CANADA EMISSIONS REDUCTION INNOVATION NETWORK (CERIN) PUBLIC REPORT

1. PROJECT INFORMATION:

Project Title:	Methane Emissions Monitoring Technologies Assessment
Emissions Reduction Scope/Description:	The project focuses on addressing the gaps on conducting a Methane Monitoring Assessment in Canada and the USA, in specific to reconciliation of estimation from top-down vs bottom-up approaches. The scope of work of this project will entail a broad review of current methane emission sources, inventories, monitoring technologies, methodologies dependent on regulatory requirements or supplemented with additional voluntary methods and alternatives. The type of monitoring technologies versus the magnitude of emissions and techno-economic effectiveness of the methods will be assessed and relevant case-studies and best-practices with be studied. Following this study, relevant data will be consolidated for a critical analysis and assessment. The final deliverable is in the form of an assessment report that will be submitted to PTAC.
Applicant (Organization):	SAIT
Project Completion Date:	31St March, 2023

2. EXECUTIVE SUMMARY:

Natural Resources Canada | Ressources Naturelles Canada

Canada

ALBERTA INNOVATES

PTAC PETROLEUM TECHNOLOGY ALLIANCE CANADA

Provide a high-level description of the project, including the objective, key results, learnings, outcomes and benefits.

From the report

The mission of the Petroleum Technology Alliance Canada (PTAC) is to facilitate innovation, collaborative research and technology development, demonstration, and deployment for a responsible Canadian hydrocarbon energy industry. Within this mandate, it contracted the Southern Alberta Institute of Technology (SAIT) to summarize and assess Canadian information on the current state of methane monitoring approaches. The study was undertaken by three collaborating parties – SAIT, AECOM Canada Ltd. (AECOM), and SAIT's External Consultants who have credible subject matter expertise. The work was executed by discussions with industry experts in monitoring and by extensive review of recent literature.

The specific elements of methane monitoring addressed in this report, associated with petroleum storage tanks in the context of the broader industry, are:

- Preparation of an inventory of methane monitoring technology/methodology solutions in Canada
- Summarization of solution performance, application, and limitations
- Discussion of remote monitoring options vs. on-site options vs. continuous monitoring options
- Canadian based monitoring technologies or processes compared to those used in the US
- The state of methane emissions data inventories provincially and federally
- Any knowledge gaps that require further R&D and
- A list of organizations involved with monitoring (quantification) research in Canada.

One rationale for this study is that many independent methane monitoring studies have highlighted differences between measured quantities of methane being released into the atmosphere and what is recorded in industry and national inventories. Inventories are typically based on the use of approved engineering estimates from specific emitting sources working normally, and emissions from known fugitive sources and upsets. Standardization of approaches leads to confidence in the estimates. At the same time, monitoring using top-down technologies (such as instruments mounted on a drone, aircraft or satellites, or on ground-based sensors that are remote from the emitting source verified by ground truthing) can directly measure emissions from sources not included in inventories including those from fugitive and upset sources at the time of the survey. These forms of measurements represent a movement to a more complete and accurate framework, albeit with knowledge gaps currently under investigation.

Quantification of emissions is also important as regulations to reduce emissions are based on a quantitative step change - reducing emissions by 45% by 2025 compared to a baseline measurement. This inherently requires monitoring to quantify the emissions to justify a reduction claim. Quantifying emissions using only a bottom-up approach requires some prior knowledge of emissions sources, or a very large sample size to ensure that all emissions are accounted for. On the other hand, technologies that quantify emissions using top-down methods may work best for an aggregate of all emissions but have difficulty pinpointing exact emission leak sources.

This report reviewed monitoring technologies grouped into the following categories: approved leak detection and repair (LDAR) technologies (OGI, method 21), handheld devices, ground-based approaches, airborne, and satellite. Benefits and limitations of each are summarized. However, while this report strives to provide a comprehensive assessment of the methane emission monitoring technologies, it is acknowledged that from a practical viewpoint there are technology assumptions and limitations that might not have been captured by this review within the timeframe of this project.

The most common sensors used for Method 21 are flame and photoionization detectors, while catalytic oxidation sensors and infrared absorption-based sensors, are also used. Although detection limits tend to be low, Method 21 instruments are labour-intensive. Method 21 is still favoured by some operators, but use is declining as OGI cameras are more convenient and efficient as they survey components remotely. OGI cameras are capable of limited screening, which is restricted by imaging distance to small spatial scales. Though more efficient than the Method 21 instruments, they are still labour intensive, requiring many hours to survey equipment.

Perimeter sensors are deployed in high-risk areas and provide continuous readings of methane concentration, triggering an alarm should concentrations exceed a predefined level. Continuous monitoring and potential for automation make fixed sensors appealing. However, these sensors can be difficult to implement as the quantity of sensors required for accurate monitoring can be very high depending on the area of the facility. Perimeter sensors may also be deployed beyond high-risk areas to measure facility-wide emissions.

Mobile ground laboratorys (MGLs) are versatile platforms for conducting local-to-regional-scale surveys of methane emissions. MGLs generally consist of a vehicle equipped with a global positioning system and a methane sensor. They have a large range of spatial monitoring capabilities; however, they are limited by road access and meteorological conditions, especially wind direction, and detection limits increasing with distance.

Novel approaches for measuring emissions from area sources typically focus on a top-down approach where concentrations are measured downwind of the source and this concentration data are related to source emissions data via the implementation of statistical or modelling approaches. These approaches include simple mass balance, eddy covariance, and inverse dispersion modelling.

In recent years, there has been a growing interest in airborne methods, such as aircraft and unmanned aerial vehicles (UAVs), for surveying site-level emissions. The strength of aircraft screening relative to ground screening methods and UAVs is the speed at which a survey can be conducted. However, piloted aircraft have a need for acquisition, maintenance, and operation of the aircraft, and are restricted by regulations on flight parameters. On the other hand, UVAs have significantly lower detection limits when compared to aircraft and are more flexible to operate; however, a smaller size comes with payload and power constraints limiting the types of sensors UVAs can carry, as well as survey duration.

Methane-sensing satellites cover a greater measurement area than any other technology. They can quantify global atmospheric methane concentrations with little ongoing maintenance. The downside of having a large field of view is that satellites are unable to discriminate between thermogenic and biogenic sources, making source attribution complex or impossible and over-estimating the impact of human driven sources on the global contribution to methane emissions. New generations of satellites offer improvements in both spatial resolution and detection limit.

Monitoring approaches in the US are like those in Canada, using ground-based, airborne, and/or spaceborne sensing modalities, as well as several emissions estimation methods. In recent years, there have been extensive efforts from academics and industry researchers to evaluate new technologies and solutions that are currently being used for methane monitoring and mitigation. The solutions being developed will combine various technology groupings to provide a clearer picture of total emission profiles. Two approaches are worthy of note: the use of a standardized emission monitoring test facility used by many technology providers and the development of modelling approaches to optimize tiered monitoring approaches.

In Canada, the state of facility methane emissions inventories is primarily influenced by the requirements of the applicable reporting regulations. Emissions inventories are maintained specifically for the purposes of reporting, voluntary or otherwise, thus inventories are optimized along with methane emissions calculated to meet be cost-efficient and typically meet the minimum emissions reporting standards. Bottom-up inventories generally require emissions from similar equipment types to be tallied although monitoring and reporting frequencies can differ.

There were several knowledge gaps that were found over the process of developing this report, including:

- Researching new approaches to methane emissions that can be measured via process related parameters – the research gap is determining what measurements are relevant and linking them to methane emissions,
- Better quantifying process emissions and sporadic flaring events to routinely detect and quantify intermittent super-emitters,
- Developing a comparison system, with combinations of multiple technologies, by which technologies can be simulated at facilities to determine the best fit,
- Establishing a framework for fixed sensors to optimize sensor placement to improve coverage and quantification of releases,
- Streamlining fixed sensors to separate actionable items from instrument noise which implies more work on analytics and machine learning,
- Reducing quantification uncertainties of bottom-up inventories,
- Standardized testing of emission quantification technologies using controlled release testing of evolving technologies to derive conclusive evidence of performance,

- Finally, understanding there is value in making an inventory of new emerging measurement technologies more widely available, especially to small to mid-sized operators, as this is expected to encourage the adoption of lower emitting technologies faster.

The development and refining of measurement technology or the refining of statistical or analytical approaches to aid in quantification to improve inventories is expected to be best addressed through a combination of approaches. A layered or tiered approach can lead to improved emission quantification accuracy. How data are expected to be used drives which approach should be used. No single option is best in all cases. Either for the purpose of quantifying equipment emissions or simply to find and repair leaks, there appears to be no better approach than the combination of Method 21 and OGI. The methods are essential to accurately determining emission rates of specific equipment or sources albeit only during the survey. These surveys can lead directly to equipment repair or replacement and therefore to emission reduction.
A layered or tiered approach can lead to improved emission quantification accuracy. Here the goal is to attempt to survey all emissions from all equipment as a basis to establish an inventory and a sufficiently accurate periodic emission determination to track progress toward reduction:

- Large oil and gas operators augment OGI surveys with airborne surveys, most often using LiDAR. Aircraft platforms offer the ability to map emission rates over large areas and provide a screening level of source identification. Combining this with ground-based quantification improves measurement accuracy.
- For smaller operators or small facilities, fixed or mobile ground-based quantification can provide the spatial coverage to quantify known and unknown sources as well as provide screening-level guidance on source location
- For facilities with large area sources, several techniques are available to quantify emissions that involve direct emission measurement (flux chambers), point source measurements coupled with inverse dispersion modelling, or open path measurements including inverse dispersion modelling. Measurements from an aircraft platform is another option.

For governments, the goal is typically to establish an accurate national or regional inventory, and one that can be used to track emission reductions and political commitments. At present, no single strategy can accomplish this, and a combination of approaches is needed. This could involve regional aircraft surveys where available, corrected or enhanced with ground-based measurements, and supplemented in most geographic areas by emission factor estimation approaches. It is not an absolute requirement that the top-down and bottom-up versions of measurements match, as they are fundamentally different. In the next decade, it is possible that high resolution, low detection limited satellite coverage will be available to provide an additional basis of comparison.

This report does not consider the cost of measurement. Practically, there is a trade off between cost, accuracy, and frequency and cost is clearly a factor in determining optimal approaches to measurement depending on factors such as the capital cost of the measurement devices and mounting platform, operating cost, measurement frequency, scale of operations, data processing costs, and whether the work is conducted by staff or external consultants. These factors are highly user specific.

3. KEY WORDS

Add up to 5 key words

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Methane Emission Reduction; Methane monitoring technologies; Top-down vs bottom up approaches; Greenhouse gas emissions;

Natural Resources Canada Ressources Naturelles Canada

Canada

ALBERTA INNOVATES

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4. APPLICANT INFORMATION:

Applicant (Organization):	Southern Alberta Institute of Technology (SAIT)
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Applicant Contact Information:	Applied Research and Innovation Services

5. LEAD CONTRIBUTING PARTNER INFORMATION:

Organization:	Petroleum Technology Alliance Canada (PTAC)
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Representative Name:	Brian Spiegelman
Title:	CanERIC Project Manager, Petroleum Technology Alliance Canada (PTAC)

6. PROJECT PARTNERS

Please provide an acknowledgement statement for project partners, if appropriate.

AECOM, Taylor and Assoc, and Brown and Assoc

A. INTRODUCTION

Please provide a narrative introducing the project using the following sub-headings.

- **Sector introduction:** Include a high-level discussion of the sector or area that the project contributes to and provide any relevant background information or context for the project.
- **Project Specific Information:** Explain the knowledge or technology gap that is being addressed along with the context and scope of the technical problem. We talked about the sector at first, now for this specific project, what are the goals and proposed outcomes?

From the Writeup

Methane emissions from oil and gas production emanate from numerous sources, but particularly from the natural gas supply chain. Methane emissions are a key factor in determining the greenhouse gas footprint of natural gas production and use. After carbon dioxide, methane is the second greatest contributor to anthropogenic climate warming and has between 28 – 84 times the global warming potential of carbon dioxide depending on the time frame considered (Allen, 2014). Significantly reducing methane emissions is an efficient and effective route to immediately address climate change (Erland, B.M.; A.K. Thorpe and J.A. Gamon, 2022). The oil & gas industry has been in the process of reducing its emissions through technologies and processes to address monitoring and mitigation, and the work of PTAC is central to those efforts.

Motivations for efficient monitoring stem from two fundamental goals that are to understand emissions and mitigate emissions (Fox, T.A., T.E. Barchyn, D. Risk, A.P. Ravikumar and C.H. Hugenholtz, 2019). For each goal, equipment can be targeted at a granular scale or parties can look at emissions at a regional or even global scale. Different technologies and methods are required for each goal, and different results can be expected.

More specific goals are a function of the parties involved such as industry, regulators, government, academia, and technology providers and include:

- The regulatory requirements for the upstream and midstream oil and gas industries to monitor methane emissions
- To find and eliminate methane emissions leaks to support mitigation, that may or may not require quantification of emissions
- Providing accurate information to establish quantified emission reduction targets and tracking the success of adopted mitigation approaches by industry
- The establishment of accurate emission inventories, at industry and government scales

- The research into and development of improved quantification and emission mitigation technologies.

Developing emissions factors requires accurate quantification, often at the component-level, whereas estimating top-down emissions requires mobile or airborne platforms capable of detecting small concentration enhancements downwind of a source. Close-range methods may favour real-time imaging and may not require quantification. However, screening methods done on a larger scale with a higher area covered can inform directed application of follow-up surveys. When emissions sources are detected, using large scale screening methods can help triage follow-up and repair based on a size-ordered list of flagged facilities, reducing emissions as the largest leaks are repaired first. Additionally, large-scale screening methods can focus on super-emitter targeting. Early identification of super-emitter leaks can mitigate many fugitive emissions at a facility. In super-emitter targeting, screening methods should have high spatial coverage and frequent sampling.

For close-range methods, detection, and localization (e.g., pinpointing the location of the source) are often accomplished simultaneously and quantification is generally less important. For screening, quantification is often necessary to determine the scale of emissions. For technologies with high detection limits, quantification could be less important as each detection event could trigger a follow-up survey. If multiple detection events occur during screening, relative quantification can enable triaging. Quantification may also permit the separation of vented from fugitive emissions, but only where vented emissions are precisely known.

Accuracy is related to measurement scale and duration. Figure 1 shows the distance scale and the length of time over which a single survey is completed.

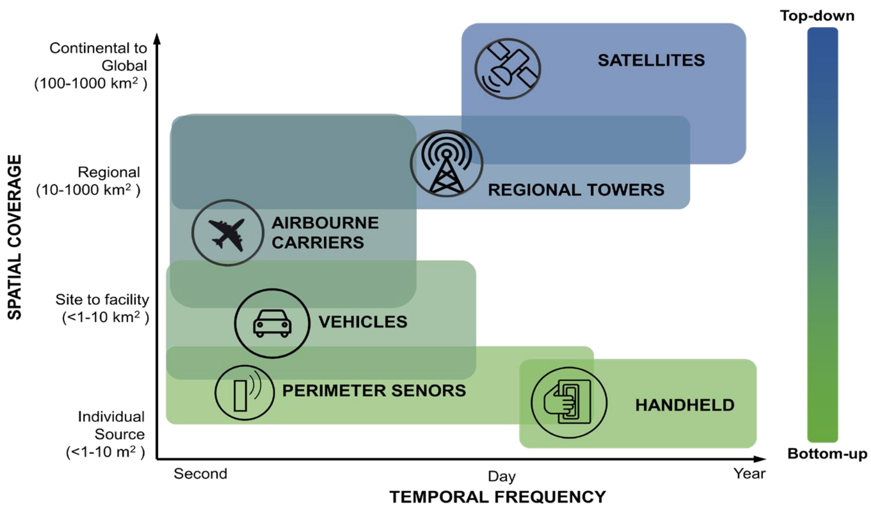

Figure 1. Top-down and Bottom-up Spatial Coverage of Methane

Accurate monitoring provides a foundation for locating sources, quantifying super emitter events, implementing effective regulatory policies, and reducing emissions. Estimates of emissions have varied widely because of the variety of source types and the wide range in emission rates and degree of intermittency, as well the many different measurement and estimation approaches. Some of the largest atmospheric methane budget uncertainties arise from the differences in anthropogenic bottom-up inventory estimates and top-down budget estimates due to their individual characteristics. Understanding differences between ambient methane concentration measurements and direct measurements of emissions from individual sources remains critical 2014).

Bottom-up emissions estimates use direct measurements of emissions taken from individual sources. These measurements when applied to a dispersion model can be used to estimate regional or national estimates of emissions for the natural gas supply chain. The goal in this approach is to measure emissions from a statistically representative sample of sources, then extrapolate to larger populations. Top-down emissions estimates are based on atmospheric concentration measurements in a particular area. The "background emission profile" is subtracted from the total emissions in an area of interest to estimate the impact of emissions from a particular source or group or sources.

Quantifying emissions using only a bottom-up approach requires some prior knowledge of emissions sources, or a very large sample size to ensure that all emissions are accounted for. This is because large emission sources, aka "super-emitters", can often go unchecked by technologies and methods used for bottom-up reconciliation. A large sample requires an extensive amount of time to conduct the necessary measurements to gain an accurate emissions profile. In a study systematically comparing 20 years of top-down and bottom-up estimates of anthropogenic methane emissions from the U.S. natural gas and oil sectors, official bottom-up derived inventories were found to consistently under-report methane emissions (Miller, 2013).

On the other hand, reconciling emissions using top-down methods may work best to quantify an aggregate of all emissions, specifically when the natural atmospheric concentrations of the emissions in question are accurate (Miller, 2013). Top-down approaches can have issues identifying specific emission sources as they are best suited for generalizing emissions on a large-scale. Additionally, levels of compounds and "background" emissions have the potential to be over or underestimated, leading to a misrepresentation of emissions profiles.

This project addresses a series of specific questions with a focus on monitoring technologies most suited to determining emissions from petroleum storage tanks. To establish the relative importance of tank sources, consider a study (PTAC, 2020) showing 19% of all methane emissions from a typical upstream oil site are from tank vents; devices intended to provide pressure and/or vacuum relief for atmospheric or low-pressure storage tanks.

This report summarizes and assesses information on the current state of technologies and methods used for methane monitoring, with a particular focus on methane emissions from the upstream oil & gas sector and specifically those technologies that can support the quantification of emissions from petroleum storage tanks. Many independent methane monitoring studies have highlighted large discrepancies between measured quantities of methane being released into the atmosphere and what is recorded in national inventories. This report briefly outlines the strengths and weaknesses of technologies ranging from hand-held to satellite devices, and the potential for integration between them. The specific points addressed in this report are as follows:

- An inventory of methane monitoring technology/methodology solutions in Canada,
- Solution performance, application, and limitations,
- Remote monitoring options vs. on-site options vs. continuous monitoring options,
- Canadian based monitoring technologies or processes compared to the US, our closest neighbour,
- The state of methane emissions data inventories provincially and federally,
- Any knowledge gaps that are or are not being addressed in R&D projects, and
- A list of the top 20 organizations involved with monitoring research in Canada.

B. METHODOLOGY

Please provide a narrative describing the methodology and facilities that were used to execute and complete the project. Use subheadings as appropriate.

From the report

The methodology adopted for this project will broadly address the Questions that form the scope of work as follows:

Conduct interviews with key PTAC personnel to:

- identify the key specific data sources to include in the project
- identify key industry and government contacts to interview as part of the work scope. This step is expected to broaden the data sources considered as well as focus the team's work on the most important sources.

Conduct interviews with industry and government identified by PTAC. It is assumed these will be largely Canadian contacts. This initial set of contacts will be asked for additional contacts (with a focus on US monitoring researchers and practitioners). The goal of the interviews will be to identify key sources of information to refine the information search.

Conduct interviews with additional monitoring researchers in the US identified as above, augmented with those identified by SAIT team.

Conduct literature reviews, desk top reviews, reviews of manuscripts, guides and case studies to address the questions in the monitoring work scope.

Consolidate the knowledgebase gathered from the interviews, literature reviews and from documents identified by PTAC in the form of a report.

The following Questions form the basis to understand the gaps in various methane monitoring technologies that are currently adopted by various agencies which result in

Q1: What is the inventory of methane monitoring equipment solutions in Canada?

The path to improved emission estimates begins with coarse estimates based on generic emission factors and progresses to increasing granularity with source-specific emission factors combined with LDAR measurements. Site level measurement approaches can be introduced designed to estimate facility emissions of sources not specifically measured. According to Highwood, over 100 methane detection solutions are on the market to cover this range in measurement approaches. The trend in measurement frameworks standardizes a rigorous and transparent emissions accounting practice so that company performance against targets, and performance against peers, can be compared.

Both NRCan and PTAC have initiated research aimed at measuring and mitigating emissions and the research results will provide valuable input to measurement options. The deliverable for this question is to identify, of the many technologies available for measurement of methane emissions, the ones that are used in Canada and the ones most applicable to tankage.

According to GTI (2021), the deployed detection platforms can be classified into broad categories: hand - held, mobile/vehicle-based, aerial-based, fixed/continuous monitoring (CM), and satellite-based. These broad categories can be further divided to be more representative of the types of data that are collected. For instance, the handheld technologies are the more traditional leak detection and repair (LDAR) technologies that satisfy current regulatory requirements and can be broken down into EPA Method 21 devices or EPA Optical Gas Imaging (OGI) devices.

Q2: How do the different solutions perform? Where is their best application? Limitations?

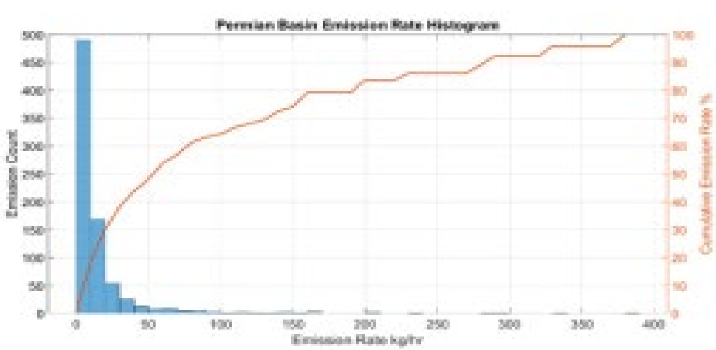

Figure 2. The emissions curve

The utility of monitoring solutions is determined by their ability to reflect the character of the sources they measure. An example of the variability of source emissions (not necessarily those of tanks) from GTI (2021) follows, showing the need to measure both high frequency low-rate emissions and low frequency large emissions to characterize sources adequately. The shape of the curve is similar whether using airborne measurements or continuous fixed sensors as shown in Figure 2. A knowledge of the full range is needed to implement appropriate mitigation approaches.

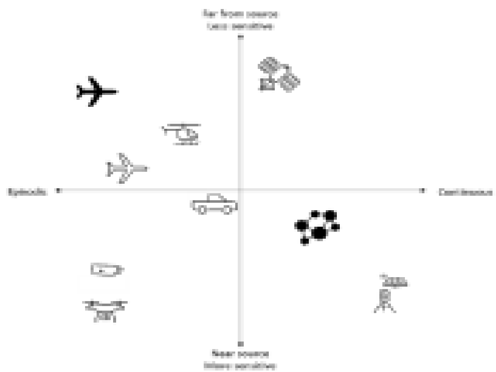

Figure 3. Altitude specific Multiple sensors

For example, aerial remote sensing technologies vary, some generally fly at a higher altitude and faster speeds, therefore are focused on finding only the largest emission sources; others fly at lower altitudes and slower speeds so do not cover as much ground each day (Figure 3).

Continuous monitor methodologies at fixed locations generate large numbers of data points by each sensor. These systems can include multiple sensors placed around the site to wait for a methane plume to be carried on the wind to the location of the sensor. The systems measure high frequency concentration data (e.g., 1 Hz) and report the data on an aggregated/time averaged basis, ranging between 1 and 60 minutes.

LDAR approaches using regulated or OGI devices typically collect low volumes of data infrequently.

Our approach to documenting the limitations of the solutions will be to review the literature on monitoring approaches with emphasis on reports and papers comparing methods. The comparisons will include a summary of the technology as well as reported uncertainty and data quality estimates, where available.

Q3: How do remote sensing monitoring options compare to on-site options to continuous monitoring options?

As an example of the issue, work conducted by Carleton (https://carleton.ca/eerl/quantification-of-methane-venting-through-fixed-roof-liquid-storage-tanks/) has found using preliminary aerial survey data from 2500 facilities in Saskatchewan that around 83% of detected emissions were attributed to storage tanks, engine sheds, and wellhead casing vents. At the top of this list are liquid storage tanks, accounting for most total methane emissions.

Regulations in Canada are mostly based on surveys that use optical gas imaging (OGI) cameras at oil and gas sites to detect sources of methane leaks. The Carleton study, which is supported by other studies funded by PTAC in Alberta, suggests bottom-up methods underestimate emissions compared to remote sensing approaches. In the Carleton study, more than half of methane emissions were attributed to storage tanks, reciprocating compressors and unlit flares, according to the study. Storage tanks were found to be a particularly concerning source of emissions since they alone accounted for a quarter of methane emissions at oil and gas sites. These sources are harder to detect with OGI surveys because they are elevated and could be missed by a camera at ground level.

To answer the question, several key bottom-up and top-down studies in Canada and the US will be summarized and the reasons for the differences in site-wide emissions will be documented as an aid to identifying mitigation approaches as well as guiding research priorities.

Q4: How do Canadian based monitoring technologies or processes compare to the US?

Several Canadian companies provide examples of successful methane monitoring technologies. For example:

GHGSat operates a fleet of satellites that track greenhouse gas emissions from the Earth's orbit. Its space-based system for greenhouse gas monitoring uses spectrometer imaging to obtain high-resolution images of methane emissions. GHGSat is the only entity in the world (https://www.canada.ca/en/innovation-science-economic-development/news/2021/11/government-of-canada-supports-world-leading-canadian-satellite-based-emissions-detection-system.html) capable of detecting methane emissions from sources 100 times smaller than those detected by other satellites. Its technology can detect and quantify methane emissions from point sources as small as individual oil and gas wells.

Qube has developed continuous fixed methane monitoring technology applicable to emitting sites that uses AI to back-calculate emission rates from the measured data.

To compare the technologies and process in Canada and the US, advice from the government and industry experts interviewed will used to identify the key technology providers in both countries. This information will be augmented by additional literature reviews as well as the research team based in both countries. To the extent that technology is driven by regulations, monitoring regulatory requirements, also reflected in emissions inventory requirements, will be considered.

Q5: What is the state of methane emissions data inventories in BC, AB, SK, and NL? Please compare provincial and federal sources.

Emission inventories are typically based on the application of specifically approved measurement or estimation approaches. Only sources emitting above thresholds are reportable by industry into the inventories. Clearstone (2020) found that measured tank emissions in a BC study were almost five times greater than reported.

Approved emission quantification approaches vary by jurisdiction making corporate inventories, and therefore corporate mitigation approaches, inconsistent unless standardized across jurisdictions.

To address this question, the SAIT team will summarize the approaches taken to development of inventories in each of the four provincial jurisdictions identified (BC, AB, SK and NL) with the largest share of O&G emissions. Federal approaches will also be summarized in Canada and the US.

Q6: What are the key knowledge gaps of monitoring technologies that are being addressed in research projects, and which ones are not?

Key knowledge gaps will be identified as follows considering the findings of the project:

Based on discussions with PTAC, government and industry experts

Based on the results of documents considered in the literature review

Based on the experience of the SAIT team.

It is expected these gaps will be industry wide although where possible Canadian gaps will be specifically listed.

Q7: List the top 20 organizations involved with monitoring research in Canada

To answer this question, the SAIT team proposes the following criteria by which to rank the "top 20" organizations:

Funding organizations, by money spent, including enabling organizations like PTAC

Research executing organizations, by money spent

The team will work with PTAC to fine-tune the criteria, such as the estimation of in-kind contributions to research funding. Should other research criteria be preferred by PTAC (e.g., number of papers published), or other criteria altogether (e.g., annual sales of methane monitoring services), these will be incorporated into the ranking.

C. PROJECT RESULTS AND KEY LEARNINGS

Please provide a narrative describing the key results using the project's milestones as sub-headings.

- Describe the project learnings and importance of those learnings within the project scope. Use milestones as headings, if appropriate.
- Describe the importance of the key results.
- Include a discussion of the project specific metrics and variances between expected and actual performance.
- IF APPLICABLE, discuss the broader impacts of the learnings to the industry and beyond; this may include changes to regulations, policies, and approval and permitting processes

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Measurement Technologies Used in Canada

The purpose of this section is to address the PTAC questions:

- What is the inventory of methane monitoring technology/methodology solutions in Canada?
- How do the different solutions perform? Where is their best application? What are their limitations?

- How do remote sensing monitoring options compare to on site options to continuous monitoring options?

Inventory of Methane Monitoring Technologies

Most methane concentration measurements are made with optical instruments, using either laser spectroscopy or imaging spectrometry. Laser spectroscopy determines the concentration of target molecules by measuring characteristic absorption of a mid- or near-infrared laser along a path length of metres to kilometres. The laser path may be "open," where it goes through the immediate atmosphere, or "closed," using a mirrored cavity into which gas is pumped. Image spectrometers measure spectral densities using pixel-based sensor elements. Imaging spectrometers generate a multi-pixel field of view measurement that captures column-integrated concentrations.

For instruments that quantify concentration data, atmospheric dispersion models (and other approaches) can help determine source location and emission rate. Regulators publish guidance documents mandating what models to apply and how. However, most established techniques were designed and validated for stationary sensing, and it remains unclear how transferrable they are to mobile platforms.

Table 1 summarizes the technologies reviewed as part of this study. Follow report sections describe the technologies and the platforms on which they are mounted in more detail, giving examples of some specific applications that are not to be interpreted as endorsement. To be clear, we are not just considering fugitive emissions but also planned emissions or those inherent in the use of various aspects of industry.

Table 1. Summary of Technologies Inventory

Category	Method	Strengths	Limitations	Spatial Coverage (m)	Temporal Frequency (min)	Limit of Detection (g/h)	Flux Estimation Uncertainty (%)	Technology Readiness Level for LDAR	No. of Commercial Systems in Use
Handheld Devices	Method 21	▪ Approved by regulators. Well accepted method across North America. Highly sensitive.	▪ Limited to close-range monitoring. Extremely labour-intensive.	0	240 – 960	<1	–	High	20+
	Optical Gas Imaging Camera's	▪ Current "Status-quo" for methane monitoring. Approved by regulators. High spatial and spectral resolution. Does not rely on external sources for wind measurements. Can be used for continuous monitoring.	▪ Accuracy dependant on ambient temperature and wind speed. Limited to small scale monitoring.	3 – 6	120 – 480	20	3 – 15	High	20+
Ground-based Monitoring	Flux Chambers	▪ High certainty of emission estimation, operates independent of atmospheric modelling, and 24-hour operation capabilities.	▪ Limited to small scales monitoring, heavily reliant on well-developed sampling schemes, experiences bias from chamber artifacts, and has difficulty capturing sporadic emissions as it cannot be used for continuous monitoring but not many technologies available.	<1	30 – 90	<1	9.5	High	20+
	Perimeter Sensors	▪ Well suited for facilities with high component density. Operates continuously. Can be installed to cover large monitoring areas.	▪ Installation & maintenance is a labour-intensive process. Accuracy dependant on ambient temperature and wind speed. Can be disrupting to operators on site.	0 – 1,000	–	96	31	Moderate	20+
	Mobile Ground Laboratory's	▪ Ability to conduct local-to-regional-scale surveys. Can have a very high sensitivity. Less time spent conducting the survey.	▪ Limited by road and site access. Have greater uncertainties. Cannot detect elevated sources. Can underestimate small sources. Accuracy dependant on ambient temperature and wind speed.	5 – 500	0.5 – 5	6 – 2,124	5 – 350	Moderate	10+
	Eddy Covariance	▪ Largest ground-based scale of atmospheric sampling. Ideal for capturing temporal trends. Measures uptake as well as loss.	▪ Requires consistent & stable atmospheric conditions for accuracy. Requires an extremely rapid-response sampling device.	100 – 2,000	<1	–	18 – 22	Moderate	–
	Air Mass-Balance	▪ Low uncertainty in estimating stationary plume sources. Provides ideal, detailed modelling of regional emissions. Used for validation of both ground-based and satellite methods.	▪ Requires high quantity of samples from known sources. Limited by boundary layer height. Issues with external sources, shifting plumes, and widely dispersed ground sources. Dependent on good extrapolation from lowest flight path to the ground.	–	–	–	2 – 60	Moderate	–
	Inverse Dispersion Modelling	▪ Robust method robust that is more accurate than chamber or tracer methods. Can be used to quantify temporal trends.	▪ Larger errors can occur from inconsistent wind and mobile plume sources. Difficult to quantify and isolate complex sources. ▪ Reliant on externally modelled atmospheric conditions that may not match sampling conditions.	–	30	–	–	Moderate	–
UVA's / Aircraft	LiDAR	▪ Can be used to quickly characterize and capture unknown emissions from a region. Under ideal conditions can obtain a low uncertainty.	▪ Aircraft vibration can create discrepancies in the data. Dependent on accurate geolocation and wind speed data.	0 – 1,000	5 – 30	2,000 – 4.6x10^{3}	1 – 24	Moderate	20+
	Optical Gas Imaging Spectrometers Atmospheric Sensor	▪ Quick sampling. Best for surveying large areas. Can identify unknown sources. Avoids temporal issues inherent to mass-balance methods.	▪ Limited by meteorological conditions. Requires multiple samples to determine persistence of a source. Unable to perform continuous monitoring.	0 – 1,000	5 – 30	2,000 – 5,000	30 – 40	Moderate	20+
Satellites	Optical Gas Imaging Spectrometers Atmospheric Sensor Thermal Infrared LiDAR	▪ Used frequently to perform reliable samples of global and regional emissions. Site access not needed to perform sampling.	▪ Currently has low spatial resolution. Restricted by spectral interference. Difficulty sampling dark scenes with low contrast, or high reflectance scenes such as snow or water.	500,000 – 800,000+	<0.01	20 – 8,800	–	Low	1

Monitoring Approaches in the United States

The purpose of this section is to address the PTAC question: How do Canadian based monitoring technologies or processes compare to the US?.

Like the monitoring approaches used in Canada, methane emitters in the United States rely on ground-based, airborne, and/or spaceborne sensing modalities, as well as several emissions estimation methods. Some facilities choose to employ a combination of these sensing modalities and emissions estimation techniques to capitalise on the advantages of the different technologies. In recent years, there have been extensive efforts from academics and industry researchers to evaluate new technologies and solutions that are currently being used for methane monitoring and mitigation. The following section will summarize the recent evaluation studies (most relevant to the scope of this report) and their results.

A recent field campaign used multiscale methods to measure methane emissions from 38 oil and gas facilities across the Marcellus, Haynesville, and Permian basins in the United States (Wang, et al., 2022). The multiscale measurement approach followed a quantification, monitoring, reporting, and verification protocol (QMRV project). The project consisted of three phases which included baseline emissions measurements using multiscale methods, enhanced monitoring using continuous emissions monitoring systems (CEMS), followed by end-of-project aerial snapshot measurements. The snapshot measurements included an OGI camera paired with a Hi-Flow Sampler to measure component-level emissions, as well as SeekOps Inc.'s drone-based mass balance technology and Bridger Photonics' aerial LiDAR plume identification system to measure equipment-level emissions. GHGSat also conducted satellite measurements concurrently when weather conditions were favourable. The site-level measurements (estimated from equipment-level measurements) from SeekOps and Bridger were used to develop measurement-informed inventory (MII) estimates. This work chose not to include OGI measurements in the MII estimates since they are known to miss emissions (including engine slip) which leads to underestimated site-level emissions.

Based on these findings, the authors recommended guidelines for measurement protocols that would help accurately capture methane emissions estimates and inform mitigation strategies. The guidelines developed by the researchers included the following:

- Snapshot measurements are essential to quantify all methane sources at the equipment- and site-level and to reconcile measurements with inventory estimates. Measurement-based inventories can be created using site-level estimates only, but equipment-level data can help reconcile measurements with inventory estimates with the final goal of providing data to develop mitigation strategies.

- The use of high sampling rate technologies like CEMS is necessary for the development of distributions of the frequency and duration of intermittent emission events. Pairing with an understanding of facility-level events is important to accurate accounting of short-duration, episodic, and high-volume events that can be missed in snapshot surveys.

- Detailed record-keeping of one-time events, malfunctions, and maintenance activities can reconcile measurements with engineering calculations-based inventory estimates. This will enable a correlation of emissions with specific work practices which helps with the development of suitable mitigation strategies.

- Measurements and quantified emissions (alongside operational data) should be independently verified using peer-reviewed approaches to enable public trust. The verification should go beyond checklists of operator actions and involve academic experts who can provide independent evaluations of all relevant data.

Researchers from The University of Texas at Austin, ExxonMobil, Aerodyne Research Inc. and SeekOps investigated the utility of short duration methane measurements in predicting longer term emission estimates using models that account for intermittency in emissions (Tullos, et al., 2021). The study – which was conducted in an East Texas dry gas producing region – used a drone-mounted miniaturized tunable diode laser absorption spectrometer (TLDAS) that detects methane at a high time resolution (<0.2 s) and with high precision (10 ppb), as well as a vehicle equipped with quantum cascade tunable infrared laser differential absorption spectrometer (QC-TILDAS, time resolution of 1 s) as a downwind tracer measurement method. Their work demonstrated that sets of short-duration measurements can be useful if distributions of emissions at multiple sites (rather than measurements at individual sites) are compared. Additionally, with the help of a model that accounts for intermittency in emissions (Tullos, et al., 2021), the findings showed that short-duration measurements made at the equipment-level can be extrapolated to accurately estimate longer-term site-level emissions.

Another study led by researchers from The University of Texas at Austin and various industry partners (ExxonMobil, Scientific Aviation, SeekOps) was conducted in the Permian Basin in west Texas, and found that aircraft systems differed in their estimates of total emissions from the ensembles of sampled sites, and in the percentage of sites with emissions greater than 10 kg/hr (Stokes, et al., 2022). They conducted aircraft surveys using Bridger's Gas Mapping LiDAR and Scientific Aviation's Picarro CRDS and using Seek-Ops' drone system (TDLAS) as an independent measurement method to verify the distribution of emission rates for sites with low emissions (<10 kg/hr). Similar conclusions were drawn from the studies conducted in East Texas (Tullos, et al., 2021) and this study in West Texas in that emission rates that were less than 10 kg/hr could be reasonably represented through engineering estimates which employed either region-specific or national emission factors.

Recent work from researchers at the University of Colorado Boulder, the National Oceanic and Atmospheric Administration (NOAA) Earth System Research Laboratory, and Scientific Aviation, highlighted the importance of sustained, co-ordinated measurements of methane (e.g., ground-based measurement techniques) alongside snapshot observations by satellites (Pétron, et al., 2020). The work was inspired by the 2014 satellite-based measurement of a methane hotspot in the Four Corners region of Arizona, Colorado, New Mexico, and Utah (dubbed the "Four Corners hotspot") which initially gained a lot of traction in the scientific community due to the high methane emissions that significantly exceeded estimations from a widely used GHG database. The follow-up study utilized a combination of ground-based measurements such as the NOAA Mobile Laboratory (containing a Picarro G2301/G2401 CRDS and programmable flask sampling apparatus) and a CU/INSTAAR van equipped with a Picarro G-2132-i CRDS and a 2D anemometer. Up to five instrumented aircrafts (the NOAA Twin Otter, NOAA P-3, and Scientific Aviation Mooney) were equipped with a Picarro G2301 CRDS and an Aerodyne in situ C2H6 analyzer, and some also collected discrete air samples to be analyzed by the flask sampling apparatus. Additionally, two contracted NOAA Twin Otters were equipped with NASA CH4 partial atmospheric column remote sensing instruments AVIRIS-NG and HyTES (Hyperspectral Thermal Emission Spectrometer). The researchers concluded that the anomalously high methane emissions detected by the satellite in 2014 were likely the result of a mixture of local sources and unfavourable meteorology causing accumulated emissions under low winds and during surface temperature inversions which are common from nighttime till mid-morning. The work highlighted the importance of real-time high-resolution methane detection from a combination of vehicles, drones, aircraft, and satellites to help industry detect and repair methane leaks (National Oceanic and Atmospheric Agency, 2020).

Another study led by researchers from Stanford University, University of Michigan, and ExxonMobil focused solely on satellites as a tool for identifying large methane point sources (Sherwin, et al., 2023). They conducted single-blind controlled methane release testing during overpasses of five satellites: GHGSat-C2, WorldView 3 (WV3) instruments, Sentinel-2, Landsat 8, and PRISMA satellites, which (except for GHGSat-C2) were not explicitly designed for methane sensing but have had their data used to measure methane. Five independent teams analyzed the data and reported in compliance with the airplane and satellite systems protocol outlined by the Methane Emissions Technology Evaluation Centre (METEC) . The teams were able to correctly identify 71% of all emissions ranging from 0.2 to 7.2 tonnes per hour. They found that 75% of quantified estimates were within ± 50% of the metered value which is comparable to airplane-based remote sensing technologies. GHGSat's targeted system quantified an emission as low as 0.20 tonnes per hour, while the wide-area Sentinel-2 and Landsat 8 satellites detected emissions as low as 1.4 tonnes per hour.

Alternative Methods of Estimating Emissions

Given the wide variety of technologies currently available for methane monitoring and the continuously developing landscape of new technologies, researchers recognize the importance of evaluating new methane detection technologies in a time-effective manner. Two tools are among the most widely known in evaluating different LDAR programs: Highwood Emissions Management's LDAR-Sim (Highwood Emissions Managment, 2023) and the Sustainable Energy Transitions Laboratory's FEAST (Fugitive Emissions Abatement Simulation Toolkit) model (Kemp & Ravikumar, 2021). The following section describes how the two open-source models have been used to evaluate the performance of next-generation LDAR programs.

LDAR-Sim

This tool managed by Highwood Emissions Management provides predictions of emissions mitigation abilities of different LDAR programs. A recent white paper published by GTI in collaboration with High Emissions Management and prepared for the Environmental Defense Fund evaluated data from handheld, mobile/vehicle based, aerial-based, continuous monitoring (CM), and satellite-based methane measurements (GTI, 2021). LDAR-Sim was used to estimate cost ranges for various programs, and the effectiveness of more frequent measurement surveys. Some of the report's key findings were as follows:

- Identical technologies deployed with different work practices can result in different levels of detection translating into different levels of mitigation. This finding highlighted the need for data and reporting standards to streamline the comparison of emissions data from different technologies.
- Continuous monitoring (CM) sensors had the highest potential for reducing emissions but had higher monitoring costs.
- CM data had great potential for finding long-term emission trends for an individual site, with the caveat that there will be an initial learning curve to determine site operating parameters, sensor placement, and emissions characteristics. This is necessary for each site to properly operationalize data and avoid false-positive notifications.
- Timeseries or histograms of CM data showed highly variable emission rates since emissions are measured across entire sites, necessitating follow-up OGI investigations using ground crews at appropriate times to locate sources of leaks.
- Aircraft-based technologies had the lowest cost per ton for emissions mitigation, but were only able to focus on large, high-value sources thereby mitigating the smallest percentage of emissions.
- Emissions reduction varied based on technologies used, but a sensitive CM sensor combined with aggressive follow-up work practices was found to be the most effective way of identifying and mitigating emissions.

Fugitive Emissions Abatement Simulation Toolkit (FEAST) Model

The US EPA received comments on a November 2021 proposed rule (US EPA, 2022) encouraging the EPA to use publicly available LDAR program effectiveness models (LDAR-Sim or FEAST) to determine a matrix of survey frequencies and detection thresholds that would demonstrate equivalency of alternative screening techniques (e.g., advanced technologies) with the standard fugitive emissions monitoring program. Accordingly, the EPA used the FEAST model to directly compare alternatives to the results of the OGI fugitive emissions program. The FEAST model allows for the modelling of the following LDAR programs: OGI cameras, aerial surveys (equipment- and site-level surveys), drone surveys, continuous monitoring systems, and satellite-based detection.

In their supplemental proposal, the EPA stated that a primary advantage of more frequent screening which used advanced technologies is the prompt identification of large emissions events ("super-emitters"). They used FEAST to conclude that technologies with a minimum detection threshold >30 kg/hr could not be deemed equivalent to their proposed fugitive emissions monitoring and repair program (NSPS OOOOb and e.g., OOOOc) at any screening survey frequency, even when they are coupled with annual OGI ground-based surveys. Thus, they proposed that the alternative periodic screening approach is limited to technologies with a minimum detection threshold less than or equal to 30 kg/hr.

Methane Emission Estimation Tool (MEET)

Recent work from ExxonMobil researchers recognized a limitation in studies utilizing FEAST and LDAR-Sim models in that they have not evaluated combinations of multiple technologies (Cardoso-Saldaña, 2022). This work utilized a model similar in operation to FEAST and LDAR-Sim but based on a leak module of the Methane Emission Estimation Tool (MEET). They ran simulations of combinations of methane detection technologies in a tiered approach for facilities representative of the Permian basin, which is a basin with skewed emission rates and many high emitters. The monitoring technologies included sensors on satellites, aircrafts, continuous monitors, and OGI cameras with varied survey frequencies, detection thresholds, and repair times. They found that strategies which increased the frequency of surveys targeting high emitters while decreasing the frequency of OGI inspections (which usually detect smaller emissions) led to higher reductions than quarterly OGI inspections and can reduce emissions further than monthly OGI inspections in some cases.

Researchers at Colorado State University recently evaluated the performance of continuous emission monitoring solutions under single-blind controlled testing protocols at the Methane Emissions Technology Evaluation Centre (METEC) which is an 8-acre outdoor laboratory in Fort Collins, Colorado (Bell, Ilonze, Duggan, & Zimmerle, 2023). The test protocol focused on evaluating key performance metrics including probability of detection (POD) curves, localization accuracy/precision, and quantification accuracy. This work tested solutions (e.g., sensors, deployment, and data analytics, rather than just sensor technologies) and found that there was large variability in performance between CM solutions, coupled with highly uncertain detection, detection limits, and quantification results indicating that the performance of individual CM solutions must be better understood before their results can be relied on for regulatory reporting or internal emissions mitigations programs. A major conclusion of this work was that stochastic results such as POD curves are a key input to LDAR simulation software such as FEAST and LDAR-Sim and can play a major role in determining the best monitoring and mitigation approaches.

Like the single-blind testing of CM solutions at METEC, researchers also ran single-blind intercomparisons of mobile methane measurement technologies (Ravikumar, et al., 2019). They found that 6 out of 10 of technologies correctly detected over 90% of test scenarios, and all technologies were able to demonstrate pad-level localization of leaks. Table 2 shows the summary of performance of the 9 technologies tested in this mobile monitoring challenge, including information on true- and false-positive detection effectiveness, detection limits, and quantification accuracy. The authors noted that all the systems tested in this work would require secondary inspections to identify leak locations for repair and therefore mobile leak detection technologies can only complement, not substitute, currently used OGI systems.

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Table 2: Summary of performance of the 9 technologies tested in the Stanford/EDF Mobile Monitoring Challenge. Adapted from (Ravikumar, et al., 2019)

Technology	Technology Type	Detection Effectiveness		Detection Limit (leak rate where detection probability is 100%, scfh)	Quantification Accuracy (Measured/Actual, % tests)	
		True Positive (%)	False Positive (%)		0.5 – 2x*	0.1 – 10x*
ABB/ULC Robotics	Drone	77	22	≥8	30	78
Advisian	Drone	94	7	3-5	25	79
Aeris Technologies	Truck	88	15	5-8	38	79
Baker Hughes (GE)	Drone	68	71	≥8	24	54
Ball Aerospace	Plane	76	0	450-600	53	83
Heath Consultants	Truck	93	26	≥8	48	95
Picarro	Drone sampling	92	39	≥8	45	92
Seek Ops Inc.	Drone	100	0	≤1	36	100
U. Calgary (Truck)	Truck	94	60	450-600	18	74

*Note: *Fraction of tests where the measured emission rates are within (a) 0.5–2 times, and (b) 0.1–10 times of the actual emission rate.*

Legislation Supporting Advances in Methane Monitoring and Quantification Approaches

The US EPA reports that the majority (30%) of US methane emissions can be attributed to natural gas and petroleum systems (followed closely by enteric fermentation at 27%) (US EPA, 2023). Consequently, there has been a recent focus on updating and introducing new legislation which will help decrease methane emissions, specifically from the oil and gas sector.

In November 2021, the White House Office of Domestic Climate Policy published the US Methane Emissions Reduction Action Plan which discusses methane emissions reduction from several sectors including the oil and gas sector (The White House Office of Domestic Climate Policy, 2021). The US EPA also published a proposed rule in November 2021 titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" then published an updated Supplemental Proposal in December 2022 to improve standards pertaining to the Clean Air Act in the 2021 proposal, and to add requirements for sources not previously covered (US EPA, 2022). The programs and resources available from the US Inflation Reduction Act are designed to incentivize early implementation of novel methane mitigation technologies and support mitigation and monitoring activities.

The most notable updates in the EPA's Supplemental Proposal allow for owners and operators in methane-emitting facilities to have the flexibility to use advanced methane detection technologies to monitor for fugitive emissions; specifically, the EPA is allowing the use of a broader range of technologies in lieu of OGI or EPA Method 21. Owners and operators would also be allowed to use continuous monitoring technologies that would operate continuously to check for methane leaks. If a facility chooses to use continuous monitoring technologies, they would be required to determine causes for leaks and take corrective actions whenever emissions exceed actionable levels (which is an approach like the fence-line monitoring requirements in the EPA's air toxics rules for petroleum refineries). The proposal also encourages continued development of novel technologies by outlining a streamlined pathway for technology developers and other interested entities to seek approval from the Agency to use advanced technologies for methane monitoring. When the Agency approves a technology and/or technique, owners and operators may use that technology or technique widely without requesting any additional approvals (US EPA, 2022).

An additional notable part of the proposal is the Super Emitter Response Program which aims to reduce the number of super-emitting events by quickly identifying the events for prompt mitigation. The Super-Emitter Response Program would leverage expertise and data from regulatory agencies or EPA-approved third parties that have access to EPA-approved remote methane detection technologies. The program would allow regulatory authorities or qualified third parties to notify owners and operators of regulated facilities when a super emitter is detected (defined as an event releasing >100 kilograms of methane per hour). Once a notification is received, the owner/operator would be required to conduct an analysis determining the cause of the release within 5 days, and to take correction action within 10 days (or more than 10 days for more complicated events, with the requirement of submitting a corrective action plan to the EPA or appropriate state agency). A major difference from previous rules is that the third parties notifying owners/operators of super-emitter events no longer have to be official regulatory entities. They do however have to be approved by the EPA as having appropriate expertise and experience, use EPA-approved remote detection technology, and include specific, required factual information in the notification to document the super-emitting event. The event notifications and owner/operator's response and correction actions taken would be available on a public website. To ensure that the third parties are reliable, the EPA proposed a mechanism for owners/operators to ask the Agency to revoke any notifier's certification if their repeated notifications contained verifiable errors (US EPA, 2022).

Governmental Funding of Emerging Technologies

The US EPA has awarded research grants for small businesses to work on methane quantification (US EPA, 2022). To date they have funded two small businesses working on methane measurement technologies: (1) Censys Technologies Corporation who will develop a Remote Sensing platform to monitor fugitive methane using retroreflector-based Differential Laser Absorption Spectroscopy (DLAS) System on a UAV Pair, and (2) Mesa Photonics LLC which will develop a "rugged, sensitive, and selective" optical methane monitoring technology consisting of a network of sensors. The sensor network will be capable of long-term unattended operation and will allow solar- and battery-powered operation.

Additionally, the Department of Energy announced $32 million in funding towards the research and development of “Innovative Methane Measurement, Monitoring, and Mitigation Technologies (iM4 technologies)” in August 2022, in keeping with the US Methane Emissions Reduction Plan (U.S. Department of Energy, 2021). The funding opportunity is meant for projects that aim to advance networks of surface-based methane sensor technologies that will allow more timely observations of methane leaks across large oil and gas producing basins (FedConnect, 2022) (U.S. Department of Energy, 2022).

Other Efforts in Measurement-based GHG Assessments

In January 2021, a group of researchers from the University of Texas at Austin, Colorado State University, and the Colorado School of Mines, launched the Energy Emissions Modelling and Data Laboratory (EEMDL) with the mission of becoming a global data and analytics hub that supports improved accounting of GHGs including methane across oil and gas supply chains (Energy Emissions Modeling and Data Lab, 2023). Their goals are to (1) develop reliable and peer-reviewed models and tools to enable GHG emissions estimates that are measurement-based, (2) publish timely, high-resolution, measurement-based, and standardized methane emissions datasets across O&G supply chains, and (3) train interested parties in industry, government, and other organizations on the use of EEMDL’s models and tools. Certification programs like OGMP 2.0, MiQ, Project Canary, and GTI Veritas provide frameworks for methane monitoring and reporting; EEMDL aims to develop tools that will be used for emissions reconciliation, developing measurement-informed inventory estimates, or other applications as required by various standards and reporting systems. All models, tools, and datasets developed by the group will be published in peer-reviewed scientific journals, and all information will be publicly available on their website. Their datasets will integrate direct measurements from technologies such as satellites, aerial surveys, CEMS, site-level operational data, and other relevant information. So far, they have published work on multiscale methane measurements at O&G facilities (Wang, et al., 2022).

The Colorado School of Mines has another initiative called the “Responsible Gas Initiative” which is led by the Payne Institute for Public Policy (Colorado School of Mines, 2023). The initiative conducts third-party reviews of data collected from O&G locations of participating companies. They consult with industry to leverage their nuanced understanding of O&G operations. The program advocates for the integration of monitoring data from satellites, aircraft, drones, and continuous monitoring systems to help with the quick identification and resolution of leaks, and to help regulators and communities report and visualize all relevant data. The Colorado School of Mines has another initiative called the “Responsible Gas Initiative” which is led by the Payne Institute for Public Policy (Colorado School of Mines, 2023). The initiative conducts third-party reviews of data collected from O&G locations of participating companies. They consult with industry to leverage their nuanced understanding of O&G operations. The program advocates for the integration of monitoring data from satellites, aircraft, drones, and continuous monitoring systems to help with the quick identification and resolution of leaks, and to help regulators and communities report and visualize all relevant data.

The State of Provincial & Canadian Federal Inventories

This section addresses the PTAC question: What is the state of methane emissions data inventories in BC, AB, SK, and NL. Please compare provincial and federal sources.

Federal

Reduction Goal and Commitment

In Canada's current National Inventory of GHG Emissions (2021), methane makes up approximately 13% of Canada's total GHG emissions inventory, and approximately 21% of the oil and gas sector's total GHG emissions in CO2e. The oil and gas sector accounts for about 40% of Canada's methane emissions, and it is noted that the majority of methane emissions from this sector are from upstream activities (production and field processing of light and heavy crude oils, bitumen, natural gas and natural gas liquids). In general, there are two sources of GHG emissions from oil production: methane emissions released during the extraction of oil, and GHG emissions related to the use of fossil fuels to power and operate facilities. While the focus of this section is on the first source of methane, the reporting of methane from the second category of emissions has historically been closely linked and informed by the general GHG monitoring practices of companies.

In 2016, the Government of Canada committed to a national 40% to 45% methane reduction below 2012 levels by 2025 from oil and gas as Canada's highest GHG emitting sector. This goal was agreed to with the U.S. through the issuing of a Joint Statement on Climate, Energy, and Arctic Leadership (2016). In support of this goal, Canada finalized its methane regulations titled Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (referred to as the Federal Regulations) (Government of Canada, 2018). Under the Regulations, a facility that has a high potential to emit (>60,000 m3 hydrocarbon gas per year), its operator is required to regularly inspect and repair facility equipment to control emissions.

In March 2022, Canada announced a commitment to at least a 75% methane reduction from the sector by 2030, a goal recommended in the International Energy Agency's Net Zero by 2050 roadmap (Government of Canada, 2022). Regulations to support the commitment are expected in 2023.

Equivalency Agreements

Although Canada's commitment to reducing oil and gas methane emissions is at a federal level, several of Canada's provinces have previously regulated methane or required reporting from oil and gas production facilities. As such, the Federal Regulations are intended to work alongside existing and amended provincial regulations.

To increase alignment with provincial governments, Section 10 of the Canadian Environmental Protection Act (CEPA) (1999) authorizes the Canadian Minister of Environment and Climate Change to enter into an equivalency agreement with a province, territory or Aboriginal government if the Minister and government of the other jurisdiction agree (in writing) that they are in force under the laws applicable in that jurisdiction:

- Provisions that are equivalent to a regulation made under CEPA.

- Provisions like sections 17 to 20 of the CEPA, allowing for citizens to request investigation of alleged offences.

The intent of equivalency agreements is to minimize the duplication of environmental regulations between the federal and provincial level. As previously stated, the tracking and quantification of methane at the provincial level has historically been closely linked to the general GHG monitoring practices required by provincial regulations. In 2020, the Government of Canada announced finalized equivalency agreements regarding provincial methane regulations as meeting equivalent emissions-reduction outcomes to the federal regulations for the following provinces:

- British Columbia
- Alberta
- Saskatchewan

These agreements allow the provincial methane regulations to replace the federal regulations for up to 5 years.

Emissions Reporting

For industrial facilities that emit 10,000 tonnes CO2e per year, they are required to submit a report under the federal Canadian Greenhouse Gas Reporting Program (GHGRP) for quantification. As of the 2022 calendar year, these data must be reported by facilities separate from the provincial greenhouse gas reports. This inventory helps assess Canada's overall environmental performance through accurate tracking of GHG emissions.

The Greenhouse Gas Quantification Requirements (2022) state specific recommendations pertaining to several industries and emission source categories (Fuel Combustion and Flaring; Carbon Capture, Transport and Storage; Petroleum Refining, etc.). In general, the quantification of fugitive emissions for the oil and gas industry are recommended to be quantified using process or equipment-specific methane composition data using AP-42, or methods specified in the Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (A.P.I. 2009) in which equipment emission factors are used. However, it is not made explicitly clear in Canada's Greenhouse Gas Quantification Requirements (2022) what methodology should be used to quantify venting and fugitive emissions from oil and gas production.

The Government of Canada also introduced the Output-Based Pricing System (OBPS) Regulations (2019), which is separate from the GHGRP but aligned in terms of reporting criteria. The OBPS is designed to put a price on the carbon pollution of industrial facilities that emit a minimum of 50,000 tCO2e / year and set an emissions limit for each facility subject to the OBPS. Like the GHGRP, it is not made explicitly clear in Schedule 3, Part 1 of the OBPS what methodology should be used to quantify venting and fugitive emissions from bitumen and other crude oil production.

The Federal Regulations (2018) favours a bottom-up approach to quantifying fugitive emissions, in which source-specific estimates are required and reported.

Emission Source Categories

To fulfill Canada's methane reduction commitment, the Federal Regulations were enforced to specifically reduce methane emissions from upstream oil and gas facilities and the following sources in Table 3:

Table 3: Federal Regulations for Methane Reduction

Emission Source	Detail	Effective Date	Limits / Requirements
Fugitive (leaks)	■ Implementation to stop natural gas leaks	■ January 1, 2020	■ LDAR Program, with inspections for leaks three times per year and corrective action when leaks are found
Venting from Compressors	■ Centrifugal compressors	■ Compressor installed after January 1, 2023	■ Flow rate limit of 0.14 m^3 / min
	■ Reciprocating Compressors	■ Compressor installed after January 1, 2023	■ Product of 0.001 m^3 / min and number of pressurized cylinders compressor has
Venting from Well Completions Involving Hydraulic Fracturing	■ Conservation of natural gas for re-use on site or for sale, or flaring / clean incineration of natural gas	■ January 1, 2023	■ No venting
General Facility Production Venting	■ Conservation of natural gas for re-use on site or for sale, or flaring / clean incineration of natural gas	■ January 1, 2022	■ Venting limit of 15,000 standard m^3 of hydrocarbon gas / year
Venting from Pneumatic Devices	■ Conservation of natural gas for re-use on site or for sale, or replacement with non-emitting or low-bleed pneumatic device	■ January 1, 2021	■ Venting limit of 0.17 m^3 / hr of natural gas / year for pneumatic controllers

These emission sources were identified as having a higher potential to emit methane and as a result emissions limits were introduced depending on when the compressor was installed. As such, individual facility methane emissions inventories in Canada are mainly correlated to the monitoring and reporting of emissions from these categories as the largest fraction of total methane emissions. Further delineation on a provincial basis will align with the focus on these emission source categories.

British Columbia

Emissions Regulation

In 2018, the British Columbia (BC) Oil and Gas Commission (OGC) approved amendments to the Drilling and Production Regulation (DPR, or the BC Regulations) to manage methane emissions from the oil and gas sector. These standards contain control measures to reduce fugitive and methane emissions from the upstream oil and gas sector and align with the Federal Regulations with additional standards for glycol dehydrators.

While the BC Regulations require a lower leak detection frequency at some facility types compared to the Federal Regulations, these standards apply to a greater number of facilities in BC Under Section 41.1 of the BC Regulations (amended in 2020), a facility permit holder who operates a facility must carry out the following surveys of the facility, including any pneumatic devices at the facility:

Three comprehensive surveys per year, if the facility is

1. A gas processing plant,

- A compressor station,
- A multi-well battery, or
- A single-well battery that includes a controlled storage tank.

2. One comprehensive survey per year, if the facility is

- A custom treating facility,
- An injection and disposal facility,
- A single-well battery not described in paragraph (a) (iv), or
- A facility that includes a storage tank, other than a facility described in paragraph (a).

A similar requirement is in place for a well permit holder who operates a well who must complete one comprehensive survey per year if the well has a storage tank or is producing from an unconventional zone. Surveys are typically performed using optical gas imaging cameras used by trained inspectors. The use of advanced ground, aerial and satellite technology is not commonly utilized in BC at this time, although recently airborne technology has been used to quantify emissions from facilities (Tyner & Johnson, 2021).

The Federal Regulations state that an upstream oil and gas facility must not vent more than 15,000 sm3 of hydrocarbon gas during a year. In comparison, the BC Flaring and Venting Reduction Guideline (2022) released separate vent gas source limits and requirements for different equipment with different limits depending on when facilities began operation. This includes the following emission and equipment sources, with the most recent effective dates stated as examples (Table 4):

Tank-related emissions typically make up the largest fraction (almost 2/3) of total venting and fugitive emissions (Ravikumar, et al., 2020) .As a result of this focus by the BC Regulations, there will be higher scrutiny and associated detail related to this part of the methane emissions inventories.

Emissions Reporting

BC facilities that emit 10,000 tonnes or more of carbon dioxide equivalent (CO2e) per year – and those that have emitted more than 10,000 tonnes in any of the previous three years – must report their greenhouse gas emissions annually. The Government of BC utilizes the Western Climate Initiative (WCI) Methodology (2013) to monitor and quantify these emissions for industrial facilities.

Table 4: B.C. Regulations for Methane Reduction

Emission source	Detail	Effective Date	Vent Limits / Requirements
Storage Tank Venting	▪ Tanks at facilities that began operations before January 1, 2022	▪ January 1, 2023	▪ Less than 9000 m^3/month ▪ (All tanks combined)
Reciprocating Compressors Seal (RCs) Venting	▪ RCs with fewer than four throws regardless of the installation date	▪ January 1, 2022	▪ Less than 5 m^3/hr/throw for each compressor in the fleet.
Centrifugal Compressor Seal Venting	▪ Centrifugal compressors installed before January 1, 2021, that have an engine rated 75 kw or more; or operate for 450 hours or more per year	▪ January 1, 2022	▪ Less than 10.2 m^3/hr per compressor
Pneumatic Devices	▪ Facilities that began operation before January 1, 2022, other than gas processing plants or large compressor stations	▪ January 1, 2022	▪ No natural gas venting, unless: – pneumatic vent rate < 0.17 m^3 / hour per device or – a professional engineer signs a statement that the device is required for safe operation of the facility and it is not practical to replace the device to meet vent limit, venting is minimized, and device is tagged
Pneumatic Pumps	▪ Pumps installed on or after January 1, 2021 or operating more than 750 hours per year	▪ January 1, 2021	▪ Zero natural gas venting.
Pneumatic Starters	▪ Natural gas operated pneumatic starters at facilities with conservation equipment or flare system to which starter vent gas cannot be routed	▪ January 1, 2022	▪ Maintain a record of description of starter and, ▪ Maintain a record for each calendar month: – Volume of gas used in start attempts – Number of hours starter is operated – Volume of gas emitted

Under WCI.360 Petroleum and Natural Gas Production and Gas Processing, methane is required to be quantified and reported from several emission source types (including storage tanks, natural gas pneumatic continuous high bleed device venting, associated gas venting and flaring, centrifugal and reciprocating compressor venting, well testing venting, etc.). These quantification methodologies typically require a count of the applicable devices or pumps, which are then multiplied by appropriate population emission factors for the specific device.

Historically, facilities in BC have typically taken a bottom-up approach to estimate emissions based on equipment component count surveys and the Clearstone Estimation of Air Emissions Manual (2021) (referred to as the Clearstone Manual) for emission factors. The transition to optical imaging cameras has become widespread in the past few years based on the regulatory requirements of an LDAR program.

Although facility permit holders are required to carry out leak detection and repair surveys on a regular basis, the transition of using these surveys to quantify fugitive and venting emissions into inventories for the purposes of GHG emissions reporting has not been fully completed based on the BC emission reporting regulation not specifying this method to be used.

Alberta

Emissions Regulation

In December 2018, the Alberta Energy Regulator (AER) made amendments to Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting Directive (D060) and Directive 017: Measurement Requirements for Oil and Gas Operations (D017) (Government of Alberta, 2022). These amendments put in place requirements for methane emissions reductions, which are incorporated by reference in the Methane Emission Reductions Regulation (MEER) (Government of Alberta, 2018). The AER has also released Manual 016: How to Develop a Fugitive Emissions Management Program (Government of Alberta, 2020) for further reference on best practices for managing fugitive emissions. Together, these documents will be referred to as the Alberta Regulations). Control measures were introduced to the Alberta Regulations to reduce fugitive and venting emissions of methane from the upstream oil and gas sector.

Compared to the Federal Regulations, the Alberta Regulations contain more stringent requirements for pneumatic controllers and introduce specific requirements and vent limits for glycol dehydrators. However, the Alberta Regulations allow for a lower leak detection survey frequency at certain facility types and contains less stringent routine venting and pneumatic pump requirements. Under Table 4 of Directive 060, the duty holder must carry out the following surveys of the facility:

- Three comprehensive surveys per year, if the facility is one of the following:
  - Sweet gas plants
  - Compressor stations (<0.01 mol/kmol H_2S in inlet stream)
  - Liquid hydrocarbon storage tanks with vent gas control
  - Produced water storage tanks with vent gas control
- One comprehensive survey per year, if the facility is one of the following:
  - Sour gas plants
  - Straddle and fractionation plants
  - Compressor stations (>0.01 mol/kmol H_2S in inlet stream)
  - Battery and associated satellite facilities
  - Custom treating facilities
  - Terminals
  - Injection/disposal facilities

Directive 060 includes the requirements for surveys to include equipment components with hydrocarbon throughput, hydrocarbon gas-drive pneumatic devices, tank-top equipment (including thief hatches and gauge-board assemblies), surface casing vents, equipment used to destroy and conserve vent gas. Directive 060 further defines a 'component' as "a piece of equipment that has the potential to release hydrocarbons", along with a list that includes the following:

- Valves
- Connectors
- Pump seals
- Actuator seals
- Flow meters
- Pressure regulators
- Sampling connections
- Instrument fittings
- Engine and compressor crankcase vents
- Sump and drain-tank vents and covers
- Blowdown system vents
- Open-ended valves and lines
- Pressure vacuum relief valves
- Gauge-board assemblies

The Alberta Regulations are the only standards (compared to the Federal, BC, Saskatchewan, and Newfoundland and Labrador) that specifically define which equipment falls under components to be inspected for leaks. In comparison, the Federal Regulations define an 'equipment component' as "a component of equipment at an upstream oil and gas facility that comes into contact with hydrocarbons and that has the potential to emit fugitive emissions of hydrocarbon gas."

The Federal Regulations state that an upstream oil and gas facility must not vent more than 15,000 sm3 of hydrocarbon gas during a year. In comparison, Directive 060 released separate vent gas source limits and requirements for different equipment with different limits depending on when facilities began operation. This includes the following emission sources, with the most recent effective dates stated as examples (Table 5).

Emissions Reporting

As Canada's largest oil and gas producing province, Alberta has the relatively most documented emissions estimation and documentation regulations. The AER uses two systems for reporting methane emissions – Petrinex and OneStop. Petrinex is used by both Alberta and Saskatchewan for the management of data of record information essential to the operation of the petroleum sector, including venting and fugitive methane emissions. Based on the scrutiny of review by the AER and public access of the data reported, Petrinex is often referred to as the source of truth for production and methane data. Under Directive 060, duty holders are required to have a documented fugitive emissions management program (FEMP) designed to reduce and manage fugitive emissions. This plan includes preventative maintenance practices to reduce or prevent fugitive emissions and is used to meet the required frequency of fugitive emission surveys and screenings as set out in Directive 060. This plan also details the techniques, equipment used for the surveys, calibration methods, data management practices, etc.

Table 5: Alberta Regulations for Methane Reduction

Emission source	Detail	Vent Limits / Requirements
Overall Vent Gas	■ All routine and nonroutine vent gas	■ Less than 15,000 m^3 vent gas / month or 9,000 kg methane / month
Defined Vent Gas	■ Routine venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators	■ Less than 3,000 m^3 vent gas / month or 1,800 kg methane / month
Crude Bitumen Batteries	■ Crude bitumen fleet, facilities with non-zero production or vent volumes reported to facility IDs	■ Less than an average vent gas rate of 1,500 m^3 vent gas / month per facility ID
Pneumatic Devices	■ Duty holder must prevent or control vent gas from pneumatic instruments installed on or after January 1, 2022. ■ Duty holder must ensure that pneumatic pumps installed on or after January 1, 2022, that operate more than 750 hrs / year do not emit vent gas.	■ No natural gas venting, unless: ■ pneumatic vent rate < 0.17 m^3 / hour per device and manufacturer-specified steady-state vent gas rate
Centrifugal Compressor Seals	■ Applies to seals rated 75 kW or more and pressurized for at least 450 hrs / calendar year	■ Must limit vent gas from RCS fleet to less than 3.40 m^3/hr/compressor
Reciprocating Compressor Seals (RCS)	■ Applies to seals rated 75 kW or more and pressurized for at least 450 hrs / calendar year	■ Must limit vent gas from RCS fleet to less than 0.35 m^3/hr/throw
Glycol Dehydrators	■ Natural gas operated pneumatic starters at facilities with conservation equipment or flare system to which starter vent gas cannot be routed	■ Must limit methane emissions from each glycol dehydrator installed to less than 68 kg methane / day

Leak detection surveys are typically performed using optical gas imaging cameras used by trained inspectors. Historically, facilities in Alberta have typically taken a bottom-up approach to estimate emissions based on equipment component count surveys and the Clearstone Manual (2021) for emission factors. The AER has carried out remote sensing pilots and implemented satellite and aircraft approaches to screen and detect large leaks from diffuse or point sources from orbit and aircraft surveys, however this is not commonly undertaken.

In addition to reporting methane emissions to the AER, facilities in Alberta are required to report to Alberta Environment and Parks (AEP) under the Technology Innovation and Emissions Reduction (TIER) Regulation if they emit 100,000 tCO_2e on annual basis, along with a minimum opt-in threshold of 2,000 tCO_2e. The guidance document Standard for Completing Greenhouse Gas Compliance and Forecasting Reports (2023) includes examples of maintenance, leak detection and repair programs to help reduce fugitive emissions, along with the option to use component count surveys and equipment emission factors to calculate these emissions.

AEP has also introduced the TIER Aggregate Application, which allows for conventional oil and gas facilities that emit less than 100,000 tonnes of CO_2e per year and share a common person responsible to create a combined aggregate facility under TIER. This aggregate facility is then subject to an emissions reduction obligation as well as reporting and compliance requirements under TIER. However, under TIER, aggregate facilities' regulated emissions only include stationary fuel combustion emissions and total production for benchmarking applications and annual compliance reports. As such, any facilities that are not opted-in to TIER will report under the Federal OBPS regulations and have methane venting and fugitive emissions inventories that are relatively less granular based on these requirements.

Based on alignment with the AER reporting, most companies have transitioned to using their FEMP and LDAR surveys to quantify their GHG emissions for regulatory reporting under TIER.

Saskatchewan

Emissions Regulation

In January 2020, the Government of Saskatchewan enacted The Oil and Gas Emissions Management Regulations (OGEMR) (Government of Saskatchewan, 2020), which apply company-level GHG emissions intensity limits to venting and flaring emissions from oil facilities. In addition, the Government of Saskatchewan published Directive PNG036: Venting and Flaring Requirements (Directive PNG036) (Government of Saskatchewan, 2022) to provide venting limits on facilities, and requirements for companies to implement an LDAR program for gas facilities. The Government of Saskatchewan also published Directive PNG017: Measurement Requirements for Oil and Gas Operations (Directive PNG017) (Government of Saskatchewan, 2022) for the purposes of consolidating, clarify and update requirements for facilities for how fuel gas, vent gas, and flare gas volumes are measured for accounting and reporting purposes. Together, these documents will be referred to as the Saskatchewan Regulations.

Compared to the Federal Regulations, the Saskatchewan Regulations allow a lower leak detection frequency at facility types and contains less stringent routine venting and pneumatic pump requirements. Under Section 8.1 of Directive PNG036 (Government of Saskatchewan, 2022), applicable gas facilities that are expected to produce or receive a combined volume of more than 60,000 m3 of gas annually must complete the following:

- At least two surveys per year, if the facility is one of the following:
    - Single-Well Gas Batteries
    - Multi-Well Gas Batteries
    - Sweet Gas Plants
    - Sour Gas Plants
    - Straddle and Fractionation Plants
    - Gas Gathering Systems

The Saskatchewan Regulations has a similar definition of an 'equipment component' to the Federal Regulations: "A component of equipment that comes into contact with hydrocarbons and that has the potential to emit fugitive emissions". In comparison, the Federal Regulations defines an 'equipment component' as "a component of equipment at an upstream oil and gas facility that comes into contact with hydrocarbons and that has the potential to emit fugitive emissions of hydrocarbon gas."

While there is not a comprehensive list of equipment components that should be included in fugitive surveys, an example table in Guideline PNG035, Appendix 3 (Government of Saskatchewan, 2019) was included for different component types for fugitive emissions. This includes the following:

- Valve
- Flange
- Connector
- Open-ended line
- Pressure relief valve
- Pump seal
- Pump
- Agitator seal

However, as these are only sample calculations for hypothetical examples to walk through how vented gas would be estimated and reported, this list of components is not enforced or required by the Saskatchewan Regulations. Instead, gas venting calculations are included by equipment type, including the following:

- Storage Tank Venting
- Hydrocarbon Liquid Loading Losses
- Online Gas Analyzer Purge Vents
- Solid Desiccant Dehydrators
- Pig Trap Openings and Purges
- Pneumatic Devices
- Reciprocating and Centrifugal Compressors
- Glycol Dehydrators
- Blowdowns
- Well Testing, Completions and Workovers
- Well Venting for Liquids Unloading
- Engine or Turbine Starts
- Other Vent Gas Sources
- Determining Fugitive Emission Volumes

Based on the Saskatchewan Regulations, the only venting limit stated is an Associated Gas Venting Limit, in which oil wells and oil facilities that vent and flare a combined volume of gas greater than 900 m3 / day must flare all non-conserved volumes of gas unless the gas is vented to avoid serious risk to human health or safety arising from an emergency. Compared to other provincial emissions regulations, there is no stated vent gas limits for facilities or individual emission sources.

Emissions Reporting

Like Alberta, Saskatchewan uses Petrinex for the management of data of record information essential to the operation of the petroleum sector, including venting and fugitive methane emissions. As per Directive PNG032: Volumetric, Valuation and Infrastructure Reporting in Petrinex, an operator must report the volume of gas vented during well or facility operations, including the well identifier or facility ID (Government of Saskatchewan., 2018). This includes fugitive emissions, which are defined in Directive PNG017 as an "unintentional release of hydrocarbons to the atmosphere". Based on the scrutiny of review by the energy regulator and public access of the data reported, Petrinex is referred to as the source of truth for these data.

Under Directive PNG036 (Government of Saskatchewan, 2022), duty holders are required to have a documented LDAR program for the purposes of limiting leaks from equipment components. This plan includes preventative maintenance practices to reduce or prevent fugitive emissions and is used to meet the required frequency of fugitive emission surveys and screenings as set out in Alberta Directive 060. This plan also details the techniques, equipment used for the surveys, calibration methods, data management practices, etc. These surveys are submitted separately through IRIS for both facility-level information for facilities at which leaks were not found, as well as specific equipment-level information when leaks were found.

The Saskatchewan Regulations for mandatory methane emissions reduction requirements are stated to be results-based at the company level, and not prescribed for individual facilities or pieces of equipment. The intent was stated to allow companies the ability to be able to plan their emissions reduction across all facilities to achieve the most cost-effective approach.

Under the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations (Government of Saskatchewan, 2018), a person who emits greenhouse gasses from an industrial facility more than 10,000 tCO2e each year is required to provide an annual compliance report to the Government of Saskatchewan. This includes all direct emissions source categories (stationary fuel combustion, venting, flaring, leakage, etc.). The recommended provincial standard to quantify venting and fugitive emissions is the same regulation as used to report venting and fugitive emissions to Petrinex, Guideline PNG035 (Government of Saskatchewan, 2019). It is noted that a bottom-up approach is recommended by Guideline PNG035 (Government of Saskatchewan, 2019) for the quantification of fugitive emissions, either through the direct measurement of the whole facility using a gas imaging infrared camera or through quantifying volumes using leak rates or from engineering estimates.

Like the Alberta Regulations, Saskatchewan has a separate standard allowing for Upstream Oil and Gas Aggregate facilities, in which case aggregate facilities may be formed and reported under if there are at least two individual facilities operated by the same operator with regulated emissions less than 25,000 tCO2e in the prior year. However, like the Alberta Regulations, aggregate facilities' regulated emissions only include stationary fuel combustion for annual compliance reports. As such, any facilities that are not regulated under the Saskatchewan Regulations will report under the Federal OBPS regulations and have methane venting and fugitive emissions inventories that are relatively less granular based on these requirements.

Newfoundland and Labrador

Emissions Regulation

Compared to the previously discussed provinces, Newfoundland and Labrador does not have an equivalency agreement with the Government of Canada in accordance with a methane emissions reduction target. Instead, the federal government of Canada and the provincial government of Newfoundland and Labrador jointly regulate oil production off the coast under the Canada-Newfoundland and Labrador Atlantic Accord Implementation Act. This rule applies to these facilities and is in tandem with the Management of Greenhouse Gas Act (Government of Newfoundland and Labrador, 2018) from the Government of Newfoundland and Labrador. The provincial government of Newfoundland and Labrador has committed to interim targets to achieve a reduction of 10% from 1990 GHG emission levels by 2020, and a 30% reduction from 2005 levels by 2030. In 2020, the Newfoundland and Labrador offshore upstream oil and gas production accounted for 16% of the province's GHG emissions total, and 1% of Canada's upstream oil and gas sector emissions. Based on this lower contribution relative to other provinces, it is expected that the methane emissions inventories for these facilities will be less detailed.

Emissions Reporting

Industrial facilities in Newfoundland and Labrador that emit a minimum of 15,000 tCO2e on an annual basis are required to quantify and report GHG emissions for the facility under the Management of Greenhouse Gas Act (Government of Newfoundland and Labrador, 2018). The associated Management of Greenhouse Gas Reporting Regulations (Government of Newfoundland and Labrador, 2017) state the regulations apply to industrial facilities that generate emissions from petroleum and natural gas production and natural gas processing. Like BC, Newfoundland and Labrador refer to the WCI reporting protocol (2013) for the quantification of GHG emissions from this emission source category. However, in the provincial Guidance Document for Reporting Greenhouse Gas Emissions for Large Industry in Newfoundland and Labrador, the relevant emission source category of petroleum and natural gas production (WCI.360) is not referenced.

Based on a report by the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB), several case studies were performed to describe work that has been undertaken in the oil and gas industry in the Canada-Newfoundland and Labrador Offshore Area to reduce GHG emissions and reach net zero (Canada-Newfoundland and Labrador Offshore Petroleum Board, 2022, 2023). As a result of this report, the status and further references for operator's methane emissions inventories can be better known. Of the six producers contacted for this report, one has implemented a FEMP in line with their corporate practices, and two utilize LDAR programs. The two producers who use LDAR programs utilize OGI to identify and mitigate fugitive emissions. In general, methane emissions from natural gas production outside of industrial facilities are not specifically required to be reported provincially, and so it is expected that provincial methane emissions inventories are relatively less detailed compared to other provinces.

Comparison Summary

The federal government of Canada and provincial governments adopt a bottom-up approach to quantifying methane emissions from fugitive and venting sources. This approach has historically involved compiling an inventory of equipment and quantifying the associated emissions for that equipment using engineering estimates and emission factors, although the use of OGI cameras in an LDAR program has become a regulatory requirement for oil and gas facilities over the past few years. This is aligned with the present United Nations Framework Convention on Climate Change (UNFCCC) reporting guidelines, which require the reporting of source-specific estimates. However, the government of Canada recognizes the usefulness of top-down studies as a comparative tool to determine discrepancies in bottom-up approaches and identify super-emitters, where a small number of facilities contribute a disproportionately high percentage of total emissions due to abnormal conditions. The government of Canada is currently supporting several opportunities to advance the use of measurements and modelling to improve the quantification of methane emissions, including the practicality of top-down estimates through aerial measurements and satellite technology.

In general, the state of facility methane emissions inventories is primarily influenced by the requirements of the applicable reporting regulations. Emissions inventories are maintained specifically for the purposes of reporting (either voluntary corporate reporting or regulatory), and inventories are therefore optimized along with methane emissions calculated to meet be cost-efficient and typically meet the minimum emissions reporting standards. While the equivalency agreements formed between the federal government of Canada and the provincial governments of BC, Alberta, and Saskatchewan show that the general methane quantification and reporting regulations are similar and can be considered equal, there are still slight differences in specific requirements. The most impactful differentiations include the regulatory requirement of a LDAR program or FEMP and further delineation of required leak detection monitoring frequency and survey quantification requirements (Table 6).

The Federal Regulations have the most stringent leak monitoring frequency requirements with at least three inspections per year regardless of facility type. The BC and Alberta Regulations are alike in this requirement, with facilities that require three surveys per year and only one survey for certain facility types. One difference noted is the further delineation in Alberta's Directive 060 for differences between sweet and sour gas plants and compressor stations with differences in H_2S concentration in the inlet stream. The Saskatchewan regulatory requirements are midway among the BC, Alberta and Federal Regulations, with two required surveys for all facility types. Leak repair timelines are similar among the provincial regulations and Federal Regulations, within 30 days of detection or during the next turnaround if the repair requires the facility to be shut down.

Priority emission source categories and venting limits have been stated for the Federal, Alberta, and BC Regulations, but not for the Saskatchewan and Newfoundland and Labrador Regulations. In a similar vein, it is noted that Alberta also has the most clearly defined regulations for what sources must be included in a fugitive survey while other provinces do not have this delineation.

Table 6: Differences in Regulatory Reporting Requirements Across Canada

	Federal	British Columbia	Alberta	Saskatchewan	Newfoundland and Labrador
Leak Detection Survey Monitoring Frequency	Tri-annually	Tri-annually or annually, depending on the type of facility	Tri-annually or annually, depending on the type of facility	Biannually	No regulatory requirement
Specific Venting Controls and Component Definitions	Venting limits stated for priority emission source categories	Venting limits stated for priority emission source categories	Venting limits stated for priority emission source categories, including definitions of components to be surveyed	Inclusion of venting emission source categories to be quantified, no venting limits	Venting emission source categories not included in provincial guidance
Venting Limit Inclusions	• Venting from compressors • Venting from well completions involving hydraulic fracturing • General facility production venting • Venting from pneumatic devices	• Storage tank venting • Reciprocating compressors seal venting • Centrifugal compressor seal venting • Pneumatic devices • Pneumatic pumps • Pneumatic starters	• Overall vent gas • Defined vent gas • Crude bitumen batteries • Pneumatic devices • Centrifugal compressor seals • Reciprocating compressor seals • Glycol dehydrators	N/A	N/A

Top Companies

The purpose of this section is to address the PTAC question: What are the top organizations involved with monitoring research in Canada.

Table 7 below is a summary of just a portion of the organizations involved in methane emissions monitoring technologies. The organizations come from a broad range of sectors including industry, government, academia, and technology providers. Some of the listed companies and academia research papers were reviewed in this report, but this list provides a more comprehensive picture of the companies that are operating in Canada,

The table is broken down into five main columns; the first column is the list of companies operating in Canada. The second column, "Methods", describes what sensors or technologies are used or studied by the organizations. The third column, "Platforms", describes what method of deployment is used for the corresponding sensors or technologies, or what is studied or funded by the organization for R&D. The fourth column describes the services provided by the organizations listed, whether it be GHG consulting services such as certifications or verifications, research & development (R&D), LDAR services, etc. The fifth and final column describes which sector, if any, the funding for R&D projects comes from, public or private.

For example, Airdar's method uses atmospheric sensors (methane analyzers, metal oxides, etc.) in their technology, they use fixed perimeter sensors to conduct their surveys, the services they provide are continuous monitoring and quantification of methane sources, and they do not receive R&D funding as their technology is in the deployment stage.

Table 7. Companies & Institutions Involved in Methane Emissions Monitoring Technologies in Canada

Company	Methods							Platforms							Services						R&D Funding	
	Method 21	Flux Chamber	Optical Gas Imaging	Shortwave Infrared	Thermal Infrared	Methane Analyzers, Metal Oxides, etc.	Inverse Dispersion Modelling	LiDAR	Handheld	Perimeter Sensors	Mobile-Ground Laboratories	Aircraft	UVA	Satellite	Continuous Monitoring	Emission Quantification	LDAR	Simulation Modelling	Certification, Inventories, Verification Services	R&D	Public Sector	Private Sector
4Blue Energy Services			√	√				√		√					√	√			√			
AECOM			√				√		√	√					√				√	√		√
Airdar						√				√					√	√						
Arolytics																		√	√			
Baker Hughes a GE Company						√		√											√			
Bridger Photonics				√				√				√				√						
Calscan Solutions						√	√	√		√					√	√			√			
Calvin Consulting Group Ltd.	√															√	√		√			
Carbon Mapper			√											√		√						
Carleton University Energy & Emissions Research Laboratory									√	√	√	√	√	√							√	
Cerex Monitoring Solutions						√		√		√					√	√	√					
Clearstone Engineering	√	√	√			√		√	√	√	√					√	√			√		√
CMC Research Institutes Inc.								√											√			√
CNTRAL Inc.																√	√		√			
Eosense Inc.		√						√									√					
European Space Agency				√										√		√						
GHGSat				√										√		√						
GreenPath Energy					√	√		√												√		
Grid Environment			√						√							√	√					
Highwood Emissions Management						√		√										√	√	√		
Infrared Corp.			√	√	√											√	√		√			
InnoTech Alberta								√								√			√			
Kuva Systems			√							√					√							
LiDAR Services International Inc.								√				√	√			√						
McGill University									√	√	√	√	√	√						√		√
MERC Systems Inc.								√		√					√	√						
MethaneSAT					√									√								
Millennium EMS Solutions Ltd.							√									√	√		√			
Modern West Advisory																√			√			
Montrose Environment	√		√						√							√	√					
Optisense Solutions	√								√							√	√					
Project Canary						√		√		√					√							
PTAC				√	√	√	√	√	√	√	√	√	√		√		√	√		√		√
Qube Technologies						√		√		√					√	√						
Radicle Balance																			√	√		√
RWDI							√	√		√					√	√	√		√	√		√
SAIT									√	√	√	√	√	√						√	√	
Saskatchewan Research Council									√	√	√	√	√	√						√	√	
Sonoma Technology Inc.						√		√								√	√					
St. Francis Xavier University									√	√	√	√	√	√						√	√	
Teledyn FLIR			√						√													
The Sniffers	√		√						√							√	√					
University of Alberta Department: Electrical and Computer Engineering									√	√	√	√	√	√						√	√	
University of Calgary									√	√	√	√	√	√						√	√	
University of Guelph									√	√	√	√	√	√						√	√	
University of Texas: Institute for Geophysics									√	√	√	√	√	√						√	√	
Vertex	√		√						√							√	√					

D. PROJECT AND TECHNOLOGY KEY PERFORMANCE INDICATORS

Organization:	Current Study	Commercial Deployment Projection
Project cash and in-kind cost ($)	$219,990.16	
Technology Readiness Level (Start / End):	9 and above	
GHG Emissions Reduction (kt CH4/yr):	N/A	
Estimated GHG abatement cost ($/kt CH4)	N/A	
Jobs created or maintained:	Therese Curtis, Albino Dominic, Lifeng Zhao, Dawson Bachand and Aecom Personnel	

NOTES:

- You can put explanation notes here if you want to give some colour on where the numbers above are coming from. Not critical…

E. RECOMMENDATIONS AND NEXT STEPS

Please provide a narrative outlining the next steps and recommendations for further development of the technology developed or knowledge generated from this project. If appropriate, include a description of potential follow-up projects. Please consider the following in the narrative:

- If tests are still ongoing, or if more tests are needed, describe what they are and what outstanding questions still need to be answered
- Based on the project learnings, describe the related actions to be undertaken over the next two years to continue advancing the innovation.
- Describe the long-term plan for commercialization of the technology developed or implementation of the knowledge generated.
- IF APPLICABLE, describe any potential partnerships being developed to advance the development and learnings from this project.

RESPOND BELOW AND DELETE THIS BOX

Conclusions

Summary of Suitability and Applicability

This section identifies the features of the methane measurement types considered in this review at the current stage of application in the industry. It includes a summary of commentary from individuals surveyed as part of the work. Additional information is found in Table 1.

Satellite Platform

The role of satellite observations (top-down analyses) is to guide the improvement of bottom-up emission inventories relating emissions to the underlying processes (Jacob, et al., 2016). If launched, geostationary observations would allow estimation of emissions with both high spatial and temporal resolution but depending on the mission profile of the satellites which may instead be used to offer high temporal and low spatial resolution.

Satellite observations are not commonly used in the oil and gas industry for the following reasons:

- Cloud cover or smoke in atmosphere
- Low light in northern-latitude winter affecting sensitivity
- Higher uncertainty in high reflectance areas (snow or water)
- Low spatial resolution

Measurement over a column depth influenced by stratospheric concentrations (more important in more northern latitudes)

In addition, satellites follow sun-synchronous orbits, so do not estimate nighttime emissions, and do not provide continuous estimates of emissions at specific points on the ground.

Aircraft Platform

Aircraft measurements can be used to estimate emissions from individual facilities. Platforms carrying passive instrumentation (e.g., LiDAR) have the limitations of satellite measurements but to a much smaller degree given the nearness of the platform to the emission sources. The method is useful when ground is snow free, during adequate daylight, and when other weather limitations do not occur. The spatial resolution of typical instrumentation is equipment level. Under ideal conditions accuracy is < 10% (Erland, B.M.; A.K. Thorpe and J.A. Gamon, 2022); however more common estimates of uncertainty are in the range of 63% (MacKay, et al., 2021) when comparing emission estimates to tracer studies.

According to industry representatives, aerial surveys detect most methane on-site and find sources that LDAR on the ground misses. An example is methane from thief hatches. An airborne survey can see these plumes, but a hand-held FLIR camera may not since the operator cannot see the top of the tank. In addition, an aerial survey visualizes methane emissions over a wide area which is especially useful in conveying the scope of operations required to senior management and to field operations staff. This has helped change behaviours and culture.

Platforms with an on-board methane analyzer typically fly concentric closed flight paths at multiple altitudes around a source and use a mass balance approach to estimate emission rates. This approach works best when there are no interfering sources near the facility, where there are no restrictions on the lowest flight level, and when the lowest flight level is near the bottom of the plume, as this approach can only detect emissions that are encountered at flight level (National Academies of Sciences, Engineering, & Medicine, Division on Earth & Life Studies, Board on Environmental Studies & Toxicology, Board on Energy & Environmental Systems, Board on Earth Sciences & Resources, 2018). Analyzer methods can have very low uncertainty (2%) if the entire plume can be sampled and accurate wind data are available (Erland, B.M.; A.K. Thorpe and J.A. Gamon, 2022).

Perimeter (Fixed) Sensors

Point Analyzers

Analyzers used in methane monitoring range from regulatory grade instrumentation capable of high accuracy and period zero concentration checking to mass-produced electrochemical devices with relatively high detection limits. The latter work well for identifying high emitters contributing most to emission inventories. Analyzer methods can localize potential emission sources given enough measurement locations and can quantify emissions given sufficient measurements and accurate wind data. Point analyzer networks detect on and off-site sources. Measurements are continuous and well designed to quantify infrequent emission events. If set back from facilities, emission detection from all non-stack sources can be achieved. Limitations of the approach is that identifying specific source locations is complicated by complex wind flows around site structures, which may not be adequately measured. Plume lofting due to atmospheric instability is a challenge.

Optical Sensors

OGI camera networks can provide continuous coverage over large portions of facilities with high spatial resolution. Uncertainties increase as the temperature contrast of GHG to the background decreases. The ability to quantify large areas is limited and is restricted by the distance of sampling (Erland, B.M.; A.K. Thorpe and J.A. Gamon, 2022) . In operational situations, detection (and therefore alarms) can be overly sensitive, responding to system noise due to temperature variations in the facility.

Line integration sensors are well suited for permanent installations and especially for fence lines. Both emitters and reflective mirrors require solid installation, and separation distances are typically 500 m or less. Quantification requires accurate wind measurements.

Mobile Land-based Platforms

Mobile platforms have many of the same benefits and limitations as fixed sensors. Mobility provides additional benefits:

- More efficient use of time and can always relocate downwind of sources
- Can measure at multiple distances

Emission rates can be quantified to +/- 20% to 40% per pass. With the addition of tracer techniques, the uncertainty can be reduced to +/- 20%.

Limitations are that measurements are continuous only in the survey period and thus dependent on the weather and emission conditions at the time. The ability to georeference sources is limited by wind direction and access around the facility.

Equipment Level Measurements

Method 21 measurements can be labour intensive. OGIs are more convenient and efficient. Equipment level methods are included in all monitoring programs that aim to find and repair specific leaks.

Factors influencing OGI performance include:

- Camera-to-source distance - imaging distances more than 10 m suffer reduced performance
- High wind speeds, low ambient air temperatures, and low background emissivity contrast
- Operator expertise

- Most current OGIs do not provide a quantitative flux estimate

Several alt-FEMP programs exist in Alberta. Ravikumar et al. (2020) presented a case study of one, examining the performance of two truck-based screening systems for detecting, attributing, and quantifying methane emissions at upstream oil and gas facilities, compared to baseline OGI surveys. The study noted several challenges: wind conditions and atmospheric stability that affect quantification, on pad access downwind of equipment, and lack of quantification by QOGI. The study determined between 4% and 17% of known emission sources could not be quantified by QOGI. Methane sources were inherently harder to detect with OGI because of strong heat signatures interfering with methane emissions at the facilities tested (e.g., catadyne heaters and engine exhausts).

Significant efforts can be needed to gain regulatory approval. Alt-FEMP programs have the potential to reduce costs and/or achieve deeper methane emission reductions (MacKay, et al., 2021) but are site specific.

Comment on Measurement Reconciliation

Many independent methane monitoring studies have highlighted large discrepancies between measured quantities of methane being released into the atmosphere and what is recorded in industry and national inventories in many more studies than are cited here. For example, Mackay et al. (2021) recently proposed that top-down inventories in western Canada were about 50% higher than bottom-up inventories. Understanding why reported emissions do not seem to match atmospheric data collected using top-down technologies, (such as instruments mounted on a drone, aircraft or satellites verified by ground truthing), or why there is no consensus on bottom-up technologies (such as the estimates of potential sources of emissions from many miles of pipeline, number of storage tanks, wells, valves, pumps, etc.), is worthy of comment.

Bottom-up estimates of emissions commonly rely on emission factors based on historical field measurements applied to site-specific facility activity data and can be augmented by direct measurements of flow from emitting sources. These form the most common means of achieving a site or facility level emission inventory. Bottom-up inventories at facilities are also used to develop industry, provincial or national inventories. The difficulty with bottom-up approaches is obtaining a truly representative sample from a large, diverse population. If emissions were normally distributed about a mean value, obtaining a representative sample would be reasonably straight-forward. For many types of emission sources in the natural gas supply chain, however, extreme values can strongly influence average emissions (Allen, 2014). If extended to the natural gas supply chain, estimates of methane losses in US basins range from 1% to 10% (volume of methane emitted as a fraction of the volume of natural gas produced) to more than 10% (e.g., (Allen, et al., 2013) In western Canada the range in a recent study was 0.1% to 7.6%, depending on the field (MacKay, et al., 2021).

While top-down methods are more comprehensive, in that bottom-up inventories do not count all emitting sources, they have large uncertainty. Mackay et al. (2021) notes a 63% quantification uncertainty. Furthermore, there can be additional challenges in applying a top-down approach. For example, separating emissions from natural and legacy emission sources, as well as other background concentrations, from current natural gas operations (Allen, et al., 2013). This level of uncertainty makes use of these emission estimates alone challenging when charting progress toward emission reduction targets.

One approach to reconciling top-down and bottom-up approaches is to apply a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters in the bottom-up measurements, thus directly addressing the issue of super-emitters (Rutherford, et al., 2021). If this approach is used, the authors demonstrate better agreement between site-level measurements coupled with activity factors and larger-scale top-down studies, such as (Alvarez, et al., 2021) who note that bottom-up methods systematically underestimate total emissions because they miss high emissions caused by abnormal operating conditions (e.g., malfunctions), including those from tankage.

It should further be noted that Alvarez et al. (2021) in a 9-basin study found that bottom-up and top-down estimates were not significantly different, although top-down estimates were on average about 11% higher. This is borne out by recent studies underway in Alberta (Modern West Advisory, 2023) which confirmed that single-well oil batteries without separators are a major source of tank vent emissions and that the sum of aerial detections from batteries with separators is only slightly higher than the sum of reported vent volumes.

One final issue for all methane measurement approaches, not limited to the reconciliation issue discussed here, is the need for transparency of data. Responses to climate change, and to the means to measure emission reduction, are political as well as scientific. It is important that data used to drive government policy and regulation be openly available for review and for uncertainty in measurements to be clearly understood.

Recommended Monitoring Approach

This report has reviewed various approaches to measuring methane and to using those measurements to estimate emissions at the equipment-level, facility-level, or larger scales. How that data are expected to be used drives which approach should be used. No single option is best in all cases.

To estimate emissions from individual pieces of equipment or specific locations at a facility, either for the purpose of quantifying emissions or simply to find and repair leaks, there appears to be no better approach than the combination of Method 21 and OGI. The methods are essential to accurately determining emission rates of specific equipment or sources albeit only during the survey. These surveys can lead directly to equipment repair or replacement and therefore to emission reduction.

A layered or tiered approach can lead to improved emission quantification accuracy. Here the goal is to attempt to survey all emissions from all equipment as a basis to establish an inventory and a sufficiently accurate periodic emission determination to track progress toward reduction:

- Large oil and gas operators augment OGI surveys with airborne surveys, most often using LiDAR. Aircraft platforms offer the ability to map emission rates over large areas and provide a screening level of source identification. Combining this with ground-based quantification improves measurement accuracy, e.g., (Johnson & Tyner, 2022).
- For smaller operators or small facilities, airborne approaches may not be feasible or cost effective. Fixed or mobile ground-based quantification can provide the spatial coverage to quantify known and unknown sources as well as provide screening-level guidance on source location, e.g., (MacKay, et al., 2021).
- For facilities with large area sources, several techniques are available to quantify emissions that involve direct emission measurement (flux chambers), point source measurements coupled with inverse dispersion modelling, or open path measurements including inverse dispersion modelling. Measurements from an aircraft platform is another option.

For governments, the goal is typically to establish an accurate national or regional inventory, and one that can be used to track emission reductions and political commitments over time. At present, no single strategy can accomplish this, and a combination of approaches is needed. This could involve regional aircraft surveys where available, corrected or enhanced with ground-based measurements, and supplemented in most geographic areas by emission factor estimation approaches. It is not an absolute requirement that the top-down and bottom-up versions of measurements match, as they are fundamentally different. In the next decade, it is possible that high resolution, low detection limit satellite coverage will be available to provide an additional basis of comparison.

The development and refining of measurement technology or the refining of statistical or analytical approaches to aid in quantification to improve inventories is also expected to be best addressed through a combination of approaches. Measurement comparison at test facilities such as METEC is warranted to provide a large base of data to facilitate comparison. Simulated emissions testing at the University of Calgary Research Centre laboratory and live testing at Tourmaline Oil's West Wolf Gas Processing Plant in Alberta can also accelerate development of technologies to reduce methane emissions.

Several papers identify that periodic OGI/LDAR surveys only occasionally find new leaks, and thus after initial repair the surveys just confirm low emissions while possibly missing potential larger super-emitters that exist between surveys. It is possible that an aircraft or ground-based survey (or a ground-based continuous measurement program) to geolocate leaks, followed by an OGI survey, is a more efficient approach. This is like the (Cardoso-Saldaña, 2022) approach which found that strategies that increased the frequency of surveys targeting high emitters while decreasing the frequency of OGI inspections led to higher reductions than quarterly OGI inspections.

Finally, although not addressed in this report, cost is clearly a factor in determining optimal approaches to measurement and depends on factors including the capital cost of the measurement devices and mounting platform, operating cost, measurement frequency, scale of operations, data processing costs, and whether the work is conducted by staff or external consultants. These factors are highly operator specific.

Gaps in Monitoring Research

This section addresses a specific PTAC question: What are the key gaps of monitoring technologies that are being addressed in research projects, and which are not?

Gaps being Addressed

Rutherford et al. (2021) found that that unintentional emissions from liquid storage tanks and other equipment leaks are the largest contributors to divergence with GHG inventories (in the US). PTAC has initiated a series of research initiatives to better characterize emissions from petroleum storage tanks, engine slip, and flares. This gap is being addressed in Canada.

Funding of research to monitor methane remains a major issue for the oil & gas industry. It important given the outsized role methane has in short term global warming potential. This is also true if Canadian technologies are to be competitive against technologies from the larger US market which has just received a significant funding injection under the IRA for R&D programs including the US EPA and US DOE. This gap is being addressed, but not at a rate commensurate with need.

Remaining or Ongoing Gaps

The ability to routinely detect and quantify short term super-emitters remains an implementation gap. The technology exists. Advances in obtaining regular coverage using spectral airborne and satellite sampling methods will be important for quantifying process emissions and sporadic flaring events to monitor changes and capture leaks, identifying the largest emitters so that mitigation can be implemented more quickly, and emission estimates are more accurate (Erland, B.M.; A.K. Thorpe and J.A. Gamon, 2022).

At the same time, there is a need for characterizing intermittent super-emitters (frequency, magnitude, duration) which would include storage tanks so they can be more accurately included in emission inventories.

Tools such as LDAR-Sim and AroFEMP play roles in alt-FEMP development. These models and FEAST play important roles in optimizing emission inventories but may be limited in that they have not evaluated combinations of multiple technologies. This limitation has been partially and recently addressed (Cardoso-Saldaña, 2022) but given the value of these tools, further work in empirically validating these models is needed.

Fixed sensors (at or beyond facility perimeters) with unattended operation offer the potential to all emissions from a facility including super-emitters. Chen et al. (2023) have developed an approach to assess the effectiveness of continuous sensor networks in detecting infinite-duration and fixed-duration emission events. There is a need to develop a corresponding framework to optimize sensor placement to improve coverage and quantification of releases.

Several operators have tested point source measurement and alarm technologies at operating sites. Further work is required to improve the ability of such systems to accurately respond when methane plumes are detected and not to respond when they are not (this is a genuine challenge for all monitoring technologies – see Table 5 for mobile systems examples). At a practical level, such systems may need to be de-tuned to respond only to larger detected concentrations, which are then investigated further using OGI. More generally, more work is needed to separate actionable items from instrument noise which implies more work on analytics and machine learning.

Many studies comparing quantification methods suggest that more work is needed to reduce quantification uncertainties, among them are Bell, et al. (2017) and Caulton, et al. (2018). More measurement-based evaluations of bottom-up inventories are needed to establish the differences more consistently. This will provide more confidence in using measurement-based approaches (e.g., mobile or fixed measurements) in regional or national inventories.

There is a need for continued standardized testing of (all) emission quantification technologies using controlled release testing to derive conclusive evidence of performance in terms of detection limits and attribution skill as well quantification accuracy and precision. These data can then be used by operators to assess options for their quantification programs, given site specific condition or limitations, and by those establishing inventories at various scales to assess the reliability of the data.

For operational use, or for field intercomparison studies, for mobile platforms, documentation (or a data completeness / data quality index) needs to be developed that provides an assessment of the completeness of the survey e.g., whether the platform was able to work downwind of all the equipment on site.

There is value in making an inventory of new emerging measurement technologies more widely available, especially to small to mid-sized operators, as this is expected to encourage the adoption of lower emitting technologies faster. Large operators maintain their own and periodically refresh them. An independent organization like PTAC could do the same (for example, updating annually).

One approach to long-term and continuous measurement does not necessarily require methane to be measured. In principle, it may be possible to measure process related parameters – temperature or temperature differential, pressure differential, flow rates – at relevant locations as a surrogate for methane emissions. This approach is likely to allow source-level continuous emission estimates using conventional industry approaches. The research gap is determining what measurements are relevant and linking them to methane emissions. This approach seems well suited to the detection and repair of virtually all categories of emissions.

One of the issues raised by the evolution of monitoring technology is how to document baseline emissions from a decade ago using the technology and emission inventories of the day, when the most effective technologies might not be determined for another decade. Improvements in airborne and satellite technology offer such a dilemma because we can't go back in time and re-measure and yet they provide the scale of measurement needed to provide the spatial coverage needed to measure a complete range of industrial, agricultural, urban and natural sources provided monitoring and processing continue to improve. Or, to put it another way: as monitoring technology continues to evolve, how do we measure to show the new emissions meet the 45% or 75% reduction targets assuming they provide more accurate emission estimates? How do we compare to baselines measured using old approaches? The means to provide retrospective baselines using remote sensing technology is a gap requiring further thought.

Currently, remote sensing approaches are alt-FEMP solutions – shown to be equivalent to a standard but not a standard per se. Do we continue to require that alternative approaches be equivalent to standard Method 21 approaches, when those standard approaches appear to have shortcomings for some equipment types? This is also a question that requires further thought.

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