Methods to Reduce Methane Emissions in the Gas Industry

Internship report
by

Devakka Kommalapati
MS in Environmental Engineering(8894)
University of Bologna
Italy

&

Intern at
Levegő Munkacsoport
Clean Air Action Group (CCAG)
Budapest, Hungary.

Under the supervision of

András Lukács
President
Levegő Munkacsoport
Clean Air Action Group (CCAG)

During the period of
01/09/2025-05/01/2026

Abstract

The rapid increase of natural gas consumption has induced the continuous growth of methane emissions. Methane emissions from oil and gas supply chain represent a significant environmental challenge due to methane's high global warming potential which is much greater than CO2 and its contribution has severely exacerbated greenhouse effects and climate change. This report provides a comprehensive analysis of methane emissions, its sources across the natural gas value chain, with a particular focus on detection, identification, measurement and mitigation strategies. Various methane detection methods were discussed including satellite based, aerial and ground-based technologies highlighting the advantages and disadvantages of top-down and bottom-up approaches. The report further discusses emission quantification methods at site, equipment, and component levels, emphasizing their accuracy, applicability, and limitations. Leak Detection and Repair (LDAR) programs are analyzed as a key mitigation measure, outlining their operational elements, regulatory requirements, costs, and associated environmental and economic benefits. In addition, the study reviews best available technologies and emerging solutions such as green completions, vapor recovery units, dry gas seals, low-bleed pneumatic devices, and innovative abatement techniques. Cost analyses demonstrate that a substantial portion of methane emissions can be reduced at low or even negative net cost, with rapid payback periods. International initiatives and policy frameworks supporting methane mitigation are also presented. Overall, the report concludes that systematic implementation of advanced detection technologies, effective LDAR programs, and proven abatement measures can significantly reduce methane emissions while delivering environmental, operational, and economic benefits.

List of Contents

List of Figures

List of Tables

1. Methane emission analysis

1.1 Methane Emissions

Many human activities agriculture, burning fossil fuels, cutting down forests, raising livestock, etc. add huge quantities of greenhouse gases to those naturally present in the atmosphere, increasing the greenhouse effect and global warming [1,2]. Carbon dioxide (CO2) is the most emitted anthropogenic greenhouse gas: it is responsible for more than half of global warming. Methane (CH4) comes next with a contribution of 20–30% [3,4]. Two properties characterize the impact of greenhouse gases on climate: the time they remain in the atmosphere and their ability to absorb energy. Methane has a much shorter lifespan in the atmosphere than CO2 (around 12 years versus centuries for CO2) [5].

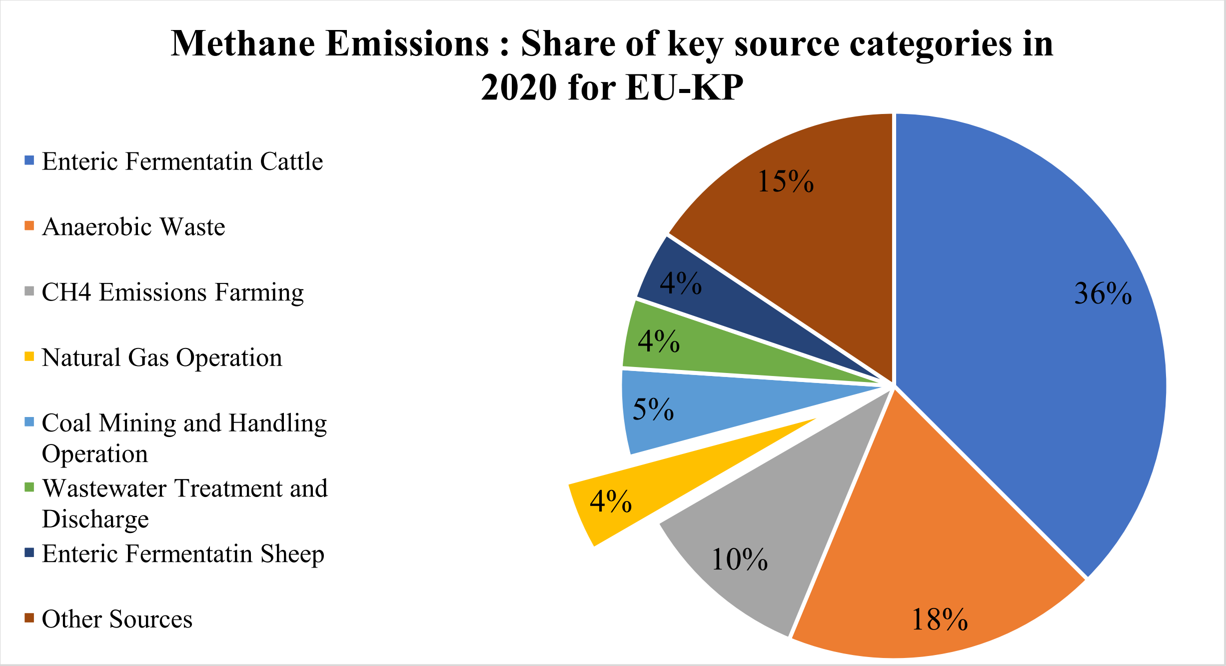

Figure 1: *Methane Emissions: Share of key source categories in 2020 for EU-KP*[6]

---

[1] Hureau, Geoffroy, et al. "Global methane emissions from natural gas transmission and distribution networks." *Science and Technology for Energy Transition* 80 (2025): 28.

[2] Jackson, Robert B., et al. "Increasing anthropogenic methane emissions arise equally from agricultural and fossil fuel sources." *Environmental Research Letters* 15.7 (2020): 071002.

[3] Intergovernmental Panel on Climate Change (IPCC). Climate Change 2021 – The Physical Science Basis: Working Group I Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge: Cambridge University Press, 2023. Print.

[4] International Energy Agency (IEA). (2024) Methane tracker. https://www.iea.org/data-and-statistics/data-tools/methanetracker-data-explorer

[5] Stocker, Thomas F., et al. "Technical summary." *Climate change 2013: the physical science basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge University Press, 2013. 33-115.

[6] Annual European Union greenhouse gas inventory 1990–2020 and inventory report 2022

1.2 Methane Emissions from Natural Gas Supply Chain

Methane, the primary constituent of natural gas, is also the second most significant greenhouse gas, with a potential impact on global warming that is 28 times greater than that of carbon dioxide over a 100year period. The mitigation of methane emissions could contribute to a reduction in greenhouse warming. The natural gas transmission system is a significant component of the natural gas industry, encompassing a vast distance, a considerable number of stations and equipment, and a high potential for methane emissions [[7]]. Natural gas withdrawn from natural gas or crude oil wells is called *wet natural gas* because, along with methane, it usually contains NGLs—ethane, propane, butanes, and pentanes—and water vapor[8].

The natural gas transmission pipeline is an extensive network system that connects upstream treatment plants and downstream city gate stations. It consists of long-distance transmission pipelines, compressor stations, distribution stations, underground storage stations, liquefied natural gas (LNG) terminals, and metering and testing centers. The different types of stations have their own characteristics in terms of the processes they undertake, while some common processes exist. There are a large number of sealing components, such as valves and flanges in the stations. Due to issues such as corrosion, wear and tear, and personnel misuse, the sealing of these components may fail, resulting in the internal high-pressure natural gas escaping from the sealing surface of the components and leaking into the atmosphere[9].

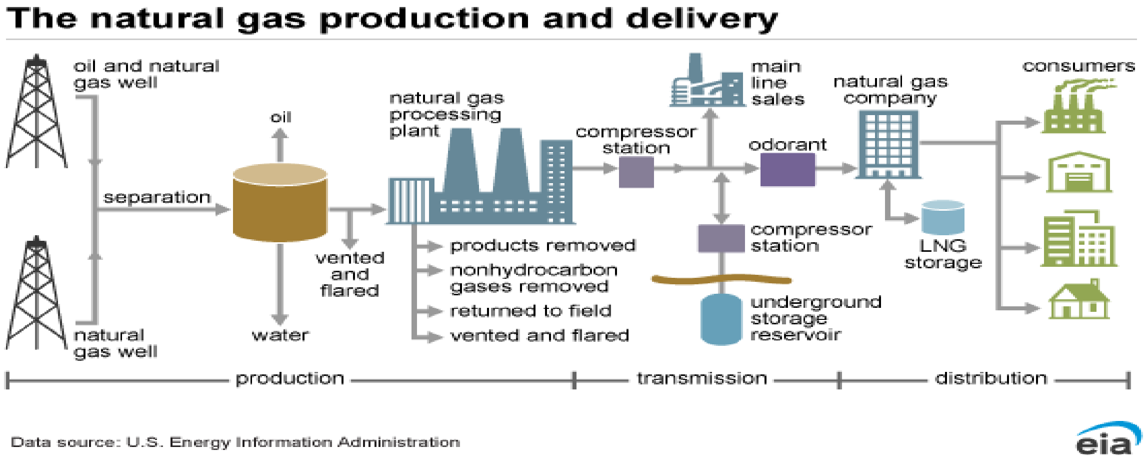

Figure 2: Methane emissions along the natural gas value chain

Source: https://www.eia.gov/energyexplained/natural-gas/images/natgasproduction.png

Methane emissions along the natural gas value chain depend considerably on the upstream, midstream and downstream practices established as shown in fig.2[10].

---

[7] Jia, Wenlong, et al. "Quantification of methane emissions from typical natural gas stations using on-site measurement technology." *Journal of Pipeline Science and Engineering* 5.2 (2025): 100229.

[8] U.S Energy Information Administration, https://www.eia.gov/energyexplained/natural-gas/ Accessed on 155/10/2025

[9] Kim, Changkyu, et al. "Global and local parameters for characterizing and modeling external corrosion in underground coated steel pipelines: A review of critical factors." *Journal of Pipeline Science and Engineering* 1.1 (2021): 17-35.

[10] Scarpelli, Tia R., et al. "Updated Global Fuel Exploitation Inventory (GFEI) for methane emissions from the oil, gas, and coal sectors: evaluation with inversions of atmospheric methane observations." *Atmospheric Chemistry and Physics* 22.5 (2022): 3235-3249.

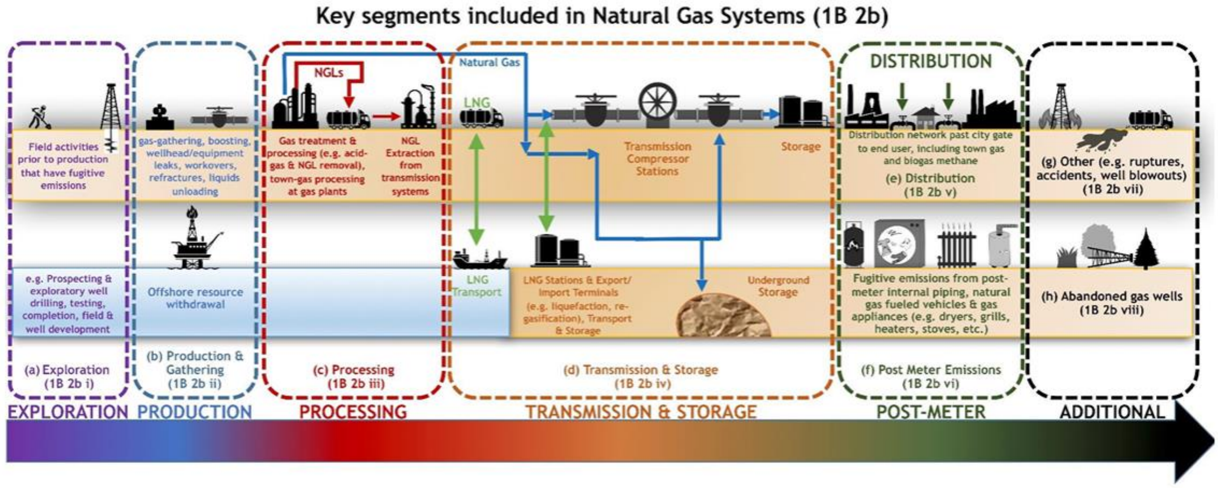

Figure 3: *Key segments in Natural Gas System*[11]

1.3 Gas system

***Transmission system*:** High-pressure gas transport over long distance including pipelines, compressor stations, metering and regulating stations and a variety of above-ground facilities to support the overall system. Underground gas storage and LNG are excluded. Transport from production companies to the distribution companies and to the industries. Operating pressure is normally equal or greater than 16 bar.

Methane emissions from gathering pipelines, which are part of the gathering system that transports natural gas from well sites to processing plants for treatment, or directly to the transmission system for produced gas already near pipeline composition. Gathering pipelines are most often made of steel, plastic, or cast iron, and inlet pressures of gathering systems typically range from 100 to 2000 kPa (1 to 20 bar), making gathering pipeline pressures generally lower than transmission pipeline pressures and higher than distribution pipeline pressures. Gas is moved through the gathering pipeline network by compressor stations, which are components of the gathering system sometimes used to dehydrate gas and which have also been shown to be significant sources of emissions[12].

Gathering pipelines generally emit methane in three different ways: (1) from leaking (typically underground) pipelines, (2) from leaking (above-ground) auxiliary equipment, and (3) during intentional venting at auxiliary equipment (e.g., maintenance blowdowns)[13].

Emissions from pipelines tend to be more challenging to measure than emissions from other types of natural gas infrastructure. Pipelines often form complex linear networks, which are more difficult and time-consuming to monitor than large discrete facilities that contain infrastructure elements known to be significant sources of fugitive missions (e.g., well sites, storage tanks, and compressor stations). Moreover, many gathering pipelines are underground

---

[11] Yona, Leehi, et al. "Refining national greenhouse gas inventories." *Ambio* 49.10 (2020): 1581-1586.

[12] Yu, Jevan, et al. "Methane emissions from natural gas gathering pipelines in the permian basin." *Environmental Science & Technology Letters* 9.11 (2022): 969-974.

[13] Zimmerle, Daniel J., et al. "Gathering pipeline methane emissions in Fayetteville shale pipelines and scoping guidelines for future pipeline measurement campaigns." *Elem Sci Anth* 5 (2017): 70.

and in difficult-to-access locations, potentially complicating their identification and inspection[14].

***Distribution system*: ** Medium to low pressure transport including distribution pipelines, service lines and a variety of above-ground facilities to support the overall system. Local transport from transmission system to customer meters. Pressure normally ranges less than 5 bar. But new polyethylene systems up to 10 bar are now developed in some EU countries. Medium pressure: 0,200 – 5 bar. Low pressure: less than 200 mbar[15].

The O&G value chain can be broadly broken down into four subsectors: upstream, midstream, downstream, and end use. The upstream sector, which includes the production and processing of O&G, has been the primary focus of CH4 measurement efforts over the last several years, because themajorityofCH4 is expected to be emitted from well sites and processing facilities. However, the midstream (gas transmission and storage), downstream (gas distribution to consumers), and end-use (consumption of gas) sectors also emit underestimated amounts of CH4 and therefore need to be accurately quantified[16].

1.4 Sources for the Methane emissions:

Methane emissions in the natural gas industry are heavy-tailed, which means that there are locations with extremely high levels of methane emissions, which account for the majority of the emissions. This can be observed in all streams of the natural gas industry[17].
The major and common methane emission source categories along the value chain through different stages of production(P), gathering and processing (G), transmission and storage (T), and distribution (D) are[18]:

---

[14] U.S. Environmental Protection Agency. Annex 3.6: Methodology for Estimating CH4, CO2, and N2O Emissions from Natural Gas Systems. 2022.

[15] EPA 2013a; ICF 2014-17

[16] MacKay, Katlyn, et al. "A comprehensive integration and synthesis of methane emissions from Canada's oil and gas value chain." *Environmental Science & Technology* 58.32 (2024): 14203-14213.

[17] Balcombe, Paul, et al. "The natural gas supply chain: the importance of methane and carbon dioxide emissions." *ACS Sustainable Chemistry & Engineering* 5.1 (2017): 3-20.

[18] Torleif Haugland, "Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector", (2019)

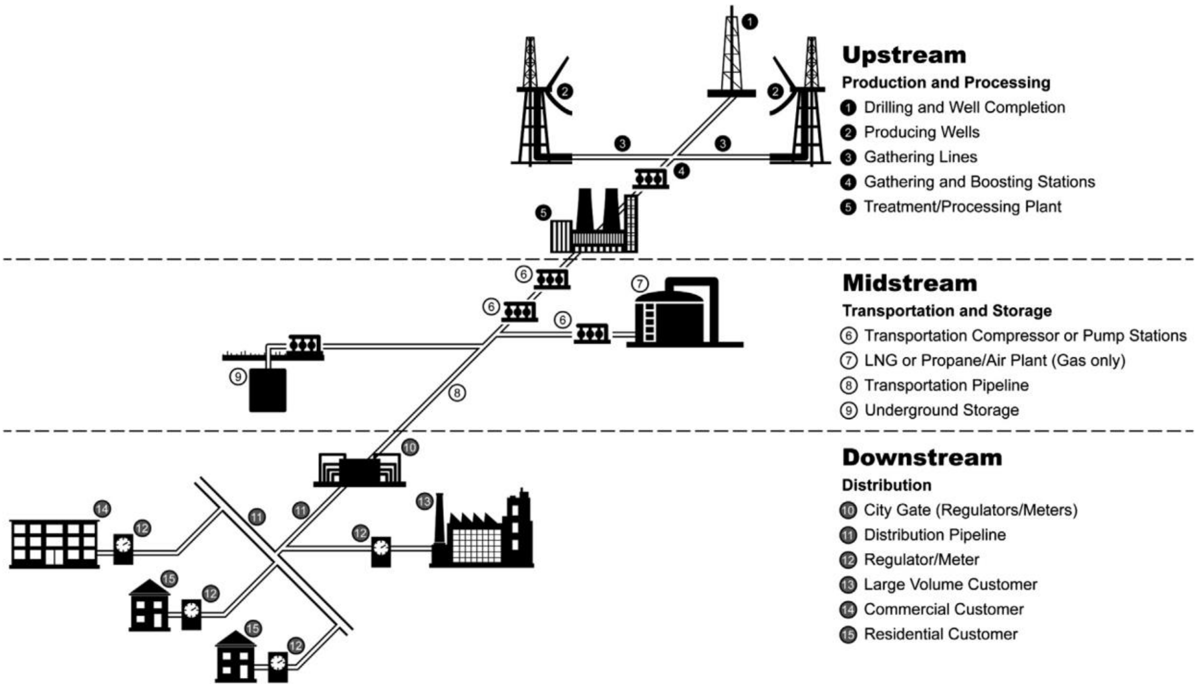

Figure 4: *Conceptual diagrams of a typical oil and gas value chain*[19]

1. Hydraulic fracturing and well completion (P)
2. Ceasinghead venting from oil wells (P)
3. Liquids unloading from gas wells (P)
4. Glycol dehydrators (P,G,T)
5. Natural gas driven pnuematic controllers and pumps (P,G,T)
6. Wet-seal centrifugation compressors (P,G,T)
7. Reciprocating rod packing compressors (P,G,T)
8. Venting of associated gas at oil production facilities (P)
9. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge (P,G,T)
10. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge (P,G,T,D)
11. Component and equipment leaks (P,G,T,D)
12. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge (P,G,T)

1.5 Identification of causes for the Methane emissions:

Emissions of methane arise along the entire gas chain, depending on the process type, materials used, equipment and operations. They can be divided into fugitive, vented and incomplete combustion emissions.

Fugitive emissions are continuous emissions, they consist of all small leaks from pipe equipment, flanges, valves, joints, etc. Vented emissions come from the natural gas released into the atmosphere from the gas network. Such emissions occur during normal planned

---

[19] US EPA (u.d.)

maintenance and control, but also during unplanned events, caused by the failure of the system and third-party activities.

Flaring, when natural gas is burned during normal operations (more often in oil sector), also contributes to vented emissions by unburned methane, which is released into the atmosphere (from 0% to 5% used in flares, depending on the combustion efficiency).

Incomplete combustion emissions are caused by all unburned methane in the exhaust gases from normal operation of gas turbines, gas engines and combustion facilities.

Table 1: *Methane Emission types – Sources examples*

Methane Emissions			
Type of Emissions			Examples
Fugitives	Leaks due to connections		Tightness failure
	Permeation		
Vented	Operational Emissions	Purging/venting for works, commissioning and decommissioning	Works, Maintenance
		Regular emissions of technical devices	Pnuematic emission actuators, flow control valves…
		Starts and stops	Emissions from the start and stop of compressors
	Incidents		Third party corrosion, construction defect/ material failure, ground movement, failure of installation
Incomplete Combustion			Unburned methane in exhaust methane gases from combustion installations

Causes for the methane emissions from gas infrastructure include unintentional leaks (fugitive emissions), intentional releases (venting), and incomplete combustion. These occur throughout the entire natural gas supply chain, from production and processing to transmission and distribution[20].

Unintentional or fugitive emissions

Fugitive emissions refer to accidental, continuous leaks of natural gas from system components. These releases are often caused by aging infrastructure, wear and tear, or equipment failure[21].

Leaking pipelines and equipment: Methane can seep from pipe joints, seals, valves, and other connections. Older infrastructure is particularly prone to this, with some larger events referred to as "super-emitters".

System incidents: Major equipment failures, such as the explosion of the Nord Stream pipelines in 2022, can cause significant, sudden methane releases. A study coordinated by the

---

[20] Čegir, K. "Report on methane emissions by gas transmission and distribution system operators in the Energy Community Contracting Parties, Energy Community." (2021).

[21] EPA, https://www.epa.gov/natural-gas-star-program/methane-emissions-data

United Nations Environment Programme (UNEP) found that the Nord Stream rupture resulted in the largest single human-caused methane release ever recorded[22].

Intentional or vented emissions

Venting is the deliberate release of natural gas into the atmosphere by operators, most often for maintenance or operational purposes.

Routine maintenance: Operators may vent or "blow down" gas from pipelines and compressor stations to reduce pressure before performing repairs or decommissioning.

Equipment design: Some equipment, such as natural gas-powered pneumatic controllers, are designed to continuously release a small amount of gas as part of their normal function.

Emergency procedures: In emergency situations, such as a pipeline over-pressurization, operators may vent gas for safety.

Venting in oil and gas production: During oil extraction, natural gas is often a by-product. If there is no infrastructure to capture it economically, it may be intentionally vented directly into the atmosphere, a less preferred method compared to flaring[23].

Incomplete combustion

This occurs when natural gas is burned inefficiently and some of the methane escapes before being fully combusted. This is also referred to as "methane slip"[24]

Inefficient or unlit flares: Flares are used to burn off excess gas, but if they are inefficient or unlit, a significant amount of methane can be released into the atmosphere. A 2022 study published by the University of Michigan and the Environmental Defense Fund (EDF) found that flares in the U.S. were only 91% efficient on average, which led to a fivefold increase in estimated methane emissions from this source.

Combustion equipment: Methane slip can also occur in the engines, turbines, and other combustion equipment used at various points in the natural gas supply chain, particularly when the equipment is not operating optimally[25].

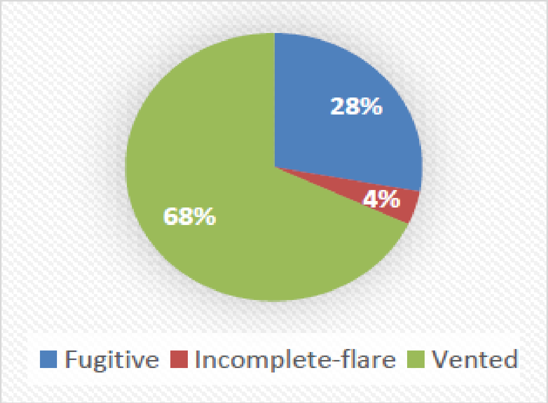

Figure 5: *Relative portions of methane emissions from Oil and Gas operations*[26]

---

[22] Yu, Jevan, et al. "Methane emissions from natural gas gathering pipelines in the permian basin." *Environmental Science & Technology Letters* 9.11 (2022): 969-974.

[23] ANDRE, MORGADO SIMOES HENRIQUE. "Fit for 55 package: Reducing methane emissions in the energy sector." (2022).

[24] Čegir, op.cit

[25] Plant, Genevieve, et al. "Inefficient and unlit natural gas flares both emit large quantities of methane." *Science* 377.6614 (2022): 1566-1571.

[26] Economic and Social Council, distr: general, Agenda (2020)

1.6 Methane Detection and Quantification Approaches:

Multiple techniques are used to detect methane emissions from gas infrastructure, ranging from large-scale satellite and aerial surveys to highly precise ground-based and fixed sensors. The most effective monitoring programs often combine several methods in a "top-down" to "bottom-up" approach to identify emissions and pinpoint their exact location.

Satellite-based detection
Satellites are a top-down method for spotting large methane "super-emitters" over wide areas. This helps to identify major problem regions for further investigation by more targeted techniques.
Imaging spectrometers: Instruments like the European Space Agency's TROPOMI and MethaneSAT detect the unique infrared signature of methane in sunlight reflected from Earth.
Global mappers: Satellites like TROPOMI and GHGSat's global mappers provide broad, large-scale views of atmospheric methane concentrations but may not identify specific facility sources.
High-resolution monitors: Specialized satellites such as GHGSat's constellation and Carbon Mapper offer higher-resolution imagery to pinpoint the specific facilities responsible for large plumes.
Initiatives: International programs like the United Nations' Methane Alert and Response System (MARS) use satellite data to alert governments and companies of large emissions events[27].

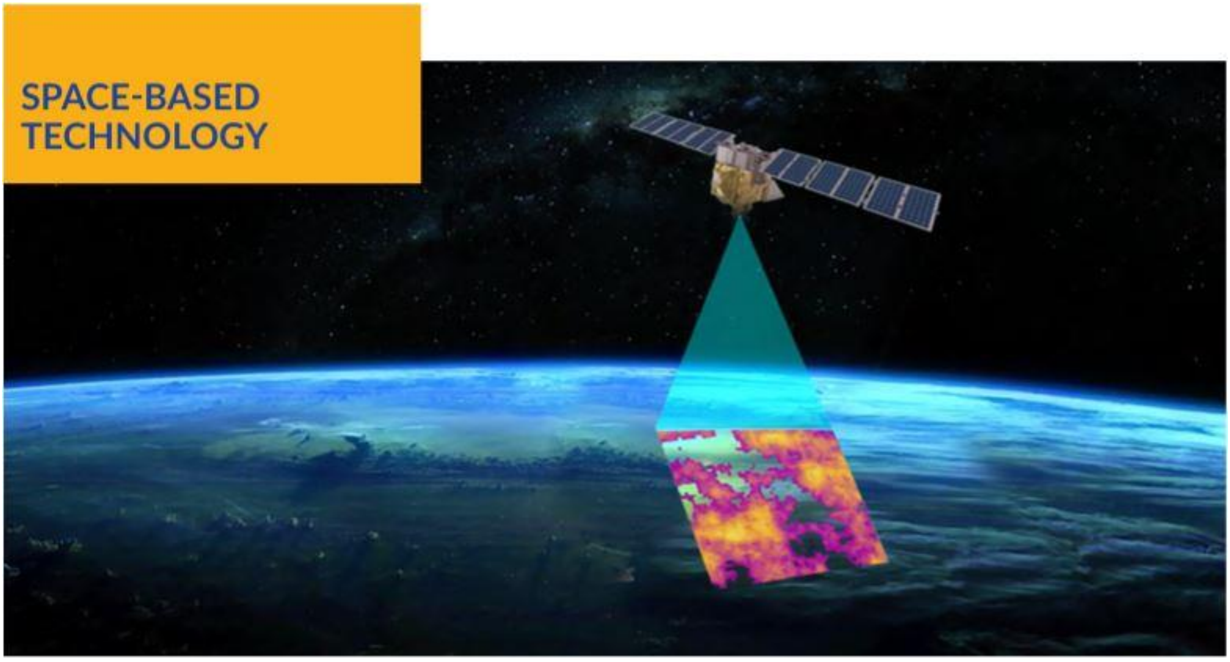

Figure 6: *Space or Satellite Based Technology*

Aerial and drone-based detection
Aerial platforms bridge the gap between wide-area satellite mapping and on-site ground inspections. They can scan large or difficult-to-access areas quickly and efficiently.

---

[27] Hill, Brady. "Quantifying Emissions to Mitigate Climate Change: Approaches and Solutions from COP27." *Climate Change through the Lens of a New Generation*. American Chemical Society, 2024. 135-148.

Manned aircraft (airplanes and helicopters): Equipped with advanced sensors like Gas Mapping LiDAR, aircraft can survey thousands of square miles daily, making them ideal for large-scale pipeline networks.

Unmanned aerial vehicles (UAVs/drones): Drones can be fitted with laser-based sensors or infrared cameras to perform targeted, high-resolution surveys of specific facilities or complex areas. They are useful for inspecting equipment in hard-to-reach locations, such as flare stacks.

Aerial LiDAR: This technique uses laser technology to scan infrastructure from the air. By measuring how methane absorbs specific laser frequencies, it can detect and quantify emission rates with high precision.

Hyperspectral sensors: Some aerial systems use hyperspectral sensors that capture data in hundreds of different wavelengths, which can be analyzed to detect methane plumes in real time.

***Figure** 7: Aerial Technology*

Ground-based detection

For detailed, site-specific monitoring, ground-based techniques are used for both continuous surveillance and pinpointing leaks during inspections[28].

Handheld sensors: Technicians use portable, laser-based detectors or flame ionization detectors (FIDs) to scan equipment, pipes, and valves. These are a bottom-up method for precise leak location and are highly accurate.

Optical Gas Imaging (OGI): Specialized infrared (IR) cameras make otherwise invisible methane plumes appear as dark smoke or clouds on-screen. This allows operators to quickly visualize leaks from a distance.

Fixed sensors: Infrared (IR) or catalytic bead sensors are installed around facilities, like compressor stations, for continuous, 24/7 monitoring. This provides real-time data and can immediately alert personnel to potential leaks.

Vehicle-mounted systems: Some systems are mounted on vehicles to perform mobile surveys along pipeline routes and at facility sites.

---

[28] Singh, Aditya. "Overview of Emerging Technologies for Methane Measurement, Monitoring and Reduction in US Onshore Upstream Oil & Gas Industry." Paper presented at the ADIPEC, Abu Dhabi, UAE, October 2023. doi: https://doi.org/10.2118/216088-MS

Figure 8: *Ground based technologies*

Advanced and emerging techniques
New technologies integrate software and multiple sensor types to improve accuracy and efficiency[29].
AI and data analytics: Artificial intelligence and machine learning are increasingly used to analyze data from multiple sources (satellite, aerial, ground) to identify emissions, quantify leak rates, and predict where future failures might occur.
Advanced analytics: Sophisticated software processes raw sensor data to create georeferenced methane concentration maps, helping operators prioritize repairs and track emissions over time.
Acoustic leak detectors: For buried pipelines, acoustic sensors can detect the sound of gas escaping, though they are less common for atmospheric releases.

1.7 Quantification of Emissions and Verification Methods:

Quantification varies from detection in that it determines an emission rate, such as mass per time (e.g., g/h) or volume per time (e.g., m3/min), rather than detects the presence or absence of methane (and provides e.g., a concentration in ppmv). Quantification can be done directly through measurement of the emissions, or indirectly through estimations, calculations, and modelling based on measured parameters.[30]
Quantification of methane emissions can occur at three distinct levels - **site**, **equipment**, and **component**, each representing a different degree of detail and accuracy in determining emission sources.

Site-Level Quantification:

At this level, the technology estimates the total emission rate for an entire facility. It can identify major emission sources within a site but may not attribute emissions to individual equipment. The accuracy of site-level quantification depends on factors such as sensor placement, detection thresholds, and the spatial coverage of the monitoring system. In large or densely spaced sites, distinguishing emissions between neighbouring areas can be challenging.

Equipment-Level Quantification:

This level focuses on determining the total emission rate from specific pieces of equipment, such as wellheads or manifolds. Technologies capable of equipment-level quantification provide reliable emission estimates for individual units when sources are spatially distinct.

---

[29] https://www.qedenv.com/markets-applications/oil-and-gas-survey-solutions/natural-gas-leak-detection/how-to-detect-methane-gas/

[30] Adapted from https://www.ipieca.org/resources/awareness-briefing/methane-emissions-glossary/

However, accuracy can decrease when multiple sources are located close together or when overlapping plumes make it difficult to assign emissions to a particular unit.

Component-Level Quantification:

Component-level quantification targets emissions from individual parts, such as valves, flanges, or vents. It allows operators to measure emission volumes from known or detected components with high precision. This level of quantification is particularly useful for identifying small leaks or assessing vented emissions that vary over time or between similar equipment types. Technologies designed for this level provide the most granular information but require higher resolution and more complex data interpretation.

These are some quantification equipment and methodologies that can be applied depending on the emission source and the detection technology used. Different sources such as pneumatic devices, compressors, and storage tanks require specific instruments for accurate measurement. Optical and laser-based systems are commonly used for detection, while devices like flow meters, anemometers, and high-volume samplers support precise quantification of methane emissions across various operational conditions.[31]

Table 2: *Methane emission Quantification Equipment with respect to the source and Detection Equipment*

Emissions Source	Detection Equipment	Quantification Equipment
Natural Gas Driven Pneumatic Controllers and Pumps	Optical Leak Imaging Laser Leak Detector	Calibrated Vent Bag High Volume Sampler Flow Meter
Fugitive Equipment and Process Leaks	Optical Leak Laser Leak Soap Bubble Organic Vapor Analysers (OVAs) / Toxic Vapor Analysers (TVAs) Acoustic Leak Detection	Calibrated Vent Bag High Volume Sampler Vane Anemometer Hotwire Anemometer Turbine Meter Acoustic Detection Device (through-valve leaks)
Centrifugal Compressors (with Wet Seals)	Optical Leak Imaging	Vane Anemometer Hotwire Anemometer Turbine Meter
Reciprocating Compressor Rod Seal/Packing Vents	Optical Leak Imaging	Vane Anemometer Hotwire Anemometer Turbine Meter Calibrated Vent Bag High Volume Sampler Acoustic Detection Device (through-valve leaks) Orifice Meter (vent flow measurement device)
Glycol Dehydrators	Optical Leak Imaging	Vane Anemometer Hotwire Anemometer

---

[31] Appendix A: Conducting Emissions Surveys, Including Emission Detection And Quantification Equipment May 2017

Emissions Source	Detection Equipment	Quantification Equipment
		Turbine Meter
Hydrocarbon Liquid Storage Tanks	Optical Leak Imaging	Turbine Meter Calibrated Vent Bag Vane Anemometer Hotwire Anemometer High Volume Sampler Note: These instruments provide spot readings and are less suitable for long-term measurements compared to a turbine meter with totalizer.
Well Venting for Liquids Unloading	Optical Leak Imaging	Vane Anemometer Hotwire Anemometer Turbine Meter
Well Venting/Flaring During Well Completions (Hydraulic Fracturing)	Optical Leak Imaging	Vane Anemometer Hotwire Anemometer Turbine Meter
Casinghead Gas Venting	Optical Leak Imaging	Turbine Meter Hotwire Anemometer Vane Anemometer

2. Methane emissions reduction technologies for gas network

Taking quick and decisive action on methane from oil and gas operations could avoid as much as 0.1 degrees Celsius of warming by mid-century—equivalent to zeroing out the emissions of every single car and truck in the world. Cutting methane emissions is low-hanging fruit in tackling climate change, and is vital to aligning the global energy sector with a global 1.5˚C warming trajectory[32].

A number of empirical studies have documented that oil and gas methane emissions can be substantially reduced at a low abatement cost. Because methane is a powerful GHG and short-term climate pollutant emission reductions measures can offer large near- term climate mitigation benefits and are among the most cost-efficient opportunities of emission reduction efforts[33].

In order to decrease the atmospheric methane abundance and decarbonize industries, several pathways can be taken, which fall into (I) emission reduction at the sources, (II) atmospheric methane capture and removal, (III) atmospheric methane destruction and (IV) replace methane-emitting sources with green solutions like transiting from use of fossil fuel to renewable sources in the energy sector.

These efforts fall into two main categories: (I) emissions prevention and (II) reduce or eliminate carbon footprints of activities. There have been several long-term and deep discussions and debates on how to proceed productively without using more resources to save less and avoid greenwashing[34].

Methane mitigation involves a combination of technical, operational, and policy measures aimed at reducing emissions across all stages of production, processing, transportation, and use. Since methane is a potent greenhouse gas with a global warming potential many times higher than carbon dioxide, minimizing its release is essential for achieving near-term climate goals. Effective mitigation requires a systematic approach that integrates engineering design, operational management, leak detection, and continuous monitoring. The following strategies outline key areas of focus for reducing methane emissions across industrial and energy systems[35]:

---

[32] Pollard, A. "Global Flaring and Methane Reduction Partnership(GFMR)."

[33] Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector Monitoring, Reporting and Verification (MRV) and Mitigation, 2019

[34] Maazallahi, Hossein, Jia Chen, and Julianne M. Fernandez. "Gas Systems: A Synthesized Review and Insights into Mitigation Gaps." *Natural Gas in the 21st Century* (2025): 3.

[35] Exhibit, O. C. D. "Reducing Methane Emissions: Best Practice Guide." (2019).

1. Systematically minimise methane emissions through Engineering, Design and Construction
2. Reducing methane emissions from flaring
3. Reducing methane emissions that result from energy use
4. Reducing methane emissions from equipment leaks
5. Reducing methane emissions from venting
6. Reducing methane emissions from natural gas driven pneumatic equipment
7. Reducing methane emissions related to operational repairs
8. Systematically improving methane management through continual improvement
9. Reducing methane emissions through identification, detection, measurement and quantification
10. Reducing methane emissions in transmission, storage, LNG terminals and distribution

Four types of abatement measures within the natural gas supply chain account for a majority of those at net zero cost or lower[36]:

- Leak detection and repair (LDAR) of sources of fugitive emissions
- Capturing vented gas
- Replacing high-bleed pneumatic devices with low- bleed pneumatics
- Replacing Kimray pumps (i.e., gas-powered) with electric pumps

Table 3: *Main abatement options by emission source[37]*

Emission Source	Abatement Options
1. Hydraulic fracturing & well completion	• Green completion system
2. Casing head venting from oil wells	• Install compressors/VRU to capture casing head gas or • connect casing to tanks equipped with VRUs or • re-route casinghead gas to flare (increase in CO_2 emissions)
3. Liquids unloading from gas wells	• Install plunger lift systems in gas well • Manually redirect the well to the production system as soon as the unloading is completed • Plunger Lift optimization • Add foaming agents, soap strings, surfactants • Install velocity tubing
4. Glycol dehydrators	• Install flash tank separator and optimise glycol circulation rates • Route flash tank (if present) and dehydrator regenerator vents to VRU for beneficial use

---

[36] Warner, Ethan, et al. *Potential cost-effective opportunities for methane emission abatement*. No. NREL/TP-6A50-62818. National Renewable Energy Lab.(NREL), Golden, CO (United States), 2015.

[37] Pollard, Op.cit

	• Route flash tank (if present) and dehydrator regenerator vents to flare (note: increase CO2 emissions) • Replacing by zero emissions (e.g. desiccant) dehydrators • Replace the gas assist lean glycol pump with an electric lean glycol pump • Reroute glycol skimmer Gas
5. Natural gas driven pneumatic controllers and pumps	• Replacement or retrofit to from high bleed to low bleed devices • Routing emissions to an existing combustion device or vapor recovery unit • Ensure intermittent bleed controller are properly functioning i.e. only vents/emits during the de-actuation portion of a control cycle with no emission when the valve is in a stationery position. • Replacement by zero emission options (electric or air driven)
6. Wet-seal centrifugal compressors	• Re-route gas at lower pressure to VRU, flare, or to a low-pressure inlet • Convert compressor wet seals to dry seals
7. Reciprocating rod-packing compressors	• Regular replacement of rod packing (ideally based on measured emission rate) • Re-route vents points to VRU or fuel gas system • Re-route vents points to flare (note: increase CO2 emissions)
8. Venting associated gas at upstream oil production facilities	• Flaring without energy recovery instead of venting • Capturing vent gas for gas utilization • Install flare ignition systems
9. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge	• Reduce operating pressure upstream • Increase tank working pressure • Change geometry of the loading pipe • Installing a Vapor Recovery Unit (VRU) and directing to productive use as fuel gas, compressor suction, gas lift • Hydrocarbon blanketing • Install separate systems to control loading losses from the tank vehicles and storage losses from the tanks. Implement a system to balance or exchange vapors between the tanks and tank vehicles and add a common vapor control device if needed • Install stabilization towers ahead of tanks to obtain a low oil vapor pressure suitable for loading onto ships or barges

10. Equipment depressurization and blowdowns from pipelines and facilities	• Use Isolation valves to minimize impact • Re-direct gas into storage vessel (field), flare, or low-pressure header (fuel gas or gathering system) • Minimise the number of starts ups • Lower pressure in the pipeline prior to event through main line compressors and a mobile compressor stations (for pipeline repairs) • Install plugging equipment to shorten segment of pipeline involved in outage, Use isolation valves to minimize impact • Rerouting the natural gas to a duct burner, thermal oxidizer or flares where possible (upstream) to recover a portion of all of the blowdown gas.
11. Component and equipment leaks	• Perform LDAR • Implement effective leak-prone pipe replacement program. • Planned / carefully executed activities when excavating • Abandoned or suspended wells: Plug the well
12. Incomplete combustion (including Associated petroleum gas (APG) flaring, engines, turbines, fired heaters)	• Install automated air/fuel ratio controls • Minimise the number of start-ups • Installing catalytic converters on gas fuelled engines and turbine • Increase combustion efficiency by upgrading to more efficient engines/turbines • Minimize gas flaring by utilising the gas • Improve combustion efficiency by Change flare tip / installing flare ignition systems

2.1 green completion system or reduced emission completion (rec)

REC is a methane emission abatement technique in the oil and gas industry that captures natural gas during the well completion process. This technology prevents the release of methane, a potent greenhouse gas, that would otherwise be vented or flared into the atmosphere[38].
Wells that require hydraulic fracturing to stimulate or enhance gas and oil production may require a lengthy completion, and therefore are good candidates for RECs. Lengthy completions mean that a significant amount of gas may be vented or flared; this gas could potentially be recovered and sold for additional revenue. REC equipment could be shared between newly developed fields that have many wells drilled in close proximity to minimize transport, set-up, and equipment rental costs.

---

[38] Methane Mitigation Technologies Platform, US EPA.

Energized Fracturing: RECs can also be performed in combination with energized fracturing, wherein inert gas (e.g., CO2 or nitrogen) is mixed with the fracturing water under high pressure to enhance the process of fracturing the formation. The process is generally the same with the additional consideration of the composition of the flowback gas. The percent of inert gases in the flowback gas is, at first, unsuitable for delivery into the sales line, but as the fraction of inert gases decreases, the gas quality becomes be suitable for injection into the sales line. A portable membrane acid gas separation unit can further increase the amount of methane recovered for sales after a CO2 energized fracture.

Gas Lift: In low pressure (i.e., low energy) reservoirs, RECs are often carried out with the aid of compressors for gas lift. Gas lift is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracturing fluids up the tubing at high enough rates to expel the frac fluids. The increased pressure facilitates flow into the separators and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during an REC[39].

Limitations:

Some limitations exist for performing RECs because technical barriers vary from well to well. Three main limitations include the following:

1) Proximity of pipelines
2) Pressure of produced gas
3) Inert gas concentration

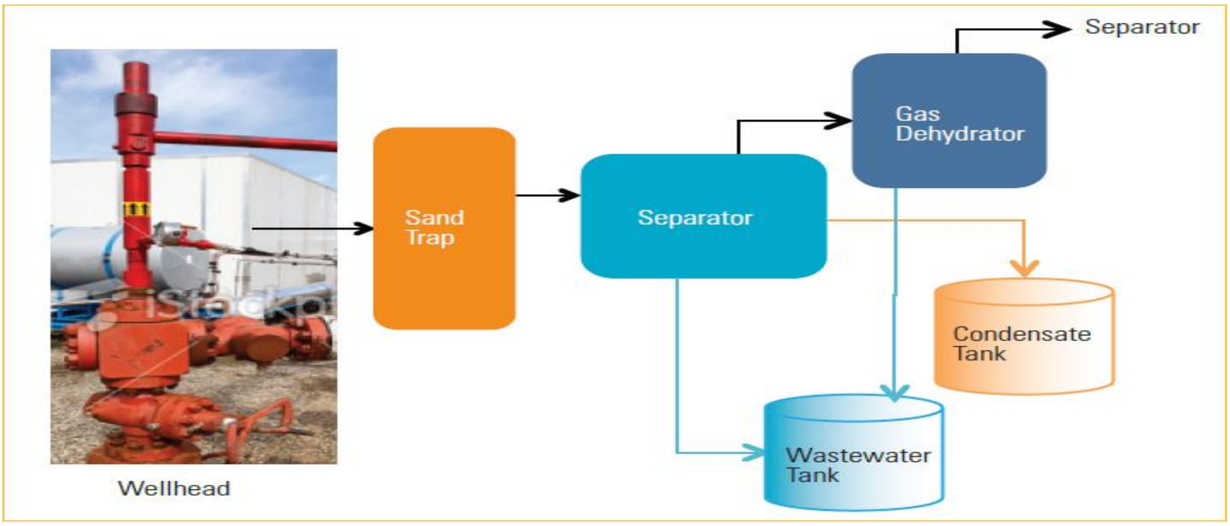

Figure 9: *Green Completion Equipment Schematic*[40]

---

[39] https://www.epa.gov/natural-gas-star-program/reduced-emission-well-completions-and-workovers

[40] Harvey, Susan, Vignesh Gowrishankar, and Thomas Singer. "The US Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste." *no. March* (2012).

Effectiveness: The emission reductions from RECs can vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. The representative control efficiency for RECs at gas wells is estimated to be 90%, and efficiencies greater than95 - 98% were achieved at wells that co-produced oil and gas[41], [42].

Cost Estimates: Green completions are economical due to significant methane savings and condensate recovery, leading to a rapid return on investment. Despite a total capital cost of $180,000 for necessary equipment, amortizing this cost over a decade for 60 wells per year results in annual capital charges under $10,000. With natural gas priced at $3 per Mcf and condensate at $19 per barrel, costs for green completions are projected to pay back in about one year[43],[44].

Economic and Environmental Benefits:
Green completions provide a number of additional benefits, aside from profitability and methane emission reductions.

Green completions:

- Collect potentially explosive gas vapors, rather than venting them into the atmosphere (improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability)
- Reduce or eliminate the need for flaring
- Reduce emissions, noises, odors, and citizen complaints associated with venting or flaring
- Reduce VOCs and HAPs contained in natural gas along with methane. If flared and not captured, VOCs and
- HAPs generate nitrogen oxides (NOX) and particulate matter (PM), contributors to ground-level ozone and regional haze.
- Improve well cleanup and enhance well productivity, as wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring
- Reduce the need to drill new wells as more methane is kept in the system and brought to market[45].

2.2 Vapour recovery units:

In the chemicals, petroleum refining and natural gas industries, storage vessels are used to contain various liquids, such as condensates, crude oil and produced water. Condensate and crude oil are usually kept in fixed-roof, atmospheric-pressure tanks between production wells

---

[41] Well, Hydraulically Fractured Oil. "Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production." *Report for Oil and Natural Gas Sector Oil Well Completions and Associated Gas during Ongoing Production, Review Panel* (2014).

[42] Pollard, op.cit.

[43] Greem completions, Pro Fact Sheet No. 703, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, natural gas star Partners EPA, 2003.

[44] Reduced Emission Completions, "From Natural Gas STAR Partners."

[45] Harvey, op.cit

and pipelines or truck transportation. In offshore fields, the storage vessels usually contain crude oil and condensate produced from connected wells, or from nearby platforms.

In most cases, light hydrocarbons, such as methane, volatile organic compounds (VOCs), natural gas liquids (NGLs) and hazardous air pollutants (HAPs), in the crude oil tend to vaporize and collect within the space between the fixed roof and liquid level of the tank. Ambient temperature changes cause the fluctuation of liquid level in the tank, leading to the escape of vapors into the atmosphere. These escaped vapors cause income losses due to reduction in hydrocarbon volume and changes in the American Petroleum Institute (API) gravity measure of the oil. Apart from potential fire hazards, they also contribute to environmental pollution, because methane (C1) and carbon dioxide (CO_2) are greenhouse gases that contribute to global warming.

Flash gases may be flared or vented directly to the atmosphere the latter results in an environmental emissions impact. Therefore, a commonly accepted option to simultaneously reduce light hydrocarbon emissions and realize significant economic savings is to install vapor-recovery units (VRUs) on storage vessels. VRUs are relatively simple systems that can capture approximately 95% of the light hydrocarbon vapors for sale, or for onsite usage as fuel and generation of savings from recovering light hydrocarbons, while at the same time reducing the volume of HAPs and methane emissions.

Losses of the remaining lighter hydrocarbons are categorized in three ways:
Flash losses occur when the separator or heater treater, operating at approximately 35 pounds per square inch (psi), dumps oil into the storage tanks, which are at atmospheric pressure. Working losses refer to the vapor released from the changing fluid levels and agitation of tank contents associated with the circulation of fresh oil through the storage tanks. Standing losses occur with daily and seasonal temperature changes [46],[47],[48].

Effectiveness:
Ideally, in the correct operating condition, VRUs can recover nearly all vapors from a storage tank. Based on a VRU operating factor of 95 percent (allowing 5 percent yearly downtime of the VRU for maintenance), partners can expect to reduce methane emissions from a storage tank by 95 percent after implementing this technology[49].

---

[46] Lim, Yik Fu, Dominic CY Foo, and Mike Boon Lee Ooi. "Optimizing Vapor Recovery from Storage Tanks." *Chemical Engineering* 129.2 (2022).

[47] Schneider, G. W., Brian E. Boyer, and Mark A. Goodyear. "Recovery of Flash Gas from Storage Tanks at an Offshore Production Platform Using Scroll Compression Technology." *SPE International Conference and Exhibition on Health, Safety, Environment, and Sustainability?*. SPE, 2010.

[48] U.S. Environmental Protection Agency, Lessons Learned from Natural Gas STAR Partners, Installing Vapor Recovery Units on Storage Tanks, 2006

[49] Plisson-Sauné, S., et al. "How to Establish a Methane Reporting in Line with the UNEP-CCAC-OGMP (United Nations Environment Program, Climate and Clean Air Coalition, Oil & Gas Methane Partnership) within an Oil & Gas Company." *SPE International Conference and Exhibition on Health, Safety, Environment, and Sustainability?*. SPE, 2016.

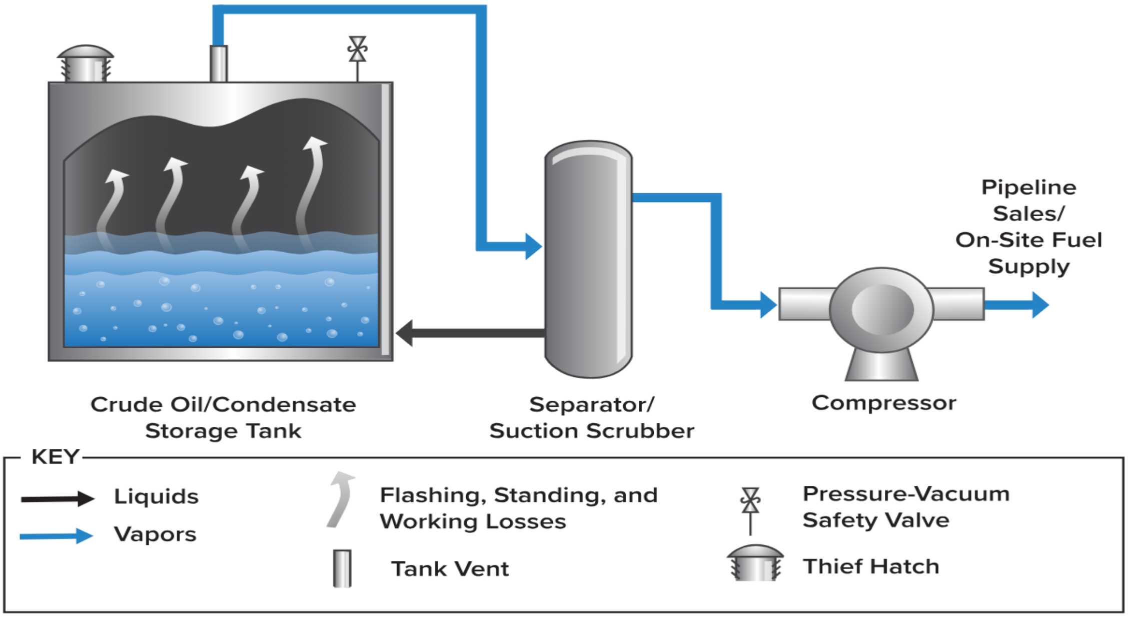

Figure 10: *Vapor Recovery Unit*[50]

Cost Estimates:
According to the economic estimates shown, installing vapor recovery units (VRUs) can deliver quick and substantial financial returns while reducing methane emissions. For example, recovering about 7,300 Mcf of methane annually can generate significant savings, ranging from roughly \$23,300 to \$54,400 per year depending on gas prices. Even with implementation and operating costs, the payback period remains very short between 2 and 4 months. This makes VRUs an attractive investment, as they not only reduce environmental impacts by capturing methane but also turn previously lost vapors into valuable revenue[51].

Economic and Environmental Benefits:
VRUs can provide significant environmental and economic benefits for oil and gas producers. The gases flashed from crude oil or condensate and captured by VRUs can be sold at a profit or used in facility operations. These recovered vapors can be:

- Piped to natural gas gathering pipelines for sale at a premium as high Btu natural gas.
- Used as a fuel for onsite operations.
- Piped to a stripper unit to separate NGLs and methane when the volume and price for NGLs are attractive.

VRUs also capture HAPs and can reduce operator emissions below actionable levels specified in Title V of the Clean Air Act. By capturing methane, VRUs also reduce the emissions of a potent greenhouse gas[52].

---

[50] https://www.epa.gov/natural-gas-star-program/vapor-recovery-units#reductions

[51] Natural Gas STAR technical document *Connect Casing to Vapor Recovery Unit*

[52] U.S. Environmental Protection Agency, Lessons Learned from Natural Gas STAR Partners, Installing Vapor Recovery Units on Storage Tanks, 2006

2.3 Plunger lift systems

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well "blowdown"), which produces substantial methane emissions[53].

The plunger lift was developed as a way to control liquid loading. Deliquification is an important part of the pumping process. Failure to deliquify properly can slow or even stop well production. The plunger lift uses the well's own pressure or gas flow rate to lift liquids to the surface and remove them from the tubing.

A tube is seated into the well and the plunger creates a seal with the tube's interior wall. During periods of optimal flow rates, the plunger rests at the top of the well. Over time, as production levels fall, liquid accumulates at the tube end. This is the beginning of liquid loading. When loading occurs, the decrease in pressure causes the plunger's valve to close, and the plunger falls to the bottom of the tubing. This forms a seal in the well, and pressure begins to rise. The plunger rides this pressure back to the top of the well, delivering the accumulated liquid to the surface and restoring the well to prime operating conditions.

The plunger lift system can be used to remove several types of contaminants from natural gas wells. These include water, sand, and oil. However, lubrication is required to form a good seal and to allow the plunger to travel easily through the tube. Plunger lifts differ from other artificial gas lifts in that they primarily maintain optimal conditions rather than directly facilitate the movement of the gas[54].

---

[53] United States Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners: Options for Removing Accumulated Fluid and Improving Flow in Gas Wells. Air and Radiation (6202J), 2011, www.epa.gov.

[54] Estis Compressions. (2022, January 4). How to compare artificial lift options for unconventional oil production.

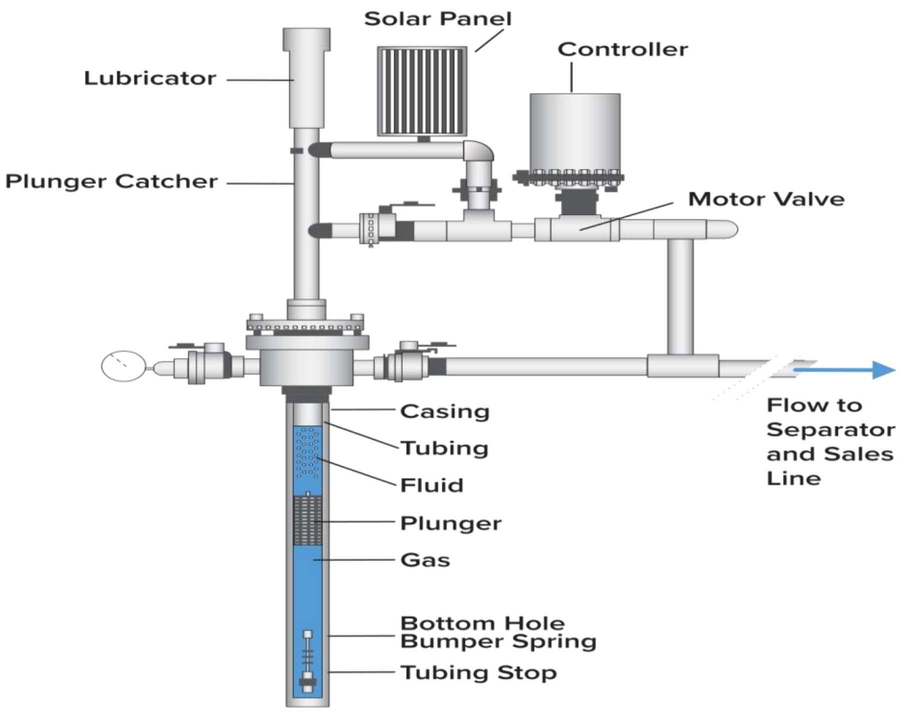

Figure 11: *Plunger Lift System*[55]

Effectiveness:

Plunger lift systems substantially reduce methane emissions per unloading event compared to wells without plunger lifts. The study shows that manually triggered plunger lift unloadings release on average about 9650 scf of methane per event, while automated plunger lift systems emit even less around 1260 scf per event. In contrast, wells without plunger lifts typically emit 21 000-35 000 scf per event, indicating that plunger lift technology can cut per-event emissions by a factor of two to more than twenty. Automated systems are especially effective because they trigger unloadings more efficiently and prevent the large, prolonged venting seen in manual operations. Overall, the use of plunger lift systems represents a significant mitigation measure for reducing methane emissions during liquid unloading events[56].

The EPA estimates that 4,700 to 18,250 Mcf/year of methane gas can be recovered per well with plunger lift systems.70,71 In 2011, the EPA estimated that 237 Bcf of methane was emitted from well cleanups annually. A large fraction of these emissions could be controlled using plunger lift systems[57],[58],[59].

Cost Estimates:

Installing a plunger lift system in a gas well involves a small initial investment, estimated by the EPA to be between $2,600 and $10,400 per well. Plunger lift system maintenance
may cost about $1,300 per year, but yields other operational savings such as avoided chemical treatment of about $13,200 per year, resulting in a net savings. Each plunger lift installed in an

---

[55] https://www.epa.gov/natural-gas-star-program/plunger-lift-system-without-planned-atmospheric-venting

[56] Allen, David T., et al. "Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings." *Environmental Science & Technology* 49.1 (2015): 641-648.

[57] U.S. EPA Natural Gas STAR, Installing Plunger Lift Systems in Gas Wells, Lessons Learned from Natural Gas STAR Partners, 2006

[58] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2009), April 15, 2011

[59] Harvey, op.cit

older gas well could result in 600 to 18,250 Mcf per year of recovered gas, valued at \$2,000 to \$103,000, when operations and maintenance savings are included. The value of methane gas recovered and sold rapidly covers that initial investment cost.

Most companies report a less than one-year payout and substantial profit thereafter, depending on the gas recovery rate. Future profits will be offset eventually by declines in gas recovery rates, and by minimal additional operating and maintenance costs, but since most plunger lift systems pay back in less than a year, plunger lift installations typically start profitable and remain profitable for many years after the initial investment[49,35].

Additional Benefits:

The installation of a plunger lift system serves as a cost-effective alternative to beam lifts and well blowdown and yields significant economic and environmental benefits. The extent and nature of these benefits depend on the liquid removal system that the plunger lift is replacing.

- Lower capital cost versus installing beam lift equipment
- Lower well maintenance and fewer remedial treatments
- Continuous production improves gas production rates and increase efficiency
- Reduced paraffin and scale build-up[50]

Alternate Mitigation options to Liquids unloading from gas wells

1. Furthermore, install Smart Well technology to plunger lift systems, an automated system that determines when a plunger lift cycle need to be actuated to determine optimally when liquids should be unloaded.
2. Add foaming agents, soap strings, surfactants to reduce velocity needed for the gas to carry liquids out of the well.
3. Install velocity tubing to reduce the cross-sectional area of the well, thereby increasing the velocity[60].

2.4 High Bleed to Low or No Bleed Pneumatic controllers:

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas. Natural gas- powered pneumatic controllers use natural gas as motive force operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate. Methane emissions occur from natural-gas powered pneumatic controllers when the pressurized gas is directed to atmosphere after the control action is performed[61].

The three predominant process variables that PCs control on gathering compressor stations are liquid level, pressure and temperature. Isolation valves, emergency shutdown (ESD) valves in safety systems, and liquid or chemical injection pumps may also be controlled and actuated pneumatically. A pneumatic control loop consists of a controller, a process sensor, process valve and a source of high-pressure supply gas. On gathering compressor stations, high-pressure gas is typically drawn from the discharge side of station compressors and any treatment equipment (such as dehydrators and liquid separators) and is typically regulated to 20-40 psig. Each process valve has a dedicated controller that monitors a process variable and generates a signal to operate the valve when the variable falls out of its desired range. PCs monitor processes variables through mechanical, electrical or pneumatic sensors. The majority of PCs vent a portion of supply gas to the atmosphere by design while pressurizing or

---

[60] Best Practice Guidance (MRV), Op.cit

[61] New Mexico Methane Advisory Panel. (2019, Fall). New Mexico Methane Advisory Panel draft technical report.

depressurizing valve actuators. These emissions occur either continuously between control events (continuous bleed PC) or in intermittent bursts, depending on the design and specific application of the PC. In addition to emissions from venting during normal process control operation, PCs can also emit gas through leaking tube fittings, valve stems, and damaged or malfunctioning controller components.

The U.S. Environmental Protection Agency (EPA) classifies PCs according to their normally operating vent behavior as intermittent or continuous bleed. Continuous bleed devices are further classified as low-bleed or high-bleed based on their steady state (inactive) emissions. PCs that vent **< 6 scfh of gas are classified as low-bleed** and those that vent **≥ 6 scfh of gas are classified as high-bleed.**

On the other hand, **Zero-bleed pneumatic controllers** do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic devices are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable[62],[63].

Effectiveness: Replacement or retrofit from high bleed to low bleed devices, up to 97% emission reductions achievable. Devices should be inspected and maintained on a regular basis[64]. High-bleed pneumatic controllers have vent rates that are typically more than 1standard cubic meter per hour (scm/h). At these rates, natural gas with a value of more than US$1000 a year is lost from each high-bleed device. If the operating conditions do not need high-bleed devices, low-bleed or intermittent controllers, with average vent rates of between 0.03 and 0.4scm/h, can significantly reduce methane emissions and the loss of natural gas[65].

---

[62] United States Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry. Air and Radiation (6202J), October 2006, https://www.epa.gov/natural-gas-star-program.

[63] US Environmental Protection Agency, OOAARAOOAQPA Standards, and US Environmental Protection Agency. "Control Techniques Guidelines for the Oil and Natural Gas Industry." *Research Triangle Park* (2016).

[64] Op.cit, Best Practice Guidance(MRV)

[65] Exhibit, O. C. D. "Reducing Methane Emissions: Best Practice Guide." (2019).

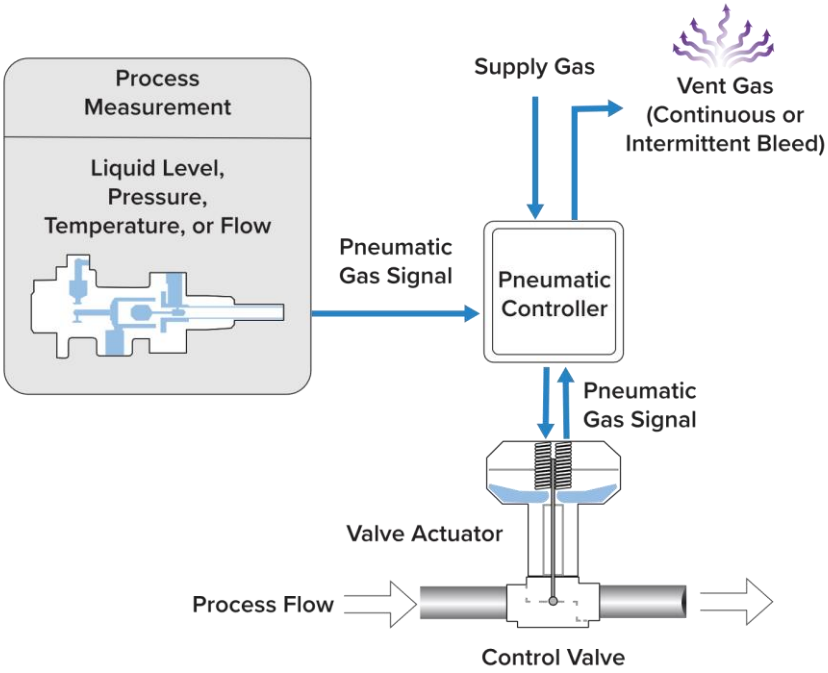

Figure 12: *Natural-Gas powered Pneumatic Controller*

Cost Estimates: The costs for installing a low-bleed pneumatic controller include capital and annual operation and maintenance (O&M) costs. The capital costs for a low-bleed controller can range from approximately $400 to $3,500, depending on the controller's function and design. Annual O&M costs are typically negligible, and the avoided maintenance costs for an older controller are typically included as a benefit in the economic analysis[66].

With vent rates from high-bleed devices typically being higher than 1scm per hour, installing a lowbleed or intermittent-vent controller could prevent losses of more than US$1000 per year from each device.

The cost of this mitigation strategy depends on whether the controller is: being replaced at the end of its useful life; being replaced early; or being converted with a retrofit kit.

Natural Gas Star partners12 report the following. The cost of replacing a high-bleed controller with an intermittent-vent or low-bleed controller at the end of the high-bleed controller's useful life is between US$210 and US$340. The cost of replacing a high-bleed controller before the end of its useful life is US$1850. The cost of converting a high-bleed controller with a retrofit kit is US$675. These figures mean that costs could be recovered within a period ranging from a few months to two years[67],[68].

Additional options and opportunities to reduce Methane emissions from pneumatic devices are:

- replacing pneumatic devices with electrical pumps or controllers;
- replacing pneumatic devices with mechanical controllers;
- using compressed air rather than natural gas to power pneumatic devices;

---

[66] Op.cit 62, OOAARAOOAQPA

[67] Op.cit, Exhibit, O. C. D. 64

[68] Op.cit. 61 Pneumatics.II pdf

- inspecting devices and repairing those that release emissions that are higher than expected.

2.5 Desiccant Dehydrators

Dehydrators are used in the oil and gas industry to remove water from gas, to meet pipeline quality standards. The liquid desiccant most often utilized is triethylene glycol (TEG). During the dehydration process, TEG absorbs water along with methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) when contacted with the wet gas. TEG is then regenerated (i.e., water and impurities are removed) through heating in a reboiler, where absorbed methane, VOCs, and HAPs are vented to the atmosphere along with the water vapor. The TEG is often circulated with a gas-assist glycol circulation pump wherein produced gas is injected into the TEG to provide more power to the pump, resulting in additional methane emissions[69].

Replacing glycol dehydrators with desiccant dehydrators that use moisture absorbing (deliquescent) salts to remove water reduces emissions of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) and reduces operating and maintenance costs.

Desiccant dehydrators use moisture absorbing (deliquescent) salts to remove moisture from natural gas. Deliquescent salts used by the oil and gas industry include calcium chloride, potassium chloride, and lithium chloride. The amount of moisture that can be removed from natural gas depends on the type of desiccant used, as well as the temperature and pressure of the gas. Calcium chloride, the most common and least expensive desiccant, can achieve pipeline-quality moisture content at temperatures below 59 degrees Fahrenheit (°F) and pressures above 250 pounds per square gauge (psig). Lithium chloride has a wider operating range of up to 70 °F and above 100 psig.

Desiccant dehydrators can be used permanently in place of a glycol dehydrator where the wellhead gas is cold--below 59 to 70 °F, depending on the desiccant salt used--and pressure is above 100 to 250 psig, again, depending on the desiccant salt used. Desiccant dehydrators can be used temporarily in situations where a large amount of gas would otherwise be vented during glycol dehydrator maintenance. Desiccant dehydrators can also be used for dehydrating gas captured by reduced emissions completion units following gas well hydraulic fracturing.[70].

Unlike a traditional glycol dehydrator, there are no pumps, contactors, regenerators, or reboilers, and only a small amount of methane is released intermittently when the unit is opened to replace the salt[71].

Effectiveness: The EPA states a reduction in methane by 99% using a desiccant dehydrator, or PDS (passive dehydration system) unit, over a glycol dehydrator. Unlike the TEG unit, all waste in a PDS unit is condensed into a non-hazardous brine solution and safely disposed of. The PDS unit allows for the conservation of natural resources, a reduction in environmental and health liabilities, eliminates permitting for air emissions, and the emissions themselves while complying with all state and federal environmental regulations[72].

---

[69] U.S. Environmental Protection Agency. *Glycol Dehydrators*. Natural Gas STAR Program. Last updated March 17, 2025. https://www.epa.gov/natural-gas-star-program/glycol-dehydrators

[70] U.S. Environmental Protection Agency. *Desiccant Dehydrators*. Natural Gas STAR Program. Last updated June 24, 2025. https://www.epa.gov/natural-gas-star-program/desiccant-dehydrators

[71] Op.cit, Harvey,

[72] Croft Production Systems, Inc. *Glycol Dehydration versus Solid Desiccant Dehydration*. Oil & Gas Blog. Posted May 21, 2020 by Cameron P. Croft. https://www.croftsystems.net/oil-gas-blog/teg-versus-passive-dehydration-systems/

Cost Estimates: Economic analyses demonstrate that replacing a glycol dehydrator processing 1 million cubic feet per day (MMcfd) of gas with a desiccant dehydrator can save up to $4,403 per year in fuel gas, vented gas, and operation and maintenance (O&M) costs and reduce methane emissions by 564 thousand cubic feet (Mcf) per year.

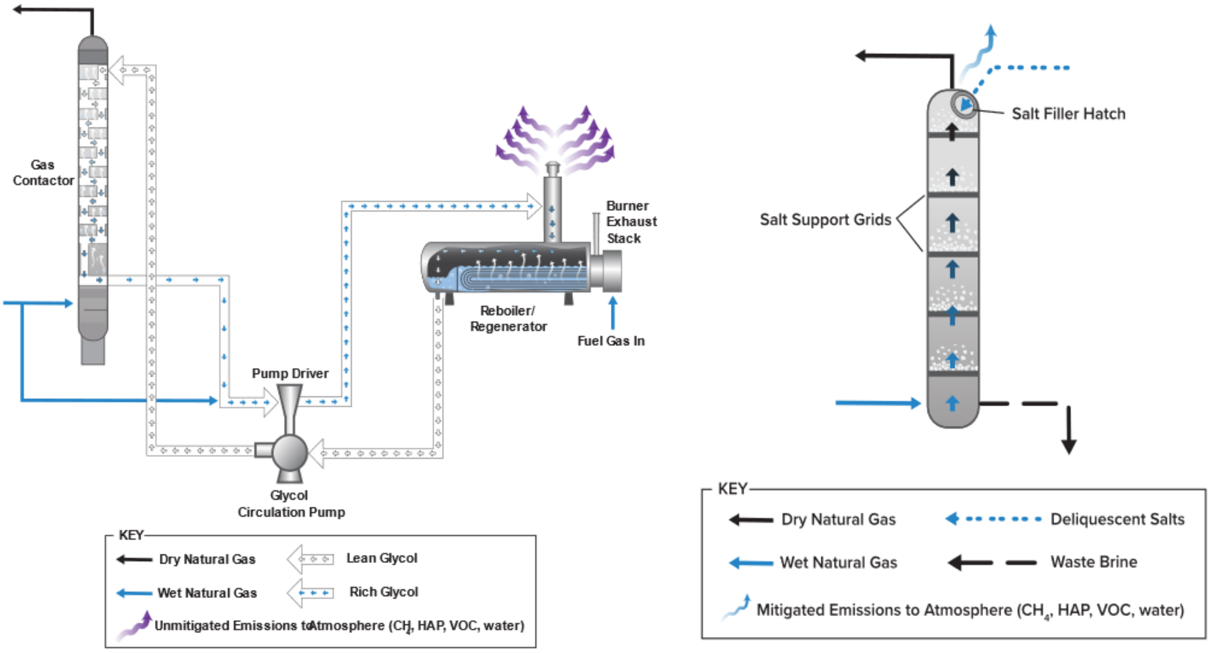

Figure 13: *Glycol Dehydrator (Left) and Desiccant Dehydrator (Right)*

The EPA estimates that profit could amount to $6,000 per year, including operations and maintenance savings. The initial investment of $16,000 for replacing a glycol dehydrator with a desiccant dehydrator is paid out in less than three years[73].

In 2007, BP reported that it eliminated 858 glycol dehydrators, replacing them with desiccant dehydrators, for a $27 million profit and "immediate-payout." This amounts to a profit of $31,469 per unit total, or about $31,000 per year averaged over a 10-year period[74],[75].

Additional Benefits:

In addition to reducing emissions of methane, replacing a glycol dehydrator with a desiccant dehydrator may:

- Reduces emissions of volatile organic compounds and hazardous air pollutants.
- Eliminates glycol chemical costs and degraded glycol disposal costs.
- Eliminates the maintenance time and costs associated with glycol circulation pump maintenance.

Use of a desiccant dehydrator temporarily, during glycol unit maintenance shutdown, may:

- Allows a continuity of supply to downstream processing, transmission, and sales outlets, in spite of necessary maintenance shutdown.

---

[73] U.S. Environmental Protection Agency. *Replacing Glycol Dehydrators with Desiccant Dehydrators: Lessons Learned from Natural Gas STAR Partners*. Washington, DC: U.S. Environmental Protection Agency, 2004

[74] Smith, G.R., BP America Production Company, Natural Gas Industry Green House Gas Control & Business Opportunity Presentation, 2007.

[75] Op.cit, Harvey.

- Eliminates the need for venting or flaring during maintenance shutdown[76].

2.6 Zero emissions dehydrators

Conventional glycol dehydrators can have substantial methane emissions from the venting of still column vapors and leaks from gas-driven glycol circulation pumps. Zero emissions dehydrators reduce these emissions by using electric power for pumps and re-using still column vapors for fuel. Zero emissions dehydrators are designed to collect all condensable components from the still column vapor and use the remaining non-condensable still vapor (methane and ethane) as fuel for the glycol re-boiler. A water exhauster is used to yield high glycol concentrations without the use of a gas stripper. Electric driven circulation pumps are used in zero emissions dehydrators instead of gas-driven pumps to further reduce methane emissions. Zero emissions Dehydrators can be newly installed or existing glycol dehydrators can be retrofitted with zero emissions technology. A conventional dehydrator of similar size shows losses of 5.95 scf (standard cubic feet) per gallon of glycol that is circulated with a Kimray pump at 4 gpm. The conventional dehydrator also has gas losses of 4 scf per gallon of glycol that is circulated through the gas stripper. The zero emissions dehydrator avoids these gas losses by eliminating the use of Kimray pumps and gas strippers. It is reported that condensate is also recovered from the still column vapor at 2.88 gal/hr (gallons per hour) while the non-condensable vapor is used to fuel the glycol re-boiler in the zero emissions dehydrator[77]. Replacing by zero emissions dehydrators, up to 100% emission reductions achievable

Additional Mitigation Techniques for Methane Emissions from Glycol dehydrators:

1. Install flash tank separator and optimize glycol circulation rates, up to 90% emission reductions achievable.
2. Route flash tank (if present) and dehydrator regenerator vents to VRU for beneficial use, such as fuel gas, up to 90% emission reductions achievable, or re-route to flare, up to 98% emission reductions achievable.
3. Reroute glycol skimmer Gas, up to 95% emission reductions achievable.
4. Replace the gas assist lean glycol pump with an electric lean glycol pump, up to 100% emission reductions from the pump achievable.[78]

2.7 Reciprocating compressor

A reciprocating compressor, or positive displacement compressor, uses a plunger or piston to compress gas in the compressor cylinder as the engine drives the piston back-and-forth inside the cylinder. The engine turns the crankshaft, which connects to the piston rod via a "crosshead" that converts the engine rotating motion to the piston reciprocating motion. Piston rod packing systems are mounted where the rod passes through the inboard cylinder head and are used to maintain a relatively tight seal around the piston rod, preventing the compressed gas in the compressor cylinder from leaking, while allowing the rod to move freely. Reciprocating compressors often use multiple cylinders with gas moving from the inlet low pressure to intermediate pressure, and then to high pressure[79].

---

[76] Op.cit, Desiccant Dehydrators, 69

[77] Environmental Protection Agency. *Natural Gas STAR Program: Zero Emissions Dehydrators*. U.S. EPA.

[78] Op.cit, Best Practice Guidance(MRV)

[79] U.S. Environmental Protection Agency, *"Reciprocating Compressors,"* Natural Gas STAR Program, last updated March 17, 2025, accessed December 20, 2025, https://www.epa.gov/natural-gas-star-program/reciprocating-compressors

Methane leaks occur between the rings and piston rod shaft, around the outside of the rings, and between the packing. Packing leaks can occur for a number of reasons, such as a worn piston rod, an incorrect amount of lubrication, dirt or foreign matter in the packing, or packing material out of tolerance. The amount of leakage will be a function of the amount of misalignment between the piston rod, packing materials, and rings and packing case. Also, misalignment of the piston rod and any imperfections on the piston rod surface can cause leakage.

Rod packing case leaks are also a function of the quality of initial installation, packing material selection, and the way in which the unit was operated during the initial, or break-in, operating period[80].

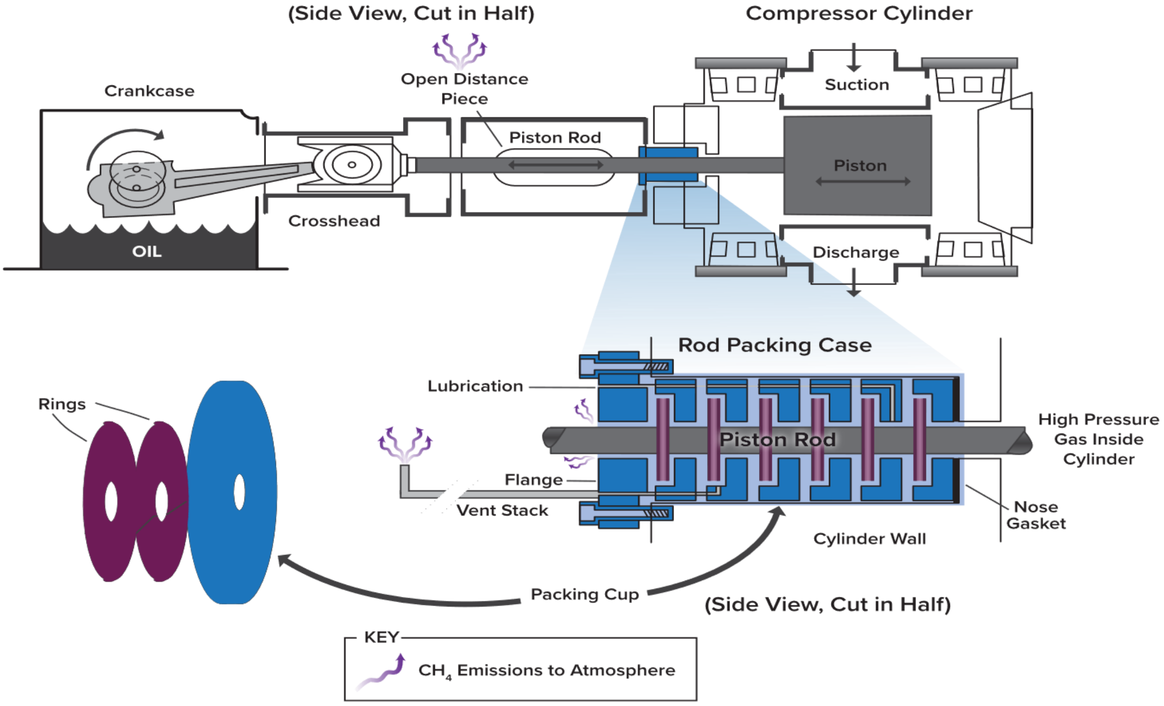

Figure 14: *Rod Packing for Reciprocating Compressor*

Effectiveness: The regular replacement of rod packing, 50-65% emission reductions achievable[81]. Rod packing replacement in reciprocating compressors leads to significant reductions in hydrocarbon emissions (used here as a proxy for ethane-rich VOC emissions) across the oil and gas supply chain. The largest percentage of emission reductions occurs in the transmission segment, which accounts for roughly 32% of total individual compressor emission reductions, followed by processing at about 28%, and storage at around 21%. Smaller but still meaningful reductions are observed in gathering and boosting (approximately 11%) and production well pads (about 8%)[82].

---

[80] Op.cit Harvey,

[81] Op.cit, Best Practice Guidance (MRV)

[82] U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors: Report for Oil and Natural Gas Sector Compressors Review Panel.* Office of Air Quality Planning and Standards (OAQPS), April 2014. PDF.

Cost Estimates: The EPA estimates that refurbishing the rings and packing material may cost between $135 and $2,500, depending on the size of the unit. Rod replacement can range from $2,400 to $13,500, depending on the number of rods replaced. The pace at which replacements are necessary is a function of the compressor type, use, maintenance and operating conditions, and is highly variable. In most cases, though, payout is achieved in less than a year. The EPA has estimated that on average, the annual investment expense of replacing one rod packing system is about $600, with an initial investment of about $1,600. The methane gas captured has a value of about $3,500 per year, allowing payout to be achieved in less than half a year.123 Another EPA reference reports a slightly lower initial cost for replacing rod packing of $1,200, but with similar natural gas savings, to allow for payout in less than half a year[83].

Additional Benefits: Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions to the atmosphere and save money.
Monitoring and cost-effective replacement are able to achieve several benefits:

- Reduced methane emissions.
- Gas savings from lower leakage rates.
- Extended service life of compressor rods[84].

Alternate Mitigation Technology: Re-route “distance piece” or packing case vents (point where rod packing leakage exits the compressor) to VRU, fuel gas system or flare. Emission reductions up to 95% achievable when sent to VRU and up to 99% when implementing a flare connection[85].

2.8 Centrifugal compressors (wet seal to dry seal)

A centrifugal compressor uses a rotating shaft to increase the velocity of the natural gas and direct the gas to a divergent duct section that converts the velocity energy to pressure energy. Centrifugal compressors have a series of rings to prevent gas from escaping where the shaft exits the compressor casing. Seals are used to prevent these releases – either wet seals that use a specialty oil or dry seals that use a mechanical barrier. Wet seals use a viscous oil under high pressure between a center ring (attached to the rotating shaft) and a ring on each side (stationary in the seal housing) pressed against the rotating ring with springs. A thin film of oil flows between the rings both to lubricate and to act as a leak barrier. The perimeter of the stationary rings is sealed in the case by rubber “O-rings” to prevent leakage of seal oil around the stationary rings. Very little process gas escapes through the oil barrier created between the stationary and rotating rings or through the outboard labyrinth seal, but gas is entrained and absorbed by the oil at the compressor side (inboard) seal oil/gas interface, thus contaminating the seal oil. The seal oil is purged of the entrained gas (using heaters, degassing tanks, and degassing techniques) to maintain its viscosity and lubricity before mixing with the uncontaminated outboard oil in a sump for recirculation back to the seals. This process results in methane emissions where the separated gas is vented to the atmosphere. Fig.13 depicts a centrifugal compressor with a wet seal configuration. On the other hand, compressors with a dry seal configuration use the opposing force created by hydrodynamic grooves and springs to provide a seal. The opposing forces create a thin gap of high-pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other.

---

[83] Op.cit, Harvey

[84] United States Environmental Protection Agency. *Air and Radiation (6202J).* Washington, DC: U.S. Environmental Protection Agency, October 2006.

[85] Op.cit, Best Practice Guidance (MRV)

Effectiveness: A dry seal can save about $135,000 per year and pay for itself in as little as 14 months. One Natural Gas STAR partner who installed a dry seal on an existing compressor, for example, reduced emissions by 97 percent, from 75 to 2 Mcf per day, saving almost $80,000 per year in gas alone[86].
Cost Estimates: The actual costs for a dry seal system will depend on compressor operating pressure, shaft size, rotation speed, and other site-specific factors. The EPA reports that a dry seal retrofit costs on average $324,000, but results in an operations and maintenance cost savings of more than $100,000 per year and can generate up to $400,000 in additional annual revenue from captured methane, resulting in a payout of approximately one year.110,111 One of the major factors in the profit equation is the lower O&M costs for dry seals—$8,400 to $14,000 per year—compared to wet seal costs of $140,000 per year per compressor or more. The EPA's 2011 Greenhouse Gas Inventory and other sources estimate the leak rate to be approximately 18,000 to 100,000 Mcf per year. If captured and sold, this could annually yield up to $400,000 in additional revenue, and up to $120,000 in operations and maintenance savings[87].

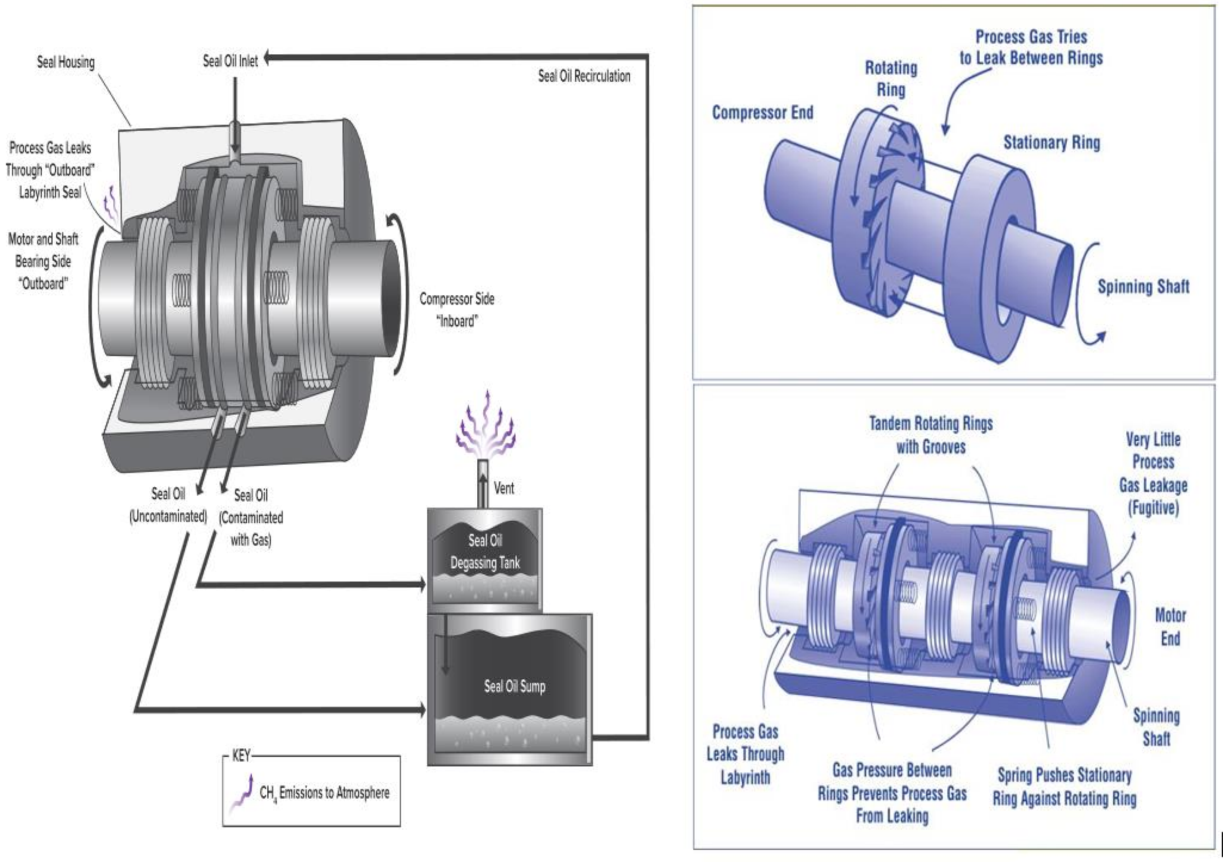

Figure 15: *Wet Seal Centrifugal Compressor (left) and Dry Seal Centrifugal Compressor (right)*

---

[86] U.S. Environmental Protection Agency. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors.* Natural Gas STAR Program, October 2006. PDF

[87] Op.cit Harvey

Benefits: Dry gas seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates: During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal, depending on the size of the seal and operating pressure. While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas from the oil is usually vented to the atmosphere, bringing the total leakage rate for dual wet seals to between 40 and 200 scfm, depending on the size and pressure of the compressor.
- Mechanically Simpler: Dry seal systems do not require elaborate oil circulation components and treatment facilities.
- Reduced Power Consumption: Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability: The highest percentage of downtime for a com pressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance: Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves).
- Elimination of Oil Leakage from Wet Seals: Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline[88].

Other mitigation options for centrifugal compressors:

Re-route gas to a high-pressure separator VRU, or to a low-pressure inlet such as compressor suction, fuel gas, or flare, emission reductions of 95% achievable[89].

2.9 Pipeline maintenance and repair

Methane is typically vented into the atmosphere when a gas pipeline is repaired or replaced, or must be cut to install a new connection point. Typically, an operator will isolate the pipeline section to be worked on by shutting pipeline valves on either side of the repair, replacement, or connection point. The gas contained in the piping section is typically vented into the atmosphere to eliminate a potential fire or explosion risk while work is completed on the piping. Subject to a thorough safety evaluation, alternatives exist to mitigate methane release. These alternatives involve either re-routing gas to be burned as fuel or allowing work to be conducted on the pipeline while it is in operation.

During pipeline repair, methane gas venting can be mitigated by:

1. Using hot tap connections
2. Re-injecting gas into a nearby low-pressure fuel system
3. Using a pipeline pump-down technique to route gas to sales

Hot Tap Connection:

---

[88] Op.cit, *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*

[89] Op.cit, Best Practice Guidance (MRV)

Hot tapping a pipeline allows an operator to make a connection to a pressurized piping system without causing any service interruption. Hot tapping is completed by first welding a branch fitting and permanent valve body onto the pipeline while the pipeline remains in service. Next, the hot tapping machine is installed on the valve body (Figure). The hot tap pipeline cutting tool is inserted through the valve body and used to cut into the pipeline while maintaining a complete seal between the valve body and the hot tap machine. This process does not allow any methane gas to escape. Once the pipeline wall is cut, the piece of pipe is removed along with the cutting tool by pulling both back through the valve body. The valve is closed and the hot tap machine is removed. Finally, the branch line is connected and installed without releasing any methane into the environment.

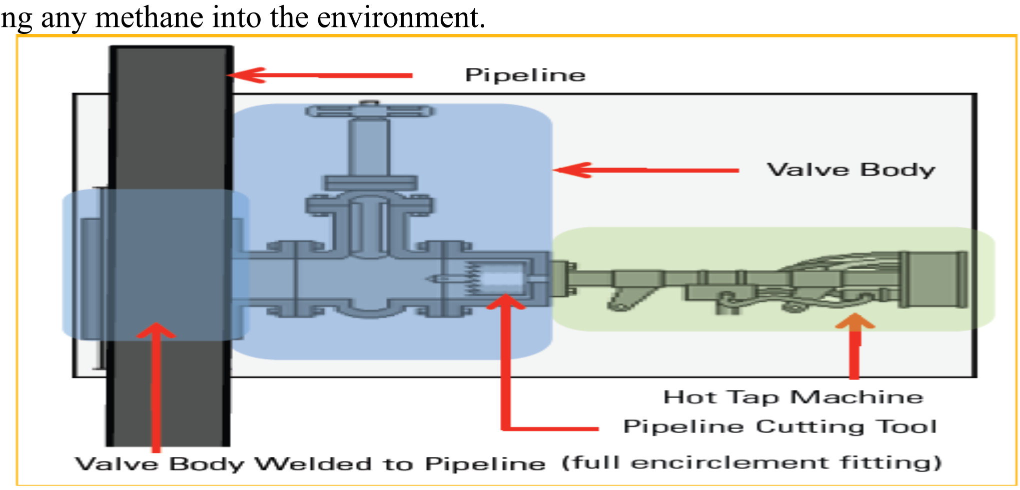

Figure 16: *Pipeline Hot Tapping Schematic*

Re-injecting gas into a nearby low-pressure fuel system

In some cases, complete gas evacuation is required to safely repair, replace, or conduct maintenance on a pipeline section. Rather than venting methane to the atmosphere, an operator can de-pressure the pipeline to a nearby low-pressure fuel system. Some pipelines are initially designed and installed with a bypass connection from the high-pressure pipeline to a lower pressure fuel gas system. If a permanent bypass connection does not exist, a temporary bypass connection can be installed.

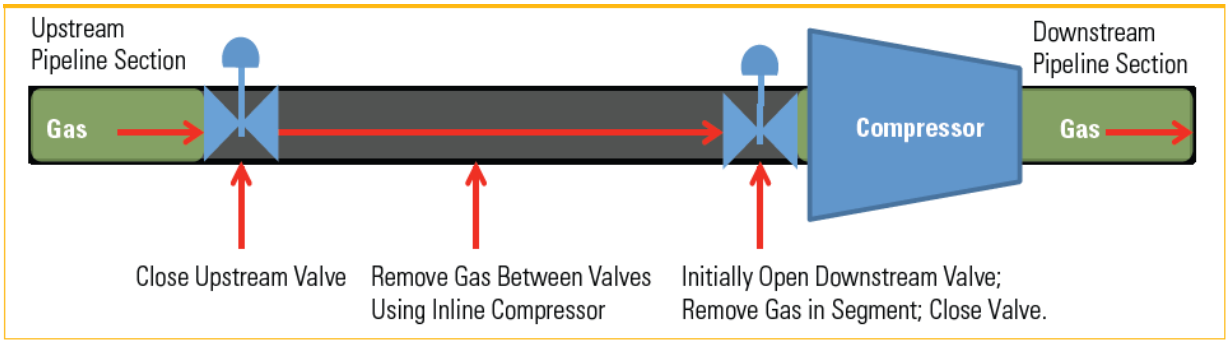

Figure 17: *Pipeline Pump-Down Technique Using In-Line Compressor Schematic*

Pipeline pump-down technique:

Gas can be removed from the pipeline by using in-line compressors along, or in sequence with, portable compressors. As explained above, an operator often will isolate the pipeline section to be worked on by shutting in pipeline valves on either side of the repair, replacement, or connection point. The gas contained in the piping section is then vented into the atmosphere to eliminate a potential fire or explosion risk. Alternatively, in the pipeline pump-down technique, the operator only shuts in one valve (the upstream valve), which stops any new gas from entering the pipeline section to be worked on. Then gas is removed from the pipeline section by running an inline compressor located downstream of the repair section. This technique will not completely remove all the gas in the pipeline section, but may reduce the gas pressure or concentration to a level that is safe for some repairs (Figure).

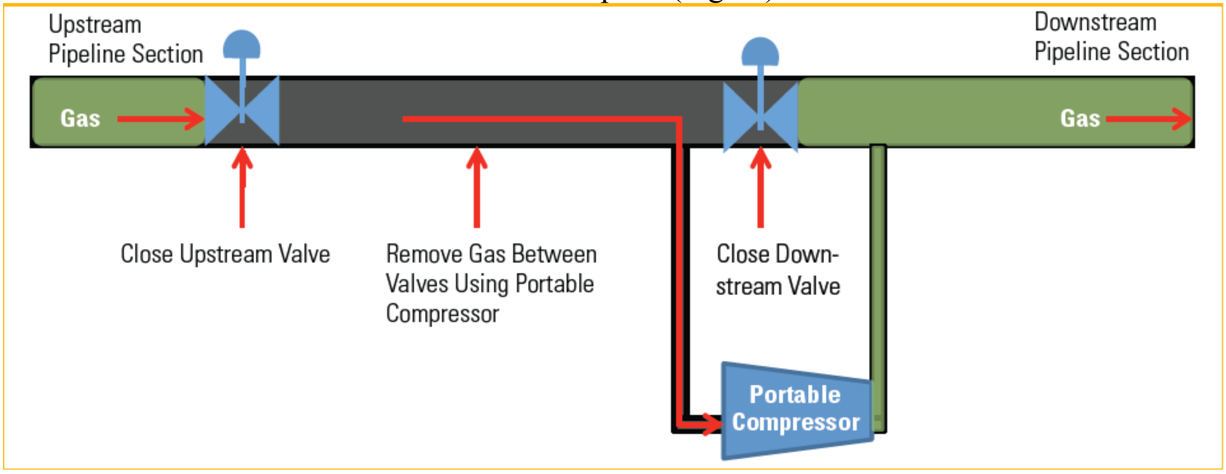

Figure 18: *Pipeline Pump-Down Technique Using Portable Compressor Schematic*

Advantages of Pipeline Management and Repairs:

Use of a hot tap tool prevents venting gas into the atmosphere, allowing that gas to reach market, and eliminates the cost of evaluating the pipeline to install the connection. Hot tap profitability will vary widely based on the pipeline size, flow rate and number of taps done in a period of time. However, in general the EPA reports that payback is short (less than one year) and the procedure is profitable. The EPA estimated that the capital cost of installing a low-pressure piping bypass to re-inject gas during a pipeline blowdown into a low-pressure fuel system is less than $1,000. The pipeline pump-down technique is most profitable for higher pressure, higher volume pipelines with existing in-line compressors, or where valve manifolding exists to easily connect a portable compressor. Overall, use of in-line compressors to remove gas from a pipeline during a pipeline pump-down technique is very profitable because there is no initial investment or rental costs, and payback is essentially immediate. If portable compressors are required, economics will vary and will require a site-specific evaluation. Still, this procedure is typically profitable, with a short payout. Gas collected by the compressors can be routed to a gas sales line[90].

Emissions from Hydrocarbon liquid storage tank, loading & transportation, produced water discharge:

Vapors, consisting of methane, VOCs and other hazardous air pollutants are released from liquid hydrocarbon products during storage and loading due flashing losses (due to a rapid pressure drop), working losses (from changing fluid levels) and standing losses (due to ambient temperature and pressure changes). The volume of vapor emitted from a fixed-roof storage tank is dependent on several factors including the composition of the hydrocarbon liquid, the pressure in the gas/liquid separator and the hydrocarbon flow rate from this separator into the tank.

---

[90] Harvey, op.cit

During loading and unloading (transfer) activities between storage tanks (including for transportation), emissions released are attributed to physical displacement of residual vapors by the incoming liquid, evaporation effects promoted by agitation, and also leakage/spillage during the connection/disconnection of transfer lines and during the transfer process. Blanket gas represents an additional source of emissions during loading/unloading. Finally, emissions from produced water discharged are grouped into this source as they arise from a similar physical process.

Mitigation Techniques:

1. Installing a Vapor Recovery Unit (VRU) and directing to productive use as fuel gas, compressor suction, gas lift, emission reductions of up to 98%
2. Reducing operating pressure upstream,
3. Install separate systems to control loading losses from the tank vehicles and storage losses from the tanks (applicable when product is not transported by pipeline)
4. Implement a system to balance or exchange vapors between the tanks and tank vehicles and add a common vapor control device if needed (applicable when product is not transported by pipeline)
5. Install stabilization towers ahead of tanks to obtain a low oil vapor pressure suitable for loading onto ships or barges. Stabilization removes virtually all methane from liquid hydrocarbons[91].

2.10 LDAR

In the oil and gas industries, leak detection and repair (LDAR) is a program implemented to systematically repair gas leaks that can otherwise go unnoticed. These leaks, or fugitive emissions, contribute to global warming. Collectively, fugitive emissions are one of the largest sources of emissions from the oil and gas sector and can result in significant losses.

In some cases, more than 2% of gas that enters the pipeline may be lost to fugitive emissions before reaching the end consumer. The exact quantity of losses depends on factors like the number of leaks, the flow rate of gas through the pipeline and the ambient temperature and pressure surrounding the leak sites. An LDAR program can reduce fugitive emissions of methane by over 90% in the oil and gas facilities where it is applied, contributing to climate change mitigation efforts.

LDAR can be implemented across the aboveground transmission and distribution facilities that transport natural gas from production facilities to end consumers. Leaking components may be repaired at the processing plant where contaminants are removed from raw natural gas, compressor stations where gas is pressurized to match the connecting networks, gate stations where measuring and metering of the fuel occurs and any other aboveground portions of the pipeline.

Throughout these facilities, leaks can occur at connection points like valves, flanges and risers. These aboveground leak sources are usually accessible to repair. However, LDAR is often overlooked because repairing fugitive emission sources is generally not crucial to the

---

[91] Best Practice Guidance (MRV), Op.cit

distribution system's operation and because advanced equipment and dedicated personnel are often required to implement a thorough LDAR program[92].

Leaks are the unintentional releases of natural gas from equipment used in oil and gas operations. They are typically caused by mechanical (vibration) and thermal stresses, loss of tightness or wear of mechanical joints, seals, and rotating surfaces over time. Equipment components include connectors, open-ended lines, valves, sampling connections, pressure relief devices emitting below design pressure, agitators, and LNG pump[93].

Table 4: *Potential components and equipment and their associated leak points*[94]

Component		**Leak Points**
Connections		flanges (gasket), threaded connections, tube fittings, and other types of joints/seals
Open ended lines		closed valve leak directly to the atmosphere or through an open vent pipe
Blow-down open-ended lines		stem, gland, bonnet, (all that is related to valve shaft sealing)
Pressure relief valves		rupture disk, valve seat (or outlet),
Others	LNG Pumps, Rotary Compressors and Agitators	shaft seal such as rotary screw, rotary vane and scroll compressors, excluding design emissions
	Covers	Manways, boilermakers, blind flanges, access hatches.
	others	Grease nipples

Fugitive emission control is a two-part process that includes both a monitoring program to identify leaks and a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.

There are many different monitoring tools listed in table 4 that can be used to identify leaks, including electronic gas detectors, acoustic leak detection systems, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, toxic vapor analyzers, and infrared optical gas detectors[95].

Elements of LDAR Program:

The requirements among the regulations vary, For each element, this section outlines the typical but all LDAR programs consist of five basic LDAR program requirements, common compliance elements.

---

[92] Calyx Global. 2025. "An Introduction to LDAR." March 24, 2025. Accessed December 22, 2025. https://calyxglobal.com/research-hub/research/an-introduction-to-ldar/

[93] Oil & Gas Methane Partnership 2.0 (OGMP 2.0). *Technical Guidance Document: Unintended Equipment Leaks (Final – SG Approved).* April 2025. OGMP Partnership. https://www.ogmpartnership.org/sites/default/files/2025-04/Leaks-TGD-Final-SG-Approved.pdf

[94] Op.cit, *Technical Guidance Document: Unintended Equipment Leaks*

[95] Op.cit, Harvey

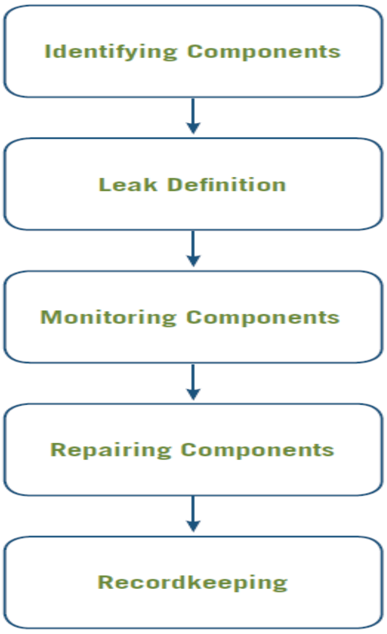

Figure 19: *Basic elements of LDAR*

Leak identification

At chemical, oil, or gas facilities, field operators measure emissions potentially leaking from different kinds of components. Thus, any LDAR program must first identify where to look for methane leaks. Depending on the emission type, operators may use specialized equipment. Equipment used for methane detection may differ meaningfully from that used to detect other VOCs. For methane detection in particular, optical gas imaging (OGI) is a common approach, although some nascent technologies rely on different means of detection (e.g., continuous monitoring by way of gas sensors).

LDAR surveys typically identify, label, and track all components which have leaked before. This process is known as tagging. Operators and regulators should define and agree upon thresholds for escalatable leaks when establishing an LDAR program. These thresholds can be defined on the basis of emission rates or mixing ratios. Establishing an action plan for monitoring different components is also important.

Leak Monitoring

The protocol and duration for emissions monitoring usually depends on the method used. For instance, plane-, drone-, or satellite-operated leak detection may provide sensitive assessment of larger, outdoor areas, but generally cannot provide sustained readings over time due to higher operating costs[96].

Repairing Leaking Components and Reporting

To stop detected leaks while they are still small, most rules require a first attempt at repair within 5 days of the leak detection and a final repair within 15 days. However, any component that cannot be repaired within those time frames must be placed on a "Delay of Repair" list to be repaired during the next shutdown cycle.

---

[96] Ben Montgomery, "*Understanding LDAR Requirements for Oil and Gas Operators: Emissions Reduction Through Continuous Monitoring*," *Qube IoT*, June 21, 2025, accessed December 23, 2025, https://www.qubeiot.com/expert-insights/understanding-ldar-requirements-for-oil-and-gas-operators

First attempts at repair include, but are not limited to, the following best practices where practicable and appropriate:

- Tightening bonnet bolts;
- Replacing bonnet bolts;
- Tightening packing gland nuts; and
- Injecting lubricant into lubricated packing[97].

Detailed record keeping should allow operators to identify the source, frequency, level, and type of leak over time. This includes an assessment of the components that typically pose leak risks, and those that do not, and as a result, which deserve more monitoring. One stated aim of LDAR is to give operators a better understanding of the typical risk associated with specific components[98].

Cost Estimates:

The cost of inspection differs depending on the value chain segment in question—LDAR programmes tend to be more cost effective for upstream operations since it takes longer to inspect compressors on transmission pipelines, relative to those concentrated in a production facility[99].

EPA *Lessons Learned* documents for both gas processing plants and compressor stations show the average cost of repair was between $26,000 and $59,000 per year per facility. Methane captured through these programs averaged 30,000 and 87,000 Mcf/year. For gas processing plants, leak screening and monitoring cost about $32,000 annually per plant. At both gas processing plants and compressor stations, the investments are profitable generating as much as $314,000 in profit per facility, with payback periods of just a few months.

Benefits of LDAR:

Implementing LDAR programs offers a range of co-benefits, beyond reducing the amount of greenhouse gases and harmful substances released into the atmosphere. They also deliver:

Environmental Benefits

Reduced air pollution and improved air quality by reducing harmful airborne chemicals.

Water and soil protection by preventing toxic chemicals that are often found with methane from seeping into soil and water resources.

Operational Benefits

Enhancing operational efficiency by optimising resource use, saving energy, and reducing the need for additional gas extraction or production.

Cost savings by preventing the loss of product through gas leaks and reducing the need for additional extraction or production.

Improved maintenance and reliability due to regular monitoring and repairing leaks that lead to better-maintained equipment.

Economic Benefits

Creation of environmental jobs through the implementation and maintenance of LDAR programs. Higher market competitiveness of companies with effective LDAR programs, which

---

[97] United States Environmental Protection Agency, Office of Compliance, Office of Enforcement and Compliance Assurance. 2007. *Leak Detection and Repair: A Best Practices Guide*. EPA-305-D-07-001. October. https://www.epa.gov/compliance

[98] Ben Montgomery, Qube IOT, Op.cit

[99] IEA (2020), Methane Tracker 2020, IEA, Paris https://www.iea.org/reports/methane-tracker-2020, Licence: CC BY 4.0

may give them a competitive edge by operating more efficiently and sustainably, which appeals to consumers and investors[100].

2.11 Best Available Technologies (BATs)

As a contribution to the technical implementation of the requirement to minimise venting and flaring and building on the technical experience of its members, MARCOGAZ proposes a concise list of 9 Best Available Techniques (BATs) to reduce, prevent and minimise methane emissions related to Venting and Flaring activities in the mid and downstream gas sector. This initiative aligns with the European Commission's methane mitigation priorities under the European Green Deal and methane regulation framework, which emphasizes measurement, reporting, verification (MRV), leak detection and repair (LDAR), and restrictions on venting and flaring except for safety or essential operations[101].

1. Reduce pressure before venting
2. Recover and recompress emissions in the process gas: mobile compressor
3. Recover and recompress emission in the process gas: stationary compressor
4. Flaring as replacement of venting (to reduce the environmental impact)
5. High bleed continuous pneumatics mitigation
6. Electrical or pneumatic air starters
7. Use of nitrogen to purge LNG pipes
8. LNG truck loading (dry coupling connectors)
9. Excess flow valves in new service lines

2.12 Alternative and innovative technologies

The IEA's analysis includes technologies and techniques in addition to the categories above. In the marginal abatement curve, these technologies appear under the label "Other," which includes the following:

Install new methane-reducing catalysts: Exhaust from gas-burning engines and turbines contains methane from incomplete fuel combustion. Oxidation catalysts are used to reduce unburned emissions for other hydrocarbons; new catalysts are being developed to do the same for methane.

Deploy microturbines, mini-CNG, mini-GTL (gas to liquids), or mini-LNG facilities: Micro-technologies can offer capacity for compression or liquefaction of associated gas in remote locations. These technologies avoid venting and flaring by capturing gas for use at the facility, in the surrounding community, or for transport by truck or rail[102].

---

[100] Integrity Council for the Voluntary Carbon Market. "*Leak Detection & Repair in Gas Systems*." *ICVCM*. Accessed December 23, 2025. https://icvcm.org/leak-detection-repair/

[101] **MARCOGAZ.** *Best Available Techniques to Reduce Methane Emissions from Venting and Flaring Activities in the Mid-Downstream Gas Sector.* MARCOGAZ, December 20, 2023.

[102] IEA (2020), Methane Tracker 2020, IEA, Paris https://www.iea.org/reports/methane-tracker-2020, Licence: CC BY 4.0

3. Abatement technologies and costs

A wide variety of technologies and measures are available to reduce methane emissions from oil and gas operations.

If all options were to be deployed across the oil and gas value chains, IEA estimated that around 75% of total oil and gas methane emissions could be avoided. Importantly, since methane is a valuable product and, in many cases, can be sold if it is captured, alsoaround 40% of total emissions could be avoided with measures that would have no net cost (at 2019 natural gas prices).

There is a large degree of variation between countries given different gas prices and capital and labour costs, but the global averages for the key options in the marginal abatement cost curve are shown.

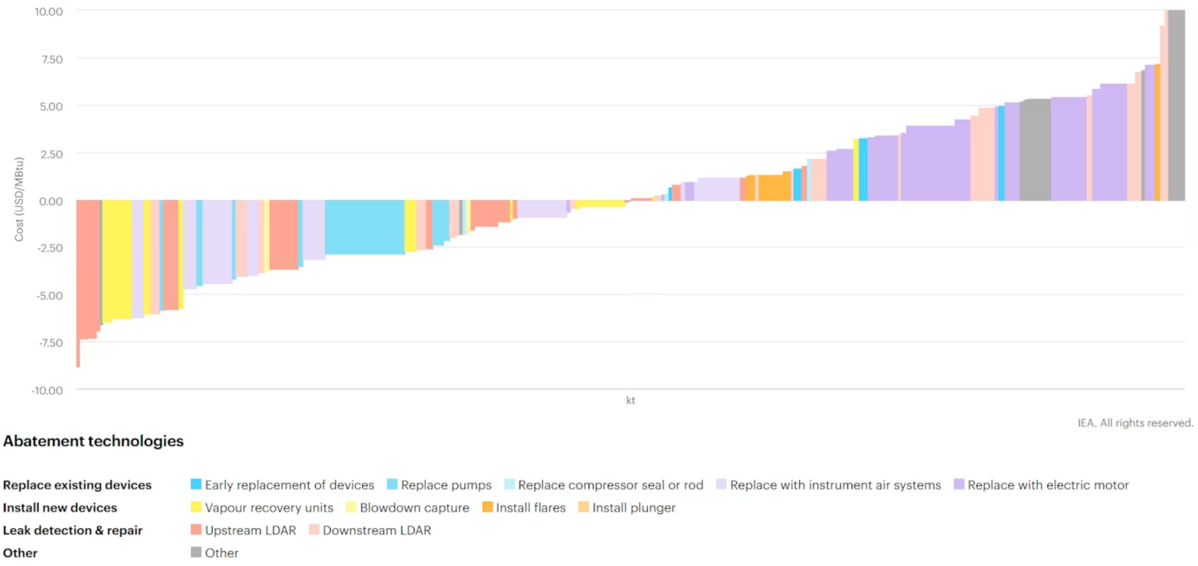

Figure 20: *Marginal abatement cost curve for oil- and gas-related methane emissions by mitigation measure, 2019*[103]

---

[103] Op.cit Methane tracker 2020, IEA.

4. International initiatives with focus on methane emissions

In order to aggregate efforts to respond to the challenge of climate change related to oil and gas sector operations a number of association, consisting of public and private players, have were created in the past few years; some of them are focused on methane, such as the Global Methane Initiative (GMI) and the Methane Guiding Principles (MGP), others include methane mitigation in a broader scope of action such as Climate and Clean Air Coalition (CCAC), via the Oil and Gas Methane Partnership (OGMP) and Oil and Gas Climate Initiative (OGCI). Inter alia, these initiatives looks into mitigation actions and projects, best practices and knowledge sharing, technical assistance, policy development, with a focus on improving the quality of emissions data and on transparency of reporting. These initiatives encompass an important part of the national and international oil and gas industry.

Global Methane Initiative (GMI) is an international public-private partnership focused on reducing barriers to the recovery and use of methane as a clean energy source. GMI's 45 Partner Countries and more than 500 Project Network members exchange information and technical resources to advance methane mitigation in key sectors, including Oil and Gas. GMI's Oil & Gas Subcommittee encourages collaboration between delegates from Partner Countries and Project Network members to build capacity, develop strategies and markets and remove technical and non-technical barriers to methane mitigation project development in order to increase environmental quality, improve operational efficiency and strengthen the economy from the additional gas brought to market.

Oil and Gas Methane Partnership (OGMP) is a voluntary, public-private partnership under the Climate and Clean Air Coalition, with 13 private and state-owned partner companies, governments, inter-governmental organizations and civil society. OGMP requires companies to survey nine "core" sources of emissions, evaluate cost efficient technology option and report annual progress. The partner companies have surveyed more than 65 assets in 15 countries to date. The European Commission is the latest lead partner of the CCAC Oil and Gas initiative.

Oil and Gas Climate Initiative (OGCI) comprising 13 of the largest international oil companies which jointly, as part of a larger scope of methane mitigation actions, have set a target at 0.25% on the collective average methane intensity of aggregated upstream gas and oil operations by 2025 versus 2017 (representing 25% of reduction compare to the baseline which is at 0.32%), and with an ambition to achieve as far as 0.2% (corresponding to a 25 – 33% reduction in total methane emissions)) OGCI will report on progress. The specific quantitative target and ambition set by OGCI require companies to have in place rigorous methodologies and practical steps to monitor emission levels and progress in reduction efforts. OGCI has published a methodology note in relation to the target, but this and other company reports do not, at this stage, offer much detail on how emissions are quantified.

Methane Guiding Principles (MGP) for reducing methane emissions across the natural gas value chain. The Guiding Principles have been signed by 16 oil and gas companies and 10 other organizations, as of January 2019. The guiding principles cover both MRV and mitigation along the natural gas value chain. The companies have committed to present emissions data, methodologies to derive these data, and progress and challenges in methane emissions management. A close collaboration exists between MGP and OGCI[104].

International Methane Emission Observatory

The Commission supported the establishment of the International Methane Emission Observatory (IMEO) in 2021, together with the United Nations Environment Programme (UNEP), the Climate and Clean Air Coalition and the International Energy Agency.

UNEP’s IMEO provides data to the individuals who can act to reduce emissions. To do this, IMEO collects and publishes data through rigorous industry reporting via the Oil and Gas Methane Partnership 2.0 (OGMP 2.0), from satellites via the Methane Alert and Response System (MARS), from its series of global methane science studies, and from national emissions inventories. The IMEO launched its ‘An Eye on Methane’ data platform in November 2024. Building on both OGMP 2.0 and MARS, the observatory is working on the development of a Methane Supply Index of the emission intensity of global oil and gas production to be used by market participants to make purchasing choices based on emissions.

At COP29, the Commission co-hosted the first ever IMEO Ministerial, reaffirming donors’ strong political and financial support to data driven solutions to catalyse methane reductions[105].

---

[104] Best Management Practices (MRV), Op.cit

[105] European Commission. “International Methane Emission Observatory.” Methane emissions. Accessed January 2, 2026. https://energy.ec.europa.eu/topics/carbon-management-and-fossil-fuels/methane-emissions_en

Academic consultations and industrial site visit and consultation

As part of this study, academic consultations and an industrial site visit were conducted to gain practical insights and validate the technical understanding of methane emission detection, quantification, and mitigation presented in this report. These interactions significantly contributed to clarifying the current state of technologies, operational challenges, and real-world implementation practices.

An academic visit was undertaken to the University of Miskolc, where discussions were held with **Professor Dr. Szunyog István**, Vice Dean for Financial Affairs, Associate Professor, and Head of the Institute at the Faculty of Earth and Environmental Sciences Engineering, Institute of Mining and Energy. In addition, consultations were conducted with **Dr. Tróhák Attila**, Associate Professor and Head of the Institute at the Faculty of Mechanical Engineering and Informatics, Institute of Automation and Infocommunication. These discussions provided a comprehensive overview of methane emission issues, with particular emphasis on detection technologies, quantification challenges, and ongoing research activities. Dr. Tróhák Attila further explained these aspects using examples from his current research projects, offering valuable technical insights and helping to contextualize the theoretical concepts discussed in this report.

Furthermore, an industrial site visit was carried out at the **FGSZ Földgázszállító Ltd. natural gas facility in Kápolnásnyék**, where discussions were held with **Mr. Róbert Simigla**, Decarbonization Technology Expert. During the visit, detailed explanations were provided regarding the equipment and methodologies used for methane detection and quantification at the site. The visit also included hands-on exposure to selected monitoring instruments, allowing direct observation of operational procedures, challenges faced during implementation, and the strategies adopted to address them. This practical experience enhanced the understanding of real-world constraints and reinforced the relevance of the technologies and mitigation measures discussed in the report.