TECHNICAL REPORT

Leak detection methods for natural gas gathering, transmission, and distribution pipelines

HIGHWOOD
EMISSIONS MANAGEMENT

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We are emissions reduction experts. Working with industry, government, and innovators around the world, we leverage data, knowledge, and experience to optimize greenhouse gas emissions management. Our mission is to collaborate, innovate, and educate our way to a world with effective and affordable emissions management solutions.

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Executive summary

Natural gas pipeline leaks pose a safety concern, lead to product waste, and consist primarily of methane, a potent greenhouse gas. In recent years there has been a growing interest in finding ways to identify and resolve sources of fugitive (i.e., unintentional) methane emissions from oil and gas operations. At first, interest and regulations were focused more on above ground upstream and midstream operations, and belowground infrastructure in urban environments (due to safety). Recently, addressing methane leakage from pipelines has come into sharper focus, including gathering, transmission, and distribution lines. This shift has been driven by learnings from new measurement campaigns and a growing need to reduce methane loss from the entire supply chain to mitigate climate change, improve carbon accounting, and enable the demonstration of responsibly sourced gas.

Identifying pipeline natural gas leaks, which are invisible and often odourless, is a significant challenge. Legacy methods, which have existed for decades, include walking along pipelines with handheld instruments (e.g., organic vapor analyzers and combustible gas indicators) and flying aircraft along right-of-ways to search for visual signs of disturbance (e.g., dead vegetation and encroachment). Although legacy methods find leaks, their overall effectiveness remains unclear and a growing body of research demonstrates that pipeline methane emissions are of greater significance than previously thought. Newer advanced solutions exist that detect and interpret atmospheric methane concentrations remotely or in

situ at a variety of spatial and temporal scales. Many of these advanced solutions are now commercially available and in use.

This report presents operators and regulators with a cohesive understanding of the technologies available for detecting natural gas leaks from pipelines across the supply chain. We perform a comprehensive literature review and supplement it with targeted, semi-structured interviews with industry experts, including pipeline operators, researchers, innovators, and technology solution providers. We establish a methodology for categorizing methane leak detection methods for pipelines and present the following key findings.

Key findings

1. Pipeline methane emissions are an important environmental and safety concern.

2. Methane emissions from pipelines vary dramatically across space and time.

3. Methane leaks from pipelines can be persistent and typically require detection to be resolved.

4. The effectiveness of legacy detection methods remains unclear, despite forming the basis of most regulations.

5. Considerable innovation over the past decade has led to a growing number of advanced leak detection methods.

6. Advanced methods are commercially available today and adoption rates are accelerating.

7. Growing adoption of advanced solutions in the absence of regulation signals their value.

8. Gathering lines are the least regulated pipeline type but could be the biggest emitters.

9. Transmission line leaks are uncommon but may be of high consequence.

10. Distribution lines have smaller leaks but can be more numerous and pose a greater safety concern.

11. Each segment is unique and benefits from the use of different leak detection methods.

12. Full coverage of a pipeline may require the use of multiple complementary methods.

13. Ongoing monitoring, research, and data sharing are important to improve understanding of natural gas pipeline leaks and detection methods.

Glossary

Emission Factor

A value that relates the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. Such factors facilitate an estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).[1]

LDAR

Leak detection and repair is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. A component that is subject to LDAR requirements must be monitored at specified, regular intervals to determine whether or not it is leaking. Any leaking component must then be repaired or replaced within a specified time frame.[2]

Leak

The unintentional release of hydrocarbons to the atmosphere. Often referred to as fugitive emissions.

Methane

A colourless, odourless gas that occurs abundantly in nature and as a product of certain human activities. Methane is the simplest member of the paraffin series of hydrocarbons and is among the most potent of the greenhouse gases. Its chemical formula is CH_4.[3]

Natural gas

Natural gas is a naturally occurring and flammable hydrocarbon gas that is used for fuel. Its primary component is methane, but it can also contain ethane, propane, butane, and pentanes. Often, impurities including oxygen, hydrogen sulfide (H_2S), nitrogen, water, and carbon dioxide (CO_2) are also present.

Upstream

The first stage in the oil and gas value chain, consisting of exploration and production processes. Activities include drilling, infrastructure development, and production.

Midstream

The stage in the oil and gas value chain following production and preceding distribution. Activities include processing, pipeline transportation, refining, and storage.

Downstream

The final stage in the oil and gas value chain. Activities include distribution, retail, marketing, product development, and consumption by the end user.

Gathering

The collection of petroleum products from their extraction point (wells), and their transport to a processing facility. A typical gathering system is highly branched, and consists of small-medium diameter pipelines with medium operating pressures.

Transmission

The transportation of petroleum products from processing facilities to distribution hubs. Transmission systems consist of large-diameter, high-pressure pipelines that transport high volumes of petroleum products across large distances.

Distribution

The transportation of refined petroleum products from distribution hubs to the end users of these products.

Follow-up survey

An inspection to confirm or deny potential leaks detected through a screening survey. Typically, a screening technology will identify a potential leak at the site or equipment-scale. Follow-up surveys diagnose leaks at the component scale, typically with handheld detection methods.

Introduction

Efforts to reduce emissions of methane, a potent greenhouse gas, are necessary to transition to a decarbonized economy. Natural gas, which consists primarily of methane, has become a critical energy source around the world and will play an important role in the energy transition. When combusted, natural gas can have a much lower carbon intensity than coal. However, uncombusted methane has a global warming potential that far exceeds carbon dioxide (the Environmental Protection Agency (EPA) estimates as much as 28-36X more[4]) and leaky supply chains can cancel or reverse the climate benefits of natural gas.[5] Natural gas leaks are also a safety concern; although incidents are rare, they can have dire consequences. Over the past decade, natural gas leaks have killed dozens of people in the U.S. and injured hundreds, resulting in property damages in excess of $500 million.[6] Finding and repairing pipeline leaks is an important way to mitigate safety concerns.

In recent years, understanding of fugitive and vented methane emissions from the oil and natural gas (O&G) sector has improved. A growing body of research on methane emissions, monitoring, and abatement efforts reveals widespread underestimation of official emissions inventories for O&G.[7] Existing research and accounts from industry experts show that unintentional methane leaks from gathering and distribution lines can be higher than inventory estimates. Fugitive emissions from transmission lines are not well documented, though it is generally assumed that intentional operational releases are the more prevalent source of methane from transmission pipelines. Recent aircraft surveys in the Delaware and Midland basins found that pipeline emissions are comparable to methane emissions from natural gas compressor stations (in terms of mass per year). Of the 176 persistent gathering line emission sources identified in the study, most were larger than 100 kg/h (~5,370 scfh).[8]

The natural gas production supply chain consists of three main categories of pipeline: gathering, transmission, and distribution (note that some would consider flow lines as a fourth category, but that these are not covered in this report). Gathering pipelines connect wellheads to central tank batteries, compressor stations, and/or processing facilities. Transmission pipelines are large diameter, high pressure, and carry large quantities of processed natural gas over long distances. Distribution lines are smaller diameter and deliver natural gas to end users. The Pipeline and Hazardous Materials Safety Administration (PHMSA) currently mandates cyclical leak inspections for distribution lines, transmission pipelines that cross state boundaries, and some gathering lines if near populated areas.[9]

Interest in methane reduction has expanded over the past decade, alongside rapid innovation. Many strategies exist for detecting methane leaks from pipelines, and more advanced leak detection methods have become commercially available in recent years. These newer technology deployment platforms include (but are not limited to) drones, passenger vehicles, aircraft, and satellites. Many of these new technology options perform rapid screening surveys, which are used to direct follow-up at close range when necessary. Legacy methods in gathering and transmission, which remain in use, involve inspecting pipeline right of ways for visual signs of disturbance (e.g., dead vegetation) and monitoring for changes in pipeline pressure. In distribution, portable gas sensors (sniffers) are used by inspectors who walk above lines at regular time intervals (typically 1-5 years).

The PIPES Act of 2020 directs PHMSA to establish a nationwide standard requiring the use of advanced leak detection technology by pipeline operators and to enhance practices to find and fix leaks.[10] In

this report, we consider 'advanced' solutions to be those that present a step change in methane detection and quantification innovation from traditional methods, whether in the form of advanced sensors, deployment strategies, work practices, or analytics. For example, combinations of distinct technology types with different strengths may improve the ability of pipeline operators to find and repair leaks. Automated methane detection techniques may lead to more data collected at a higher frequency. The ability to store and analyze this data may improve work practices and lower the cost of emissions mitigation by detecting more leaks sooner and predicting future leaks.[11]

A sound body of knowledge on the capabilities and costs of methane detection technologies is essential to support development of emissions management strategies and policies that are effective, efficient, and innovation friendly. To date, there has been an emphasis on technology evaluation studies on aboveground infrastructure for production, compression, and processing of petroleum products. However, a growing number of studies indicate that available technologies can be used to detect and quantify methane emissions from buried pipelines.[8,12-14]

This report addresses pipeline methane emissions and available leak detection methods through literature review and expert interviews. We first provide an overview of the current state of knowledge on methane emissions from gathering, transmission, and distribution pipelines. We then describe available methane detection techniques and explore how and whether they are used – or could be used – on each of the pipeline segments. We catalogue and categorize commercially available leak detection technologies for detecting pipeline leaks and describe their performance, capabilities, and limitations. Ultimately, the purpose of this report is to provide industry, regulators, and vendors with an informed understanding of pipeline methane emissions and how leak detection technologies can help to cost-effectively decarbonize the natural gas supply chain.
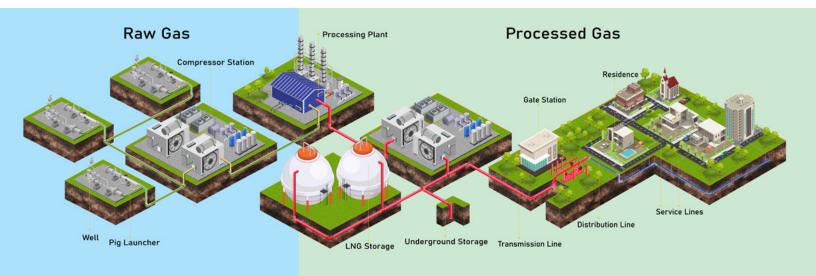
This report is focused on methane emissions from pipelines and available leak detection solutions, especially advanced mobile detection methods such as sensors deployed via car, drone, or airplane. Given that there exist over 100 methane detection solutions on the market, technologies are grouped according to deployment platforms, work practices, and sensing principles.[11] Inspection requirements differ significantly among gathering, transmission, and distribution pipelines due to the magnitude of emissions, environment, and complications of nearby human infrastructure. As such, there is space for a broad range of approaches, including potentially less precise methods that can provide significant coverage. Furthermore, technologies and their capabilities are evolving rapidly. This report will therefore review the capabilities of a broad range of different solutions and not target any individual solution provider. The report is focused primarily on the United States, but learnings may be applicable to most regions with natural gas pipelines.

Pipeline Infrastructure and Methane Emissions

Natural gas is composed primarily of methane, so any leakage or release from a gas pipeline constitutes direct emission of methane into the atmosphere. Natural gas pipeline emissions can be intentional (i.e., operational releases such as venting) or unintentional (i.e., leaks/fugitive emissions). Large emission events resulting from pipeline failures tend to be rare, especially for high throughput pipelines, which tend to be carefully engineered and carry processed gas. Smaller leaks are more common, but with millions of miles of pipeline in the U.S., may collectively amount to a large source of fugitive methane.[15]

Fugitive emissions may arise anywhere along a pipeline. Gathering, transmission, and distribution pipelines mostly travel underground, but occasionally rise to the surface where ancillary equipment is used to monitor and control operations. This equipment consists of pigging stations, compressor stations, valves, meters, regulators, and gauges. Experts interviewed for this report indicate that aboveground equipment experiences more leaks than underground pipeline components, but research on this topic is inconclusive, and belowground leaks may just be more difficult to detect.[12] Aboveground leaks tend to occur on valves, meters, threaded connections, welds, and flanges. A 2018 report from PHMSA states that between 1988-2008, 18% of all significant pipeline incidents were caused by corrosion.[16] A report from the Alberta Energy Regulator (AER) in Canada, published in 2021, states that internal corrosion is the leading cause of pipeline incidents, accounting for up to 46% of all gas pipeline incidents in the province.[17]

Experts also agree that the age and material of a pipeline has an important impact on its overall leakiness. Older pipes tend to leak more than newer ones because they are often built with less sophisticated materials and may have endured more wear and tear. Currently approved materials for gas pipelines include steel, copper, brass, ductile iron, aluminium, PVC and polyethylene,[18] while older pipes are typically made of cast iron.[19]

There are three main categories of pipelines within the natural gas industry: gathering, transmission, and distribution (Table 1). These three categories form a network to transport natural gas from the well to the consumer. Gas producing countries such as the U.S. and Canada have complex webs of gathering,

transmission, and distribution pipelines for gas transportation. The states displayed in Table 2 have the highest mileage of pipelines (of all types) in the US. Note that the mileage in Table 2 for gathering pipelines is low; these numbers represent only the gathering pipelines regulated by PHMSA. There are hundreds of thousands of miles of gathering pipelines that remain unregulated across the U.S. The EPA cited in September 2021 that there were approximately 434,000 miles of onshore gathering pipelines within the country, based on Enverus data.[20] Based on this total, compared to the mileage in Table 2, approximately 2.76% of all gathering pipelines are regulated by PHMSA as of January 2022.

As of 2020, PHMSA reported and regulated ~12,000 miles of gathering lines, ~300,000 miles of transmission lines, ~1,330,000 miles of distribution main lines, and ~955,500 miles of distribution service lines in the United States, totalling ~2,600,000 miles.[21] However, in 2020, the U.S. Energy Information Administration (EIA) stated that the natural gas pipeline network in the country had approximately 3 million miles of natural gas *main line*.[23] This disparity in reported pipeline mileage suggests a lack of clarity around total U.S. pipeline mileage, and that significant mileage is unregulated.

In November of 2021, an expansion of the gas gathering pipeline regulations were approved by PHMSA, requiring the regulation of an additional 426,000 miles of gathering lines, effective May 2022.[22] Under the new regulations, all gathering lines will be subject to annual incident reporting, while an estimated 20,000 miles of gathering lines will be subject to leak survey, line marker, corrosion control, and public awareness measures.[22]

Category of Pipeline	Relative operating pressure	Diameter	System Complexity
Gathering	Medium	Medium	Medium
Transmission	High	Large	Low
Distribution	Low	Small	High

Table 1. *Relative ranking of the different categories of pipeline*

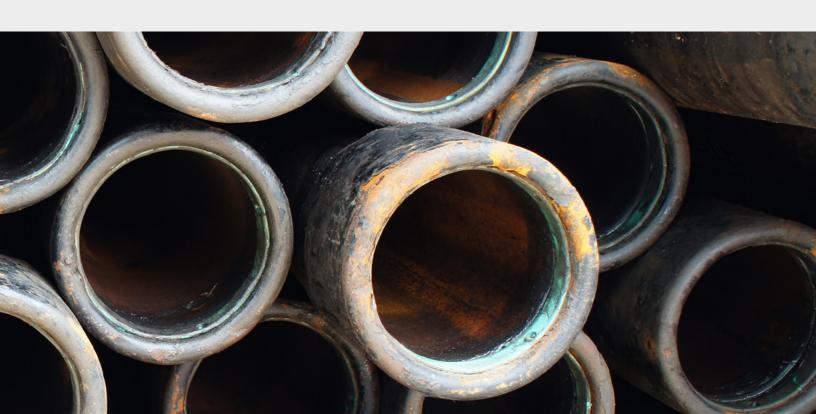| Jurisdiction	Regulated Gas Gathering miles	Gas Transmission Miles	Gas Distribution Miles (Mains)	Gas Distribution Miles (Service)	Total
Texas	6,028	47,153	109,753	52,591	**215,525**
California	156	12,080	107,899	95,543	**215,678**
Illinois	10	9,232	62,527	54,571	**126,340**
Ohio	1,143	10,582	59,528	46,599	**117,852**
Michigan	306	8,672	60,592	59,393	**128,963**
Pennsylvania	755	10,487	48,697	30,488	**90,427**
New York	80	4,595	49,601	43,978	**98,254**
Louisiana	789	24,247	27,857	15,448	**68,341**
Georgia	0	4,888	46,099	42,127	**93,114**
Indiana	0	5,356	42,197	32,456	**80,009**
Tennessee	11	4,875	41,310	27,695	**73,891**

Table 2. *2020 regulated pipeline mileage data. Taken from PHMSA Portal.[21] The states listed are the top 10 states for total pipeline mileage in the country. Note that gas transmission and gas distribution are regulated by PHMSA, whereas it is estimated that only 5% of gas gathering lines are regulated until May 2022.*
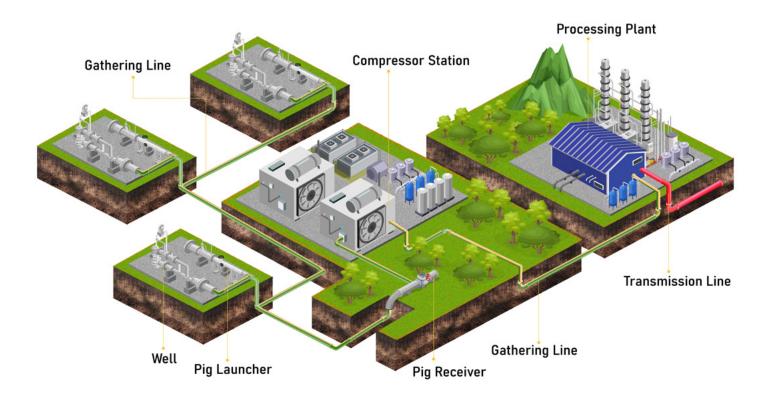
U.S. Natural Gas Pipeline Mileage			
Pipeline Type	Miles	Subset Pipeline Type, if any	Subset Miles
Gathering	434,000	Regulated (2020)	11,569
		Regulated: Annual Reporting (May 2022)*	~434,000
		Regulated: Subject to Leak Survey Requirements (May 2022)*	31,905
Transmission	301,665		
Distribution	2,284,379	Distribution Mains	1,328,873
		Distribution Services	955,507
TOTAL	**3,020,044**		

Table 3. Mileage of gas gathering pipelines in the United States. *New PHMSA regulations will come into effect on May 16, 2022, requiring annual reporting for all onshore gathering lines.[22] **Of these, 20,336 miles will be newly subject to leak detection survey requirements, resulting in a total of 31,905 miles subject to leak survey requirements.[10] Primary source: PHMSA Annual Pipeline Mileage Report.

Emissions from Gathering Lines

Gathering systems consist of highly branched segments of pipeline, which connect well sites and production facilities to gas processing plants (Figure 1). The lengths and diameters of segments of a gathering pipeline system are highly variable, ranging from yards to miles per segment, and from around 4 to as large as 36 inches in diameter.[23,24] Gathering pipeline emissions typically come from one of three sources: the lines themselves (from corrosion, failed joints, and structural stresses), the auxiliary equipment (the aboveground equipment that is part of the regular operations of the pipeline), and episodic events from operations (e.g., blowdowns, pigging, vents).

Emissions data from gathering lines are rare, but a growing number of studies suggest that these pipelines are an important source of methane leakage. Cusworth et al. used aerial leak detection methods and covered 55,000 km^2 in the Texas portion of the Permian Basin.[8] The study identified **176 persistent methane point sources** (most with emission rates above 100 kg/h) that were attributed to pipelines in the area (most – if not all – from gathering lines). Pipeline leaks represented 19% of all quantified emissions detected in the study, for a total of 0.27 ± 0.09 Tg/year.

The emissions quantified from the Permian Basin during the study period were higher than indicated in previous studies of the area. Proposed reasons include: (i) gas production exceeding

the system's capacity, (ii) high prevalence of unlit flares, (iii) material defects, (iv) corrosion, and (v) fitting/joint failures. The emissions detected from the Permian Basin were heavy-tailed, similar to those observed in California and the Four Corners region of New Mexico. The number of methane plumes observed > 500 kg/hour in the Permian was more than 2.5 times that of California and more than 4 times that of the Four Corners region (36%, 14% and 8%, respectively).

The study also found that of all leaks detected (1100 in total), the leaks from gathering pipelines tended to have higher leak rates and could be persistent across flights. This was echoed during two expert interviews that were conducted for this white paper. Experts suggested that leak persistence in gathering lines could be due to a lower frequency of routine maintenance, which suggests that finding and repairing leaks could lead to long-term emissions reductions.

Three additional studies measuring emissions from gas gathering pipelines were conducted in the Utica shale area,[13] the San Juan basin,[14] and the Fayetteville shale.[12] These three studies used a vehicle mounted system to survey a total of 228 miles of gathering pipelines and identified one leak from an underground pipeline that accounted for roughly 80% (4 kg/h) of the total emissions found in the Fayetteville study. All remaining leaks were detected on associated aboveground infrastructure,

including pig launcher doors and block valves. These studies raise the question whether the methods used were adequate for inspecting belowground pipelines. A post-campaign analysis of the sensing technology was performed,[12] and it was determined that the vehicle mounted system was sensitive enough to detect leaks that were up to two orders of magnitude smaller than the single 4 kg/h leak detected. This suggests that either there were leaks that went undetected by the study that were much smaller than 4 kg/h, or that this leak was the only leak present in the study area. All three studies were conducted using similar methane sensing technology, and all three experienced challenges with accessibility as well as pipeline location uncertainty. In addition, super-emitters are rare, and a sample of only 228 miles may fail to adequarely constrain the frequency of large underground sources.
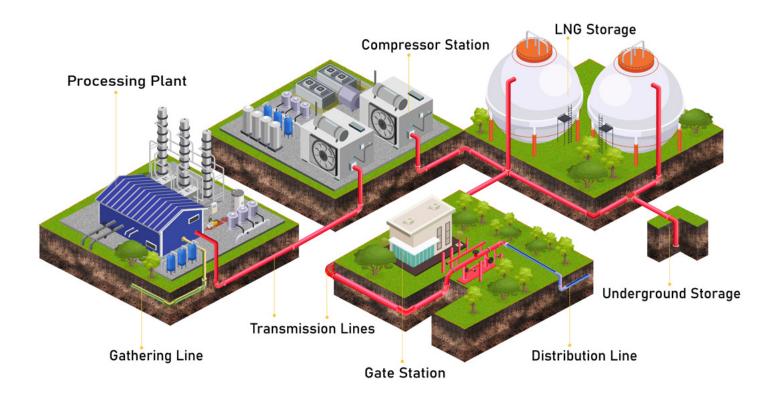
The aerial hyperspectral imagery used in Cusworth et al. had a controlled release detection limit of 10-20 kg/h under ideal conditions (the 90% probability of detection for the study was likely > 100 kg/h).[26] The majority of the emissions sources that were seen by the aircraft for this study were much larger than what was observed elsewhere by slower, more sensitive ground-based methods. The trade-off between sensitivity for coverage is therefore important to navigate when attempting to account for large but rare leaks.

Figure 1. A natural gas gathering system in Alberta, Canada. The red lines travel from well leases (which are visible on the figure as the small white squares) to larger gathering lines, which then direct the gas towards gas processing facilities. In this figure, the black arrows show the direction of gas flow through the pipeline. Inside the yellow circle is a large gas processing plant in the area. Finally, the large highlighted yellow line visible in the figure is a large (30" diameter) transmission line that takes processed gas from the plant and transmits it southeast.[25] Comparable maps of pipeline infrastructure in the United States are not publicly available.

Emissions from Transmission Lines

Transmission lines are the largest pipeline type, in both diameter and length. They are used to transport large volumes of natural gas across long distances. For example, the Texas Eastern pipeline (operated by Enbridge)[27] consists of 8,825 miles of pipeline and can transport up to 13 billion cubic feet of natural gas per day.[28] Transmission pipelines range in diameter, from 4 to 48 inches.[29] In the United States, as of 2020, there were approximately 301,955 miles of transmission lines.[21] In Canada, there are about 75,000 miles of transmission lines.[29] As they operate under high pressures and have high capacities, the potential economic and environmental consequences of a leak are high. Implications for safety are variable, as transmission lines are often in remote areas but can sometimes be near human activity.

Transmission pipelines are typically operated by midstream companies. The midstream sector includes storage, transportation, and processing of hydrocarbons from the processing plant to the distribution hubs, as well as to natural gas power plants for electricity generation. The safe and reliable transportation of natural gas from one point to another is central to the midstream business model, and a strong focus on pipeline integrity is critical for social license to operate. Transmission pipelines are therefore subject to very strict engineering standards, constructed of durable materials, and closely monitored.

To date, there have been no peer-reviewed studies published on methane emissions from transmission pipelines. The few recorded incidents are primarily explosions and fires caused by corrosion-related leaks on gas transmission lines. In 2012, a transmission gas line in West Virginia experienced a leak, resulting in a large explosion which destroyed an 800-foot stretch of an interstate highway, and five homes. More recently, an underwater inferno burned in the Gulf of Mexico in July of 2021. The fire was caused by an underwater gas pipeline which had been leaking undetected, bubbling natural gas to the surface, where it was ignited by a lightning strike.

PHMSA collects information about incidents that have occurred on gas transmission lines. Since 2001, there have been 78 serious incidents on gas transmission systems across the U.S. (Figure 2). A "serious" incident is classified as one that involved a death or injury requiring hospitalization. State-level data on transmission lines is also comprehensive, although this varies by state. For example, the Railroad Commission of Texas has a comprehensive and accurate database of all gas transmission pipeline operators in the state, including how many miles of pipe each operator owns.[30] As of October 2021, there were 418 active transmission operators in the state, with a total of 52,000 miles of transmission pipelines (including inter and intrastate).[31]

PHMSA Pipeline Incidents: Count (2001-2020)
Incident Type: Serious   **System Type:** GAS TRANSMISSION   **State:** (All Column Values)   **Offshore Flag:** (All Column Values)
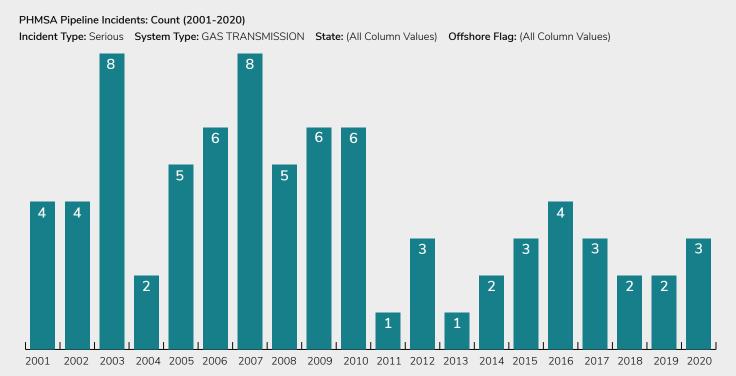

Figure 2. *Serious incidents on gas transmission pipelines as reported to PHMSA. The number of incidents is generally trending downwards.*[32]

Midstream companies publish annual sustainability reports (sometimes called ESG Reports) which include the steps the company has taken in the calendar year to manage their emissions, including from pipeline leaks. For example, the 2019 ESG Report from Kinder Morgan highlights the company's commitment to reducing their methane emissions in the following statement:

state boundaries are regulated by PHMSA, and the ones that do not are typically regulated by state commissions. In general, there have been no indications that fugitive methane emissions from transmission pipelines represent a significant concern, as they have higher standards of engineering, construction and maintenance and incidents have been historically uncommon.

> "In 2016, we set a goal of achieving an intensity target of 0.31% of methane emissions per unit of throughput by 2025 for our natural gas transmission and storage assets. Over the last three years our analysis shows that we were able to achieve a methane emission intensity rate for these operations of 0.04%, 0.02%, and 0.03%, respectively, surpassing our 0.31% target years ahead of schedule."[33]

Other major transmission companies have published similar statements, showcasing the industry's commitment to reducing overall emissions from transmission pipelines. Unlike gathering pipelines, the locations of most transmission pipelines are known, making them easier to monitor. Gas transmission lines that cross

Emissions from Distribution Lines

Gas distribution pipelines are the most prevalent type of gas pipeline by mileage. They distribute natural gas to homes, commercial buildings, and industrial users. Distribution pipelines are mostly located within populated areas. In 2020, PHMSA reported that there were 1,328,855 miles of gas mains and 955,476 miles of service lines, which are the smaller pipelines that distribute gas from the main line into people's homes. The total mileage of distribution lines was 2,284,330 in 2020, with 1,347 licensees operating these lines.[34] In 2019, the natural gas distribution system in the United States delivered over 28 trillion cubic feet of gas to customers across the country.[22] This category of pipeline transports only clean, processed, dry gas, which has usually had a scented chemical added, giving it the classic "gas" smell. Gas distribution pipelines typically operate under low pressures and flow rates and are the smallest in diameter of the three categories.

Because of their proximity to populated areas, leaks from distribution pipelines present a potential safety concern to the public and are therefore regulated by PHMSA. Due to the extent and complexity of distribution systems, leaks are relatively common.[35] One challenge is the age and material of distribution lines. In some cities, the local gas distribution system has been in place for more than 100 years, and as such, the pipe materials and infrastructure are outdated and leaky,[22] although significant improvements have been made since

the 1990s.[36,37] Cast iron pipes are commonplace in many major cities across the country. Replacing these pipelines, given their interconnectedness with our everyday lives, is an enormous task.

PHMSA publishes information on gas distribution pipeline miles by material. As of 2020, 718,813 miles of reported pipelines were made of steel, 1,506,748 miles were plastic, and 28,752 miles were made of other materials (not specified further).[34] It has been shown that replacement and improvement projects do have a large impact in reducing emissions from distribution lines.[36] Replacing leak-prone cast iron or unprotected steel pipes with newer plastic or protected steel ones will likely result in lower emissions factors, though it may never be feasible to completely replace the legacy materials.

Gas utility companies are required to conduct regular surveys of their entire network to ensure public safety. A 2020 study estimated that the number of leaks in US distribution mains exceeded 630,000 and was highly dependent on the age and material of the pipes.[35] The leaks that do occur in these systems are small and are highly persistent. Utility operators are skilled at isolating and repairing leaks from underground distribution lines. However, as is seen across the entire natural gas supply chain, a small number of large leaks account for most of the total leaked methane.[36,38] Detecting and repairing these larger leaks may

have a significant impact on reducing overall emissions from gas distribution systems, and conducting systemwide leak surveys with rapid mobile methods could prove advantageous.

The leading cause of leaks in distribution networks is line strikes (e.g., third-party dig-ins). Every state in the US has a hotline or a website that people can visit to request a line locator to locate any underground infrastructure where they intend to dig. The website www.clickbeforeyoudig.com has an interactive map that will direct people to the correct resources for their area.[39] Line strikes are much more common on distribution pipeline networks than both gathering and transmission because the systems are so interwoven with people's homes and infrastructure. Examples of activities that can lead to line strikes include sewer work, installing fences, telecommunications maintenance, and landscaping.[40]

In addition to line strikes, gas distribution pipelines experience failures in the same ways as gathering and transmission lines from corrosion, pipe fitting, and improperly threaded connections.[41] Large sources may occur in distribution systems, but due to the odorized gas, they are detected and repaired rapidly. Due to typical pipe diameters and low flow rates, the largest distribution line leaks are likely smaller than the largest gathering and transmission line events, and found sooner due to odorization.

Case Study 1: Methane Leakage from Local Distribution Systems

Weller et al. 2020 used a vehicle-based bottom-up approach to estimate methane leaks in U.S. distribution pipeline mains.[35] The study estimated **630,000** methane leaks in the U.S. distribution main network, which amounts to emissions of **0.69 Tg methane/year** (78,767 kg/hour). Prior investigations were rare and relied on small sample sizes, making them likely to discount significant super-emitters.

The Weller et al. estimate of total methane emissions of U.S. distribution mains is based on the multiplication of activity factors (leaks per mile), activity (miles of pipeline), and emissions factors. Mobile ground lab (MGL) surveys took place in 12 U.S. metropolitan areas with pipeline networks. Using GIS and PHMSA data, Weller et al. could attribute each leak identification from an MGL to a specific section of pipeline with a known material and age of the installation.

With each leak identification attributed to a section of pipeline with known characteristics (material and age), relationships between pipeline characteristics and leaks per mile (activity factors) and pipeline characteristics and mean emission size (emissions factors) were established and extrapolated to a national scale. The study found the MGL survey data reliable as surveyed leaks were more commonly attributed to older sections of pipe with less robust material (cast iron).

The Weller et al. study, which was built upon rapid screening using highly sensitive instruments and large sample sizes, represents a critical updating of previous distribution pipeline emissions estimates. In addition, the study helped demonstrate the effectiveness of monitoring distribution pipeline networks with advanced methods.

Methane Detection Technologies

A broad range of methane leak detection technologies exists on the market and can be utilized by pipeline operators to detect, localize, and quantify methane emissions. Legacy methods, including handheld systems and visual inspections for disturbance, have been in use for decades but have important limitations. For example, most legacy methods are of unknown detection effectiveness, are unable to accurately estimate emission rates, and tend to be expensive to deploy.

Over the past decade, rapid innovation has occurred and a diverse assortment of more advanced systems now exist. Ten years ago, few commercial methane detection and quantification solutions existed (outside of the legacy methods); today, at least 100 distinct methane detection technologies are commercially available for detecting leaks in the O&G industry.[42] Although application of emerging technologies began for aboveground infrastructure (typically discrete facilities such as well production sites, tank batteries, and/or compressor stations), many of these technologies are being actively used to detect pipeline methane emissions. According to our interviews, pipeline operators across the supply chain – from gas gathering to distribution – are already making use of aircraft, drones, satellites, and other technologies on a voluntary basis. Widespread uptake of emerging technologies demonstrates value and points to significant opportunities to improve the performance and cost-effectiveness of methane detection and quantification.

Detecting methane emissions from pipelines is more challenging than from other types of production infrastructure. Due to the linear nature of pipelines – and because they are often underground – conventional methods used to inspect well sites and other aboveground facilities may be less effective. Oil and gas producers conduct periodic surveys and screenings of their facilities to search for and repair any leaking components. Facility surveys are traditionally conducted on foot using optical gas imaging (OGI) cameras, or an individual facility may be monitored continuously with a stationary sensor. By contrast, conducting a handheld survey of an entire pipeline right of way (ROW) on foot can be impractical, especially for long-distance transmission lines (nevertheless, distribution lines are still surveyed in this way). Another important challenge for detecting underground leaks is that the location of pipelines is not always known, especially for gathering lines. Quality of pipeline location data varies and depends on regulation and company culture.

Pipeline methane detection technologies can be classified in several ways. Generally, pipeline-specific systems can be above or below the ground. Belowground systems can be internal or external to the pipe, while aboveground systems can be stationary or mobile. Mobile technologies can be grouped into screening and close-range. Most close-range methods are handheld (i.e., legacy) instruments that attempt to detect leaks at close range. Detection method sensitivity varies greatly and typically increases with proximity to the emission source and with sensor characteristics. However, technologies that inspect from further away (e.g., aircraft and satellites) cover larger distances, and are much faster than ground-based methods. Therefore, a trade-off exists between sensitivity, coverage, and speed, which is related to cost per site or mile of pipeline.

Screening technologies are those that can quickly flag potential leaks for directed follow-up with close-range methods. In recent years, the use of screening technologies has grown rapidly across all segments of the value chain. Rapidly screening sites for large sources to direct more targeted close-range surveys presents an important value proposition due to the emissions profiles typical of most O&G systems. Methane leak emission rates generally follow a highly skewed distribution in which a small number of leaks account for the majority of overall emissions.[38] Therefore, screening more frequently for large leaks – even at lower sensitivities – can be more effective than less frequent close-range inspections. Typically, screening surveys can neither identify leaks at the component level nor distinguish vented from fugitive emissions. Differentiating between leaks and venting requires significant coordination with pipeline operators to match detected emissions to planned venting events. To diagnose and repair leaks, screening methods must be paired with close-range systems.

Figure 3 provides a summary of the strengths, limitations, and characteristics of the various technology groups as applied to

pipeline leak detection, along with an appraisal of uncertainty for each category. The data presented in Figure 3 are based on Highwood's interpretation of existing literature and expert interviews. Results are discussed in detail in the subsequent sections of this report. The top five rows are mobile technology groups, and the remaining two are fixed sensors. In general, sensitivity declines with spatial scale of measurement (i.e., increasing distance from source to sensor, for example by moving from handheld to satellite). However, a characteristic trade-off exists, on average, between sensitivity and survey speed, and the cost of deployment tends to decline as speed increases.

Growing evidence suggests that methane detection methods differ not only in performance but also in coverage – what types of sources can be identified and how these sources are characterized. For example, a recent study using aerial surveys identified 80 (non pipeline) sources with a cumulative emission rate 1802 kg/h.[43] Handheld surveys performed at the same time found 379 sources that together amounted to only 74 kg/h. Many of the leaks found during the handheld survey were too small to

be seen by aircraft. This suggests that full coverage of a system may require the use of multiple technologies. Simulation studies have also shown that a combination of technologies can be effective under the right circumstances.[44,45]

When considering the performance of a system, it is important to distinguish among technologies and methods. Technologies are often described as the hardware, including deployment platforms and sensors, while methods include analytics and work practices.[46] In particular, understanding work practices in combination with a technology is critical when evaluating performance. In general, more data from field observations and more controlled release testing on underground infrastructure is needed for all technology types to improve understanding of performance metrics – both performance and limitations. A number of controlled release testing facilities have arisen over recent years. Most notably, the Methane Emissions Technology Evaluation Center (METEC) in Colorado has performed extensive testing and is actively evaluating methane detection technologies on underground infrastructure.
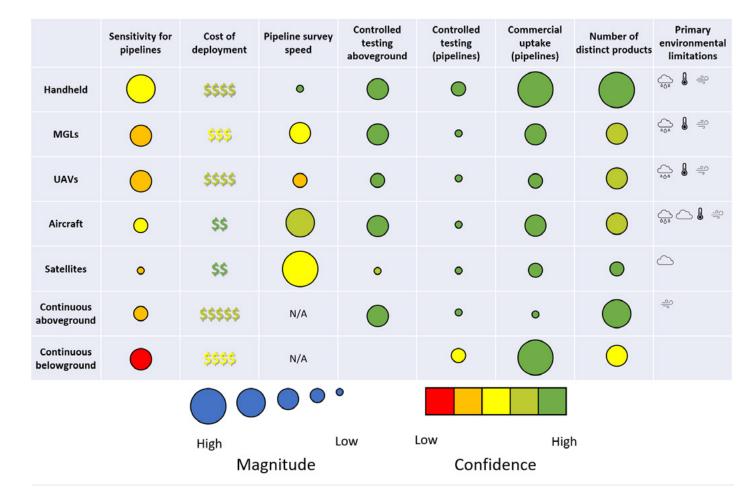

Figure 3. Leak detection technology performance comparison, based on Highwood's interpretation of interviews with industry experts and available literature. The size of the circle represents that particular technologies' strength in a specific category. The colour of the circle represents Highwood's confidence in assigning a strength value to that field based on available literature and professional experience. Knowledge of performance is more developed for aboveground infrastructure. Testing on pipelines has been limited but is improving.

Methodology

This report is focused on methane emissions from pipelines and available leak detection solutions, especially mobile detection technologies such as sensors deployed via car, drone, or airplane. Given that there exist over 100 methane detection solutions on the market, technologies are grouped according to deployment platforms, work practices, and sensing principles.[11] Leak survey requirements differ significantly among gathering, transmission, and distribution pipelines due to the magnitude of emissions, environment, and complications of nearby human infrastructure. As such, there is space for a broad range of approaches, including potentially less precise methods that can provide significant coverage. Furthermore, technologies and their capabilities are evolving rapidly. This report therefore reviews the capabilities of a broad range of different solutions and does not target any individual solution provider.

We rely on a combination of (i) desktop research, to review publications and other relevant resources, and (ii) semi-structured interviews, to engage with industry participants (technology providers, pipeline operators, and researchers) to understand their experiences and perspectives. In total, we interviewed 10 experts representing pipeline operators, solution providers, and academic researchers. All data provided by participants was anonymized. See Appendix A for questionnaires used to guide semi-structured interviews.

Technologies are classified according to sensing principle and deployment mode.

Deployment modes are defined as:

- **Handheld** – Portable systems that are held by an inspector. These technologies are the ones most commonly mandated by regulations and leak survey guidelines and include combustible gas detectors, optical gas imaging (OGI) technology, and other types of technology (e.g., handheld laser methane detectors).

- **Aircraft** – Typically small aircraft or helicopters. These systems are in widespread use in numerous countries, especially for upstream and midstream operations.

- **Unmanned Aerial Vehicles (UAVs)** – Fixed-wing and rotary-propelled UAVs are emerging for detecting methane emissions at short and medium ranges.

- **Mobile Ground Labs (MGLs)** – Pickup trucks, vans, or cars equipped with a variety of sensors for detecting methane and measuring local atmospheric conditions.

- **Continuous Monitoring** – These systems are stationary. Continuous systems are uniquely positioned to resolve temporal variability in emissions.

- **Satellites** – A growing number of space-borne methane detection systems exist for detecting emissions at both point-source and regional spatial scales.

- **Internal Mobile Methods** – Sensors that are inserted into pipelines and that acquire pipe integrity measurements, which can be used to detect abnormalities leading to leaks, while traveling the along the inside of the pipeline. The systems are often called "pigs" or "smart pigs".

Sensing modes are defined as:

- **Point sensing** (in plume sensing) – Point sensors range from simple solid-state metal oxide detectors to complex cavity ringdown spectrometers (CRDS) and gas chromatographs. Point sensors can be deployed on any platform that passes through methane plumes or has methane plumes that pass over the sensor.

- **Active imaging** (remote sensing) – Active imaging systems generate source(s) of light that traverse methane plumes, reflect off a remote surface, and return to a detector. Changes in the reflected light are used to infer methane concentrations along the path. A common example is Light Detection and Ranging (LiDAR).

- **Passive imaging** (remote sensing) – Passive imaging systems use reflected sunlight to measure methane concentration in the atmosphere. They are used in all types of platforms, ranging from OGI cameras to satellite imagery.

- **Non-methane** – Many sensors infer the presence of leaks by measuring variability in pressure, temperature, vegetation growth, physical disturbance of pipelines or the areas nearby, and other proxies.

Legacy Methods

While leak detection on pipelines is an emerging trend, it has long been the industry standard to conduct some form of monitoring on pipelines. Historically, a common technique for pipeline monitoring has been the use of human senses – auditory, visual, and olfactory (AVO). Handheld leak detection methods have existed since the early 2000s for OGI,[47] and since the 1990s for combustible gas detectors,[48] while continuous belowground monitoring using mass balance systems has been in place on pipeline systems for decades,[49] and have shown to be effective for detecting major disruptions.[33]

Handheld Instruments

Despite the rapid development of new methane detection technologies utilizing vehicles, UAVs, planes, and satellites, handheld instruments are among the most widely used approach – especially for distribution lines. Handheld technologies may be used on their own in an exhaustive search for leaks or as a "follow-up" method in combination with screening technologies. These follow-up inspections can be performed using regulatory approved instruments (i.e., "sniffers"), leak detection devices (49 CFR 192), or optical gas imaging (OGI) cameras. Figure 3 highlights the strengths of handheld instruments, including high sensitivity, commercial uptake, and the number of different products.

Most handheld instruments are point sensors, which means the probe must be in close proximity to the leaking component. Optical gas imaging (OGI) cameras are a specialized version of infrared (IR) or thermal imaging cameras that allow users to visualize methane leaks. In recent years, OGIs have become the preferred choice for LDAR in upstream settings because they generate easily communicable and intuitive results, are more efficient than Method 21, and can survey components at a distance. However, as OGI cameras rely on temperature differences between the atmosphere and the leaking gas their effectiveness for detecting underground leaks may be limited. Handheld laser-based methane detectors are also in use, which also have the advantage of being used remotely. Important work has been done to evaluate laser-based handheld systems and future testing for below-ground infrastructure is expected.[50]

Handheld instruments have existed the longest and continue to have among the lowest detection limits in terms of detectable emission rate due largely to work practices that require close proximity to source. Hanheld instruments are readily available for deployment by many leak survey service companies and have undergone numerous third-party controlled release tests to verify performance metrics for aboveground infrastructure.

The primary limiting factors for both sniffers and OGIs are weather and the highly labor-intensive nature of operation. Typically, Method 21 operators can survey 500 components per day. Depending on the size of the facility or number of miles, full surveys could take days to months to complete. OGI surveys can be performed approximately 20x faster than Method 21 surveys, allowing an operator to survey several above ground sites per day. Handheld instruments are a proven and mature technology with numerous service providers operating in this space. Even with the high labor costs of handheld instruments, combustible gas "sniffers" remain

the tool of choice for distribution lines. Emission rate quantification remains a challenge for both sniffers and OGIs, and has not been demonstrated for underground emission sources. Controlled release testing is currently underway at the Methane Emissions Technology Evaluation Center (METEC) in Colorado to better inform the performance of handheld systems.[51]

Figure 4. Method 21 and OGI (image courtesy of Montrose Environmental Group, Inc.)

Advancement in pipeline leak detection may arise from combining more "traditional" legacy methods (such as mass-balance systems) with emerging technologies (as outlined below), in order to maximize methane detection and emission mitigation. It was recommended in several expert interviews that combining different technology types will result in more leak detection events than any one technology alone.[37–39]

Continuous Monitoring

Continuous monitoring systems for pipelines can be above or below ground. Belowground continuous monitoring technologies typically must be deployed at the time of pipeline installation. Underground continuous monitoring systems can be divided into two main categories: internal and external systems.

Internal systems are installed within the pipeline and measure gas properties within the pipe. Volume-based monitoring systems, pressure-based monitoring systems, and mass balance systems are used. Mass balance systems combine volume and pressure-based methods for higher accuracy in detecting leaks from pipelines. These systems function by measuring the gas flux between two points within the pipeline and comparing the values. If there is a disparity between the two values, the operator will be alerted to a possible leak, and a follow up can be performed. These systems may have precision to within 0.01% of the throughput of the pipeline.[33]

Passenger Aircraft – Visual

A commonly used pipeline leak detection method for gathering and transmission operators is low-flying aircraft, using visual indications of natural gas leaks. Pipeline operators sit in the aircraft and visually search for any signs of a pipeline failure, including dead vegetation, ground disturbance, melted snow, right-of-way encroachment, and other abnormalities. Areas of concern are flagged for follow up, typically using handheld methods.[49] This technique may prove useful in regions where the exact locations of pipelines are unknown, but may be ineffective at reliably identifying the majority of leaks.

Advanced Methods

There has been considerable innovation in the detection, localization, and quantification of methane over the past decade. Innovation has accelerated in many areas, including sensors, deployment platforms, work practices, analytics, and testing procedures. A large and growing number of advanced methods now exist, including a range of point, active, and passive sensors deployed on handheld instruments, aircraft, drones, vehicles, satellites, and stationary systems. Advancements are not limited to technologies and deployment platforms; considerable innovation has occurred in thinking about how, when, where, and whether to deploy different types of technologies – alone and in combination with complementary solutions. The use of diverse sources of information, simulation modeling, machine learning, and other novel techniques is now common for detecting leaks and prioritizing their repair.

Passenger Aircraft with Sensors

In recent years, there has been a growing interest in using piloted aircraft for surveying site-level emissions. Three different technology classes can be installed and used on aircraft:

- Methane point measurements from a mid-infrared laser that measures the reduction of signal intensity through a flow cell. Air passes through the inlets to an onboard concentration analyzer which is then combined with wind speed and GPS data. For this technology class, the aircraft has to fly directly through the methane plume.

- Passive methane imaging from a combination of an infrared spectrometer, GPS, and an optical camera. The most common methods are imaging spectrometers on aircraft and OGI cameras from helicopters. Raw spectral data is converted into images of detected methane plumes.

- Active methane imaging from Light Detection and Ranging (LiDAR) where the reduction of signal intensity from methane is combined with GPS and wind speed data to generate plume images. Both passive and active imaging are forms of remote sensing and do not require direct sampling of the plume air.

The primary limiting factors for this technology are weather (high winds, precipitation, cloud cover), variable reflectivity from water or uneven snow cover, and flight permits. Aircraft detection limits range from a few kilograms of methane per hour to dozens of kilograms per hour. This technology is readily available for deployment and has undergone multiple third-party controlled release tests to verify performance metrics for aboveground infrastructure. Specifically, for the pipeline use case, the main advantage of aircraft technologies is the more significant spatial scale, providing the ability to survey hundreds of miles of pipeline per day or, depending on the infrastructure density, hundreds of sites per day. An industry expert estimates that aircraft can monitor pipelines at a cost of $20-100/mile.[52]

Although aircraft systems are not the most sensitive, some fixed-wing aircraft are able to fly "lawnmower" patterns across large geographic regions rather than targeting only specific sites. This makes it possible to survey entire landscapes, including not only pipelines but also wellsites and other infrastructure, for large methane sources that may not be detected by legacy methods.

Unmanned Aerial Vehicles (UAVs)

UAVs have received considerable interest for their use in LDAR. Like aircraft, UAVs are not restricted to roads and can complement close-range methods by reaching dangerous or inaccessible places, albeit often requiring site access. The most promising UAV systems use point measurement technologies that directly measure methane concentrations, however, UAVs equipped with OGI cameras are also commercially available. Typically, UAV systems use small point sensors to measure ambient methane mixing ratios, but other methods exist that include passive and active imaging. UAVs tend to be more sensitive than sensors deployed on aircraft owing to their ability to fly closer to the methane source.

The primary limitations are weather, the distance from the operator (typically the drone UAV has to be in the line of sight, as per common regulations), and the relatively short flight times of a few minutes to a few hours. Aboveground controlled release testing to evaluate minimum detection limits for UAVs suggest that they can be below 15-20 g CH_4/hr, much lower than most other technologies.[53] This technology is readily available for deployment and has undergone multiple third-party controlled release tests to verify performance metrics for aboveground infrastructure.[53] Testing on pipeline right-of-ways has been underway since 2019 and preliminary results suggest that UAVs can detect leaks as low as 5 scfh but that at least two passes are required to achieve probability of detection > 80%.[54]

For pipeline leak surveys, UAVs present some unique advantages, especially when combined with close-range follow-up surveys. However, additional work is needed to properly benchmark critical performance metrics for buried infrastructure, such as minimum detection limits under different conditions. Drone systems may show promise for surveying hard to access pipeline right of ways (e.g., steep terrain, wetlands, or water bodies). More broadly, drone systems could be used in surveying long pipeline segments if they can overcome regulations that prevent beyond visual line of sight flight[55] and overcome battery life limitations.

Figure 5. Methane detection UAV.[56]

Mobile Ground Labs (MGLs)

MGLs are defined as any ground-based vehicle (car, truck, van, ATV, etc.) equipped with a methane sensor. The methane sensors are relatively unobtrusive additions to the vehicle. Typically, MGLs will also have a GPS to track location and an anemometer to measure environmental conditions, especially wind speed, wind direction, temperature, and humidity. MGLs can be stationary (parked vehicles) or mobile (driving vehicles). Stationary MGLs are used for site measurements but are not conducive to surveying long linear features like pipelines.

MGLs can take an active or passive approach to surveying. The active approach involves MGLs driving a predetermined route along the infrastructure to be surveyed, while the passive approach entails mounting sensing equipment on vehicles performing unrelated tasks, like delivery trucks. The passive approach could prove beneficial for distribution pipeline networks that are heavily trafficked. However, gathering and transmission pipelines require an active approach due to their remoteness.

The benefit of MGLs is their ability to balance speed and sensitivity. While minimum detection limits vary by sensor used, work practice, and distance from the source, available data indicates that minimum detection limits can be as low as 100 g CH_4/hour for aboveground sources and as high as 40 kg/h.[57] MGLs can also obtain measurements while travelling highway speeds.

The primary limitations are road access and meteorological conditions. MGLs require wind to be blowing toward them. Should winds be blowing away from an MGL, any leaks present would avoid detection. An investigation by Weller et al. used MGLs to detect emissions from distribution pipeline networks across the U.S.[35] The study showed the efficacy of using MGL sensors on Google Streetview cars to detect methane leaks and is investigated further in a case study on page 19. For gathering and transmission lines, MGLs would need to drive along right of ways, which may not always be accessible.

Figure 6. Mobile optical cavity ring-down spectroscopy vehicle configuration. Image courtesy of Picarro.[58]

Continuous Monitoring

The space of continuous monitoring on pipelines is evolving, and innovation is taking place. While internal pipeline monitoring systems are commonplace in the industry, as discussed above, systems that are installed underground, on the outside of the pipeline are rising in interest and use. External systems are installed on the outside of the pipeline and can be broken down into the following categories:

- Acoustic sensors: detect the sounds of leaks, deformations, or line strikes, and can alert an operator to the approximate location of the source of the sound.

- Fiber optic cables: sense acoustic signals, changes in temperature or pressure, or vibrations caused by leaks. They are useful for leak detection and leak prevention, alerting operators to potentially disruptive conditions, including earthquakes and encroaching heavy machinery, which can allow for operators to perform pre-emptive shutdowns of sections of pipe to minimize damage and loss of gas.[59]

Note that neither acoustic sensors nor fiber optics can sense leaking gas directly, they rely on changing conditions, so detection limits can be quite variable. To our knowledge, belowground systems have not been independently verified for their performance. These systems are typically installed alongside new pipelines, as it may be prohibitively expensive to dig up and retrofit old pipelines. An interviewee quoted a price of approximately $20 per meter of pipeline for fiber optic cables,[60] and noted that they were primarily installed on large diameter transmission pipelines.

Innovation in continuous aboveground monitoring over recent years has skyrocketed. However, these systems are used almost exclusively for discrete facilities, such as wellsites, compressor stations, and processing facilities. To our knowledge, there have been no deployments of aboveground continuous measurement systems to monitor pipeline emissions due to the vast distances involved. However, new approaches are being developed and tested using metal oxide sensor networks at the ground surface.[61]

Satellites

Several methane-sensing satellites exist and more are in development; these systems are diverse in form and function. They frequently have very high minimum detection limits, to the point where even large sources are missed. Current satellites have been demonstrated to detect "ultra-emitters", which are even larger than super-emitters. Proposed satellites should offer improved sensitivity. Satellites use backscattered shortwave infrared (SWIR) radiation to infer column-integrated methane mixing ratios. Historically, the spatial resolution of methane-sensing satellites is at the regional scale (tens to hundreds of kilometer pixel widths); however, rapid innovation is occurring towards higher resolution systems (<10 km and as low as 50 m), which enable site-level measurements.

A growing number of independent efforts are using satellite data to monitor for super-emitters around the world. The European Space Agency's Sentinel-5 satellite has been used to reveal giant methane releases from dozens of countries.[62] Moving forward, planned initiatives by Carbon Mapper and Environmental Defense Fund (MethaneSAT) will seek to provide independent coverage and accountability for regions and producers prone to large methane emission events.

The minimum detection limit of satellites has been estimated to be between 1000 and 7100 kg CH_4/hr.[63] While this is easily the highest detection limit of technologies discussed in this report, the recorded emission rates of some "super-emitters" fall within this range. More recently, GHGSat has claimed facility-scale detection limits as low as 100 kg/h, but these have not yet been independently verified.

The speed with which a satellite can survey depends on orbit type. If the satellite is placed in a "sun-synchronous" orbit, the satellites are fixed relative to the sun. GHGSat, currently the only private satellite detection company, uses a 90-minute sun-synchronous orbit. Geostationary orbit sees the satellite orbit above a fixed position on the Earth. Geostationary satellites are effectively a coarse scale "continuous monitoring" solution.

As the SWIR technology employed by satellites is based on the observation of background infrared radiation reflected off the Earth's surface, many factors can affect this radiation reflection and in turn, a satellite's readings. These factors include:

- Meteorological conditions, especially clouds.

- Surface landcover (reflectivity is dependent on land cover. Water, for example, is a poor reflector of infrared radiation).

- The angle of the sun over the Earth relative to the satellite (as the angle of the sun increases, less infrared radiation is reflected directly back).

- Latitude of site location (satellites require reflected sunlight for their observations and therefore high latitude locations are unable to be observed during the winter).

Internal Mobile Methods

Smart pigs exist that travel through pipelines and collect data along the way. They have been tested primarily on transmission and distribution pipelines, which typically contain only clean, processed, dry gas. Smart pigs can monitor internal pipeline conditions in two main ways:

- Via acoustic sensors, which use sound waves to detect the sound, vibration, or temperature change caused by leaks.

- Using magnetic flux or ultrasonic waves to examine the internal structure of the pipeline. This technique should detect any internal corrosion, structural stresses, or any other potential weakness in the pipe. This is a technique that monitors pipeline integrity, it does not search for leaks, nor pinpoint their location, so there is no minimum detection limit.

Recommendations for Gathering Lines

Gathering pipelines transport a valuable product and it is in the interest of oil and gas companies to prevent product loss. The use of advanced technology to detect emissions from gathering pipelines is an important step towards minimizing lost product. Passenger aircraft with sensor-based surveys conducted on gathering pipeline systems have been successful to date in detecting methane emissions.[8,52] MGLs and UAVs have been used, but have yet to demonstrate strong performance for finding leaks from underground pipelines.[12–14]

Traditionally, mass balance systems have been adopted to monitor gas flow through gathering pipelines. These systems track the flux of gas through the network with a series of meters. Also, temperature and pressure sensors can be placed throughout the system. Drops in flow or pressure or sudden temperature changes trigger an alarm to alert operators of a potential leak. One limitation of mass balance systems is that they can only alert operators of a potential leak but do not provide a location. These systems should be as sensitive as possible, trigger alarms for even small leaks, and allow the operators to deploy follow-up solutions to identify the leak's source and conduct repairs.

Another technique that pipeline operators commonly use is an annual visual flyover, as discussed above.

This legacy method has been in use for many years by industry, but may not always be the optimal choice for detecting methane emissions. The use of emerging aerial methods, especially those that scan entire regions, can be particularly useful when an operator is unaware of gathering pipeline locations. Combining the work practices of aerial-based visual surveys with emerging passive, active, or point methane sensing aircraft technology should increase the leak detecting potential of either method alone. Visual signs of leaks can be used to help direct the aircraft methods on where to focus efforts, and the information gathered from conducting aircraft based leak detection campaigns can be analysed and used to train pipeline operators on signs of leaks.

Recommendations to improve leak detection from gathering pipelines include: (i) perform more leak detection surveys using a combination of methods, (ii) more accurate pipeline right of way data, and (iii) controlled release experiments should be conducted to verify leak detection equipment's use on underground pipelines.[13]

Internal mobile monitoring and underground continuous measurement techniques are widely used by industry,[49] although their detection performance requires empirical verification. Widespread uptake by industry suggests that these techniques are effective and have an important role to play in preventing leaks. Industry and technology experts interviewed suggested that the best approach for gathering pipelines is a combination of different techniques. For example, the use of a mass balance continuous monitoring system in conjunction with UAVs or aircraft to enable for rapid localization of large leaks and rapid leak repair.

Recommendations for Transmission Lines

Transmission pipelines are regulated to a much higher standard than gathering pipelines. Midstream companies and transmission operators monitor their pipelines closely to ensure that the gas they are transporting is not lost to the atmosphere. Advanced leak detection methods show promise for monitoring transmission lines. Internal continuous monitoring is widely used by industry, and has been proven successful at reducing emissions.[33]

Most transmission pipeline operators conduct annual visual surveys of their line to inspect for any signs of leaks or damage. This is done as a matter of both safety and asset integrity. After visual surveys, underground continuous measurement technology is the second most widely used leak detection method. Mass balance systems are common in the midstream industry since they are necessary not only for leak detection purposes but also to keep track of how much gas is flowing through their systems. Furthermore, a number of midstream companies in North America have implemented fiber optic sensors as part of their pipeline monitoring efforts, which operate well in combination with mass balance systems.[59]

Some midstream companies also use advanced methods such as satellite and aerial (fixed-wing and helicopter) methane detection technologies and laser absorption and infrared sensors.[64] Multiple major midstream companies have begun using UAV technology in both the United States and Canada to monitor sections of their lines.[65 66] A large US-based midstream company stated in their 2020 ESG report that they were using continuous belowground techniques to monitor for flow, temperature, and pressure, as well as using infrared, acoustic, and laser techniques to facilitate their leak detection efforts.[66] They also utilize internal mobile methods (smart pigging) to monitor the pipeline integrity. Another major transmission company states in their 2019 sustainability report that they "*monitor pipelines for leaks and damage using multiple, redundant methods*", which include the legacy methods of handheld OGI, handheld gas sniffers, and visual aerial patrols.[67]

It is becoming clearer that combining different strategies may be the most effective approach in the efforts to mitigate methane leaks from pipeline

systems, including transmission lines. To date, there have been no peer-reviewed studies conducted that detect methane leaks from transmission lines. The widespread opinion across the industry and among technology companies is that transmission lines are of lower risk from a methane leak perspective.[49,60] Gas Technology Institute has published a comprehensive recommended practices for transmission line leak monitoring which contains more information than is presented here.[68]

Recommendations for Distribution Lines

Utility companies perform periodic surveys of their entire systems using traditional handheld devices. They walk their entire network of pipes through customers' backyards, businesses, and sometimes even into homes, while taking measurements with handheld methods like gas sniffers and OGI cameras. The reliability of this technique is uncertain, and it is highly labor-intensive. One of the biggest obstacles in detecting emissions from distribution lines is that they are often buried under concrete or asphalt. Pavement materials tend to be impermeable to natural gas,[69] so emissions are usually detected where gas has migrated, at storm drains, cracks in sidewalks, and at boundaries of pavement.[52] Natural gas in urban settings is odorized, which can facilitate leak identification, especially for larger sources.

Over the past few years, use of MGLs has increased, both in the United States and in Canada. California-based natural gas utility company Pacific Gas and Electric (PG&E) has committed to reducing their methane emissions, and is doing so by modifying its emission management practices.[70] They have invested in vehicle-based leak detection systems, and have increased their mandatory systemwide survey frequency from every 4 years to every 3 years.

ATCO, the largest natural gas utility company in Alberta, Canada, has adopted vehicle-based leak detection, enabling them to collect pipeline information up to four times faster than through walking alone. Additionally, they claim that the new technology is up to 1000 times more sensitive than sniffers or OGI, allowing for the detection and repair of much smaller leaks.[71]

There have been instances where utility companies are using aerial methods (including satellites) to quickly scan their entire system.[72] Still, these technologies' minimum leak detection threshold may be too high to pinpoint most downstream leaks, given that average leak sizes in distribution pipelines range from 1.72 to 2.24 grams per minute,[35] and the leak detection threshold of aircraft can be as high as 250 grams per minute (15 kg/hour),[73] and satellites 1,667 grams per minute (100 kg/hour).[74]

AVO methods remain an essential component of leak detection on distribution lines. Utility companies frequently have instructions for how to recognize a gas pipeline leak posted on their website, which use AVO.[75-77] The chemical additive that is present in natural gas is called mercaptan, and it is easily recognized by people. It is also possible to train dogs to sniff out mercaptans (not to be confused with gas sensor sniffers).[78]

One of the drawbacks of the existing system in place for distribution pipeline leak surveys is the infrequency of the campaigns. Most utilities conduct systemwide surveys every 3-5 years, allowing for high persistence of small leaks that are not otherwise detected. Data on the use of other advanced technologies for detecting leaks from distribution lines is sparse. Most urban areas are complex with many sources of methane, and leaks from distribution lines tend to be small. This suggests that inspecting closer to the source using handheld or vehicle systems may be most appropriate.

Case Study 2: PG&E Adoption of Advanced Methods

Given the phenomenon of super-emitters, in which a small fraction of the total number of leaks accounts for a large fraction of the overall methane emissions, many pipeline operators have been prioritizing detection and repair of larger leaks within their systems.[70,79] Detection of larger leaks using emerging methods, including vehicle-mounted MGLs, has been proven to be effective at detecting these larger volume emissions sources.

Pacific Gas and Electric (PG&E), a gas utility company based in California, begun conducting super-emitter annual leak surveys of their entire system in 2018 using mobile ground labs.[70] The purpose of this program is to expedite the discovery of leaks larger

than 10 scfh, and ensure their timely repair. The first super-emitter survey identified 220 large sources within the system, 134 of which were in the areas not typically covered by the periodic handheld surveys. PG&E conducted an analysis of the leak detection capability of the mobile mounted methane detecting systems, and found them to be generally effective at accurately detecting and classifying emissions (78% of leaks over 10 scfh were well classified by the system).[80] The company estimated that the abatement potential from the faster detection (mobile mounted systems work approximately 10 times faster than foot surveys), and repair of these larger leaks would result in an emissions reduction of 119 MMscf per year in the first year.[80]

Conclusions

This report reviews the current state of scientific research and operator experiences on natural gas emissions from pipelines and the technologies available to detect, localize, and quantify leaks. We examined the literature and interviewed operators of gathering, transmission, and distribution pipelines as well as innovators and vendors of advanced leak detection technologies. Overall, we find that natural gas leaks from pipelines are a growing concern but can be mitigated using a broad range of technologies. In particular, the last decade has seen rapid growth in the availability of methane-sensing technologies able to identify underground pipeline leaks. We present the following key findings.

Key findings

1. **Pipeline methane emissions can be a significant environmental and safety concern.** A growing number of studies suggest that gathering and distribution pipelines are an important source of methane emissions. Pipeline leaks increase the carbon intensity of natural gas as an energy source and create potentially unsafe work and living conditions.

2. **Considerable innovation over the past decade has led to a growing number of advanced leak detection technologies and data analytics.** Dozens of systems have been developed to detect methane leaks in the oil and gas industry, including new handheld devices, drones, mobile ground labs, aircraft, satellites, and continuous measurement. Significant innovation is expected to continue over the next decade.

3. **Diverse advanced methods are available today and adoption rates are accelerating.** A growing number of operators in all segments of the supply chain are using advanced solutions to detect, localize, and quantify methane emissions.

4. **Adoption of advanced methods in the absence of regulation signals their value.** Many operators are moving to adopt advanced solutions for detecting methane emissions from pipelines despite a general lack of regulations in North America requiring their use. This is a strong indicator of their value to industry.

5. **Full coverage of a system may require the use of multiple technologies.** Studies show that different types of technologies see different leaks, and that no individual technology is a "silver bullet". The use of multiple different technologies may provide more complete coverage.

6. **Gathering lines are the least regulated but could be the biggest emitters.** Gathering lines are mostly unregulated and omitted from leak detection surveys. However, recent data suggests that gathering lines can be prone to super-emitter leaks far in excess of 100 kg/h. Furthermore, gathering line locations are often unknown by operators and regulators.

7. **Transmission line leaks are uncommon but of high consequence.** Transmission lines have greater throughput and have higher climate, safety, and economic risk than gathering and distribution lines. Transmission lines are therefore built to higher engineering standards and are monitored regularly for leaks.

8. **Distribution lines have smaller leaks but are a greater safety concern.** Delivering gas to end users in urban environments, distribution lines typically carry odorized gas. While most large leaks tend to be addressed quickly, others may persist for years. However, distribution lines are the most extensive pipeline infrastructure segment, with complex pipe networks in all urban centers. Small and medium sized leaks are therefore common and can pose both an environmental and safety concern..

9. Methane emissions from pipelines vary spatially. Recent studies on gathering lines have focused on the Permian Basin, a region known for high methane emissions. Other areas are understudied – emissions are likely higher than currently believed but unlikely to be as high as the Permian. The Leakiness of distribution lines varies considerably and is likely the product of infrastructure age and materials.

10. **Methane emissions from pipelines can be persistent.** Data show that pipeline leaks can persist through time until they are found and fixed. This presents an important opportunity for finding existing leaks and permanently reducing methane emissions.

11. **Transmission and distribution lines are already regulated, but the effectiveness of existing leak detection methods remains unclear.** Legacy methods for pipeline leak detection exist but have had mixed results. Transmission lines are visually inspected for dead vegetation using airplanes or helicopters, which may not work for small leaks or in unvegetated areas. Distribution lines are commonly inspected using handheld instruments, but impermeable surfaces may prevent detection and localization.

12. **Each segment is unique and benefits from the use of different solutions.** Gathering and transmission lines are challenging due to their spatial extent and are best surveyed by aerial methods or vehicles that can drive along the right of way. Due to complexity and confounding sources; they generally require higher sensitivity methods that measure closer to the source.

13. **The more we look, the more we learn and find.** Continuing to conduct comprehensive methane surveys of pipeline infrastructure is important to expand understanding of leakage. Opportunities exist for more measurement campaigns and research to inform on the effectiveness of methane detection and quantification methods. Transparency and accurate, uniform reporting will enhance public knowledge of pipeline methane emissions.

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Appendix A: Expert Interview Questionnaires

Leading questions for pipeline company semi-structured interviews:

Understanding surveys

- How do you currently detect leaks on your lines? Have you noticed any limitations? How frequently do you inspect for leaks? How frequently do you survey your entire pipeline system? What do you do in your day-to-day operations to monitor your gas pipelines? What techniques exist to ensure that the amount of gas that goes into the system comes out the other side?

Understanding Advanced Leak Detection

- Have you ever used any advanced solutions? If so, how was the experience? Do you have any information on cost that you could share with us? What are your future plans for use of advanced solutions? What does a perfect future pipeline leak detection system look like to you?

Understanding intentional emissions management

- What do you do to address/minimize venting from pigging, blowdowns, etc.?

- What is required to eliminate intentional sources of emissions

Understanding emissions

- How often do leaks occur? Where do the leaks usually occur? What are the leading causes? How often do you think there are emission events that you don't see?

- Is the size/rate of leaks typically correlated to the size of the pipeline?

Lower priority questions

- How long does it take to isolate the source of a leak and repair it?

- Do you inspect the entire pipeline network? Are triage techniques used to improve efficiencies?

- What materials are your lines made from? Is there a balance between operating performance and cost when considering how to construct lines?

- Do you have a system for tracking information about leaks? How is that information used in decision making beyond the repair of those leaks?

- What incentives or quotas do you have for leak surveyors to find leaks? What is your training program for leak survey? Are you happy with the training? How hard is it to get good people on your leak survey crews?

- Why do you think you find a leak one day but not another day? That is, why is it that you can't find some leaks every time you look for them?

- How often do you encounter issues with a difference between the pipeline location database and where the pipes are actually in the ground?

Leading questions for technology and service provider company semi-structured interviews:

Understanding the technology/service

- Have you used your technology to detect leaks from pipelines? How is it different from leak detection on other aboveground O&G infrastructure?

- How is your solution better and/or worse than other solutions for pipeline leak detection?

- Is your solution equally able to detect leaks on gathering, transmission, and distribution lines?

- What considerations do you make when preparing cost estimates for this type of work? Do you have any information about how much the cost of deployment is, on a $/(unit length) basis?

- How do you know it works? What might you be missing?

- What are some of the biggest challenges you've experienced to date with leak detection from pipelines? What have been the limitations?

- How does the environment impact your ability to detect leaks from pipelines?

- How does the material surrounding the pipeline impact your ability to detect leaks coming through that material? (aka soils, air, water, pavement, etc? do different soil types matter?)

- Is there variation among pipeline operators in how they deploy your technology on your technology?

Understanding emissions

- How often do leaks occur? Where do the leaks usually occur? What are the leading causes? How often do you think there are emission events that you don't see?

- Is the size/rate of leaks typically correlated to the size of the pipeline?

- Has anything about leak detection on pipelines been surprising?

Opportunities/future trajectory

- How could LDAR techniques on pipelines improve going forward?

- Why don't you see greater adoption of your solution for detecting methane emissions from pipelines? What would encourage faster adoption?

- What does your technology not do that you wish it did?

- How do you see advanced methods evolving in the next 5-10 years?

Lower priority

- If you were to participate in a technology validation testing, what features would you want to include and exclude so you'd feel it was fair?

- Are pipeline operators generally deploying your equipment well? What do you do if you think they are not doing a careful job with your equipment?

- Who owns the data that your technology & deployment generates?

- Are there any devices on the market (not yours) that you think are really inappropriate/ inaccurate?