Fugitive Emissions Management Program Effectiveness Assessment

Phase-II Final Report

Arvind P. Ravikumar, The University of Texas at Austin
Jiayang (Lyra) Wang, Harrisburg University of Science and Technology
Adam Brandt, Stanford University
Brenna Barlow, Radicle
Cooper Robinson, Radicle
Wes Funk, DXD Consulting

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Executive Summary

The Fugitive Emissions Management Program Effectiveness Assessment (FEMP-EA) was a research study to characterize spatial and temporal differences in methane emissions from oil and gas facilities subjected to leak detection and repair (LDAR) surveys through field measurements.

The study team randomly selected approximately 180 sites in the Red Deer region in Alberta to be surveyed at regular intervals between August 2018 and October 2019. The sites were split into four groups – one control group where operators were not made aware of the leaks found by the survey team, and three treatment groups where operators were provided with a list of leaks with the expectation of (voluntary) repair. The survey team used FLIR GF-320 optical gas imaging (OGI) cameras to detect methane emissions and Providence Photonics' QL-320 tablet for quantification. The study team chose the QL-320 to comprehensively quantify all emissions found at oil and gas sites which would not have been possible with conventional hi-flow sampler measurements. Detailed controlled release calibration of the QL-320 was conducted as part of the Alberta Methane Field Challenge.

The major findings from this study are summarized below across two categories: findings related to fugitive emissions mitigation, and findings related to methane emissions inventory.

Findings related to fugitive emissions mitigation:

1. **Emissions are persistent.** Temporal analysis of individual leaks by tracking them over the five surveys show that emissions are highly persistent – repaired leaks do not recur, and non-repaired leaks continue to emit. We also find that rates of individual leaking components do not grow over time. This suggests that any increase in emissions observed at oil and gas sites under mandatory LDAR programs (and where leaks are repaired) are likely from new leaks and not because of growth in existing leaks.

2. **Repairs are highly effective in reducing the average number of leaks found in a survey.** Repaired treatment sites exhibit significant reductions in the average number of leaks per site compared to control sites and non-repaired sites. Furthermore, sites that were repaired consistently saw a high reduction in the average number of leaks compared to sites that were repaired at least once. This suggest that (a) repairs are effective, (b) any observed increase in emissions likely come from new leaks and not emissions growth from existing leaks, and (c) consistent repairs of new leaks results in higher emissions reductions than inconsistent repairs.

3. **Repaired sites show more emissions reduction than non-repaired sites – the more consistent the repair, the higher the emissions reduction.** Consistently repaired sites show site-level average emissions reduction of 69%, as compared to the 62% from sites that are repaired at least once and 19% from treatment sites that are not repaired. For average fugitive emissions, consistently repaired sites see a reduction of 74%, as compared to 65% from repaired at least once sites and 19% from not repaired sites. Since emissions are highly skewed, reduction from large leaks (>180 m^3/d) can contribute disproportionately to average emissions reductions.

4. **Fugitive emissions reduced by 22% at control sites and 42%, 48%, and 77% at the three treatment sites.** In sites that were consistently repaired according to the survey schedule, emissions reduced by 48%, 77%, and 42% at 1/year, 2/year, and 3/year treatment sites, respectively. The potential for emission reductions from repairing leaks is also skewed – i.e., less than 10% of the sites found to be emitting contribute over 50% of all emissions reductions in any given survey. Thus,

irrespective of the LDAR survey frequency, the key to emissions mitigation is finding these small number of high-emitting sites quickly through potentially innovative technologies. However, small sample size at treatment sites that underwent repairs according to survey schedule suggests future research is needed to conclusively understand the role of survey frequency on fugitive emissions reductions.

5. **Understanding near-term temporal variations in emissions require detailed future studies based on continuous measurement systems.** The overall emissions reductions observed in the FEMP-EA study between August 2018 and August 2019 included a combination of emissions reduction from both repaired leaks and vents. Many large vent sources are likely episodic and therefore not detected in all surveys. Snapshot observations across time like the FEMP-EA study (or other periodic measurements) are not designed to analyze the impact of these episodic emissions. Future studies with mature continuous monitoring systems that can detect and quantify episodic emissions would be critical to better understanding the impact of short-lived emissions sources.

Findings related to methane emissions inventory:

6. **Emissions are dominated by a very small number of high-emitting components (and sites).** In every survey, 50% of emissions come from less than 5% of components, reinforcing the importance of large emitters in contributing to total emissions. At the site level, less than 10% of sites are responsible for over 50% of emissions.

7. **Tanks are the largest single source of emissions.** Tank-related components such as thief hatches, tank-level indicators, and open-ended lines contribute to between 58% and 82% of total emissions across all surveys. Future work should investigate the root cause for high tank-related emissions observed and identify potential upstream issues that manifest as tank emissions.

8. **Oil sites and multi-well batteries, on average, emit more than gas sites and single-well batteries, respectively.** Oil sites exhibit higher average methane emissions compared to gas sites, often associated with higher number and prevalence of tanks. Future studies with larger sample sizes can determine the statistical significance of this observation.

9. **Vents are the largest source of methane emissions.** Across the five LDAR surveys, vented emissions contribute between a minimum of 69% and a maximum of 86% of total emissions, underscoring the limited impact of reducing leaks in overall methane mitigation programs. However, LDAR surveys can also help identify anomalous vents – vents whose emission rates are significantly higher than designed – that could be potentially addressed cost-effectively.

10. **There are significant differences in average site-level emissions across operators as operators with a larger fraction of oil assets tend to have higher average emissions.** Average per-site emissions by operator vary by almost two orders of magnitude from about 24 m^3/d/site to over 1100 m^3/d/site. Furthermore, operators with more oil assets exhibit higher average site-level emissions compared to operators with more gas assets. 72% of emissions from the top three operators with the highest average site level emissions can be attributed to oil sites. Finally, emissions across operators also exhibit skewed behavior, similar to component-level and site-level emissions. The 4 operators with highest-average site level emissions (top 20%) contribute to 84% of total emissions – together, they operated about 50% of all sites measured in the August 2018 survey.

1. Introduction

Methane emissions from the oil and gas sector are a major source of greenhouse gas (GHG) emissions in Canada, accounting for 25% total methane emissions in 2017 [1]. Recent studies have demonstrated the importance of reducing methane emissions to keep average global temperature increase below 1.5°C [2]–[5]. Given that Canada is warming at almost twice the rate of the rest of the world, it is prone to climate change induced damages through increasing intensity and frequency of extreme rainfall, drought, and wildfires [6], [7]. Given the urgency to reduce GHGs, addressing methane emissions will immediately reduce radiative forcing because of the short atmospheric lifetime of methane. The sustainability of the natural gas industry, particularly considering growing interest in the global liquefied natural gas (LNG) trade, is dependent on reducing methane emissions along the supply chain. The arguments for natural gas being a lower carbon-intensive fuel compared to coal are valid only if methane leakage is lower than about 3% [8]–[11]. Finally, reducing methane emissions also simultaneously reduces emissions of volatile organic compounds thereby improving local air quality [12], [13].

Recently, there have been many studies measuring methane emissions at oil and gas facilities in Canada using a variety of measurement technologies at different spatial resolutions. Figure 1 summarizes these studies over the past four years across British Columbia, Alberta, and Saskatchewan. Recent measurements in Alberta using aerial systems show significant discrepancies between top-down methane emissions measurements and official inventory estimates [14]. Meanwhile, other studies have found significant variation in emissions across different producing basins [14]–[21].

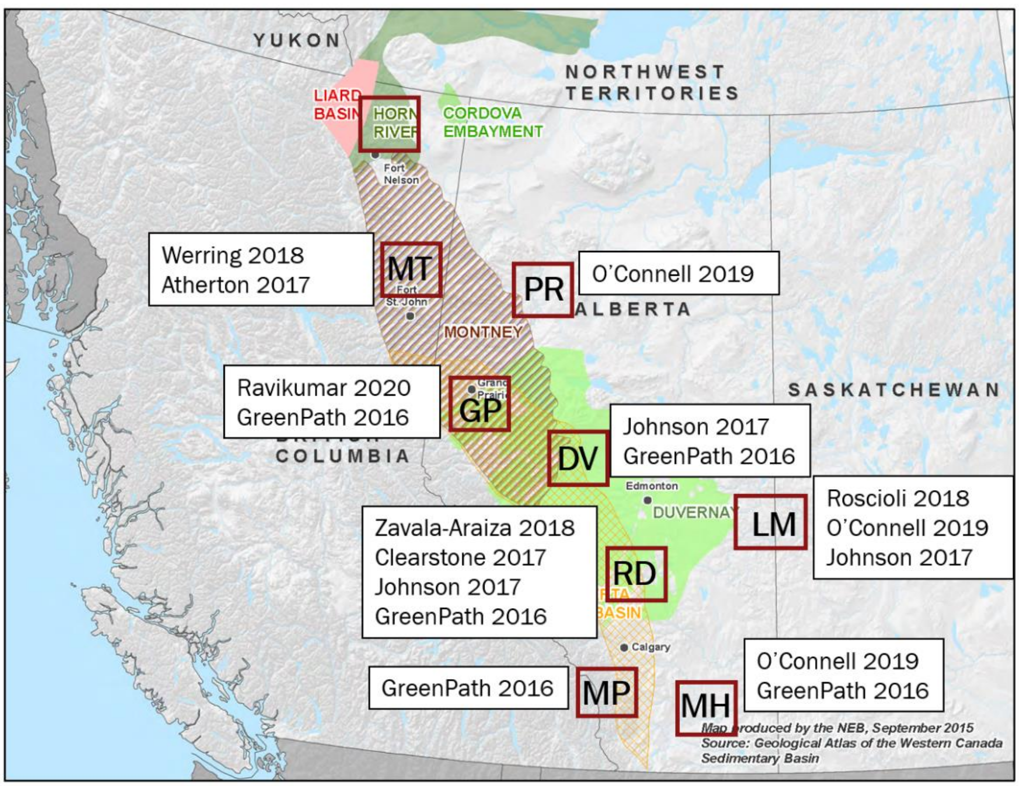

Figure 1. Summary of methane field studies in Canada covering the period 2016 – 2019.

Although extensive in coverage, the results from these studies are not directly comparable because they were conducted using a variety of technologies, in different seasons, and across basins with different characteristics [22], [23]. However, a few general features of methane emissions can be noted – these insights were derived from a combination of field studies, modeling, and analysis of national inventories in Canada and the US. Three important "*priors*" are noted. First, methane emissions are highly skewed – the top 5% of emitters typically account for about 50% of total emissions at the component-level [14], [15], [17], [24]. Second, aerial and other top-down measurements routinely find methane emissions to be significantly higher than bottom-up, component-level estimates [25]–[30]. Third, significant spatial and temporal variations in methane emissions have been observed across basins, partly because of the 'snap-shot' nature of measurements [17], [31]–[35].

In line with Canada's commitment to achieve its intended nationally determined contributions (INDCs) to the Paris Agreement, the federal government recently developed regulations to reduce methane emissions from the oil and gas sector by 40 – 45% by 2025 [36]. Even as there have been many studies on methane emissions at oil and gas facilities, few have focused on mitigation policies and outcomes. For example, Ravikumar et al. discussed the impact of technology limitations on U.S. Environmental Protection Agency (EPA)'s methane regulations [37]–[39]. Recent field work in Alberta in a liquids-rich gas play demonstrated the effectiveness of leak detection and repair (LDAR) programs at reducing methane emissions [16]. A survey among producers in Colorado also suggests that such policies are effective in reducing methane [40]. Other policy-focused studies have addressed the concept of technology and policy equivalence [22], [41], [42], science-policy frameworks [4], [43], or techno-economic analyses [44], [45]. Despite these studies, there has been no large-scale systematic study of the effectiveness of LDAR regulations in reducing fugitive methane emissions or leaks.

The Fugitive Emissions Management Program Effectiveness Assessment (FEMP-EA) sought to address the gap in understanding the efficacy of LDAR surveys in addressing methane emissions. Although one recent study based on measurements at oil and gas facilities near Grande Prairie, Alberta showed that repeated LDAR survey reduces both leaks and vents, the scale and scope was limited [16]. To the best of our knowledge, this is the first large-scale study to undertake repeated leak detection surveys over the course of a year across ~180 sites.

This report is divided into eight sections. We present an introduction to methane emissions from the oil and gas industry in Section 1. Section 2 provides a detailed study design including site selection, survey design, survey methodology, field management and communications, and data management plan. In Section 3, we describe the analysis methodology for all FEMP-EA survey data. Section 4 presents measurement results and insights from each survey individually. In Section 5, we analyze operator-level differences in site-level emissions and emissions distributions across different site-types. Section 6 compares leak data across surveys to analyze repair effectiveness and the impact of survey frequency on reducing leaks. We conclude the report by providing recommendations for future research directions in Section 7 and a summary in Section 8, followed by bibliography.

2. Study Design and Methodology

2.1. Site Selection

Study Region: There are many oil and gas producing basins in Alberta, each with its unique resource characteristics and production economics (see Figure 1). Choosing a survey region depends on consideration of several critical features including production level, number of sites, and accessibility. The three AER administrative regions of Grande Prairie, Drayton Valley, and Red Deer accounted for 76% of total natural gas production in 2016. However, choosing a survey region based on a production basis is likely to reinforce the assumption that low-producing wells do not emit as much methane as moderate to high producing wells; this has been recently proven false [16], [46]. The logistics of surveying 200 sites require that active sites be relatively densely spaced to reduce travel time – thus, wells in the sparsely distributed Grande Prairie region would not be optimal. Considering all these factors, the study team chose Red Deer to conduct the FEMP-EA study. This region provides a reasonable balance between total production (17%), site density and variety of site-types and resource (forested vs. prairie areas), and proximity to major urban centers for quick mobilization. Furthermore, production in the Red Deer region is approximately equally split between gas sites and oil sites, providing a direct and concurrent comparison of methane emissions from oil- and gas-producing sites.

Site Types and Distribution: A study area of 50 x 50 km as shown in Figure 2 was chosen based on the density and distribution of facilities in the Red Deer region. This region corresponds to townships 38 through 42, and ranges 5 through 9, west of the fifth meridian (W5) in the DLS land designation system. Six major site-types are represented in the Red Deer production region – gas gathering systems, gas multi-well (MW) batteries, gas single-well (SW) batteries, oil multi-well (MW) batteries, oil multi-well (MW) prorated batteries, and oil single-wells (SW).

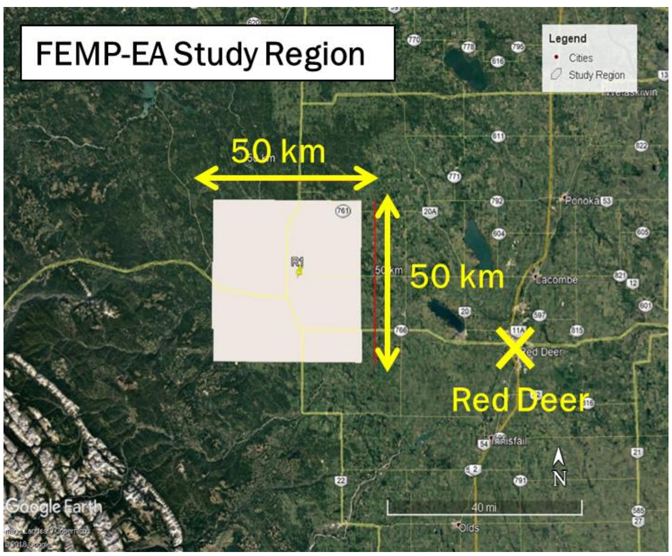

Figure 2. A Google Earth schematic of the FEMP-EA study region near Red Deer, AB. A 50 x 50 km area was chosen to reduce travel-time between survey sites – the sites chosen within this region are representative of broader oil and gas production in Red Deer.

We ensured that the sites within the selected 50 x 50 km region are representative of production and site-density across the entire Red Deer region. The production and distribution data were obtained from the publicly available Petrinex database. It is critical to note that no individual producer or site operator was consulted during the site selection process. Table 1 shows the distribution of gas single-well batteries in the selected study region across each township and range. The 251 gas SW sites in this region corresponds to 25% of all gas SW batteries as well as 25% of total production in Red Deer west of the fifth meridian. The average gas production from gas SW sites within the study region in 2016, 208,000 m^3, is similar to that of the entire Red Deer region, 215000 m^3. Such comparisons were made to all site-types to ensure representativeness of the study region.

Table 1. Number of gas single-well batteries in the selected 50 x 50 km FEMP-EA study region across each township and range.

						Township
	5	3	5	14	35	42
	6	6	5	28	34	41
	2	10	9	13	8	40
	7	6	1	5	13	39
	5	6	12	6	7	38
Range	9	8	7	6	5	

A random sample of sites was selected from the total population within the study region. The production characteristics of this sample was verified to be representative of the entire population using two-sample K-S tests. Figure 3 shows a comparison of the cumulative distribution of gas production from gas MW batteries in the sample and the population. The sampling process was done repeatedly until the null hypothesis of the 2-sample K-S tests – that the two distributions did not come from the same population – was rejected at the $p \leq 0.05$ significance threshold. In this example, the sample consisted of 117 sites while the population consisted of 369 sites.

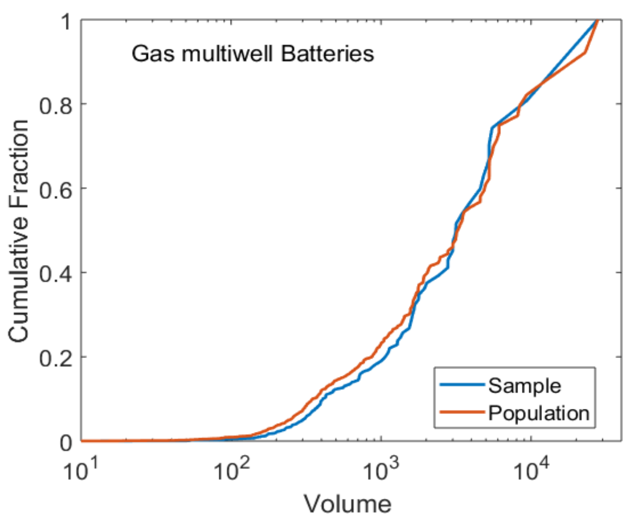

Figure 3. Cumulative fraction of production as a function of production volume at gas multi-well batteries from the study region in the (a) n = 117 sampled sites, and (b) n = 369 population sites. Two sample K-S tests were performed for all site types to ensure that sites sampled for surveys from the study region are representative of the population of that site-type in the Red Deer region.

Site Selection: The study team selected approximately 220 sites spread throughout the study region across the six site-types as shown in Table 2. The number of sites of each site-type is proportional to the distribution of each site-type in the Red Deer region. For example, 25% of the sites in the study sample are gas SW batteries – this is similar to the 27% of gas SW batteries in the Red Deer region. The total number of sites provided to the field survey team included a 20% additional buffer sites for each site-type to account for last minute in-field challenges. Because the site selection was primarily done based on data from the Petrinex database without any consultation with the producers, it was possible that sites that were shut-in had not been officially updated in the database. Furthermore, field crews could be prevented from accessing a site from the selected sample due to maintenance issues or road conditions. The buffer sites in each category would help the field crews make in-field decisions about switching sites without having to go through multiple iterations of site selection. The 220 sites selected for this study represented 18 operators in the region.

Table 2. Distribution of site-types in the FEMP-EA study including total population in the study area, study population, and buffer population to account for in-field contingencies.

Site type	Site-type code	Total Population	Study Population	Buffer Sample Population	Total study population incl. buffer
Gas multi-well batteries	Gas MW	118	**32**	4	**36**
Gas single-well batteries	Gas SW	253	**52**	8	**60**
Gas gathering systems/facility*	Gas Facility	29	**12**	4	**16**
Oil multi-well batteries	Oil MW	23	**12**	4	**16**
Oil multi-well prorated batteries	Oil MWPRO	83	**24**	8	**32**
Oil single-well batteries	Oil SW	153	**48**	12	**60**
Total Sites			**180**	40	**220**

*Some gas gathering sites were co-located with other site types such as a multi-well battery and therefore had the same LSDs. In this scenario, the study team measured all emissions at these sites. Therefore, throughout this report, we refer to these complex sites with multiple site-types associated with the location as "gas facilities".

2.2. Survey Schedule

A critical point of differentiation between this and prior published studies on methane emissions is that the site operators were not informed apriori of the LDAR survey. Instead, field crews were deputized by the Alberta Energy Regulator (AER), which allowed the field crew to enter and measure emissions at any site, with exceptions for safety and site conditions. The field crew typically obtained blanket site permits from all the operators whose sites are to be surveyed for the entire duration of the study. Throughout the five surveys, the field crews did not encounter any resistance from site operators and the deputization from AER was never explicitly used at any site. This is critical because most prior component-level studies in the US and Canada required permission from the operators to survey their facilities and the scientific community was concerned about potential sample bias. The FEMP-EA study avoided this problem by developing a fully anonymous and true random sampling procedure without any consultation with the operators of those sites. **Therefore, the results from this study present the first bottom-up, component-level methane measurement from a random selection of sites.**

All surveys were conducted by Davis Safety Consulting Ltd. (Davis Safety), with one field crew consisting of two people to detect the emission using the GF-320 FLIR camera and quantify using Providence Photonics' QL 320 tablet. In total, 5 surveys were conducted between August 2018 and October 2019 as per the schedule in Table 3, below.

Each of the sites in the overall study sample were randomly distributed across the surveys as shown in Table 3. The initial and final survey (August 2018 and August 2019) consisted of a comprehensive survey of all sites selected for the program. Ideally, the number of sites and site types in both these surveys should be identical. However, the total number of sites visited in each survey differs slightly from the planned survey (see Section 2) for several reasons including shut-in facilities, non-operating assets, ownership changes, access issues or safety considerations. However, these differences do not affect the study insights.

Table 3: Summary of facilities surveyed as part of the Fugitive Emissions Management Program Effectiveness Assessment (FEMP-EA) study between August 2018 and October 2019

Number	Survey Date	Total Sites	Site Type Distribution					
			Gas SW	Gas MW	Gas Facility	Oil SW	Oil MW	Oil MW-Pro
1	Aug – Oct 2018	172	58	20	6	61	9	18
2	Nov 2018	38	11	5	2	13	2	5
3	Mar 2019	43	15	5	1	14	4	4
4	May 2019	41	13	5	2	14	2	5
5	Aug – Oct 2019	179	56	21	7	67	11	17

The sites were split into four groups – one control group and three treatment groups. The control group sites had an initial visit in August 2018 and a final visit in August 2019 **without** any repair intervention requested through our study – the operators of these control sites were not given any information about emissions found on the sites (except for safety consideration) and the leaks found were not physically tagged. However, operators were not prevented from conducting regular maintenance operations at these sites based on their standard operating procedure. The three treatment groups simulated typical LDAR surveys at one, two, and three times per year (as specified in Environment and Climate Change Canada's (ECCC) methane regulations) [36]. The operators of facilities in the treatment groups were asked to undertake repair efforts as described in ECCC's methane regulation. Notably, this regulation would not come into force until January 1, 2020 and provincial regulations in Alberta and British Columbia had yet to be published at the commencement of the study. A summary of the designed survey schedule for control and treatment groups is shown in Figure 4. Actual number of sites visited in each survey vary slightly because of in-field adjustments.

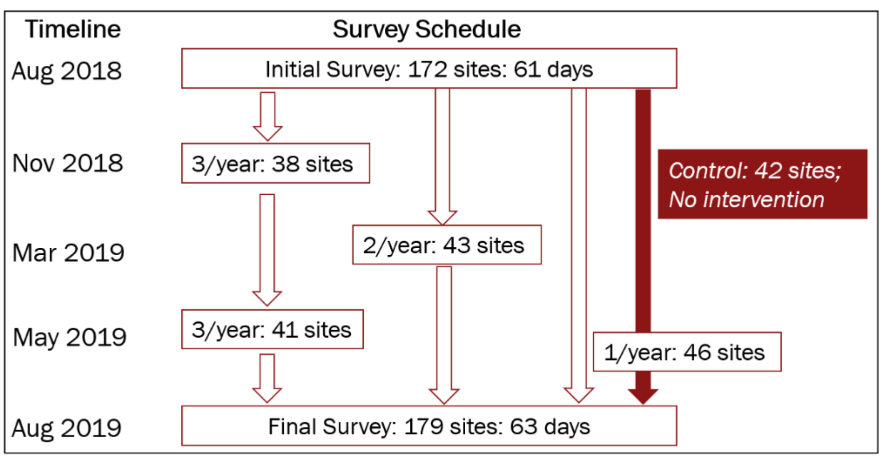

Figure 4. Summary of the all the sites surveyed as part of the FEMP-EA study, split into 4 groups – one control group of 38 sites where intervening repairs were not requested between August 2018 and August 2019 surveys, and 3 treatment groups (one, two, and three times per year LDAR) where leaks found on sites were physically tagged and operators requested to fix them as soon as possible.

2.3. Field Protocol

Survey Procedure: All surveys in the study used FLIR's GF-320 thermal infrared camera by Davis Safety Inc. The GF-320 represents the industry standard in leak detection and repair operations across North America. Davis Safety was chosen based on their experience in conducting LDAR surveys in

Canada and generating research-quality data that were used in prior peer-reviewed publications [16]. Thus, it was critical for the research team to select a survey provider whose methodologies, data, and field calibration protocols have already been peer-reviewed by the scientific community. The field thermographers for the study have all been trained in all compliance protocol by FLIR Technologies Inc and have conducted several field LDAR survey prior to this study. Field experience is important recent studies have demonstrated the importance of operator experience – the effectiveness of leak detection surveys reaches steady state only after survey crews have an accumulated experience of performing LDAR surveys at a minimum of 550 sites [47], [48].

During a survey, a thermographer examines every single component and piece of equipment on site using an infrared camera for emissions. A second crew member records meta data on every emission (location, component, equipment, site, leak vs. vent, and other relevant information) electronically, and physically attaches a tag to a leak if required. Tags are only attached to leaks that are accessible and safe, and the site being surveyed is not a control site. Irrespective of whether a site is designated a control or treatment site, any emission that poses a safety issue is immediately notified to the site manager.

Calibration Procedure: The detection limit of camera-based OGI technologies varies with weather conditions, temperature of the equipment, background radiation, and imaging distance [37]–[39]. To account for daily changes in weather, the FLIR camera is qualitatively verified every day before starting the survey using a propane standard at a flow rate of 50–60 g h^{-1} from a ¼ inch orifice, with a background at ambient temperature (e.g. equipment or a wall). The distance at which this 'standard leak' is observed is set as the maximum imaging distance for that day. The calibration was conducted in the field prior to the beginning of the survey to replicate field measurement conditions as much as possible. To be clear, weather conditions can change on an hourly basis. However, in practice, we have found that the weather outlook for a day (sunny, cloudy, windy) is quite helpful as a rough measure of the performance of the OGI camera. Hence, conventional practice in LDAR surveys (not just in this study, but also in commercial context) is to perform daily calibration checks.

Emissions Quantification: Prior ground-based, component-level studies of oil and gas facilities using FLIR OGI cameras quantified methane emissions using the standard Bacharach Hi-Flow sampler [16], [19], [28]. Because of the nature of the instrument, the Hi-Flow sampler often cannot be used on emissions that are inaccessible (e.g., thief hatch on tanks) or pose safety risks. Crucially, most tank-related emissions were not quantified with the Hi-Flow sampler, forcing scientists to either visually estimate emissions [19] or employ statistical techniques using data from other published studies [16]. Given that tanks have been shown to be one of the largest contributors to methane emissions, such approximations for tank emissions have the potential to significantly bias the measurements [49], [50]. Furthermore, several recent studies document potential issues with the Bacharach Hi-Flow sampler associated with gas composition, sensor transition, and calibration that could result in significant underestimation of emissions [51], [52]. Finally, the maximum emission rate that can be measured by the Hi-Flow sampler is limited by the maximum displacement of the blower (650 scfh).

To overcome this challenge, we use the Providence Photonics' QL-320, a leak quantification add-on to the FLIR camera that estimates leak rate using optical imaging techniques. Although the QL-320 has higher individual measurement error, it allows for the quantification of emissions that are inaccessible to the Hi-Flow system. Critically, we were able to directly measure all tank emissions in the FEMP-EA study, unlike prior bottom-up, component-level measurements in the US and Canada.

Quantification Field Procedure: All members of the field team were fully trained in the operation of the QL-320 through official training sessions organized by FLIR Technologies. Because QOGI was a new technology, the field crew was more conservative in their methodology compared to recommended practice. We now briefly describe the procedure used in the field. First, the thermographer would find an appropriate view angle to appropriately screen temperature background and minimize anomalous readings (e.g., highly reflecting surface, high-temperature background, etc.). As part of this step, the thermographer also inputs to the QOGI whether the emission plume is emissive or absorptive. Details on ambient temperature, gas type, wind speed (calm, moderate, or high winds) are entered into the QOGI tablet. The ambient temperature was measured independently and does not correspond to the temperature reading from the OGI camera. This is because the temperature recorded by the OGI camera is a combined temperature-emissivity reading and does not directly read ambient temperature. Second, ten sets of 100-frame video recordings are captured (batch mode) from a tripod that is set up to align with the view angle as identified in the first step. Third, all videos are reviewed to ensure there was no distortion or interference and only true plume images are captured (for more details, see QOGI Videos QA/QC section below). Fourth, outliers (one standard deviation from the mean of the 10 quantification estimates) in the estimated flow rate based on recommended practice are discarded, as well as any videos that exhibited distortion. As a final step, the average value of quantification for all videos (after excluding outliers) is considered the assigned flow rate to the emitter. As an additional QA/QC step, the field team also compared this assigned value with the median quantification estimate across all the videos. If the assigned value and the median are significantly different, the assigned quantification estimate is discarded, and a new set of videos are taken.

Despite all precautions undertaken here to produce reasonable emission estimates, the accuracy of the QOGI fundamentally depends on plume detection algorithms that separate out plume pixels from non-plume pixel. As FLIR Technologies improve the algorithms over time, so will the quantification accuracy. A detailed discussion of uncertainty is provided in Section 3.5 as well as in other studies [53].

QOGI Videos QA/QC: Not all videos of emissions taken in the field will be useful in estimating emission rate. Recent field research with OGI cameras have demonstrated that experience camera operators have higher effectiveness in detection emissions [48]. This is partly because experienced operators make in-field evaluations of whether a particular image/video provides the most effective contrast for detecting emissions. These evaluations take the form of collecting multiple videos of the emissions from different angles and choosing those that provide the highest contrast. In this study, the field crew used similar procedures to collect the most useful videos for quantification. Of all the videos and quantification estimates that were collected for a given emission, the following were discarded:

a. Videos that showed interference either from optical glare or unintended physical movement in the shot.
b. Videos where the contrast between emission and background is poor, rendering plume tracking by the QOGI instrument unreliable.
c. Outliers in quantification that were one standard deviation away from the mean of 10 quantifications of the same emission.
d. Videos where the plume tracking by the QOGI instrument did not match the plume boundaries as visualized on the OGI camera.

The videos and quantification estimates remaining after undergoing the above QA/QC procedure were used to estimate the average emission rate. Typically, about 30% of initial videos and quantifications were discarded through this procedure. Thus, the final list of emission points and quantification estimates included as part of this analysis is a subset of those that were collected in the field after the QA/QC procedure was completed.

Post-Survey Protocol: After the leaks are recorded, tagged, and quantified, the facility operator at treatment sites is supplied with reports detailing the findings, equipment affected, photos and videos capturing each leak. Because of potential follow-up measurements at each site, each operator was also asked to repair as many of the identified leaks as possible and document the reasons for those leaks that were not repaired. To minimize bias in the study design, operators were not told about the date of the next survey at their facility. The site operators were also provided with a standard questionnaire to be completed after repairs were undertaken at that site – this questionnaire inquired about major changes to site between two surveys, the frequency of one-time events such as liquids unloadings and an approximate methane emission rate, cost and details of the repair process undertaken, and a general inventory of major equipment at the site. The process of repairing leaks at treatment sites and completing the questionnaires was done on a voluntary-basis by the operators and they were neither compensated nor penalized – this lowered the response rate for these questionnaires in the study, particularly for sites involved in multiple surveys.

Classification of leaks and vents: Leaks and vents are classified based on the intended function of the component or equipment being surveyed. If the component emits in the course of its intended, normal functioning, the emission is classified as a vent. If the component emits unintentionally (malfunction, failure of control measures, etc.), the emission is classified as a leak. While defined in many regulatory standards and within the industry, this classification can be subjective in some scenarios and subject to both human error and interpretation of definitions and operational status. This is not a unique feature of the FEMP-EA program. LDAR surveys, research-oriented or otherwise, encounters the issue of ambiguity in leak vs. vent classification. The surveys conducted as part of the FEMP-EA program are intended to be representative of an LDAR survey that would be undertaken in typical regulatory scenarios. In that aspect, it is important for the survey results to resemble – as much as possible – a 'real' survey. To change the designation of leaks and vents post-survey would then be unrepresentative of typical LDAR surveys and risks providing insights that are not observed in practice. Yet, in cases where the science team found a potentially mismatched leak/vent emission classification, we followed up with Davis Safety to confirm or change the leak/vent assignment. For example, at Site 144, an emission was originally classified as a leak during the field program. However, the notes indicated that this emission was from a candy cane on a tank and may be classified as a vent. A follow-up conversation with Davis confirmed this, and the classification was updated. Scenarios requiring these classification changes in the FEMP-EA data were rare.

A summary of component-level classification is shown in Table 4. The numbers in the 'comment' column includes data from all five surveys. The number in parenthesis represent most surveys. For example, over 92% of valves are classified as leaks in all surveys, while it is typically >98% in four of the five surveys. (i.e., one survey may have had valves classified as leaks between 92 – 98%). In the case of pneumatics, although majority are classified as vents, anomalous emissions were classified as leaks. This observation is similar to one recently found in the BC MEFS study where a separate category of 'excessively venting pneumatics' was established to address malfunctioning pneumatic devices [54]. The designation of whether a thief hatch is a vent or a leak depends on equipment design – emissions from thief hatches on tanks with a vapor recovery unit are classified as leaks, while emissions in the absence of any capture equipment is classified as a vent.

Table 4: Classification of major component types as leaks and vents in the FEMP-EA study

Component	Major Classification	Comment

Flange/Connectors	Leak	>95% designated as leaks (typically 97+%)
Valves	Leak	>92% designated as leaks (typically 98+%)
Open-ended lines	Vent	>92% designated as vents (typically 97+%)
Thief Hatch	Leak/Vent	Varies by survey, depending on individual emitter*
Tank-level Indicator	Leak/Vent	Varies by survey (small sample)
Pneumatics	Vent/Leak	Majority classified as vents; some anomalous emissions classified as leaks

*Thief hatch emissions are classified as a leak if the associated tank has a vapor recovery unit. Otherwise, it is classified as a vent.

3. Analysis Methodology for FEMP-EA Data

The following section details the data analyses undertaken across the 5 surveys. All emissions detected by the OGI camera are included in the analysis. We have not performed any correction to include emissions below the detection threshold of the camera. Recent studies of the performance of these cameras in controlled test conditions have shown a low detection threshold and thus ignoring below threshold emissions thus do not affect estimates of overall emission rates [38], [48]. The analyses were conducted at several scales including component level, site level and operator level.

3.1. Component-level analysis

3.1.1. **Rank-ordered emissions:** We first analyze the skewness of the emission-size distribution observed in the survey using a conventional rank-ordered plot of emissions. Here, we plot the cumulative component-level emissions as a function of the cumulative number of emitters, sorted in a descending order. This figure can be used to extract numerical data about the skewed leak-size distribution, such as the proportion of total emissions that can be attributed to the top 5% and top 10% of emitters. Higher proportions show a higher skewness of the emission-size distribution – i.e., a few high-emitting components are responsible for the majority of emissions in the survey.

3.1.2. **Component-level emission rate:** Here, we analyze the distribution of emission rates by plotting the fraction of total emissions as a function of sorted (descending) component-level emission rates. The x-axis is in log-scale to better visualize the orders of magnitude difference between the highest and lowest-emitting components. Error bars represent one standard deviation. The figure can be used to understand the distribution of large emitters in the survey. Because of the skewed emission-size distribution, the mean emission rate is significantly higher than the median emission rate.

3.1.3. **Emission rate by component-type:** All components surveyed in the FEMP-EA were classified under six major component-types: flanges/connectors, valves, pneumatics, open ended lines (OELs), thief hatch, and tank-level indicator. Components that did not fit into any of these six categories were grouped under ‘other’ – less than 1% of all components were classified as ‘other’. Here, we present the average emission rate associated with each component type. Because a complete inventory count was out of scope of the study, the average emission rates presented here correspond to the leaking emission rate. OELs, in particular, are a broad category of emissions found on many different types of equipment. To better understand this component-type, we also disaggregate OELs by those that were found on tanks versus other equipment – this is because tank-related emissions are significantly higher than emissions from other components. Finally, we also classify all component-level emissions into tank-related and non-tank related emissions to understand the role of tanks in overall emissions.

Treatment of emissions not estimated using QOGI: During the surveys, a few component-level emissions were not quantified ('CNQ: could not quantify') because of access or safety consideration and some were too small to measure (TSTM). Components with CNQ classification were supplemented with the average emission rate for that component-type in each survey. Components with TSTM classification were assumed to not emit methane (coded as zero emission).

3.2. Site-level analysis

3.2.1. **Rank-ordered emissions:** We analyze the skewness of the site-level emission-size distribution using a rank-ordered plot of emissions. Here, we plot the cumulative site-level emissions as a function of the cumulative number of sites, sorted in a descending order. This figure can be used to extract numerical data about the skewed leak-size distribution, such as the proportion of total emissions that can be attributed to the top 5% and top 10% of sites. Typically, site-level emissions are less skewed than component-level emissions because they represent the aggregation of several component-level emissions found on a site. The number of sites in any given survey is denoted by $\mathbf{n_s}$ and the number of facilities is denoted by $\mathbf{N_f}$. In a small number of cases, a facility (identified with an LSD) can contain multiple sites.

3.2.2. **Site-level emission rate:** Here, we analyze the distribution of emission rates by plotting the fraction of total emissions as a function of sorted (descending) site-level emission rates. The x-axis is in log-scale to better visualize the orders of magnitude difference between the highest and lowest-emitting sites. We plot both site-level total emissions and site-level vents – this is because certain regulatory thresholds apply to vented emissions at sites. Here, total emissions refer to both emissions that were directly quantified and emissions that were estimated based on component-type average (see Section 3.1. for treatment of 'CNQ' emissions).

3.2.3. **Emission rate by site-type:** Here, we analyze average emission rates across each site-type included in the study. Sites across all surveys are classified into six major site types – large gas facilities, gas multi-well (MW) batteries, gas single wells (SWs), oil multi-well (MW) batteries, oil multi-well (MW) prorated batteries, and oil single wells (SWs). Error bars represent one standard deviation. Emissions across all site types are further distinguished by vents and leaks. Average oil and gas site emissions are analyzed by aggregated emissions from all sites classified as an oil or gas site, respectively. In addition, we also present average gas-site emissions that exclude large gas facilities for two reasons: (1) large gas facilities may contain more than one site-type at the same physical location and average emissions are ill-defined; and (2) the small number of these facilities in the study (and the study region) may not be representative of the emissions profiles associated with the broader population in the Red Deer area.

3.3. Operator analysis

The FEMP-EA study involved surveys of about 180 sites across 18 operators. Because of the fully blind nature of the site selection process, this study avoids potential sample bias of prior methane studies that required operator consent. All operators in this analysis have been anonymized with numbers – operator 1, operator 2, etc. We also maintain the anonymous ID given to each operator throughout the section – i.e., operator 1 always refers to the same operator across all surveys. We note that the observed differences across operators may be attributed to several factors: voluntary maintenance and emissions management practices, number and type of assets, resource type, age, or production levels. Finally, the total number of sites visited in the initial and final survey differs slightly for many reasons including shut-in facilities, non-operating assets, ownership changes, access issues, locked gates, or safety considerations. However, these differences do not affect the insights from the data.

We perform two analyses in this section. First, we compare average site-level emissions across all operators between the initial and final surveys – this provides insight on the emissions distribution across operators, role of gas vs. oil assets in contributing to total emissions, and the effectiveness of emissions reductions. Second, we compare average site-level emissions across operators disaggregated by major site-types in this study to isolate sites that exhibited highest average emissions – this helps us to understand the subset of sites under each operator's control that contribute to a majority of emissions.

3.4. Repair analysis

The analysis of repair effectiveness compares leak emissions across the five surveys. There were several challenges to this analysis:

1. Not all sites were followed up with repair (there was no regulatory requirement to do so at the time of the study and participation was voluntary). This reduced the sample size significantly at sites that underwent multiple surveys and therefore required multiple rounds of repairs.
2. Estimates of emissions reductions from repair exhibited high uncertainty because of uncertainty associated with QOGI-based quantification.
3. Addressing ambiguity in repair process (e.g., missing tags on leaks that continue to emit in subsequent surveys) required several assumptions to interpret the data that are detailed in Section 6.
4. The analysis of the effectiveness of repair depends on consistent survey and repair of sites according to the repair schedule – annual, biannual, or triannual. Several sites were not consistently surveyed because of changes to well status (e.g., operational to shut-in), safety, road conditions, and accessibility.

Considering these challenges, we analyzed the time evolution of leaks with the following methodologies and assumptions.

For this analysis, we only selected sites that were consistently visited on schedule. For example, if a site in the tri-annual survey treatment group was not visited during one of the scheduled visits because of challenging road conditions, that site was removed from the repair analysis. After reconciling across temporal surveys, we have 148 production sites that were visited "on schedule" (excluding large facilities that had multiple site-types associated with a single LSD and included gas gathering systems), including 47 sites in the annual group, 35 sites in the bi-annual group, 29 sites in the tri-annual group, and 37 sites in the control group.

We conduct two types of analyzes. One, we use the number of leaks found during the survey to analyzes how repair processes affected leak count. This analysis has the advantage of avoiding uncertainty associated with QOGI-based quantification. Two, we discuss the emission reductions associated with repair process – however, the uncertainty in emissions reduction estimates is high.

3.4.1. **Pre- and post-repair emissions counts:** Here, we analyze the observed changes in the number of leaks and vents between control sites and treatment sites. Treatment sites were further broken down into three categories: sites where no repairs were conducted, sites where repairs were conducted at least once, and sites that were consistently repaired according to the survey schedule. In this analysis, sites are considered 'repaired' if there was confirmation of at least one leak found in prior surveys to be repaired. This confirmation was done in one of two ways – one, a previously identified leak is not leaking in subsequent leak detection surveys and two, the tag on the leaking component includes a date of repair by the operator.

3.4.2. **Tag analysis:** On non-control sites visited during August 2018, November 2018, March 2019, and May 2019, the OGI crew tagged fugitive emissions for the operator to repair prior to a subsequent survey. The operators include a 'date of repair' on the tag after repairs are conducted. By tracking these tags and the date of repair, we can understand the time evolution of component-level fugitive emissions.

3.4.3. **Pre- and post-repair emissions:** Here, we analyze the change in emissions in leaks and vents between control sites and treatment sites. This corresponds to the change in the number of leaks and vents described in Section 3.4.1. above. Compared to emission counts, the uncertainty in emissions reduction estimates is higher.

3.4.4. **Survey frequency analysis:** Here, we analyze the changes in leak emissions across the control and treatment sites that underwent repairs according to the survey schedule. In this analysis, only sites that underwent all required repairs were included – i.e., sites on the 3 times/year survey schedule must have undergone repairs 3 times after each survey. If only one or two of those repairs were conducted, the site was excluded.

3.5. Sources of Uncertainty

There are several sources of uncertainty associated with this data as noted below.

a. **Gas composition:** Gas composition will likely differ depending on the site, emitting equipment, and age of a facility. Throughout the analysis, an average gas composition of 82% methane associated with production in the Red Deer region is used to calculate emission rates.

b. **QOGI estimates:** Providence Photonics' QOGI allowed us to estimate emissions from over 90% of components identified by the OGI camera as emitting. However, QOGI is also a relatively new instrument with less precision compared to conventional techniques such as Bacharach Hi-Flow sampler. To independently test the accuracy of the QOGI instrument, we undertook several controlled release test experiments as part of the Alberta Methane Field Challenge [54]. These tests represented one of the largest, single-blind controlled releases of the technology at the time of testing. The QOGI instrument exhibited a parity slope of 0.82 for controlled release rates from about 20 standard cubic feet per hour (scfh) (~14 m^3/d) to over 2000 scfh (~1360 m^3/d). Therefore, the aggregate error in QOGI-based quantification estimates is 18%, comparable to that of the Hi-Flow Sampler in ideal conditions (~10%). However, errors in individual QOGI estimates can be significantly higher – thus, it is critical for stakeholders to not directly interpret individual emissions estimates. Monte-Carlo analysis shows that a single estimate can be uncertain by many times the true emissions estimate. Thus, site-level or operator-level average emissions as estimated by QOGI are more reliable than any individual emission estimate.

Throughout this report, we use aggregate emissions at the site-level or component-type level to determine insights into methane emissions. We note that the 18% aggregate error estimated by controlled release tests does not represent the limit of epistemic errors (which is independent of sample size). In general, analysis of emissions in this report includes sample sizes in the hundreds component-level estimates and in the tens of sites for site-level estimates, thus justifying the use of 18% as an approximate error estimate.
These recommendations on using aggregate QOGI estimates as a reasonable indicator of emissions are similar to the conclusion reached by an independent analysis of the instrument by the Saskatchewan Research Council (SRC) [55]. In its detailed report of controlled release experiments, the SRC conclude the following in the best practices recommendation: "if an operator were to take a large number of readings in the field…, they could be 95% confident that the average of those readings would be the same as the actual flowrate. However, because of the large standard deviation of these readings, if an operator was to take a single reading of a leak/vent, the actual flowrate could be anywhere from zero to double that reading."

Thus, analyzing estimates of individual emissions using QOGI is contrary to the practice recommended by two independent studies. It is possible for individual estimates of emissions from specific components (e.g., pneumatic devices) to seem higher than what is expected based on experience or comparison to Hi-Flow sampler data. For example, we recorded an emission rate of 2230 m^3/d from a pneumatic device on site 74 in a survey that is significantly larger than expected from that component. This is because, as the Providence Photonics' documentation of the QOGI notes, individual quantification estimates are more prone to environmental conditions such as background, wind-speed, and the quality of plume extraction by the QOGI algorithm. While the accuracy of QOGI estimates in aggregate has been verified through controlled release tests, the potential discrepancy between QOGI and the Hi-Flow sampler is an issue worthy of further investigation. While we can speculate potential root causes for this discrepancy, further simultaneous testing of the two devices is recommended especially for improving individual emissions estimates.

Given recent field use of QOGI in methane emissions survey and interest from the regulatory community, we recommend further controlled release testing to fully characterize the quantification precision of the instrument. For example, real world emissions at oil and gas facilities are strongly influenced by local turbulence around equipment which potentially impact QOGI quantification estimates [48]. Testing QOGI under different environmental and operational conditions would provide a better estimate of its accuracy and precision. Similar to the recommendations in the SRC report, we also suggest future studies on QOGI focus on the impact of gas composition, ambient conditions, and sensitivity to emission rates – refer to Section 7 of this report for a detailed discussion.

c. **Measurements outside the range of recommended practice:** The QOGI was used to estimate all emissions detected by the OGI camera. Some of these measurements were larger than the upper limit of the QOGI, as established by the manufacturer. However, this upper limit was established as a conservative measure to avoid underestimating emissions – plumes from large leaks tend to go outside the field of the view of the camera, and therefore potentially result in an underestimation of the leak rate. We chose to include these measurements in the report to prevent bias in the dataset by excluding high emitters. A section on outlier measurements is included in this report to provide clarity on the measurements that were above this limit.

d. **Measurements not directly estimated by the QOGI:** 95% of all emitting components identified by the OGI camera were estimated directly using QOGI across all five surveys. The remaining 5% of emitters were not directly estimated by QOGI either because they were too small to measure ('TSTM') or could not be quantified because of access restrictions ('CNQ'). The November 2018 survey has the highest rate of CNQ (18%), which is mainly due to reflection from snow and interference from nearby heaters. Components with CNQ classification were supplemented with the average emission rate for that component-type in each survey. Components with TSTM classification were assumed to not emit methane (coded as zero emission). Uncertainty from this substitution for a small number of emitters did not affect the average emission rate as demonstrated by the overlapping 95% confidence intervals.

To evaluate the impact of our methodology, we conducted statistical tests to compare the mean and 95% confidence interval of 1) the dataset without CNQ and TSTM emitters and 2) the dataset with processed CNQ and TSTM emitters. As Table 5 shows, the mean emission differences between the two datasets are <0.5 kg CH_4 day^{-1} and the 95% confidence intervals overlap almost completely, indicating minimal difference introduced between the two datasets. Welch two sample t-test was also conducted to investigate whether the difference is statistically significant. The resulting p-values are all >0.95, much higher than the 0.05 threshold to reject the null hypothesis – the true difference in means is zero. In other words, our missing data methodology did not introduce statistically significant differences to the dataset.

Table 5: Impact of missing data methodology on the average component-level emissions rate across all five surveys

	Total Emitters	Without CNQ & TSTM		With CNQ & TSTM		T-test
		Mean	*95% CI*	*Mean*	*95% CI*	*p-value*
August 2018	1025	49.8	39.4 – 61.7	49.4	39.7 – 60.4	0.96
November 2018	212	11.5	8.4 – 15.3	11.3	8.7 – 14.4	0.95
March 2019	275	29.1	19.7 – 40.8	29.1	19.9 – 40.7	0.995
May 2019	394	23.5	15.1 – 34.7	23.8	15.7 – 34.2	0.96
August 2019	1004	28.7	23.1 – 35.6	28.6	23.0 – 35.8	0.99

In all the results presented in the next three sections, the error bars on figures correspond to standard error associated with finite sample sizes and does not include errors associated with individual measurements.

4. Results by Survey

In the next three sections, we discuss the results of the FEMP-EA field measurements through inventory analysis. To standardize analysis methods across all surveys, we use a few common metrics. For all five surveys, we first present component-level results followed by site-level analysis.

Of interest is the number of sites in each survey where the survey crew did not find emissions. Emissions can include both vents and leaks. Throughout this section, we report the number of sites where the survey crew found neither vents nor leaks, and the number of sites that the survey crew found vents but did not find any leaks. The report of detection is based on the performance of OGI-based camera surveys. Emissions that are below the detection limit of the OGI camera are not estimated.

4.1. Survey 1 (August 2018)

The first survey of the FEMP-EA study was conducted between August and October 2018. 163 facilities containing 172 sites were surveyed – this included 58 gas single wells, 20 gas multi-well batteries, 6 gas facilities, 61 oil single wells, 9 oil multi-well batteries, and 18 oil multi-well prorated batteries. Of the 172 sites surveyed, 26 sites did not have any emissions and a further 29 sites did not have any leaks. Thus, 55 out of 172 sites surveyed (32%) did not have any leaks. A total of 1091 components were found emitting across all sites, of which 563 were classified as leaks and 528 were classified as vents. A further 26 emission sources were too small to quantify and were assigned zero emissions.

Figure 5 shows the rank-ordered component-level emissions as a function of total emissions. We observe a skewed leak-size distribution with the top 5% and 10% of emitters contributing to 61% and 75% of total emissions, respectively. Such distributions have been widely observed in natural gas systems in Canada and the US [15], [17], [18], [24]. Across all sites, leaks and vents contributed to 31% and 69% of total emissions, respectively. This indicates that the majority of emissions at oil and gas sites come from vented emissions However, recent studies on LDAR effectiveness show that these surveys can identify anomalous vented emissions that are often fixable [16]. Therefore, LDAR surveys may help reduce more than 31% of emissions (leaks) if vents included anomalous emitting sources.

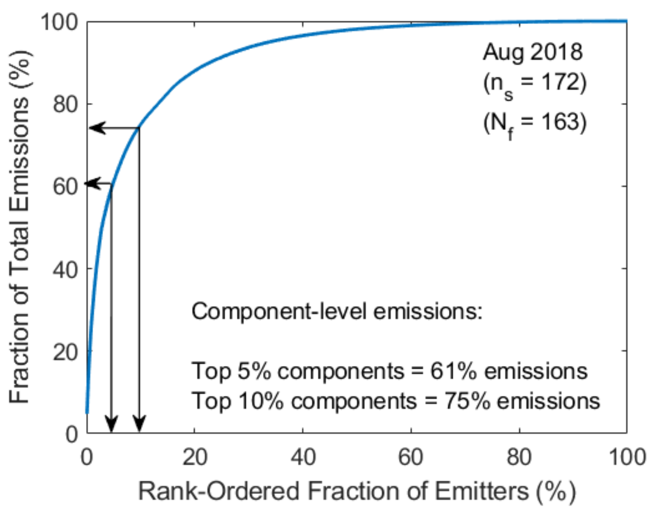

Figure 5. Fractional total emissions as a function of rank-ordered component-level emitters in the August 2018 survey across all facilities. The highest emitting 5% of components contribute to 61% of total emissions.

Figure 6 shows the fraction of total emissions as a function of component-level emission rate. 50% of emissions can be attributed to components emitting at least 585 m^3/d – these emissions come from only 31 out of 1091 components found to be emitting in the survey. Of the largest 31 components contributing to 50% of total emissions, 11 are classified as leaks and 20 as vents. These 11 leaks and 20 vents contribute 18% and 32% of total emissions, respectively.

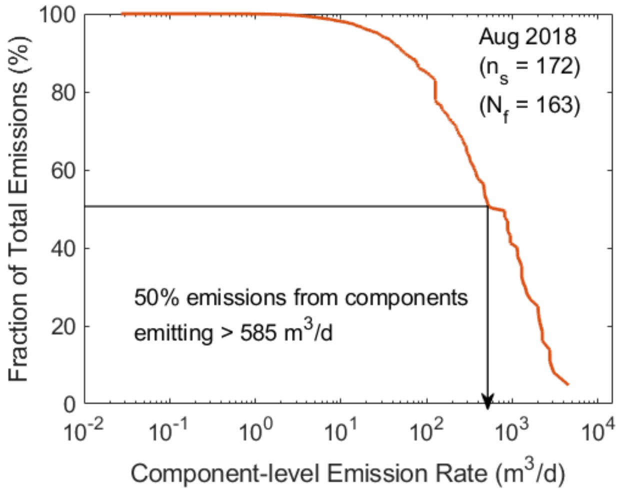

Figure 6. Fractional total emissions as a function of component-level emission rate in the August 2018 survey. 50% of emissions are from components emitting at least 585 m^3/day. Across all emitting components, vents and leaks contribute 69% and 31% to total emissions, respectively.

Figure 7 shows the average component level emission rate across all sites in the August 2018 survey. Flanges and valves comprise 33% of all emitting components but only contribute to approximately 11% of total emissions, with a combined average emission rate of 30 m^3/d. Pneumatics comprise approximately 22% of all emitting components and contribute to 19% of total emissions, with an average emission rate of 77 m^3/d. The largest class of emitters are thief hatches and tank-level indicators, emitting on average, 330 m^3/d and 179 m^3/d, respectively. Open-ended lines (OELs) contribute to 56% of all emissions with an average emission rate of 125 m^3/d. OELs describe a broad set of components that can be found on any equipment such as a candy-cane vent on a tank. 130 of the 425 (31%) OEL emission sources are found on tanks with an average emission rate of 282 m^3/d. Tank-related emissions contribute to 69% of all OEL emissions.

By isolating all emissions on tanks (both leaks and vents), we find an average tank-related emission rate of 252 m^3/d – they comprise 52% of total emissions from only 18% of emitters (196/1091). On the other hand, non-tank-related components emit an average 51 m^3/d – these comprise 48% of total emissions from 82% of emitters (895/1091).

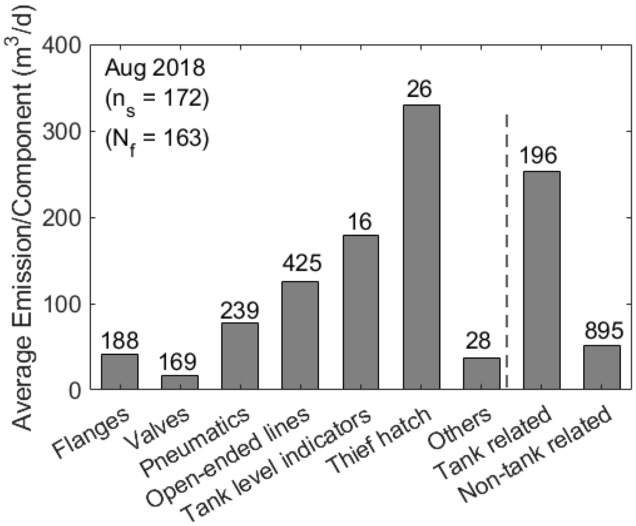

Figure 7. Average emission (both leak and vent) rate at the component-level across 168 sites in the August 2018 survey. Tank-related components emit, on average, 262 m³/d and contribute to 52% of total emissions, while non- tank related components emit 48 m³/d and contribute to 48% of total emissions. The numbers above the bars denote the sample size for each component type.

Figure 8 shows the fractional total emissions as a function of rank-ordered site-level emissions. In line with many recent studies, site-level emissions are less skewed than component-level emissions, with the top 5% of sites contributing to 43% of total emissions [15], [25], [55]. This is commonly observed in the literature because aggregation of component-level emissions to the site-level reduces skew of the distribution by mitigating the impact of individual high emitters [55]. Of these, oil sites and gas sites contribute to 54% and 46% of total emissions, respectively. The top 10 emitting sites consists of 6 oil sites and 4 gas sites.

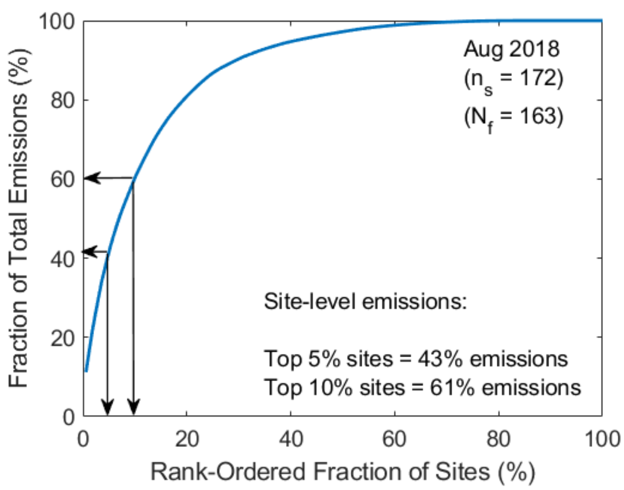

Figure 8. Fractional total emissions as a function of rank-ordered site-level emissions in the August 2018 survey. The top 5% and 10% of sites contribute to 43% and 61% of total emissions, respectively.

Figure 9 shows the fraction of total and vent-related site-level emissions as a function of emission rate. The average site-level emission rate is 550 m^3/d, while the median site level emission is 122 m^3/d. 50% of total emissions come from sites emitting at least 2186 m^3/d – there are only 12 sites with such high emissions, corresponding to 7% of all sites. The remaining 160 sites emit an average of 290 m^3/d.

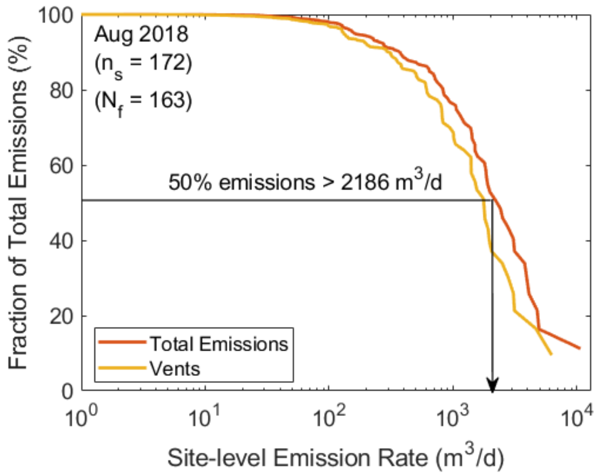

Figure 9. Fractional total emissions (red) and vented emissions (yellow) as a function of site-level emission rate in the August 2018 survey. 50% of emissions are from sites emitting at least 2186 m^3/day. There were only 12 sites emitting at or above this threshold, corresponding to 7% of all measured sites.

Figure 10 shows the average per-site emission rate across the different site-types and disaggregated by leak and vents. Vents contribute to 69% of total emissions. Oil sites tend to have higher emissions than gas sites, often associated with a higher prevalence of tanks. On average, oil sites emit 605 m^3/d, while gas sites (excluding gas facilities) emit 404 m^3/d.

The 6 gas facilities emit an average of 2077 m^3/d – the high average emission is dominated by two sites. Excluding these two high emitting sites, the average gas facility emission reduces to 900 m^3/d. These emissions should not be interpreted as representative of a single site-type – since several of these facilities contained multiple site-types at the same location (e.g., both a gas gathering system and a gas multi-well battery), they only represent aggregate emissions from all sites on that facility. Single wells, both at oil and gas sites, also emit significantly less than multi-well batteries. Oil and gas single wells emit an average of 190 m^3/d and 549 m^3/d, respectively. Multi-well batteries, on the other hand, exhibit high emissions across oil and gas sites. The difference in emissions across sites that produce mostly gas versus oil and gas has been observed in prior methane emissions studies [31], [32], [50], [56].

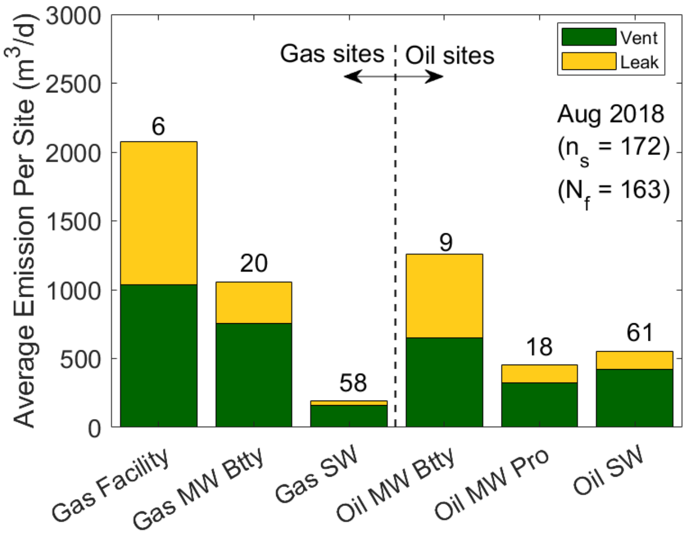

Figure 10. Average site-level emissions observed in the August 2018 survey disaggregated by vents (green) and leaks (yellow), and site types (Gas Facility – large site containing multiple gas site-types, Gas MW Btty – Gas multi-well battery, Gas SW – Gas single well, Oil MW Btty – Oil multi-well battery, Oil MW Pro – Oil multi-well prorated battery, and Oil SW – oil single well). On average, gas sites emit 404 m³/d, while oil sites emit 605 m3/day. The numbers above the bars denote sample size for each site type.

4.2. Survey 2 (November 2018) – 3x/year LDAR Frequency

The second survey of the FEMP-EA project was conducted in November 2018. This survey consisted of a total of 38 sites that were on a 3 times per year survey schedule as shown in Table 3 – this included 11 gas SWs, 5 gas MW batteries, 2 gas facilities, 13 oil SWs, 2 oil MW batteries, and 5 oil MW prorated batteries. Of the 38 sites surveyed, 3 sites did not have any emissions and a further 8 sites did not have any leaks. Thus, 11 out of 38 sites surveyed (29%) did not have any leaks. A total of 254 components were found emitting across all sites, of which 140 were classified as leaks and 114 were classified as vents. Three more emission sources were detected but were too small to quantify and therefore assigned zero emissions.

Figure 11 shows the rank-ordered component-level emissions as a function of total emissions. The top 5% and 10% of emitters contribute to 33% and 48% of total emissions, respectively. This is less skewed than the August 2018 survey where the top 5% of components contributed to 61% of total emissions. This reduced skewness could be attributed to several factors. First, repairs conducted at some of the sites between August and November 2018 may have reduced emissions [16]. Second, tank flashing is likely to be lower in the winter due to colder temperatures [57]. Overall, leaks and vents contributed to 28% and 72% of total emissions, respectively. Furthermore, The November 2018 survey has the highest rate of CNQ (18%), which is mainly due to reflection from snow and interference from nearby sources. Because our methodology replaced CNQ sources with average emission rate for that component-type, it is likely that some of the high-emitting but not directly quantified sources were underestimated. Underestimation of high-emitting sources will lead to reduced skewness of the emissions-rate distribution.

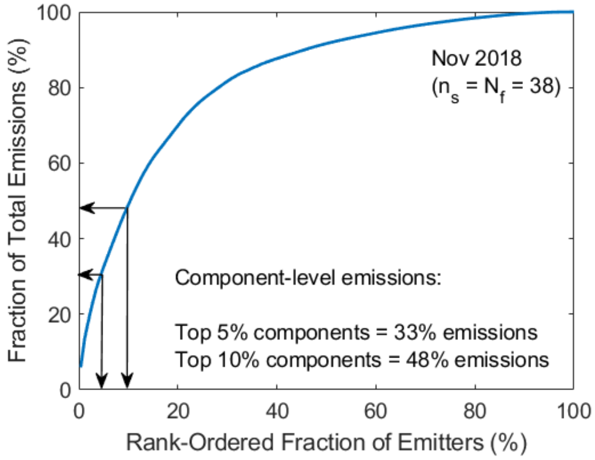

Figure 11. Fractional total emissions as a function of rank-ordered component-level emitters in the November 2018 survey across all facilities. The highest emitting 5% of components contribute to 33% of total emissions.

Figure 12 shows the fraction of total emissions as a function of component-level emission rate. 50% of emissions can be attributed to components emitting at least 73 m^3/d – these emissions come from only 27 out of 254 components in the survey. Of the largest 27 components contributing to 50% of total emissions, only 5 are classified as leaks.

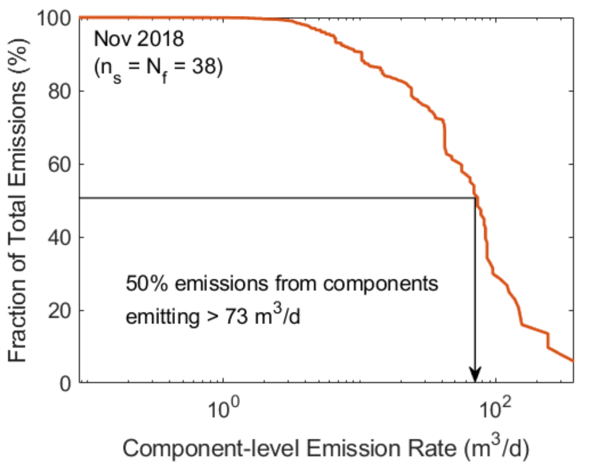

Figure 12. Fractional total emissions as a function of component-level emission rate in the November 2018 survey. 50% of emissions are from components emitting at least 73 m^3/day. Across all emitting components, vents and leaks contribute 72% and 28% to total emissions, respectively.

Figure 13 shows the average component level emission rate across all sites. Flanges and valves comprise 37% of all emitting components but only contribute to approximately 13% of total emissions, with a combined average emission rate of 9 m^3/d. Pneumatics comprise approximately 33% of all emitting components and contribute to 31% of total emissions, with an average emission rate of 24 m^3/d. The component with the highest average emission of 84 m^3/d was thief hatches. There were no emissions associated with tank level indicators in the November survey. OELs emitted 42 m^3/d on average, with 23 of the 67 observed on tanks. These tank related OELs emitted on average 74 m^3/d.

By isolating emissions on tanks (both leaks and vents), tank-related components have an average emission rate of 69 m^3/d – they comprise 39% of total emissions from only 14% of total emitters

(36/254). On the other hand, non-tank-related components emit an average of 18 m^3/d – these comprise 61% of total emissions from 86% of total emitters.

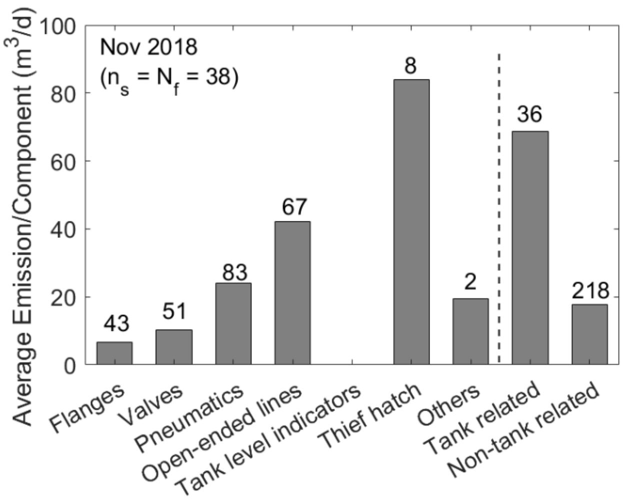

Figure 13. Average emission (both leak and vent) rate at the component-level across 38 sites in the November 2018 survey. Tank-related components emit, on average, 69 m^3/d and contribute to 39% of total emissions, while non- tank related components emit 18 m^3/d and contribute to 61% of total emissions. The numbers above the bars denote sample size for each component type.

Figure 14 shows the fractional total emissions as a function of rank-ordered site-level emissions. The top 5% and 10% of sites contributing to 19% and 37% of total emissions, respectively. Of these, oil and gas sites contribute to 54% and 46% of total emissions, respectively.

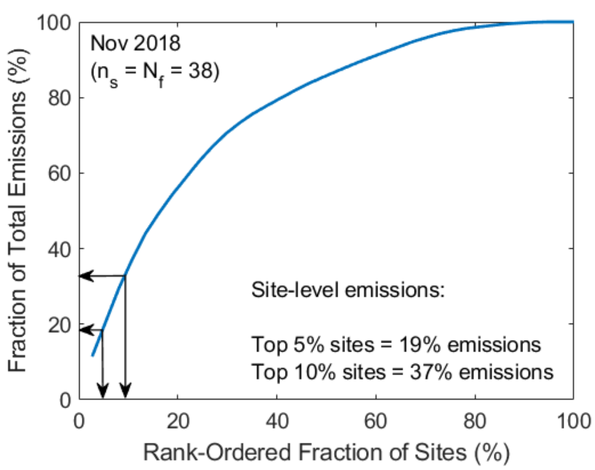

Figure 14. Fractional total emissions as a function of rank-ordered site-level emissions in the November 2018 survey. The top 5% and 10% of sites contribute to 19% and 38% of total emissions, respectively.

Figure 15 shows the fraction of total and vent-related site-level emissions as a function of emission rate. 50% of total emissions come from sites emitting at least 338 m^3/d – thus, only 6 sites out of 38 (16%) contribute to half of all emissions.

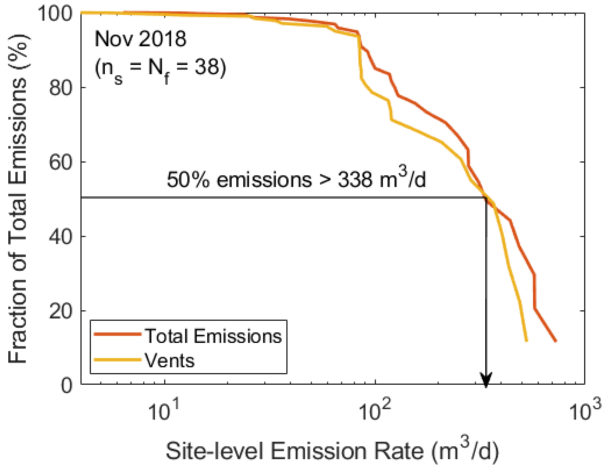

Figure 15. Fractional total emissions (red) and vented emissions (yellow) as a function of site-level emission rate in the November 2018 survey. 50% of emissions are from sites emitting at least 338 m³/day.

Figure 16 shows the average per-site emission rate across the different site-types and disaggregated by leak and vents. On average, oil sites emit 172 m^3/d, while gas sites (excluding gas facilities) emit 119 m^3/d. As seen previously, both oil and gas SW sites emit less than multi-well batteries. In this survey, oil and gas SWs emit an average of 125 m^3/d and 116 m^3/d, respectively.

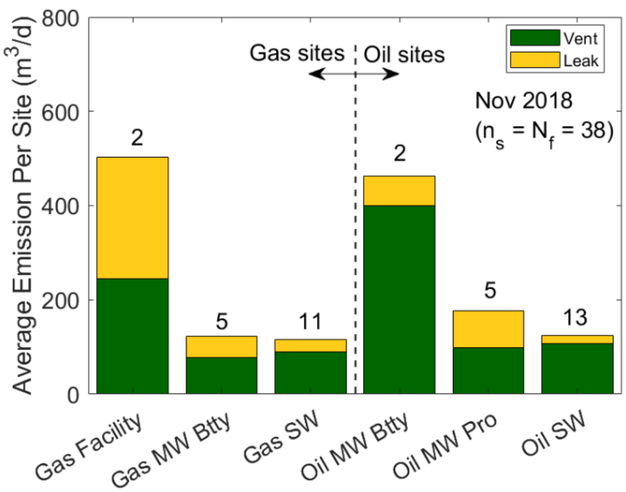

Figure 16. Average site-level emissions observed in the November 2018 survey disaggregated by vents (green) and leaks (yellow), and site types. Excluding gas facilities, gas sites emit 119 m³/day, while oil sites emit 172 m³/day. The numbers above the bars denote sample size for each site type.

4.3. Survey 3 (March 2019) – 2x/year LDAR Frequency

The third survey of the FEMP-EA project was conducted in March 2019, corresponding to facilities in the semi-annual or two times per year treatment group. This is the first re-visit of these sites after the initial August 2018 survey. 43 facilities (also 43 sites) were surveyed in this round – including 15 gas SWs, 5 gas MW batteries, 1 gas facility, 14 oil SWs, 4 oil MW batteries, and 4 oil MW prorated batteries. Of the 43 sites surveyed, 2 sites did not have any emissions and a further 7 sites did not have any leaks. Thus, 9 out of 43 sites surveyed (21%) did not have any leaks. A total of 312 components were found emitting across all sites, of which 139 were classified as leaks and 173 were classified as vents. Two more emission sources were detected but were too small to quantify and therefore assigned zero emissions.

Figure 17 shows the rank-ordered component-level emissions as a function of total emissions. The top 5% and 10% of emitters contribute to 55% and 69% of total emissions, respectively. Across all sites, leaks and vents contributed to 14% and 86% of total emissions, respectively.

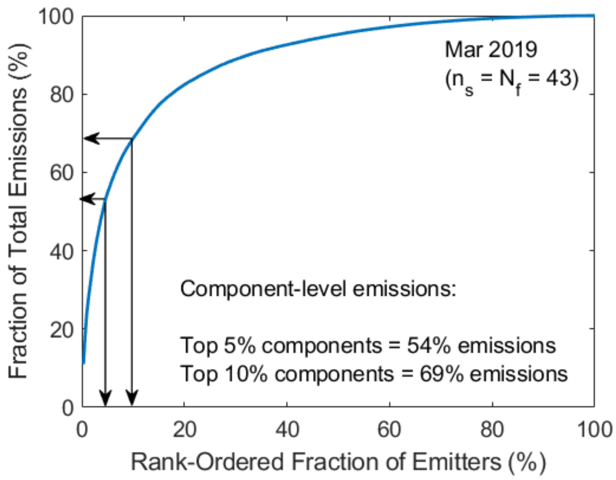

Figure 17. Fractional total emissions as a function of rank-ordered component-level emitters in the March 2019 survey across all facilities. The highest emitting 5% of components contribute to 55% of total emissions.

Figure 18 shows the fraction of total emissions as a function of component-level emission rate. 50% of emissions can be attributed to components emitting at least 285 m^3/d – these emissions come from only 14 out of 312 components found to be emitting in the survey. All the 14 largest emissions in this survey were classified as vents and were associated with tanks, either as thief hatch emissions or OEL emissions.

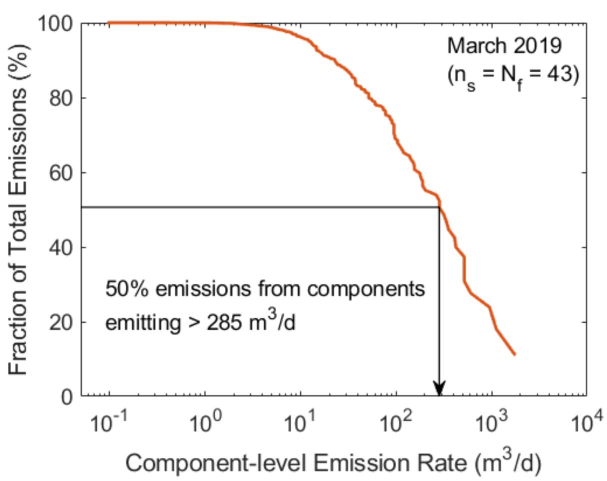

Figure 18. Fractional total emissions as a function of component-level emission rate in the March 2019 survey. 50% of emissions are from components emitting at least 285 m^3/day. Across all emitting components, vents and leaks contribute 86% and 14% to total emissions, respectively.

Figure 19 shows the average component level emission rate across all sites. Flanges and valves comprise 28% of all emitting components but only contribute to approximately 11% of total emissions, with a combined average emission rate of 21 m^3/d. Pneumatics comprise approximately 32% of all emitting components and contribute to 12% of total emissions, with an average emission rate of 19 m^3/d. OELs comprise 38% of all emitting components and contribute to 72% of total emissions. In addition, 49 of the OEL emitters (41%) were detected on tanks, contributing to 57% of all OEL emissions. Therefore, similar to prior surveys, a majority of OEL emissions are associated with tanks. The component types with the highest average emissions are thief hatches and tank-level indicators, emitting about 144 m^3/d and 139 m^3/d, respectively. By isolating emissions on tanks (both leaks and vents), we observe that tank-related components have an average emission rate of 127 m^3/d – they comprise 47% of total emissions from only 19% of total emitters (59/312). By contrast, non-tank-related components emit an average 34 m^3/d, 4 times lower than average tank-related emissions.

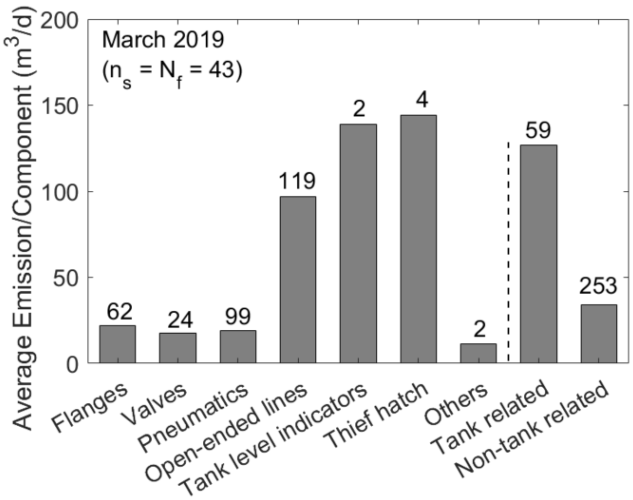

Figure 19. Average emission (both leak and vent) rate at the component-level across 43 sites in the March 2019 survey. Tank-related components emit, on average, 127 m^3/d and contribute to 47% of total emissions, while non- tank related components emit 34 m^3/d and contribute to 53% of total emissions. The numbers above the bars denote sample size for each component type.

Figure 20 shows the fractional total emissions as a function of rank-ordered site-level emissions. The top 5% of sites contribute to 28% of total emissions. Of these, oil sites and gas sites contribute to 55% and 45% of total emissions, respectively.

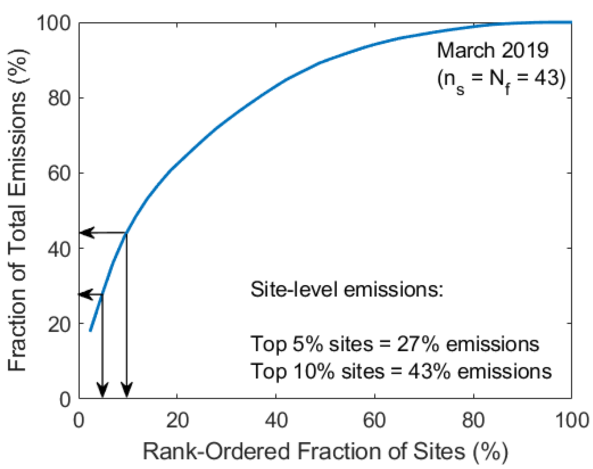

Figure 20. Fractional total emissions as a function of rank-ordered site-level emissions in the March 2019 survey. The top 5% and 10% of sites contribute to 27% and 43% of total emissions, respectively.

Figure 21 shows the fraction of total and vent-related site-level emissions as a function of emission rate. 50% of emissions come from sites emitting at least 814 m^3/d – there are only 5 sites with such emissions, corresponding to 12% of all sites measured in this survey.

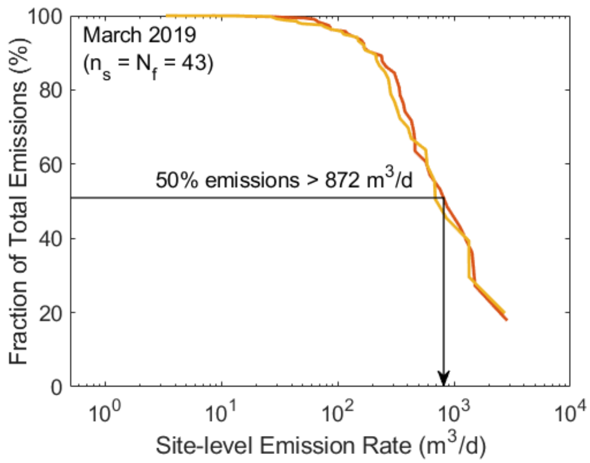

Figure 21. Fractional total emissions (red) and vented emissions (yellow) as a function of site-level emission rate in the March 2019 survey. 50% of emissions are from sites emitting at least 814 m^3/day.

Figure 22 shows the average per-site emission rate across the different site-types and disaggregated by leak and vents. Vents contribute to 84% of total emissions. On average, oil sites emit 404 m^3/d, while gas sites emit 336 m^3/d. Unique to this survey was the higher average emission rate from gas MW batteries at 749 m^3/d. This is because of the small sample size (n = 5) and one multi-well battery with an emission rate that is approximately four times the average emission rate for that site type at 2866 m^3/d. Excluding this site, the average emission rate from the remaining 4 gas MW batteries is 220 m^3/d. In this survey, oil and gas single wells emit an average of 279 m^3/d and 198 m^3/d, respectively, while oil MW batteries emit on average 719 m^3/d.

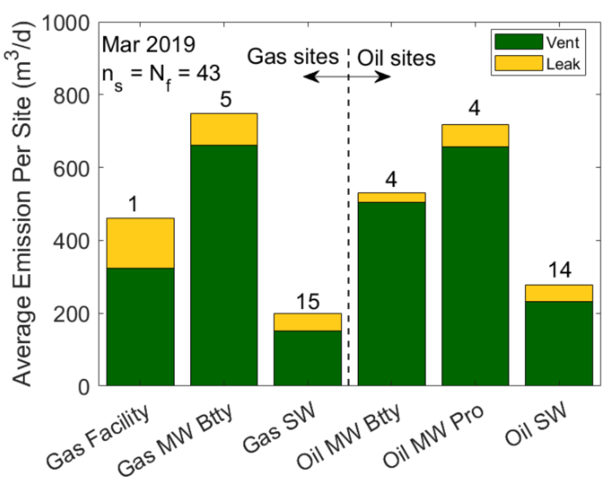

Figure 22. Average site-level emissions observed in the March 2019 survey disaggregated by vents (green) and leaks (yellow), and site types. On average, gas sites (excluding gas facilities) emit 336 m^3/day, while oil sites emit 404 m^3/day. The numbers above the bars denote sample size for each site type.

4.4. Survey 4 (May 2019) – 3x/year LDAR Frequency

The fourth survey of the FEMP-EA project was conducted in May 2019 – this corresponds to the second survey of the 3 times per year treatment group. These sites were previously surveyed in November 2018. Overall, 41 sites were surveyed including 13 gas SWs, 5 gas MW batteries, 2 gas facilities, 14 oil SWs, 5 oil MW batteries, and 2 oil MW prorated batteries. Of the 41 sites surveyed, 2 sites did not have any emissions and a further 7 sites did not have any leaks. Thus, 9 out of 41 sites (22%) did not have any leaks. A total of 450 components were found emitting across all sites, of which 275 were classified as leaks and 175 were classified as vents. Two more emission sources were detected but were too small to quantify and therefore assigned zero emissions.

Figure 23 shows the rank-ordered component-level emissions as a function of total emissions. The top 5% and 10% of emitters contribute to 62% and 78% of total emissions, respectively. Across all sites, leaks and vents contributed to 27% and 73% of total emissions, respectively.

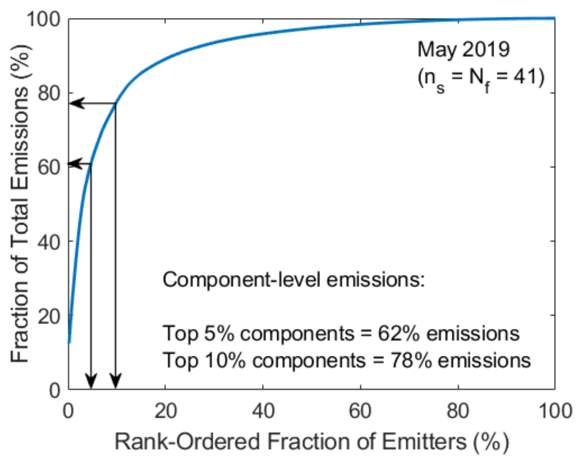

Figure 23. Fractional total emissions as a function of rank-ordered component-level emitters in the May 2019 survey across all facilities. The highest emitting 5% of components contribute to 61% of total emissions.

Figure 24 shows the fraction of total emissions as a function of component-level emission rate in the March 2019 survey. 50% of emissions can be attributed to components emitting at least 463 m^3/d – these emissions come from only 13 out of 450 components (<3%) found to be emitting in the survey. 2 out of these 13 component-level emissions are classified as leaks, while the remaining 11 are vents associated with tanks.

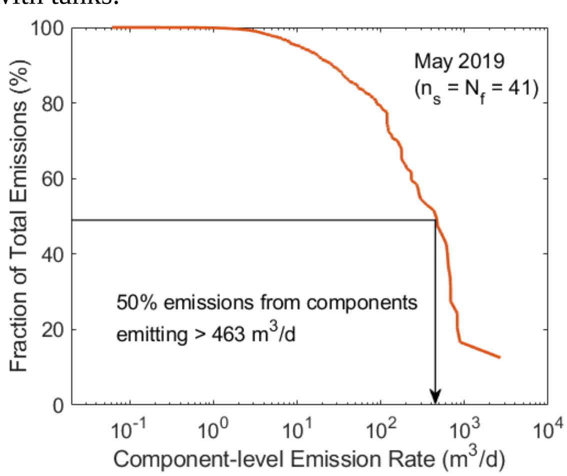

Figure 24. Fractional total emissions as a function of component-level emission rate in the May 2019 survey. 50% of emissions are from components emitting at least 463 m³/day. Across all emitting components, vents and leaks contribute 73% and 27% to total emissions, respectively.

Figure 25 shows the average component level emission rate across all sites. Flanges and valves comprise approximately 51% of all emitting components but only contribute to ~12% of total emissions, with the average emission rate of 11 m^3/d. Pneumatics comprise 22% of all emitters, and contribute to 20% of total emissions, with an average emission rate of 41 m^3/d. OELs also constitute 22% of all emitters but contribute to 54% of total emissions. 89% of these OEL emissions are associated with tanks, emitting on average 152 m^3/d. The component types with the highest average emissions are thief hatches and tank-level indicators, emitting about 267 m^3/d and 189 m^3/d, respectively. By isolating emissions on tanks, we find that tank-related components have an average emission rate of 156 m^3/d – they comprise 64% of total emissions from only 19% of total emitters (87/450). On the other hand, non-tank-related components emit an average 21 m^3/d – these comprise 36% of total emissions from 81% of total emitters.

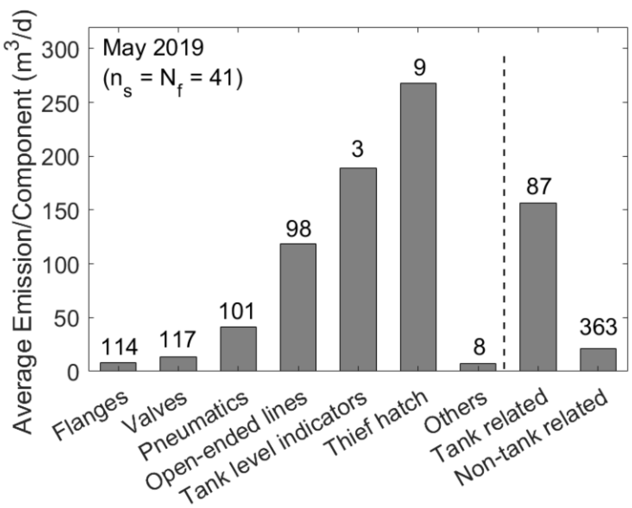

Figure 25. Average emission (both leak and vent) rate at the component-level across 41 sites in the May 2019 survey. Tank-related components emit, on average, 156 m^3/d and contribute to 64% of total emissions, while non- tank related components emit 21 m^3/d and contribute to 36% of total emissions. The numbers above the bars denote sample size for each component type.

Figure 26 shows the fractional total emissions as a function of rank-ordered site-level emissions. Site-level emissions are less skewed than component-level emissions, with the top 5% of sites contributing to 29% of total emissions. Of these, oil sites and gas sites contribute to 62% and 38% of total emissions, respectively.

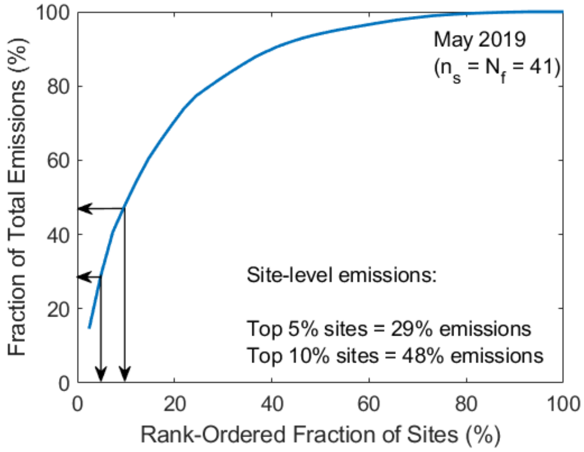

Figure 26. Fractional total emissions as a function of rank-ordered site-level emissions in the May 2019 survey. The top 5% and 10% of sites contribute to 29% and 48% of total emissions, respectively.

Figure 27 shows the fraction of total and vent-related site-level emissions as a function of emission rate. Overall, sites emitting at least 1466 m^3/d contribute to 50% of total emissions – these correspond to 5 out of the 41 sites (12%) surveyed in this round. These 5 highest emitting sites included 3 oil sites and 2 gas sites.

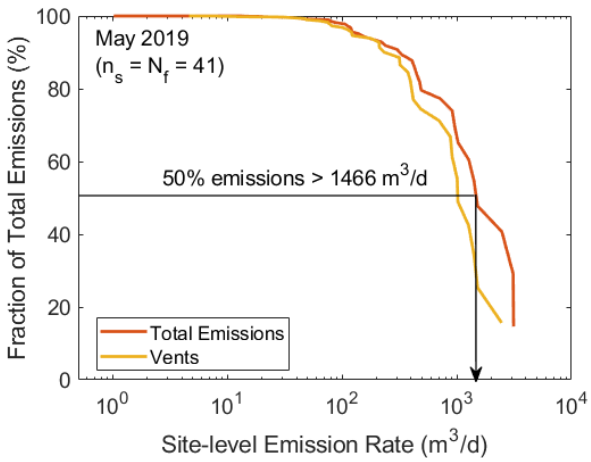

Figure 27. Fractional total emissions (red) and vented emissions (yellow) as a function of site-level emission rate in the May 2019 survey. 50% of emissions are from sites emitting at least 1466 m^3/day.

Figure 28 shows the average site-level emission rate across the different site-types and disaggregated by leak and vents. Vents contribute to73% of total emissions. On average, oil sites emit 628 m^3/d, about 54% higher than the average gas site emission of 345 m^3/d. SWs, both at oil and gas sites, also emit significantly less than MW batteries, with an average emission rate of 270 m^3/d and 172 m^3/d, respectively.

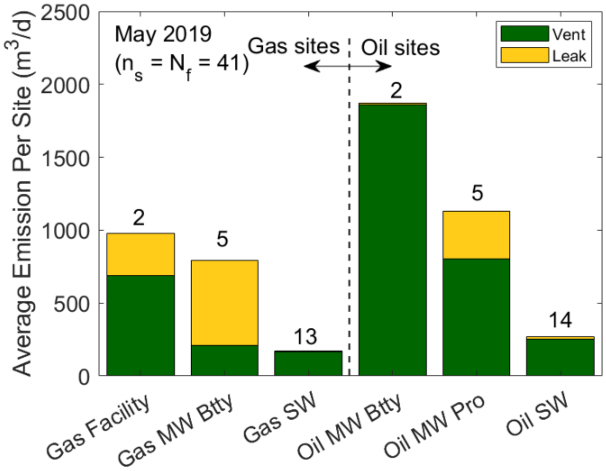

Figure 28. Average site-level emissions observed in the May 2019 survey disaggregated by vents (green) and leaks (yellow), and site types. On average, gas sites (excluding gas facilities) emit 345 m³/day, while oil sites emit 628 m³/day. The numbers above the bars denote sample size for each site type.

4.5. Survey 5 (August 2019)

The final survey of the FEMP-EA project was conducted between August and October 2019. This final round surveyed all facilities in the initial August 2018 survey. 169 facilities containing 179 sites were surveyed – this included 56 gas SWs, 21 gas MW batteries, 7 gas facilities, 67 oil SWs, 11 oil MW batteries, and 17 oil MW prorated batteries. Minor changes in the numbers of each site type between the August 2018 and August 2019 surveys can be attributed to several potential factors: site changes (e.g., a SW battery expanded to a MW battery), access challenges, changes in operator or owner, inactive or shut-in sites, or mis-classification in Petrinex associated with either survey. Of the 179 sites surveyed, 14 did not have any emissions and a further 31 sites did not have any leaks as detected by the OGI camera. Thus, 45 out of 179 sites surveyed (25%) did not have any leaks. A total of 1103 components were found emitting, of which 614 were classified as leaks and 489 were classified as vents. A further 14 emission sources were too small to quantify and were assigned zero emissions.

Figure 29 shows the rank-ordered component-level emissions as a function of total emissions. The top 5% and 10% of emitters contribute to 58% and 73% of total emissions, respectively. In addition, leaks and vents contributed to 26% and 74% of total emissions, respectively.

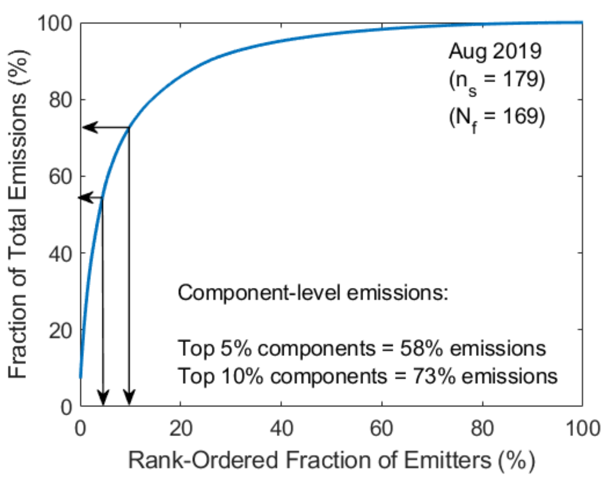

Figure 29. Fractional total emissions as a function of rank-ordered component-level emitters in the August 2019 survey across all facilities. The highest emitting 5% of components contribute to 57% of total emissions.

Figure 30 shows the fraction of total emissions as a function of component-level emission rate. 50% of emissions can be attributed to components emitting at least 374 m^3/d – these emissions come from only 44 out of 1103 emitting components (4%). Of these highest emitting 44 components, 10 are classified as leaks and 31 as vents. Compared to the August 2018 survey, the 50% component-level emission threshold reduced by 36% from 585 m^3/d to 374 m^3/d. Furthermore, the average emission rate for all components in the August 2019 survey is 55 m^3/d, compared to 87 m^3/d in the August 2018 survey.

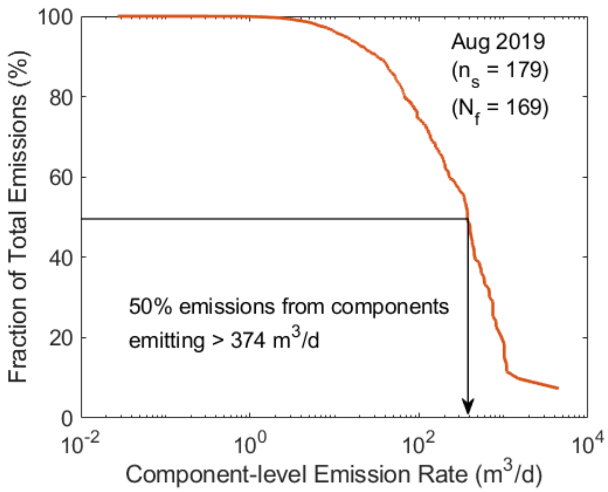

Figure 30. Fractional total emissions as a function of component-level emission rate in the August 2019 survey. 50% of emissions are from components emitting at least 374 m^3/day. Across all emitting components, vents and leaks contribute 74% and 26% to total emissions, respectively.

Figure 31 shows the average component level emission rate across all sites. Flanges and valves comprise 40% of all emitting components but only contribute to approximately 16% of total emissions, with a combined average emission rate of 22 m^3/d. Pneumatics comprise approximately 34% of all emitting components and contribute to 14% of total emissions, with an average emission rate of 23 m^3/d. OELs contributed to the largest share of total emissions, 61%, with an average emission rate of 149 m^3/d. Of these, 73% of all OEL emissions are associated with tanks with an average tank related OEL emission rate of 194 m^3/d. The highest average emitting component type was thief hatch, with an emission rate of 227 m^3/d. By isolating emissions on tanks (both leaks and vents), we find that tank-related components have an average emission rate of 201 m^3/d – they comprise 62% of total emissions from only 17% of total emitters (188/1103). On the other hand, non-tank-related components emit on average 25 m^3/d – these comprise 38% of total emissions from 83% of total emitters.

Compared to August 2018, the average tank-related emission rate has reduced by ~20%, decreasing from approximately 252 m^3/d to 201 m^3/d. Similarly, the average non-tank-related emission has reduced by 51%, from 51 m^3/d in August 2018 to 25 m^3/d in August 2019. Overall, average vent and leak related emissions in August 2019 reduced by 26% and 50%, respectively, compared to the initial survey in August 2018. Between August 2018 and August 2019, this corresponds to a net reduction in emissions of 36%, with a combination of 46% reduction in leaks and 31% reduction in vents.

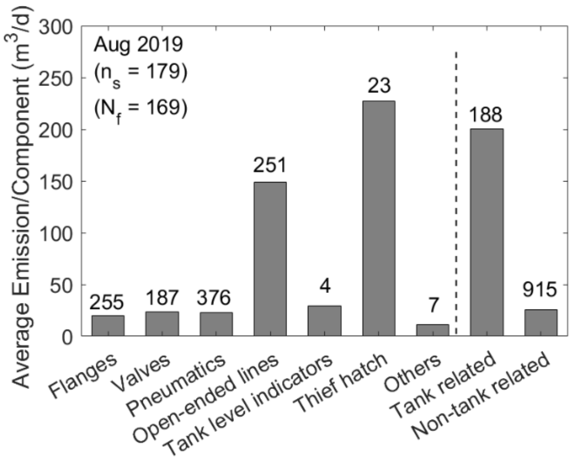

Figure 31. Average emission (both leak and vent) rate at the component-level across 175 sites in the August 2019 survey. Tank-related components emit, on average, 201 m^3/d and contribute to 62% of total emissions, while non- tank related components emit 25 m^3/d and contribute to 38% of total emissions. The numbers above the bars denote sample size for each component type.

Figure 32 shows the fractional total emissions as a function of rank-ordered site-level emissions. The top 5% of sites contribute to 39% of total emissions. Of these, oil sites and gas sites contribute to 64% and 36% of total emissions, respectively. The top 10 emitting sites, which contribute 44% to total emissions, consists of 6 oil sites and 4 gas sites, of which 3 were gas facilities with typically high emissions as observed throughout this study.

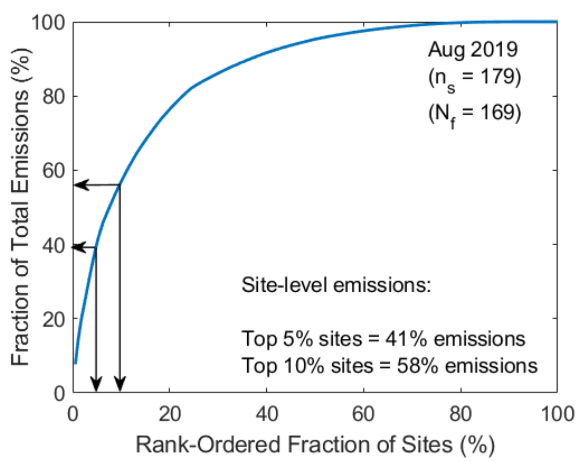

Figure 32. Fractional total emissions as a function of rank-ordered site-level emissions in the August 2019 survey. The top 5% and 10% of sites contribute to 39% and 56% of total emissions, respectively.

Figure 33 shows the fraction of total and vent-related site-level emissions as a function of emission rate. 50% of total emissions come from sites emitting at least 1074 m^3/d – there are only 13 sites with such high emissions, corresponding to 7% of all sites measured in this survey. This represents a 51% reduction compared to the emissions cut-off observed in the August 2018 survey (2186 m^3/d).

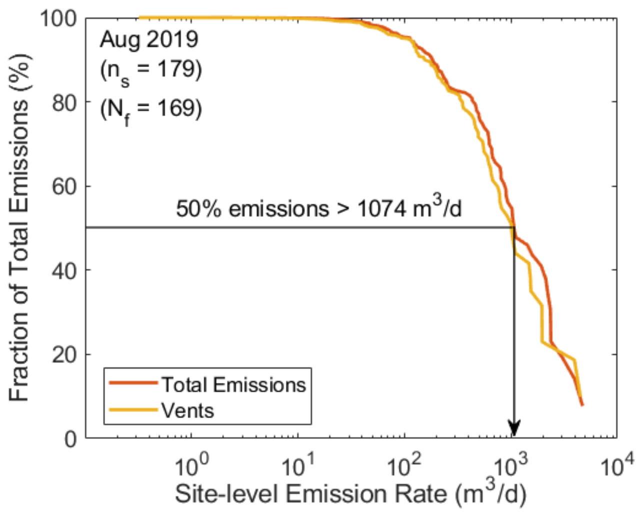

Figure 33. Fractional total emissions (red) and vented emissions (yellow) as a function of site-level emission rate in the August 2019 survey. 50% of emissions are from sites emitting at least 1074 m^3/day.

Figure 34 shows the average per-site emission rate across the different site-types and disaggregated by leak and vents. On average, oil sites emit 422 m^3/d, while gas sites (excluding gas facilities) emit 166 m^3/d. The 7 gas facilities emit an average of 1366 m^3/d, a reduction of 34% from the August 2018 survey. SWs, both at oil and gas sites, also emit significantly less than MW batteries. In this survey, gas and oil single wells emit an average of 80 m^3/d and 267 m^3/d, respectively. MW batteries, on the other hand, exhibit high emissions – gas MW batteries, oil MW batteries, and oil MW prorated batteries emit, on average, 283 m^3/d, 1127 m^3/d, and 551 m^3/d, respectively. Comparing August 2018 and August 2019, we observe emissions reductions across all site-types.

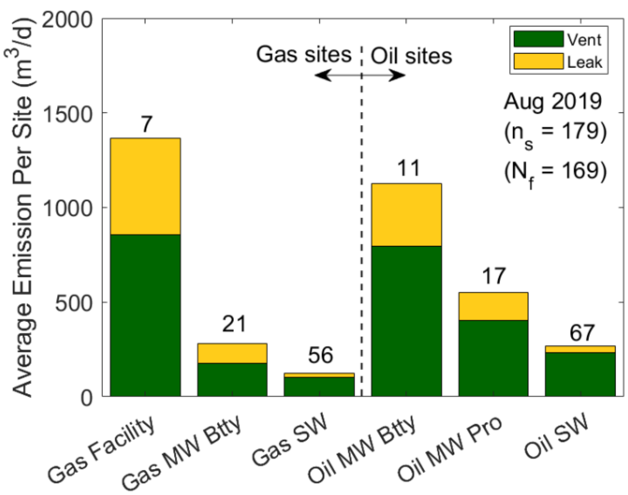

*Figure 34. Average site-level emissions observed in the August 2019 survey disaggregated by vents (green) and leaks (yellow), and site types (*Gas Facility – large site containing multiple gas site-types, *Gas MW Btty – Gas multi-well battery, Gas SW – Gas single well, Oil MW Btty – Oil multi-well battery, Oil MW Pro – Oil multi-well prorated battery, and Oil SW – oil single well). On average, gas sites emit 166 m^3/day, while oil sites emit 422 m^3/day. The numbers above the bars denote sample size for each site type.*

4.6. Outlier Data

In the analysis presented above, a small number of high-emitting components contributed disproportionately to total emissions. Although we included all data collected in this study as part of the survey-level statistics, this section provides information on potential outlier data points. Outliers for each survey are shown in Table 5. These are defined as data points in each survey that are larger than four times the inter-quartile range of measurements for that survey. Inter-quartile range is defined as the middle 50% of the sample data, in this case the difference between the 75th percentile and the 25th percentile emission rate.

Table 6: Analysis of outlier data points across all 5 surveys

Survey	**Total number of non-zero components**	**IQR (m^3/d)**	**Number of components above 4xIQR**	**Fraction of outliers in survey**	**Average emission rate of outliers (m^3/d)**
Aug 18	1091	1054	98	0.09	705
Nov 18	254	552	10	0.04	180
Mar 19	312	690	27	0.08	403
May 19	450	402	56	0.12	313
Aug 19	1103	706	108	0.10	411

5. Operators and Emissions

One of the key advantages of the FEMP-EA study is the fully random and anonymized nature of site selection – beyond site access and health and safety considerations that involved field operators only, no operators/producers were given advance notice of the site surveys. Additionally, sites were not "volunteered" to the program by producers; they were randomly selected avoiding potential for sample bias. Therefore, the FEMP-EA study provides a unique dataset to understand the differences in emissions across operators. The observed differences across operators may be attributed to several factors: differences in voluntary maintenance and emissions management practices, asset profile, number and type of assets, resource type, age, or production levels. Identifying the root cause of the observed differences is beyond the scope of this project.

Figure 35(a) shows the average per-site total emissions for each of the 18 operators in the August 2018 survey. The number of sites surveyed for each operator is shown above their average emission bar. Let N and E denote the number of sites and associated total site emissions, respectively. Let subscripts g and o refer to gas sites and oil sites, respectively. Let the 3 types of gas sites and oil sites be denoted with superscripts 1,2, and 3. The bar heights in Figure 35 correspond to the following formula:

$$Average\ Emission\ Per\ Site = \frac{(E_g^1 + E_g^2 + E_g^3 + E_o^1 + E_o^2 + E_o^3)}{(N_g^1 + N_g^2 + N_g^3 + N_o^1 + N_o^2 + N_o^3)}$$

The orange and blue hues correspond to oil and gas sites, respectively. The colored stacks for each site type represent the fraction of total emissions attributable to each site type. For example, the fraction of emissions attributable to gas site type '1' (E_g^1) is given by:

$$Fraction\ of\ emissions\ attributable\ to\ gas\ site\ type\ '1' = \frac{E_g^1}{(N_g^1 + N_g^2 + N_g^3 + N_o^1 + N_o^2 + N_o^3)}$$

Note that this fraction does not correspond to emissions intensity attributed to gas site type '1', which will be given by E_g^1/N_g^1.

For example, operator 4 has an average site level emission of 1184 m^3/d/site, across all site types. Of these, 34% can be attributed to large gas facilities (darkest blue) and about 36% to oil single well sites (lightest orange).

Average per-site emissions by operator vary by almost two orders of magnitude – operator 9's eight sites emitted approximately 24 m^3/d/site, while operator 4's fifteen sites emitted 1184 m^3/d/site. This is likely due to the differences in type of assets controlled by the operators. For example, operator 9's emissions mostly came from gas single-well sites which have some of the lowest average emission in this study, while operator 4 had a mix of oil sites and large gas facilities, which are also the highest emitting site-types in the study.

Operators with more oil assets exhibit higher average site-level emissions compared to operators with more gas assets. 72% of emissions from the top three operators with the highest average site level emissions can be attributed to oil sites. Most operators with a significant number of gas-based assets have low average emissions at the site-level, including operators 7, 11, 14, 17, and 18. Further exploration of the role of operator behavior in addressing methane emissions could shed light on best practices for the industry.

Average site-level emissions by operator also exhibit skewed behavior, similar to component-level and site-level emissions. The four operators with highest-average site level emissions (top 20%) contribute to 84% of total emissions – together, they operated about 50% of all sites measured in the August 2018 survey.

Figure 35(b) shows the average per-site emission across the 18 operators in the August 2019 survey. Overall, emissions across all sites reduced by 38%, from 550 m^3/d/site in August 2018 to 341 m^3/d/site in August 2019. Oil sites constitute a larger fraction of total emissions than gas sites for most of the operators. In addition, gas facilities have high average site-level emissions, unlike other gas sites. However, compared to August 2018, emissions from large gas facilities reduced by 34% from 2077 m^3/d/site to 1366 m^3/d/site (see Figure 36).

Emissions reductions over the course of one year (August 2018 to August 2019) is not uniform across operators. Three of the four highest average emitting operators in August 2018 – operators 4, 12, and 16 – reduced average site-level emissions by 59%, 78%, and 55%, respectively, contributing to a majority of the overall emissions reductions. On the other hand, 5 of the 6 operators with less than 100 m^3/d/site average emissions in the August 2018 survey saw their average emissions increase in August 2019. Despite this, overall emissions reduced because of the skewed nature of operator-specific emissions. This observation empirically confirms prior modeling studies – sites with high baseline or initial emissions also have the highest potential to reduce emissions [37]. Therefore, future studies on evaluating emissions reductions need to consider the underlying distribution in emissions across site-types, operators, and regions.

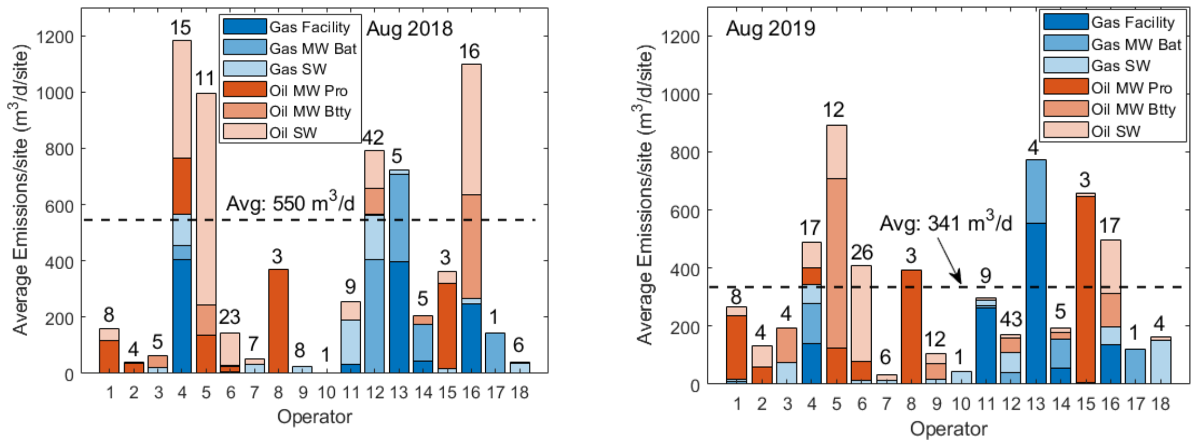

Figure 35. Average site-level emissions by operators in the FEMP-EA study in (a) August 2018, and (b) August 2019, respectively, sorted from highest to lowest. Blue hues correspond to gas sites and orange hues correspond to oil sites. The number of sites for each operator is specified as a number above their respective bars. The individually colored sections represent proportional emissions by site-type and do not correspond to average emissions by site-type. Compared to August 2018, average emissions across all operators decreased by 38%. However, there are significant differences amongst operators, with the highest emitting operators in August 2018 survey largely reducing emissions, while lowest emitting operators in August 2018 saw increased emissions.

Figure 36 and Figure 37 shows the average site-level emission for each operator disaggregated by major site types in the study in the August 2018 and August 2019 survey, respectively. The order of the operators has not changed from Figure 35. Oil sites, on average, emit more than gas sites. Interestingly, we also observe differences across operators in site-level average emissions for the same site-type. In the August 2018 survey, operators 4, 5, 12, and 16 have emissions averaging about 1000 m^3/d/site for oil SW sites, while the average for all oil SW sites is 517 m^3/d/site. All This is because other operators with oil single well sites emit only about 100 m^3/d/site on average. All four operators had significantly reduced oil SW emissions in the August 2019 survey, resulting in an average oil SW emission rate of 255 m^3/d/site. Such intra-operator differences are most prominent for oil sites than gas sites.

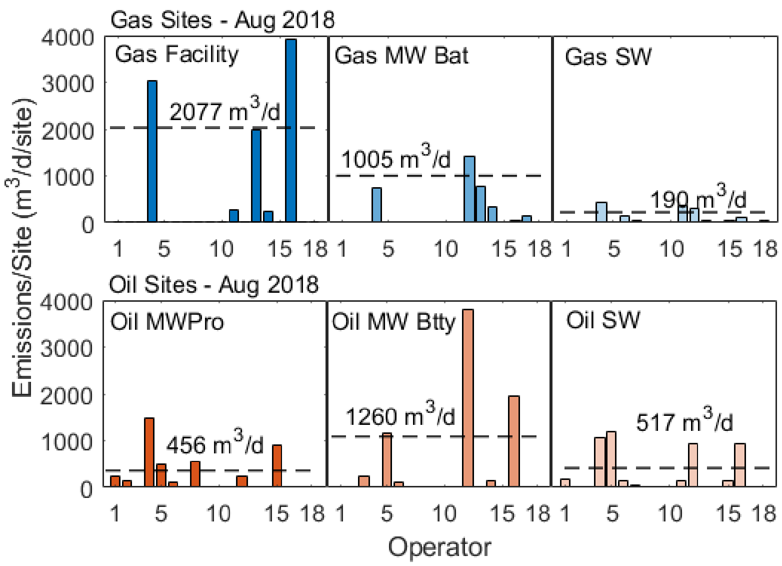

Figure 36. Average per-site emission by operator for each of the six site-types in the August 2018 survey– the order of the operators is the same as shown in Figure 35.

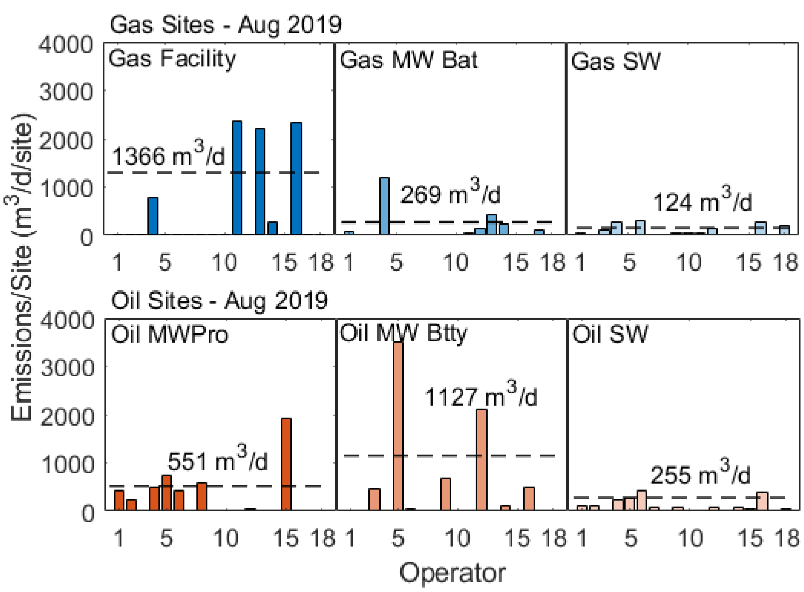

Figure 37. Average per-site emission by operator for each of the six site-types in the August 2019 survey – the order of the operators is the same as shown in Figure 35.

6. Repair Effectiveness

One of the objectives of the FEMP-EA study is to understand the effectiveness of LDAR surveys in reducing fugitive methane emissions.

At control sites, the operators were not provided with the list of leaks found by the survey team, and hence no repair was initiated as a result of this study. However, operators do fix leaks as part of routine maintenance – such ‘routine’ changes to leaks were not prevented by the study team to minimize intervention at control sites. Without any study-mandated requirement for fixing leaks and the absence of any federal or provincial policy on LDAR surveys at the time of the study, the emissions reductions observed at the control sites are likely to represent the ‘native repair process’. This is the expected emissions reduction from routine maintenance without any mandated LDAR programs. At treatment sites, operators were given the list of leaks (and vents) found by the survey team, and all leaking components were physically tagged whenever possible. Furthermore, operators were requested to repair the leak with the expectation of a future survey.

Because the project was voluntary, operator behavior played a significant role in observed changes to fugitive emissions – some operators routinely fixed emissions found by the survey team, while other operators did not undertake any repair process. We define two types of repairs undertaken by operators: consistently repaired and repaired at least once (or inconsistently repaired). Consistently repaired sites refer to those treatment sites where repairs were conducted after each LDAR survey. If a treatment site was surveyed 3 times during the study, repairs were also conducted after each survey. Inconsistently repaired sites refer to those treatment sites that had undergone bi-annual or tri-annual surveys and where repairs were conducted at least once. Disaggregating sites where repairs were completed from non-repaired sites is critical to understand the effectiveness of the repair process, and consequently, LDAR surveys. There are a number of reasons why operators might not have repaired emissions on-site – one, the requested repairs were part of a research project and likely were not high priority; two, operational challenges might have prevented operators from making repairs before the follow-up survey (for example, a major shut-down event is required to make a repair); three, budgetary constraints could have limited the frequency and extent of repairs undertaken for this study; and, four, operators were not under any regulatory requirement to conduct repairs. In general, changes observed between the initial and final surveys can be attributed to 3 potential reasons – repairs conducted through the year, reduction in stochastic emissions especially from tanks, and changes to sites that reduced activity factors associated with equipment most susceptible to emitting methane.

6.1. Pre- and post-repair emissions counts

Figure 38 shows the changes in the average number of leaks and vents at control sites, treatment sites that are not repaired, treatment sites that were repaired at least once, and treatment sites that were consistently repaired. The latter two categories distinguish sites where repairs were undertaken to some extent. For example, tri-annual sites where all 3 post-survey repairs were conducted would be classified under ‘treatment sites that were consistently repaired’. If only one or two post-survey repairs were conducted at tri-annual sites, they would be classified under ‘treatment sites that were repaired at least once’. Using this definition, sites on an annual survey schedule will always be classified under ‘treatment sites that were consistently repaired’ since only one repair was required at these sites. A site is considered to have undergone a repair survey if at least one of the leaks at the site was found to be repaired (e.g., if a tagged leak was found to be non-emitting in a subsequent survey, or if a ‘date of repair’ is present on a tagged leak). Based on these definitions, there are 54 sites that underwent repairs at least once, including 26 sites that are consistently repaired based on the survey frequency. Of the 26 consistently repaired sites, 15 are from the annual survey treatment group, 6 from the bi-annual survey treatment group, and 5 from the tri-annual survey treatment group. As the frequency of survey increases, the sample size of consistently repaired sites decreases.

Because the subsample of sites used to evaluate repair effectiveness is different from that of the study sample, the composition of site types in control and treatment groups are different. This results in different average number of leaks per site in the different groups in Figure 38. Repaired treatment sites exhibit significant reductions in the average number of leaks per site compared to control sites and non-repaired sites. Furthermore, sites that were repaired consistently saw a high reduction in the average number of leaks compared to sites that were repaired at least once. This suggest that (a) repairs are effective, (b) any observed increase in emissions likely come from new leaks and not emissions growth from existing leaks, and (c) consistent repairs of new leaks results in higher emissions reductions than inconsistent repairs. At consistently repaired treatment sites, the average number of leaks decrease by approximately 50%, from 5.0 per site to 2.6 per site. At treatment sites that are repaired at least once, the average number of leaks decrease from 4.6 per site to 3.8 per site. However, at treatment sites that are not repaired, the number of leaks increased from 1.2 per site to 1.6 per site, indicating the potential impact of new leaks created between the initial and follow-up surveys. Similarly, the average number of leaks changed from 2.3 per site to 2.0 per site at control sites, with the small reduction potentially associated with voluntary inspection and maintenance actions taken by the operator.

Similar to leaks, the average number of vents only decreased slightly by approximately 0.3 vents per site in the control sites and 0.4 at treatment sites that were not repaired. However, by contrast, the number of vents at treatment sites that underwent leak repairs did not decrease as significantly as the number of leaks because leak emissions can be repaired by operator while vent emissions are part of operational process by design. The average number of vents reduced only slightly – from 3.5 (95% CI [2.8 – 4.2]) per site to 3.1 (95% CI [2.5 – 4.0]) per site at sites that are repaired at least once and from 4.3 (95% CI [3.2 – 5.4]) per site to 3.4 (95% CI [2.5 – 4.9]) per site at sites that are repaired consistently. The slight reduction in the average number of vents can be attributed to several potential causes. Even though vents are not the target of LDAR surveys, frequent site visits give operators more opportunity to examine and capture anomalous venting events. Anomalous venting events refer to nominally vented emissions that emit more than designed or can be easily fixed. For example, an open thief hatch on a tank would be considered an anomalous vent and can be fixed if detected during the LDAR survey. Additionally, vent emissions could be episodic and thus, not detected in every survey.

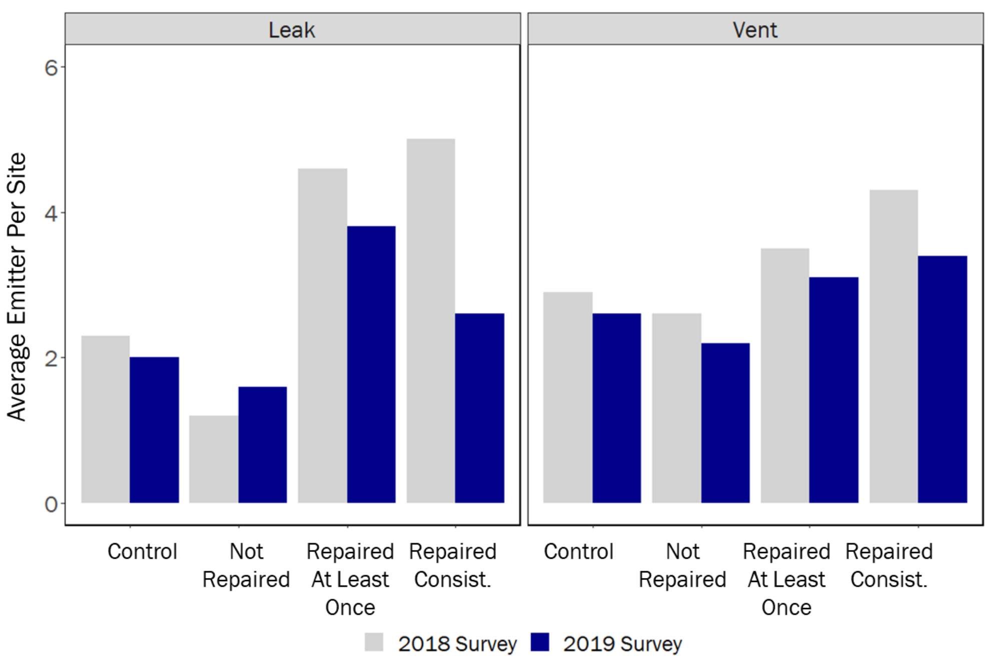

Figure 38: Site-level average count of emitters from control and treatment groups in 2018 (gray) and 2019 (blue) surveys. Emitters per site are further disaggregated by leak and vent emissions. One control site was repaired by accident and removed from the analysis. As a result, there are 36 control sites. Repair activity is

identified by operators' notes on physical tags. "Repaired At Least Once" include sites that are repaired at least once throughout temporal surveys (n = 54). "Repaired Consistently" include sites that are repaired at each of the temporal surveys (n = 26). "Not Repaired" include sites that are not repaired at any temporal surveys (n = 57).

6.2. Tag analysis

The ground OGI teams placed tags on leaking equipment at treatment sites for operators to repair prior to a subsequent survey. Operators note a 'date of repair' on the tag when the emitting component is repaired. These tags provide a way to analyze component-level individual leak growth rate by comparing emissions from the same component across the five surveys. Because tags are placed only on leaking equipment, we assume that only repair activities can eliminate emissions from a tagged component. There are four main scenarios to consider:

a. There is a 'date of repair' to the tag and the component is not emitting in the subsequent survey.
b. There is no 'date of repair' on the tag and the component is not emitting in subsequent survey.
c. There is a 'date of repair' on the tag and the component is still emitting. Here, we assume that the leak recurred.
d. There is no 'date of repair' on the tag and the component is still emitting. Here, there are two sub-cases. One, the leak was repaired and recurred, and two, the leak was not repaired. These are treated as equivalent since it is not possible to distinguish the sub-cases from the available data.

The analysis presented here considers tags across the fives surveys and compares emissions between when the tag was first created ('initial survey') and when it was re-examined ('follow-up survey'). If a tag was created during the November 2018 survey at a tri-annual site ('initial survey'), the 'follow-up survey' for that site would be from May 2019. Only components with more than 30 tagged emissions are included in this analysis to ensure statistical robustness.

Figure 39 shows changes in average emissions from tagged components between the initial and final survey as a function of repair. Emissions are persistent – repaired leaks were not likely to be emitting in the follow up survey while leaks that were not repaired were likely to be emitting in the follow-up survey. The average leak rate of non-repaired flange/connecter (n = 137) stays the same between initial and follow up surveys at 4 kg CH_4/d. Similarly, valves (n = 103) that are not repaired after the initial survey exhibit similar leak rates in the follow-up survey. The increase in pneumatics between the initial and follow-up survey is not statistically significant. This is because the difference is driven by one large emitter. In other words, even if this outlier was removed from the population of pneumatics, there would be no difference in pneumatic emissions between initial and follow-up survey. This shows that leaks that are not repaired do not increase significantly in size during the time between LDAR surveys.

Repairs are highly effective – leaks that are repaired stay fixed and did not leak in follow-up surveys. Flange/connector (n = 53), pneumatics (n = 57) and valves (n = 43) are all emitting, on average, <0.5 kg CH_4/d after repair. As a result, any increase in measured emissions in LDAR surveys is likely to come from new leaks rather than an increase in emissions from unrepaired leaks.

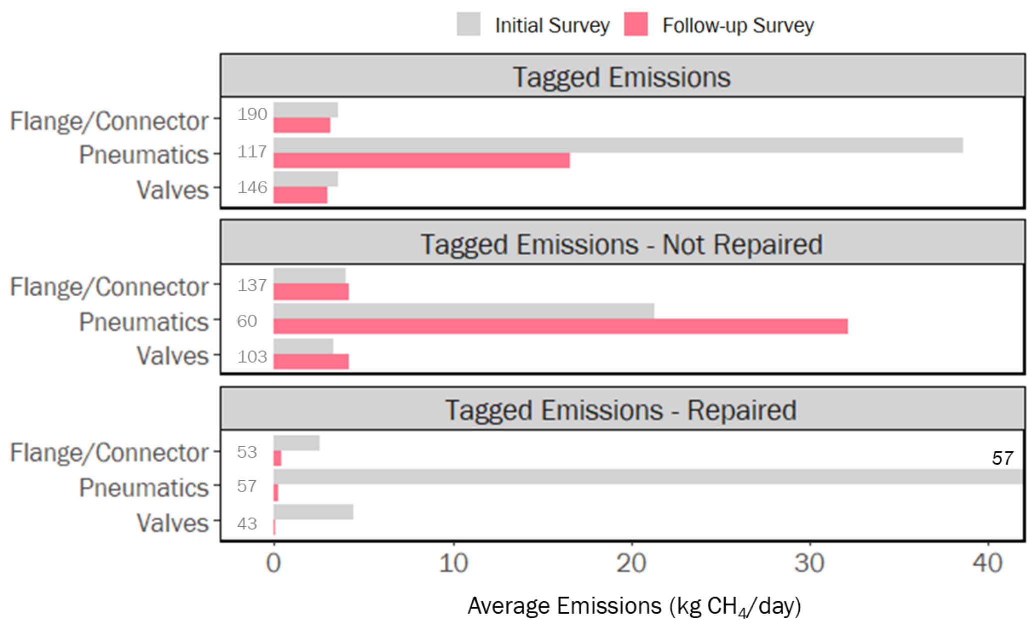

Figure 39: Average of tagged component-level emissions. Only components with >30 tagged leaks are included. The numbers between y-axis and the bars represent the counts of emitters included.

6.3. Pre- and post-repair emissions

As mentioned previously, the count of leaks and vents provide a more robust perspective of the effectiveness of repairs. However, associated emissions reductions allow to potentially understand the impact of repair activities on methane mitigation, albeit with higher uncertainty. Figure 40 shows the site-level average leak and average vent emissions at control and treatment groups between the initial August 2018 survey and the final August 2019 survey. The number of sites in each of the control and treatment group in this analysis is similar to that in Section 6.1 which describes the changes in leak and vent counts. The uncertainty in emissions reductions is higher than that in emission counts because of the uncertainty associated with quantification.

The site-level average emissions in August 2018 survey for both 'repaired once' and 'repaired consistently' groups are higher than that from control and non-repaired groups. This is due to differences in the composition of site types in each group – this arose because the sub-sample of sites eligible for this analysis (see Methods) is different from the overall population of sites in the study. For example, at least three quarters of the sites in the control group and not repaired treatment group are Gas SW and Oil SW, which have lower average site-level emissions and emitters. On the other hand, approximately half of the sites in repaired once and repaired consistently treatment groups are from multi-well batteries, whose average emissions and average number of emitters per site are more than double that of single wells.

Repaired sites show more emissions reduction than non-repaired sites – the more consistent the repair, the higher the emissions reduction. Figure 40 shows changes in total, leak, and vent emissions between initial and final surveys across control sites and the three treatment sites. Consistently repaired sites show site-level average total emissions reduction of 69%, as compared to the 62% from sites that are repaired at least once and 19% from treatment sites that are not repaired. For average leak emissions, consistently repaired sites see a reduction of 74%, as compared to 65% from repaired at least once sites and 19% from not repaired sites. Since emissions are highly skewed, reduction from large leaks (>180 m^3/d) can contribute disproportionately to average emissions reductions. For example, while the number of large leaks (>180 m^3/d) at 'not repaired' sites are similar (n = 3 vs. n = 4) between two surveys, the average emission rate of these leaks reduced from 529 m^3/d to 297 m^3/d. The reduction from these large leaks contributed to 67% of total leak reduction. The 57% reduction in average leak emissions at control sites is similarly driven by reductions from large leaks (>180 m^3/d). Thus, even when the average number of leaks per site did not change significantly between the initial and final survey at control and 'not repaired' sites (see Figure 38), we observe a significant reduction in leak emissions.

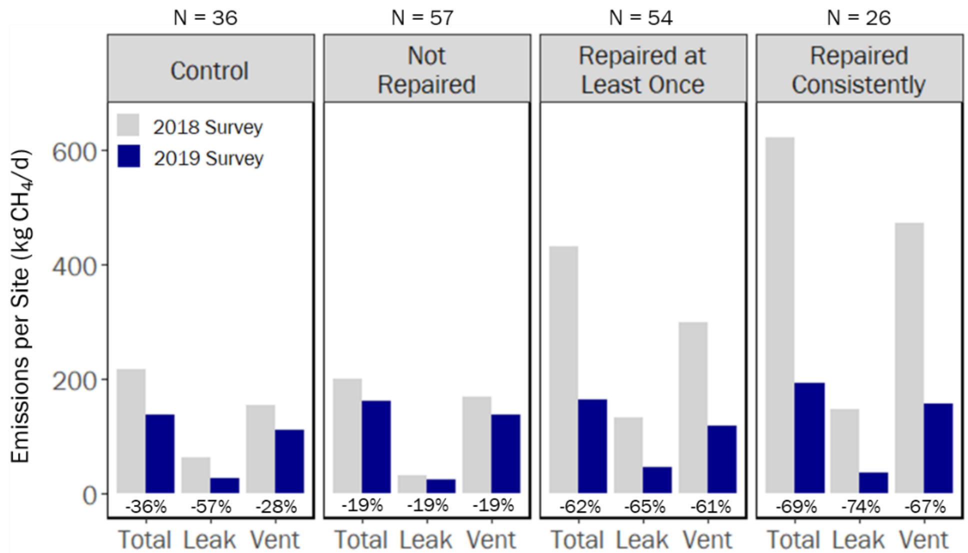

Figure 40: Site-level average emissions evolution from control and treatment group. Emissions per site are further disaggregated into leak and vent emissions. The numbers on top of the chart show the sample size of each category. "Not Repaired" include sites that are not repaired at any temporal surveys. "Repaired at Least Once" include sites that are repaired at least once throughout temporal surveys. "Repaired Consistently" include sites that are repaired at each of the temporal surveys.

6.4. Survey frequency analysis

Figure 41 shows the changes in leak emissions across the control and treatment sites that underwent repairs according to the survey schedule. In this analysis, only sites that underwent all required repairs were included – i.e., sites on the 3 /year survey schedule must have undergone repairs 3 times after each survey. If only one or two of those repairs were conducted, the site was excluded. This strict repair requirement results in a progressively smaller sample sizes as the survey frequency increases. 11 of 31 sites in the annual survey schedule had undergone repairs, while only 7 and 3 sites underwent repairs according to the survey schedule in the bi-annual and tri-annual treatment sites. Leak emissions at treatment sites under the 1/year, 2/year, and 3/year schedule reduced by 48%, 77% and 42%, respectively. Furthermore, emissions at control sites also reduced by 22% - this is a combination of potential voluntary LDAR programs of some of the operators or regular site maintenance. This 22% reduction could be interpreted as a proxy for the 'natural repair rate' at oil and gas sites – emissions reductions that are likely to be achieved from routine maintenance.

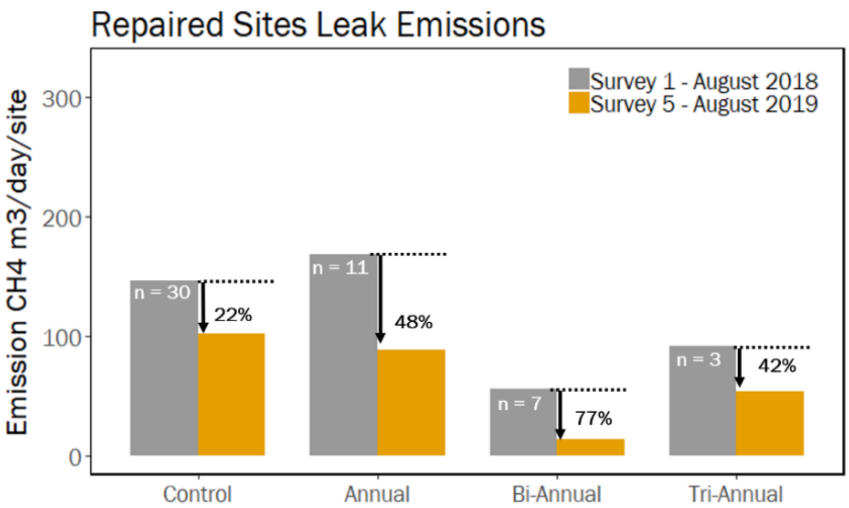

Figure 41. Observed changes to leak emissions at the control and treatment sites that have undergone repairs according to the survey schedule – for example, sites in the tri-annual schedule must have undergone 3 repairs after each survey to be included in this analysis. Initial August 2018 emissions are shown in gray, while final August 2019 emissions are shown in yellow. Sample size for the control and treatment samples are also noted.

7. Future Research Considerations

The FEMP-EA is the first study, to the authors' knowledge, to extensively use the QOGI instrument for quantifying methane emissions from oil and gas facilities. There were two main reasons to favor the QOGI instead of the more conventional Bacharach Hi-Flow sampler:

1. QOGI can be used estimate a larger fraction of emissions at sites compared to the Hi-Flow Sampler that can only be used to estimate emissions that are accessible and safe. This helped us directly measure emissions from high-emitting sources such as tanks that were only visually estimated or statistically inferred in prior studies. However, the quantification uncertainty associated with QOGI needs to be investigated in more detail [53].
2. QOGI improves the range of measurement capabilities, from relatively small emissions (< 10 m^3/d to over 1000 m^3/d as measured through controlled releases during the Alberta Methane Field Challenge [[53]) while the Hi-Flow sampler is limited by the maximum displacement of the blower (650 standard cubic feet per hour [51]).

Recognizing the versatility of QOGI in providing comprehensive emissions estimates, jurisdictions in Canada and US either require or are exploring the use of the instrument in formal regulatory settings to quantify methane emissions. In this context, the FEMP-EA study provides important performance characterization data that can help in accurate interpretation of emissions quantification and provide guidelines for future research directions.

Based on prior controlled release testing of QOGI in the Alberta Methane Field Challenge (AMFC) and Saskatchewan Research Council (ASRC) studies, we recommend the use of QOGI in applications requiring aggregate emissions quantification. On a limited scale, these independent tests have shown aggregate errors of about 18% in relatively stable, in-field conditions. However, this error estimate is based on a relatively small number of controlled release tests (~110) and precision of individual quantification estimates depends on emission rate, wind speed, atmospheric conditions, scene contrast, and other factors that were not tested during the AMFC. In this study as well as applications in updating methane inventories in a regulatory context, an overall understanding of methane emissions across oil and sites is a function of aggregate emissions across sites and components. Thus, confidence in aggregate measurements is more critical in developing scalable insights into methane emissions. The QOGI instrument in this regard provides a more comprehensive dataset to analyze aggregate emissions compared to other quantification technologies widely used in ground-based LDAR surveys.

Individual estimates of QOGI-based quantification tend to have significantly higher error than aggregate estimates. Stakeholders should avoid drawing insights from single emissions measurements. For example, it is possible for individual estimates of emissions from specific components such as pneumatic devices to seem higher than what is expected based on experience or comparison to the Bacharach Hi-Flow sampler data. This is because, as the Providence Photonics' documentation of the QOGI notes, individual quantification estimates are more prone to environmental conditions such as background, wind-speed, and the quality of plume extraction by the QOGI algorithm. Future studies should consider detailed controlled release tests for the QOGI under varying atmospheric and imaging conditions. Tests at simulated sites such as the Methane Emission Technology and Evaluation Center (METEC) in Fort Collins, CO will help researchers to better characterize uncertainty in this technology. These controlled release tests can be conducted based on prior field studies with standardized test protocols that have been used in several recent tests of methane emissions technologies [23], [48].

While the accuracy of QOGI estimates in aggregate has been verified through controlled release tests, more controlled release testing of QOGI is necessary to better estimate precision for individual emissions estimates. Furthermore, these should be compared with conventional quantification approaches such as Hi-Flow sampler or tracer methods.

8. Summary and Conclusions

The Fugitive Methane Emissions Program Effectiveness Assessment (FEMP-EA) sought to understand the impact of periodic LDAR operations on fugitive emissions at oil and gas facilities. Through a rigorous and anonymous site selection process, a scientifically sound survey procedure, and detailed statistical analysis, we identify critical characteristics of methane emissions at oil and gas sites that can directly inform the development of cost-effective methane management practices and programs While the study has confirmed prior observations and provided many new insights into methane emissions and management, we conclude by highlighting the most important findings in this report.

1. **Emissions are dominated by a very small number of high-emitting components (and sites).** In 4 out of 5 surveys, 50% of emissions come from less than 5% of components, reinforcing the need for large sample sizes to appropriately sample the long tail in emissions distribution. Furthermore, such highly skewed leak-size distributions also indicate the potential for high-speed, high-detection threshold screening technologies to quickly identify such high-emitters. Thus, large emissions reductions can be achieved cost-effectively by finding and fixing a small number of high emitters. Similarly, at the site level, less than 10% of sites are responsible for over 50% of site-emissions, reinforcing the need to target highest emitting sites for emissions reductions.

Table 7. Summary of the highest-emitting component- and site-level emissions across the five surveys in the FEMP-EA study.

Survey	50% emission rate cut-off (m^3/d)		Fraction above cut-off (%)	
	Component-level	**Site-level**	**Component-level**	**Site-level**
Aug 2018	585	2186	2.8%	6.4%
Nov 2018	73	338	10.6%	13.1%
Mar 2019	285	872	4.5%	9.3%
May 2019	463	1466	2.9%	9.8%
Aug 2019	374	1074	4.0%	7.3%

2. **Tanks are the largest single source of emissions.** Tank-related components such as thief hatches, tank-level indicators, and open-ended lines contribute to between 58% and 82% of total emissions across all surveys. Thus, any methane reduction approach should focus on reducing emissions from tank-related components. While understanding the root cause of tank emissions were beyond the scope of this study, future work should investigate potential upstream issues that manifest as tank emissions.

3. **Leak rates of emitting components do not grow significantly over time.** Temporal analysis of individual leaks by tracking them over the five surveys show that emissions are highly persistent – repaired leaks do not recur, and non-repaired leaks continue to emit. We also find that rates of individual leaking components do not grow over time. This suggests that any increase in emissions observed at oil and gas sites under mandatory LDAR programs (and where leaks are repaired) are likely from new leaks and not because of growth in existing leaks.

4. **Repairs are highly effective in reducing the average number of leaks found in a survey.** Repaired treatment sites exhibit significant reductions in the average number of leaks per site compared to control sites and non-repaired sites. Furthermore, sites that were repaired consistently saw a high

reduction in the average number of leaks compared to sites that were repaired at least once. This suggest that (a) repairs are effective, (b) any observed increase in emissions likely come from new leaks and not emissions growth from existing leaks, and (c) consistent repairs of new leaks results in higher emissions reductions than inconsistent repairs.

5. **Repaired sites show more emissions reduction than non-repaired sites – the more consistent the repair, the higher the emissions reduction.** Consistently repaired sites show site-level average emissions reduction of 69%, as compared to the 62% from sites that are repaired at least once and 19% from treatment sites that are not repaired. For average fugitive emissions, consistently repaired sites see a reduction of 74%, as compared to 65% from repaired at least once sites and 19% from not repaired sites. Since emissions are highly skewed, reduction from large leaks (>180 m^3/d) can contribute disproportionately to average emissions reductions.

6. **Fugitive emissions reduced by 22% at control sites and 42%, 48%, and 77% at the three treatment sites.** In sites that were consistently repaired according to the survey schedule, emissions reduced by 48%, 77%, and 42% at 1/year, 2/year, and 3/year treatment sites, respectively. The critical insight from this analysis is that the potential for emission reductions from repairing leaks is also skewed – i.e., less than 10% of the sites found to be emitting contribute over 50% of all emissions reductions in any given survey. However, small sample size at treatment sites that underwent repairs according to survey schedule suggests future research is needed to conclusively understand the role of survey frequency on fugitive emissions reductions.

7. **Oil sites and MW batteries, on average, emit more than gas sites and SW batteries, respectively.** Oil sites tend to exhibit higher methane emissions compared to gas sites, often associated with higher number and prevalence of tanks. This persistence of high emissions across all oil sites, and especially multi-well sites. Future studies with larger sample sizes can inform whether these differences in average site-level emissions are robust and statistically significant.

8. **Vents are the largest source of methane emissions.** Vented emissions contribute between 69% and 86% of all emissions across the five surveys, underscoring the limited impact of reducing leaks in overall methane mitigation programs. However, LDAR surveys can also help identify anomalous vents – vents whose emission rates are significantly higher than designed (e.g., open thief hatch) – that could be potentially addressed cost-effectively. Indeed, prior studies have shown that addressing anomalous vents identified in routine leak detection surveys help reduce overall emissions [16].

9. **There are significant differences in average site-level emissions across operators as operators with a larger fraction of oil assets tend to have higher average emissions.** Average per-site emissions by operator vary by almost two orders of magnitude from about 24 m^3/d/site to over 1100 m^3/d/site. Furthermore, operators with more oil assets exhibit higher average site-level emissions compared to operators with more gas assets. 72% of emissions from the top three operators with the highest average site level emissions can be attributed to oil sites. Finally, emissions across operators also exhibit skewed behavior, similar to component-level and site-level emissions. The 4 operators with highest-average site level emissions (top 20%) contribute to 84% of total emissions – together, they operated about 50% of all sites measured in the August 2018 survey. This shows that sites with high baseline or initial emissions also have the highest potential to reduce emissions.

10. **Understanding near-term temporal variations in emissions require detailed future studies based on continuous measurement systems.** The overall emissions reductions observed in the FEMP-EA study between August 2018 and August 2019 included a combination of emissions reduction from both repaired leaks and vents. While anomalous emissions (e.g., open thief hatch) may have been fixed by an operator, many large vent sources could likely be episodic and therefore not detected in all surveys. For example, outgassing from liquid storage tanks strongly depend on liquid level and outside temperature – snapshot observations across time like the FEMP-EA study cannot (or other periodic measurements) are not designed to analyze the impact of these episodic emissions on both repair effectiveness and overall emissions inventory. Future studies with mature continuous monitoring systems that can detect and quantify episodic emissions would be critical to better understanding the impact of short-lived emissions sources.

The findings presented in this summary directly addresses the questions in the initial study design and satisfies the key success factors as defined in the initial scope of the project. The FEMP-EA project successfully achieved the following project objectives:

- Characterized all emissions sources as fugitive emissions or vents and quantified over 90% of all emissions detected by the OGI camera.
- Classified all emissions sources across standard terminology for components and equipment, making it easier to compare to future studies and internal data.
- Discussed the impact of repair process on fugitive emissions reductions across different LDAR survey frequencies. Given the uncertainty around repair process, we make recommendations for future areas of study.
- Identified the importance of characterizing and quantifying all sources to appropriately sample the small number of high-emitting components and sites that contribute disproportionately to overall emissions.
- Collaborated and coordinated with on-going alternative technologies studies such as the Alt-FEMP and the Alberta Methane Field Challenge.
- Provided one of the largest comprehensive data set of bottom-up methane leaks and vents at oil and gas facilities across Canada and the U.S., expanding insights on the sources and components most prone to exhibiting high emissions.
- Developed critical insights into methane management by highlighting the importance of vented emissions to overall emissions, demonstrating the significant differences across site types and operators, and confirming that the majority of emissions can be reduced by addressing the small number of high emitters.

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