod. 172: 2019–2032. DOI: https://doi.org/10.1016/j.jclepro.2017.11.223

Besag, J. 1992. Simple Monte Carlo p-values. Comp. Sci. Stat. 158–162. Springer. DOI: https://doi.org/10.1007/978-1-4612-2856-1_20

Brantley, HL, Thoma, ED and Eisele, AP. 2015. Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and on-site direct measurements. J. Air Waste Manage. Assoc. 65(9): 1072–1082. DOI: https://doi.org/10.1080/10962247.2015.1056888

Bruhwiler, L, Basu, S, Bergamaschi, P, Bousquet, P, Dlugokencky, E, Houweling, S, Ishizawa, M, Kim, HS, Locatelli, R, Makaryutov, S, Montzka, S, Pandey, S, Patra, PK, Petron, G, Saunois, M, Sweeney, C, Schwietzke, S, Tans, P and Weatherhead, EC. 2017. US CH4 emissions from oil and gas production: Have recent large increases been detected? J. Geophys. Res. Atmos. 122(7): 4070–4083. DOI: https://doi.org/10.1002/2016JD026157

CFR. 2016. CFR Title 40, Part 60, Subparts OOOO and OOOOa. Available at https://www.gpo.gov/fdsys/pkg/FR-2016-06-03/pdf/2016-11971.pdf.
Edwards, GC, Neumann, H, Den Hartog, G, Thurtell, G and Kidd, G. 1994. Eddy correlation measurements of methane fluxes using a tunable diode laser at the Kinoseho Lake tower site during the Northern Wetlands Study (NOWES). J. Geophys. Res. Atmos. 99(D1): 1511–1517. DOI: https://doi.org/10.1029/93JD02368

Englander, JG, Brandt, AR, Conley, S, Lyon, DR and Jackson, RB. 2018. Aerial inter-year comparison and quantification of methane emissions persistence in the Bakken formation of North Dakota, USA. Environ. Sci. Technol. 52(15): 8947–8953. DOI: https://doi.org/10.1021/acs.est.8b01665

EPA. 2015. Compliance Alert: EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities. Washington, D.C.: United States Environmental Protection Agency. Available at https://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf.

EPA. 2018. Actions and Notices about Oil and Natural Gas Air Pollution Standards. Available at https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas-regactions. Accessed 2018.

Epperson, D, Lev-On, M, Taback, H, Siegell, J and Ritter, K. 2007. Equivalent leak definitions for smart LDAR (Leak Detection and Repair) when using optical imaging technology. J. Air Waste Manage. Assoc. 57(9): 1050–1060. DOI: https://doi.org/10.3155/1047-3289.57.9.1050

Field, R, Soltis, J and Murphy, S. 2014. Air quality concerns of unconventional oil and natural gas production. Environ. Sci. Proc. Imp. 16(5): 954–969. DOI: https://doi.org/10.1039/C4ES00081A

Foster, C, Crosman, E, Holland, L, Mallia, D, Fasoli, B, Bares, R, Horel, J and Lin, J. 2017. Confirmation of Elevated Methane Emissions in Utah’s Uintah Basin With Ground-Based Observations and a High-Resolution Transport Model. J. Geophys. Res. Atmos. 122.: 13026–13044. DOI: https://doi.org/10.1002/2017JD027480

Fox, TA, Barchyn, T and Hugenholtz, C. 2017. The winter gap effect in methane leak detection and repair with optical gas imaging cameras. AGU Fall Meeting abstract #A41F-2355. New Orleans, Louisiana.

Fox, TA, Barchyn, TE, Risk, D, Ravikumar, AP and Hugenholtz, CH. 2019. A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas. Environ. Res. Lett. 14(5). DOI: https://doi.org/10.1088/1748-9326/ab0cc3

Hendler, A, Nunn, J and Lundeen, J. 2009. VOC emissions from oil and condensate storage tanks: Final report prepared for Texas Environmental Research Consortium. Texas Environmental Research Consortium. Available at http://www.mclaincompany.com/Decision_Tree/subscriber/articles/Emissions_From_Oil_and_Condensate_Storage_Tanks_Final_Report.pdf.

ICF. 2016. Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems. Fairfax, Virginia: ICF International. Available at https://onfuture.us/wp-content/uploads/2018/07/ICF-Study.pdf.

Lamb, BK, Edburg, SL, Ferrara, TW, Howard, T, Harrison, MR, Kolb, CE, Townsend-Small, A, Dyck, W, Possolo, A and Whetstone, JR. 2015. Direct measurements show decreasing methane emissions from natural gas local distribution systems in the United States. Environ. Sci. Technol. 49(8): 5161–5169. DOI: https://doi.org/10.1021/acs.est.5b05116p

Lyman, SN, Watkins, C, Jones, CP, Mansfield, ML, McKinley, M, Kenney, D and Evans, J. 2017. Hydrocarbon and Carbon Dioxide Fluxes from Natural Gas Well Pad Soils and Surrounding Soils in Eastern Utah. Environ. Sci. Technol. 51(20): 11625–11633. DOI: https://doi.org/10.1021/acs.est.7b03408

Lyon, DR, Alvarez, RA, Zavala-Araiza, D, Brandt, AR, Jackson, RB and Hamburg, SP. 2016. Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites. Environ. Sci. Technol. 50(9): 4877–4886. DOI: https://doi.org/10.1021/acs.est.6b00705

Mansfield, ML, Lyman, SN, O’Neil, T, Anderson, R, Jones, C, Tran, H, Mathis, J, Barickman, P, Oswald, W and LeBaron, B. 2017. Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin. Vernal, Utah: Utah State University. Available at https://documents.deq.utah.gov/air-quality/planning/technical-analysis/DAQ-2017-009061.pdf.

Miller, SM, Wofsy, SC, Michalak, AM, Kort, EA, Andrews, AE, Biraud, SC, Dlugokencky, EJ, Eluszkiewicz, J, Fischer, ML, Janssens-Maenhout, G, Miller, BR, Miller, JB, Montzka, SA, Nehrkorn, T and Sweeney, C. 2013. Anthropogenic emissions of methane in the United States. Proc. Natl. Acad. Sci. U. S. A. 110(50): 20018–20022. DOI: https://doi.org/10.1073/pnas.1314392110

MODIS. 2018. MODIS Snow Cover. Available at https://modis.gsfc.nasa.gov/data/dataset/mod10.php. Accessed 2018.

NCDC. 2018. National Climatic Data Center. Available at https://www.ncdc.noaa.gov/. Accessed 2018.

Omara, M, Zimmerman, N, Sullivan, MR, Li, X, Ellis, A, Cesa, R, Subramanian, R, Presto, AA and Robinson, AL. 2018. Methane emissions from natural gas production sites in the United States: Data synthesis and national estimate. Environ. Sci. Technol. 52(21): 12915–12925. DOI: https://doi.org/10.1021/acs.est.8b03535

Pétron, G, Karion, A, Sweeney, C, Miller, BR, Montzka, SA, Frost, GJ, Trainer, M, Tans, P, Andrews, A, Kohler, J, Helmig, D, Guenther, D, Dlugokencky, E, Lang, P, Newberger, T, Wolter, S, Hall, B, Novelli, P, Brewer, A, Conley, S, Hardesty, M, Banta, R, White, A, Noone, D, Wolfe, D and Schnell, R. 2014. A new look at methane and nonmethane...
hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin. J. Geophys. Res. Atmos. 119(11): 6836–6852. DOI: https://doi.org/10.1002/2013JD021272

Ravikumar, AP, Wang, J, and Brandt, AR. 2016. Are optical gas imaging technologies effective for methane leak detection? Environ. Sci. Technol. 51(1): 718–724. DOI: https://doi.org/10.1021/acs.est.6b03906

Ravikumar, AP, Wang, J, McGuire, M, Bell, CS, Zimmerle, D and Brandt, AR. 2018. Good versus Good Enough? Empirical tests of methane leak detection sensitivity of a commercial infrared camera. Environ. Sci. Technol. 52(4): 2368–2374. DOI: https://doi.org/10.1021/acs.est.7b04945

Robertson, AM, Edie, R, Snare, D, Soltis, J, Field, RA, Burkhart, MD, Bell, CS, Zimmerle, D and Murphy, SM. 2017. Variation in Methane Emission Rates from Well Pads in Four Oil and Gas Basins with Contrast Production Volumes and Compositions. Environ. Sci. Technol. 51(15): 8832–8840. DOI: https://doi.org/10.1021/acs.est.7b00571

Safitri, A, Gao, X and Mannan, MS. 2011. Dispersion modeling approach for quantification of methane emission rates from natural gas fugitive leaks detected by infrared imaging technique. J. Loss Prev. Process Indus. 24(2): 136–145. DOI: https://doi.org/10.1016/j.jlp.2010.11.007

Schwietzke, S, Harrison, M, Lauderdale, T, Branson, K, Conley, S, George, FC, Jordan, D, Jersey, GR, Zhang, C, Mairs, HL, Petron, G and Schnell, R. 2018. Aerially guided leak detection and repair: A pilot field study for evaluating the potential of methane emission detection and cost-effectiveness. J. Air Waste Manage. Assoc. DOI: https://doi.org/10.1080/10962247.2018.1515123

Schwietzke, S, Pétrot, G, Conley, S, Pickering, C, Mielke-Maday, I, Dlugokencky, EJ, Tans, PP, Vaughn, T, Bell, C, Zimmerle, D, Wolter, S, King, CW, White, AB, Coleman, T, Bianco, L and Schnell, R. 2017. Improved mechanistic understanding of natural gas methane emissions from spatially resolved aircraft measurements. Environ. Sci. Technol. 51(12): 7286–7294. DOI: https://doi.org/10.1021/acs.est.7b01810

Subramanian, R, Williams, LL, Vaughn, TL, Zimmerle, D, Roscioli, JR, Herndon, SC, Yacovitch, TI, Floerchinger, C, Tkacik, DS and Mitchell, AL. 2015. Methane emissions from natural gas compressor stations in the transmission and storage sector: Measurements and comparisons with the EPA greenhouse gas reporting program protocol. Environ. Sci. Technol. 49(5): 3252–3261. DOI: https://doi.org/10.1021/acs.est.5b060258

Thoma, ED, Deshmukh, P, Logan, R, Stovern, M, Dresser, C and Brantley, HL. 2017. Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions. J. Environ. Prot. Sci. Technol. 8(4): 394–415. DOI: https://doi.org/10.4236/jep.2017.84029

UDAQ. 2018a. Oil & Gas Source Registration (Air Quality). Available at https://deq.utah.gov/air-quality/oil-gas-source-registration-air-quality. Accessed 2018.

UDAQ. 2018b. Uinta Basin: 2014 Air Agencies Oil and Gas Emissions Inventory. Available at https://deq.utah.gov/legacy/destinations/u/unibashterinair-agencies-emissions-inventory/index.htm. Accessed 2018.

UDOVM. 2018. Data Research Center. Available at http://oilgas.ogm.utah.gov/Data_Center/DataCenter.cfm. Accessed 2018.

Zar, JH. 2005. Spearman rank correlation. Encyclopedia of Biostatistics 7. DOI: https://doi.org/10.1002/0470011815.b2a15150