Reducing Oilfield Methane Emissions: How Technology, Data Analytics and Stakeholder Engagement Can Drive Emission Reductions

TRP | ENERGY

With foreword provided by Environmental Defense Fund

> “We hope this case study inspires oil and gas operators at the start of their environmental management journey to take the first steps in using new technologies and methods to identify and address methane emissions.”

Andrew Baxter
Director of Energy Strategy
Environmental Defense Fund

Foreword

More than 25% of the warming the planet is experiencing today is caused by human-made methane emissions, with nearly 10% coming from the U.S. The oil and gas industry is responsible for 40% of U.S. methane emissions.[1,2] Methane has become a strategic business and climate concern for the sector as it is increasingly under pressure to decarbonize.

Groundbreaking research published in April 2021 shows a rapid, full-scale effort to reduce methane emissions could slow the worldwide rate of warming by as much as 30%.[3] The report singled out oil and gas as the sector with the highest potential to contribute climate benefits from fast action to cut emissions, citing 80% of no-cost actions in this sector alone. The results underscore both the major opportunity and obligation oil and gas companies have to work on decreasing these emissions today.

Independent operators are the engine of the U.S. oil and gas industry. According to IPAA, these companies develop 91% of oil and gas wells.[4] Better controlling methane at these sites could play a seismic role in shrinking industry’s overall methane footprint.

Small oil and gas operators do not always have in-house atmospheric science and environmental expertise, and as such, it can be a daunting prospect to take the first steps to tackle this issue. Furthermore, the oil and gas industry is facing a methane emissions data challenge. Most U.S. companies estimate methane emissions using desktop calculations versus quantifying actual emissions based on field measurements and simulation tools. This lack of high-quality emission data can create a murky picture of the emissions profile of a company’s assets, making it difficult to develop an effective strategy to find, prioritize and eliminate emissions in a cost-effective manner.

As operators assess the tactics of methane mitigation, they face increased scrutiny from regulators, customers and investors on climate transition risks, which can be material to the company’s profitability and asset values and their ability to raise capital to finance operations.

TRP Energy (TRP), a small, independent operator based in Houston, Texas, is acutely aware of the urgency of the situation and the intricacies of the challenge. In November 2020, TRP assembled a team to tackle its methane emissions, trialing a variety of sensors and deployment methods to detect and categorize the leaks from their facilities. The pilot has significantly improved TRP’s understanding of its methane emissions and has unlocked new opportunities to better manage the issue, including focusing efforts on high emission sources first. The initiative is helping TRP chart a new path forward that other companies within the industry can emulate and/or apply to their own methane solutions. In this paper, TRP explores the assessment of methane emissions on its own oil and gas assets in the Permian Basin. We hope this case study inspires oil and gas operators, big or small, at the start of their environmental management journey to gain confidence in using new technologies and methods to identify and address methane emissions from their own operations. The urgency of the climate crisis demands it.

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1. IPCC, Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. ipcc.ch/report/ar5/wg1/chapter-8sm-anthropogenic-and-natural- radiative-forcing-supplementary-material
2. Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, *Science*, July 2018. science.sciencemag.org/content/361/6398/186
3. Ilissa Bonnie Ocko et al, Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming, Environ. Res. Lett. in press 2021. doi.org/10.1088/1748-9326/abf9c8
4. Independent Petroleum Association of America. www.ipaa.org/independent-producers/

Executive Summary

Greenhouse gas (GHG) emitted from the production and consumption of oil and gas erode some of the societal economic benefit derived from these low-cost, high-density energy sources. Access to low-cost energy drives GDP in developed nations and is a matter of public health in the emerging world, but the unfortunate reality is GHG emissions from oil and gas are also directly linked to climate damage. While there is no perfect energy supply today and as we transition to cleaner energy alternatives, we all stand to benefit from responsibly produced oil and gas with a lower carbon footprint.

> "Answering the methane call will allow responsible operators to display environmental stewardship and maintain the social license to provide reliable, affordable energy to consumers."

Randy Dolan
Co-founder and CEO
TRP Energy

Joey Bernica
VP, Business Development
TRP Energy

GHG emissions largely occur at the end user where hydrocarbons are combusted, downstream of the oil field where they are produced. IHS Markit states that these Scope 3 emissions comprise 70%-80% of total oil and gas emissions. New research has come to light, aided by the latest detection technology, that suggests methane emissions within the oil field (Scope 1 emissions) have been underestimated and are more prevalent than previously understood. In addition, methane emissions from all industries are under intense scrutiny given their detrimental near-term climate impact. Methane has 85x the potency of carbon dioxide over a 20-year time span. Many industry stakeholders now agree oil field methane emissions are higher than previously thought but if mitigated could have a significant beneficial impact on near-term climate ambitions.

TRP, a private operating company in the Permian Basin, saw this methane issue as an opportunity for collaboration across industry stakeholders in an effort to find practical solutions in a real-world environment. We collaborated with the Environmental Defense Fund (EDF) to leverage our operational expertise with the latest technology and to add a science-driven, environmental perspective to our methane emissions study. Several observations rose to the surface during our methane initiative, with one of the most important being that U.S. upstream operators can play a role as environmental stewards and help combat climate change.
Beginning in November 2020, we deployed four methane detection methods over a two-week period across our 11,000-acre Midland Basin asset, ranging from fixed wing aircraft to ground-based continuous monitoring. Our position is a prototypical oil and gas field with a combination of older vertical Wolfberry wells and newer horizontal Wolfcamp wells that all flow into central separation and treatment facilities prior to sale. We compared various detection methods to study the quantum of methane emissions, the common culprits and the difference in measurement readings. Armed with actual emission data, our objective was to develop a bespoke, yet practical leak detection and repair (LDAR) program that prioritizes methane abatement on dollars spent per metric tons of CO_2e mitigated.

Our overarching conclusion is methane issues span a spectrum, from the easily solvable and economical to repair (e.g., valve leaks that could be captured and sold) to the much more complicated and expensive to fix (e.g., tanks at low-rate facilities below the economic threshold for a vapor recovery unit). Though there is no silver bullet detection technology that will work for all assets and measurement readings oftentimes differ for practical reasons (e.g., temporal variability), our analysis of overlapping detection data directionally pointed us to substantive emissions. Moreover, given the potential for leaks to occur between required detection visits, there is a strong case to be made for voluntary continuous monitoring of high-risk facilities on a go-forward basis.

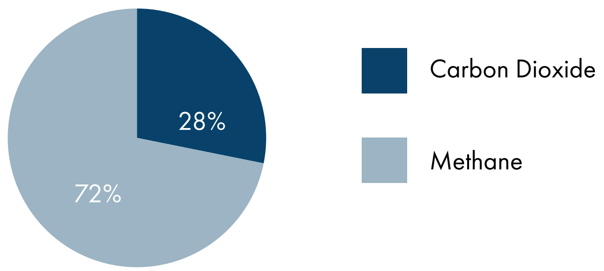
We also realized detection is only part of the solution. For example, tanks were our common culprit, but deciphering the underlying issue at fault may require a fulsome inspection of the closed vent system by a specialized facility engineering team. Our asset warrants a holistic LDAR approach, including automated detection and monitoring technology, a trained field crew with an OGI camera and a specialized facilities engineering team.

Our hope is this methane pilot highlights the potential for new detection technologies, the nimbleness and ingenuity of private companies, and that cross-industry collaborations can accelerate methane mitigation solutions. Answering the methane call will allow operators to take responsible environmental action and maintain the social license to operate in a rapidly transforming energy market. Solving the methane challenge will require capital, human resources and unique solutions, but the benefits are significant for the environment, the energy industry and the consumer. We hope the following paper, detailing our real-world study and practical takeaways, will help progress the cause.

Why Methane?

The U.S. industry can responsibly tackle the methane issue and rewrite its narrative with all stakeholders. Investor sentiment toward U.S. oil and gas producers has deteriorated in recent years due to poor capital allocation, mediocre returns, governance concerns and environmental headwinds, resulting in an exodus of capital from the sector and corporate consolidation. The surviving U.S. oil and gas producers have taken heed and quickly adopted a new business model prioritizing cashflow and returns over production growth. While this value-based strategy should yield better outcomes over the next cycle, investors still question the sector's environmental risk, notably its surface impact, water use, air pollution and GHG emissions.

Figure 1: Allocation of Scope 1 Emissions across U.S. oil and gas value chain



Source: EPA 2018. Emissions expressed in CO_2e using a 25x GWP for methane.

There are numerous efforts underway across the oil and gas supply chain to identify and reduce GHGs, all of which are commendable and will be needed to meet the goals of the Paris Agreement. We identified reducing methane emissions as the most cost-effective way to lower our own GHG footprint.

We believe methane should be prioritized for the following reasons:

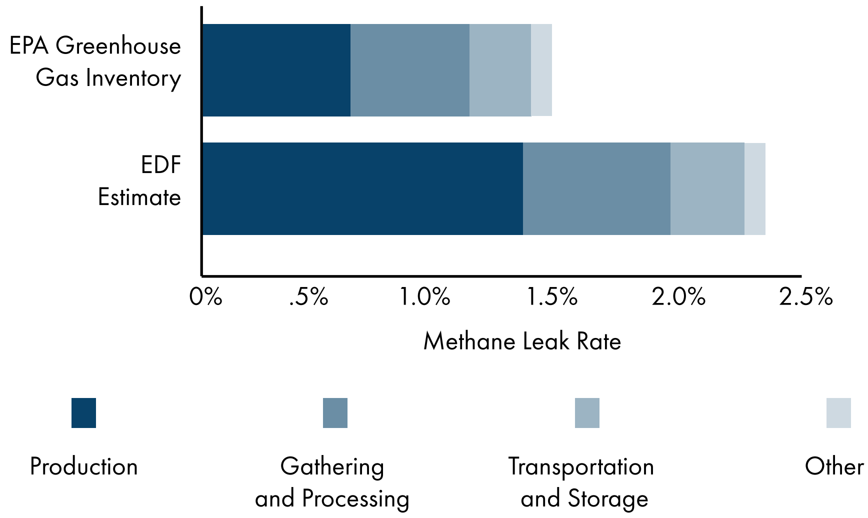
- We want to ensure a future for natural gas. Methane emissions from upstream and midstream operations roughly double the 20-year climate impact of natural gas and therefore reduce the benefits of switching from coal in power generation.
- Methane has an outsized impact on near-term climate. Methane has a short lifespan in the atmosphere relative to carbon dioxide, but it has a more detrimental impact while present. Methane's global warming impact over a 20-year period is 85x that of carbon dioxide.
- Oil and gas production operations account for a large portion of methane emissions.
    - Man-made methane accounts for ~25% of the global climate changes we experience today.
    - The oil and gas industry accounts for ~22% of global methane emissions.[5]
    - In the U.S., the oil and gas industry is responsible for ~40% of total methane emissions.[6]
- Methane emissions from oil and gas operations are poorly understood and likely understated in oil plays because estimates primarily rely on desktop calculations rather than field measurements. Oil plays only produce ~20% of natural gas in the U.S. yet are responsible for a disproportionate share of methane emissions given gas plays tend to have lower methane intensities.
- Methane emission solutions are cost-effective. Recent advances in methane detection technologies allow operators to cost-effectively identify emission sources. TRP has found the all-in cost to identify and reduce methane emissions is lower than reducing carbon dioxide emissions from production operations.

> "We identified reducing methane emissions as the most cost-effective way to lower our own GHG footprint."

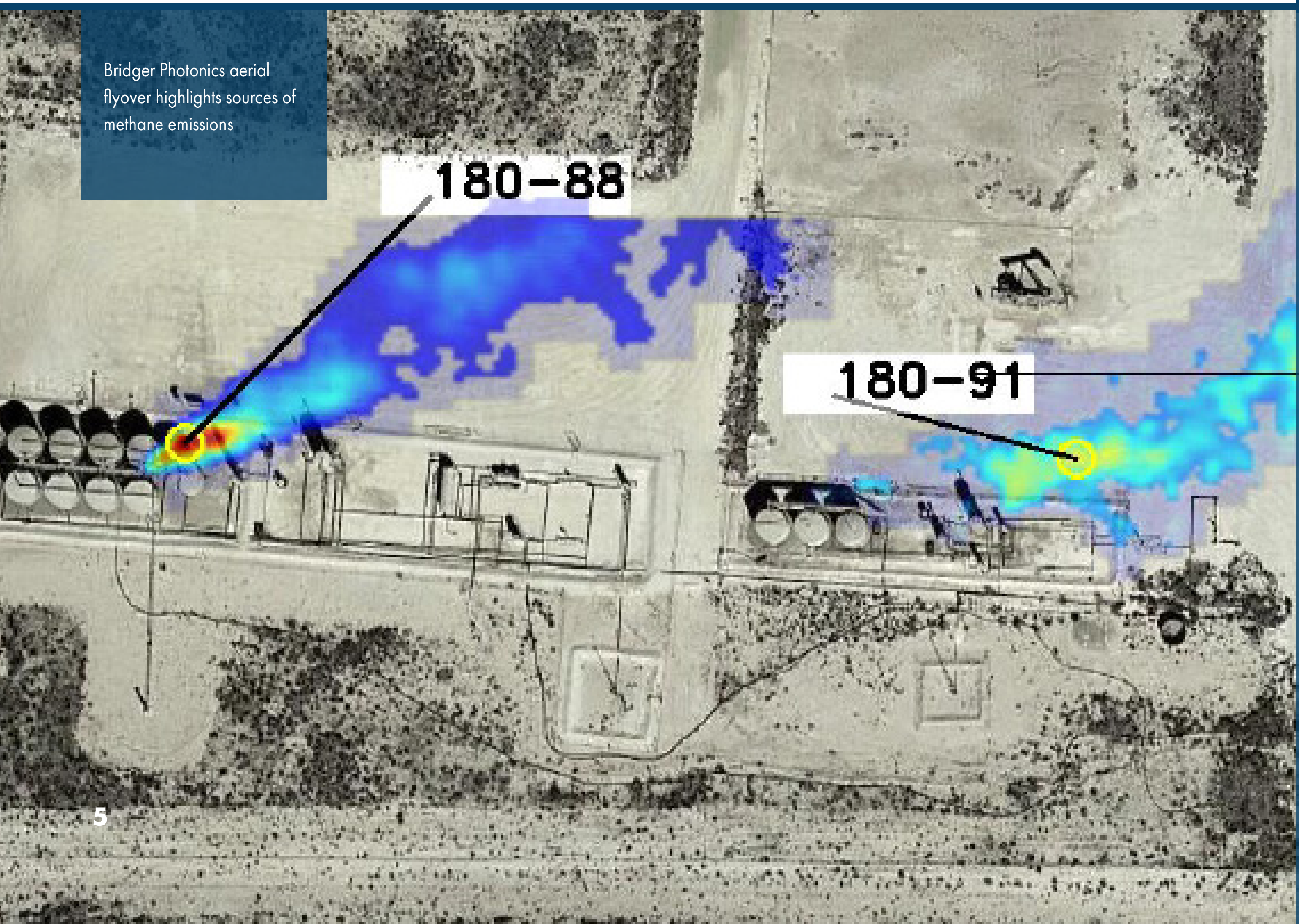
[5] Global Carbon Project. 36% of anthropogenic methane comes from fossil fuels of which 62% is from the oil and gas industry. globalcarbonproject.org

[6] United States Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks. epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

Figure 2: Discrepancy in methane leak rate from the natural gas value chain (Actual Measurements from EDF vs. EPA Emission Factors)



Source: Alvarez et al., 2018



Bridger Photonics aerial flyover highlights sources of methane emissions

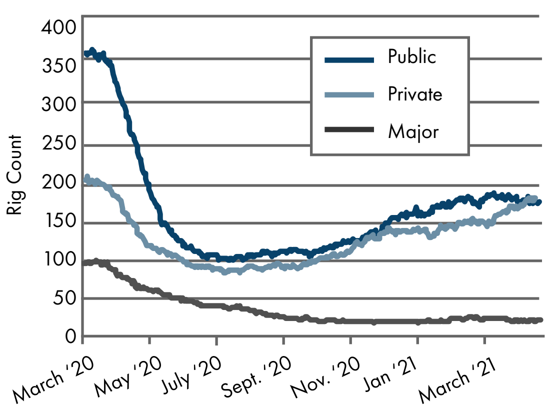
TRP Energy routinely inspects emission mitigation equipment

Private Operators Can Drive Innovation

Private oil and gas operators like TRP Energy comprise a significant portion of U.S. production and activity, currently accounting for 47% of U.S. rig count in major shale basins.[7] The environmental contributions of private operators are often overshadowed by headlines from the majors and large independents. Yet private operators need to continue to do their part for the industry to achieve its collective environmental goals.

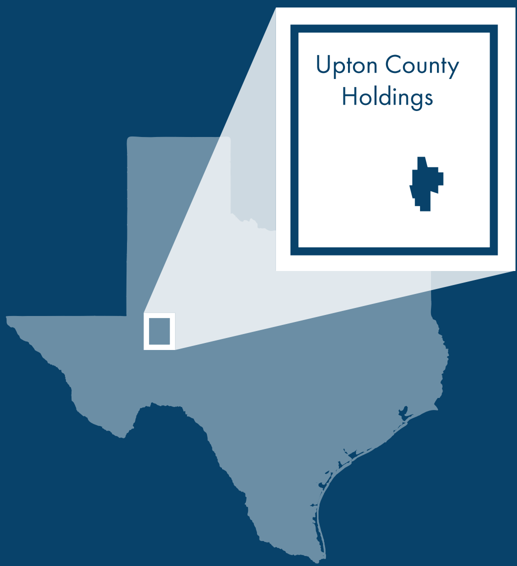
Privates are often stereotyped as having tighter budgets and lax when it comes to environmental practices. What is lost in this personification is private operators' ability to quickly adapt and roll out new technology due to a lack of bureaucracy. We believe private operators in the U.S. will be instrumental in tackling GHG emissions in our industry in a capacity similar to their role in accelerating the shale revolution.

Figure 3: Horizontal Rig Count in Major U.S. Shale Basins



Source: U.S. Capital Advisors

[7] U.S. Capital Advisors. Rig count in major U.S. shale basins

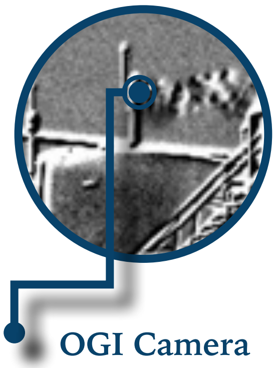


Statistics on TRP's Upton Asset (2020)

- **Q1 2022E Production Rate: 9,000 boe/d (70% oil)**
- **66% oil; 34% gas***
- **115 vertical wells**
- **12 horizontal wells**
- **Artificial lift types: rod pump, plunger lift, gas lift, plunger-assisted gas lift**
- **25 central facilities**
- **71% oil on pipe**
- **100% gas sales on pipe**
- **98% water on pipe**

*Gross wellhead figures. 6:1 boe basis

Building a Methane Program



OGI Camera
Highlights emissions on top of a tank

The first step toward reducing oilfield methane emissions is to identify emission sources through a robust detection program. Numerous research studies have concluded methane emission estimates using industry-standard emission factors consistently misrepresent the sources and magnitude of actual emissions.[8] This emission quantification discrepancy has led to reporting distrust between the oil and gas industry and environmentalists, investors and the public.

The conventional method for identifying both volatile organic compound (VOC) and methane emissions is to use an Optical Gas Imaging (OGI) camera. OGI surveys are performed on a routine basis by trained crews. OGI is one of two EPA-approved inspection technologies and is currently the most widely used by industry. OGI is good at consistently identifying emissions but suffers from the following deficiencies:

- OGI measures thermal signatures and not methane or VOCs directly so it has issues with interference from hot surfaces and other high temperature gases.
- An OGI camera inspects equipment at one point in time whereas certain methane emissions come and go throughout the day.
- Traditional OGI surveys are labor-intensive and have limited spatial coverage which makes them expensive on a per-facility basis and difficult to deploy at large scale.
- OGI is primarily qualitative, although there are emerging quantitative approaches.

Fortunately, advances in methane detection technology have led to cost-effective avenues for operators to address these issues. While there is currently no silver bullet for methane detection, alternative methods excel at improving certain areas where OGI remains deficient. These technologies utilize various sensor types across a wide range of deployment methods, such as satellites, airplanes, drones, truck-mounted and ground-based sensors. Each sensor technology has its own advantages and limitations. We found that deploying a wide range of technologies helped us dial in our knowledge of actual methane emissions across our assets.

We scoped over 20 methane detection companies and technologies, ranging from aircraft to ground-based sensors. In November 2020, we deployed four different methane detection technologies over a two-week period across the Upton County footprint. Importantly, each technology utilized a different type of sensor and a different deployment method.

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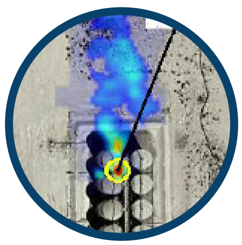
8. Miller et al., 2013; Caulton et al., 2014; Karion et al., 2015; Lavoie et al., 2015; Lyon et al., 2015; Zavala-Araiza et al., 2015; Frankenburg et al., 2016; Robertson et al., 2017; Alvarez et al., 2018; Duren et al., 2019; Robertson et al., 2019

Table 1: Summary of Detection Technologies Deployed

Company	Deployment Method	Sensor Type	Data Type	Spatial Resolution
Bridger Photonics	Fixed-wing aircraft	Light detection and ranging	Plume image and emission rate	Equipment-level
Avitas	Drones	Optical gas imaging	Emission video	Component-level
University of Wyoming	Truck-mounted	Cavity ring-down spectrometer	Emission rate	Facility-level
Scientific Aviation	Continuous, ground-based	Metal oxide	Continuous methane concentrations and emissions rate	Equipment-level

Methane Technologies Deployed



Bridger Photonics | Laser-based sensor technology flown on fixed-wing aircraft at low flight altitudes of approximately 500 feet. Light Detection and Ranging sensors detect methane emissions from wells and facilities. They quantify emission rates based on methane concentration measurements (ppm-m) and wind data and provide high-resolution aerial images of the facilities. Bridger flew all 25 of TRP's central facilities on Nov. 5 and revisited the facilities with emissions on a second flight on Nov. 9.

Avitas | OGI cameras affixed to drones capture up-close videos of facility emissions. The flight path is pre-planned to visit and inspect all potential sources of emissions in an efficient manner. The final product directly links the emission to a piece of equipment and includes video support. Product is approved for EPA OOOOa inspections. TRP used Avitas across nine of our largest producing facilities on Nov. 18.

University of Wyoming | Department of Atmospheric Sciences operates a van equipped with a high-end Picarro methane sensor and weather station. The van parks downwind of the emitting facility and quantifies methane emission rates based on precise concentration readings and wind data and uses EPA Other Test Method 33a. The research team published extensive methane emission data collected from facilities across major U.S. shale basins since 2014. The team visited nine of TRP's facilities on Nov. 12.

Scientific Aviation | A continuous, ground-based sensor monitors methane concentration and wind data. Software algorithms triangulate the source of emissions and quantify methane flow rate. Generally multiple sensors are used around a central facility to improve data quality. The sensors are inexpensive, which allows for cost-effective, continuous monitoring of facilities. Colorado regulations were adopted in 2020 that require continuous monitoring during D&C operations and the first six months of production. TRP placed six Scientific Aviation sensors surrounding one central facility starting on Nov. 12.

Separators, heater treaters and their associated equipment represented a small share of overall emissions on TRP's assets.

Table 2 summarizes the methane detection campaign that took place in November 2020. An initial overflight was conducted to survey all of TRP's facilities on Nov. 5. Another repeat overflight was conducted Nov. 9 to account for the known intermittency and unpredictability of methane emissions. The second overflight could also identify emission events that did not appear in the initial overflight, as well as identify events that had persisted over the four-day period.

Table 2: TRP's November 2020 Methane Detection Program

Company	Deployment Method	Date	Scope
Bridger Photonics	Fixed-wing aircraft	Nov. 5	Bridger Photonics flew all 25 of TRP's central facilities
Avitas	Drones	Nov. 8	TRP utilized Avitas across nine of their largest producing facilities
University of Wyoming	Truck-mounted	Nov. 12	The University of Wyoming team visited nine of TRP's facilities
Scientific Aviation	Continuous, ground-based	Ongoing	TRP placed six Scientific Aviation sensors around one central facility

Based on the results of the overflights, TRP targeted facilities of interest with drones to inspect all potential sources of emissions on site. The drone's optical gas imaging camera was capable of determining the source of the emission. For a selection of sites, site level emissions were quantified using the University of Wyoming's truck-mounted Picarro sensor, allowing for a snapshot in time of the methane emissions footprint of the site. Finally, using a risk-based approach from data gathered by the aerial surveys, continuous ground-based monitors were installed on one central facility to provide live insights into methane emissions once the teams had left the location.

Detection Program Takeaways

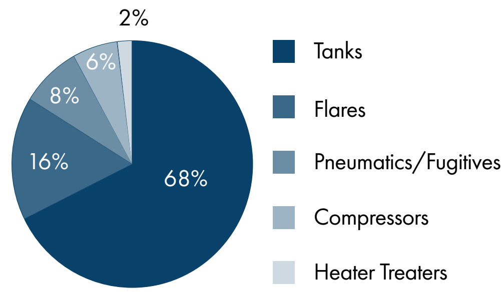
TRP's multi-faceted approach to detecting methane emissions yielded unique insights. The most notable takeaways that emerged were that tanks were the primary emission source and emissions did not correlate with production volumes. Outlined below are detailed findings from the program.

Tanks were the primary source of unexpected emissions

The majority of TRP's unexpected methane emissions occurred at the tank batteries which were supposed to be controlled by vapor recovery units (VRUs) or combustors. These emissions manifest as high BTU vapors emanating from the thief hatches and pressure relief valves on top on the tanks. The tank vapors have low methane concentrations of 10%-20% relative to the sales gas stream at 65%-75% methane. Oftentimes, the underlying problem that leads to emissions at the tanks is difficult to diagnose. TRP found a wide range of problems that lead to issues at the tanks from malfunctioning VRUs to restrictions in the vent piping to stuck dump valves upstream of the tanks.

Methane Emissions by Volume

Based on Actual Measurements



Emission factors do a poor job approximating actual methane emissions

Distribution of Methane Emissions

Source	Emission Factors	Actual Measurements
Tanks	12%	68%
Flares	2%	16%
Pneumatics	42%	8%
Fugitives	41%	Not meaningful
Compressors	2%	6%
Heater Treaters	1%	2%

Component-level emission factors that are used for EPA reporting do a poor job approximating actual emissions. In certain cases, such as pneumatic devices, they overestimated emissions and in others they underestimated emissions. Emission factors struggle to incorporate equipment malfunctions and process upsets which, although short-lived, can comprise a significant portion of annual emissions. This discrepancy has been widely researched but we feel it warrants further attention and ultimately incorporation into reporting technologies.

Low oil rate facilities cannot be dismissed as negligible

The majority of methane emissions stem from central facilities where oil and gas are separated and processed from multiple wells as opposed to at the individual wellheads. TRP has a wide range of central facilities from high-rate horizontal facilities to low-rate vertical facilities. A few facilities collect production from only one well while most aggregate production from multiple wells. Although our high-rate facilities have a higher potential to emit in the event of a process upset, our measured emissions were distributed across our high-rate and low-rate facilities in a relatively uncorrelated manner. In fact, we found a higher correlation between methane emissions and the complexity of a facility (measured by the total number of separators and tanks) than we did with the production rate. The coefficients of determination (R2) of methane emissions against facility complexity and BOE production rate were 18% and 4%, respectively.

The majority of TRP's unexpected methane emissions occurred at the tank batteries.

Annual emission profiles more valuable than actual methane intensity at a point-in-time

Actual measurements of methane emissions are valuable in determining where actual emissions deviate from emissions factors; however, using actual measurements to calculate asset-level methane intensity can be difficult because certain emissions occur intermittently and large emissions are often associated with non-routine process upsets. Because of these limitations, TRP did not attempt to calculate the methane intensity of individual assets based on the actual measurement data. Instead, we concluded actual methane emission data reflecting emissions across the entire asset for extended time periods provides more actionable insight than methane intensity levels at a point-in-time.

There is no silver bullet for methane detection

Each technology has its strengths and limitations. Asset characteristics, such as the number of wells, type of wells, production rates and position concentration will ultimately influence the ideal detection technology for the asset. TRP encourages regulators to refrain from being prescriptive when drafting detection policy.

Start with aerial methods and use a cross-section of technologies

Companies that are implementing methane detection for the first time should consider utilizing multiple, overlapping forms of detection technology to better discern the temporal variability and distribution of emissions. If the position is concentrated, we would recommend utilizing an aerial method first given the cost-effectiveness per facility.

Procure detection technologies offering visual images of emission plume

Detection technologies that provide a visual image of the emission plume are preferred, particularly for initial surveys. We found it difficult to use non-visual detection methods without prior knowledge of where the leaks originate.

Factor wind speeds into data gathering

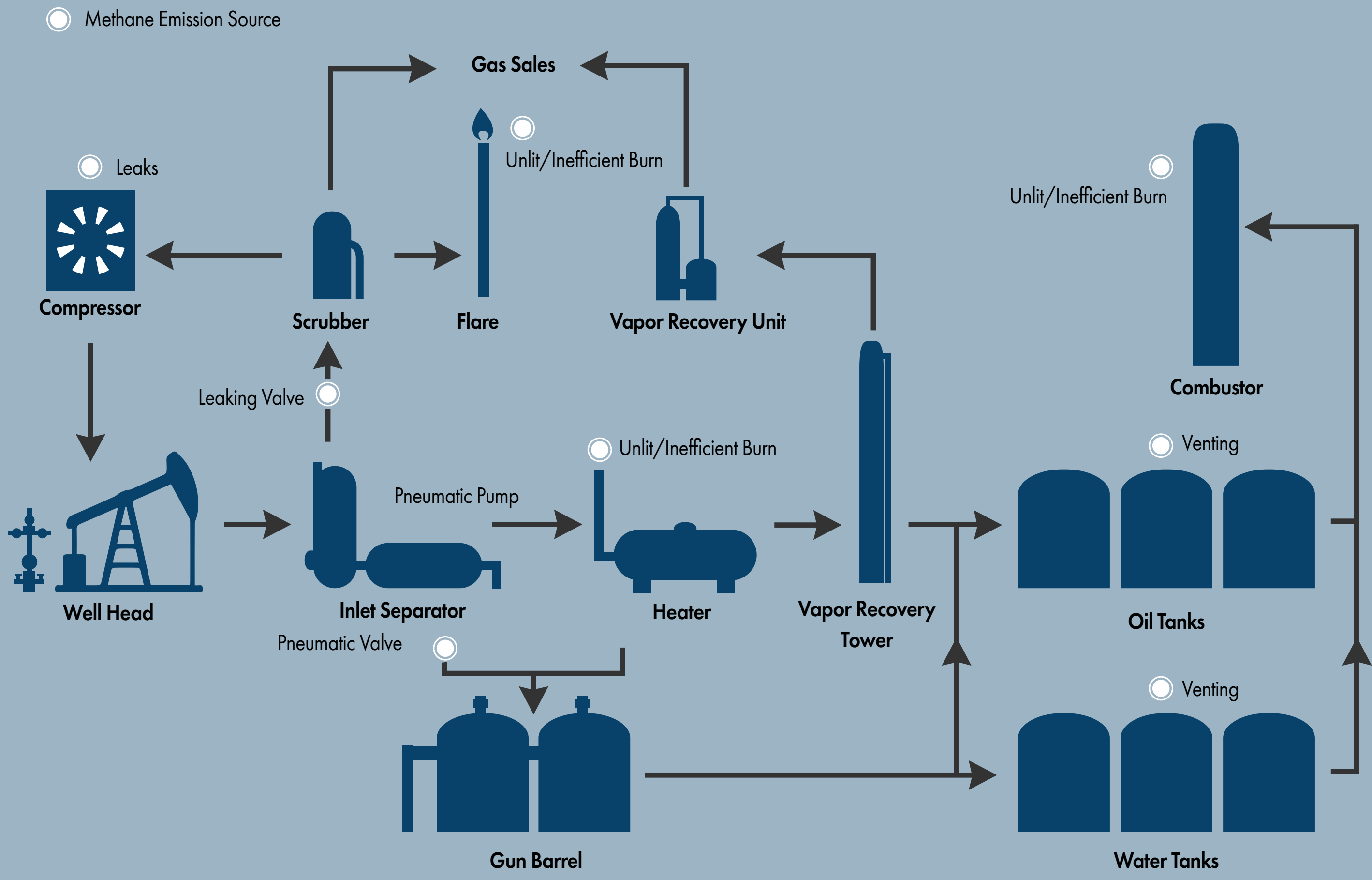
Methane detection technologies depend on wind for accurate detection and quantification. Wind speeds in the Permian Basin are relatively high (10.9 mph on average) and highly variable day-to-day. The wind speed (and for some technologies also wind direction) during the survey will greatly impact the minimum detection threshold and quantification accuracy of most technologies.[9] An accurate detection campaign may require multi-day windows to ensure high-quality measurements.

Tank vapor composition is key to emission calculations

Tank vapor composition assumptions are key inputs to the calculation of methane and VOC emissions. Most operators are required to have a representative tank vapor sample for state air permitting processes, although not much attention is placed on the quality or true representativeness of these samples. TRP collected a new pressurized oil sample from the last stage of separation that was flashed in a lab to infer our tank vapor composition and, in particular, our methane percentage of the tank vapors.

9. National Weather Service. Midland, TX annual average wind speed

Simplified Facility Diagram Showing Possible Sources of Methane Emissions



“Given the nimbleness of private operators, we see a terrific opportunity for them to help lead the way and export newly developed best practices globally to fight the climate crisis.”

Methane Emission Repair Program

A significant amount of research and media attention is focused on methane detection particularly with the recent advances and exciting technologies focused on space. The repair side of tackling methane emissions is more challenging and often more expensive than detection. Yet certain repairs end up improving overall facility operations, making the repair investment worthwhile not only for methane mitigation but operational efficiency and safety. Outside of complying with state and federal regulations, the goal of any repair program should be to maximize emissions mitigated on a CO_2e basis per dollar spent. There are uncertainties on both sides of this equation, but it is still a useful framework to think through an optimal repair program.

After completing our detection program, we classified each emission into one of three categories:

Emission Category	Examples	Commentary on Repair
Expected Emissions	• Gas-driven pneumatic actuators that are properly functioning • Tanks designed to vent • Uncontrolled liquids unloading events	We spent time carefully analyzing whether these processes could be eliminated in a cost-effective manner.
Unexpected Emissions: Find and Fix	• Unlit flares • Heater treater burner unlit • Malfunctioning pneumatics • Gas-driven compressors burning inefficiently • Leaking valves	These emissions are the cheapest to abate and mitigating these generally leads to ancillary benefits by improving other aspects of facility operation.
Unexpected Emissions: Process	• Tank vent system • Flare or combustor burning inefficently	These emissions are difficult to diagnose and repair, sometimes requiring advanced engineering solutions.

The majority of our emissions fell into the third category (Unexpected Emissions: Process). Since we completed our detection work, we have spent a considerable amount of energy repairing our process emissions. We believe tank vent systems are a large source of methane emissions in oil plays and plan to publish additional work on process emission repair solutions in the near future.

Conclusion

This study is one of many examples of our industry addressing methane concerns, and with further collaboration with likeminded stakeholders such as EDF, the industry will quickly and meaningfully lower its carbon footprint. Our hope is this paper is useful for those pursuing methane LDAR for the first time; preliminary detection benchmarking of assets is a crucial step in getting a mitigation program off the ground and identifying where initial repairs and preventative measures need to be made. On-going detection campaigns complement these efforts to ensure new emissions sources are promptly remedied.

Given the nimbleness of private operators, we see a terrific opportunity for them to help lead the way, and then export newly developed best practices globally to fight the climate crisis. In the meantime, U.S. producers will maintain the social license to provide vital, domestic energy, and reduce our reliance on imported oil and gas with unregulated emissions.