UNECE

Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector

Monitoring, Reporting and Verification (MRV) and Mitigation

UNITED NATIONS

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Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector

Monitoring, Reporting and Verification (MRV) and Mitigation

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Foreword

Growing atmospheric methane concentrations are of major concern for climate change. Methane has a global warming potential significantly higher than that of CO2, so reducing methane emissions should be a top priority for all emitting sectors to achieve the Paris targets. There are several collaborative initiatives focused on the topic.

Human activities are not the only source of methane emissions, but they are an important and growing source. The energy industries have recognized that they are responsible for an important share of these emissions in the production, transformation, and delivery of energy and they are taking steps to remedy the problem for commercial, safety and environmental reasons. It is necessary to improve our understanding of the scale of methane emissions, potential sources, and opportunities for reductions. This initial analysis of best practices in the monitoring, reporting, and verification of methane emissions from the upstream oil and gas industries is an important step in addressing an important contributor to global warming.

The natural gas industry has an important contribution to make in reducing the carbon intensity of the world's energy system. The expected contributions are not only in home heating and power generation, but also in transportation and enabling greater deployment of intermittent renewable energy sources. If the challenge of methane is not addressed, however, then the sustainability credentials of the industry will be questioned, and the opportunities presented by natural gas might be missed. For this reason, accurate understanding of the scale of the problem and deployment of commensurate mitigation strategies are imperative.

Olga Algayerova
Executive Secretary
United Nations Economic
Commission for Europe

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The **Global Methane Initiative** (GMI) is an international public-private partnership that works with government agencies around the world to facilitate project development in five key methane-producing sectors: agricultural operations, coal mines, municipal solid waste, oil and gas systems, and wastewater. Launched in 2004, GMI works in concert with other international agreements, including the United Nations' Framework Convention on Climate Change, to reduce greenhouse gas (GHG) emissions. It is comprised of 42 partner countries and the European Commission, representing about 70 percent of the world's anthropogenic methane emissions.
www.globalmethane.org

Structure

The work on the document was directed by the *Executive Steering Committee*, which defined the overall vision, as well as the scope, form and the tone of the publication. It was coordinated by the *Project Manager* who supervised the process and provided administrative support. The text was prepared by a *Technical Expert* who under the supervision of the *Executive Steering Committee* drafted and edited the document. The draft was first reviewed by a *Stakeholders Advisory Group* to ensure that messages were clear and effective for senior decision-makers, before undergoing a formal technical peer review process.

Disclaimer: The document does not necessarily reflect the position of the reviewers and partners listed below who provided their comments and helped to develop this publication.

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- World Meteorological Organization (WMO)

Case Studies: Case studies illustrating application of best practices identified in this document will be posted at: https://www.unece.org/index.php?id=53067.

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Acronyms and Abbreviations

BAT – Best Available Techniques

CIS – Commonwealth of Independent States

CO_2 – Carbon dioxide

CORSIA – Carbon Offsetting and Reduction Scheme for International Aviation

DI&M – Directed Inspection and Maintenance

FQD – Fuel Quality Directive

EU ETS – European Union Emissions Trading System

GCF – Green Climate Fund

GHG – Greenhouse gas

GPS – Global Positioning System

GWP – Global warming potential

ECE (UNECE) – United Nation's Economic Commission for Europe

EDGAR – Emissions Database for Global Atmospheric Research

EF – Emission Factor

ETS – Emission Trading System

FID – Flame Ionization Detector

GMI - Global Methane Initiative

ICAO – International Civil Aviation Organization

IEA – International Energy Agency

IIASA - International Institute for Applied Systems Analysis

INDCs – Intended Nationally Determined Contributions

IPCC – Intergovernmental Panel on Climate Change

IPECA - International Petroleum Industry Environmental Conservation Association

ITMOs – Internationally Transferable Mitigation Outcomes

KPI – Key Performance Indicator

LDAR - Leak Detection and Repair

MDP – Multilateral Development Banks

MRV – Monitoring, Reporting and Verification

Mt – Million tonnes

MPG – Modalities, Procedures and Guidelines

NC – National Communications

NDC – Nationally Determined Contributions

NIR – National Inventory Report

OGCI - Oil and Gas Climate Initiative

OGMP - The Oil and Gas Methane Partnership

OVAs – Organic Vapor Analyzers

PID – Photoionization Detector

RMLD – Remote Methane Leak Detector

TVAs– Toxic Vapor Analyzers

UNFCCC – United Nations Framework Convention on Climate Change

USD – US Dollars

US EPA - The United States Environmental Protection Agency

VOC – Volatile Organic Compounds

VRU – Vapor Recovery Unit

Glossary and Terms

Based for a large part on Methane Glossary published by IPECA.[1]

Abatement costs - The incremental cost of a low-emission technology compared to the reference case.

Abatement potential - The potential of an abatement option to reduce GHG emissions in a specific year compared to the business-as-usual development

Bottom-up emissions estimate - Method of using 'ground-based' techniques to directly measure or estimate emissions at the facility level (e.g. well pad, compressor station) or the emissions source/activity level (e.g. compressor engine exhaust, storage tanks, equipment leaks).

Bottom-up emissions inventory - Inventory based on measurements, engineering calculations, manufacturer's data, and emissions factors for emissions sources/activities, compiled to develop an account of emissions discharged to the atmosphere from a facility (e.g. compressor station) or a geographic area (e.g. basin, state, region).

Cost effective or cost efficient - Relationship between the monetary inputs and the desired outcome, such as e.g. between expenditure and emission reduction.

Fugitive emissions in Oil and Gas Systems according to the IPCC[2] The intentional or unintentional release of greenhouse gases that occur during the exploration, processing and delivery of fossil fuels to the point of final use. This excludes greenhouse gas emissions from fuel combustion for the production of useful heat or power. It encompasses venting, flaring, and leaks

A narrower definition of fugitive emissions is commonly used, as for example reflected in the definition quoted on Wikipedia: *"Fugitive emissions are emissions of gases or vapor from pressurized equipment due to leaks and other unintended or irregular releases of gases, mostly from industrial activities."*[3]

Methane leaks: The unplanned release of methane from plant, production operations, systems and processes, typically from flanges, joints and connections.

Methane measurement - The process of taking a reading of the methane concentration or methane emission rate within an air sample at a specific point in time. Typical units for a measurement would be parts per million (ppm), parts per billion (ppb) or kilograms per hour. Note that it is important to understand global and local background methane concentrations to contextualize the data. Emissions measurements may be performed as one-time activities, at regular intervals or on a continuous basis, but it is important that the measurements are representative. A variety of techniques are described in Annex 2 to this document.

Methane quantification - Includes methods for determining the size of a methane emission source in terms of customary units of emissions rate, such as mass per time (e.g. kilograms per hour), or volume per time (e.g. standard cubic metres per hour). This can be accomplished by engineering estimations, direct measurement of the methane source (such as bagging procedures), and from models that use ambient measurements and meteorological data to infer an emission rate ('top-down' or 'bottom-up' approaches—see above).

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[1] http://www.ipieca.org/resources/awareness-briefing/methane-glossary/
[2] https://www.ipcc.ch/site/assets/uploads/2019/06/19R_V0_02_Glossary_advance.pdf
[3] https://en.wikipedia.org/wiki/Fugitive_emission

Super-emitter - A term used to describe the concept that certain methane sources can represent a disproportionate amount of the total methane emissions released from all sources. The term 'super-emitter' can refer to e.g. malfunctioning equipment, particularly in unmanned installations where such equipment has the potential to exist for long periods of time. Care should be taken when utilizing methodologies for identifying super-emitters to differentiate between episodic events (e.g. gas actuation events), erroneous measurements and/or malfunctioning equipment. The term 'fat-tail' is often used to describe the statistical representation of the data—a probability distribution that is highly skewed relative to a well-behaved distribution such as the normal or an exponential distribution.

Tier (IPCC GHG Guidelines): A tier represents a level of methodological complexity. Usually three tiers are provided. Tier 1 is the basic method, Tier 2 intermediate and Tier 3 most demanding in terms of complexity and data requirements. Tiers 2 and 3 are sometimes referred to as higher tier methods and are generally considered to be more accurate.

Top-down emissions estimate -Estimate made using different 'aerial-based' techniques to measure ambient air concentrations of methane, calculate methane flux based on atmospheric and meteorological conditions, and then attribute the emission portion due to different activities. Each measurement technique has different resolution capabilities, strengths, and weaknesses. Methane emissions are allocated to the oil and gas industry by: (a) using a ratio of methane to ethane or propane (longer chain aliphatics which do not occur from biogenic sources); (b) isotopic ratio analysis, using a co-located tracer (such as SF6 or C2H2); or (c) subtracting estimates of other sources of methane emissions such as, livestock, wetlands, agriculture, waste management, etc. together with background methane concentrations.

Executive Summary

Direct releases of methane, a powerful greenhouse gas, comprise an important share of the energy sector's greenhouse gas emissions. Methane emissions represent one quarter of human-induced global warming and, after agriculture, the oil and gas sector contributes the most. The enduring role of oil and gas obliges increased attention to methane emissions from exploration, extraction, processing, transportation, and distribution as emissions from the oil and gas sector will grow significantly if measures are not taken. There are significant opportunities for cost-effective mitigation. Awareness is growing in companies and governments, but there is an urgent need for information about the scale of methane emissions and for action to minimize releases.

This document provides guidance for effective methane management practices for the oil and gas sector. It is a resource for a owners and operators of oil and gas facilities and government policymakers. It is "principles-based" as conditions vary greatly across oil and gas facilities and legal, political and institutional aspects differ by jurisdictions.

- Methane emission reductions are among the most cost-efficient measures with large near-term mitigation benefits. Nearly 50% of oil and gas sector methane emissions can be eliminated at no net cost. Exploiting the opportunities requires better knowledge of emission sources and understanding of barriers to action. Methane emissions occur along the full oil and gas value chain and proper methane management should be performed at all stages. Best practices for detection and mitigation must be established from the field and corporate level to the level of national policies and regulation. Active coordination between institutional levels and across physical dimensions of the oil and gas supply systems can deliver superior results.
- Major gaps exist in information about emissions originating from the oil and gas sector. Reported estimates often diverge by 10% or more, and revisions of national inventory reports from some of the largest emitters highlight the lack of reliable data. Methane emissions cannot be quantified through continuous measurement alone. Emissions originate from a vast number of sources and monitoring each source would be prohibitively expensive. Emission detection and measurement must complement calculation-based approaches that quantify emissions by multiplying activity data by relevant emission factors. Estimates will be more reliable if they reflect field and country specific circumstances, so empirical studies of emissions and emission intensities are a key to improved quantification. Detection and measurement consist of top-down methods that measure concentrations of methane in the atmosphere and bottom-up methods involving on-site quantification of emissions from individual sources. The technology for both top-down and bottom-up approaches is improving and the choice of approach depends on the objective. Best practices for top-down or bottom-up detection and measurement and for calculation-based methods depend on the objectives and the manner of reporting.
- Company level reporting provides information on environmental performance and can be a basis for mitigation programmes. With ever more industry associations and public-private partnerships engaged in methane emissions reporting, there is a great deal of ongoing work on developing and streamlining reporting guidelines and on publishing

emissions reports. These efforts reduce the knowledge gap and improve transparency and comparability of data across companies and countries. Understanding national methane emissions provides a basis for deploying effective measures and for monitoring progress. Improving national inventories for oil and gas methane emissions requires collaboration among companies, researchers, and other stakeholders able to provide inputs such as emissions factors and activity data. Several countries have broad collaborative processes that result in improved national inventories. Internationally agreed methods and guidelines influence national calculations and reporting of methane emissions. Standardized reporting of national inventories is increasingly important, as the Paris Agreement "Rulebook" becomes operational.

- Oil and gas methane emissions can be reduced at low cost, but further analysis is needed to guide mitigation priorities. Understanding the barriers that hinder implementation of cost-efficient measures is also important. Barriers include insufficient knowledge and awareness, lack of financing, attention of decision-makers, and structural and regulatory inefficiencies. The barriers can be removed by corporate measures, policies shifts, and by collaboration among public institutions and the corporate sector. Action to reduce methane emissions is made at the company/operator level. Emission surveys that set a company-wide inventory of methane emissions can form the basis for identifying project opportunities and setting priorities. Best practices and technologies that can be applied to reduce methane emissions are surveyed in this document.
- Large emission sources are likely to represent a significant portion of emissions in many companies and call for special attention with targeted measures.

National policies and regulations

National authorities have several options for imposing policies and regulations to reduce methane emissions from the oil and gas sector. Three broad categories are:

i) Standards in the form of specific technologies and/or operational practices to use or quantifiable emission limits;
ii) Economic instruments that cover emission fees/taxes, emission trading systems, and tax rebates and financial grants;
iii) Public-private partnerships and negotiated agreements, from loosely defined partnerships with voluntary targets, to formalized agreements with a threat of subsequent mandatory regulations, if specific quantitative targets are not met.

Even if there has been little of active policies and regulations for methane, all three categories are in use. They are typically part of broader national legal and regulatory structures, and they are rooted in distinct institutional traditions and capabilities. For this reason, one "best practice regulation" or blueprint for regulation of methane emissions does not exist.

Nevertheless, emissions of methane have some typical features that are important when considering the suitability of different approaches. They include:

a) Cost-efficiency, which means that measures with low abatement costs should be implemented before those with the higher ones;
b) Clarity and transparency in rules and procedures for standards, economic instruments, and negotiations and enforcement mechanisms;
c) Institutional capability, which means that regulatory ambitions must be attuned to capacities and capabilities of regulatory institutions.

International cooperation

Various international initiatives contribute to methane mitigation efforts. With the Paris Agreement entering into its operational phase and with the Paris Agreement "Rulebook" adopted by Parties to the Agreement, climate policies can set important framework conditions for mitigation actions.

The significant impacts of the near term and cost-efficient methane emission mitigation actions contribute to attainment of the goals set by the Paris Agreement. In countries with large methane emissions, reduction efforts should be incorporated in their NDCs. This requires careful planning and implementation of policies and measures supported by sound monitoring and reporting practices.

Conclusions

The key conclusions and principles from this document are as follows:

- There is considerable uncertainty about the level of methane emissions from oil and gas operations and increased efforts are needed by private and public sector institution to reduce the knowledge gap.
- Quantification of methane emissions is challenging but technologies to assist in methane detection and quantification are readily available and should be adopted by companies and authorities in their MRV activities.
- Some oil and gas companies are making progress in quantifying and mitigating emissions. Increased recognition of proper methane management as being important for resource efficiency and environmental protection has led a number of large companies to undertake an action, unilaterally and/or through industry associations and public private partnerships, to address the issue.
- Government attention, through either regulatory standards, economic instruments and/or agreements between the industry and national authorities can all be part of an effective and cost-efficient policies to address methane emissions from the oil and gas sector.
- The Paris Agreement "Rulebook" calls for enhanced national reporting of emissions and mitigation efforts. This should improve knowledge about the scale and nature of methane emissions and the benefits of mitigation.

1. Introduction

1.1 Scope and objectives of this guidance document

This document provides guidance for effective monitoring, reporting and verification (also called MRV hereafter)[4] practices and for mitigating methane emissions from the oil and gas sector. It is meant to serve as a resource for a broad audience, including owners and operators of oil and gas facilities, and policymakers at all levels of government. It is "principles-based", recognizing that conditions vary greatly across oil and gas facilities, and that legal, political and institutional aspects differ by jurisdiction.

The document covers methane management along two dimensions:

i. Physical dimension: The whole oil and gas supply system is included, from exploration, extraction, gathering and processing, to long distance transmission and transportation, and to refining and distribution to end users.

ii. Institutional dimension: Methane management practices are addressed at the company, national, and international levels. Synergies that might be achieved through coordination and cooperation across the levels are also addressed.

There are numerous initiatives focused on methane emissions in the oil and gas sector, as well as broader research efforts to improve understanding of the problem. This document presents some of these initiatives and, in some cases, draws heavily on referenced technical guidance documents to inform the discussion of best practices for methane MRV and mitigation.

1.2 The issues

Oil and gas will support future economic growth and social progress even under a scenario in which stringent climate policies and measures are implemented. The Sustainable Development Scenario presented in IEA's World Energy Outlook 2018, which assumes a global reduction of energy-related greenhouse gas emissions of more than 45% by 2040, estimates that oil and gas will still account for 48% of total energy supplies in 2040 (down from 55% in 2017), with total volume for that period contracting by 29% for oil and increasing by 10% for gas.[5]

The world's energy supply mix will be determined by a blend of policy and market competition. The enduring role of oil and gas obliges increased attention to methane emissions from the entire oil and gas value chain, from exploration and extraction to end use.

Methane is a short-lived climate pollutant with an atmospheric lifetime of about 12 years. According to the 5th Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) its ability to trap heat in the atmosphere, also known as the global warming potential (GWP), is 28 times greater than that of carbon dioxide (CO_2) over a 100-year time horizon, and

[4] The term MRV covers three categories of activities: i) monitoring, including direct measurement and other methods for quantifying emissions; ii) reporting, which covers compilation of estimated emissions in various formats; and iii) verification, often by a third party. See Glossary and Terms for further explanation.
[5] https://www.iea.org/weo2018/

84 times higher than CO_2 when measured over a 20-year period.[6, 7] On an instantaneous basis, methane's GWP is 120 times greater than that of CO_2. Methane emissions are responsible for at least one fourth of manmade global warming, and that they continue to rise.[8] Reducing methane emissions presents an important near-term opportunity to address climate change.[9]

Currently, the oil and gas sector accounts for nearly ¼ of global anthropogenic methane emissions, and there are several projections indicating that those emissions could increase significantly.[10, 11] By reducing the emissions the sustainability credentials of oil and gas supply would be improved considerably. The IEA has estimated that 75% of global oil and gas methane emissions are technically feasible to eliminate, 45% of them at zero net cost (see **Chapter 4** below).[12]

Many oil and gas companies have procedures to improve flare efficiency and to remedy methane emissions for safety. Many companies and governments are increasing their methane MRV and mitigation efforts, as contributions to climate action.

1.3 MRV and mitigation

While MRV and mitigation may be considered distinct activities, they are related as mitigation is most cost effective when based on sound MRV practices (see **Figure 1.1**). MRV is important for policy design as reliable quantification of emissions is essential for monitoring compliance and assessing progress of emission reduction efforts. With respect to technology application and practices, MRV and mitigation can also be integrated, for example with leak detection and repair programs.

MRV and mitigation practices at the facility and company level often interconnect with those developed at national level. National level practices can be influenced by international guidelines and commitments, particularly those established under the IPCC and the United Nations Framework Convention on Climate Change (UNFCCC) and the Oil and Gas Methane Partnership (OGMP).

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[6] https://www.ipcc.ch/pdf/assessmentreport/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf

[7] In the IPCC 4th Assessment Report the GWP for methane were set at 25 and 72 time that of CO2 respectively for 100-year and 20-year time horizons, see https://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

[8] IPCC fifth assessment reports Chapter 8. https://www.ipcc.ch/report/ar5/wg1/mindex.shtml

[9] See for example https://www.iea.org/weo2017 page 432

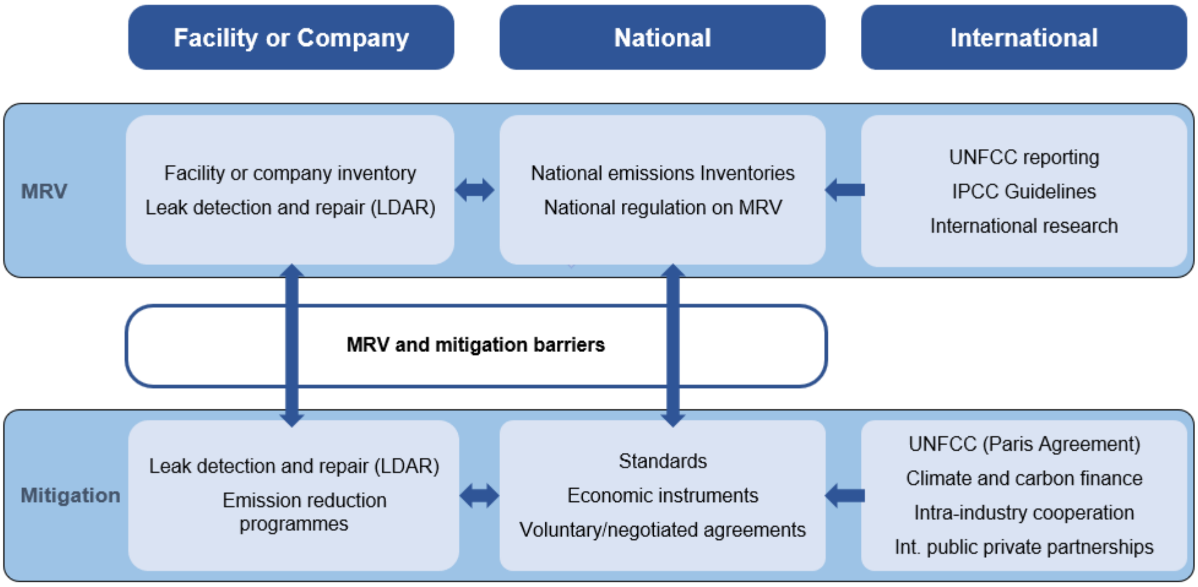
[10] https://www.globalmethane.org/documents/gmi-mitigation-factsheet.pdf
https://www.globalmethane.org/documents/gmi-mitigation-factsheet.pdf

[11] https://www.earth-syst-sci-data.net/8/697/2016/essd-8-697-2016.pdf, and IEA World Energy Outlook 2017.

[12] See IEA World Energy Outlook 2018 page 493.

Figure 1.1

MRV and Mitigation – Facility or Company, National, and International Levels



1.4 Structure of this document

Chapter 2 of this document surveys methane emission levels and emission reduction opportunities, then Chapters 3 and 4 present MRV and mitigation.

Chapter 3 discusses approaches and practices for MRV at the facility, company, and national levels. It also covers the interplay between the levels and the influence from international processes such as those under the UNFCCC, intra-industry associations and public- private initiatives, and international research. Chapter 4 explores mitigation, starting with the facility and company perspective followed by a discussion on mitigation policies and regulations at the national level. This chapter also discusses commonly-encountered barriers to implementation of mitigation opportunities and identifies policies and regulations that might be helpful in addressing these barriers. Finally, Chapter 4 covers aspects of international climate policies, including carbon pricing, that can enhance methane mitigation efforts.

Chapter 5 presents key conclusions and summary for policy makers. Two annexes are included at the end of the document that address emission sources and mitigation techniques (Annex 1) and emission detection and quantification technologies (Annex 2).

Annex 1 describes in detail 12 emissions sources, including mitigation techniques and applicable emission detection equipment and quantification methods.[13] The presentation is based on referenced sources. More categories are listed than in the Technical Guidance Documents of the OGMP since the Annex covers the full value chain. Annex 2 presents a brief overview of available methane detection and quantification technology (based on Climate and Clean Air Coalition's Technical Guidance Document and EPA's Gas STAR Program).[14, 15]

[13] http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents
[14] https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf
[15] *Id.*

2. Methane emissions in the oil and gas industry

2. 1 The basis for emissions quantification

Methane emissions cannot be quantified accurately based solely on emissions factors derived from a limited number of direct measurements. For estimates to be accurate the emission factors need to capture the distribution of emissions per unit of the selected activity (e.g. numbers of facilities and operations, throughput of oil and gas, and a robust understanding of the number of activities and facilities present). Emission factors for methane vary greatly depending on factors such as facility design, gas composition, configuration of the oil and gas supply chain, the age and technical standard of machinery and equipment, severity of operating conditions and maintenance and other operational practices. Quantification is further complicated by the fact that methane emissions originate from many sources along the entire oil and gas value chain.

The quality of methane emissions data and national inventories depends on the availability of country-specific emission factors coupled with detailed and reliable activity data.

The Intergovernmental Panel on Climate Change (IPCC) has developed guidelines for preparing greenhouse gas (GHG) inventories (IPCC Guidelines).[16] Those Guidelines distinguish between three levels for emissions calculations, with Tier 3 being the most rigorous method of calculation, and Tier 1 the simplest (see **Box 2-1**). They are the basis for preparing and reporting national GHG inventories to the UNFCCC.

Progressing from Tier 1 to Tier 3 represents a reduction in the uncertainty of GHG estimates. However, the ability to use a Tier 3 approach will depend on the availability of detailed production statistics and infrastructure data, and therefore it may not be possible to apply Tier 3 approach under all circumstances.

Currently, most ECE member states use the Tier 1 method (see **Table 2.1**), resulting in large uncertainties in current estimates. United States, Canada, Norway and some countries in the European Union use Tiers 2 or 3 for all segments of the Oil and Natural Gas Systems, while Russia applies a combination of Tier 2 and 1 (see **Table 2.1**)

Uzbekistan, Ukraine, Azerbaijan and Kazakhstan all apply Tier 1 methods.

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[16] https://www.ipcc-nggip.iges.or.jp/public/2006gl/ with the chapter on fugitive emissions: https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf

Box 2-1 Three tiers for emissions calculations according to IPCC Guidelines

The IPCC Guidelines include methods for quantifying emissions. Typically, estimates are made using the following equation (according to so-called Tier 1 and 2 methods):

$E_{\text{methane, industry segment}} = A_{\text{industry segment}} \bullet EF_{\text{methane, industry segment}}$

Where:

$E_{\text{methane, industry segment}}$	are the annual emissions of methane (tonnes) for specific segment of the Oil and Gas System[17]
$A_{\text{industry segment}}$	is an activity value for the specific segment. Activity data would typically be throughput of oil and gas which represent emission sources
$EF_{\text{methane, industry segment}}$	is the emission factor (emissions per unit of activity for the segment)

Calculation of emissions from the gas production segment can be calculated using an emission factor per unit gas produced in Sm^3 multiplied by the volume of gas produced for the period in question.

The IPCC Guidelines distinguish between three levels, or tiers, for calculation of emissions:

Tier 1: The simplest method using relatively aggregate and readily available activity variables, with default emission factors for activity variables. Default emission factors listed in the IPCC Guidelines.

Tier 2: Similar specification for the level of activity data as for Tier 1 but with emission factors which are specific to the country, e.g. based on national measurements and analysis.

Tier 3: Detailed approach based on rigorous bottom-up assessment at facility level, identifying equipment-specific emission sources, # of equipment units and measurement of rates per type, etc.

Table 2.1

Reporting of national methane emissions inventory data to the UNFCCC by selected ECE countries

Country	*Year*	*Latest submission (*)*	*Tier used*
Russia	2017	2019 – NIR	Tier 2 for gas production and transportation Tier 1 for the other activities
USA	2017	2019 – NIR	Tiers 2 and 3
Uzbekistan	2012	2016 – NC3	Tier 1
Canada	2015	2019 – NIR	Tiers 2 and 3
EU	2015	2019 – NIRs	12 Member States reporting under Tier 1(0.5 $MtCH_4$) The others mixed, different for different segments
Turkmenistan	2010	2015 – NC3	Tier 1
Ukraine	2015	2018 – NIR	Tier 1
Azerbaijan	2012	2015 – NC3	Tier 1
Kazakhstan	2015	2018 – NIR	Tier 1

Note: (*) NIR: National Inventory Report, annual by Annex 1 Parties, NC: National Communications (not annual) by non-Annex 1 Parties (NC3 means third submission).

Many countries use Tier 1 methods as they lack empirical data about methane emissions. New technologies to quantify methane emissions (see **Annex 2**) and various initiatives (see **Box 3-1**) to measure emissions in countries should lead to more accurate estimates for states that use Tier 1 "default emission factors".

[17] The Oil and Gas System as defined in the IPPC Guidelines Oil and Gas System covers a number of defined segments in the supply chain from exploration, production, gathering & processing to long distance transmissions/transport, to refining and distribution to end use consumers.

In addition to national inventories being reported to the UNFCCC, other institutions/sources publish aggregate methane emissions estimates.[18] These sources have estimates that often diverge considerably.

Institutions publishing estimated methane emissions use UNFCCC data, but often with their own estimates when consistency in methods and level of specification across sectors is important (see **Box 2-2**).

Box 2-2: Data sources for oil and gas sector methane emissions quantifications

Methane emissions estimates from five different institutions are presented in this Chapter:

UNFCCC data[19] include methane emissions from all parties to the Convention. Data coverage, quality, and regularity vary historically, with different reporting requirements for Annex I and non-Annex I countries. As shown in Table 2.1, several countries with large emissions (e.g. Uzbekistan, Turkmenistan and Azerbaijan) have only reported data for 2012 or earlier.

Emissions Database for Global Atmospheric Research (**EDGAR**)[20], a joint research project of the EU Commission and Netherlands Environmental Agency, calculated emissions of greenhouse gases and other pollutants, often using data from UNFCCC. Activity data are taken from many statistical sources.

The International Institute for Applied Systems Analysis (**IIASA**)[21] has compiled detailed methane emissions data. The GAINS model used for analysis of air pollution and GHG emissions has a detailed breakdown of country specific energy sector variables with related emissions factors. Many sources are used including UNFCCC data, activity data from national and international statistics, and emission factors from IPCC and recent research literature.

The United States Environmental Protection Agency (**US EPA**)[22] has published methane emissions data as part of the International Emissions and Projections, 2010-2030. The data are a combination of country-reported inventory submissions to the UNFCCC and calculations based in IPCC Tier 1 methodologies used to fill in for missing or unavailable data.

The International Energy Agency (**IEA**) publishes global methane emissions data as part of their World Energy Outlook. Data can be retrieved using an online "methane tracker".[23] The IEA estimates are based on many data sources, including own survey of company and country emission intensities.

Over the past decade data have become available that improve the understanding of methane emissions. This knowledge has been incorporated in national inventories (NIRs). Revisions have been made in the emissions inventories for the United States and the Russian Federation to incorporate new data. US methane emissions estimates for 2005 were 6.3 Mt in the 2010 inventory report, were revised to 10.3 Mt in the 2011 inventory report, and were brought down to 8.2 Mt in the 2017 inventory report.[24] Russia's NIR for 2019[25] reported methane

[18] Some good background science can also be found here http://www.ccacoalition.org/en/slcps/methane
[19] UNFCCC site only has separate pages for non-Annex I: https://unfccc.int/process-and-meetings/transparency-and-reporting/reporting-and-review-under-the-convention/national-communications-and-biennial-update-reports-non-annex-i-parties/national-communication-submissions-from-non-annex-i-parties and Annex I: https://unfccc.int/process-and-meetings/transparency-and-reporting/reporting-and-review-under-the-convention/greenhouse-gas-inventories-annex-i-parties/national-inventory-submissions-2019
[20] http://edgar.jrc.ec.europa.eu/overview.php?v=432
[21] http://gains.iiasa.ac.at/models/index.html
[22] https://www.epa.gov/global-mitigation-non-co2-greenhouse-gases
[23] https://www.iea.org/weo/methane/database/
[24] https://www.iea.org/weo2017/ (Figure 10.5 page 441)
[25] https://unfccc.int/documents/194822

emissions from the oil and gas sector to be in the range of 6.2 to 6.7 Mt, whereas previously it had reported data on annual emissions in excess of 20 Mt. The revisions came from a change in use of Tier 1 emission factors (from "developing" to "developed" country emission factors as listed in the IPCC Guidelines). In addition, there have been significant revisions to the split of methane emissions by supply chain segments in Russian inventories.[26] All these changes reflect ongoing efforts to obtain more reliable primary data and to improve the methods used to estimate methane emissions.

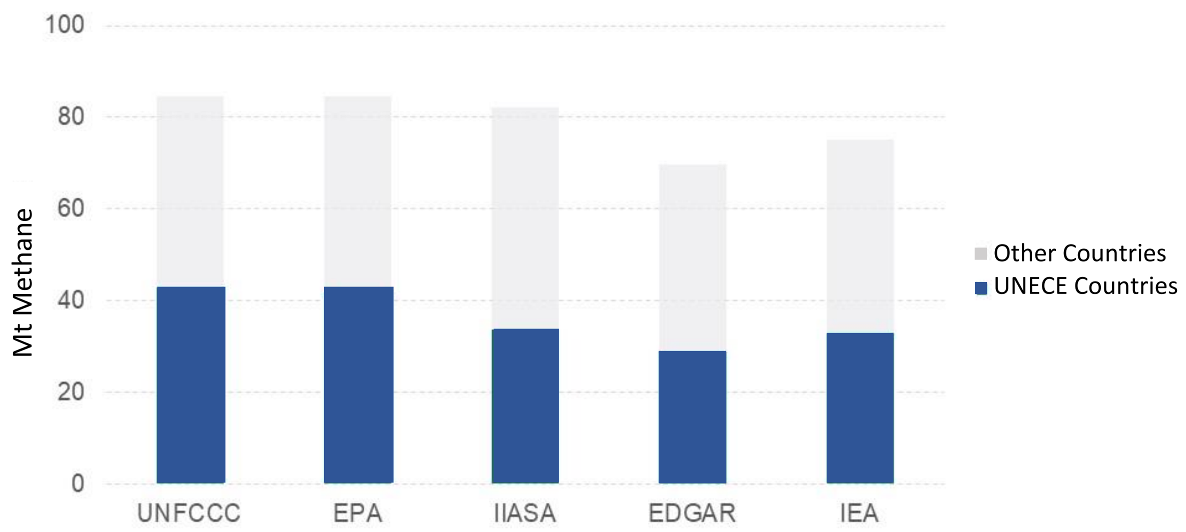
The Environmental Defense Fund, industry, and several philanthropic funds have initiated and financed several scientific studies that improved the understanding of emission levels particularly in the United States. However, further studies are still needed.[27] In the US, new data are available from the US Greenhouse Gas Reporting Program and from new scientific studies.

2.2 Estimated methane emission levels – global and for the ECE countries region

UNFCCC data for the year 2015 estimate global oil and gas sector methane emissions at 84 million tons, of which about half are reported by ECE member states.[28] While three other sources have similar estimates, EDGAR's number is significantly below the UNFCCC predictions (see **Figure 2.1**).

Figure 2.1

Oil and gas sector methane emissions according to different data sources[29]



According to IPCC Guidelines, emissions are to be specified for segments of the Oil and Natural Gas System, but for many countries this specification is of poor quality and in certain cases

[26] The revisions resulted from work carried out by a group of researchers, including Roshydromet, International Centre for sustainable energy development and Russian Energy Agency of the Ministry of Energy. See http://www.isedc-u.com/images/pdf/2017/evr_11_17_berdin.pdf (in Russian)

[27] http://science.sciencemag.org/content/early/2018/06/20/science.aar7204

[28] Data are from 2015 for most countries, otherwise for the most recent year submitted estimates. (see Table 2.1).

[29] UNFCCC data for 2015 for annex 1 countries and latest available for non-annex 1 countries. US EPA estimate is used for total global methane emissions from the oil and gas sector.

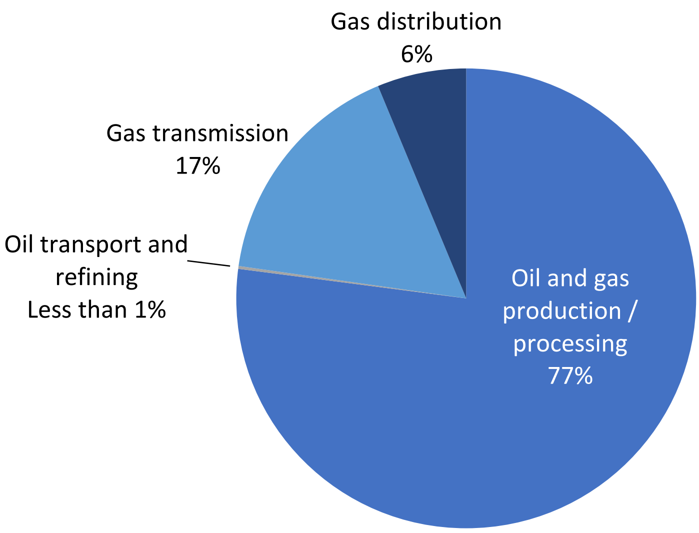
without estimates being provided. Therefore, aggregate UNFCCC estimates are not available for detailed segments of the oil and gas value chain. Even data for very broad categories might be unreliable. There are four or five categories that are typically published.

Four segments of UNFCCC data are shown in **Figure 2.2**. Upstream oil and gas segments (including exploration, production, gathering and processing) account for 77% of the sector's emissions in ECE member states and 72% globally. The share for gas transmission is 22% globally and 17% in the ECE while gas distribution is 6% both globally and in the ECE region. Oil transportation and downstream oil facilities accounts for less than 1%.

The IEA estimates upstream oil and upstream gas separately. The oil segment is the largest with 45% while upstream gas is 36%. The upstream segment estimates are much higher than data reported to the UNFCCC.[30] The split into oil and gas upstream segments is important in relation to the discussion on lifecycle of the GHG emissions. The total value chain emissions of gas supplies have become an important topic in discussions about the environmental advantages of natural gas versus other fossil fuels. Data from UNFCCC shows great variation in emissions by supply segment (see **Figure 2.3**), some of which reflect real differences in industry structures and emission intensities, while others are likely to result from errors in specification by segment.

Figure 2.2

Breakdown of oil and gas methane emissions by segment, for ECE member states, 2015.

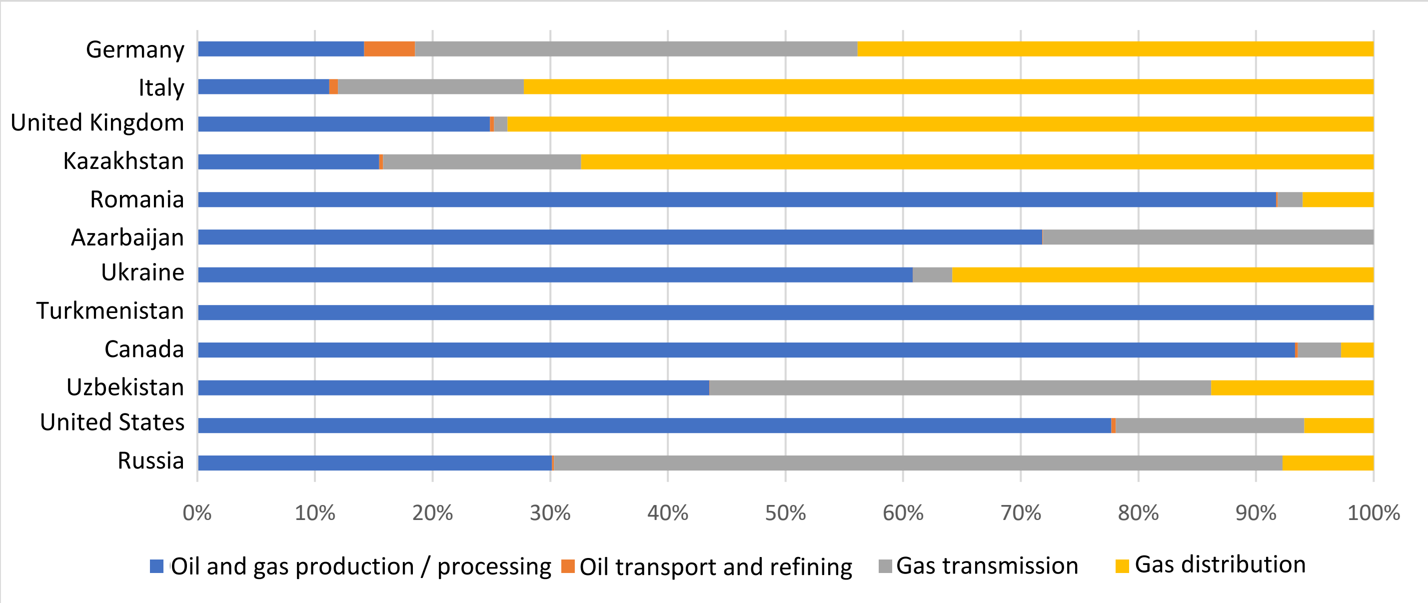


Source: UNFCCC

[30] https://www.iea.org/weo/methane/database/

Figure 2.3

Share of methane emissions from oil and gas per value chain element in UNECE countries



Source: UNFCCC

An alternative way of specifying methane emissions is by emission source (compressors, storage tanks and pneumatic controllers and pumps) that can appear at all stages of the supply chain. For national reporting, this information can be used as input to Tier 2 or 3 approaches. While this is important information for understanding causes and finding remedies to emissions, few data have been collected, analyzed and published outside a few countries (notably USA, Canada, and Norway). The partner companies of the Oil and Gas Methane Partnership (OGMP) report by individual asset and publishing aggregated information of emissions and mitigation progress for nine "core" upstream emission sources.[31] Information on main emission sources and progress in mitigation efforts are published in the Third-Year Report from OGMP.[32]

[31] http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents

[32] http://ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-third-year-report

3. Monitoring, reporting and verification (MRV)

Key messages

- MRV covers methods for quantifying emissions through bottom-up or top-down approaches, reporting by compiling quantified emissions, and verifying emissions and/or emission reductions.
- MRV serves several purposes: identifying specific mitigation at company level, providing data and information for decisions on policies and regulations, and tracking effectiveness.
- Use of sound detection and MRV methodologies and practices is essential for methane management and for closing the current knowledge gap (reconciling top-down and bottom-up methods).
- To construct a robust methane emission inventory at the company (or facility) level, a combination of quantification methods can be used, including measurements to establish emissions rates/factors, engineering calculations and other calculation-based methods. Technologies are emerging that can improve technical feasibility and reduce costs of methane quantification.
- International cooperation is important for building institutional capacity and capability to perform sound MRV activities and deliver methane emissions reductions. While guidelines from the IPCC and reporting requirements under the UNFCCC continue to be essential references, a growing number of international initiatives are increasingly important for sharing information and experience.
- Given the importance of 'super emitters', MRV should be designed to account for this dominant emission sources.

3.1 Challenges and approaches to methane measurement

3.1.1 Why quantification requires a methodical approach

Quantification of methane emissions requires a combination of operational measurements and calculation-based methods. The methodological and practical issues involved in determining methane emissions are demanding given the diversity of system characteristics within the oil and gas sector, but they are well understood:

- Each site might include a few to hundreds of emissions points. For example, compressor stations in Canada are estimated to have 6 leak points, on average, while gas plants include tens of thousands of components of which a few percent are typically leaking (19 leak points on average).[33] In addition, both types of installations may include vent and flaring emissions sources.

[33] https://carbonlimits.no/project/statistical-analysis-leak-detection-and-repair-canada/ Note: This study refers only to leaks (i.e. unintended emissions). Vents are not included in these figures

- Methane emissions can be spread across locations. Each well site, compressor station, gas plant, and pipeline segment is an emission source. Equipment is often dispersed and in remote locations, increasing the costs of measurement. Oil and gas supply patterns evolve fast, increasing the challenge for timely emissions reports. Physical accessibility of emissions sources and safety are important considerations.
- Field data show that emission rates from similar equipment and processes are variable[34] depending on factors including the type and the age of the equipment, frequency of its controls, climatic conditions, maintenance practice, and the operating conditions. In addition, many emission points are intermittent. Using emission factors from a limited number of sites/equipment introduces uncertainty if they are not appropriately stratified across key variables. In addition, an MRV program should identify higher emitting points for mitigation.
- Methane emissions provide limited sensory feedback to humans (invisible, and odourless[35]), making it impossible to identify and estimate emissions without costly specialized equipment.[36, 37]

The challenges listed above reflect the intrinsic difficulties in methane emissions quantification and explain the large uncertainties in existing estimates.

New emerging technologies (remote sensing) will make continuous monitoring feasible in the near future. Quantification rarely is based on direct measurements,[38] but direct detection and measurements can be combined with calculation-based methods. Technical feasibility of making measurements, uncertainty assessments, and MRV costs all play a role and must be taken under consideration to find the right balance. Assumptions on the statistical distribution of emissions are key determinants of emissions rates and could lead to misleading conclusions if not appropriately addressed.

3.1.2 Detection and measurement

Bottom-up estimates involve on-site quantification and estimation of emissions from individual sources.[39] They provide the most fine-grained information about specific equipment level sources of emissions and can be time-consuming and expensive to make.[40]

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[34] "Quantifying cost effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras", Carbon Limits report CL-13-27 (2014)
[35] Many emission sources from odorized gas sources can be detected by smell, but some very small leaks of odorized gas cannot be detected without sensor equipment
[36] Odorized natural gas and sour gas will have noteworthy odor potential.
[37] Vents are in theory easier to identify than leaks.
[38] Emission rates vary over very short timeframes (e.g. a natural gas driven intermittent bleed controller actuating with variable frequency) or over longer timeframes (e.g. storage tank emissions depend on external temperatures).
[39] Extrapolation of a measurement to the year involves some calculations due to variability in processes (e.g. a compressor may be under pressure only a few months in the year).
[40] In addition, some sources of emissions are not easily measured (ref Annex 1)

Top down estimates methods measure concentrations of methane in the atmosphere using satellites,[41] airplanes, or drones.[42] These methods use ambient measurement, weather conditions, and models to infer emission rates from specific well pads or from an entire region.[43] Scaling such data to entire regions or companies' portfolios of facilities is less costly and may be more accurate than using bottom-up measurement approaches. These techniques for estimating emissions can provide more continuous quantification of methane emissions and allow to detect "super emitters". They often do not allow identification of the specific sources of emissions (e.g. stuck valve, leaky flange, or liquids unloading), but analytical methods for backtracking or mapping the emissions distributions are developing quickly.

Numerous studies have relied on top-down approaches to estimate methane emissions at regional scales, including airborne mass balance techniques. For top-down methods, one of the key challenges is attributing emissions of methane to one of many possible sources. Methods of attribution have improved through a combination of isotope and/or hydrocarbon ratios, and inverse modelling.

To address variability in emission rates over time, it is important either to collect data frequently[44] or to use data collection techniques that can characterize the population of emissions within a region accurately and precisely. Single point measurements and the resulting emission estimates used to derive emissions for entire regions are likely to be spurious, thus robust sampling that considers differences across time and space need to be deployed.

3.1.3 Calculation based methods

Emissions can be calculated using a combination of gas composition, activity data, engineering data, and emission factors, e.g. emissions per unit of equipment, or the activity data (e.g. number of pieces of each type of facility, equipment type, activities undertaken and/or oil or gas throughput). Estimation of methane emissions can be based on:

i) default emission factors per unit of throughput of oil and gas (high-level assessment),
ii) emission factors per equipment, component or activity (e.g. per compressor, compressor seals or pipeline blowdown), or
iii) engineering calculations, which encompass a range of different approaches including the use of process engineering software or some formula-based estimates considering numerous parameters (e.g. intermittent gas well liquids unloading can be estimated using parameters such as casing diameter, well depth, etc.).[45]

[41] Satellites measurement present specific challenges such as the detection levels and cloud cover, measurement over water or over vegetation.
[42] Mobile lab-based methods (such as tracer, OTM-33A) that measure enhanced emission plumes generally are categorized as 'down-wind' methods.
[43] Please refer to Glossary for the different methods to allocate methane to the oil and gas industry
[44] For example, some large intermittent vents emissions sources may be missed or assumed to be continuous.
[45] http://www.ccacoalition.org/en/resources/technical-guidance-document-number-7-well-venting-liquids-unloading

Choice of method depends on data availability, homogeneity of the oil and gas sector (in terms of equipment and operational practices as well as gas composition), the type and relative size of particular emission sources, and the intended use and required accuracy of the estimates.

Emission factors are used to develop emissions inventories, e.g. national inventories reported to UNFCCC (see **Box 2-1**). Generally, the uncertainty of such estimates will decrease the more disaggregated the activity data is. Estimates become more imprecise with decreasing source population size and are not appropriate for making mitigation investment decisions for individual emissions sources.

Engineering calculations based on robust data and assumptions can provide reliable estimates[46] when the underlying assumptions have been tested against empirical data. They may be considered appropriate where improved precision is needed, for example as part of detailed assessments of a specific abatement project. Some sources, e.g. glycol dehydrators, must use engineering calculations because measurements are not feasible and emission factors are not suitable for investment decisions.

Detection and measurement are applicable not only at the facility and company levels, where the technology has already matured, but also, thanks to the rapid progress in top down methods, such as remote sensing, at a country and regional level.

Generally, new technological development[47] has the potential to shift the balance towards methane emissions' quantification based on measurement. As a result, more disaggregated and specific emission factors will be available for calculation-based quantification, thus providing more accurate and precise data.

Companies and public institutions have to strike a balance among measurement- and calculation-based methods, as well as the specific calculation-based method and a level of disaggregation that is to be use. Some pros and cons of the different approaches are summarized in **Figure 3.1**.

There are several scales at which the observational data can be collected in support of the measurement, to characterize methane emissions from the oil and gas system (see **Table 3.1**).

Key issues in utilizing and combining both bottom-up and top-down methane data are related to source apportionment, heterogeneity of background levels, multiple source characteristics, and the disambiguation of anthropogenic and natural sources.

[46] in particular for sources which can be readily modelled based on fundamental engineering principles such as thermodynamics, continuity equations, mass transfer, heat transfer, and potentially chemical kinetics

[47] For a large part remote sensing, such as non-direct measurement by airplanes, satellites, sensors, etc.

Figure 3.1

Overview of the methane quantification approaches

		Positive	Negative
Detection and Measuremen	Top-down estimate	Insights into overall levels of methane emissions Potential to identify "hot spots"	Typically do not allow to estimate emissions from individual sources Challenges to isolate O&G methane from other nearby sources
	Bottom-up estimate	Emission estimate for individual sources Allow to contact information for mitigation assessment	Some emissions sources are difficult to measure. Systematically under estimates emissions
Calculation based approaches	High level emission factors	Simple collection process for activity data	High level of uncertainty. Do not allow to estimate emissions from individual sources
	Equipment specific emission factors	Emission estimate for individual sources	Expensive to collect enough data to obtain accurate estimates
	Engineering calculation	Particularly relevant for some specific emissions sources	Expensive to collect enough data to obtain accurate estimates

Table 3.1

Summary of available measurement and modelling techniques specifically used to constrain oil and gas methane emissions, classified by scale of measurement and expected purpose of the output[48]

Scale of measurement	*Size of measured element*	*Measurement and model methods*	*Purpose/ use of data*
Regional	100's km	Satellite, towers, airborne, ICOS, regional inverse models	Detect oil and gas methane emission hotspots, estimate regional fluxes
Sub regional	10's km	Airborne (in-situ and remote sensing)	Source detection, basin-wide estimates (e.g. mass balance techniques).
Facility	100's m to 1 km	Airborne (in-situ or remote sensing), ground based, mobile surveys, optical remote sensing, inverse dispersion models.	Identify super-emitters, facility-wide emission factors.
Site area/unit	100's m	Optical sensing techniques	Emission reporting, input to facility scale reporting, leak identification.
Component	<1m	Sniffing, optical gas imaging, Hiflow	Individual leak quantification, mitigation – leak detection and repair programs. Component scale emission factor development

[48] Source: IG3IS implementation plan http://www.wmo.int/pages/prog/arep/gaw/documents/IG3ISImplementationPlanEC70.pdf

3.2 MRV at the facility and company level

Companies quantify emissions: i) to comply with reporting requirements, ii) to have a sound basis for developing and implementing mitigation strategies, and iii) to report environmental performance and progress**.**

Aspects with company monitoring and reporting are discussed here under three headings:

i. Detection and measurement of emissions at the facility level;

ii. Calculation-based approaches for quantification of emissions at the facility- and company-level;

iii. Emissions reporting (including voluntary reports).

In addition, issues related to verification of monitoring reports are briefly discussed.

3.2.1 Detection and Measurement

Detection and measurement at site level can be resource- and time-demanding activities and require careful planning. Depending on the objectives of the measurement campaigns, operators should consider:

- Selection of the detection and measurement technology;
- Selection of the sites/emissions sources.

Both selection of technologies and of sites for detection and measures depend on the purpose for which the task is performed; whether it is for inventory work or for mitigation. Distinction between the two might not always be clear, and an operator may strive to improve understanding of the magnitude of emission and to identify available mitigation projects.

3.2.1.1 Selection of the detection and measurement technology

To perform emission surveys, operators have a choice of technology (see **Annex 2**). Infra-red leak imaging cameras are used for emission detection at production sites, compressors stations, processing plants, and LNG facilities. Compared to older technologies (e.g. soap bubble screening, or organic vapour analysers), infra-red cameras are easy to use, allow for effective screening of numerous components in a relatively short period, and permit to identify both leak and vent sources. As described later in this report, infrared cameras are mainly used for LDAR, and infra-red camera surveys require a crew of technicians to visit each site regularly (a non-negligible share of total cost).[49, 50]

A variety of technologies have been used over the last few years for emission quantification. These approaches typically present some limitations in terms of accuracy, threshold, costs, or applicability to certain types of emissions sources. However, there are many new technologies to detect and quantify methane emissions that are changing quantification practices by allowing for (i) rapid identification of large emitters, and (ii) quantification of emissions at lower costs at the facility level. While there is limited practical field experience with these new

[49] Including labor and travel costs
[50] More information on the limitations of IR camera in the Annex 2

technologies in many operating companies, there is a growing community of service providers with the required expertise.

Given the variety in site configurations and the rapidly evolving technologies available, there is not a one set of best available technologies for emissions quantification.[51] Technologies should be selected for each specific application:

- Different approaches can cover different types of installations: aerial surveys are used for basin estimates but may not be relevant for a large processing plant. The type of on-site emission sources may affect the technologies selected: a high-volume sampler may be used to measure emissions from a leaking connector, but not to measure emissions from a large venting stack.
- Aerial or drive-by surveys can estimate total emissions from multiple sites while infra-red leak imaging camera identify specific emissions sources (e.g. components to be repaired).
- The purpose of quantification (i.e. inventory or mitigation decision), level of accuracy required, and the type of emission source bears on which technology is appropriate.
- Some emissions sources vary over time, so consideration is given to the time and length of measurement and whether given variability could be captured more effectively by increasing the frequency of measurement.
- Many methane emission sources are inaccessible or unsafe to access with hand-held instruments.
- Costs for deploying different technologies vary. Labour costs, calibration methodologies and frequency, and internal or contracted services all should be considered.

3.2.1.2 Selection of the sites to be surveyed by the detection and measurement campaign

If all sites cannot be surveyed, the operator will have to select a subset of sites, and the selection process will depend on the ultimate objective of the measurement campaigns. If the campaign is to develop emissions factors or if the results will be extrapolated, the sample set must be representative. Considerations include age, operating status, type of facility, type and technology of equipment emitting methane, operating and maintenance practices, industrial segment, size or throughput, and product composition. An unbiased but stratified sampling approach is usually effective at producing accurate high precision emission factors but is likely to be costly.

If the measurement campaign is to identify emissions reduction projects, it should target sites with large abatement potential. Finally, practical consideration such as site location and safety aspects are considered in the site selection process.

[51] Stanford University has created a model that can be used by operators to compare a set of 4 detection approaches: https://ngi.stanford.edu/sites/default/files/Adam_Brandt.pdf

3.2.2 Calculation based methods – Elements of best practices[52]

Calculation-based or indirect methods for estimating methane emissions can be based either on (i) high-level default emission factors, (ii) emission factors per equipment, component or event, or (iii) engineering calculations.[53] The latter two are particularly relevant at the facility and company level, while the first approach is used for national inventories (IPCC tier 1).[54]

Operators should consider:

Disaggregation level**:** The appropriate granularity to account for emission sources must be selected together with categorization of emission sources. The categorization must balance the need for details and the added complexity. It should ideally allow to: (i) minimize uncertainties, and (ii) identify emissions reductions opportunities. For example, storage tanks can be classified depending on factors such as the liquids contained, their size and/or the type of the roof.

Emission factors selection: Ideally, representative emission factors should be used to estimate emissions. When these are not available, international emission factors are used as an intermediate measure, recognizing that important differences in local practices may affect the uncertainty of the final results.[55] Typically, a company may select a mix of "internal" and published emissions factors, depending on the emission source category. Emission factors should also be updated over time as new information becomes available.

Activity data and other information gathering: To perform emission estimates, site-specific information is required: equipment counts (e.g. number of storage tanks without a vapor recovery unit (VRU)), throughput information (e.g. volume of gas being dehydrated), or other technical information (e.g. number and length of liquid unloading events). If the information is not readily available, the data collection/retrieval approach should be considered.

Statistical distribution: Calculating aggregates should be adjusted appropriately, depending on whether the emissions follow a normal or a heavy-tail distribution.

3.2.3 Reporting

Reporting is an essential tool for companies to track emissions, present overview of the level and structure of emissions, and show progress/changes over time. Reporting can take different forms depending on its purpose and requirements. It can be performed e.g. for regulatory reason, as a part of a voluntary program, or for internal purposes. There are two main types of reports:

- Measurement surveys reports,[56]
- Emissions inventory reports.

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[52] Operator can find detailed guidelines in the OGMP technical guidance documents: http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents

[53] The engineering calculations are particularly complex for certain sources of emissions (e.g. storage tanks, ref to annex 1). Field data can be used to calculate emissions from a given source, e.g. in case of the vent of a pipe section, the level of methane emission can be accurately derived from the pipe section volume and the pressure condition in that particular pipe section during that event.

[54] The first approach will not identify emission reductions opportunities or assess progress over time.

[55] There are few information sources for emission factors for some emissions sources (e.g. blowdown)

[56] Part of the emission inventory report

3.2.3.1 Measurement surveys (bottom up) reports:

The report from a measurement campaign will depend on the technology and approach used for the campaign. Each identified emission point can be quantified and recorded during a measurement campaign. **Figure 3.2** presents typical information presented in a report for the bottom-up measurement campaign. Consistency in reporting different measurement campaigns will allow for future comparison and aggregation of the results.

Figure 3.2

Potential information to be included in a measurement survey report[57]

Type of information
Facility name, location, type of facility …
Section of the facility or/and process blocks
Information on the component or emission source: - Component type and subtype (e.g. flange or vent) - Make and model of the emitting component when relevant - If relevant: Unique ID number for each component (to be verified with process data and diagram if relevant); Tag number if emission sources have been tagged
Emission source: Type of emissions sources, leak/vent
Engineering information for future mitigation assessment Information on past maintenance and inspection: date of last inspection, date of last maintenance.
Date and hours of the measurement. Length of time of the measurement
Measured emissions (rate and/or concentration)
Type of gas emitted or gas composition when relevant/available
Quantification method used
Repair: Note on repair recommendations and/or repair performed. List of the repair attempts if relevant

The measurement report can then be used for several purposes:

- Performing repairs and assessing abatement options: The maintenance team will use the report and the tag number to identify the different repairs and replacement to be performed. The results can be used to assess the benefits of mitigation.
- Evaluate historical progress: Past measurement reports can be used over time to (i) evaluate the effectiveness of mitigation, (ii) identify components which are more prone to emit, and (iii) measure progress.
- Derive emission factors: when measurement campaigns are representative, the results of the measurements can also be used to derive emission factors for the population of facilities/equipment.

3.2.3.2 Emissions inventory reports

Emissions inventory reports provide an overview of emissions sources and their magnitude across a geographical area or a selection of facilities. Internal reports can be used to track Key Performance Indicators (KPIs), and as tools to identify opportunities to reduce emissions. KPIs

[57] The details will depend on the objective of the study e.g. initial scoping survey or prioritization of mitigation projects survey; or project decision survey.

can link to external reporting. Public/external reports can be used to: (i) comply with regulatory requirements, (ii) comply with voluntary commitments, or (iii) communicate externally on ongoing efforts. An interesting development is the number of initiatives taken by industry association and other institutions focusing on methane management including reporting on emission levels as well as on progress in mitigation efforts (see **Box 3-1**).

Box 3-1 International initiatives with focus on methane emissions

A number of initiatives launched over the past few years (e.g. the Global Methane Initiative (GMI), the Methane Guiding Principles (MGP),[58] the Climate and Clean Air Coalition's (CCAC) Oil and Gas Methane Partnership (OGMP)[59] and the Oil and Gas Climate Initiative (OGCI).[60] look into mitigation actions and projects, best practices and knowledge sharing, technical assistance, and polic, with a focus on improving the quality of emissions data and on transparency of reporting.

Global Methane Initiative (GMI) is 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 among 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 to improve environmental quality, improve operational efficiency and strengthen the economy.

Oil and Gas Methane Partnership (OGMP) is a 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.[61] OGMP provides detailed reporting methodologies and results for its members companies. The European Commission is the latest lead partner of the CCAC Oil and Gas initiative.[62]

Oil and Gas Climate Initiative (OGCI), comprising 13 large international oil companies, set a target to reduce from 0.32% to 0.25% their collective average methane intensity of aggregate upstream gas and oil operations by 2025. The companies have an ambition to achieve an even more ambitious target of 0.2%.[63] The specific quantitative target and ambition set by OGCI require companies to have in place rigorous methodologies and practical steps to monitor and reduce emissions.[64]

Methane Guiding Principles (MGP) for reducing methane emissions across the natural gas value chain. As of January 2019, the Guiding Principles have been signed by 16 oil and gas companies and 10 other organizations. 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.

Gas Infrastructure Europe (GIE)[65] is an association representing 70 members of infrastructure industry in the natural gas business in Europe. **Marcogaz**[66] is the technical association of the European natural gas industry. Both are working on methane management and in June 2019 they jointly published a report on approaches to reducing methane emissions.[67]

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58 http://www.ccacoalition.org/en/resources/reducing-methane-emissions-across-natural-gas-value-chain-guiding-principles

59 http://ccacoalition.org/en/resources/oil-gas-methane-partnership-ogmp-overview

60 https://oilandgasclimateinitiative.com/

61 http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-reporting

62 http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-reporting

63 https://oilandgasclimateinitiative.com/oil-and-gas-climate-initiative-sets-first-collective-methane-target-for-member-companies/

64 https://oilandgasclimateinitiative.com/blog/methodological-note-for-ogci-methane-intensity-target-and-ambition

65 https://www.gie.eu/

66 https://www.marcogaz.org/

67 https://www.gie.eu/index.php/gie-publications/methane-emission-report-2019/27786-gie-marcogaz-report-for-the-madrid-forum-potential-way-gas-industry-can-contribute-to-the-reduction-of-methane-emissions/file

Depending on the context/objective of the emissions report, there are specific requirements for monitoring and reporting methodologies and plans (monitoring points, frequency, use of equipment, data recording and storage, uncertainty ranges etc.) consistent with ISO 14064 or other standards and might be subject to verification by third party certification companies.[68] A number of elements should be considered when designing company/facility reporting procedures:

- An emission inventory does not need to be completely exhaustive but should include all medium and large emissions sources.[69]
- To allow data analysis and comparison between facilities or regions, consistent approach(es) and vocabulary should be defined. Time consistency should also be considered to allow comparison of emissions over time.
- To allow improvements over time and meaningful analysis, the methodology used to estimate emission or emission reduction needs to be transparent and trackable. Using a transparent and verifiable approach is central to a credible report.
- The report should be detailed enough to assess emission reduction opportunities. In addition to information on the level of emissions, emissions reports may include information on past emission reductions and past projects. Reports can track progress and evaluate past projects' performance to improve the future project design.
- Reports should be updated on a regular basis. Results of new measurements campaigns should also be incorporated e.g. by updating relevant emissions factors.
- Inventories are constructed based on a combination of measurement campaigns and calculation-based method. The approaches used to select sites for measurement and their representativeness should be documented. An uncertainty approach could support focusing improvements on relevant emission categories.

With the increasing focus on demonstrating the climate impact of natural gas, operators have more pressure to document emissions credibly along the gas value chain. In this context, and given the specific challenges associated with methane MRV, emissions reports should be based on robust and transparent approaches. In addition, operators may consider the value of opening facilities to independent parties who can assess the situation.

[68] https://www.iso.org/standard/66453.html

[69] Materiality is a concept (derived from accounting) relating to the importance or significance of a source or sink. This can be expressed in different ways. For example, in some reporting requirements, a source may only be reported if it is larger than a materiality threshold that could be either an absolute size or a fraction of the total emission. (https://www.ipcc-nggip.iges.or.jp/public/tb/TFI_Technical_Bulletin_1.pdf). IPCC provides guidance on materiality of emissions. This is the standard that a third party verifier will use to make the "verification statement" that "there are no material discrepancies in this inventory." Some companies, like financial institutions, use 5% of the total corporate emissions as a material standard, while the EU-ETS refer to the major/minor/de-minimis thresholds. There is no common international material threshold.

3.2.4 Verification

Verification of emission reports, or verification of changes in emissions is an independent and documented evaluation of a greenhouse gas inventory report, or of an emission reduction report, against agreed verification criteria. Verification is typically performed by a third party[70] according to a standard with rules and guidelines. Certain guidelines and standards used as verification criteria are broad and general, while others are specific to the nature of emission sources, and to the emissions in question. Verification should go beyond simple accounting of reported numbers and should extend to the methodologies applied.

3.3 MRV at the national level and international reporting

Calculation and reporting of national methane emissions are the basis for design and implementation of effective policies and measures, and for monitoring progress on mitigation.

Internationally the agreed methodologies and practical guidelines (IPCC Guidelines) strongly influence national calculations and reporting of methane emissions. IPCC Guidelines are briefly described, followed by a discussion on important aspects of national reporting and presentation of the new reporting requirements adopted under the Paris Agreement.

3.3.1 The IPCC Guidelines

The Task Force on Greenhouse Gas Inventories was established in 1991 by the IPCC and the latest version of the IPCC Guidelines for National Greenhouse Gas Inventories was issued in 2006.[71] The IPCC Guidelines are described in **Section 2.1** above. The UNFCCC estimates presented in **Chapter 2** are derived from National Inventory Reports (NIRs) based on IPCC Guidelines.[72]

A process of refinement of the 2006 IPCC Guidelines began in 2017 with the goal to complete the task by May 2019.[73] The 2019 Refinement does not aim to replace the 2006 IPCC Guidelines, but rather to update, or/and supplement them wherever the gaps or out-of-date science have been identified.

As in the 2006 Guidelines, the oil and gas value chains are treated separately. However, in the 2019 Refinement, the types of segments and sub-segments are more detailed, as indicated in **Figure 3.4** below.

[70] Definition is based on ISO 14064

[71] https://www.ipcc-nggip.iges.or.jp/public/2006gl/ with the chapter on fugitive emissions: https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_4_Ch4_Fugitive_Emissions.pdf

[72] Applying the 2006 IPCC Guidelines is currently only required for Annex 1 (developed) countries. Non-Annex 1 (developing) countries can use the 1996 IPCC Guidelines. All Parties to the Paris Agreement will be required to use the 2006 Guidelines when reporting starts in 2024 - see below, section 3.3.3 “International reporting and the Paris Agreement Rulebook”.

[73] https://www.ipcc.ch/2019/05/13/ipcc-2019-refinement/l

Figure 3.4

Segments and sub-segments of the Oil and Gas Systems in the 2019 Refinement document

Segment	*Sub-segments*
Oil Systems	
Exploration	Unconventional without flaring or recovery (well completions with hydraulic fracturing)
	Unconventional with flaring or recovery (well completions with hydraulic fracturing)
	Conventional (well completions without hydraulic fracturing)
Production	Onshore with high emitting technologies and practices
	Onshore with low emitting technologies and practices
	Oil sands mining
	Oil sands upgrading
	Offshore
Transport	Pipelines
	Tank trucks and rails cars
	Tanks
	Loading offshore with VRU
	Loading offshore without VRU
Refining	All
Distribution	Gasoline
	Other petroleum products
Other	Fugitive emissions from spills and other accidental releases, waste oil treatment facilities and oilfield waste disposal facilities
Abandoned oil wells	Onshore plugged – leaks
	Onshore unplugged – leaks
	OR Onshore: All wells (plugged and unplugged) – leaks
	Offshore: plugged – leaks
	Offshore: unplugged – leaks
	OR Offshore: All wells (plugged and unplugged) – leaks
Gas Systems	
Exploration	Unconventional gas exploration without flaring or gas capture
	Unconventional gas exploration with flaring or gas capture
	Conventional Gas exploration
Production	Onshore: Most activities occurring with higher- emitting technologies and practices
	OR Onshore: Most activities occurring with lower-emitting technologies and practices
	Onshore Coal Bed Methane
	Gathering
	Offshore
Processing	Without LDAR, less than 50% of centrifugal compressors are dry seal
	OR With LDAR, around 50% or more centrifugal compressors are dry seal
	Sour Gas (Acid gas removal)
Transmission and storage	Transmission: Most activities occurring with higher emitting technologies and practices
	OR Transmission: Most activities occurring with lower emitting technologies and practices
	Storage: Most activities occurring with higher emitting technologies and practices
	OR Storage: Most activities occurring with lower emitting technologies and practices
	LNG: Import/Export
	LNG: Storage
Distribution	Less than 50% plastic pipelines, and limited or no leak detection and repair programs
	OR Greater than 50% plastic pipelines, and leak detection and repair programs are in use
	Short term surface storage
	Town gas distribution: All
	Natural gas-fuelled vehicles
	Appliances in commercial and residential sector
	Leakage at industrial plants and power stations
Other	emissions from well blowouts and pipeline ruptures or dig-ins, accidents, and emergency pressure releases
Abandoned Gas Wells	Same as for Oil Systems

The Refinement document lists Tier 1 emission factors for each sub-segment and the applicable activity variable(s). There are more sub-segments in the Refinement than in the 2006 Guidelines, e.g. now gas distribution has 7 sub-segments against 1 before. Specifically, sub-segments have been added for unconventional exploration and production of oil and gas. Another important change is that in the 2019 Refinement there is no more distinction between a developed and developing country Tier 1 emission factors.

Tier 2 emission factors are country specific, but the breakdown into segments is the same as for Tier 1 (see **Figure 3.4**). The emission factors may be developed from quantification and analysis of national circumstances but can also be drawn from other sources, most notably from the Emissions Factor Database (EFDB),[74] developed by the IPCC.

Tier 3 emission factors are developed through rigorous bottom-up analyses with data from individual facilities. Field specific information about reserves, production conditions, quality of equipment, and operational practices must be collected and combined with specific methane emissions measurement and/or other analytical approached and results.

In principle, complete coverage of all emission sources is easier when calculations are done at a high level of aggregation using national statistics on oil and gas supplies as activity data. Where activity data are from counts of oil wells, equipment, or other stationary variables, the full coverage of the Oil and Gas Systems is more difficult to assess. The same holds true if oil and gas supply data is not a part of a complete national statistical system. It is therefore important to carefully assess the completeness of activity data for each segment.

As methods, availability, and quality of primary data improve, historical data will, and should, be revised. It is important to use the same methods for the entire time series to ensure that they reflect true trends in emissions. For example, it will be important to assess whether new values for emission factors reflect better understanding of emission sources and intensities or are only a result of the improved technology/equipment standards and operational practices.

The IPCC Guidelines include good practice to conduct quality control checks and quality assurance procedures such as review of direct emission measurements (e.g. that site measurements are done according to recognized standard methods), the availability and quality of activity data (e.g. from multiple sources), and active involvement from industry and other technical experts.

3.3.2 National Inventory Reports

Progressive improvement of national inventories towards higher tier approaches is essential to create a sound foundation for mitigation policies and measures. Improving national inventories for oil and gas methane emissions requires collaboration with all stakeholders who can provide important inputs such as emissions factors and activity data. Stakeholder processes involving companies and public institutions are important means to improve the quality of national oil and gas methane inventories. Several countries have established broad collaborative processes which result in greatly improved national inventories for oil and gas methane emissions. Examples are summarized in **Box 3-3**.

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[74] https://www.ipcc-nggip.iges.or.jp/EFDB/main.php

Box 3-3: Improving national inventories reports (NIR) for oil and gas methane emissions

The United States, Canada, Russia and Norway others have improved the quality and the level of details of data on methane in their NIRs through active collaboration of government with industry and non-governmental institutions.

In **Norway** a two-year study (2014-16) was initiated by the Norwegian Environmental Agency to survey methane emission sources at offshore installations.[75] The objective was to quantify emissions, improve quantification, undertake BAT assessments, and identify suitable mitigation measures. The detailed analysis was conducted by a consultant, with active participation (and data inputs) from companies operating on the Norwegian Continental Shelf, the oil industry association and other relevant regulatory institutions. The work resulted in revisions and a more detailed breakdown of emissions by source, and in specific recommendations for methodology improvements. Revised emissions levels were found to be lower than previous estimates, but there were considerable variations between emission sources. The emission abatement potential was found to be around 10%.

In preparing its annual NIR the **U.S. EPA** collaborates with many experts and institutions. U.S. EPA receives information and data related to the emission estimates through GHGRP reporting, the annual Inventory formal public notice periods, stakeholder feedback on updates under consideration, and new studies. In recent years, new data have been incorporated into the US estimates across all segments of the oil and gas supply chain.

In **Canada** Environment and Climate Change Canada (ECCC) uses a variety of data from industry and provincial/territorial governments and works actively to improve the methods and data used to prepare emission estimates. Recently, ECCC funded a study on the Canadian oil sands' mining and upgrading industry, and improved estimates of flaring, venting, and other fugitive emissions for this part of the Canadian oil and gas industry. In addition, emission estimates for abandoned oil and gas wells were recently added to Canada's NIR by analyzing historical records, developing an inventory of abandoned wells, and utilizing emission factors developed in the U.S.

In **Russia** in 2016 the Ministry of Energy of the Russian Federation initiated a study to develop and update national emission factors for the Oil and Natural Gas Systems based on national statistics, measurements, and analysis. As a result, the country specific emission factor for gas production was implemented in National Inventory 2018. Country specific emission factors for other segments are now in the process of scientific approbation.

The process of moving towards Tier 2 and Tier 3 calculations is not straight-forward and requires, among others, careful consideration of the following steps:

- Definition of the categories of emissions: The IPCC Guidelines include definitions of segments of the Oil and Natural Gas Systems, but there is no internationally recognized categorization of emissions subcategories relevant for Tier 3 quantification.
- Definition of the approach to emission estimate for each emission category: An emission estimation approach is selected for each segment and/or emission sources, depending on available data.
- Data compilation: Two types of data should be assembled: (i) activity data and (ii) emission factors. Activity data can be compiled from several sources, including from data collected from oil and gas companies. The emission factors should be statistically representative of emissions categories.

[75] http://www.miljodirektoratet.no/no/Publikasjoner/2016/Juni-2016/Cold-venting-and-fugitive-emissions-from-Norwegian-offshore-oil-and-gas-activities--summary-report/

- Construction of the inventory: Based on the results of the steps above, the inventory is prepared. Documentation of the approaches and assumptions should be an integral part of the inventory report.

- Update process: A process is needed for updating the inventory, including updating activity data, refining emission factors, and improving the management uncertainty in estimates. Updates should be also retroactive, when information is found to improve data used in prior years. It is important to assure that the improved knowledge is used correctly across time series.

A reliable national methane emissions inventory supports the design and implementation of regulation. In addition, MRV activities, as part of regulatory requirements and data submissions, can improve national inventories. Inventory development and MRV activities imposed by policies and regulations are closely related and will be discussed further in the next Chapter.

It is important to have in place procedures and capabilities that demonstrate progress from mitigation efforts over time which requires reliable quantification of how emissions intensities are affected by mitigation efforts arising from new technologies and operational practices.

3.3.3 International reporting and the Paris Agreement "Rulebook"

All ECE member states are signatories to the UNFCCC and they are obliged to prepare national GHG emissions inventories. Annex 1 Parties submit National Inventory Reports (NIRs) on an annual basis based on the 2006 IPCC Guidelines.[76] Non-Annex 1 Parties, using the 1996 IPCC Guidelines, report their inventories with less regularity and often as part of the National Communications (NCs) and Biennial Update Reports (BURs).[77]

With more focus on reporting under the Paris Agreement, the call on countries to improve the quality of estimates of emissions from methane and other GHGs and to report mitigation actions will grow. National authorities will play an important role in data compilation for international reporting and for supporting policies and regulations regarding methane.

The Paris Agreement "Rulebook" was adopted in December 2018[78] and included the modalities, procedures and guidelines (MPGs) for the Transparency Framework (Article 13) of the Paris Agreement.[79] The MPGs include a robust and common system that all Parties to the Paris Agreement must use in reporting on and accounting for their emissions.

The Transparency Framework is at the heart of the Paris Agreement. It refers to sharing comprehensive and comparable information. The MPGs build on the reporting requirements developed under the Convention but establishes common guidelines for reporting and review. As a result, there are greater expectations for the frequency, scope, and level of detail for developing countries, many of which have reported infrequently using less detailed guidelines.

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[76] Industrialized countries and countries with economies in transition (including the Russian Federation), as listed in Annex 1 to the UNFCCC.
[77] Developing countries, including those not listed in Annex 1 to the UNFCCC.
[78] The 24th Conference of the Parties (COP) to the UNFCCC held in Katowice. Poland with the main objective to complete the Paris Agreement Work Programme (often called the Paris Agreement Rulebook).
[79] The full text of MPGs for the transparency framework can be found at https://unfccc.int/sites/default/files/resource/l23_0.pdf

Beginning in 2024, all Parties to the Paris Agreement will report a full NIR at least every two years, providing annual data on emissions and removals following the 2006 IPCC Guidelines. Each Party must report on all sectors and on seven gases (including methane) at the most disaggregated level possible in the NIR.

For many counties significant efforts will be needed to meet the MPGs of the Transparency Framework.

1. All Parties will report using the same MPGs. Reporting requirements have been different for Annex 1 and non-Annex 1 countries, but this differentiation does not exist in the MPGs. There is some time-limited flexibility for developing countries needing to enhance capacity.
2. All Parties will use common reporting formats.
3. Biennial transparency reports (BTRs) and national inventory reports (NIRs) are to be submitted biennially starting from end 2024.
4. Two aspects of biennial transparency reports are particularly relevant:
    a. The National Inventory Report consistent with the 2006 IPCC Guidelines;
    b. Information necessary to track progress in implementing and achieving the NDCs.

ECE member states that are non-Annex 1 may need additional capacity to be able to report according to the transparency reporting requirements, particularly for the part that relates to methane originating from the oil and gas sector in the national inventory report. Whether methane is included in reporting on progress relative to the submitted NDC depends on whether methane is explicitly covered in the NDC. Currently this is not the case for many ECE member states (see **Section 4.3**). Many countries have large opportunities for cost-efficient methane mitigation and may wish to include them in their NDCs. They would have to implement IPCC Tier 1 and Tier 2 methodologies for monitoring and reporting methane emissions on a regular basis and provide consistent time series.

3.3.4 Review of national GHG inventories

Currently, the UNFCCC review of Annex 1 national inventories is carried out in 2 steps: (i) initial assessment by the secretariat (assessment of reporting format, overall consistency and completeness); and (ii) review by expert teams of data, methodologies, and procedures used to prepare the national inventory (compliance with guidelines and a focus results of previous reviews).

The MPG document describes the scope of work for reviewing national inventory reports and biennial transparency reports. Two areas under review will be reporting on the NIRs and providing information on progress relative to NDC targets. The Technical Expert Review Team will recommend improvements in reporting and assess capacity building needs of those developing countries that are Parties to the Agreement and exercised the flexibility provision. To the extent that methane emissions from the oil and gas sector are key categories, or are explicitly covered in the NDCs, this part will obviously be included in the Technical Expert Review.

4. Mitigation

Key messages

- Some methane emissions can be reduced quickly and at low cost. Barriers (lack of knowledge, awareness, and financial incentives) and regulatory factors hinder many of the opportunities.
- Companies must understand emission sources, acquire an overview of abatement options/technologies, and establish sound procedures to execute projects and monitor results.
- Policies and regulations for methane emission can vary greatly between countries. Effectiveness can be achieved with different approaches, but there are some general principles and examples of good practices, regulations, and policies that countries should consider (notably available new technology for detection and measurement).
- As countries focus on their targets, methane emission reductions could be embraced in their NDC. International carbon and climate finance and carbon pricing can also play a role in incentivizing mitigation.

4.1 Abatement opportunities and barriers to action

Several 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 a short-term climate pollutant, emission reductions measures can offer large near-term climate mitigation benefits and are among the most cost-efficient opportunities for emission reductions.

In its 2017 World Energy Outlook, the IEA estimated that 50% of global oil and gas sector methane emissions can be mitigated with a positive net present value,[80] while studies commissioned by the Environmental Defense Fund report similar estimates - 40% (in 2014) for USA[81] and 45% (in 2015) for Canada.[82] A more recent study[83] for the US commissioned by ONE Future, Inc.[84] showed a lower economic mitigation potential for a subset of US operations. The IEA has recently launched "methane tracker" which estimates the US potential for economic abatement of methane emissions to be about 35%. This tool, which assesses both, methane emissions by country broken down by 8 emission sources, as well as the abatement potential, still estimates the global potential to be around 50%.[85]

It should be noted that estimates of methane emissions and abatement cost potentials by country are often based on limited empirical data for the country in question, and frequently

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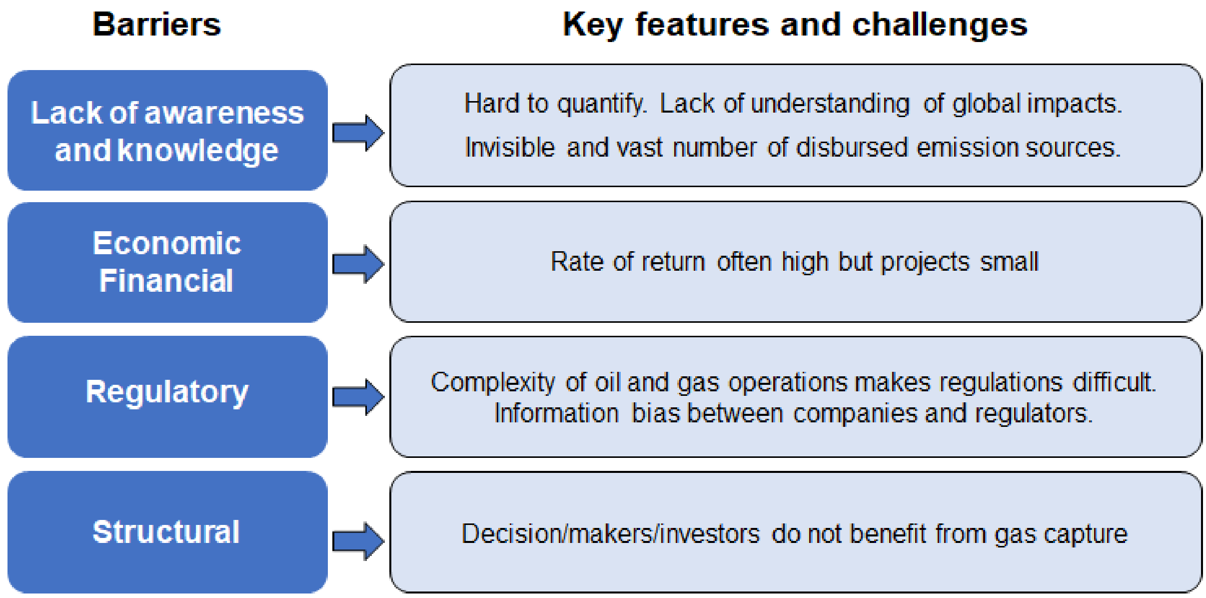
80 https://www.iea.org/weo2017/, page 426
81 https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
82 https://www.edf.org/sites/default/files/content/canada_methane_cost_curve_report.pdf
83 https://onefuture.us/wp-content/uploads/2018/07/ICF-Study.pdf
84 https://onefuture.us/
85 https://www.iea.org/weo/methane/database/

base their analysis on data from a few North American and European states for which detailed studies have been conducted.

The potential for economic methane abatement opportunities in the oil and gas sector is significant even in countries were sound methane management practices are prevalent. Barriers to action may vary from country to country and across companies, but there are some common features that are summarized in **Figure 4.1**.

Figure 4.1

Overview of barrier to methane emission mitigation



4.1.1 Lack of awareness and knowledge

Methane emissions are invisible, and often unknown to the public. Even if there was awareness, there could be a lack of motivation or experience to implement mitigation technologies. Particularly small companies would typically lack experience or the resources to address the issue.

The poor quality of inventories for methane hinders mitigation. Uncertainty in estimates often halts decision-making at the corporate level and alienates participants of the political debate.

4.1.2 Economic - Financial

Even when companies understand their emissions and have identified profitable mitigation opportunities, not all projects are pursued because of a lack of human resources or capital. Without guidelines or policies to prioritise methane managements, the projects/programmes may not be selected in the internal competition for human and capital resources.

Financial returns on methane emission reduction projects depend on the value of captured gas. If gas prices are low because of over-supply, regulation, or subsidies, then the incentives for capturing gas would be weak. A serious hindrance also exists if the relevant gas market is "demand constrained," i.e. the additional supplies from gas capture does not lead to increased sales, but rather to less production. In such cases there are insufficient benefits to justify gas capture.

4.1.3 Regulatory

In many jurisdictions methane emissions from the oil and gas sector have received little political attention. Regulatory measures are limited for several reasons:

- In many countries climate change mitigation has emerged only recently as a political priority and often it is seen as a threat to revenues, jobs, and activity.
- There is little appreciation of the temporal nature of climate, the significance of methane over the short to medium term is poorly understood, and action on methane is not prioritised.
- Methane is largely invisible and emitted in low volumes from a number of dispersed sources, so emissions have not attracted attention.
- There are major challenges in deploying good methane regulations (e.g. establishing competent regulatory institutions). In some countries there are not separate and independent regulatory institutions and/or policy making branches that regulate energy, environment, and commercial activities.

4.1.4 Structural

Structural barriers are related to framework conditions for operators and other partners in the oil and gas supply, operations, and development sectors. One important aspect in the upstream segment of the industry is the coverage of gas in Technical Service Contracts or Production Sharing Agreements between companies and host country authorities. Such agreements often reserve the ownership rights of gas produced in association with oil to the state or have clauses for delivery and sales of such gas, which offer poor incentives to operators to develop and manage gas handling facilities. In consequence, considerable gas volumes are flared or otherwise wasted with significant economic losses and environmental damage. With the increased focus on flare reduction, many countries either have taken or are taking steps to incentivize gas capture and use.

Distribution companies often lack incentives to prevent gas losses. They often do not purchase and sell gas but are paid for volumes gas distributed. Consequently, their revenues are insensitive to the rate of losses and their incentives to maintain systems and detect leaks may be dictated only by contractual obligations, safety considerations, and avoidance of supply disruptions.

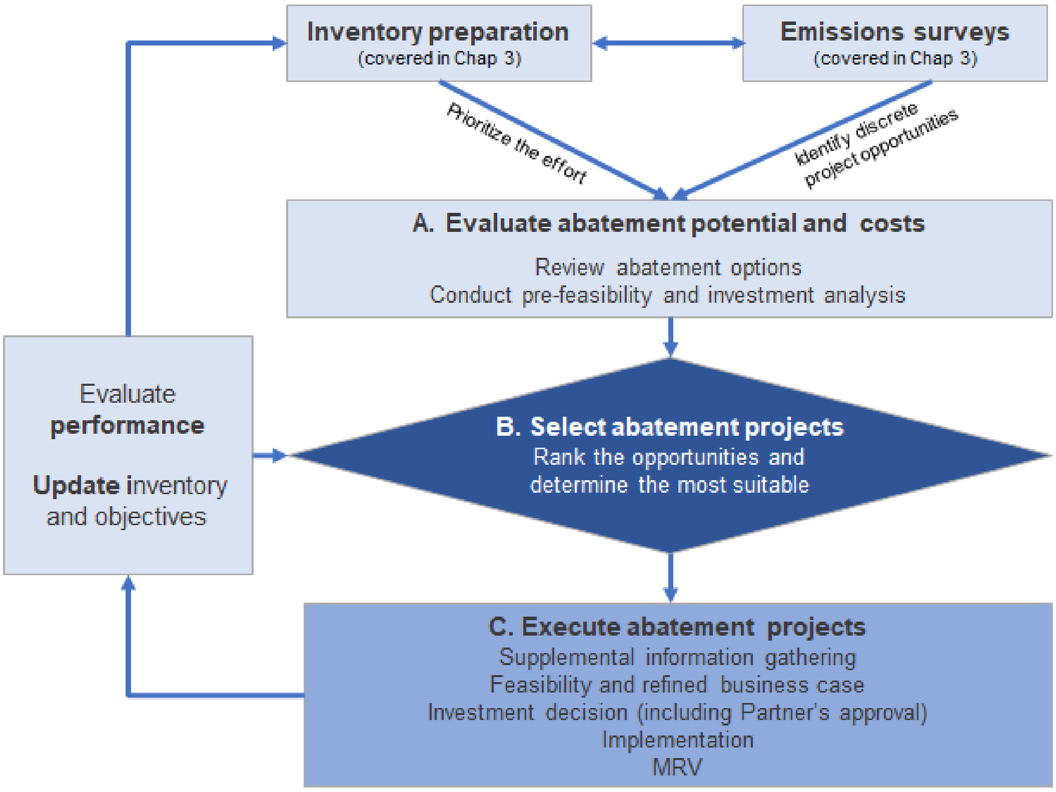
These and other barriers can be removed by both corporate measures and through policies and regulations imposed by national authorities, including collaborative efforts between public institutions and the corporate sector and framework conditions agreed at the international level.

4.2 Company strategies and actions

Decisions and actions to reduce methane emissions are made at the company/operator level.[86] A starting point is to have available a company-wide inventory of methane emissions that which can help prioritize the effort and select sites for measurement campaigns. Existing measurement campaigns can be used directly to identify separate emission reduction projects. A three-step process is illustrated in **Figure 4.2**.

Figure 4.2

Steps in implementing a methane mitigation strategy and plan



4.2.1 Evaluate abatement potential and costs

There are many best practices and technologies to reduce methane emissions from the oil and gas value chain. These practices are documented in publicly-available reports.[87] An overview of the main abatement options by emission source categories is provided in **Table 4.1** and presented in more detail in **Annex 1**. The technologies listed and emissions reduction levels noted in the table cannot be achieved in every location. In addition, some of the options might compete with one another.

[86] Note: Many operations are joint ventures (JV).

[87] Including CCAC OGMP technical guidance documents, http://www.ccacoalition.org/fr/news/public-review-ccac-oil-and-gas-methane-partnership-technical-guidance-documents, EPA natural gas star program recommended techniques (https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions), but also emission sources specific reports/articles.

Table 4.1

Main abatement option by emission source

Emission source	*Abatement options*	*Methane emission reduction for the emission source*[88]
1. Hydraulic fracturing & well completion	Green completion system	95%
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 (note: the latter alternative increase CO2 emissions)	
3. Liquids unloading from gas wells	Install plunger lift systems in gas well	Variable
	Manually redirect the well to the production system as soon as the unloading is completed	Variable
	Plunger Lift optimization	Variable
	Add foaming agents, soap strings, surfactants	
	Install velocity tubing	
4. Glycol dehydrators	Install flash tank separator and optimise glycol circulation rates	Up to 90%
	Route flash tank (if present) and dehydrator regenerator vents to VRU for beneficial use	
	Route flash tank (if present) and dehydrator regenerator vents to flare (note: increase CO2 emissions)	Up to 90%
	Replacing by zero emissions (e.g. desiccant) dehydrators	100%
	Replace the gas assist lean glycol pump with an electric lean glycol pump	
	Reroute glycol skimmer Gas	Up to 95%
5. Natural gas driven pneumatic controllers and pumps	Replacement or retrofit to from high bleed to low bleed devices	Up to 97%
	Routing emissions to an existing combustion device or vapor recovery unit	Up to 95%
	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.	Up to 90%
	Replacement by zero emission options (electric or air driven)	100%
6. Wet-seal centrifugal compressors	Re-route gas at lower pressure to VRU, flare, or to a low-pressure inlet	Up to 95%
	Convert compressor wet seals to dry seals	Variable
7. Reciprocating rod-packing compressors	Regular replacement of rod packing (ideally based on measured emission rate)	Typically, 50-65%
	Re-route vents points to VRU or fuel gas system	Up to 95%
	Re-route vents points to flare (note: increase CO2 emissions)	Up to 95%
8. Venting associated gas at upstream oil production facilities	Flaring without energy recovery instead of venting[89]	Up to 98%
	Capturing vent gas for gas utilization	up to 100%
	Install flare ignition systems[90]	Variable

[88] For each emission reduction, a baseline technology is assumed. For more information please refer to the existing documentation on these technologies which are listed in the annex 1.

[89] Only when gas utilization is not economically or technically possible. CO_2 emissions increase with this measure. However overall the GHG emissions decrease

As the gas is not conserved (i.e. it is burned without energy recovery instead of vented) this mitigation option typically has no economic benefits.

Flaring is more visible than venting

[90] Avoid venting from small flares being "blown out." As the gas is not conserved (i.e. it is burned instead of vented) this mitigation option typically has no economic benefits.

9. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge[91]	Reduce operating pressure upstream[92]	Up to 30%
	Increase tank working pressure	10-20%
	Change geometry of the loading pipe	Poor data
	Installing a Vapor Recovery Unit (VRU) and directing to productive use as fuel gas, compressor suction, gas lift	Up to 98%
	Hydrocarbon blanketing[93]	Variable
	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	Variable
	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.	Variable
11. Component and equipment leaks	Perform LDAR	Depends on frequency[94]
	Implement effective leak-prone pipe replacement program.	Variable
	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	Variable/poor data
	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	Variable
	Minimize gas flaring by utilising the gas	Variable
	Improve combustion efficiency by Change flare tip / installing flare ignition systems[95]	Increase to up 99.8% combustion efficiency

A couple of key emissions sources can be highlighted:

- Component and equipment leaks: Regular LDARs are typically a central part of methane mitigation.
- Compressor: Compressors are a significant source of emissions. Various mitigation approaches can be considered including (i) retrofitting to dry seal compressor, (ii) re-

[91] In a number of cases, VOC represents a large share of the emissions for this emission source category. As a result, the abatement presented are also (and sometimes mainly) VOC emission mitigation measures.
[92] Needs to be combined with other mitigation upstream or downstream as the emission will happen at a different point in the value chain.
[93] https://www.carbonlimits.no/wp-content/uploads/2015/11/Nordic-initiatives-to-abate-methane-emissions.pdf p. 77
[94] Amongst other parameters (including type of asset, type of equipment, maintenance and operating practices, experience of camera operator...)
[95] As the gas is not conserved (i.e. it is burned instead of vented) this mitigation option typically has no economic benefits.

routing vent emissions to a low-pressure gas inlet, and (iii) regular replacement of rod packing.

- Unstabilized liquid storage tanks: vapor recovery units (VRUs) can be installed to collect methane and VOC emissions, compress them and transport them for productive use (local power production, export to existing processing facilities etc.)
- Incomplete combustion from gas flaring (best addressed by using the gas and minimizing flaring).

Many methane mitigation technologies and practices are mature and have been used by the industry. A few technologies such as electric controllers and new methane detection technologies, are more recent.[96]

A detailed inventory with emissions broken down by emission source subcategories, contributes to identifying a program with a large abatement potential and focuses effort. Individual projects are identified through specific facility assessments or measurement campaigns. For each potential abatement project, an investment analysis can estimate the potential emission reduction and the project's expected cost/profitability:

- Investment capital costs typically include engineering, drafting, site preparation, materials, equipment, instrumentation, utilities, logistics, labor, construction management, permitting, and commissioning costs. While project implementation costs vary from site to site, they typically are modest compared to other oil and gas investments. Projects can be implemented as large aggregated programs, which combined represent substantial investment.
- The impact of mitigation on operating costs can be quite substantial.[97]
- Emission reduction estimates are derived from measurement campaigns and/or from engineering calculations.[98] In some cases, the volume of gas that can be saved by the implementation of a mitigation technology needs to be assessed carefully through use of models. Annual and short-term variations also should be considered when estimating the benefit. Finally, the lifetime of the abatement measure ought to also be considered in the assessment.
- Recovered methane can, in theory, be sold and generate revenue to offset the abatement costs. Some abatement options do not, however, produce revenues. Depending on the specific ownership or contractual circumstances, it is not always possible for the company that implements a project to benefit fully from the saved gas. As a result, some projects that are economic from a societal perspective, are not economic for the owner/operator of the infrastructure.[99]

[96] https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/
[97] https://carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/
[98] Rarely from emission factors which are too uncertain for investment analysis
[99] A number of mechanisms can be implemented to address this barrier, see section 4.4.

- The payback period and abatement costs for methane emission reduction projects are highly site specific. Given the variation in emissions factors, abatement costs can vary even for the same abatement options. The indicators must be assessed for each project.

4.2.2 Select abatement project

Companies typically select projects based on several criteria including economic considerations (net present value, internal rate of return, etc.), methane emission reduction, and practical considerations:

- During LDAR, leaks are first detected, then measured,[100] and finally repaired. It is virtually always economic to repair a leak once it has been detected.[101] Regular LDAR represents should be integrated into regular HSE operations. Details on the design of LDAR program are presented in **Box 4-1**. IR camera surveys allow to identify vents and so are at the intersection of inventory development and mitigation.
- A small number of emissions points typically represent most emissions (see **Box 4-2**). Giving priority to these emission points provides substantial emission reductions and is cost effective.[102]
- Given the nature of methane emissions with many relatively small sources, it is natural to consider a program of projects (e.g. install VRU on all un-stabilized liquid storage tanks in a region). Bundled investments offer important economies-of-scale as procurement and installation costs are lower[103] and there will also be costs savings in planning and execution of monitoring and results. Success with program implementation involves a sequential approach with prior results informing subsequent scale up.

Box 4-1 Identification, quantification and maintenance of methane leaks and vents

Facility surveys are vital for methane emission management in oil & gas systems. Surveys are conducted to identify leaking components, and often include quantification of the emission sources. Leak detection, measurement and repair (LDAR) campaigns are performed with the primary objective to mitigate emissions.[104]

[100] Quantification has a cost and therefore it might be more cost effective to repair immediately after detection.
[101] "the vast majority of emissions from leaks (more than 97% of the total leak rate), are economic to repair (NPV>0), even when the value of gas is 3 USD/Mcf" https://carbonlimits.no/project/quantifying-cost-effectiveness-of-systematic-leak-detection-ldar-using-infrared-cameras/
[102] There is not a single definition for large or super emitters. NAS report Improving Characterization of Anthropogenic Methane Emissions in the United States «High-Emitting sources» in https://www.nap.edu/catalog/24987/improving-characterization-of-anthropogenic-methane-emissions-in-the-united-states While there is no single quantitative definition of a super-emitter some consider them to be the top 5% of emissions sources while others consider them to be sources defined vis-a-vis an average emission factor (e.g. 5 times the average emission factor) or with the top 15% emission factors.
[103] Based on interviews with Canadian operators on their experiences
[104] For definition of LDARs and DI&Ms see http://www.ipieca.org/resources/awareness-briefing/methane-glossary/

Facility surveys, when they include emissions quantification, also serve important MRV purposes. They are performed regularly with each new campaign allowing for identification of new emission points that appeared since the last inspection. Increasing the frequency of LDAR campaigns reduces emissions as new emission sources are detected and fixed earlier. On the other hand, increasing frequency increases costs and, in turn, reduces the cost effectiveness of the surveys. Studies have shown that abatement costs increase with increased survey frequency.[105]

Given the variable nature of many emission sources, repeated surveys reduce uncertainty in emissions estimates. A minimum facility survey frequency is imposed in some jurisdictions. Elsewhere, frequency is set on a case by case basis, depending on:

- The facility size/type: It is more cost effective to inspect a large facility often than small, dispersed production sites.
- Other maintenance practices**:** Regular maintenance and component replacement/repair have a bearing on the magnitude of emissions and thus LDAR practices (e.g. planning a LDAR just before a large maintenance to identify additional repairs that could be performed and just after to check results).
- Results of past inspections: Results of past inspections provide valuable information on the past sources of emissions.[106]

Continuous monitoring can also be considered. Such an approach allows for early detection of new emission sources (in particular super-emitters). A maintenance crew is then sent on-site to identify the specific emissions source and to fix it.

Existing documents summarize elements of best practices for LDARs.[107] They include:

- Written program with an objective for the program, procedures for leak identification and quantification, procedures for repairing and keeping track of leaking equipment, and the roles and responsibilities of personnel involved.[108]
- Training for personnel involved in the program, and awareness rising for relevant operators.
- Repair and follow-up programs for the emissions sources identified (only for LDAR program).
- Quality assurance and control procedures including calibrations protocols.
- Internal and third-party audits of the program, if relevant, to ensure that the program is correctly conducted and that issues are identified and corrected.
- Database and software to store the monitored data.

Box 4-2 Focus on large emission sources (« super-emitters »)

Recent research has documented that a small number of sites and components are major sources of methane emissions.[109] The figure below, taken from a large research effort in the Barnett Shale in the USA, illustrates the impact of high emitting sites and the shape of the distribution curve of emissions:

> «The cumulative percent of CH_4 emissions (blue curve) as a function of the cumulative percent of sites, which are plotted in rank order of increasing emissions. The secondary y-axis (red curve, log scale) shows the corresponding absolute CH4 emission rate. Roughly 30% of sites had emissions below the method’s detection limit. (...) [While] the 5% of sites with the highest emission rates (...) are responsible for 60% of the emissions.»[110]

[105] See https://carbonlimits.no/project/quantifying-cost-effectiveness-of-systematic-leak-detection-ldar-using-infrared-cameras/

[106] See examples of the analysis of past inspections. https://carbonlimits.no/project/statistical-analysis-of-leak-detection-and-repair-in-europe/

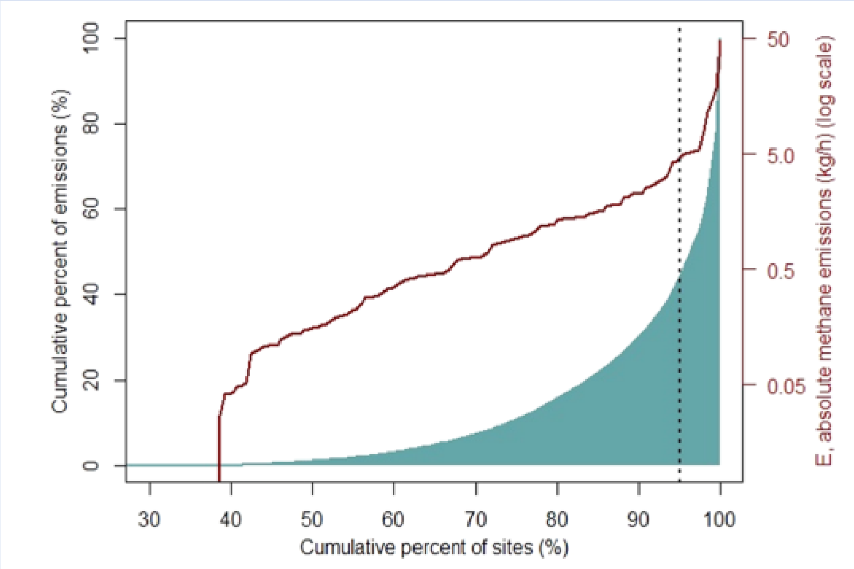
[107] For example: https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf

[108] In the case of a LDAR program

[109] For example: http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133 https://www.nature.com/articles/ncomms14012.pdf

[110] http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133

Distribution of measurement of CH4 emissions from natural gas production sites in the Barnett Shale region[111]



There is a limited published scientific literature on the main causes for the existent of these sources of emissions, but there are indications that equipment age, gas composition, and maintenance practices play a key role. Super-emitters can occur along the value chain of oil and gas from upstream production to downstream transmission. Certain components are more likely to become large emitters than others (e.g. faulty devices such as stuck open valves or continuously emitting intermittent controller), although large emitters can be found in all types of facilities and for all types of components.[112] Human error can play an important role.

The characteristic distribution of the emissions (so-called "fat-tailed" distribution) has an important impact on the abatement strategy for methane emissions. Addressing the largest emitters is not only very efficient from a climate mitigation perspective, it also is often cost-effective.[113]

Super-emitters tend to be transient in time and in location, making them relatively unpredictable when it comes to locating them. Systematic and frequent surveys allow for identifying and addressing these sources of emissions in a timely manner. Given the magnitude of the super emitters, less-sensitive and cheaper detection technologies can be used.

4.2.3 Execute abatement projects

Once an abatement project has been selected, the project execution phase can start. Companies have internal processes and decision gates that typically include project development, project implementation, and project monitoring stages:

- <u>Organizational considerations:</u> Implementing emission reduction programs is perceived as complex due to the large number of actors involved. Decisions and project implementation involve many departments and actors including subcontractors and often overseas internal stakeholders/subcontractors. Local operations have a key role in ensuring project success.

[111] *Id.*
[112] https://carbonlimits.no/project/statistical-analysis-leak-detection-and-repair-canada/
[113] Brandt, et. al., Methane Leaks from Natural Gas Systems Follow Extreme Distributions, Environ. Sci. Technol., 2016, pp 12512-12520

- Coordination with other maintenance operations: While many emissions points can be fixed outside of scheduled facility maintenance, many emission reduction measures need to be implemented during planned maintenance, and thus need to be planned well in advance and coordinated/integrated in the maintenance plan.
- The importance of monitoring: Experience has demonstrated that emissions reductions need to be confirmed after project implementation to evaluate project success over time, or to identify and fix implementation issues.[114]
- Greenfield/new infrastructure project: Implementing methane emissions management best practices during the early stages of a new project design can reduce abatement costs compared to retrofit projects.

4.3 National policies and regulations

National authorities have several options for imposing policies and regulations to reduce methane emissions from the oil and gas sector. This section distinguishes three categories:

a. **Standards** that require use of specific technologies and/or operational practices, and quantifiable emission limits. Technical standards are the most common. Emission limits often are used with technical standards or with economic instruments such as fees or fines. Requirement for regular leak detection and repair (LDAR) programs fall under this category.

b. **Economic instruments** that cover emission fees/taxes and emission fines (for emissions above a permitted level), emission trading systems and offset credit scheme, as well as tax rebates and financial grants for specific emission reduction investments. Gas price and gas price reforms can also be considered as part of this category.

c. **Public-private partnerships and negotiated agreements** between the industry and political authorities or the regulator can take different forms, from loosely defined partnership with voluntary targets to formalized agreements with a threat of subsequent mandatory regulations if specific quantitative targets are not met. Negotiated agreements may include: i) agreed emission reduction targets, ii) an institution with the mandate to manage and coordinate emission reduction measures that are to be implemented by companies, and iii) procedures for monitoring, reporting and verification of compliance, as well as eventual enforcement measures.

Even though there have been few active policies and regulations on methane across countries, examples of application of all three above-mentioned categories are available (see **Box 4-3**).

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[114] For example, a number of recent measurement studies reported higher emissions from low-bleed and intermittent bleed controllers than expected: Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers Allen et al., 2015; Measurements of methane emissions at natural gas production sites in the United States. Allen, David, T., et al. 2013. www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html

Box 4-3 Examples of national policies and regulations

Standards for practices (e.g. LDARs) and equipment are the most common measures, implemented primarily in North America. As a part of its ambitious methane emission reduction targets (40 to 45% reduction from 2012 levels by 2025 in the oil and gas sector), Canada imposed stringent performance standards on compressors and pneumatic devices.[115] At the provincial level there are requirements for periodic inspection of leaks, leak detection and repair (LDAR) programs, and offset schemes.

In many ECE member states **Best Available Techniques (BAT) standards** increasingly refer to methane emissions. Russia plans a pilot transition BAT for 300 companies that will start in 2019 and aims to reduce emissions from the oil and gas sector. Several BAT standards covering methane emissions are included in the sector's guidance documents: vapor recovery from storage tank farms, increased durability of pipelines, and compressor station optimization. Another example is the European Commission, which in April 2019 published the Hydrocarbons BAT Guidance Document. The techniques listed therein represent current techniques adopted in upstream oil and gas operations. The identification of best practices in that document serves organizations engaged in hydrocarbon activities and the regulatory/permitting authorities as guidance for planning new facilities, modifying existing ones, planning changes and investments, and permitting across the EU.[116]

Economic instruments have not been much in use. Methane emission sources are rarely covered by emissions trading schemes and other types of "carbon pricing," largely due to MRV challenges. The situation is changing. Offset schemes for methane have been put in place in several provinces in Canada. Russia and other Republics of the Commonwealth of Independent States (CIS) regulate methane as a pollutant hazardous from a health and safety perspective. Emission limits were established, and penalties apply for volumes that exceed them. Emission charges are set in accordance with emissions quantification methodologies. At the same time, there are two other specific developments in Russia that merit attention: i) steps are taken to improve methodologies for quantification of GHG emissions by enterprises, and ii) emissions charges for air pollutants are used as a powerful policy measure to curb emissions from associated gas.[117, 118]

Agreements and public-private partnership serve as important coordinated measures to reduce methane emissions. A pioneer scheme in this regard is the Natural Gas STAR Program, a voluntary partnership with oil and natural gas companies launched by the U.S EPA in 1993. It was recently updated with a "Methane Challenge" component added in 2016. It has been estimated that from their inception through 2017, the Natural Gas STAR and Methane Challenge programs resulted in cumulative methane emissions reductions in the United States of over 42 billion cubic meters.[119] Canada has a long tradition of fostering agreements with the oil and gas industry on environmental matters. For the major part it has done so through initiatives taken by provincial regulatory authorities.[120] Since 2016, Norwegian regulatory authorities have collaborated with oil and gas operators to reduce emissions.

Policies and regulations in the oil and gas sector concerning methane emissions vary substantially across countries, if exist at all! They are part of broader national legal and

[115] https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=FF677357-1&offset=2&toc=hide

[116] https://publications.europa.eu/en/publication-detail/-/publication/f9265d2b-574d-11e9-a8ed-01aa75ed71a1/language-en/format-PDF/source-93598867

[117] Government Decree No. 716-p and 300 from 2015 ("On a framework for monitoring, reporting and verification of GHG emissions" and "On establishing a methodology for quantification of GHG emissions by enterprises"). Emission points that together do not exceed 5% of the total volume of company's emissions (and below 50 000 tonnes CO_{2e}/year) do not have to be reported

[118] Government decree No. 1148 from 08.11.2012 on "Emission fees for negative environmental impacts from emissions of air pollutants due to APG flaring or venting"

[119] https://www.epa.gov/natural-gas-star-program/natural-gas-star-program-accomplishments

[120] e.g. the Alberta Energy Regulator

regulatory structures and are rooted in distinct institutional traditions and capabilities. A unified compendium of "best practices" for regulation of methane emissions does not exist.

Nevertheless, certain general features characterize the different approaches to management of methane emissions:

1. **Cost-efficiency**. Measures with low abatement costs should be implemented before those with higher costs. Due to the sensitivity of emission reduction costs to site-specific conditions, there are challenges with ensuring cost-efficiency. The most difficult part is acquiring adequate and unbiased information on emissions and abatement costs. The administrative costs of compliance and enforcement can be significant and must be considered in cost-efficiency considerations. Compliance and enforcement costs may drop with new technology.

2. **Clarity and transparency**. Rules and procedures for approving emission limits, technology standards, compliance and enforcement mechanisms, and other regulatory measures should be clear and transparent. Predictability in the use of regulatory and enforcement tools is also important, especially for reducing investment risks.

3. **Institutional capability.** Regulatory ambitions must be attuned to the capacity and capability of regulatory institutions. Regulatory institutions must have the staff with adequate sector specific competency, or otherwise the principles of cost-efficiency and clarity/transparency will be undermined. More fundamentally, the regulatory staff must act impartially and without risk of corruption/mismanagement. The regulatory requirements, data reporting, and enforcement procedures that are flexible (e.g. for the sake of cost-efficiency and innovation) will generally be more susceptible to economic mismanagement than rules that are simple and rigid. Consequently, there is a difficult trade-off between cost-efficiency and clarity/transparency. Finally, regulatory institutions should have clear and not overlapping functions. This may also pose practical challenges, as methane emissions cause concern for climate change, local environmental damages, and safety. All these issues are rarely handled by one regulatory institution, and/or by one set of coordinated regulatory measures.

It can be misleading to give regulations a weighted average score on the basis of the three above-mentioned criteria. While some of the regulatory approaches will by design "pick" the emission reduction with the lowest abatement cost (e.g. economic instruments such as emissions trading, offset schemes, and emission charges), for others cost efficiency will be determined rather by the specificities of the regulation.

Another complication with a comparative analysis comes from the fact that in many cases the approaches/tools are used in combination, and that applicable regulations serve different, at times conflicting, purposes (e.g. local versus global environmental concerns, environment versus economic returns). In practical terms it means that design and implementation of regulations would always require certain case-specific trade-offs, thus making it difficult to give any generally applicable recommendations in this regard.

Despite these caveats, **Figure 4.3** provides a schematic overview of three broad categories of regulations with an indicative assessment of how each of them scores in the criteria discussed above.

Figure 4.3

Illustrative assessment of regulatory tools

	Cost efficiency	Clarity and transparency	Institutional requirements
Standards	Likely yes, but variable	Yes if well specified	Modest, but can be high
Economic instruments	By design yes Monitoring can be problematic	Can be complex	Modest to high
Negotiated agreements	Likely yes, but variable	Yes if well specified Broad participation a plus	Modest

Some further considerations are summarized below.

4.3.1 Technical standards and emission limits

Technical standards offer a transparent and simple mechanism to reduce emissions. They can be an option which does not involve the need for cumbersome monitoring. On the other hand, however, they may also include reporting and monitoring requirements to assure compliance. In such case, cost efficiency of that tool will decrease. The design, update, and enforcement of a regulation might impose a considerable burden on the regulator. Achieving cost-efficiency requires, therefore, a good understanding of a variety of specific conditions in the oil and gas sector. Leak detection and repair programs can be considered as standards, and empirical studies suggest that they can be cost-efficient. However, empirical analysis of emissions' sources and survey & repair costs should be conducted before any such programs are designed and operationalized in order to determine, among other things, the relevant monitoring frequency. This was done in the United States and Canada before the standards that are currently in force were imposed.

The increased interest in methane emissions across the world also means that there is a considerable focus on research and development of progressive technologies. Inter alia, this will improve the opportunities for effective and cost-efficient monitoring of regulatory compliance.

4.3.2 Economic instruments

The most obvious and cost-efficient measure under this category is a gas price reform assuring that prices reflect the actual costs and market conditions. In some countries, prices are set through political interventions and kept at an artificially low level, hence de-incentivizing any action against wastage of gas. A reform prohibiting or limiting the scope of such interventions would make application of any gas loss preventing measures more economical.

In the context of the climate policy, carbon pricing is recently receiving ever more attention. It is also important to note that increasing number of oil and gas companies are applying carbon pricing in their investment analysis and decision-making processes. In other words, since a cost is attached to every ton of GHG emissions, investments that reduce their amount are rewarded accordingly. In light of the above it is clear that the suitability and effectiveness of economic instruments depend critically on the ability to monitor and verify emissions. Costs and accuracy of emissions quantification must therefore be carefully considered in order to determine whether economic instruments should be applied and what their design should be. Emissions trading system, or emission charges for all types of methane emissions are difficult to implement, due to a large number and a great variety of emission sources, which results in difficulties with effective monitoring, reporting and verification. The cost-efficiency typically attributed to economic instruments may therefore be undermined by high MRV costs. In this context it is important to observe that the largest emissions trading scheme, EU ETS, has been in operation since 2005, and despite the fact that it has since increased its sectoral scope on a few occasions, it still does not include methane emissions.

However, methane emissions from both, the waste and the oil and gas sectors, are part of the project-based emissions trading mechanisms (see **Section 4.3.3** below) and therefore the achieved reductions can, under certain conditions, be used as "offsets" in ETS. In addition, methane offsets can also be used as compliance tools under regulatory GHG emissions commitments, as it is already the case in Canada. Developing an offset scheme for methane in conjunction with emissions trading has also been considered for implementation in Kazakhstan.[121]

Further developments of such offset schemes can give important incentives for emission reductions, both in a national/regional context, as well as through international emissions trading, including those related to the UNFCCC (see **Section 4.4**). Effective monitoring, reporting and verification measures that are required for any credible offset scheme will, in turn, provide a great insight into methane emissions from the oil and gas sector.

4.3.3 Negotiated agreements

Public-private partnerships have been successfully applied in North America and Europe, see **Box 3-2** and **Box 4-1**. Such partnerships may include negotiated agreements between companies and political authorities/regulators. Agreements are an interesting approach as they might be both, effective and cost efficient. However, to assure that they hold that promise certain conditions need to be met: i) there must be strong institutions, both on the industry and regulatory/political side, which are capable and willing to communicate and agree on practical solutions, and ii) the scope of the agreement(s) must be carefully delineated so that results can realistically be reported and verified.

As one of the steps, the regulator, companies, and their industry associations can, drawing from available company data, national statistics, and international data sources, jointly develop a report summarizing common knowledge of emission sources and their amount (including relevant emission factors and uncertainty levels). Relevant research institutions may also be involved in this work.

[121] https://www.ebrd.com/documents/climate-finance/the-domestic-emissions-trading-scheme-in-kazakhstan.pdf

There is a number of active national and international public-private partnerships orientated on methane emissions. They are important and effective in creating knowledge and awareness of the matter, and it remains to be seen what role they will have in spurring action.

4.4 International initiatives and climate policies

In addition to national policies and regulations, various international initiatives can make an important contribution to methane mitigation. As noted earlier, there are international public-private partnerships and industry initiatives which are already making a notable impact.

With the Paris Agreement soon entering its operational phase, and with the Paris Agreement "Rulebook" now adopted by the Parties (see **Section 3.3** above), climate policies can set important framework conditions for mitigation actions by national authorities and the corporate sector. Two aspects of the Paris Agreement are further discussed here:

1. Greenhouse gas emission reductions targets and the related plans for policies and measures to achieve these targets as submitted by national governments as a part of the NDCs;
2. Carbon market mechanisms and climate finance mechanisms, which can help to remove barriers and accelerate mitigation efforts.

4.4.1 NDCs and the Paris Agreement "Rulebook"

Parties to the Paris Agreement are obliged to submit, on a regular basis, their NDCs. Intended NDCs were already submitted either just prior to, or shortly after the Paris COP21 meeting in 2015; these were converted into NDCs when the Party joined the Paris Agreement, unless a revised NDCs was submitted. By 2020 each Party is next required to recommunicate or update its NDC.

Most NDCs are brief and include little information on planned policies and measures. Specification of sectoral contribution is not a requirement and there is currently little information in NDCs on methane emissions reductions from the oil and gas sector. One positive example is Azerbaijan, the NDCs of which include some details.[122]

The Paris Agreement Rulebook contains guidance on information that should accompany each NDC for the purpose of assuring clarity, transparency, and understanding of the commitment, as well as on accounting for it. While both sets of guidance must be applied to the second and subsequent NDCs (starting in 2030 for most Parties), the Parties are also encouraged to apply them to the first ones. These guidelines[123] represent an important step towards developing a common and clear basis for measuring and communicating plans for emission reduction and reporting of progress. Guidance on accounting includes the use of common metrics (100-year GWP from AR5) and the use of the IPCC 2006 Guidelines, a quantified reference point, time frames for implementation, as well as the scope and the coverage of the NDC target. As with the MPGs for the Transparency Framework (see **Section 3.3**), there are no differentiation

[122] Azerbaijan states that: measures are: i) "Modernization of gas pipelines, gas distribution system and other measures to decrease losses up to 1% by 2020 and ensure the volume of reduction in compliance with international standards by 2050", and ii) "prevention of gas leakages during oil-gas processing" see https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Azerbaijan%20First/INDC%20Azerbaijan.pdf
[123] https://undocs.org/FCCC/CP/2018/L.22

between developed and developing countries, although it is stated that capacity building support will be granted for the latter ones.

An important issue is the scope and coverage of sectors and emission sources in the NDCs that each Party selects as a part of its target. On the one hand, as explained throughout this document, currently there are large shortcomings with accounting for methane emissions for many countries, which cause a major challenge with setting targets and credible methods and procedures for monitoring progress. On the other hand, in many ECE member states methane emission reductions are viewed as being able to offer large and cost-efficient mitigation opportunities (see **Section 4.1** above), and therefore those states may wish to include them in their NDC.

Quantitative coverage of emissions in NDCs is also a condition for any emission reductions, including those of methane, to be eligible for trading under cooperative approaches involving the international transfer of mitigation outcomes under the Paris Agreement (Article 6) and other trading schemes. It is because without solid accounting of emissions and emission reductions, any forms of trading would simply lack credibility and thus also a support (due to a risk of double counting of emission reductions).

Countries wishing to improve their reporting on methane emissions, and to implement policies and measures reducing these emissions, may benefit from a range of financial and technical support. An overview of international schemes for financial support suitable for methane emission reduction projects and programs are summarized in the next section.

4.4.2 Climate finance and carbon market mechanisms

A distinction is made here between two broader categories of financing schemes to reward environmental benefits:

i. <u>Climate finance</u> refers to local, national or transnational financing—drawn from public, private and alternative sources of financing—that seeks to support mitigation and adaptation actions that will address climate change;[124]
ii. <u>Carbon finance</u>, which involves trade in verified emission reduction (carbon credits).

Although many methane mitigation options appear to be financially viable, there are certain economic barriers, which hinder their implementation. Climate finance can be a means to overcome those barriers (see **Section 4.1** above), particularly in cases where small projects can be bundled into larger programs with significant GHG emission reduction impacts. The financing can assume the form of commercial "green financing/bonds," or of financing on concessional terms. The latter often constitutes a part of a greater support for developing countries, which is an important feature of climate change efforts under UNFCCC. Developing states perceive climate finance as an important means to reaching the targets set in their NDCs.

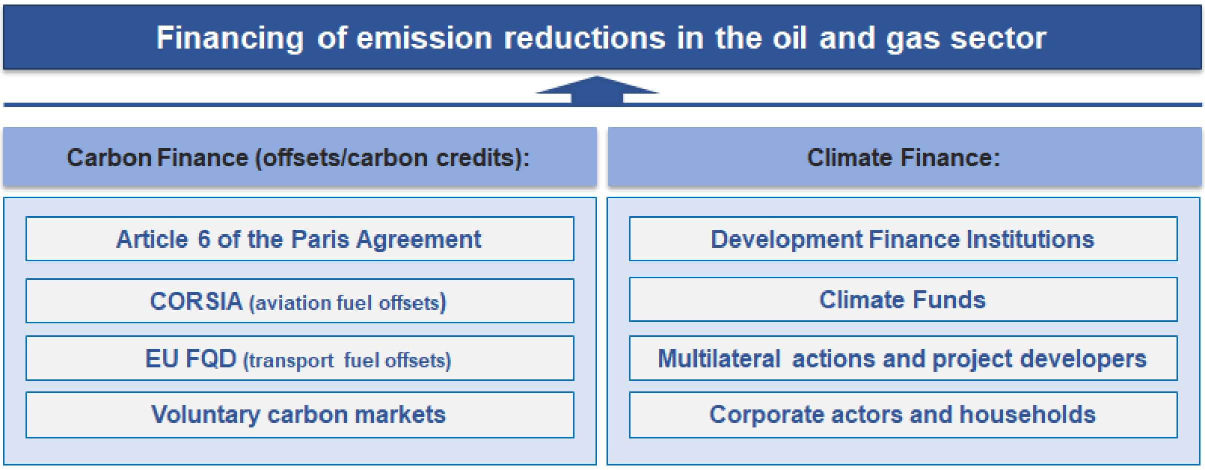
Carbon market mechanisms offer payment for emission reduction units as a commodity, thereby setting a price on carbon. They may be a part of a voluntary, or compliance carbon pricing scheme. Some of these mechanisms are discussed further below.

There are a large number of financing sources and schemes, with a summary of some of the main categories illustrated in **Figure 4.4**.

[124] See https://unfccc.int/topics/climate-finance/the-big-picture/introduction-to-climate-finance

Figure 4.4

Overview of carbon market mechanisms and climate finance sources



4.4.3 Carbon finance

The objective of **article 6 of the Paris Agreement** is to achieve higher ambitions in mitigation through voluntary cooperation. Paragraph 2 of the said article (i.e. Article 6.2) introduces the concept of "Internationally Transferable Mitigation Outcomes" (ITMOs), which means that Parties to the Agreement can, through cooperative approaches, transfer mitigation outcomes across borders and account for those transfers towards their respective NDCs. This implies that countries must make a strategic decision about whether to use emission reductions from mitigation activities to reach their own NDC goals, or whether to sell these reduction commitments to others. In other words, there is an "opportunity cost" to selling emission reductions. To ensure that emission reductions are used for one purpose only rather than double counted, a decision to transfer emission reduction units under Article 6.2 requires states to make "corresponding adjustments." Article 6.4 introduces a new international mechanism, which will have certain similarities with the CDM of the Kyoto Protocol, regarding transfer of GHG emission reduction units. There seems to be a common view, however, that the Article 6.4 mechanism must be simpler to operate than the CDM, which was plagued with onerous rules and procedures. Negotiations on rules and procedures for Article 6 were not concluded at COP24, and therefore those are still under negotiation. It should be noted that under the CDM a specific methodology for LDAR projects[125] had been developed and it was applied for 14 projects (all in distribution networks), which were successfully registered under the mechanism.[126] This methodology could become a useful reference and a starting point for further development of methane emissions projects under Article 6 of the Paris Agreement.

A UN specialized agency **International Civil Aviation Organization (ICAO)**, which is not directly linked to UNFCCC, has agreed with the international aviation industry to achieve zero growth in GHG emissions from 2020. A principal means to achieving that goal is through purchase of carbon credits/offsets through the CORSIA (Carbon Offsetting and Reduction Scheme for International Aviation) scheme. Rules and procedures are still under development, but the scheme should be operational by 2020. A first period from 2020 is voluntary for the industry

[125] https://cdm.unfccc.int/methodologies/DB/PZN9ZCTGF3KHFH0W21NY0NYL6X5CIR
[126] https://cdm.unfccc.int/Projects/projsearch.html

and may create a demand of 300-400 mill tons CO_2 eq. From 2026 onwards demand is expected to be considerably higher. It is not yet clear what sources of supply will be allowed, but so far there is no indication that reduction projects for methane emission from the oil and gas sector are to be excluded.

Another scheme outside the Convention and the Paris Agreement is the **Fuel Quality Directive's (FQD)**[127] offsets introduced by the European Union (EU) as a mechanism whereby which transport fuel suppliers in the EU can meet a part of their obligation to reduce the GHG intensity of supply by 6% from 2010 to 2020. Co-financing GHG emission reductions from upstream oil and gas sector activities is offered as an alternative or a complementary measure to the blending of biofuels. For example, fuel suppliers could co-finance methane emission reduction projects in Azerbaijan in exchange for using verified emission reductions. FQD is transposed into national law of all EU countries and it is to be operational from 2020. However, it currently appears that apart from Germany where it is expected to last until 2030, the scheme will be rather short-lived, staying in operation for one year only (2020).

There are also so-called **voluntary carbon market schemes**. They cover primarily sales of emission reductions to entities that voluntarily chose to reduce emissions using offsets. Projects and emission reductions are validated and verified according to voluntary standards, often by the same verification companies that are engaged in other carbon financing schemes. In this context, it has to be observed that oil and gas sector's emission reductions have been channelled to voluntary carbon markets only to a very limited extent.

This section highlighted the important role that the Paris Agreement can play in promoting methane mitigation action, particularly through NDCs and the international cooperation mechanism (Article 6). Article 6 of the Paris Agreement was established to "allow for higher ambitions in mitigation." [128] This is directly related to implementation of NDCs and the accounting procedures and guidelines contained in the Paris Agreement "Rulebook". As a result, in the context of international cooperation on methane emissions reductions, mitigation efforts are clearly interrelated with MRV requirements.

[127] For further information see http://ec.europa.eu/clima/policies/transport/fuel_en
[128] https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement

5. Conclusions and summary for policy makers

Oil and gas supplies will continue to play a key role in a future sustainable energy system to support economic growth and social progress, even under a scenario in which stringent climate policies and measures are implemented. In the end, the world's energy supply mix will be determined by the implemented policies and measures and by market competition wherein the costs and sustainability attributes of energy alternatives are the decisive factors. The enduring role of oil and gas requires an increased attention to methane emissions from the entire oil and gas value chain, from exploration and extraction to end use.

Methane emissions from the oil and gas sector's installations represent a waste of a valuable resource, have impact on air quality, and are a substantial contributor to climate change. Recent research shows that methane emissions are responsible for at least one fourth of man-induced global warming that we experience today. At the same time, the oil and gas sector's operations account for one fourth of the current global anthropogenic methane emissions, and according to certain projections they will increase significantly in the future.

In most countries it is technically and economically feasible to eliminate a large part of methane emissions from the oil and gas sector. Empirical studies suggest that almost 50% of such emissions can be reduced at no net costs. Furthermore, in most cases the costs of deeper reductions are also likely to be modest, as the required solutions are known and readily available. Nevertheless, a number of barriers, including lack of awareness and knowledge, have been hindering a full exploitation of that potential.

This document focuses on methane emissions and provides guidance for developing and implementing effective practices for their monitoring, reporting, and verification (MRV), as well as mitigation. The term MRV covers three categories of activities: i) quantifying emissions; ii) reporting of estimated emissions in specific formats; and iii) verification of emissions and/or emission reductions.

While MRV and mitigation are distinct activities, they are also closely related. Mitigation is most effective and cost-efficient when based on sound MRV practices. Furthermore, MRV and mitigation practices conducted at the facility and company level are often interrelated with those developed at the national level, as well as influenced by the international reporting guidelines, particularly those established under the Intergovernmental Panel on Climate Change (IPCC), and the United Nations Framework Convention on Climate Change (UNFCCC).

This document is meant to serve as a resource for a broad audience, including owners and operators of oil and gas facilities and policymakers at all levels of government. It strives to provide guidance for developing sound MRV practices, as well as effective and cost-efficient mitigation measures. It is intentionally "principles-based", recognizing that conditions vary greatly across oil and gas facilities, and that legal, political and institutional aspects differ by jurisdictions.

The key conclusions and principles from this document are as follows:

1. **There is considerable uncertainty about the level of methane emissions from the oil and gas operations**. National GHG inventory data reported to the UNFCCC are the main source of the global and country estimates of emissions of GHGs, including methane. The quality of methods and primary emissions data used for these estimates vary significantly by country. There are other (independent) estimates of the global, regional, and country emissions. Estimated emission levels from the independent sources often diverge, and countries and sector estimates produced by these sources can be twice or half the level of the official UNFCCC reports. Improving the practices for estimating national methane emissions methods and the quality of data are essential for enhanced methane emissions management.

2. **Quantification of methane emissions is difficult.** Unlike CO_2 emissions, methane emissions typically come from very large number of dispersed emission sources, which are often hard to detect. Quantification is only for a modest part based on measurement or continuous monitoring. Procedures should be in place to combine measurements with calculation-based methods. Technologies to assist in methane detection and measurement are readily available and should be adopted by companies and the authorities in their MRV activities.

3. **Oil and gas companies are making progress in quantifying and mitigating emissions.** Increasing recognition of methane management as important for resource efficiency and environmental protection has led a number of large companies to undertake an appropriate action, either unilaterally and/or through industry associations and public private partnerships. Knowledge and best practices are being shared, and results are gradually emerging. At the same time, many factors continue to hinder action in large parts of the industry. Lack of awareness and knowledge, as well as economic and regulatory barriers prevail and need to be addressed. Sharing best practices needs to be encouraged and continued.

4. **The Paris Agreement "Rulebook" calls for enhanced national MRV efforts.** Such efforts have a great potential to improve knowledge about the scale and nature of methane emissions, and thus to facilitate mitigation. In some countries a considerable support might be required to build institutional and technical capacity for reporting (biennially) on emissions and on the progress in mitigation efforts. For this purpose, a number of capacity building initiatives have been set up. Sharing knowledge and best practices, both nationally - between public institutions and companies, and internationally - between a broad set of institutions, is essential to succeeding on this task.

5. **Government attention, regulatory standards, economic instruments, and agreements between the industry and the national authorities can all be part of effective and cost-efficient policies to address methane emissions from the oil and gas sector.** Alike all policies and regulations of the oil and gas sector, those concerning methane emissions also vary substantially across different countries. They are typically part of broader national legal and regulatory structures, and as such they are rooted in distinct institutional

traditions and capabilities. For this very reason, a unified compendium of “best practices,” or a blueprint for regulation of methane emissions does not exist. Suitability of different approaches must be considered in light of national circumstances, including the nature of emissions and related infrastructure. Technological developments and improvements in MRV practises might offer new approaches to application of all above-mentioned categories of policy instruments.

6. **Enhanced methane emission reductions efforts can enhance countries’ efforts to meet Paris Agreement targets**. The significant, near term and cost-efficient mitigation impacts of methane emission can contribute to NDCs. In countries where methane has not been included in the NDC, there might be a value in adding it to the contribution. Such move, however, requires careful planning, as well as implementing appropriate mitigation policies and measures, supported by sound MRV practices. Several countries with large methane emission potentials might need support in developing capabilities and capacity required for MRV and mitigation planning activities. Furthermore, some countries might also be able to achieve more ambitious reduction through investment support. The latter would typically be granted based on documented results based on sound MRV methods and practices.

Annex 1 Emission source categories along the value chain

The following table lists 12 important sources of methane emissions along the oil and gas value chain.[129] For each emission sources, the following information are presented:

- A brief description of the emission sources.
- A list of typical mitigation techniques. In this context it is important to highlight that site-specific considerations needs to be taken into account when selecting a mitigation technique.
- A non-exhaustive list of links to further information (including in the footnotes);
- Applicable emission detection and quantification equipment: in many instances, these were based on the CCAC OGMP document "Conducting emission detection and quantification equipment." Other detection and quantification equipment, including emerging technologies (see **Annex 3** below) may be used in addition to those listed.
- Finally, typical quantification methodologies are presented based on existing inventories methodologies.[130] The resulting uncertainty varies significantly depending on the approach selected.

It should be noted that mitigation technologies, while reducing methane emissions, in some cases might have also some negative environmental impacts. For example, flaring instead of venting the gas increases CO_2, NO_x, and particulate matter emissions.

In addition, each mitigation technology typically has its own limitations that under certain conditions restrict their applicability to some emission sources. Additional information could be found in references provided under "Further Information" section in each table.

Emission source categories along the value chain			**P**	**G&P**	**T&S**	**D**
P: Production, G&P: Gathering and Processing, T&S: Transmission and Storage, D: Distribution						
1. Hydraulic fracturing & well completion			●			
Hydraulic fracturing is undertaken in hydrocarbon bearing sources to create pathways for hydrocarbons and water to flow into a wellbore. During this process gas may be entrained with water and hydrocarbon liquids from the wellbore during the flowback phase, as well as during production. The result is that significant volumes of gas can be vented into the atmosphere if no equipment is in place to separate the gas from the liquids & solids and to subsequently capture it.			 • Image Source: http://www.USGS.gov			
Mitigation Techniques: • Adopting "green completion" practices to capture gas during well completion and route flowback gas to fuel gas, sales gas, or flare rather than vent, up to 95% emission reductions achievable.			**Further Information:** http://www.ccacoalition.org/en/resources/technical-guidance-document-number-8-well-ventingflaring-during-well-completion			
Applicable emission detection equipment[131]	**Applicable Emission Quantification equipment**[132, 133]	**Typical quantification Methodologies**				

[129] The list build on the 9 core emissions sources defined in the CCAC OGMP Technical documents
[130] Including OGMP reporting guidelines, EPA GHG inventory approach etc.
[131] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[132] *Id.*
[133] Only emissions to release to air are measured by these equipments, not the pollutants entrained in the water.

• Optical Gas Imaging (to visualize the vent)	• Turbine Meter • Hotwire anemometer • Vane anemometer • Orifice meter	• Direct measurement and calculation methodology[134] • Default emission factors (e.g. Sm^3/completion/year or Sm^3/hr)

Emission source categories along the value chain	P	G&P	T&S	D
2. Casinghead venting from oil wells	●			
Casing Head gas can be built up in the annular wellbore space between the tubing and casing. In mature oil wells equipped with a beam pump or electric submersible pump, this gas can begin to restrict oil flow, thereby decreasing a well's production with vapor locking the pump. Combined with the backpressure of an oil well's surface equipment, the resultant pressure from casing head gas can severely restrict oil production. The gas pressure build-up in a well's annular space must therefore be removed to maintain production, and a common solution is to vent the casing head gas to the atmosphere or a flare at or near the wellhead.	 Image Source: http://www.weatherford.com			
Mitigation Techniques: • Install compressors/VRU to capture casinghead gas or connect casing to tanks equipped with VRUs or re-route casinghead gas to flare, up to 95% emission reductions achievable.	**Further Information:** http://www.ccacoalition.org/en/resources/technical-guidance-document-number-9-casinghead-gas-venting			

Applicable emission detection equipment[135]	Applicable Emission Quantification equipment[136]	Typical quantification Methodologies
• Optical Gas Imaging (to visualize the vent)	• Turbine Meter • Hotwire anemometer • Vane anemometer	• Direct measurement • Engineering calculation[137] • Default emission factors (e.g. Sm^3/well or Sm^3/event/year)

Emission source categories along the value chain	P	G&P	T&S	D
3. Liquids unloading from gas wells	●			
Many natural gas wells initially have sufficient reservoir pressure when completed to flow the formation fluids to the surface along with the produced gas. However, as gas production progresses and the reservoir pressure declines, the velocity of the fluid in the well tubing keeps decreasing. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface and the liquid droplets begin to accumulate in the tubing. This creates an additional pressure drop and significantly slows the gas velocity. As the bottom well pressure approaches the reservoir shut-in pressure, gas flow ultimately stops and the liquids accumulate at the bottom of the tubing. A common approach for wells that infrequently need unloading to temporarily restore flow is to vent the well to the atmosphere (well "blowdown"), which can produce substantial methane emissions.	 Image Source: CCAC			
Mitigation Techniques: • Install plunger lift system optimized to achieve minimal gas venting. • Install Smart Well technology to plunger lift systems, an automated system that determines when a plunger lift cycle needs to be actuated to determine optimally when liquids should be unloaded. • Add foaming agents, soap strings, surfactants to reduce velocity needed for the gas to carry liquids out of the well. • Install velocity tubing to reduce the cross-sectional area of the well, thereby increasing the velocity.	**Further Information:** http://www.ccacoalition.org/en/resources/technical-guidance-document-number-7-well-venting-liquids-unloading			

[134] Such as shown in 40 CFR Part 98.233 (g) (Mandatory Greenhouse Gas Reporting – Subpart W – Petroleum and Natural Gas Systems - Section 98.233 Calculating GHG Emissions. 40 CFR 98.233(g). http://www.ecfr.gov/cgi-bin/text-idx?SID=9db68a97576bb01eea9073c37d6f0e90&node=40:21.0.1.1.3.23&rgn=div6)

[135] From the CCAC OGMP document: Conducting emission detection and quantification equipment

[136] *Id.*

[137] An engineering calculation relies on a representative sample of well production taken with no casinghead gas venting. This may be more costly and less accurate than direct measurement, given the sampling method can affect the production rate and composition. From this sample a gas/oil ratio (GOR) may be determined. For mature wells, Partners should use the estimated well's producing GOR (scf/bbl or scm/bbl) multiplied by the production rate of oil per year (bbl/year) and the methane content of the gas to estimate annual methane emissions

Applicable emission detection equipment[138]	Applicable Emission Quantification equipment[139]	Typical quantification Methodologies
• Optical Gas Imaging (to visualize the vent)	• Turbine Meter • Hotwire anemometer • Vane anemometer	• Direct measurement • Engineering calculation[140] • Default emission factors (Sm^3/well or Sm^3/event/year)

Emission source categories along the value chain	P	G&P	T&S	D
4. Glycol dehydrators	●	●	●	

Glycol dehydrators in the natural gas industry remove water from an incoming wet gas stream using monoethylene glycol, diethylene glycol, or, most commonly, triethylene glycol. Glycol is pumped via a pneumatic or electric pump to a gas contactor where it mixes with the natural gas stream. Resulting emissions are highly dependent on how a unit is configured and operated, but the two potential emission points are the flash tank overhead gas and the regenerator vent off-gas. Dehydrating the gas is necessary in some settings to meet pipeline specifications designed to maintain pipeline integrity.

Image Source: MESSCO

Mitigation Techniques:

- Install flash tank separator and optimize glycol circulation rates, up to 90% emission reductions achievable.
- 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.
- Replacing by zero emissions dehydrators, up to 100% emission reductions achievable.[141, 142]
- Desiccant dehydrators, up to 90% emission reductions.
- Reroute glycol skimmer gas, up to 95% emission reductions achievable.
- Replace the gas assist lean glycol pump with an electric lean glycol pump, up to 100% emission reductions from the pump achievable.

Further Information:
http://www.ccacoalition.org/en/resources/technical-guidance-document-number-5-glycol-dehydrators

Applicable emission detection equipment[143]	Applicable Emission Quantification equipment[144]	Typical quantification Methodologies
• Optical Gas Imaging (to visualize the vent)	• Vane Anemometer • Hotwire Anemometer • Turbine meter	• Direct measurement (but challenging) • Engineering calculation with software • Default emission factors (e.g. Sm^3/MM Sm^3 throughput/year)

Emission source categories along the value chain	P	G&P	T&S	D
5. Natural gas driven pneumatic controllers and pumps	●	●	●	

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. Natural Gas driven control devices emit CH_4 both through continuous bleeding and during actuating. Emissions vary greatly depending on the design, the working pressure, type and conditions of the instrument, and frequency of actuating. Some controllers (continuous bleed) will have emissions dominated by bleeding while others (intermittent vent) will be a result of actuations. In addition, when operating not as designed, intermittent vent pneumatic controller loops and pneumatic pumps can emit gas due to a defect or maintenance issue.

Image Source: CCAC

[138] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[139] *Id.*
[140] Ref for example to API, ANGA. Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Sept 21, 2012. Retrieved from: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf
[141] Based on a 1 MMcfd dehydrator operating at 450 psig and 47°F, and the difference between methane vented from the glycol and desiccant dehydrators.
[142] https://www.epa.gov/sites/production/files/2016-06/documents/ll_desde.pdf
[143] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[144] *Id.*

Mitigation Techniques:	Further Information:
• Replacement or retrofit from high bleed to low bleed devices, up to 97% emissions. reductions achievable. Devices should be inspected and maintained on a regular basis. • Ensure intermittent bleed controller emits according to the specifications. • Replace with non-methane emitting controller.[145] • Routing emissions to an existing combustion device or vapor recovery unit, up to 95% emission reductions achievable. • Converting pumps and/or controllers to electric or solar powered. • Converting gas pneumatic controllers to mechanical controllers.	http://www.ccacoalition.org/en/resources/technical-guidance-document-number-1-natural-gas-driven-pneumatic-controllers-and-pumps http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf

Applicable emission detection equipment[146]	Applicable Emission Quantification equipment[147]	Typical quantification Methodologies
• Optical Gas Imaging • Laser leak detector	• Calibrated Vent Bag • High volume sampler (ideally altered to capture 1-2 second data) • Upstream flow meter in the supply gas line	• Direct measurement • Manufacturer estimate (should be used with caution) • Engineering estimates using a specified formula[148] • Default emission factors (in Sm^3/device/year) depending on the type of equipment

Emission source categories along the value chain	P	G&P	T&S	D
6. Wet-seal centrifugal compressors	●	●	●	

In wet seal centrifugal compressors, high-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is entrained by the oil. The seal oil is purged of the entrained gas (using heaters, flash tanks, and degassing techniques) and recirculated. The gas purged is commonly vented to the atmosphere. The mechanical dry seal system is an alternative to the traditional wet seal. Using high-pressure gas to seal the compressor, dry seals result in much lower levels of emissions compared to the wet seals.	 Image Source: Siemens.com
Mitigation Techniques: • 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. • Convert compressor wet seals to dry seals.	**Further Information:** http://www.ccacoalition.org/en/resources/technical-guidance-document-number-3-centrifugal-compressors-%E2%80%9Cwet%E2%80%9D-oil-seals http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-compressors.pdf

Applicable emission detection equipment[149]	Applicable Emission Quantification equipment[150]	Typical quantification Methodologies
• Optical gas Imaging (to visualize the vent)	• Vane Anemometer • Hotwire Anemometer • Turbine meter • High volume sampler (when vent flowrate is low)	• Direct measurement[151] • Default emission factors (in Sm^3/compressor/year) depending on the type of compressor

[145] http://www.catf.us/resources/publications/files/Zero_Emitting_Pneumatic_Alternatives.pdf
[146] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[147] *Id.*
[148] For intermittent vent controllers in on/off service the same volume of gas is vented and this volume per actuation (Volscf) can be calculated by equations as per the CCAC document under *further information*. This approach requires a count of actuations for each device in order to calculate annual emissions. Therefore, an estimated number of actuations per year must be developed employing onsite knowledge. If the process is highly variable or cyclic throughout the year, estimation of the number of actuations per year can be inaccurate. Throttling intermittent controllers do not lend themselves to engineering estimates because the bonnet volume and the frequency of actuation are both highly variable.
[149] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[150] *Id.*
[151] If the vent line does not have an in-line flow meter or a measurement port for insertion of a measurement device such as an anemometer

Emission source categories along the value chain	P	G&P	T&S	D
7. Reciprocating rod-packing compressors	●	●	●	

Though there is a number of leaking points, the highest volume of gas loss within the reciprocating compressors is associated with piston rod packing systems, which are the components ensuring the sealing of the compressed gas. Piston rod packing consists of series of cups containing several seal rings side by side, held together by a spring installed in the groove running around the outside of the ring. Considerable leak reduction could be achieved by periodic replacement packing rings and, in some cases, the piston rods.[152]

Image Source: MESSCO

Mitigation Techniques:

- The regular replacement of rod packing, 50-65% emission reductions achievable.
- 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.

Further Information:

http://www.ccacoalition.org/en/resources/technical-guidance-document-number-4-reciprocating-compressors-rod-sealpacking-vents

http://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-compressors.pdf

Applicable emission detection equipment[153]	Applicable Emission Quantification equipment[154]	Typical quantification Methodologies
• Optical gas Imaging (to visualize the vent)	• Vane Anemometer • Hotwire Anemometer • Turbine meter • Calibrated Vent Bag • High volume sampler • Orifice meter (vent flow measurement device)	• Direct measurement[155] • Default emission factors (in Sm^3/compressor/year or Sm^3/cylinder/year) depending on the compressor conditions[156, 157, 158, 159]

Emission source categories along the value chain	P	G&P	T&S	D
8. Venting of associated gas at upstream oil production facilities	●			

The venting of associated gas at oil production facilities is the discharge or disposal of gases produced as a by-product at oil production facilities. The gases are released directly and unburned into the atmosphere where there is inadequate infrastructure for the possibility of economical utilization of this gas. Venting of associated gas can also occur during gas flaring when a gas flare fails to ignite or is shut down and the associated gas is released unburned into the atmosphere.

Image Source: TZN Petroleum

Mitigation Techniques:

- Flaring gas without energy recovery, up to 98% methane emission reductions achievable.[160]
- Capturing vent gas for gas utilization, emission reductions up to 100% at location.[161]

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[152] This source is mitigated either through replacement on a schedule or through measurements to confirm emissions are not excessive (with replacement if that occurs).

[153] From the CCAC OGMP document: Conducting emission detection and quantification equipment

[154] *Id.*

[155] If the packing vent does not have an in-line flow meter or a measurement port for insertion of a measurement device such as an anemometer

[156] The emission factor is a composite of the methane emission factor per cylinder and the average number of cylinders for compressors in the sector. The number of average cylinders varies and is detailed in EPA/GRI. Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Appendix B.

[157] A factor of 150% should be applied to default operating emission factors for standby under pressure factors. https://www.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf

[158] The emission factor is a composite of the methane emission factor per cylinder and the average number of cylinders for compressors in the sector. The number of average cylinders varies and is detailed in EPA/GRI. Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Appendix B.

[159] A factor of 150% should be applied to default operating emission factors for standby under pressure factors. https://www.epa.gov/sites/production/files/2016-06/documents/ll_compressorsoffline.pdf

[160] Gas flaring results of course in significant CO2 emissions.

[161] Other emissions points may appear on the utilization route.

Applicable emission detection equipment[162]	**Applicable Emission Quantification equipment**[163]	**Typical quantification Methodologies**
• Optical gas Imaging (to visualize the vent)	• Vane Anemometer	• Direct measurement • Site specific emission factor based on past measurement (in % of throughput) • Estimation of gas flare/vent volumes based on Gas-to-oil ration (GOR)

Emission source categories along the value chain	**P**	**G&P**	**T&S**	**D**
9. 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, typically representing a large share of the total emissions), 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.
During loading and unloading (transfer) activities[164] 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.

Image Source: Intechww.com

Mitigation Techniques:
- Installing a Vapor Recovery Unit (VRU) and directing to productive use as fuel gas, compressor suction, gas lift, emission reductions of up to 98%.
- Reducing operating pressure upstream.[165]
- 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).
- 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).
- 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.

Further Information:
Hydrocarbon liquid storage tanks:
http://www.ccacoalition.org/en/resources/technical-guidance-document-number-6-unstabilized-hydrocarbon-liquid-storage-tanks

Applicable emission detection equipment[166]	**Applicable Emission Quantification equipment**[167]	**Typical quantification Methodologies**
• Optical gas Imaging • Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs)	• Turbine Meter • Calibrated vent bag* • Vane anemometer* • Hotwire anemometer*	• Direct measurement in conjunction with vent gas composition analysis[168] • Estimation method through calculation with software (AspenTech HYSYS, E&P TANKS)[169] • Lab analysis of hydrocarbon liquid • Emission factors (e.g. Sm^3/bbl depending on the type of tank)

[162] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[163] *Id.*
[164] This source of emission is composed mainly of nmVOC
[165] Also applies to methane emissions from water discharge (reducing to the lowest pressure possible before discharge)
[166] From the CCAC OGMP document: Conducting emission detection and quantification equipment
[167] *Id.*
[168] However, standing and working losses are less accurately quantified by direct measurement and with changes in crude oil from multiple wells.
[169] In addition, emissions from scrubber dump valve need to be estimated

<table>
<tr><th colspan="2">Emission source categories along the value chain</th><th>P</th><th>G&P</th><th>T&S</th><th>D</th></tr>
<tr><th colspan="2">10. Equipment depressurization and blowdowns from pipelines and facilities</th><td>●</td><td>●</td><td>●</td><td>●</td></tr>
<tr><td colspan="2">The term gas blowdown refers to the venting of gas accumulated in equipment, process facilities, and pipelines. During equipment depressurization and blowdown, gas is released from a pipeline or other equipment and facilities prior to maintenance or in the case of emergency shutdown. In the case of a pipeline blowdown for example, the amount of methane released is related to the diameter of the pipe, the pressure of the gas in the pipe, and the length of the section that is blown down. The amount of methane released from general equipment depressurization is extremely variable.</td><td colspan="4">
Image Source: Pipeliner Channel</td></tr>
<tr><td colspan="2">Mitigation Techniques:
• Lower pressure in the pipeline prior to event through a mobile compressor stations (for pipeline repairs).
• Install plugging equipment to shorten segment of pipeline involved in outage.
• Use isolation valves to minimize impact.
• Re-direct gas into storage vessel (field) or low-pressure header (fuel gas or gathering system).
• 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.
• Recompression using mobile compressor stations instead of venting.</td><td colspan="4">Further Information:
http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf</td></tr>
</table>

<table>
<tr><th>Applicable emission detection equipment[170]</th><th>Applicable Emission Quantification equipment[171]</th><th>Typical quantification Methodologies</th></tr>
<tr><td></td><td>(When the blowdown is purged through a vent stack or pipe):
• Vane Anemometer
• Hotwire Anemometer
• Turbine meter
• Calibrated Vent Bag</td><td>• Direct measurement (but difficult)
• Engineering calculation based on isolation volume
• Emission factors (Sm^3/event depending on the type of event) – only relevant for some components</td></tr>
</table>

<table>
<tr><th colspan="2">Emission source categories along the value chain</th><th>P</th><th>G&P</th><th>T&S</th><th>D</th></tr>
<tr><th colspan="2">11. Component and equipment leaks</th><td>●</td><td>●</td><td>●</td><td>●</td></tr>
<tr><td colspan="2">The potential variety of components or sources of unintentional emissions from operations at oil and gas installation and operations include flanges, screw and compression fittings, stem packing in valves, pump seals, compressor components, and through-valve leaks in pressure relief valves, tubing fittings, hatches, meters, open-ended lines and improperly operated storage tanks. Leaks can be found along the full gas value chain, including in upstream facilities, processing plants, compressor stations, metering stations, and along gas pipelines.

This category also includes unintended emission due to e.g. excavating pipelines or plugged / abandoned wells which can also represent a source of gas leakage (and require different mitigation than traditional LDAR). Methane emissions from equipment designed to vent as part of normal operations, such as gas-driven pneumatic controllers, are not considered leaks.</td><td colspan="4">
Image Source: EDF.org</td></tr>
<tr><td colspan="2">Mitigation Techniques:
• Leak detection and repair (LDAR), variable emission reductions - Direct Inspection and Maintenance (DI&M).
• Re-working the plugging or just properly plugging) wells.</td><td colspan="4">Further Information:
http://www.ccacoalition.org/en/resources/technical-guidance-document-number-2-fugitive-component-and-equipment-leaks

Plugged / abandoned wells:
http://www.pnas.org/content/pnas/113/48/13636.full.pdf</td></tr>
</table>

<table>
<tr><th>Applicable emission detection equipment[172]</th><th>Applicable Emission Quantification equipment[173]</th><th>Typical quantification Methodologies</th></tr>
<tr><td>• Optical gas Imaging
• Laser leak detector
• Soap Bubble Screening</td><td>• Calibrated Vent Bag
• High volume sampler</td><td>• Leak screening and direct emission rate measurement or leaker emission factor application
• Emission factors per component (in Sm^3/component equipment) or per throughput[174]
• Hyperspectral/multispectral detectors</td></tr>
</table>

[170] From the CCAC OGMP document: Conducting emission detection and quantification equipment

[171] *Id.*

[172] From the CCAC OGMP document: Conducting emission detection and quantification equipment

[173] Same as above

[174] An annual volume of methane emissions is calculated by multiplying the estimated or measured methane emissions flow rate by half the operating hours of a piece of equipment between the last leak survey that found

<table>
<tr><td>Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs)
Acoustic Leak Detection (for through-valve leaks)</td><td></td><td></td></tr>
</table>

<table>
<tr><th colspan="3">Emission source categories along the value chain</th><th>P</th><th>G&P</th><th>T&S</th><th>D</th></tr>
<tr><td colspan="3">12. Incomplete combustion (including Associated petroleum gas (APG) flaring, engines, turbines, fired heaters)</td><td>●</td><td>●</td><td>●</td><td></td></tr>
<tr><td colspan="3">Methane emissions result from the incomplete combustion of natural gas, which allows some of the methane in the fuel to be emitted with the exhaust stream. While it is a small percentage, it can represent a significant source of emission in aggregate, especially in gas engines which emit 40 to 150 times more methane than gas turbines. Methane emissions from APG flares are the result of incomplete combustion of the waste gas. A number of external parameters including gas composition, gas velocity, wind velocity, atmospheric pressure and relative humidity play a significant role in affecting the combustion efficiency.[175]</td><td colspan="4">
Image Source: Sparrows group</td></tr>
<tr><td colspan="3">Mitigation Techniques:
Increase combustion efficiency by upgrading to more efficient engines/turbines.
Flaring: Increase gas utilization, improve combustion efficiency (Changing flare tip, Install flare ignition systems)[176]</td><td colspan="4">Further Information:
https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_1_Ch1_Introduction.pdf
https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf

https://inis.iaea.org/search/search.aspx?orig_q=RN:36034943

https://www.nyserda.ny.gov/-/media/Files/EERP/Commercial/Sector/Municipal-Water-Wastewater-Facilities/flare-efficiency-estimator.pdf

https://globalmethane.org/documents/events_oilgas_20081203_oilgas-5Dec08_johnson.pdf</td></tr>
<tr><td>Applicable emission detection equipment[177]</td><td>Applicable Emission Quantification equipment[178]</td><td colspan="5">Typical quantification Methodologies</td></tr>
<tr><td>Aerial measurement</td><td>Direct quantification difficult</td><td colspan="5">Engineering calculation based on fuel or flaring volumes
Video Imaging Spectro-Radiometry (VISR)[179]</td></tr>
</table>

the component not leaking and the time when a leak is found and repaired. Operators can use a default factor of 12 months for estimating leak quantity.

[175] More information: https://carbonlimits.no/project/assessment-of-flare-strategies-techniques-for-reduction-of-flaring-and-associated-emissions-emission-factors-and-methods-to-determine-emissions-to-air-from-flaring/

[176] See more information: https://carbonlimits.no/project/assessment-of-flare-strategies-techniques-for-reduction-of-flaring-and-associated-emissions-emission-factors-and-methods-to-determine-emissions-to-air-from-flaring/

[177] From the CCAC OGMP document: Conducting emission detection and quantification equipment

[178] Id.

[179] US EPA Environmental Workforce and Innovation, March 2017

Annex 2 Mature detection and quantification technologies

This Annex presents a very brief overview of various methane detection and/or quantification technologies that currently available. The overview is primarily based on Climate and Clean Air Coalition's Technical Guidance Document and the EPA's Natural Gas Star Program.[180, 181]

<table>
<tr><th colspan="2">Table 1: Mature detection equipment</th></tr>
<tr><th colspan="2">1. Optical Gas Imaging (Infrared Cameras)</th></tr>
<tr><td>

Technology

OGI infrared cameras are able to detect the presence of methane emissions from components and equipment at oil and gas facilities. Hydrocarbon emissions absorb infrared (IR) light at a certain wavelength and an IR camera uses this characteristic to detect the presence of hydrocarbon gas emissions from equipment at an oil and gas facility. The IR camera operator scans the leak area in real time (user selectable for cold/hot temperature environments). This scanned area is viewed as a live, black and white image such that the gas plumes are visible on the camera display due to their absorption of the IR light. IR cameras detect a wide variety of hydrocarbon compounds, not just methane, and therefore a knowledge of which streams and piping or vessel components contain a significant methane content is necessary to identify the leaks subject to this source category. Also, steam plumes diffract IR light, and appear the same as a hydrocarbon gas plume in the IR camera. The camera operator can easily distinguish between a steam plume (visible to the eye as a white plume) and a hydrocarbon gas (not visible to the eye).

Operation / Detection
OGI Cameras can be hand-held or remotely operated from ground-mounted installations or through mobile deployment (vehicular & aerial). Hand-held units are however well suited to field surveys and considered a recommended detection method for a broad range of components, hence are most practical for identifying exactly the leak sources, so that repairs can be properly directed. The camera is simple to use with point and detect features. An operator can scan the leak area in real time by viewing a live image of visible gas plumes on a screen. Several hand-held models also come equipped with recording capabilities for later analysis.

</td><td>

Handheld Infrared Optical Gas Imaging Camera

Image Source: Carbon Limits[182]

Investment Costs
approx. $85,000 - $115,000 for handheld versions

</td></tr>
<tr><td>Method of Usage:</td><td>Generally simple to operate, especially handheld versions that are used at an optimal distance of one to three meters from the source of leak to actually see the leak point. Remotely operated versions from mounting poles or for mobile deployment (vehicular & aerial) also available but must have line of sight to emission sources.</td></tr>
<tr><td>Applicability:</td><td>Leaks and vents of all sizes, typically scans at a distance up to 200 meters away (small leaks can be detected only from short distance).[183] A wide variety of compounds, including steam, can be detected using OGI cameras (not just methane) and knowledge of equipment may be required to specifically identify methane leaks.</td></tr>
<tr><td>Detection Speed:</td><td>Scans area in real time, capable of 100`s of components / hour.</td></tr>
<tr><td>Climatic Constraints:</td><td>Generally applicable for hot and cold environments, however, climatic conditions affect the detection efficiency (temperature, wind & humidity).[184]
Darkness could be a limitation, although cameras are typically equipped with lamps.</td></tr>
<tr><td>Safety Concerns:</td><td>Generally considered safe, however, some cameras are not certified intrinsically safe if hydrocarbon presence is significant (battery exposure).</td></tr>
<tr><td>Service Requirements:</td><td>No calibration required (regular service recommended by vendors).</td></tr>
<tr><td>Cost Considerations:</td><td>High initial purchase price and labor costs.</td></tr>
</table>

[180] http://www.ccacoalition.org/en/file/3385/download?token=vTrJd-N5
[181] https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf
[182] Image source: Carbon Limits measurement campaign
[183] https://ngi.stanford.edu/sites/default/files/acs.est_.6b03906.pdf
[184] *Id.*

2. Laser Leak Detector

Technology

Laser leak detectors are proven tools for locating methane emission sources in the oil and gas industry. A popular detector is the Remote Methane Leak Detector (RMLD), which uses a tunable diode-infrared laser that is tuned to a frequency which is specifically absorbed by methane. As the laser beam from an RMLD device passes through a gas plume (and is reflected back to the camera) it will detect if methane is present in the beam path by comparing the strength of the outgoing and reflected beams.

Operation / Detection

An operator points the RMLD device towards the equipment or general facilities from a distance along the sight line. The laser beam must have a reflective surface no more than 110 feet (30 meters) from the RMLD with the leak source between. Unlike the Leak Imaging IR cameras, the RMLD cannot detect a leak against the sky or distant backgrounds. The device uses an invisible infrared laser to detect the presence of methane coupled with a visible green spotter laser to help the operator to confirm the emission source which is being pointed at. The operator turns the device on and off by suppressing a trigger button on the device. As the IR beam is being reflected back to the instrument receiver it is collected by the RMLD and the signal is processed into a methane concentration in parts per million per meter (ppm-m) of beam path length. As the instrument does not indicate where in the laser beam path the gas plume occurs, the typical operating technique is to direct the laser beam from different angles to try and identify single plumes and their origin (leak point).

Laser Remote Methane Leak Detector

Image Source: Heath Consultants Inc[185]

Investment Cost
approx. $15,000

Method of Usage	Generally simple to operate, especially handheld versions, however require a background surface to reflect back laser beam (not applicable for open fields).[186] Available in remotely operated models with mounting poles or through mobile deployment (vehicular & aerial) - with automated alarm upon detection.
Applicability	Useful for detecting methane leaks originating from hard-to-reach sources or throughout difficult terrain. Allows the detection of methane in the beam path up to a distance of approximately 30m. Specifically tuned to detect methane and does not give a false reading for other hydrocarbons (low cross-sensitivity[187, 188]).
Detection Speed	Unit responds almost instantaneously, quickly scans area in real time and can cover large open areas, reducing the time spent on searching for leaks (as well as manpower), capable of 100`s of components/ hour.
Climatic Constraints	Applicable for most conditions (-17 C to 50 C, 5 to 95% relative humidity)
Safety Concerns	Safe method of leak detection; measurements can be made remotely, keeping operators out of harm`s way. Most models certified intrinsically safe.[189]
Service Requirements	Calibration is minimal.[190] Most models feature built-in self-test and calibration function which verifies operation and adjusts laser wavelength for maximum sensitivity.[191, 192]
Cost Considerations	Relatively low-cost solution for methane leak detection, but high labor costs.

[185] Image source: Turkmenistan Symposium on Gas Systems Management - Methane Mitigation, Ashgabat, Turkmenistan, April 26, 2010: “Methane Leak Detection and Measurement Technologies,” presented by Heath Consultants Inc.
[186] https://thehazmatguys.com/thmg141-laser-methane-detectors/
[187] *Id.*
[188] Nevertheless, limited testing on cross sensitivity to other hydrocarbon species is performed, and thus recommended to detect presence of methane and not quantification.
[189] http://www.hetek.com/wp-content/uploads/RMLD-Brochure.pdf
[190] https://thehazmatguys.com/thmg141-laser-methane-detectors/
[191] http://www.hetek.com/wp-content/uploads/RMLD-Brochure.pdf
[192] Calibration is different from servicing, which refers to how often the device would need to be sent into the vendor for inspection or the lifetime of the technology.

3. Soap Bubble Screening

Technology

Soap bubble screening is a simple but relatively time-consuming process to detect methane or other gas leaks from smaller components. It uses the surface tension of soap bubbles applied on a suspected leak to detect gas leakages.

Operation / Detection

A combination of soap and water is applied onto small and accessible components such as flanges, valves, fittings and threaded connections. Bubbles will form on the surface in the presence of a leak and can be observed visually.

This is not a methane specific technology. It shows that gas is bubbling out, so presence of methane in the stream should be known to the operator.

This solution is commonly used to check that a repair is effective.

Soap Bubble Screening

Image Source: TransCanada[193]

Investment Cost
under $100

Method of Usage	Generally simple to and quick method, manual applicable of solution.
Applicability	Effective for locating loose fittings and connections which can typically be eliminated on the spot, however not effective on large openings such as open-ended pipes or vents. Not effective for hard to reach components
Detection Speed	Depending on man-power and facilities / component accessibility, around 1 fitting or connection every few minutes. Bubbles appear within seconds of application in case of leak detected.
Climatic Constraints	Cannot be used on equipment above the boiling point of water or below freezing temperature.
Safety Concerns	Generally considered safe.
Service Requirements	N/A
Cost Considerations	Relatively low capital-intensive solution for methane leak detection, however, labor intensive.

4. Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs)

Technology

OVAs and TVAs are portable hydrocarbon detectors which can effectively be used to detect methane leaks.[194] The devices consist of a flame ionization detector (FID) which is sensitive to methane and a range of other hydrocarbons, and which is typically capable of measuring organic vapor concentrations ranging from 9 to 10000 ppm. TVAs combine a FID with a photoionization detector (PID), which is sensitive to other hydrocarbons but insensitive to methane, to measure the total organic vapor concentrations over 10,000 ppm. If the upper measurement limit of the TVA is 10,000 ppm, a dilution probe can be used to detect screening concentrations up to 100,000 ppm.[195]

The response factor varies based on the hydrocarbon mixture, thus the response to methane is not inherently greater than other hydrocarbons unless methane is the dominant species in the gas phase being detected.

Operation / Detection

Screening using these devices is performed by placing the suction probe in close proximity (no more than 1cm) of a seal or opening where a methane leak can occur. The OVA or TVA suck in the air and measures the concentration of combustible hydrocarbons as the device is slowly moved along the opening or seal.

Once a maximum concentration reading is determined the device records a leak screening value (in ppm) for the component being tested. This reading is typically compared to a repair threshold (i.e. 500 ppm, 10,000 ppm, etc.) to designate components above the threshold for repair.[196]

OVA / TVA Screening

Image Source: UNEP[197]

Investment Cost
under $10,000[198]

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[193] Image source: Natural Gas STAR Technology Transfer Workshop, Houston, Texas, September 22, 2004: "Methane Emissions Management at TransCanada Pipe Lines," presented by TransCanada
[194] Also called "sniffers" because they suck air into the instrument through a wand or tube
[195] Directed Inspection and Maintenance at Gate Stations and Surface Facilities
[196] OVA or TVA do not quantify the gas emission, only the concentration of combustible hydrocarbon in air sucked into the probe. To quantify emissions, there are default emission factor tables based on different screening techniques, e.g. SOCMI emission tables.
[197] Image source: CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP
[198] EPA. Lessons Learned: Directed Inspection and Maintenance at Compressor Stations. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimcompstat.pdf

Method of Usage	Manual operation requiring an operator to test each component. No remote capabilities.
Applicability	Particularly effective with fittings and connections, however, not effective on large openings such as open-ended pipes or vents. Not effective for hard to reach components and required direct access to the emission point. Errors can occur in pinpointing exact leak points in adjustment leaking components.
Detection Speed	Depending on man-power and facilities / component accessibility, around 1 fitting or connection every few minutes. Quick response time, however overall relatively slow, operators can survey approximately 40 components per hour.[199]
Climatic Constraints	Cannot be used below freezing point (temperature range of 0 C to 50 C).[200]
Safety Concerns	Operator required to be directly next to emission source for detection.
Service Requirements	Requires frequent calibration.
Cost Considerations	Relatively low capex solution for methane leak detection, however, limited applicability and labor intensive, and may require high cost software and tagging.

5. Acoustic Leak Detection

Technology

Acoustic leak detectors capture the acoustic signal of pressurized gas escaping a valve plug or gate that is not tightly sealed. These detectors come in both a «gun» style that detects leaks from a distance, or «stethoscope» style that detects internal leaks through a valve plug or gate. They can detect either low or high frequency audio signals and are useful for detecting internal through valve leaks or airborne ultrasonic signals from blowdown valves and pressure relief valves (ultrasonic signals at a frequency of 20 - 100 kHz). Most detectors typically have frequency tuning capabilities which allow the sensor to be tuned to the specific leak.

Operation / Detection

Acoustic leak detectors are generally equipped with a handheld sensor which is pointed at a possible leak source. To detect a signal, an operator places the acoustic sensor directly on the tested equipment and the intensity reading will reflect whether a through valve leak has been detected. The operator can also gain a relative idea of a leak´s size as a louder reading will generally indicate a higher leak rate.[201] For airborne ultrasonic signals, an ultrasonic leak detector is pointed at a possible leak source up to 30 meters away and by listening for an increase in sound intensity through the headphones.[202] Ultrasonic leak detectors can also be installed on mounting poles typically around 2 m above the ground around a facility and send a signal to a control system indicating the onset of a leak.

Acoustic leak screening

Image Source: UNEP[203]

Investment Costs
$1,000 - $20,000 depending on instrument sensitivity, size, and any associated equipment or associated parts[204]

Method of Usage	Manual operation requiring an operator to test each component with handheld units. Available in remotely operated models on mounting poles (with automated alarm upon detection).
Applicability	Particularly useful for internal valve leakage and pressurized gas. Not as useful for smaller leaks or low-pressure gas (150 psi is required for ultrasonic leak detectors).[205]
Detection Speed	With handheld models, speed depends on man-power. Automated pole-mounted systems are available with rapid response speed and will sound alarm instantly upon detection.
Climatic Constraints	Sensitive to background noise, however, can be tuned to specific frequencies of a leak.
Safety Concerns	Handheld units may require operator to be in close proximity of gas leak, pole-mounted systems don’t require operator in the vicinity of equipment.
Service Requirements	No routine calibration required.
Cost Considerations	Relatively low capex solution for methane leak detection, however, limited applicability and labor intensive with hand-held unit.

[199] *Id.*
[200] https://www.enviroequipment.com/rentals/thermo-tva-1000-fidpid-rental
[201] Certain models have correlation tables to quantify internal leaks through valves.
[202] EPA. Lessons Learned: Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations. June 2016. https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgasproc.pdf
[203] Image source: CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: “Fugitive Equipment and Process Leaks,” presentation by UNEP
[204] *Id.*
[205] http://s7d9.scene7.com/is/content/minesafetyappliances/07-8313-MC_UltrasonicGasLeakDetectWP

6. Spectrometer Sensors

Technology

Spectrometer sensors are able to detect large methane concentrations from the air by measuring the infrared wavelengths of reflected sunlight in the range that has been absorbed by methane molecules in the air.

Operation

A sensor is typically flown from fixed wing or rotary aircraft and can rapidly spot the sources of methane emissions over large areas. It simultaneously collects optical images to allow positive identification of a region where emissions are occurring. Dependent on the platform on which it is deployed, and the chosen technology, up to 800km of pipeline or 30,000 acres of wells can be surveyed in a single day, drastically reducing time required for inspecting large areas and pipelines. The sensors detect only larger methane emissions from the air and overlay them with a map using GPS coordinates to provide an aerial overview of larger methane emission leaks over a larger area or longer distance.

Spectrometer screening

Image Source: Kairos Aerospace[206]

(Investment) Cost

High cost and depends on several factors including location and aerial extent surveyed

Method of Usage	Screening requires spectrometer sensor to be attached to aircraft and flown over surveying area.
Applicability	Particularly useful to cover large areas quickly and identify large emissions sources. Also useful for surveying pipelines over a long distance. Reduces the requirement for manual labor-intensive detection screening to identify large leaks. Not useful for smaller leaks and cannot detect specific emission sources that may make up the total facility emissions.
Detection Speed	Can cover large areas quickly, and effectively reduce the screening time per facility. However, data analysis may take up to a week after surveys are conducted.
Climatic Constraints	Can be constrained by sunlight required for spectrometer and favorable weather for aircraft operation.
Safety Concerns:	Aircraft needs to be flown directly over oil and gas facilities.[207]
Service Requirements:	N/A (service providers)
Cost Considerations:	May provide maximum impact for surveying large areas for methane emissions, nonetheless, an expensive method for screening for methane leaks.

[206] Image source: http://kairosaerospace.com/methane-detection/
[207] http://kairosaerospace.com/methane-detection/

Table 2 Mature quantification equipment

1. Calibrated Vent Bag / Bagging

Technology Calibrated vent bags (also known as calibrated volume bag) are non-elastic bags of calibrated volume when fully inflated, made from antistatic plastic with a neck shaped for easy sealing around a leak or vent pipe. **Measurement** Measurement is made by timing the bag expansion to full capacity with a stopwatch. The temperature of the gas is measured to allow correction of volume to standard conditions. Additionally, gas composition should be analyzed to determine the methane content of the vented gas because in some cases air may also be entrained in the vent, resulting in a mixture of gas and air.	**Calibrated vent bag operation**  Image Source: Carbon Limits[208] **Investment Cost** Approximately \$50 each[209]
Method of Usage	Operator manually places vent bag around a vent pipe and rate is measured by operator directly at source. Stop-watch and manual measurement of gas temperature also required at source.
Applicability	Requires safe access to emission source and useful for quantifying large methane leaks/vents ranging from 17m^3 / hour to 408 m^3 / hour with an accuracy of +/- 10%.[210] Not suitable for smaller emission points.
Quantification Speed	Requires operator to record the time required to fill the vent bag using a stop-watch. Not time efficient and only capable of quantifying a few leaks per hour.
Climatic Constraints	Can measure over a range of 0°C to 49°C, difficult to use in adverse weather conditions, particularly windy conditions.[211]
Safety Concerns	Requires operator to be located in close proximity and "hands-on" the leak.
Service Requirements	Not required, vent bag can be used approximately 100 times if handled with care.
Cost Considerations	Low cost method, approximately US\$ 50 purchase cost per bag and available in various sizes, main expense lies in labour cost (usually 2 operators required[212]).

2. High Volume Sampler

Technology The high-volume sampler is an air suction pump with a combustible hydrocarbon concentration measurement designed to capture the total amount of the emissions from a leaking component or vent line.[213] A dual-element hydrocarbon detector (i.e., catalytic-oxidation/ thermal-conductivity) measures combustible hydrocarbon concentrations in the captured air stream. The calibrated air flow and hydrocarbon concentration is converted to a volumetric flow rate.[214] **Measurement** The operator places the bag or nozzle attachment that directs gas towards a suction nozzle from a component subject to a measurement. The high-volume sampler sucks in ambient air and hydrocarbon gas leak to dilute the measurement from the component of interest and measures the flowrate of hydrocarbon present. A thermal anemometer monitors the mass flow rate of the sampled air-hydrocarbon gas mixture. A background sample-collection line and hydrocarbon detector allow the sample readings to be corrected for ambient gas concentrations.	**High volume sampling**  Image Source: Carbon Limits[215] **Investment Costs:** Approx. \$17,500 + \$1,200 (calibration kit)

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208 Image source: Carbon Limits measurement campaign
209 CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP
210 *Id.*
211 *Id.*
212 Best results would be achieved if another operator observes with an OGI camera to ensure all the vent/leak is captured by the bag.
213 High-Flow Sampler® is a trademark instrument (and the only major commercial high-volume sampler product) that is no longer being manufactured. However, there are efforts underway to create an open-source design for a generation 2 high volume sample.
214 Information on the HFS estimation can be found in e.g. Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions
215 Image source: Carbon Limits measurement campaign

Method of Usage	Operator manually places nozzle, fitting or bag over suspected (or already detected) leak and rate is measured directly at source. Care needs to be taken to capture all of the gas plume in the fixed quantity of air drawn in the instrument (10 cubic feet per minute).
Applicability	Requires safe access to emission source and is useful for quantifying small leaks/vents ranging from $0.02m^3$ / hour to18 m^3 / hour with an accuracy of +/- 10%.[216] Measures combustible hydrocarbon concentrations in the captured air stream ranging from 0.01% to 100% with a reliable range of uncertainty.[217] Does not distinguish between methane and heavier hydrocarbons.
Quantification Speed	Relatively time efficient and essentially capable of quantifying multiple leaks per hour, however, requires manual operation of each measurement, which can be relatively time consuming.
Climatic Constraints	Can measure in a temperature range of 0°C to 50°C, best suited to usage in favorable weather conditions.[218]
Safety Concerns	Device is intrinsically safe (equipped with grounding wire to dissipate any static charge). Requires operator to be in close proximity to the leak but not necessarily touching the leaking equipment.
Service Requirements	Considerable calibration & maintenance required. Daily calibration throughout the measurement campaign.
Cost Considerations	Relatively expensive method, considering labour costs. More appropriate for research or periodically measurement to refine emissions factors as proper instrument usage requires specialized training.

3. Flow Meters

Technology

There are several flow meter technologies that can be used, including:[219]

- **Positive displacement flow meters** which measure volumetric flow by requiring gas to mechanically displace components;
- **Thermal mass flow meters** which measure mass flow based on heat transfer from a heated element;
- **Turbine flow meters** which measure volumetric flow based on the gas flowing pass a free spinning rotor;
- **Ultrasonic flow meters** which measure the difference in transit time of pulses that travel between two transducers.

Other flow meters could also be used to quantify flow rates in cold-venting or flare lines including Coriolis, differential pressure and vortex flow meters.

Measurement

Flow meters quantify gas flow in-line on pipes or at open-ended lines and are generally either inserted or directly mounted onto piping.

Flow meter in operation (turbine meter)

Image Source: UNEP[220]

Investment Cost

Depends on type and size of the meter (e.g. turbine meter approximately US$4,000, thermal mass flow meter US$4,500 - US$8,500)[221]

Method of Usage	Flow meters are either inserted in the gas flow from an open-ended pipe or through a port in a gas flow pipeline or flare line (e.g. thermal mass flow meter), mounted directly on piping (e.g. turbine meter) or, some types, can be clipped externally on piping (e.g. clip-on version of ultrasonic meter).
Applicability	Useful for measuring larger gas flows in open-ended pipes and other gas lines such as flare lines. Not applicable for small leaks (e.g. flanges and valves). Flow meters may be used to record flow over an extended period (e.g. 24 hours), to determine average emissions from variable flow sources. Depending on technology used, flow meters are able to measure smaller gas flows (e.g. from $8m^3$/hr for thermal mass flow meters) to extremely large flow (e.g. ultrasonic meters). Accuracy depends on type and model, however can be generally considered high especially relative to other quantification technologies within the range of the meters.
Quantification Speed	Real time measurement in cases it is permanently installed. When portable flowmeter is used, the quantification speed is rather low due to the time required for mounting the meter.
Climatic Constraints	Depending on type of flow meter. Generally applicable for a wide range of conditions.
Safety Concerns	After installing the meter, it does not require operator to be close to source, unless for taking manual reading in some meter types (e.g. some turbine meters). Installation can pose some challenges.
Service Requirements	Depending on flow meter either routine calibration required as per manufacturer. Some types come with lifetime calibration (e.g. Ultrasonic flow meters).
Cost Considerations	Depending on the monitoring requirement.

[216] CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: "Fugitive Equipment and Process Leaks," presentation by UNEP

[217] *Id.*

[218] *Id.*

[219] https://sagemetering.com/knowledge-base/topics/greenhouse-gas-emissions-monitoring-using-thermal-mass-flow-meters/

[220] Image source: CCAC Oil and Gas Methane Partnership: webinar March 12, 2015: "Hydrocarbon Liquid Storage Tanks and Casinghead Gas Venting," presentation by UNEP

[221] https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf

4. Vane Anemometer

Technology

Vane anemometer consists of a vane wheel flow velocity sensor and a handheld unit which displays the measured velocity of the gas passing through the device's vane wheel. The number of fan blade revolutions are detected with a magnetic pick-up and correlated to a flow velocity.

Measurement

The vane anemometer is placed at the center of the vent pipe opening or is inserted into it through a port in the vent pipe. Measurements should be taken at the center of the pipe, close to the open end of the vent and the temperature of the gas stream should be measured. The maximum velocity of gas being vented is then recorded. Using the pipe's diameter, the cross-sectional area of the pipe can be calculated. The cross-sectional area is then multiplied by the measured flow velocity, to estimate the volumetric flow rate of emissions through the vent.

Vane Anemometer measuring gas flow from an open-ended line

Image Source: BP[222]

Investment Cost

A device can range from $1,400 to $5,500.

Method of Usage	Vane anemometers are held by an operator on the opening of a vent line and manually held in place to take a reading of the velocity.
Applicability	Requires direct access to open-ended lines of process streams, and only suitable for larger leaks/vents (typically measuring range of gas flow velocity is 0.4 to 80 m / sec with an uncertainty of 0.9 to 1.5).[223] Recommended to avoid usage when device exerts a backpressure on the measured vent.
Quantification Speed	Velocity measured instantly, however accessing source may take time and limit the number of lines to be measures per hour.
Climatic Constraints	Ideal in low wind environments, working temperature for wheel sensor -15°C to 260°C, handheld sensor 0°C to 50°C.[224]
Safety Concerns	Requires operator to be close to source and depending on source typically at elevated heights.
Service Requirements	Requires routine calibration.
Cost Considerations	Low cost and low maintenance (in case scaffolding is required to access the emission point, there will be additional costs).

5. Hotwire Anemometer

Technology

A hotwire anemometer is similar to a vane anemometer, however, based on a heated hot-wire that is inserted into a flowing gas stream to measure gas flow velocity. The exposed hot-wire is either heated up by a constant electric current or maintained at a constant temperature when inserted into a flowing gas stream. As it operates on the principle of heat transfer, this device specifically measures the electrical current passing through the wire as the heat is conducted away due to the gas flow. The gas velocity can then be measured as the heat lost through convection is proportional to the gas flow.

Measurement

The heated hotwire is inserted through a port in a gas flow pipeline or is positioned at the center of a vent close to the open end. The temperature drop is then measured and the gas flow velocity is calculated. This can then be translated into a volumetric flowrate by multiplying the value by the cross-sectional area of flow in m^2.

Hotwire anemometer in use

Image Source: Lechtenbohmer, S., et al.[225]

Investment Costs

Approx. $1,400 to $5,500[226]

Method of Usage	Hotwire anemometers are inserted by an operator into a port in a gas flow pipeline or positioned at the opening of a vent and manually held in place to take a reading.
Applicability	Requires direct access to the process stream and only suitable for measuring gas flow velocities of 0.2 to 200 m/sec in vents, open ended lines, and flow in closed pipes of known cross sectional area (e.g. flare lines).[227] Does not require the complete capture of gas and also applicable to gas streams with liquid droplets and sticky entrained particulates which would damage a vane anemometer.

222 Image source: Global Methane Initiative All-Partnership Meeting, Oil and Gas Subcommittee – Technical and Policy Sessions, Krakow, Poland, October 14, 2011: "Routing Centrifugal Compressor Seal Oil De-gassing Emissions to Fuel Gas as an Alternative to Installing Dry Seals," presented by BP

223 https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf

224 *Id*.

225 Image source: Hot Wire Anemometer: Lechtenbohmer, S. et al, Wuppertal Institute for Climate, Environment, Energy, Germany, International Journal of Greenhouse Gas Control (2007) pp. 387 – 395 "Tapping the leakages: Methane losses, mitigation options and policy issues for Russian long-distance gas transmission pipelines," Fig. 4, August 22, 2007

226 https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf

227 *Id.*

Quantification Speed	Velocity measured instantly, however, accessing source may take time and limit the number of lines to be measures per hour.
Climatic Constraints	Not affected by wind, measures at temperatures of -10°C to 140°C. Limited to a maximum working pressure of 16 bar above atmospheric pressure.
Safety Concern	Requires operator to be close to source and depending on source typically at elevated heights.
Service Requirements	Requires routine calibration.
Cost Considerations	Low cost and low maintenance (in case scaffolding is required to access the emission point, there will be additional costs).

6. Method 21 (and using correlation equations to estimate emission rates)[228]

Procedure

The EPA method for "Determination of volatile organic compound leaks" or Method 21 was introduced in the 1990s by the US EPA as a standard for leak detection and monitoring fugitive emissions for refining and chemical plants.

Quantification

1. Screen components with an OVA to get screening values (SV) in parts per million (ppm).
   Only combustible hydrocarbon concentration in air is directly measured by an OVA using method 21. The mass or volumetric flow size of the leak is not considered, and different leak rates could have the same concentration, and vice versa.

2. Apply correlations to estimate emission rates (ER).
   Empirical equations based on field data (SV vs. ER from historic bagging tests).

3. Report Emission rates in kilogram per hour (kg/hr).
   High uncertainties and method 21 can only give an estimate of emission rates.

Correlation curves

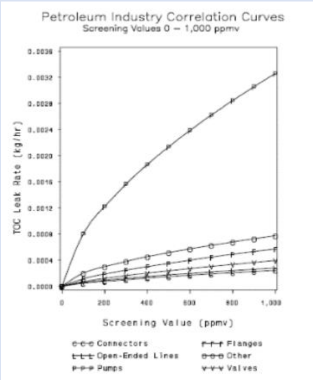

Image Source: EPA[229]

SOCMI emission tables could be included.[230]

Method of Usage	Required the concentration of methane emissions of the components to be initially measured in parts per million (ppm) and correlated with empirical equations to estimate emission rates.
Quantification Speed	Relatively slow as each leak´s concentration needs to be recorded using OVAs/TVAs.
Constraints	Not intended to accurately quantify emission of each leak. Has significant uncertainties. It is only an estimate of emissions using correlation curves. Correlation equations cannot be used above certain value (e.g.: 10´000 or 100´000 ppm); but there are pegged emission factors used to represent emissions from those sources above the instrument higher limit.
Uncertainty	Uncertainties are high for screening values (up to 200%). Also, some correlation equations are derived from various sources and combined field data and so uncertainty range is large (-80% to +300% error). Combining uncertainties could result in very high errors in emission rates. Many of the underlying studies were based on measurements in refineries and chemical plants, which may have different profiles than emissions in natural gas value chain.
Cost Considerations	Labor intensive and also requires detection equipment which record concentrations in ppm for each leak. The equipment itself require relatively low capital costs.

228 Although this is a "method" and not a technology, it is included in this section due to its methodological significance.

229 Image source: EPA (1995) Protocol for equipment leak emissions estimates. EPA-435/R-95-017. Research Triangle Park. North Carolina NC: US Environment Protection Agency

230 https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=2000MIHP.TXT

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Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector

Monitoring, Reporting and Verification (MRV) and Mitigation

This document provides guidance for developing and implementing effective practices for monitoring, reporting and verifying (MRV) methane emissions from the oil and gas sector. It also provides guidance on remediation practices. The document is meant to serve as a resource for a broad audience, including owners and operators of oil and gas facilities and policymakers at all levels of government. Its discussion of MRV and mitigation opportunities is intentionally "principles-based", recognizing that conditions vary greatly across oil and gas facilities and that legal, political and institutional aspects differ by jurisdiction.

The oil and gas industries are important sources of anthropogenic methane emissions and, though methane has a relatively short residence time in the atmosphere, its volumes are replenished continuously. Methane, the primary component of natural gas, can be released to the atmosphere during oil and gas production, processing, storage, transmission, distribution, and use. Because methane has a much higher warming potential than CO2, effective management is important for countries' climate change mitigation strategies and is one of the few approaches that represents a significant, cost-effective, and near-term opportunity.

Oil and gas will play a key role in the future sustainable energy system even under a scenario that meets stringent climate objectives – the sector will continue to support economic growth and social progress as alternatives to oil and gas will take time to emerge and achieve global scale. Addressing the methane challenge will improve the sector's sustainability credentials.

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Best Practice Guidance for Effective Methane Management in the Oil and Gas Sector

UNITED NATIONS