Fugitive Emissions Management Program Effectiveness Assessment – Phase-I

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Executive Summary

The oil and gas industry is a major economic engine in Alberta and British Columbia. Yet, methane emissions from oil and gas facilities poses a significant challenge to operators because of methane's large contribution to global warming. In 2015, about half the total methane emissions in Canada – 45 million metric tons of carbon dioxide-equivalent – was attributed to the oil and gas industry. Eliminating this source of methane emissions would be equivalent to eliminating emissions from 10 million cars. There are also additional advantages to reducing emissions: the emitted methane is worth billions of dollars and reducing methane emissions improves local air quality.

Recent field campaigns in Alberta and British Columbia that measured methane emissions from oil and gas facilities using multiple independent methods show the same thing – that actual emissions are higher than reported or estimated emissions. As concerns about the impact of climate change grows globally, reducing methane emissions simply becomes a strategic risk management choice because reductions will help maintain public support for resource development. Furthermore, sustainable development of Canada's resources is in its long-term national interest because it balances the need to grow the economy with the responsibility to protect the environment.

Environment Canada recently finalized regulations to reduce methane emissions from the oil and gas industry by 40 – 45%. These regulations include periodic leak detection and repair programs, limits on venting from pneumatic devices, compressors, and other processes in the upstream production sector. Similarly, Alberta has proposed equivalent methane regulations at the provincial level. The central question in this study then follows: how effective will these regulations – the periodic leak detection and repair programs in particular – be in reducing methane emissions as expected.

This white paper is a scoping study that aims to assess the effectiveness of fugitive emissions management programs (FEMP). It is a summary for business leaders and policy makers of the latest science on methane emissions, a review of contemporary policy approaches to mitigate methane, and a summary of scientific uncertainties and knowledge gaps. Finally, we also propose a detailed study plan that answers the fundamental question: how effective are leak detection and repair programs in reducing methane emissions from the oil and gas sector?

Methane Emissions – The Known

The past five years have seen a rapid increase in the number of methane emissions studies in the US and Canada. These studies typically take one of two forms: (1) bottom-up component or facility-level emissions estimates, or (2) top-down aircraft or satellite based regional emissions estimates. While bottom-up measurements are necessary to understand specific component-level emissions mechanisms and repair options, top-down studies can help understand regional or global trends across space and time. A few common themes across these can be identified.

Super-emitters – the '5 – 50' rule

All bottom-up site-level and facility-level studies of methane emissions show evidence of "super-emitters". A super-emitter is part of a small number of very high-emitting leaks at a given facility that are responsible for a majority of the emissions. By analyzing a wealth of peer-reviewed literature on component-level emissions estimates in US and Canada, we derived the '5 – 50' rule: the top 5% of emitters by size are responsible for 50% of the total emissions at that site. At the component level across all studies performed, 90% of aggregate leaks have emission rates greater than about 61 kg CH_4 per day (~ 34,000 m^3 per year). Variations around this rule using data from Canadian sites have also been demonstrated, where the top 20% of the emitters contribute to 88% of the total emissions.

We classify super-emitters into three categories: (1) continuous super-emitters that arise from malfunctioning equipment, (2) episodic super-emitters that arise from one-time events like liquids unloading and are generally known a priori, and (3) intermittent super-emitters that arise from high-emitting equipment such as high-bleed pneumatics. Effective leak detection and repair (LDAR) operations will need to identify and mitigate all of these super-emitter categories.

Methane emissions vary over time and space

Recent fence-line emissions measurements in Alberta and British Columbia indicate that methane emissions vary significantly over time and space. Variation in the temporal characteristics of methane emission can arise from components that emit intermittently (e.g., pneumatics), one-time events at the facility that emit large quantities of methane (e.g., liquids unloading and flashing), or maintenance procedures that temporarily increase or reduce emissions (e.g., blowdown prior to repair). A recent study in the Montney play in BC involving multiple drives past facilities showed persistent emissions only at about 10% of all the sites visited.

Variation across geography matters as well. A recent study in Alberta showed emissions to be significantly higher in the Lloydminster region compared to Red Deer region. However, the underlying reason for this variation between regions is not clear. Potential causes can include geologic features that lead to different development and production plants (i.e., rock permeability or reservoir pressure), resource composition (fraction gas, liquids, and water), hydrocarbon characteristics (API gravity), weather, infrastructure age, and operator practices. This geographic variation points to the need for measurements in multiple regions to accurately understand provincial emissions. Measurements from one region cannot in general be extrapolated to other regions.

Detection technology plays a critical role in mitigation outcomes

The recent focus on reducing methane emissions from the oil and gas sector, coupled with U.S. and Canadian federal research and development support, has led to a proliferation of detection technologies and platforms. This includes traditional optical gas imaging cameras, truck-, drone-, and plane-based systems, and even low-earth orbit satellites. The relative utility of each technology choice depends on the goals of the operator or the policy maker. For example, assessing regional trends requires low-cost and high-speed solutions that can cover large areas over a short time – satellite- or airplane-based monitoring is ideal for such purposes. However, effective mitigation requires detection technologies to be cost-effective, have the ability to detect 'super-emitters' fast, and be reliable and easy-to-use. Because super-emitters constitute a large fraction of total emissions, it is not always necessary for detection technologies to have high sensitivity. In such a scenario, lower sensitivity can be traded-in for lower cost, improving the cost-effectiveness of leak detection while sacrificing little in emissions reductions. Furthermore, spatial distribution of the facilities (sparse vs. dense) will determine the relative importance of detection speed when choosing an appropriate technology. The choice of detection technology is dependent on whether the goal is mitigation or monitoring, and whether the facilities under consideration are densely or sparsely distributed.

Preliminary evidence shows effectiveness of leak detection and repair surveys

Very little public data exist on the effectiveness of leak detection and repair surveys. However, preliminary results from recent measurements in the Grand Prairie region indicate significant benefits to LDAR surveys. An initial LDAR survey found emissions of 180 kg per day (~ 100,000 m^3 per year) at an upstream production well-site. Re-surveying the same facility after one year showed total emissions that were 64% lower than the initial survey, ~ 60 kg per day (~ 33,000 m^3 per year). Furthermore, the new emission sources (both leaks and vents) that showed up in the intervening year had emissions rates significantly smaller than the initial survey. This could indicate that emission rates do not revert to pre-LDAR levels after an annual LDAR survey. Anecdotal evidence from operators in Colorado also indicate that periodic LDAR programs are effective in reducing emissions.

Effectiveness of LDAR based mitigation is variable

Recent methane mitigation regulations in the US were based on the assumption that OGI-based LDAR programs can mitigate 40%, 60%, and 80% of methane emissions through annual, semi-annual and quarterly surveys, respectively. These assumptions were based on reported experience from operators in Colorado where the first LDAR regulations were imposed. However, our work indicates that this LDAR effectiveness is not constant but depends on a number of factors including baseline emission rates, leak-size distributions, weather, and LDAR protocols. Furthermore, dynamic simulation of the evolution of methane emissions under LDAR regulations indicate that there may be diminishing returns to increasing survey frequency. This will be verified through this study.

Methane Emissions – The Unknown

Despite all of the scientific progress in the past five years, many gaps and uncertainties exist. In the context of FEMP effectiveness assessments, the following six sources of error need to be carefully considered in the study design. Here, we briefly summarize these knowledge gaps along with potential ways we will address them in the study plan.

Sample bias in existing studies

Because detailed component-level measurements require site access, studies are conducted with the explicit consent of the operator. In such scenarios, it is likely that more responsible operators would be more likely to volunteer to have study teams on their facilities. Avoiding such sample bias is critical for a FEMP effectiveness assessment because insights are likely to be extrapolated by many orders of magnitude in space and time (e.g., policies for all facilities in Alberta or British Columbia).

The ideal sampling procedure to avoid bias is to generate a truly random selection of sites to survey from a list of all operating facilities. Yet, this presents a dilemma as operator cooperation can sometimes be necessary from a safety perspective as well as gathering data on one-time events, and activity data at their facilities.

In our study plan, we propose a compromise – we will supply operators with an over-selection list of sites that is 3 – 5 times larger than the number of sites we will visit. This will reduce bias by minimizing impact of prior knowledge while giving access to facility-specific information from the operator.

Emissions sources that are missing or poorly characterized

Bottom-up studies often have incomplete data on some emissions sources due to safety concerns, lack of accessibility for emissions quantification, or expensive-to-measure large emissions sources like tanks. This leads to issues of inconsistent regional and national inventories, and bottom-up estimates that do not match top-down measurements. Such emissions could precipitate policy choices based on emissions figures that are likely underestimated. Indeed, recent measurements indicate that both US and Canadian inventories underestimate emissions by about 50%.

In our study plan, we propose to test and employ a new quantification device, the Providence Photonics' QL-320, which acts as an attachment to conventional FLIR optical gas imaging cameras. The QL-320 can provide an estimate of the emission rate by analyzing the leak video on the camera. Using this, we can now estimate emissions from tanks that were previously inaccessible, or intermittent emissions from pneumatic devices and one-time events that were not possible or expensive to measure using the conventional Hi-Flow technology.

Lack of data on activity factors

While most field campaigns focus on reducing uncertainty in emissions factors (emission rate per component), very few studies collect reliable activity data (number of components per site). Emissions inventory estimates are calculated using both emissions factors and activity factors, and uncertainty in either term lead to increased uncertainty in overall emissions estimate. This is especially critical in Canada where activity factors vary across regions – for example, Grande Prairie region has many large well-pads with up to 15 – 20 wells per site, while Medicine Hat may only have 1 – 3 wells per pad.

In our study plan, we propose to concurrently collect activity factor data in collaboration with operators. In addition, we will supplement our own data collection with recent work from Cap-Op Energy in developing detailed activity factors for pneumatics in Alberta.

Sample size constrains and skewed emission distributions

Methane emissions studies at oil and gas facilities show that total emissions are dominated by super-emitters. Because only a small number of sites are super-emitters, by definition, a large sample size is required to appropriately capture super-emitting sites in the proportion in which they occur. Also, to conclusively tell if an observed emissions reductions is due to the LDAR intervention as opposed to random chance requires large sample sizes for observed differences to be statistically significant.

While sufficient data on the effectiveness of LDAR is not currently available, we can use simulations using available emissions data to constrain the required sample size needed to observe statistically-significant impacts of the mitigation intervention. We present detailed results of this simulation in the report, and estimate that 200 sites would be sufficient to confidently say whether observed mitigation can be attributed to LDAR interventions.

Mitigation Focused Research Design

Methane emissions studies so far have focused on improving emissions estimates at the facility or regional levels. This is critical to understanding the magnitude of current emissions, and consequently, the appropriate level of mitigation required. However, cost-effective emissions reductions require an analysis of leak forensics (the "why" questions), not just emissions location and quantification (the "where" and "how much" questions). Such leak forensics can help develop predictive models to actively prevent emissions, instead of just reducing emissions "after the fact".

In our study plan, we propose to develop a standardized nomenclature for failure mechanisms and other reasons for anomalous emissions in consultation with the operators and characterize each measured leak or vent using this nomenclature. This will assist operators and policy makers understand the most underlying causes for emissions at oil and gas facilities.

Study Design and Outcomes

We propose to sample 200 sites to assess the effectiveness of FEMP programs. The mix of sites selected in a given region (well-pads, processing plants, compressor stations) will correspond to their relative proportions in the study region. This ensures that insights from this sample can be extrapolated to the entire region. The study consists of an initial LDAR survey (OGI camera + QL-320 quantification) of all 200 sites starting in July 2018. These 200 sites are then split randomly into four groups of 50 sites each, denoted G1 through G4. The first group, G1, is a control group – no repairs will be conducted on these sites after the leak detection survey. This helps us to compare the effect of the LDAR intervention at other sites. Groups G2, G3, and G4 will be surveyed at annual, semi-annual, and tri-annual survey frequencies, respectively. Finally, all 200 sites will be surveyed at the end of one year.

At the end of this study, we expect to deliver the following results:

1. Mitigation effectiveness of periodic leak detection surveys at different inspection frequencies.
2. Potential root-cause analysis for super-emitters, their rates of occurrence and recurrence after an LDAR survey, and how that affects mitigation protocols.
3. Detailed component-level data on emissions including analysis of leaks vs. vents, root-cause analysis wherever possible, emissions factors from previously uncharacterized or poorly characterized sources, and region-specific activity factors.
4. Improved understanding of regional emissions at the component-level, and help identify the need for region-specific mitigation regulations.
5. One of the first detailed datasets on the rate at which leaks occur and recur at a facility.

1. Introduction

Methane is a short-lived and highly potent greenhouse gas (GHG). With a global warming potential that is 36 times higher than carbon dioxide over a 100-year time horizon, reducing methane emissions now would increase the carbon budget available for other economic sectors. There is also evidence that reducing methane emissions would be key to keeping global temperature increase below 1.5 degree Celsius – an important milestone of the Paris Agreement [1]. In addition, research suggests that emissions of short-lived climate pollutants like methane contribute to thermal sea-level rise over time-scales far longer than their atmospheric lifetimes [2]. Therefore, actions to limit methane emissions could mitigate centuries of future sea-level rise. In addition to direct economic, ecological, and environmental benefits, a strong commitment to reduce methane emissions will further bolster Canada's role as a responsible global player in the fight against climate change.

In 2015, methane emissions in Canada accounted for about 105 million metric tons of CO_2eq. – 15% of total national GHG emissions [3]. Approximately 45% of these methane emissions are attributed to the oil and gas industry. Recent measurements of methane emissions across Alberta and British Columbia in Canada, and across the United States paint a challenging picture – measured emissions are significantly higher than emissions calculated from reported data that are often used as the basis for national inventory estimates [4, 5, 6, 7, 8]. With recent studies estimating that Canada will likely miss Paris emissions targets by as much as 30% [9], reducing methane emissions can provide a cost-effective solution to get closer to the Paris target.

In December 2016, the Pan-Canadian framework on clean growth and climate change reiterated Canada's commitment to reduce methane emissions from the oil and gas sector by 40 – 45% by 2025 relative to 2012 levels [10]. Recently finalized regulations from Environment and Climate Change Canada (ECCC) will cover over 95% of oil and gas methane emissions sources in the production, processing, and transmission sectors [11]. Given the recent and persistent low price of natural gas, it is critical that proposed methane mitigation regulations are cost-effective.

In this report, we present a comprehensive literature review of methane emissions from the natural gas sector in the US and Canada, and develop a study plan to assess the effectiveness of fugitive emissions management programs (FEMP). After this introduction, section 2 gives a brief overview of the literature surveyed and methods to select studies for this analysis. Section 3 presents a synthesis of established knowledge on methane emissions from the upstream natural gas production and processing sector, with sections devoted to technology, emissions sources, and policy-related studies. Section 4 discusses limitations to existing studies, gaps in the literature, and how these inform the needs of future methane emission research. Finally, section 5 discusses the proposed study plan devised based on this literature analysis, as well as the combined expertise of the Stanford team in conducting policy-relevant methane emissions studies.

2. Methodology

We reviewed nearly 100 studies of methane emissions and mitigation policy in the US and Canada for this report (see references below). These included peer-reviewed publications, government policy documents, peer-reviewed reports from government agencies and think-tanks, and non-peer-reviewed reports from consultants, NGOs, and other stakeholders. In addition, we also reviewed hundreds of comments that were submitted as part of U.S. Environmental Protection Agency's (EPA) update to the 2012 New Source Performance Standards (NSPS) to regulate methane emissions from the US oil and gas sector.

Because of the wide scope of the literature survey and the sheer number of methane-related studies being published, a few guiding criteria were used to decide whether a study will be included. These can be broadly classified as follows:

a. **Bottom-up studies (upstream):** Component or site-level emissions measurements at upstream oil and gas facilities in the US and Canada using a variety of measurements techniques like Method-21 (EPA), optical gas imaging cameras, fence-line truck-based measurements, and some airplane-based studies that disaggregated data at the facility level.
b. **Top-down studies:** Regional and facility level airplane-based emissions studies that typically adopt a mass-balance approach to measure emissions at the regional and facility-level. Only those studies that explicitly compared results to bottom-up measurements or national GHG inventories were included [12, 13, 14, 15, 16, 17, 18, 19].
c. **Policy and mitigation:** Recent federal, state, or provincial regulatory actions, technical support documents, public comments on policy proposals, peer-reviewed studies on mitigation policy, techno-economic analyzes on mitigation potential, non-peer-reviewed synthesis reports on emissions mitigation, and leak detection and repair programs [20, 3, 21, 22, 23, 24, 25, 26, 27].
d. **Bottom-up studies (mid-stream):** Component and site-level measurements of methane emissions at processing plants, gathering lines, and compressor stations. Studies in the transmission and distribution sectors were not included in this analysis.
e. **Miscellaneous:** This category included studies that are related to the impact of methane emissions on the broader economy, including but not limited to, non-oil and gas methane emissions, leak detection technology studies, meta-analysis of previously published data, as well as the role of natural gas in deep-decarbonization scenarios.

An aggregated snapshot of the studies analyzed in this report is shown in Table 1.

Table 1: Summary of the type and number of studies reviewed for this report.

Study type	**Description**	**Number of studies** **Total (Canada specific)**
Bottom-up (upstream)	Component-level or site-level (fence line or aircraft) measurements in US & Canada	40 (10)
Top-down emissions	Airplane observations of regional methane emissions in US & Canada	8 (2)
Policy & mitigation	Government policies, policy frameworks and analysis, abatement potential, etc.	20 (6)
Bottom-up (midstream)	Component-level or site-level emissions at processing plants and compressor stations	9
Miscellaneous	Technology studies, non-oil & gas sector, deep decarbonization, non-oil & gas methane, meta-analysis of existing studies	15 (n/a)

3. Methane Emissions from Oil and Gas Industry

Understanding causes of methane emissions from the oil and gas sector is challenging because there are millions of possible emissions locations that are spread across a wide geography, a range of operator types, and multiple jurisdictions. In addition, emissions sources come in different forms: continuous, intermittent but periodic, one-time emissions from process failure, or random emissions that are difficult to predict arising from equipment malfunction or operator error. For this reason, one-time emissions studies ('snapshot studies') measured at the same facility separated in time can show vastly differing emissions estimates [28, 29]. For this reason, studies that disagree may do so not because either of the studies are wrong, but because of dynamic nature of methane emissions. Despite these challenges common themes and results can be discerned from the various top-down and bottom-up methane measurements, with varying degrees of uncertainty. In this section, we summarize many of the important results from an emissions, technology, and mitigation policy perspective.

3.1. Super-emitters

One of the 'constants' of all methane emissions studies is the presence of super-emitters [30, 31, 32]. 'Super-emitters' refers to a small number of very high-emitting leaks at a given facility that are responsible for the majority of emissions. Different definitions for super-emitters exist, but one working definition includes the top 5% of emissions sources at a site or facility as super-emitters. Recent work by Brandt et al., based on meta-analysis of publicly-available component and site-level studies showed that, typically, the top 5% of the emitters are responsible for over 50% of the total emissions [32]. This creates a heavy-tailed leak-size distribution at both the component- and facility-level. Heavy-tailed distributions have a small number of unusual events that account for large impacts. For example, Figure 1 shows the fraction of total emission from individual component types complied from all analyzed studies in the literature. Even though leak-sizes of individual components span 5 orders of magnitude, 90% of the aggregated leaks have leaks-sizes greater than about 61 kg CH_4/day. Several important insights can be gathered from this:

a. Effective mitigation requires detecting and repairing super-emitters as efficiently as possible. Strategies to prevent super-emitters need to be based on root-cause analysis of these leaks.
b. Because of the relatively large leak sizes of the super-emitters, leak detection technologies may not need to be highly sensitive for effective leak detection. High-speed sensors with moderate sensitivity can help significantly improve the economics of LDAR programs [33, 34].

High-emitting sources, or super-emitters, generally fall into three categories:

1. **Continuous super-emitters:** These super-emitters are caused by equipment malfunction or operator error and are stochastic [31]. Some examples include out of specification pneumatic

controllers [35], or tank thief hatches that are inadvertently left open [36]. Depending on the mitigation program in place, these high emitting sources have the potential to emit for long durations until they are fixed.

2. **Episodic super-emitters:** These are very high emission sources associated with one-time events at a facility and are generally known *a priori*. Examples include blowdown events, liquids unloading. While fence-line measurements or 'snap-shot' leak detection surveys cannot be expected to typically capture such emissions due to their episodic nature, their predictability can be used to develop new control techniques (e.g., green completions) and mitigation options.
3. **Intermittent super-emitters:** These are large emissions sources that arise from equipment designed to vent at high rates such as high-bleed pneumatics.

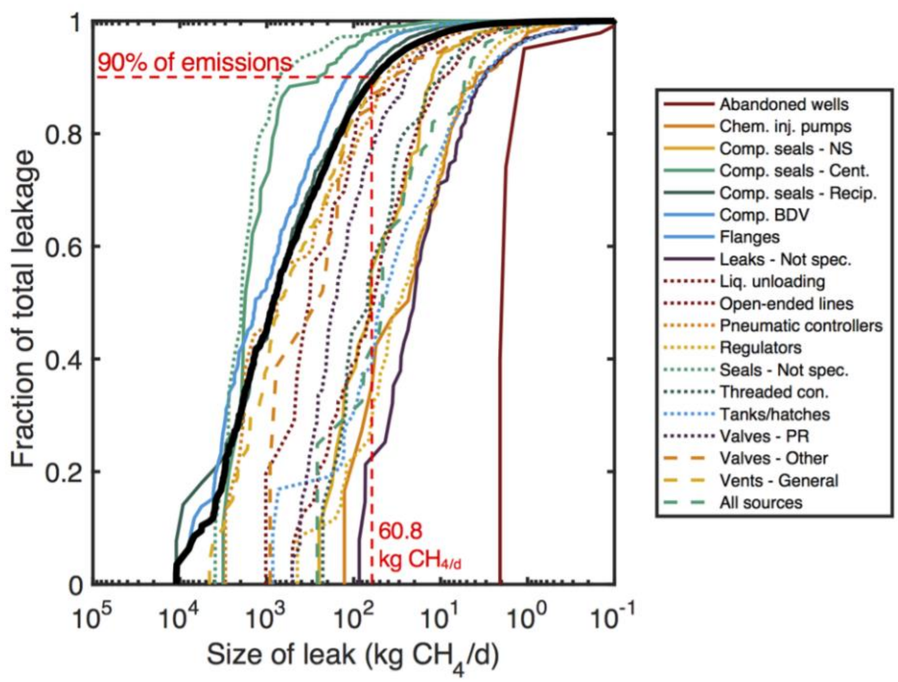


Figure 1: Cumulative fraction of leakage as a function of leak size aggregated from multiple device-specific data sets. Cumulatively, 90% of all emissions from device-level measurements come from leaks larger than 60 kg CH4/d (adapted from Brandt et al. 2017 [32])

Indeed, skewed leak-size distribution have been observed across natural gas facilities in the US and Canada. Recent fence-line measurements in British Columbia [4] and Alberta [7] show distributions where the top 20% of all emitters were responsible for between 50 and 80% of total emissions. Figure 2 shows a comparison of the cumulative leak size distributions across 6 different shale basins in the US and Canada (Red Deer).

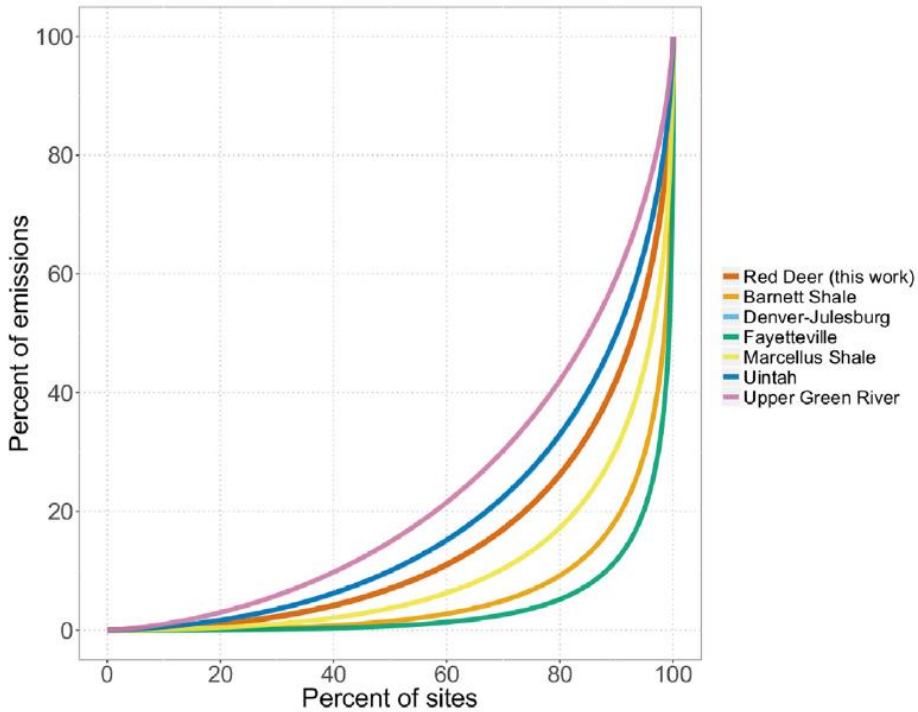


Figure 2: Comparison of the skew of leak-size distribution in Red Deer compared to similar measurements in US basins (adapted from D. Zavala-Araiza et al. 2018).

3.2. Temporal Variation in Emissions

One of the big challenges in bottom-up measurement is the limited temporal information that can be directly measured due to the high cost of ground surveys. Top-down data from the literature often exceed bottom-up component-level measurements because of the episodic emissions being captured in many top-down measurements [12]. A recent study sought to reconcile this difference and found that the top-down data has a bias towards detecting episodic emission because aircraft-based measurements occur in the afternoon with multiple fast transects that preferentially capture short-duration emissions [37].

Englander et al. (unpublished) attempted to measure the temporal variation in tank vents in North Dakota (Bakken shale) through fence-line measurements using OGI cameras over the course of a year by periodically revisiting a random selection of sites. Preliminary analysis of the results show that there is significant variation in the time evolution of tank emissions, either due to routine maintenance between operations (where leaking tanks stopped leaking) or equipment malfunction and operator error (non-leaking tanks started leaking).

A more recent study in the Montney play in British Columbia sought to measure the temporal aspects of methane emissions from well pads using multiple drive-by measurements of the same facilities over

15 days [4]. Figure 3 shows the histogram of the persistence of leaks disaggregated by well mode, well operation type, well fluid type, and well facility type. These measurements (and more recent ones in Alberta in the Red Deer, Lloydminster, and Medicine Hat) demonstrate the capacity for bottom-up measurements to capture episodic emission. However, all of these studies were limited in their attribution capabilities because fence-line or top-down measurements have higher uncertainties in attribute measured emissions to specific locations. Future component-level LDAR surveys should be conducted with full cooperation from the operator, even for unannounced or randomized inspections, to identify potential sources of episodic emissions arising from regular maintenance, or one-time events at the facility.

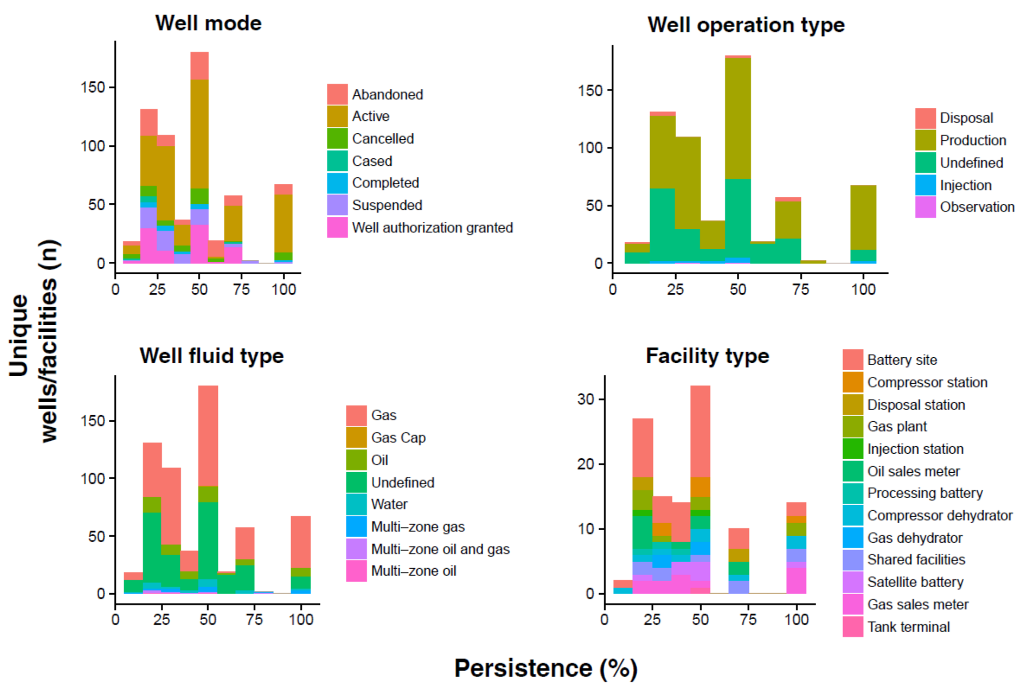


Figure 3: Bottom-up fence line measurements of leak persistence in a recent study in the Montney play in British Columbia across 30 mobile surveys. Persistence refers to the repeated tagging of a piece of infrastructure as a possible emission source based on the method of plume attribution we applied in the study (Atherton et al. 2017).

3.3. Spatial Variation in Methane Emissions

Recent studies have consistently observed geographic variations in methane emissions [38, 8, 5, 39, 36, 18, 40, 28, 41, 42]. Although a specific cause has not been identified for this behavior, a number of potential causes can be surmised. These include geologic features (rock porosity, permeability), resource composition (gas vs. liquids vs. oil), weather, infrastructure age, and operator practices. From a mitigation perspective, this points to the need for measurements of emissions and activity factors across different regions separately to arrive at an accurate provincial or national level estimate. Measurements from one region cannot be extrapolated to other regions.

Figure 4 is a compilation of production-normalized emission rates across different unconventional shale basins in the US, complied from top-down aircraft-based emissions estimates. The emission rate varies from as small as 0.4% in one study [28] in the Marcellus shale to over 10% in the Bakken shale [19]. In addition to the large spatial variation in emissions, we also note the significant uncertainty in each individual measurement even within the same basin [19, 40, 29], pointing to well-known issues in temporal variation (studies spanned a period of 4 years, episodic sources) as well as attribution (potential presence of non-oil and gas methane emissions).

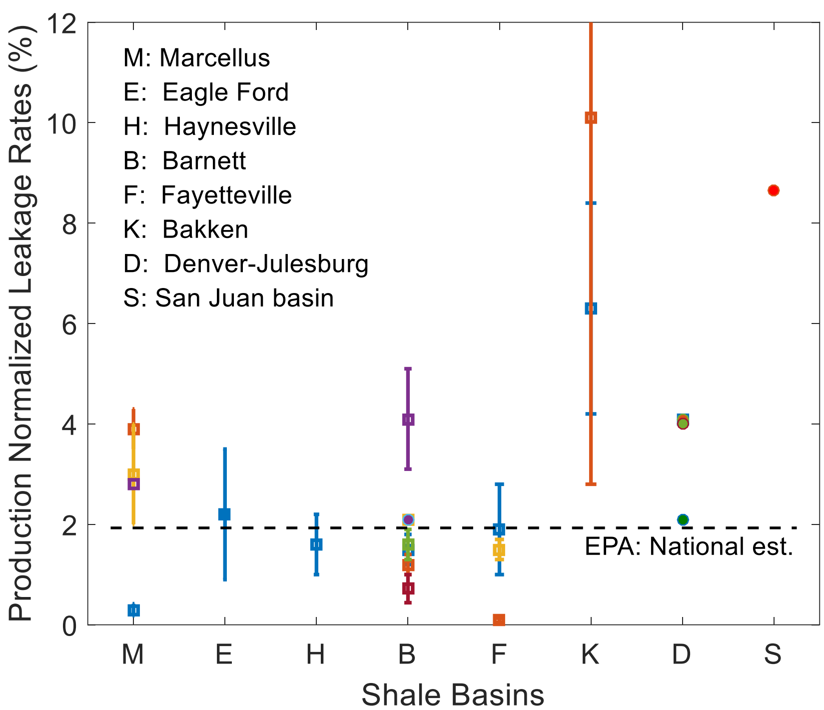


Figure 4: Production normalized leakage rates across different unconventional sale basins in the US compiled from top-down air-craft based measurements (Ravikumar et al. unpublished).

Finally, recent emissions in different regions within Alberta (Red Deer, Lloydminster, Medicine Hat) showed vastly different methane emissions, that were also larger than estimate reported to regulatory agencies [5, 43, 6, 7]. For example, Johnson et al. showed that methane fluxes near Red Deer were 17 times greater than that derived from directly reported data, while the Lloydminster area showed emissions were 5 times larger. However, on an absolute scale, the Lloydminster area (CHOPS sites) emitted 8 times more than the Red Deer area. These data point to significant issues with respect to reporting vented emissions in Alberta. These results were again confirmed recently when O'Connell et al. reported significantly higher emission in the Lloydminster area than compared to Peace River or Medicine Hat area [6]. Figure 4b shows the list of all bottom-up studies (on-site or fence-line) conducted at Canadian oil and gas facilities in AB and BC [43, 44, 6, 5, 45, 7, 4].

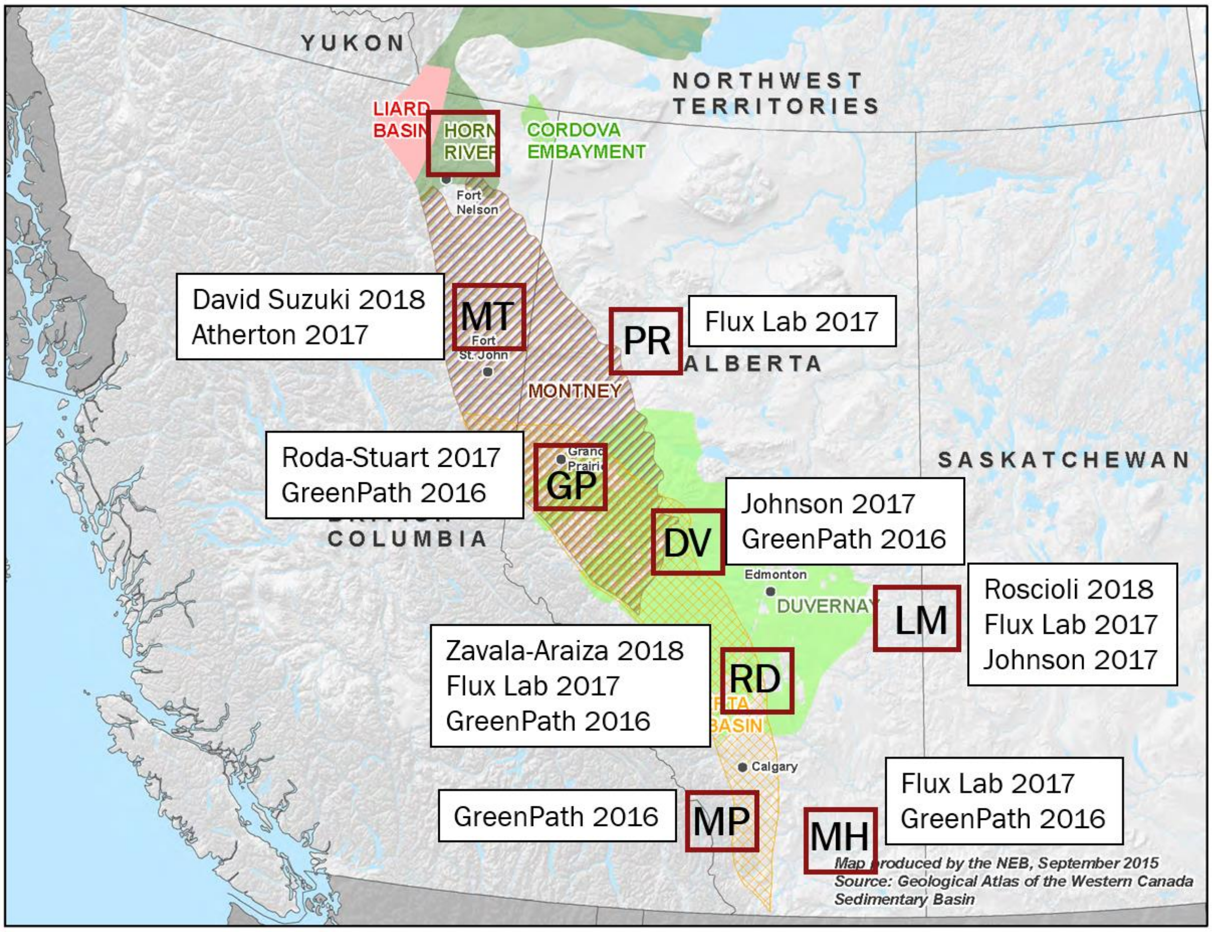


Figure 4(b): Summary of all the bottom-up (on-site and fence-line) studies conducted in Alberta and British Columbia in the past 3 years.

Figure 5 summarizes the current state of knowledge regarding methane emissions *through an emissions mitigation risk management perspective* in terms of parameter uncertainty and parameter importance. We note that this matrix will be unique for a given objective – in this case, determining the effectiveness of emissions management program. Therefore, even though regional, national, and global estimates of anthropogenic and biogenic methane emissions would be critical to international negotiations on emissions limits, it does not significantly affect sub-national emissions mitigation policies, nor would it affect our design of a study to determine how effective a mitigation effort might be. Hence it is characterized under low importance, albeit with high uncertainty in existing data.

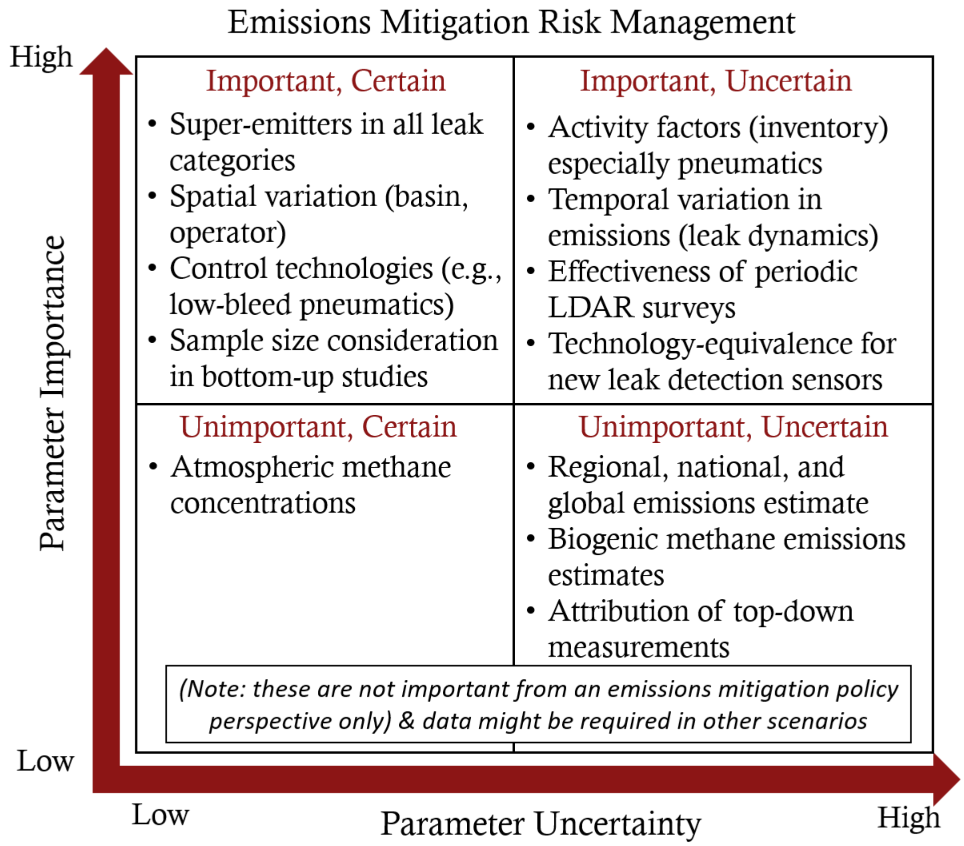


Figure 5: Summary of lessons learned from literature review of bottom-up studies through an emissions mitigation risk management, with various measurable parameters rated along and uncertainty (x) and importance (y) axes.

3.4. Detection Technology

Recent attempts to simultaneously measure methane emissions using different technologies have produced inconsistent results [46, 47]. Developing metrics to compare technologies and platforms is important yet complicated, due to 1) incompatible sensor parameters (e.g. point concentration vs. integrated path-length measurements), and 2) varying program goals (detection vs. quantification). Ultimately, research in this topic should move towards developing an equivalence-metric approach for comparing disparate technologies, as we explain in an upcoming review article [48]. Such metrics would be critical to adopt or approve new sensors as they are developed.

Technology performance metric trade-offs can be conceptualized along two complementary axes (Figure 6): 1) whether the technology is used for mitigation or monitoring, and 2) whether the infrastructure is dense or sparse. In this framework, an emphasis on monitoring compliance means prioritizing speed and efficiency of emissions detection. Effective monitoring requires relatively large spatial coverage (provincial or national scale) and repeated measurements (high temporal resolution), prioritizing detection speed over other metrics. Data in this regime can be used to update greenhouse gas inventories and discern emission trends over time. This will help to develop policies focused on sectors and regions responsible for contributing the most to total emissions. In addition, quantification would be necessary to implement a cap and trade or carbon tax regime with credits associated with mitigation efforts. Mitigation, in contrast to monitoring, requires operators to find and fix all leaking sources. In this context, quantification is less important than overall cost-effectiveness of the mobile monitoring program.

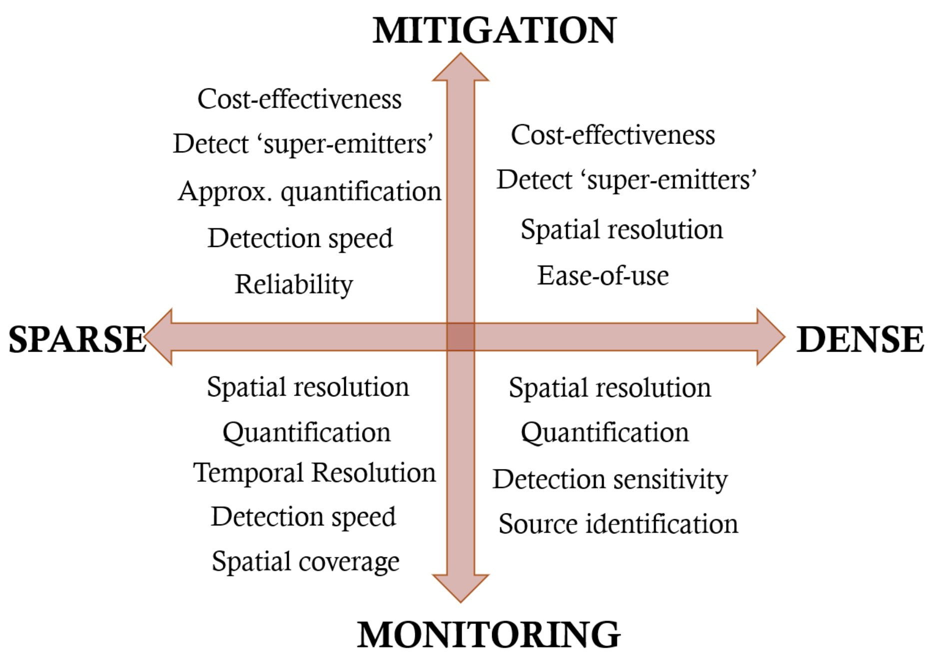


Figure 6: Metrics to consider for sensor and platform selection. Technology choice depends on the spatial density of operations and the purpose of the MMP (mitigation vs. monitoring).

The other axis of this conceptual framework is the spatial extent of facilities to be monitored. Dense facilities include processing plants, dense production well-sites, and compressor stations, while sparse facilities include single well pads and transmission/distribution lines. In the former, important evaluation metrics should include source localization (spatial resolution), ability to detect super-emitters, and overall cost-effectiveness of the mitigation program. From a technology perspective, detecting super-emitters translates to approximate quantification; i.e., there is a 90% or greater probability of finding sources that are larger than a set threshold. Top-down monitoring at dense facilities (e.g. aircraft or satellites) will also require source attribution capabilities. For sparse facilities, detection speed is critical as is transit time between sites.

Most technologies and platforms will not be ideal under all four quadrants in this framework. For example, while piloted aircraft are well-suited for mitigation at sparse-production well sites where it would be prohibitively expensive to use hand-held sensors, they are not well-suited for dense facilities due to limited ability in resolving multiple sources and the relative complexity of the facilities involved. Businesses and policy makers should use this framework to carefully consider the trade-offs involved with each technology.

Figure 7 provides another view of spatial and temporal scales. In this figure, these labels refer to the spatial extent and temporal duration (respectively), covered by a given platform, during a single measurement campaign. For example, satellite-based monitoring systems can measure across the planet, quasi-continuously, for many years (large spatial and temporal scales). Conversely, handheld cameras such as OGIs may only cover a few kilometers, albeit with much higher precision, and campaigns typically last up to a few days (small spatial and temporal scales). Stationary sensors, which are permanent installations, tend to monitor at large temporal and small spatial scales.

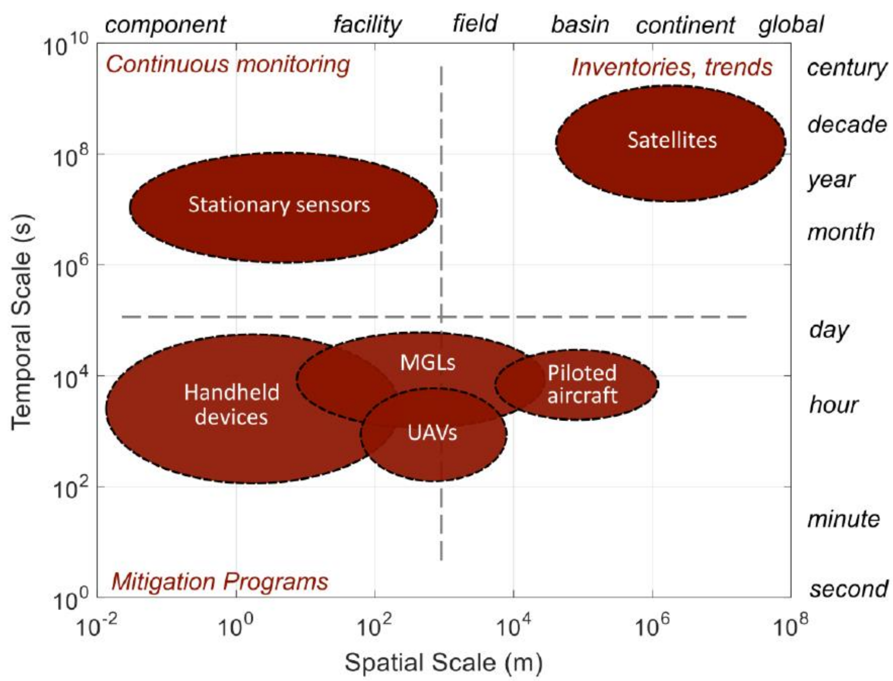


Figure 7: Illustration of the various spatial and temporal scales involved in methane emissions measurement and the appropriate leak detection technology. (Fox et al. in review (2018)).

No single permutation of scales – and by extension no individual technology platform – is inherently ideal because different applications call for different capabilities within the space-time domain. To conceptualize these differences, we divide Figure 8 into quadrants, called regimes, which represent common application needs in the O&G sector. These regimes are 'mitigation programs' (small spatial and temporal scales), ‘continuous monitoring’ (small spatial and large temporal scales), and ‘inventories and trends’ (large spatial and large temporal scales). Platforms currently used for MMPs, including handheld monitors, operate in the ‘mitigation programs’ regime. In this quadrant, more emphasis is placed on detection and repair, and less on quantification. Although less useful for mitigation, satellites typify the ‘inventories and trends’ regime, as they have the potential to monitor vast geographical areas over long periods of time. Piloted aircraft sit between the ‘mitigation programs’ and the ‘inventories and trends’ regimes, with spatial scales on the order of 100s of kilometers, and deployment intervals of just less than a day. Stationary in situ sensors for monitoring specific activities (e.g. liquids unloading, flare efficiency) belong in the ‘continuous monitoring’ regime. These are typically used to monitor for intensive events or alert personnel to unsafe operating conditions.

As technologies evolve, the size, shape, and position of the platform ellipses in Fig. 8 may change. Currently, the dotted horizontal line at y = ‘day’ splits automated from labor-based platforms. With the automation of UAVs and mobile ground labs (MGLs), their range may expand into larger temporal scales. Similarly, MGLs and UAVs could extend into ‘inventories and trends’ if, for example, 1) multiple sensors were deployed passively on vehicles used for other primary purposes, and 2) airspace regulations relax to permit UAV operations beyond visual line of sight. Finally, future satellites are expected to have improved spatial resolution, suggesting that satellites could eventually cross into the ‘continuous monitoring’ regime.

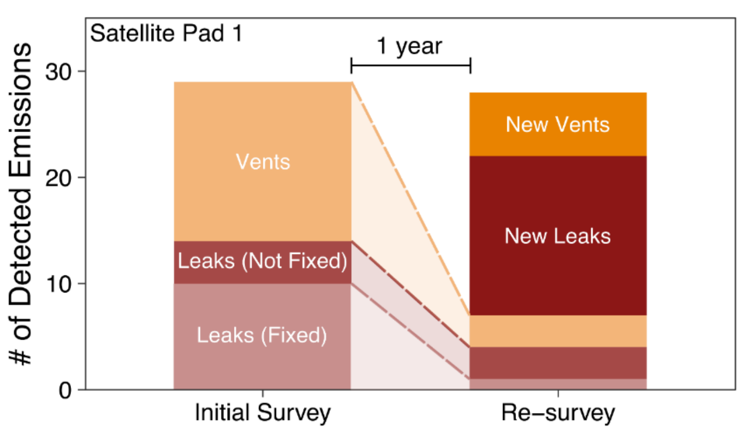
3.5. Mitigation Policy

Despite significant progress in reducing uncertainty in emissions estimates across different facilities and geographic regions, mitigation-focused measurements including leak forensics, pre- and post-LDAR emissions factors, etc. are lacking in the literature. The most prominent policy-focused measurements are those that seek to improve emissions factors at the component and equipment level [49, 43]. In addition, recent non-peer reviewed reports have developed marginal abatement cost curves for various control technologies across natural gas upstream and midstream sectors in the US and Canada [23, 24, 50].

We recently developed a simulation framework FEAST to analyze questions that directly affect policy [33]. For example, what technology provides the most cost-effective mitigation opportunities? How does survey frequency affect steady-state emissions? etc. In a recent paper analyzing EPA’s methane mitigation regulations [51, 52], we showed that EPA directed OGI surveys may miss mitigation targets by analyzing the characteristics of OGI-based leak detection surveys using multi-time step Markov simulation [27]. Furthermore, we demonstrated that methane mitigation will be more cost-effective than EPA estimates if ‘sound’ survey practices are observed [53, 34].

Understanding the limitations of the leak detection technology used in surveys is critical to estimating the mitigation potential. In addition to physics-based modeling of OGI cameras [53], we recently conducted single-blind minimum detection experiments of OGI-based leak detection at the Methane Emissions Technology Evaluation Center (METEC) in Fort Collins, CO [34]. We showed that imaging distance is a critical parameter in determining minimum detection thresholds – increasing from about 3 g/h at 1.5 m from the leak source to over 100 g/h at 15 m imaging distance [34]. Furthermore, even at a single imaging distance, the probability of leak detection can vary by up to one order of magnitude.

Recently, we conducted periodic LDAR surveys with OGI cameras at production facilities (well-pads, processing plants, etc.) near Grande Prairie, AB at one-year intervals (Roda-Stuart et al. *unpublished*). Initial surveys were conducted using a two-person camera crew (Davis Safety Inc.) for leak detection and quantification. Emissions were detected using FLIR OGI cameras and quantified using a Hi-Flow sampler whenever permissible. Emissions were classified as leaks or vents, and tagged for future repairs. The survey was repeated one year after the initial survey. Figure 8a shows the number of leaks detected between the initial survey and the re-survey. We observe a few things – (1) the total number of leaks at this facility remained similar in both surveys (~30), and (1) although the number of emission points (both leaks and vents) reduced in the first survey, many new leaks and vents appeared during the re-survey. Figure 8b shows the leakage corresponding to the two surveys. Interestingly, total emissions from the site reduced by 64% during the re-survey compared to the initial survey. This preliminary result is important for two reasons – (1) Emission rate from leaks that were not fixed during the initial survey did NOT increase in the re-survey, (2) Emission rate of the 'new' leaks and vents were substantially smaller during the re-survey, compared to the initial survey. **This preliminary result indicates that periodic LDAR programs can be effective, and that leaks once fixed do not re-appear at similar emissions rates.** Figuring out the underlying causes for observed emissions reductions as well as the impact of more frequent LDAR surveys would require more work. We are still analyzing this data-set and results will be published soon.



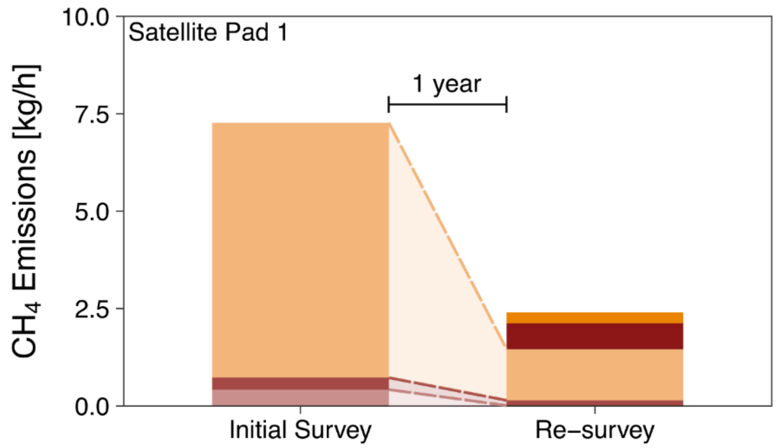


Figure 8. (top, a) Number of emission points (leaks and vents) at an upstream production facility near Grand Prairie, AB during an initial site survey and a re-survey at one-year interval, (bottom, b) Emission rates from the initial LDAR survey and the re-survey. Note that the emissions are categorized as leaks (unintentional emissions) or vents (designed emissions).

The question of survey frequency is an important one. Using our simulation model FEAST [27], we modeled emissions mitigation as a function of survey frequency for a hypothetical production facility with 2 wells and baseline emissions of 5 metric tons CH_4/year (see Figure 9). FEAST simulates the evolution of leaks at a natural gas facility using a Markov process for a period of 8 years. All components at the facility is in one of two possible 'states' – leaking or non-leaking. As the simulation proceeds, leaks are stochastically added to the facility at a rate such that the steady-state emissions correspond to the baseline-emissions for the facility as determined by the EPA. In the case of well-pads, baseline emissions are set at 5 tons per year. Leak populations used in this simulation is derived from peer-reviewed public literature on methane emissions at production well-sites across the US. LDAR programs such as OGI based surveys can be periodically performed on this facility through detailed technology models and choosing an appropriate survey frequency. It is assumed that all leaks identified during the survey are repaired immediately (reasonable assumption considering that EPA policy requires identified leaks to be repaired within 15 days).

At a semi-annual survey frequency, EPA expects a mitigation of 60%, similar to our simulated estimate of ~55%. However, we note that emissions mitigation is not directly proportional to survey frequency – i.e., doubling the survey frequency does not double the emissions mitigated. This is due to the skewed leak-size distribution of methane emissions – most of the large super-emitters are found and fixed in the first survey, and there is not enough time before the next survey for super-emitters to grow. Thus moving from a quarterly survey to a monthly survey only improves emission mitigation from about 70% to about 86%, respectively, while the costs will likely increase three-fold.

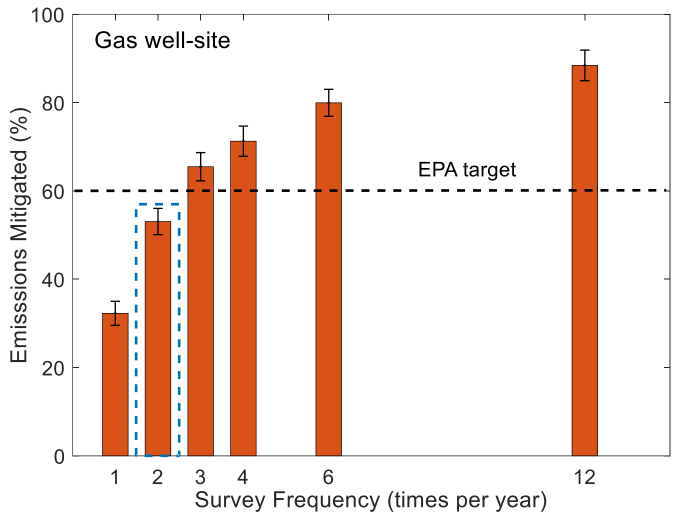


Figure 9: Simulated emissions mitigation at production well-site as a function of LDAR survey frequency. We assume that an OGI camera is used for the leak detection survey and all leaks found during the survey are fixed.

Translating this into mitigation cost, Figure 10 shows the net mitigation cost ($/mcf) as a cumulative function of the total mitigation across all production facilities subjected to the regulation in the US. An annual survey frequency yields a mitigation of 55% (~5500 metric tons of methane) at a net cost of about $4/mcf. On the other hand, a monthly survey mitigates over 85% of baseline emissions at a cost of about $30/mcf. While the simulations presented here give a general idea of how LDAR programs impact mitigation targets, it is critical to gather experimental data on the impact of periodic leak detection surveys.

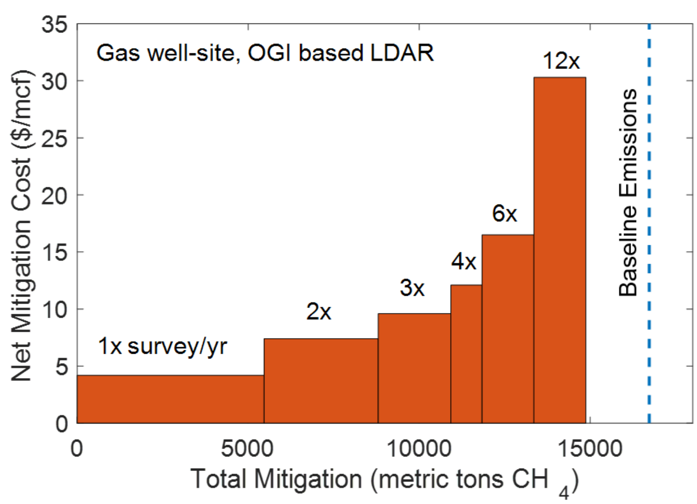


Figure 10: Simulated net mitigation cost ($/mcf) as a function of cumulative total mitigation at US natural gas production well sites.

4. Literature Gaps, and Lessons for the Future

Based on the literature survey summarize above, we identify 6 important limitations to existing and describe potential ways to resolve them in our survey design.

1. Sample bias
2. Missing and poorly characterized sources
3. Region-specific activity factors
4. Temporal variability and intermittency
5. Super-emitters and skewed emissions distribution
6. Mitigation focused research.

These six issues are discussed in more detail below.

4.1. Sample Bias

Because of the high cost of ground survey crews, most bottom-up studies can only sample a small fraction of all the facilities in any region. Given these small sample sizes, it is critical to devise sampling strategies that do not bias the resulting emissions data. Ideal sampling procedures would choose sites or facilities to study from the population of possible sources with no bias toward sites of a given size, age, ownership structure, region, operator, equipment type, or operating characteristics. Avoiding sampling bias is particularly important for studies where results are to be extrapolated by many orders of magnitude (e.g., use of bottom-up derived emissions factors in policy and management across an entire province).

Randomly sampling sites in a region presents a dilemma. On the one hand, cooperation with facility operators is necessary to perform component-level bottom-up measurements and study underlying mechanistic causes for emissions. On the other hand, it is likely that operators with robust leak management practices would be more willing to cooperate than operators who do not – an issue called the 'coalition of the willing'.

Such biases in selecting sample sites can be minimized through various strategies. If possible given regulatory requirements, random selection of sites with compulsory surveys will result in the most statistically representative results. If not possible, a study design can be followed where surveyors initially select more sites ('master list') than required to inform operators of potential leak detection surveys. Operators would not be told *a priori* which sites from the 'master list' would be actually visited on any given day. Minimizing the delay between operator notification and survey measurements will also help reduce sampling bias by reducing opportunities for modification of site conditions. Another approach is to merge quantitative off-site measurements (fence-line), by surveying some sites both onsite and offsite, coupled with a set of sites surveyed only offsite. This allows proper calibration of the off-site methods and therefore more trust in their use across a wide array of facilities.

4.2. Missing and poorly characterized sources

While our understanding of fugitive methane emissions from the oil and gas sector has significantly improved over the past five years, a significant number of possible methane sources are either uncharacterized completely ("missing") or poorly characterized. This incompleteness poses a number of issues:

- Incomplete inventories can adversely affect mitigation priorities
- Top-down estimates of total methane emissions will not match bottom-up estimates made from select source categories
- Attributing global and even regional trends from top down aircraft or satellite measurements to specific sources will be challenging without knowing the contribution from all sources.

Research in the oil and gas sector has disproportionately focused on production and processing facilities, given their relatively compact nature and recent regulatory actions. Even in the production sector, many sources that have not been well characterized . Such sources include gathering pipelines, flare efficiencies, and tanks. Recent studies (Lyon et al., Englander et al.) show significant fugitive emissions from tanks, often an indicator of possible issues in gas handling capacity. As explained in our study plan below, we aim to measure tank emissions in this study using a leak quantification tool (Providence Photonics Inc, QL-320) that complements the FLIR GF-320 leak detection camera.

Reliable emissions estimates from abandoned and suspended oil and gas infrastructure are also lacking. Although some recent studies in Alberta and British Columbia indicate relatively low emissions compared to active wells, the lack of inventories on such infrastructure adversely affects any emissions estimate. This is further complicated by legal and political questions surrounding mitigation responsibility and funding to permanently plug these sources.

4.3. Region-specific activity factors

Total emissions at a facility are usually calculated using a combination of emissions factors (emissions per component) and activity factors (components per facility). These emissions and activity factors often form the basis for developing Environment Canada's greenhouse gas inventory, a primary source on emissions for policy and regulatory development.

Much of the work in Canada have focused on improving emissions factors at the component or the site level. Indeed, recent studies across Alberta and British Columbia have measured significantly higher emissions than is calculated from reported emissions. However, none of these studies measured activity factors at oil and gas facilities, either because of design considerations (fence line measurement), or limited scope of the study (only improve emissions factors). Improved activity factors across different producing regions are required for reducing uncertainty in emissions estimate and develop mitigation targets. For example, the Grande Prairie region consists of large well-pads with 15 – 20 wells per site and other processing equipment, while well pads in the Medicine Hat or Red Deer region may have only 1 – 3 wells per pad.

Component-level activity counts are vital to developing cost estimates and mitigation potential of various control technologies. For example, the conversion of high-bleed to low-bleed pneumatics or to instrument air actuation can potentially reduce a significant fraction of currently vented emissions. However, to adopt and mandate specific control technologies require an accurate inventory count, and without such a count, the benefits of a regulation will be uncertain. To continue the example of pneumatic controllers, recent work in the United States found that EPA activity factors underestimated the number of pneumatic controllers per well by nearly a factor of 3 [35].

In our study, all leak detection surveys will be accompanied by detailed component-level activity counts to help develop a complete inventory. In particular, pneumatics – a major source of venting emissions – will be categorized based on size, type, and bleed rate. This is especially critical as a recent Cap-Op Energy study reported that observed inventory of pneumatic devices are significantly higher than is currently assumed.

4.4. Temporal Variability and Intermittency

Furthermore, it has been well documented in the literature that most bottom-up studies do not reliably capture temporal and/or episodic emissions. Collaboration with the site operator on operational and maintenance details during the surveys would be crucial to fill gaps in the bottom-up inventory. Variability in emission can take many forms:

- **Episodic emissions:** Behavior associated with individual events that are episodic or intermittent in nature – these are rarely captured in single leak detection surveys.
- **Periodic emissions:** These are typically leaks associated with pneumatic component that release methane when a set pressure threshold is reached. Although periodic, these emissions can be predicted in advance and measured.
- **Stochastic emissions:** These types of intermittent emissions result from anomalous equipment behavior or operator error. Because of the stochastic nature of this issue, they are hard to predict and can easily missed in a conventional bottom-up survey. Only a few of these events would appear in a random survey (perhaps the result of some/all super-emitter behavior)
- **Variation in trend:** Behavior associated with long-term large-scale changes including seasonal variation of non-oil and gas sources as well as trends seen in satellite observations.

Each of these deficiencies create unique challenges to both our understanding of methane emissions, as well as developing effective mitigation policies. Individual leak detection surveys conducted at various natural gas facilities rarely contain information on temporal behavior of leaks. Existing studies have limited temporal and spatial coverage information based on experimental methodology. For example, downwind studies give emissions estimates at the facility-scale integrated over a few minutes to hours (Ramon et al., Picarro et al.), aircraft mass balance studies at the basin-scale provide total emissions during mid-day and inverse modeling of satellite data operate at the regional/global scale with a time resolution of the order of months.

We know that many large emitting events (e.g. liquids unloading) and equipment such as pneumatic controllers are episodic or intermittent. Developing accurate time-averaged emissions factors for these processes require a careful understanding of their temporal behavior. Current estimates of total fossil methane emissions, including those from super-emitters, assume continuous operation. Improved data on magnitude, frequency and duration of discrete leakage events could significantly revise existing estimates. Temporal behavior of super-emitters – which could be episodic events, planned releases or equipment malfunction – will be critical to designing effective mitigation practices.

Capturing high-volume episodic events would require deployment of continuous open-path or multi-point methane sensing at various facilities. While it is unclear whether such efforts are economical in the long-run, early measurements would be critical in developing accurate emissions estimates.

In this study, we will differentiate between different types of events and incorporate them in our analysis – operation-based temporal v. 'stochastic'-based temporal, malfunction of equipment v. improper design v. 'planned venting'. Because of the instantaneous quantification capability available to us for the surveys (see study plan for more detail), we will be able to quantify episodic emissions whenever possible. Furthermore, operator cooperation will also be helpful to understand what category a leak should be classified into.

4.5. Super-emitters and skewed emissions distribution

One of the consistent themes in recent measurement campaigns conducted at various natural gas facilities is the presence of super-emitters. Super-emitters disproportionately contribute to total emissions from a facility (Brandt et al. 2016), leading to a highly skewed leak size distributions. Yet, most inventories make use of 'average' emission factors that are often estimated from a small sample size of measurements that may not adequately represent the impact of super-emitters.

Small sample sizes can adversely affect the representativeness of any measurement campaign, resulting in large uncertainties in emissions estimates. While we will design the surveys with adequate sample size as an important selection criterion, we will also utilize improved statistical models to characterize tail emissions (Brandt et al. 2017).

Lack of a standard definition for super-emitters further complicates the issue from a mitigation perspective. A super-emitter (top 5% by volume of given leak-sizes) at one facility might not be a super-emitter at another facility. Based on the results of the surveys in this study, we will try to develop general conventions on emission rates (absolute or proportional) to define super-emitters to assess the relative importance of various components and facilities and help future studies.

To further improve the usability of the data collected through surveys, we will also compare emissions data with recently published studies from AB and BC as well as inventory estimates. In addition to reducing uncertainty in inventories, this inter-comparison will also possibly help identify discrepancies in methodologies in inventory development and provide important guidelines for future bottom-up studies.

4.6. Mitigation-Focused Research

Mitigation-focused research can be analyzed under two categories: leak forensics and LDAR programs.

Leak Forensics: Answering the "why" and not just the "where" and "how much" of emissions will be vital to developing predictive algorithms and to focus mitigation efforts on those equipment/components most prone to be super-emitters. Leak forensics can directly result in effective prescriptive policies to mitigate emissions – e.g. a defective valve from a manufacturer or continuous monitoring of tanks, etc. In this work, we will develop a common nomenclature for failure mechanisms in consultation with operators and identify each measured leak or vent using them during leak detection surveys. In addition, we will also strive to identify, wherever possible, potential causes for each leak, and auxiliary characteristics associated with the leaking component (manufacturer, age, etc.).

LDAR Programs: Leak detection and repair (LDAR) programs are a commonly used regulatory tools to mitigate methane emissions. Developing an effective LDAR program requires identifying critical parameters such as survey frequency, leak detection technology used, whether leak quantification is required. A good design considering all the above factors is described in detail in the next section.

5. Effectiveness Assessment: Designing Effective Studies

There have many bottom-up studies conducted at upstream natural gas facilities in the US and Canada, as shown in prior sections of the report. These studies included component- and process-level leak detection surveys, fence-line site-level measurements, to aircraft-based facility and regional level mass balance approaches. Each of these studies serve a unique propose. However, data-intensive bottom-up studies to determine mitigation effectiveness have specific requirements listed below:

a. **Sample size:** General variability, as well as the presence of super-emitters, necessitates a large sample size to prevent under-estimating total emissions and mitigation potential.
b. **Component-level emissions estimates:** Regulations aimed at component-level interventions (e.g., repair all leaking components within a specified duration) requires detailed estimates of component-level emissions.
c. **Temporal data on effectiveness of mitigation:** Determining an appropriate frequency for leak detection surveys will require data on marginal emissions reduction pre- and post-LDAR surveys, as well as rates of problem re-occurrence following LDAR-derived repairs.
d. **Activity counts for pneumatics and other component:** In addition to leak quantification for estimating emissions factors, a mitigation effectiveness study will require detailed activity counts at the component level. This is critical to estimating potential emissions reductions in the future based on proposed regulatory actions.
e. **Cooperation from facility operator:** While many fence-line measurements do not require operator cooperation, they are challenged because of uncertainty over episodic emissions. Operator cooperation would be critical to identify and estimate the contribution of one-time events (e.g., liquids unloading) to the total emissions profile of the industry.

In this study plan, we integrate all the above criteria to design a periodic leak detection survey plan to assess the effectiveness of fugitive emissions management programs. We elaborate on this study plan across four sections – site selection, methodology, survey design, and potential outcomes. We conclude with an estimate of the budget for this proposal.

5.1. Sample Size Considerations

We want to determine whether sites with LDAR achieve higher emissions mitigation than sites without LDAR. Unfortunately, there is significant evidence that emissions vary widely from site to site. This large variation manifests itself as a relatively small number of sites with very high emissions and a much larger number of sites with low emissions. Such "heavy tailed" phenomena are difficult to study because determining statistically significant trends from an intervention require large sample sizes.

The effect of this "heavy tail" is to make estimates of mean emissions from a sampled number of sites highly variable unless the sample size is large. To illustrate this effect, we perform a simulation experiment to examine two types of sites studied in the prior literature: well pads and compressor stations. We take all site-level estimates of emissions from these sites from the work of Brandt, Heath and Cooley (2016). We treat these observations as our simulation population and sample a subset from this population with replacement. This, in effect, creates a simulation with a very large number of sites that are replicates of our existing observations (i.e., an infinity of sites, each of which is equal to one of the previously measured sites).

To illustrate the impact of skewed distributions on the variability in computed means, we sample *n samples* from these populations 100 times and compute the mean each time (Figure 11, each red dot is a sampling event). When each sampling event only draws a small *n*, the computed mean varies wildly. As *n* increases, we receive a better estimate of the mean with much less variability and bias. As *n* gets very large (*n* >500) the sample mean is an excellent representation of the population mean (black line).

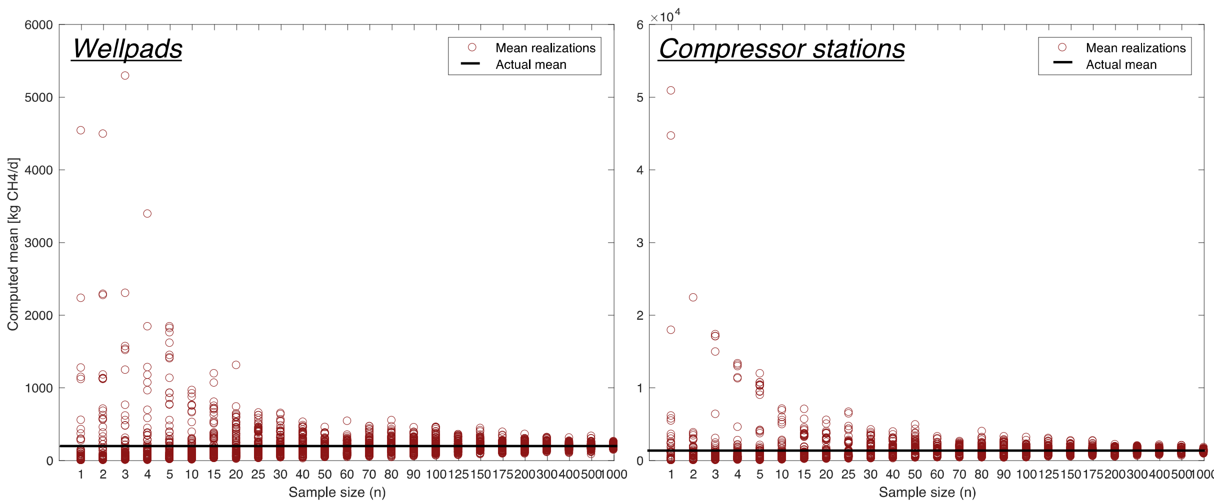


Figure 11: 100 trials of computing the mean of wellpad (left) and compressor station (right) emissions (each trial of sampling event with sample size n represented by a red circle). As n increases, the variance in the sample mean decreases and the sample mean approaches the population mean.

In light of this effect, how large of a sample size is required to reliably detect a mitigation effect of an LDAR program? We want to know: **how large of a sample size is required to be reasonably certain that a difference between the mitigation (LDAR) and non-mitigation (control) sites is actually due to the LDAR intervention and not due to chance?** This question is difficult to answer with so little empirical data on the effectiveness of LDAR.

Even so, we can explore his question by simulating two "mitigation thought experiments". Each mitigation thought experiment represents a hypothesized effectiveness of LDAR applied to these previously-observed populations. These mitigation thought experiments (MTE), which we will call MTE-1 and MTE-2, are defined as follows:

- MTE-1: The top 5% of sites in each population (the "super-emitters") are each replaced with a randomly-drawn member of the bottom 95% of the population. MTE-1 thus represents an LDAR effect where the most problematic sites are repaired but the average site emissions rate is not improved by LDAR.
- MTE-2: As in MTE-1, the top 5% of sites is replaced with a member of the bottom 95% of the population. Next, the resulting population is further mitigated by reducing emissions by 50% for each population member. Thus, MTE-2 represents a more optimistic mitigation case where super-emitters are removed *and* each site sees emissions reductions to 50% of baseline emissions. Actual FEMP-related mitigation effectiveness at super-emitter sites will depend on many parameters, including whether identified super-emitter is a leak or a vent.

We can then sample from these mitigated populations similarly to our sampling exercise above and determine how often we would expect to be able to observe the reduction in mean emissions associated with either MTE-1 or MTE-2. Box plots show the distribution of 100 attempts to compute the mean for sample sizes $n = 50$, $n = 100$, $n = 200$, modified with either MTE-1 or MTE-2. These results are plotted for both compressor stations and wellpads, in Figures 12 and 13 respectively.

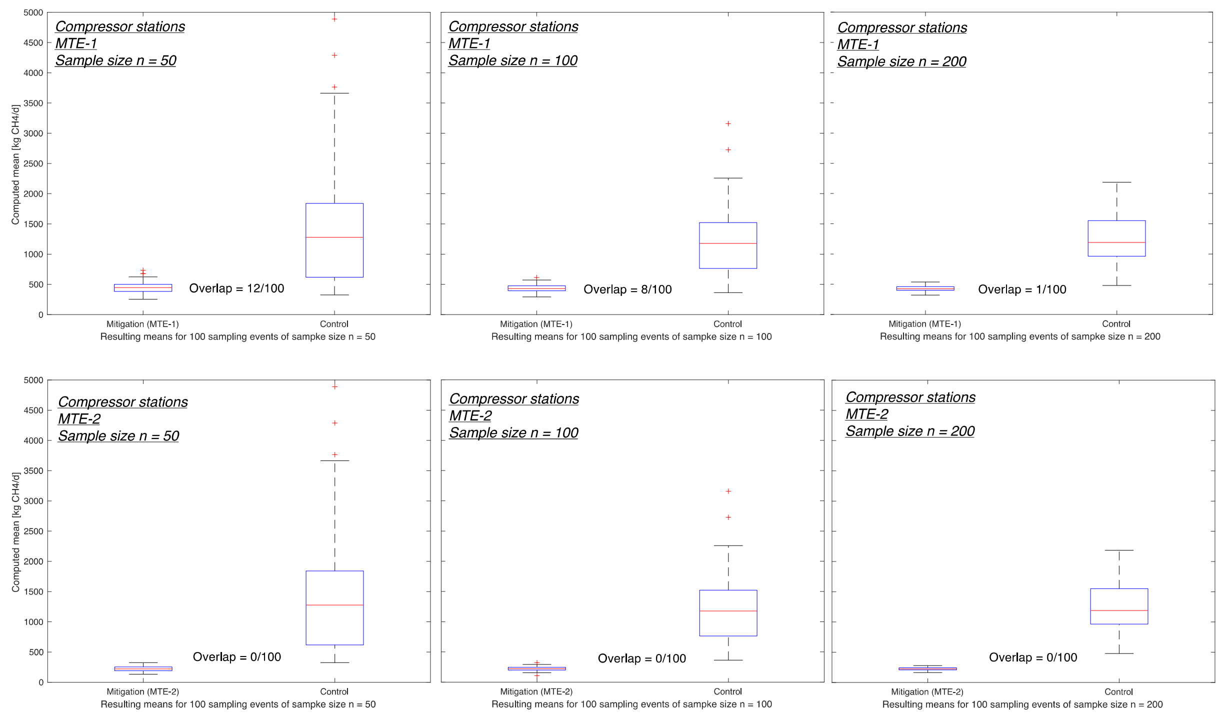


Figure 12. Distribution of compressor station means computed with different sample sizes (n = 50, 100, 200, left to right) and two mitigation thought experiments (MTE-1 and MTE-2, top and bottom).

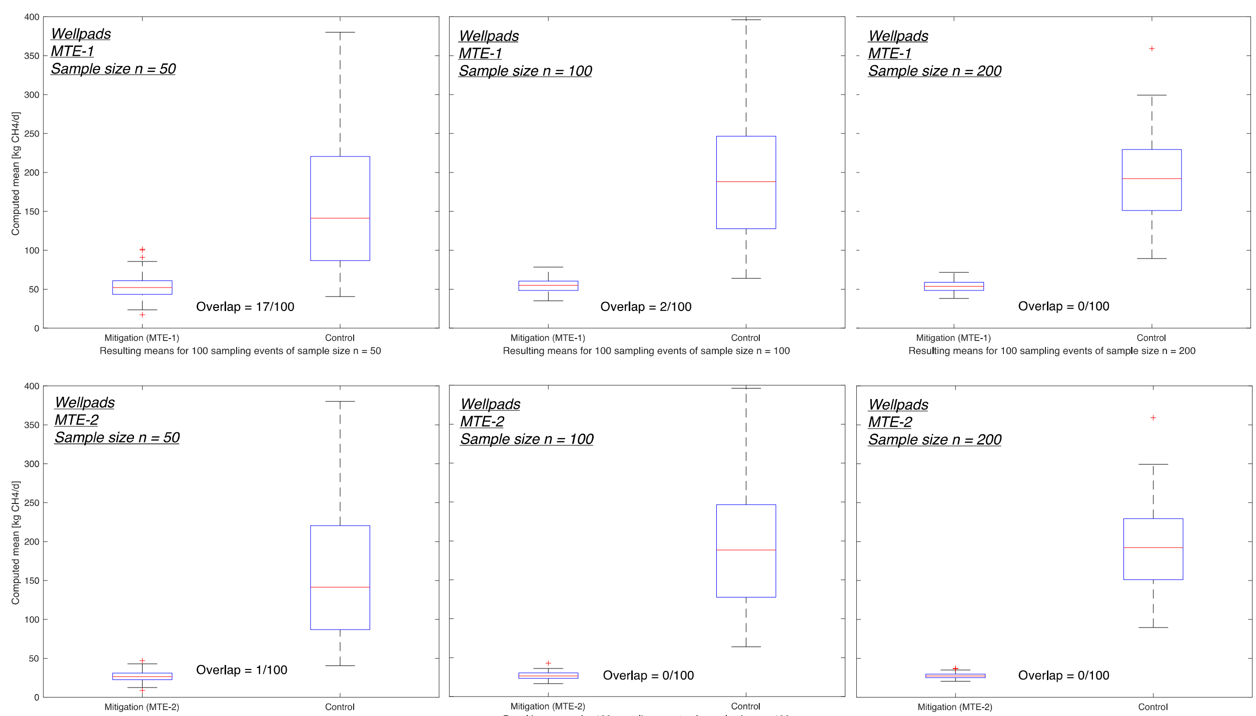


Figure 13. Distribution of well-pad means computed with different sample sizes (n = 50, 100, 200, left to right) and two mitigation thought experiments (MTE-1 and MTE-2, top and bottom).

Intuitively, we expect that the mean emissions rate of LDAR population should be lower than the mean emission rate of the control population. If we look at the marked indicator "Overlap" between the two box plots for each chart, we can say: "if we take the mean 100 times from the LDAR population and 100 times from the control population, how often would we find an LDAR mean larger than the smallest control mean?" We see that for MTE-1 (replace super-emitters with body), a sample size of 50 is not sufficient to always guarantee a smaller LDAR in mitigation – i.e., the observe emissions from LDAR population **can be higher** than that of the control population. We see though that in MTE-2 (replace super-emitters plus 50% mitigation in body), we almost never observe the largest LDAR mean exceeding the smallest control mean.

However, those metrics are too conservative. In reality, what we will be doing is repeatedly computing the mean for 50 LDAR sites and 50 control sites. We can ask ourselves, "How often would I draw a lower mean emissions rate for the control sites compared to the mean emissions estimate for the LDAR sites?" This pairwise comparison, instead of comparing the extremes of each distribution, is a more accurate estimate of the effect. If we perform this simulation, we find that only 5 times out of 100 this would occur for n = 50 and MTE-1 and only 1 time out of 100 would this occur for n = 50 and MTE-2.

In conclusion, if we perform experiments where we take sample sizes of n = 50 from control and LDAR-mitigated populations, we would not often find (5% and 1% respectively), by chance, that mean emissions are higher in the LDAR than control populations. If we expand the study to more regions (i.e., visit more facilities and increase the effective n) the chance that this poor outcome will occur becomes smaller. In order to study the effects of different LDAR frequencies, sample sizes of 50 each are proposed for control, annual, semi-annual, and tri-annual scenarios.

5.2. Site Visits

In order to reduce bias in the data collected as part of this study, it is necessary to select sites at random as much as possible – an unannounced visit would be most likely to produce truly random sampling. However, given the periodic nature of the leak detection survey, it is not possible to visit sites unannounced through the duration of this study. Moreover, prior announcements of our arrival might have advantages in terms of being able to identify episodic events and processes, supplement activity count data with company-specific inventory, etc. Four site-visit scenarios are considered here:

1. **'Coalition of the willing':** In this scenario, operators are informed of our arrival at their facility with specific site information at least two weeks before the survey. The disadvantage here is that it is likely only 'good' operators will be willing to invite the survey team onto their

site. These operators are also more likely to conduct maintenance prior to survey team arrival, resulting in data that is artificially biased low.

2. **Visit subset of selected sites:** This scenario significantly reduces prior knowledge of the operator with regards to the sites to be visited by the survey team. Here, we provide the operator with three to five times the number of sites we intend to visit and do not disclose the actual sites to be visited. Sites to be visited can then be randomly selected from the master list.
3. **Unannounced fence-line visits, announced on-site measurements:** In this scenario, announced site-visits (as explained in Scenario 1) will be complemented with unannounced fence-line visits over a larger set of facilities. This can help us compare emissions from announced vs. unannounced sites and control for any operator bias.
4. **Deputized by AER or BCOGC:** In this scenario, all site visits are unannounced and deputized by AER. In addition to the seemingly confrontational approach, this scenario might not be well suited in light of existing operations on site that could prevent a survey from being conducted. Furthermore, it is likely that operators will not be 'truly blind' to site surveys during repeat visits.

Weighing the different options and their relative advantages and disadvantages, we advocate using the scenario 2 approach: visiting subset of selected sites. This provides the right balance between random selection and operator awareness that will give us both relatively unbiased data, as well as critical operator-specific information on episodic events and activity counts. If the master list provided to the operator is 3 – 5x the actual number of sites to be visited, the effect of prior knowledge on the data collected would likely be minimal.

5.3. Site selection

To kick off the initial part of the phase-2 project, we propose selecting one or two sites each in AB and BC for detailed LDAR surveys. The selection criteria will depend on many factors including (i) existence of prior studies in the region, (ii) accessibility, (iii) recent production and drilling data, and (iv) site-specific characteristics. Although site selection is not critical when all regions will be ultimately surveyed, it is important to fill regional data gaps in the literature as a risk mitigation measure against budgetary constraints.

Type of sites selected: In order to develop an emissions estimate and FEMP effectiveness assessment in Alberta or British Columbia, it is important to sample sites in a manner that is representative of the population in a given region. For example, if a region consists of 75% well sites, 15% processing plants, and 10% compressor stations, random sample selection should roughly try to preserve this ratio. The subset of sites selected for effectiveness assessment will include well-pads, processing plants, and compressor stations, roughly in the ratio in which it is present in the region.

Alberta

Sites can be selected based on their importance to total production. For example, in 2016, 73% of Alberta's gas was produced in just three AER administrative regions – Grande Prairie (GP), Drayton Valley (DV), and Red Deer (RD). Table 2 summarizes gas production in AB by AER administrative area, while Figure 14 shows the location of the different regions in AB. Selecting sites with preference to coverage by production levels translates to surveys in the GP and DV regions for a two-region study design.

Table 2: Gas production in Alberta by AER administrative region.

AER administrative Region	Gas Production (2016, %)
Grande Prairie (GP)	29
Drayton Valley (DV)	27
Red Deer (RD)	17
Midnapore (MR)	8
Medicine Hat (MH)	7
Edmonton (ED)	5
Bonnyville (BV)	3
Wainwright (WW)	2
Slave Lake (SL)	1

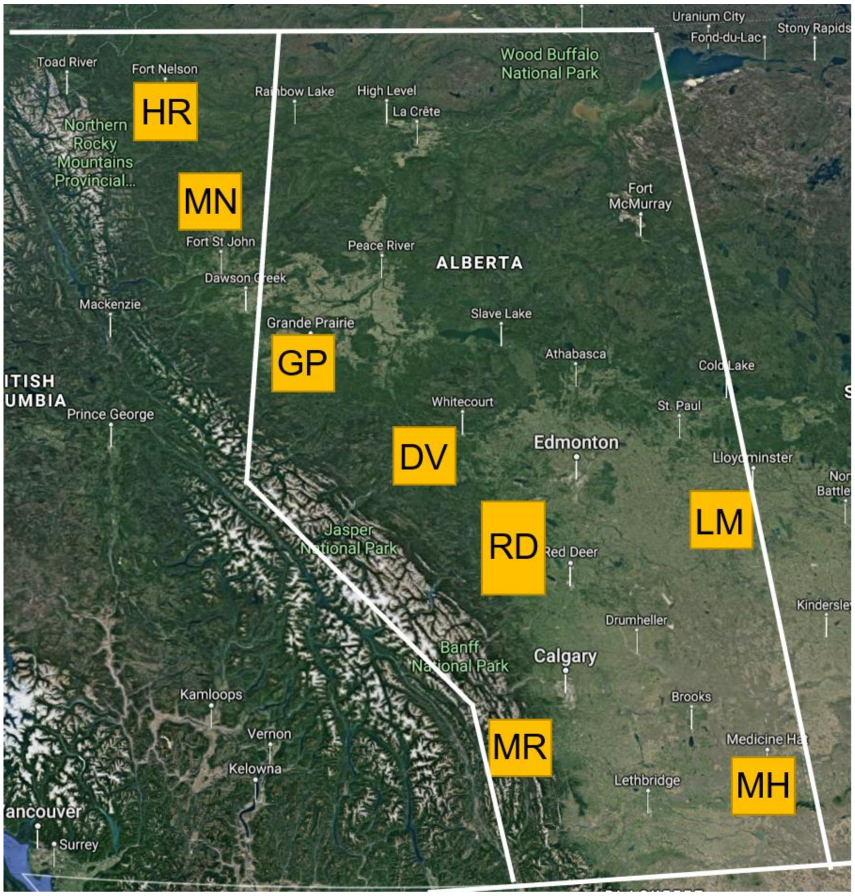


Figure 14: AER administrative regions (AB) and BCOGC management areas (BC) selected as potential sites for periodic LDAR surveys.

However, we note that low production does not translate to lower methane emissions. As our recent work in the GP area shows, while high production sites indeed have lower proportional loss rates, absolute emissions magnitude are similar across high and low production sites. Therefore, selecting sites based on production levels may not translate to maximizing mitigation potential.

Another method to select sites is to start with regions based on the number of new wells drilled or permitted in the past 2 – 3 years. This criteria allows one to estimate emissions from sites with the highest future growth potential in total gas production. For example, although only 7% of natural gas in AB is produced in Medicine Hat (MH), the region accounts for approximately 50% of all operating gas wells in the province.

In addition to the above criteria, density of the well pads in a given region determines the number of sites surveyed. For example, densely located smaller pads (1 – 3 wells/pad) such as in the MH region can be surveyed at a rate of 10 – 12 pads/day, while sparsely located larger pads (15 – 20 wells/pad) in the GP region can be surveyed at 1 – 2 pads/day.

Recommendation: Considering total production, density of facilities, and accessibility, we recommend starting this survey at the Drayton Valley and Medicine Hat administrative regions. In addition to surveying less frequently visited regions, DV and MH belong to two distinct shale formations – Duverney and Bakken, respectively. Combined with existing (and future) data collected by our teams and others in the Montney basin as part of other studies, this initial part of phase-2 study will provide some data across all major shale basins in Alberta.

British Columbia

For an effectiveness assessment of FEMP in BC-based upstream sites, we should first consider the variety in the type of upstream operations in BC (unconventional vs. conventional gas, sour gas vs. sweet gas, etc.). Typically, measurement campaigns at sour gas operations are not undertaken because of significant safety concerns for on-site personnel who are trained to operate in such hazardous conditions. As discussed in the Alberta section, we would strive to sample sites in such manner to replicate the distribution of different types of sites in the region. We will also consider the wealth of recent studies in the Montney in BC available publicly to inform the site selection process.

Most of the existing peer-reviewed and non-peer-reviewed literature on methane emissions in BC have focused on the newer non-conventional high producing Montney basin. According to the latest BC Oil and Gas Commission (BCOGC), gas production is spread across four management areas, with the Montney basin accounting for about 84% of total gas production, as shown in Table 3.

Table 3: Gas production in British Columbia by management area

BC management area	**Gas production (Tcf, 2016)**	**% Total production**
Montney basin	5.61	84
Horn River basin	1.00	15
Cordova basin	0.04	<1
Liard basin	0.05	<1

It should be noted that over 94% of all wells drilled in BC is in the Montney basin. Of the 374 wells drilled in 2016, 353 have been in the Montney basin, 5 in the Liard basin, and the rest (16 wells) spread across the other regions. In fact, development of the Horn River basin has now ceased due to unfavorable economic conditions.

Our recent work in the Montney (Grande Prairie, AB) has shown that emissions are often higher right after commissioning of a well-site or processing plant because there is a greater likelihood of site-assembly problems that can lead to leakage. In this context, we would like to survey a mix of newer and older sites in proportions seen in the specific region. In addition to providing a non-skewed regional estimate, a combination of newer and older conventional sites (sweet gas operations, for example) would give us the best data to identify site characteristics that make them prone to emissions.

Recommendation: Because of the disproportionately large production in the Montney basin and the unfavorable economics of the Horn River, Cordova, and Liard basin, we propose surveys at facilities located with the Montney basin.

5.4. Methodology

Davis Safety Consulting Ltd has been conducting optical gas imaging (OGI) based leak detection and repair (LDAR) surveys at oil and gas facilities for over a decade, with experts trained, certified, and experienced in the latest leak detection and thermography technologies and techniques.

A conventional site-survey typically takes place in two stages. In the first stage, a thermographer examines every single component and piece of equipment on site using an infrared camera (FLIR GF-320) for leaks. A second surveyor records every leak (location, component, type of leak, and other relevant parameters) electronically, and physically attaches a unique tag to the leaking component for easy identification. The client is immediately notified of leaks that pose risk to life or property. In the second stage, leaks previously identified by tags are quantified using a Hi-Flow meter.

Leak Quantification using Providence Photonics' QL-320

For this study, Davis Safety proposes to use the FLIR GF-320 imaging camera in conjunction with Providence Photonics' QL-320, a leak quantification add-on to the FLIR camera. In addition, Davis Safety is current conducting extensive tests and calibration experiments to ensure measurement results are similar to those obtained by conventional Hi-Flow meter. The advantage of using FLIR-based OGI along with the QL-320 is two-fold. One, it potentially cuts the leak detection time in half, which means we can visit double the number of sites within the limited time and budget (Note: Davis charges by the day, which means the total cost of the program will not change). Two, and potentially more important, we will now be able to quantify leaks that are typically not quantified in an OGI based survey such as tank emissions or otherwise inaccessible leaks. Episodic emissions might also be potentially quantified. This will help us get a more complete picture of methane emissions than has been possible in any prior component-level study.

While there is limited data on a comparison between the QL-320 and Hi-Flow sampler in terms of quantification accuracy, we plan to conduct an exhaustive test before deployment. This will happen in two stages.

Stage 1: We are conducting controlled release tests using the FLIR GF-320 camera and the QL-320 quantification tool at the Methane Emissions Technology and Evaluation Center (METEC) in Fort Collins, CO during May 7 – 11, 2018. During this week, we will use the QL-320 to quantify emissions ranges in the 1 – 100 scfh range, and thoroughly characterize its performance in terms of its precision and accuracy. These tests would give us a good idea on the effectiveness of this technology in quantifying methane emissions.

Stage 2: Prior to the field study in Canada, in collaboration with Davis Safety, we will conduct a comparative study of the QL-320 capabilities with that of the Hi-Flow sample. Combined with the data from Stage-1 results, this will provide a quantitative evaluation of using this technology not just for this study, but also potentially in all future regulatory processes.

The detection limit of camera based OGI technologies varies with weather conditions, temperature of the equipment, background radiation, and imaging distance. To compensate for the limitations of the camera-based OGI technologies, 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 from a ¼ inch orifice. The distance at which this 'standard leak' is seen, is set as the maximum imaging distance for that day. This provides an approximate detection limit for the leak survey.

After the leaks are recorded, tagged and quantified, the facility operator is supplied with high quality reports detailing the findings, equipment affected, possible solutions, photos and videos capturing each leak. Because there will be follow-up measurements at each site, each operator will be asked to repair as many of the identified leaks as possible and document those leaks that were not repaired. To minimize bias in the study design, operators will not be told when the next survey at their facility will be.

Finally, one thermographer will be dedicated for the surveys throughout the duration of this project to reduce variability and uncertainty associated with operator accuracy or visual acuity.

5.5. Survey Design

The number of sites surveys on any given day depends on the size and complexity of the site, distance between sites at a given location, and weather conditions. For example, the Grande Prairie region in AB contains some large production well-pads with 15 – 20 wells, along with basic processing equipment. Such sites could take an entire day (defined here as 12 hours) for one survey. On the other hand, well-pads in Medicine Hat, with 2 – 3 wells, can be completed in about an hour, assuming leak detection and quantification are done simultaneously. For smaller sites that are densely located, 10 – 12 locations can be completed in one day's survey.

The entire survey design takes place in 4 stages, within a span of 12 – 15 months. After each survey, operators will be requested to follow company procedures to repair identified leaks whenever possible. Any changes to the site (new wells drilled, new process equipment, etc.) between surveys will be noted and considered in our analysis. They are briefly described below:

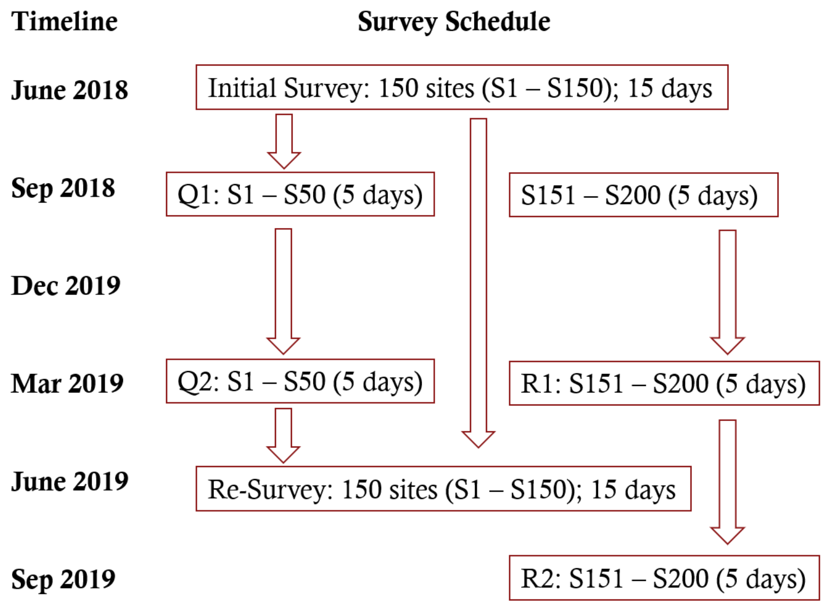
Stage 1 – June 2018: Initial survey of selected sites will be conducted within a period of 15 days (3 – 4 weeks). At an average of 10 sites/day (can be higher or lower depending on the site size), we will have an initial sample size of 150 sites (S1 – S150). This is because we assume that a future semi-annual LDAR survey schedule will likely happen in the Spring and Fall seasons. Replicating mitigation potential under this scenario would require a first survey conducted either during March/April or September/October.

Stage 2 – September 2018 – March 2019: The first quarter (Q1) repeat surveys of a subset of 50 sites from the initial S1-S150 sites (S1-S50). This will provide a set of 50 repeat visits on quarterly revisit schedule. In addition, we also conduct an initial survey of sites S151 – S200 for semi-annual LDAR evaluation.

Stage 3 – March 2019: The second quarter (Q2) repeat survey of sites S1 – S50 will be conducted – this will be the second survey of a potential 3 times a year survey schedule, as recently proposed by ECCC. In addition, the semi-annual survey of sites S151 – S200 will also be conducted.

Stage 4 – June 2019: A resurvey of all the initial 150 sites (S1 – S150) will be performed. This will complete the third quarter requirements for the sites S1 – S50 in their three times a year LDAR schedule. Furthermore, we will also have data on mitigation effectiveness on an annual LDAR schedule for 100 sites (S51 – S150). Finally, in September 2019, the one-year resurvey of the sites under semi-annual LDAR schedule (S151 – S200) will be conducted

We will analyze and document the results of the surveys and potential recommendations between October and December 2019. The entire survey plan is shown in Figure 3 below.



In the end, we will have temporal data to measure LDAR effectiveness for the following test cases –

a) Annual LDAR – 100 sites across two regions
b) Semi-annual LDAR – 50 sites across two regions, measured in the Spring and Fall
c) Tri-annual LDAR – 50 sites across two regions, measured in the Spring, Summer and Fall

Based on the data collected in Stage-1, additional areas/locations could be added on as the second part of Phase-2 of this project. Leak survey for these additional areas can be completely alongside the initial proposed survey discussed here.

5.6. Study Outcomes

Many existing methane emissions studies in Alberta and British Columbia have focused on improving emissions estimates at oil and gas facilities. These studies include drive-by measurement that estimate emissions at the facility level, fly-by measurements that estimate at the regional level, as well as bottom-up component level estimates. In all these studies, the goal is develop an improved understanding of methane emissions that includes comparison to reported emissions [5], size-distribution of leaks [7], and persistence over time [4]. However, the study proposed here and the chief goal for this project is to assess the effectiveness of fugitive emissions mitigation programs (FEMP). This is fundamentally different from every existing study because an effectiveness assessment, by definition, requires follow-up measurements after a specific action is taken (in this case, leak detection and repair surveys). In this study, we plant to periodically re-visit sites to evaluate the rate at which emission are reduced at facilities with FEMP regulations. Because of the careful study design proposed here, we will also be able to clarify some of the outstanding questions in the methane emissions field, as well as reduce uncertainty in other areas. These are discussed below, with particular reference to Figure 3 on parameter uncertainty and its importance.

- One of the first detailed datasets on the rate at which leaks are created at a facility – this will directly help inform the decision on LDAR survey frequency.
- Detailed component-level data on emissions including analysis of leaks vs. vents, root-cause analysis whenever possible, and emissions factors for previously uncharacterized (or poorly-characterized) sources like tanks and episodic emissions.
- The mitigation effectiveness of periodic leak detection surveys at different survey frequencies.
- Because measurements are done periodically, this study will also generate estimates on the rate at which super-emitters form. As is widely known from prior studies, super-emitters contribute to a large fraction of the total emissions and a better understanding will help develop targeted, cost-effective mitigation measures.
- Potential root-cause analysis for super-emitters, their rates of occurrence and recurrence after an LDAR survey, and how that affect mitigation protocols.
- In the extended version of the study, we will concurrently collect the most up-to-date activity factors including pneumatic devices (Note: recent work by Cap-Op energy on pneumatics inventory will be used to complement the data we collect as part of this study).
- Depending on the scale of the study, a better understanding of regional emissions at the component-level, and helping to identify regions that might require more attention when it comes to methane mitigation.

In addition to identifying the questions we can reasonably answer in this study, it is also equally important to clarify what this study will not be able to answer.

- Relative effectiveness of control technologies – this study can only assess the effectiveness of FEMP program based on the kind of 'repair operations' the operator undertakes after each LDAR survey. If regulations mandate specific action (e.g., switch gas-driven systems to compressed air-driven systems), the overall mitigation effectiveness will change.
- Reduce the uncertainty in national emissions estimate – this would require a more continuous monitoring to identify trends in methane emissions.
- Reduce the uncertainty in top-down measurements because this study does not attempt to measure non-oil and gas methane emission that will contribute to a top-down estimate.

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