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| Best Practice Guidance for Methane Management in the Oil and Gas Sector  Draft 14th March 2019 |

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# Foreword

# Acknowledgements

# Acronyms and Abbreviations

BAT – Best Available Techniques

CIS – Commonwealth of Independent States

CO2 – Carbon dioxide

CORSIA – Carbon Offsetting and Reduction Scheme for International Aviation

DI&M – Directed Inspection and Maintenanc

FQD – Fuel Quality Directive

EU ETS – European Eunion 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

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

INDC – Intended Nationally Determined Contributions

IPCC – Intergovernmental Panel on Climate Change

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

NPRI - National Pollutant Release Inventory

OGCI - Oil and Gas Carbon 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

To be completed based on http://www.ipieca.org/resources/awareness-briefing/methane-glossary/

# Introduction

## Scope and objectives of this guidance document

This document provides guidance for developing and implementing effective monitoring, reporting and verification (MRV) practices, as well as for mitigating methane emissions, from the oil and gas sector.[[1]](#footnote-2) Methane emissions from this sector present a safety risk, are a waste of valuable energy resources, and are also a precursor of tropospheric ozone and a significant driver of climate change. In its discussion of MRV and mitigation opportunities, 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 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 document covers many aspects of methane management, along two dimensions:

1. Physical dimension: All of the oil and gas supply systems are included, from exploration, extraction, gathering and processing, to long distance transmission and transportation, and finally refining and distribution to end users, and covering natural and technical circumstances that diverge greatly.
2. Institutional dimension: Methane management practices are addressed at the company, national and international levels, as well as discussions on how coordination and collaboration at the different levels can help enhance methane emission reduction.

There are numerous initiatives, including regulatory efforts, public-private partnerships and industry collaborations, focusing on tracking and reducing methane emissions from the oil and gas sector. This document presents some of these initiatives and, in some cases, draws heavily on the technical guidance documents they have developed to inform the discussion of best practices for methane MRV and mitigation. The reader is encouraged to explore these documents as useful complementary information when considering MRV and mitigation plans.

## The issues

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. The Sustainable Development Scenario presented in IEA’s World Energy Outlook 2017, assuming a global reduction of energy-related greenhouse gas emissions of more than 40% by 2040, still has oil and gas accounting for 48% of total energy supplies in 2040, down from 55% in 2016, with total oil volume contracting 25% and gas increasing 15% for the period.[[2]](#footnote-3)

In the end, the world’s energy supply mix will be determined by implemented policies and measures and by market competition wherein the costs and sustainability attributes of energy alternatives are decisive factors. The enduring role of oil and gas obliges increased attention on methane emissions from the entire oil and gas value chain from exploration and extraction to end use.

Methane is considered a short-lived climate pollutant with an atmospheric lifetime of about 12 years. Its ability to trap heat in the atmosphere, also known as its global warming potential (GWP), is 28 times more potent that carbon dioxide (CO2) over a 100- year time horizon and 84 times higher than CO2 over a 20-year horizon. Recent research shows that methane emissions are responsible for about one fourth of manmade global warming, and methane emissions are on the rise.[[3]](#footnote-4) Because of its relatively short atmospheric lifetime of 12 years, reducing methane emissions presents an important near-term opportunity to address climate change.[[4]](#footnote-5)

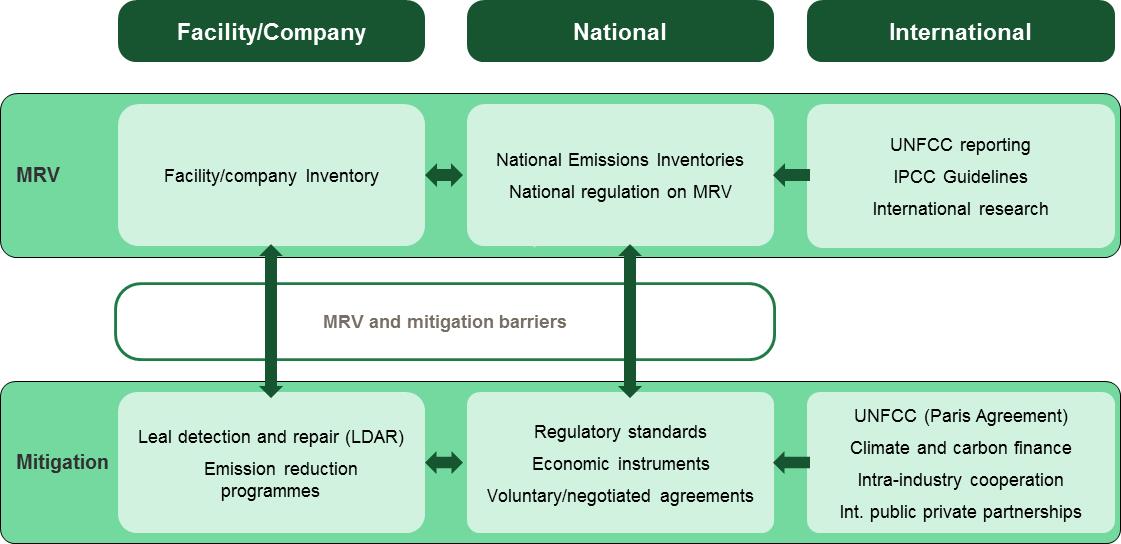
Currently, oil and gas sector operations account for one fourth of global anthropogenic methane emissions, and there are several projections indicating that emissions could increase significantly.[[5]](#footnote-6) [[6]](#footnote-7) The IEA predicts oil and gas methane emissions will increase some 40% by 2040 in the absence of new and more stringent measures.[[7]](#footnote-8) However, the sustainability of oil and gas supplies can be considerably improved through targeted and cost-efficient measures to reduce the emissions. For example, the IEA has estimated that 75% of global oil and gas methane emissions are technically feasible to eliminate (at currently expected oil and gas supply levels), while almost 50% can be reduced with no net costs.[[8]](#footnote-9)

Many oil and gas companies already have procedures in place to reduce waste methane flaring and to detect methane emissions at their facilities to avoid safety risks and health hazards. In addition, many companies and governments are now increasing their methane MRV and mitigation efforts as contributions to climate change mitigation. This guidance document, together with a number of other international initiatives, builds on this work.

## MRV and mitigation

While MRV and mitigation are distinct activities, they are also strongly related. Mitigation can be most effective and cost-efficient when based on sound MRV practices. This interplay of MRV and mitigation is important and is addressed in this document, see Figure 1.1.

Figure 1.1 MRV and Mitigation – Facility/Company, National, and International Levels



Cost-efficient and effective mitigation measures typically rely on sound results from MRV methods and practices. MRV is also important for design and implementation of policies and regulations since reliable quantification and reporting of emissions is essential for monitoring compliance and assessing progress emission reduction efforts. With respect to technology application and practices MRV and mitigation and also be integrated, as for example with so-called leak detection and repair programme, which can be mandatory or conducted on a voluntary basis by industry.

MRV and mitigation practices at the facility and company level are often interrelated with those developed at national level. Further, national level practices can be influenced by international guidelines and commitments, particularly those established under the Intergovernmental Panel on Climate Change (IPCC) and the United Nations Framework Convention on Climate Change (UNFCCC).

## Structure of this document

### After methane emission levels and emission reduction opportunities are briefly surveyed in Chapter 2 of this document, MRV and mitigation are subsequently discussed in Chapter 3 and Chapter 4. This is the core of the document and is further supported by two technical annexes: Annex 1 on emission sources and mitigation techniques, and Annex 2 on emission detection and quantification technologies.

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 processed such as those under the United Nationals Framework Convention on Climate Change (UNFCCC), intra-industry associations and public- private initiatives, and international research.

In the same way, Chapter 4 on mitigation starts with the facility/ company perspective followed by a discussion of mitigation policies and regulations at the national level. This chapter also discusses commonly-encountered barriers to implementation of cost-efficient mitigation opportunities, with a view toward informing policies and regulations that may address these barriers. Finally, this chapter covers aspects of international climate policies, including carbon pricing, which can help enhance methane mitigation efforts.

Chapter 5 presents key conclusions and summary for policy makers.

Chapter 6 presents case study examples of MRV and mitigation best practices. [In this draft only a sample of two case studies are presented. Reviewer of the draft are invited to propose case studies to be included in final version of the document]

Two annex are included at the end of the document.

Building on the nine 'core' emission sources of methane defined by the Oil and Gas Methane Partnership (OGMP) and explained in the OGMP Technical Guidance Documents, Annex 1 describe in detail twelve emissions sources, including mitigation techniques and applicable emission detection and quantification equipment.[[9]](#footnote-10) The presentation is based on a number of sources referenced in the annex. More categories are listed than the Technical Guidance Documents of the OGMP since downstream emission sources are covered.

Annex 2 presents a very brief overview of various methane detection and quantification technologies currently available. This is primarily based on Climate and Clean Air Coalition’s Technical Guidance Document and EPA’s Star Program.[[10]](#footnote-11),[[11]](#footnote-12)

# Methane emissions in the oil and gas industry

## 2. 1 The basis for emissions estimates

Making accurate oil and gas sector methane emissions estimates is difficult. Quantification cannot be based on emissions measurements alone, but requires the use of activity data (e.g. throughput of oil and gas) and corresponding emission factors, which should represent the average emissions per unit of the selected activity data. Unlike energy combustion CO2 emission factors, emission factors for methane vary greatly depending on a large number of factors, including the configuration of the oil and gas supply chain in question, the age and technical standard of machinery and equipment, severity of operating conditions and maintenance and other operational practices. The task of making reliable estimates is further complicated by the fact that methane originates from a vast number of emission sources along the oil and gas value chain.

The quality of national methane emissions data 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). [[12]](#footnote-13) The Guidelines distinguishes between three levels for emissions calculations, with Tier 3 being the most rigours 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.

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| **Box 2-1 Tree tiers for emissions calculations according to IPCCC 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 methane, industry segment = A industry segment •EF methane, industry segment  Where:  E methane, industry segment are the annual emissions of methane (tonnes) for specific segment of the Oil and Gas System[[13]](#footnote-14)  A industry segment is an activity value for the specific segment. Activity data would typically be throughput of oil and gas which represent emission sources (see Table x below)  EF methane, industry segment is the emission factor (emissions per unit of activity for the segment)  For example, calculation of emissions from the gas production segment can be calculated using an emissions factor per unit gas produced in Sm3 multiplied by the volume of gas produced for the period in question (e.g. one calendar year)  The disaggregation of industry segments is an important factor for the accuracy of emissions estimates, which again is determined by the availability of reliable data. Consequently, the IPCC Guidelines distinguish between three levels, or tiers, for calculation of emissions:  **Tier 1:** The simplest method with the use of relatively aggregate and usually readily available activity variables and with default emission factors for the activity variable chosen. Default emission factors for a set of activity data are 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:** The most detailed approach based on a rigorous bottom up assessment at the facility level, involving identification of equipment-specific emission sources, count of equipment units, measurement of emission rates per equipment type, etc. |

Currently, most ECE member states use the Tier 1 method (see Table 2.1), resulting in high uncertainties in the current estimates. Only the 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. Russia is moving towards the use of country specific emission factors (Tier 2), while Uzbekistan, Ukraine, Azerbaijan and Kazakhstan all apply Tier 1 methods. The countries listed in Table 2.1 account for almost half of global oil and gas sector methane emissions.

Table 2.1 Reporting of national methane emissions inventory data to the UNFCCC by selected ECE countries

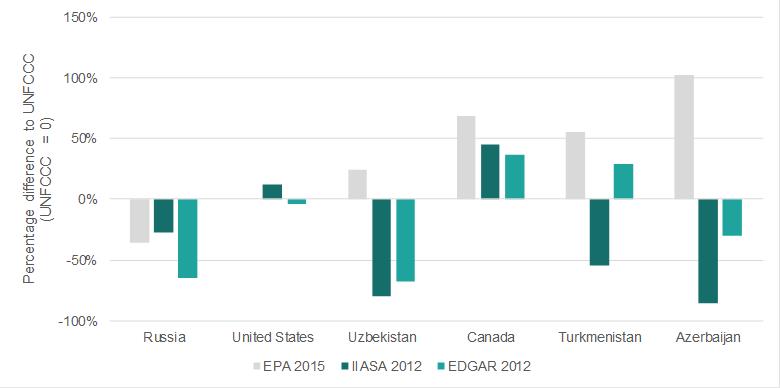
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| --- | --- | --- | --- | --- |
| Country | Mt CH4 | Year | Latest submission(\*) | Tier used |
| Russia | 25.3 | 2015 | 2018 – NIR | Tier 2 for gas transportation (3.7 MtCH4)  Tier 1 for the other activities (21.6 MtCH4) |
| USA | 8.1 | 2015 | 2018 – NIR | Tiers 2 and 3 |
| Uzbekistan | 3.2 | 2012 | 2016 – NC3 | Tier 1 |
| Canada | 1.7 | 2015 | 2018 – NIR | Tiers 2 and 3 |
| EU | 1.3 | 2015 | 2018 – NIRs | 12 Member States reporting under Tier 1(0.5 MtCH4)  The others mixed, different for different segments |
| Turkmenistan | 1 | 2010 | 2015 – NC3 | Tier 1 |
| Ukraine | 0.9 | 2015 | 2018 – NIR | Tier 1 |
| Azerbaijan | 0.5 | 2012 | 2015 – NC3 | Tier 1 |
| Kazakhstan | 0.3 | 2015 | 2018 – NIR | Tier 1 |

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

The predominant use of Tier 1 methods outside North America and the EU comes from the lack of empirical studies of methane emissions. Over time, new technologies to locate and measure methane emissions (see Annex 2) and a number of initiatives (see Box 3-1) to measure and report emissions in a number of countries should create a basis for making more accurate estimates for countries which currently use Tier 1 “default emission factors”.

In addition to national inventories being reported to the UNFCCC, a number of other institutions/sources are publishing aggregate methane emissions estimates. These sources have estimates which often diverge considerably among themselves and relative to UNFCCC data (see Figure 2.1).

Figure 2.1: Range of methane emissions estimates for selected ECE countries[[14]](#footnote-15)

Sources: See Box 2-2

Institutions publishing estimated methane emissions make use of UNFCCC data but typically in combination with their own estimates in cases when consistency in methods and level of specification across sectors is important. For IIASA, for example, completeness and consistency in use of activity and emissions data, across sectors and countries, is essential for modelling purposes, see Box 2-2.

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| **Box 2-2: Data sources for oil and gas sector methane emissions estimates**  Methane emissions estimates from five different institutions are presented in this Chapter:  **UNFCC data** (link) include methane emissions from all countries that are parties to the Convention. Data coverage and quality, and regularity of data submissions vary, historically with different reporting requirements (e.g. in terms of frequency of reporting, time series reported) for Annex I than 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**), a joint research project of the EU Commission and Netherlands Environmental Agency, calculated emissions of greenhouse gases and a number of other pollutants ([http://edgar.jrc.ec.europa.eu/overview.php?v=432#](http://edgar.jrc.ec.europa.eu/overview.php?v=432)), often using data from UNFCCC. Activity data are taken from a large number of statistical sources, however with little insight into emission factors being used.  The International Institute for Applied Systems Analysis **(IIASA)** has compiled details methane emissions data being used among others in modelling work. The GAINS model being used for analysis of air pollution and GHG emissions have a detailed breakdown of country specific energy sector variables bases with related emissions factors. A number of 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)** has published methane emissions data as part of the International Emissions and Projections, 2010-2030 (<https://www.epa.gov/global-mitigation-non-co2-greenhouse-gases>). The data are a combination of country-reported inventory submissions to the UNFCCC and calculations based in IPCC Tier 1 methodologies to fill in for missing or unavailable data.  The International Energy Agency (**IEA**) prepared a database and published global methane emissions data as part of the World Energy Outlook 2017 (<https://www.iea.org/weo2017/>). The IEA estimates are based on a large number of data sources, including own survey of company and country emission intensities. |

In recent years, the natural gas and oil sectors have experienced significant growth and changes in industry practices. Only recently have data become available to improve understanding of emissions for these sources. As expected, incorporating the newly available data has resulted in changes to emissions estimates for the oil and gas sector. For example, incorporation of new data resulted in large retroactive revisions made in the emissions inventories for the United States and the Russian Federation. US methane emissions estimates for 2005 were 6.3 Mt in the 2010 inventory report followed by an upward revision to 10.3 Mt in the 2011 inventory report, and were brought down to 8.2 Mt in the 2017 inventory report.[[15]](#footnote-16) Similarly, at different intervals Russia has made large revisions to its inventory. The 2014 Russian inventory reported 2012 emissions at 15.5 Mt, which in the 2017 inventory was increased to 25.3 Mt. In addition, there have been significant revisions to the split of methane emissions by supply chain segments in Russian inventories.[[16]](#footnote-17) All these changes reflect ongoing efforts to obtain more reliable primary data and improve the methods used for methane emissions quantification.

The revisions are in part the result of efforts by government reporting programs, the industry and other institutions to improve methane emissions data. The Environmental Defense Fund and several philanthropic funds have initiated and financed a number of scientific studies which has improved the understanding of emission levels and the share of emissions accounted for by different segments of the oil and natural gas system, particularly in the United States.[[17]](#footnote-18) In the US, revisions are largely due to newly available data from the US Greenhouse Gas Reporting Program along with data from new studies.

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

UNFCCC data estimate global oil and gas sector methane emissions at [xx] Million tons, of which 51% are reported by ECE member states. [[18]](#footnote-19) Three other sources have estimates slightly below this level, while EDGAR is significantly lower, see Figure 2.2.

Figure 2.2: Oil and gas sector methane emissions according to different data sources[[19]](#footnote-20)



The Russian Federation has by far the highest level of methane emissions followed the United States. According to the UNFCCC the two countries account for 78% of emissions by ECE member states and almost 40% of global methane emissions from oil and gas operations (Figure 2.2). Note that the Russian Federation, North America and Central Asia have the vast majority of emissions. EU countries and Norway only have 3%, according to UNFCCC inventories.

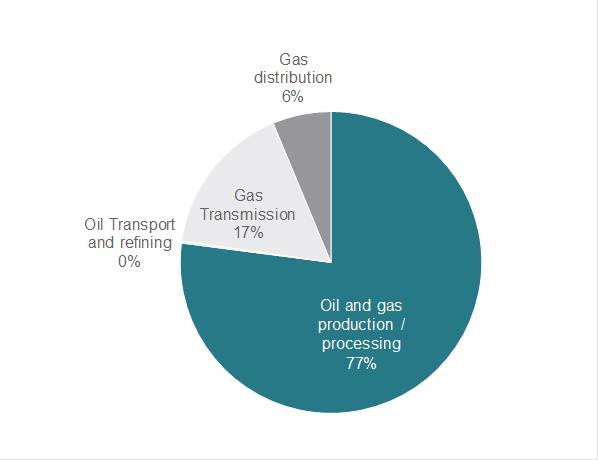
Figure 2.2: Share in total methane emissions from oil and gas sector by country in the ECE region[[20]](#footnote-21)

Source: UNFCCC

According to UNFCCC data Uzbekistan is the third largest emitter of oil and gas emissions with 8% of the total for ECE member states. However, IIASA and EDGAR estimate this share to be significantly lower (in the range 2-4%).

Although the format for submission of UNFCCC data, according to the 2006 IPCC Guidelines, are divided into 15 sub-categories (segments) of the Oil and Natural Gas System many countries do not report emissions for all categories, with some segments not occurring, not applicable, not estimated, or included elsewhere. Therefore, aggregate UNFCCC estimates are not available for all segments. Four or five categories are typically published.

*Figure 2.3 Breakdown of oil and gas methane emissions by segment, 2015.*



Source: UNFCCC

Four categories of UNFCCC data are shown in Figure 2.3. Upstream oil and gas segments (including exploration, production, gathering and processing) account for 72% of global methane emissions. The share for gas transmission is 22%, gas distribution is 6%, while emissions from oil transportation and downstream oil facilities accounts for less than 1%.

Figure 2.4 Share of methane emissions per value chain element in UNECE countries

Source: UNFCCC

The IEA has made estimates separately for upstream oil and upstream gas. The oil segment is the largest with 41% while the estimate for upstream gas is 37%, calculating a total upstream estimate that is 6 percentage points higher than in the UNFCCC data. [[21]](#footnote-22), [[22]](#footnote-23) The split into oil and gas upstream segments is important in relation to the discussion of lifecycle 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 2.4), of which some reflect real differences in industry structures and emission intensities other probably include errors in specification by segments.

Another way of specifying methane emissions is according to emission sources such as compressors, storage tanks and pneumatic controllers and pumps, which may appear at all stages of the supply chain. While this is important information for understanding causes and finding remedies to emissions, little of data have been collected, analyzed and published. However, some countries have started publishing such information (notably USA, Canada and Norway) and the partner companies of the Oil and Gas Methane Partnership (OGMP) are reporting and publishing information of emissions and mitigation progress for nine “core” upstream emission sources.[[23]](#footnote-24) Information on main emission sources and progress in mitigation efforts are published in the in the Third-Year Report from OGMP.[[24]](#footnote-25)

# Monitoring, reporting and verification (MRV)

## **Key messages**

* MRV covers monitoring though direct measurements and other methods for quantifying emissions, reporting by compiling estimated emissions in specific formats for internal use or external circulation, and verification of emissions and/or emission reductions, often by a third party.
* MRV serves several purposes, from identifying specific mitigation at the company level to providing valuable data and information for decisions on policies and regulations and tracking their effectiveness. International reporting commitments is becoming more important as the Paris Agreement enters its operational phase.
* Use of sound MRV methodologies and practices is essential for methane management for closing the current knowledge gap.
* To construct robust methane emission inventory at the company level, a combination of direct measurements and calculation-based methods are typically used. Technologies are emerging which can improve technical feasibility and reduce costs of methane measurements.
* International cooperation is important in building institutional capacity and capability to perform sound MRV activities. While guidelines from the IPCC and reporting requirements under UNFCCC continue to be essential references, a growing number of international initiatives are becoming increasingly important in sharing information and experiences.

## Overview of challenges and approaches with methane measurement

### Why quantification is difficult

Quantification of methane emissions typically requires a combination of direct measurements and calculation-based methods. The methodological and practical issues involved are demanding given the key characteristics with oil and gas sector methane emissions:

* Large number of emissions points: Each oil and gas production site or supply facility may include a few to hundreds of emissions points. For examples, compressor stations in Canada are estimated to have more than 10 leak points, on average, while gas plants include tens of thousands of components of which a few percent are typically leaking.[[25]](#footnote-26) In addition, both these types of installations may include vent and flaring emissions sources.
* Geographical dispersion of the emission points and other practical challenges: Methane emissions are spread across a vast number of locations globally.[[26]](#footnote-27) Each well site, compressor station, gas plant and pipeline segment are potential emissions sources. Equipment is often dispersed and in remote locations, increasing the costs of performing measurement campaigns. Oil and gas supply patterns evolve fast and this increases the challenges of keeping emissions reports up to date. In addition, a number of practical matters should be considered such as physical accessibility emissions sources and safety considerations.
* Variability of the emissions rate: Field data shows that emission rates from similar equipment and processes are highly variable (emission rates from similar equipment and processes can vary by a factor of 1000).[[27]](#footnote-28) Factors of importance include type and the age of the equipment, any controls, climatic conditions, maintenance practice and the operating conditions.[[28]](#footnote-29) Consequently, there are important uncertainties associated with using emission factors from a sample number of sites/equipment (which may not be representative of a full population).
* Limited sensory feedback: Methane emissions provide limited sensory feedback to humans (invisible, and odourless in most cases), and this makes it difficult to identify and estimate emissions without specialized equipment.[[29]](#footnote-30), [[30]](#footnote-31) This in turn can add to the costs of monitoring, reporting and verification.

The challenges listed above reflect the intrinsic difficulties in methane emissions quantification, and it explains the large discrepancies in estimates shown in the previous chapter.

Continuous measurement over a large number of methane emission sources is not practicable. Even at the facility level, quantification is rarely based on direct measurement alone.[[31]](#footnote-32) Depending on the specific objective of the MRV, direct detection and measurements must be combined with calculations-based methods. Technical feasibility of making measurements, uncertainty assessments and MRV costs play a role must be considered in order to find the right balance.

### Direct detection and measurement

In broad terms there are two categories of direct detection and measurement: bottom-up and top-down studies. Bottom-up studies involve on-site measurements of emissions from individual sources. They are the most detailed but can also be time-consuming and expensive (compared to pure calculation-based approaches) and must be extrapolated to the company/country level if all of the facilities cannot be surveyed.[[32]](#footnote-33)

Remote (top-down) methods typically measure the ambient concentration of methane in the atmosphere usually from airplanes/drones, moving vehicle or tall towers located on site. Another approach involves monitoring methane plumes using tracer gas. Several companies have also started performing methane measurements based on satellite technology. These measurements provide insights into overall levels of methane emissions, but tracing back the main contributing sources and their relative importance can present practical challenges.

Given the variability of the emissions rate over time, caused by daily and seasonal supply-demand patterns, and/or activity levels at sites, measurement-based methods need to be continuous or repeated regularly in order to fully capture variability. Single point measurements and emission estimates derived from such can be misleading depending on when the measurement was taken and the duration of the measurement. In addition, some large intermittent vents emissions sources may be missed.

### Calculation based methods

This is where emissions are quantified using a combination of activity data and engineering data and emission factors, e.g., emissions per unit of the activity data (e.g. 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 or event (e.g. per compressor or pipeline blowdown), or

(iii) engineering calculations which encompasses a range of different approaches including the use of process engineering software or some formula based estimates taking into account a number of parameter (e.g. intermittent unloading can be estimated using parameters such as casing diameter, well depth, etc.)[[33]](#footnote-34)

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

Emission factors are typically 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 disaggregate the inventories are. Typically, the emission estimates using default emission factors are more appropriate when used for a very large number of sources. These estimates become more uncertain with decreasing source population size and are not appropriate for making investment decisions for individual emissions sources.

Engineering calculations based on robust assumptions can provide reliable estimates in particular for sources which can be can be readily modelled based on fundamental engineering principles such as thermodynamics, continuity equations, mass transfer, heat transfer, and potentially chemical kinetics. They may be considered where improved accuracy is needed, for example during the detailed assessment of a specific abatement project.

At an aggregate (e.g. national) level, it is common to use oil and gas throughput or count of facilities as activity data (such as well counts), while at the facility and company level quantification may be done based on counts of equipment and taking into account infrastructure conditions, which provides better estimates.

Detection and measurement primarily have an application at the facility and company level, but there is rapid technology progress, including in the form of remote sensing, which can broaden the scope of measurement-based methods being applied for aggregate quantification and reporting efforts.

Figure 3.1: Overview of the methane quantification approaches



Generally, new technological development is likely to shift the balance towards more of methane emissions quantification being based on direct measurement, and with the additional benefit of a more

disaggregated and facility- and country-specific emission factors being available for calculation-based quantification.

Companies and public institutions will always have to strike a balance with the use of measurement- and calculation-based methods and the specific calculation-based method and level of disaggregation to use. Some of the pros and cons of the different approaches are summarized in Figure 3.1.

## **MRV at the facility and company level**

Companies quantify emissions for various reasons, such as: i) to comply with reporting requirements of public authorities ii) to have a sound basis for developing and implementing mitigation strategies, including the development of business case for equipment upgrade decisions and prioritizing mitigation measures and iii) for internal and external reporting of environmental performance and progress (e.g. relative to set emissions target).

Aspects with company MRV are discussed here under three headings:

1. Detection and measurement of emissions at the facility level
2. Calculation-based approaches for quantification of emissions at the facility- and company-level
3. Emissions reporting (including voluntary reports)

### Detection and Measurement – Elements of best practices

Detection and measurements at the site level are resource and time demanding activities and require careful planning. Depending on the objectives of the measurement campaigns, operators should take into account a number of considerations when developing such a program (which can sometimes be linked to LDAR program), including the following:

* Selection of the detection and measurement technology
* Selection of the sites/emissions sources to be covered by the detection and measurement campaign

#### Selection of the detection and measurement technology

To perform emission surveys, operators can choose amongst a number of technologies (more information is provided in Annex 2). Over the last few years, infra-red cameras have been used extensively for emission detection, in particular at production sites, compressors stations and processing plants. Compared to older technologies (e.g. soap or organic vapor analyzers), infra-red cameras are easy to use and allows for effective screening of a large number of components in a relatively short period of time. Infra-red camera surveys will still require a crew of technicians to visit each site on a regular basis, which can represent a non-negligible share of the cost.[[34]](#footnote-35),[[35]](#footnote-36)

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, (lower and/or upper) threshold, costs or applicability to certain types of emissions sources. There are a number of emerging and new commercial technologies for detection and quantification of methane emissions. These technologies have the potential to completely change measurement practices in the future by allowing (i) identification of the large emitters more quickly, and (ii) quantification of emissions at lower costs. However, currently there is limited practical field experience with most of the new technologies.

Given the variety in site configurations and the current evolution of the technologies available, there is not at this time one single set of best available technologies for emissions detection and quantification.[[36]](#footnote-37) Technologies should be selected for each specific application, considering a number of factors:

* Type and dispersion of the sites to be surveyed: Different approaches and technologies are required to cover different types of installations: aerial surveys are commonly used for gas transmission pipeline but may not be relevant for a large processing plant. The type of on-site emission sources may also impact the technologies selected: a high flow sampler may be used to quantify emissions from a leaking connector but not to quantify emission from a large venting stack.
* Objective of the survey: For example, aerial survey may be selected to estimate the total emissions from a number of sites while infra-red camera will be used to identify specific emissions sources e.g. components to be repaired.
* Quantification requirement:Related to the point above, the level of accuracy required and the type of emission source has also some bearing on which technologies to use.
* Duration of the measurements: Some emissions sources vary over time (for example an intermittent natural gas driven controller). Considerations should also be given on the time and length of the measurement.
* Costs: Finally, the costs for different technologies are very variable. Labor costs, which can represent a significant proportion of the total costs, should be considered when comparing alternatives.

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

When, for technical or economic reasons, not all sites can be surveyed, the operator will have to select a subset of the sites. The selection process will depend on the ultimate objective of the measurement campaigns (e.g. develop emission factors, address emissions or comply with regulation).

If the measurement campaign aims at developing emissions factors or if the results of the measurement campaign will be extrapolated to other facilities, the representativeness of the sample of sites selected needs to be carefully assessed. Considerations should include age, operating status, type of facility, industrial segment (upstream vs downstream), size or throughput, and product composition (e.g. presence of acid gas).

If the measurement campaign aims primarily at addressing emissions and at identifying emissions reduction projects, the measurement campaign should, to the extent possible, target sites with the expected largest abatement potential (old and large sites, sites with important emissions sources present such as un-stabilized oil tanks).

Finally, practical consideration such as site location and health and safety aspects are typically also taken into account in the site selection process.

### Calculation based methods – Elements of best practices[[37]](#footnote-38)

As described previously, calculation-based or indirect methods for estimating methane emissions can be based either on (i) high-level default emission factors (e.g. per unit of throughput), (ii) emission factors per equipment or event (e.g. per compressor or pipeline blowdown), or (iii) engineering calculations.[[38]](#footnote-39) The two latter are particularly relevant at the facility and company level.[[39]](#footnote-40)

Operators should take into account a number of considerations when using such approaches:

Disaggregation level**:** Theappropriate 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 and should ideally allow to: (i) minimize uncertainties, and (ii) identify emissions reductions opportunities. As an example, storage tanks can be classified depending on the liquids contained, their size and/or the type of roof.

Emission factors selection: Ideally, country or company specific emission factors (derived from measurement campaign) should be used to estimate emissions. When these are not available international emission factors may be used, as an intermediate measure, recognizing that the important difference in local practices may impact heavily the uncertainty of the final results.[[40]](#footnote-41) 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 typically required, such as 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). In cases where this information is not readily available, data collection approach should be considered, including the establishment of processes retrieve data on changes that occur over time at facilities.

### Reporting

Reporting is an essential tool for companies to track emissions, present overview of the level and structure of emissions, and show progress/changes in performance of emission reduction and abatement activities over time. Reporting can take different forms based on purpose and requirements. There are two main types of reports:

* Measurement surveys reports
* Emissions inventory reports

#### Measurement surveys (bottom up) reports:

During a bottom up measurement campaign, each identified emission point will be quantified, tagged and recorded. This record will be combined into a measurement campaign which is most often internal. Figure 3.2 presents the typical information which should be presented in a report for the bottom up measurement campaign. Consistency in reporting different measurement campaigns will allow future comparison and aggregation of the results.

Figure 3.2: Information to be included in a measurement survey report

|  |
| --- |
| **Type of information** |
| Facility name, location, type of facility … |
| Section of the facility (for large facilities) 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 * 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 turn around. |
| Date and hours of the measurement. Length 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 a number of purposes:

* Performing repairs (for leaks) and assessing abatement options (In particular for Vents): The maintenance team will use the report and the tag number to identify the different repairs and replacement to be performed. The results can also be used to assess the benefits of implementing mitigation alternatives.
* 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 emits 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.

#### Emissions inventory reports

Emissions inventory reports typically provide a comprehensive overview of emissions sources and magnitude across a geographical area or a selection of facilities. Reports can be for internal and/or external purposes.

Internal reports can be used to track Key Performance Indicators (KPIs), and as tools to identify opportunities to reduce emissions. KPIs can also be closely related to external reporting (e.g. on environmental performance, sustainable development indicators etc.).

Public/external reports can be used to: (i) comply with existing 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 and progress in mitigation efforts, see Box 3-1.

By these initiatives one can expect more information to be presented on methane emissions, as well as quantification methods and procedures.

|  |
| --- |
| **Box 3-1 International initiatives with focus on methane emissions**  The significance of oil and gas methane emissions for climate change risks and the potential for large near-term impact of mitigation has led to the creation of a number of initiatives, including but not limited to the Global Methane Initiative (GMI), the Climate and Clean Air Coalition Oil and Gas Methane Partnership (OGMP),[[41]](#footnote-42) Methane Guiding Principles[[42]](#footnote-43) and OGCI[[43]](#footnote-44). Inter alia, the initiatives focus on improving the quality of emissions data and on transparency of reporting. These initiatives encompass an important part of the international oil and gas industry. MRV activities of institutions with ownership and/or operational responsibility of assets with methane emissions are critically important.  **Global Methane Initiative (GMI)** is an international public-private partnership focused on reducing barriers to the recovery and use of methane as a clean energy source. GMI’s 45 Partner Countries and more than 500 Project Network members exchange information and technical resources to advance methane mitigation in key sectors, including Oil and Gas. GMI’s Oil & Gas Subcommittee encourages collaboration between delegates from Partner Countries and Project Network members to build capacity, develop strategies and markets and remove technical and non-technical barriers to methane mitigation project development in order to increase environmental quality, improve operational efficiency and strengthen the economy from the additional gas brought to market.  **Oil and Gas Methane Partnership (OGMP)** is a voluntary, public-private partnership under the Climate and Clean Air Coalition, with 13 partner companies. 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 50 assets in nine countries to date[[44]](#footnote-45).  **Oil and Gas Carbon Initiative (OGCI)** comprising 13 of the largest international oil companies which jointly have committed to a 25% reduction in the upstream methane emissions intensity by 2025, and with an ambition to achieve a 33% reduction by the same year. OGCI will report on progress.[[45]](#footnote-46) The specific quantitative targets set by OGCI will require companies to have in place rigorous methodologies and practical steps to monitor emission levels and progress in reduction efforts. OGCI has published a methodology notein relation to the target, but this and other company reports do not, at this stage, offer much detail on how emissions are quantified.[[46]](#footnote-47)  **Guiding Principles** for reducing methane emissions across the natural gas value chain. The Guiding Principles have been signed by 11 oil and gas companies and 8 other organizations. The guiding principles cover both MRV and mitigation, and specifically on external reporting. The companies have committed to present emissions data, methodologies to derive these data, and progress and challenges in methane emissions management. |

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.). They are typically presented protocols consistent with ISO 14064 or other standards and may be subject to verification by third party certification companies.[[47]](#footnote-48) A number of elements should be considered when designing company/facility reporting procedures:

* Emission coverage**:** Though an emission inventory does not necessarily need to be completely exhaustive (there are a large number of very small methane emissions sources), an emission inventory should include all the medium and large emissions sources.[[48]](#footnote-49)
* Consistency: To allow data analysis and comparison between facilities or regions, a consistent approach(es) and vocabulary should be defined. Time consistency should also be considered to allow comparison of emissions over time.
* Transparency: 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 also central to a credible report vis-a-vis external stakeholders.
* Identification and scale of emission reduction opportunity and progress tracking**:** 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 thus also allow tracking of progress and evaluation of past project’s performance to improve future project design.
* Regular updates**:** Finally reports should be updated on a regular basis. Results of new measurements campaigns should also be incorporated by e.g. update relevant emissions factors.
* Representativeness of the measurements (if relevant): As highlighted above, inventories are typically constructed based on a combination of measurement campaigns and calculation-based method. The approaches used to select sites for the measurement and their representativeness should thus be documented.

With the increasing focus on demonstrating the climate impact of natural gas (in comparison to coal and to renewables), operators have more pressure to document credibly emissions 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 (for example research groups) who can provide an unbiased assessment of the situation.

### Verification

### Verification of emission reports or verification of changes in emissions for a project, facility or company means a systematic, independent and documented process for the evaluation of a greenhouse gas inventory report or emission reduction report against agreed verification criteria, typically performed by a third party.[[49]](#footnote-50) The verification will be done according to standard based on which rules and guidelines are set. There are a number of guidelines and standards that could be used as verification criteria, some which are broad and general and others specific for the nature of emission sources and emissions in question.

Table 3.1 Standards and protocols for verification

|  |  |  |
| --- | --- | --- |
| Standard, Guidelines, Methodology or Protocol | General / Methane-Specific | Inventories / Reduction Projects |
| **Inventories – emissions levels** | | |
| ISO 14064: Part 1 – Specification with guidance at the organization level for quantification and reporting of GHG emissions | General | Inventories |
| ISO 14064 Part 2 – Specification with guidance to quantification, monitoring & reporting of greenhouse gas emission reductions at project level | General | Reduction Projects |
| IPCC Guidelines for National Greenhouse Gas Inventories (Chapter 4 on fugitive emissions). | Methane-Specific | Inventories |
| Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry, IPIECA, OGP and API | Methane-Specific | Inventories |
| Methodology for estimation of pollutant emission from diffuse sources of fugitive emissions in oil and gas equipment (in Russian) | Methane-Specific | Inventories |
| Recommended guidelines for emission reporting (in Norwegian), Norwegian Oil and Gas Association | Methane-Specific | Inventories |
| **Emission reductions** | | |
| CDM Approved baseline and monitoring methodology - AM0023: Leak detection and repair in gas production, processing, transmission, storage and distribution systems and in refinery facilities | Methane-Specific | Reduction Projects |
| CDM Approved baseline and monitoring methodology - Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users - AM0077 | Methane-Specific | Reduction Projects |
| Alberta Emission Offset Program - Quantification Protocol for Greenhouse Gas Emission Reductions from Pneumatic Devices | Methane-Specific | Reduction Projects |
| Alberta Emission Offset Program - Quantification Protocol for Engine Fuel Management and Vent Gas Capture Carbon Competitiveness Incentive Regulation | Methane-Specific | Reduction Projects |
| Alberta Emission Offset Program - Quantification protocol for solution gas conservation | Methane-Specific | Reduction Projects |
| British Columbia Greenhouse Gas Offset - Vented Emissions Reductions GHG Offset Protocol | Methane-Specific | Reduction Projects |

### Verification of methane emissions can be mandatory as part of regulatory requirements or voluntary for the purpose of internal use by a company or for public disclose of information.

In countries and regions such as Norway, US, Canada, Russia and Kazakhstan, operators are required to report methane emissions on annual basis, followed by verification conducted by the regulator or a third party. Typically, facilities use uniform methods prescribed by the authorities, such as direct measurement, engineering calculations, or emission factors. In some cases, operators have a choice of calculation methods for an emission source. Verification of emission reports can involve a desk verification of activity data (i.e. count of emission sources) and verification of the adequacy of the applied methodology for emissions.

|  |
| --- |
| **Box 3-2 Mandatory verification in selected counties**  **In the US** Greenhouse Gas Reporting Program, the US EPA has a multi-step data verification process, including automatic checks during data-entry, statistical analyses on completed reports, and staff review of the reported data. Based on the results of the verification process, US EPA follows up with facilities to resolve mistakes that may have occurred.[[50]](#footnote-51)  In **Canada** reporting on emissions due to oil and gas operations (including fugitive emissions) is done under the National Pollutant Release Inventory. All the necessary information about requirements for emission estimations and reporting are compiled in Reporting Guide for the National Pollutant Release Inventory. For upstream oil and gas industry, a specialized “Recommended Approach to Completing the NPRI” prescribes methodologies and emission factors for estimating emissions from various emission sources. [[51]](#footnote-52) The verification is done by Environment and Climate Change Canada which “checks the reports for inaccuracies and reporting errors, and may contact or visit facilities to verify or correct information.”[[52]](#footnote-53)  In **Norway** the updated guidelines for reporting of methane and other **Oil and Gas Carbon Initiative** emissions, released in 2018, includes a section detailing estimation methodologies for various emission sources. The estimation methods are calculation-based, i.e. *activity data × emission factor*, and the operators have been given instructions on how to obtain emission factors. Relatively strict rules on documentation of underlying activity data (flow rate, measurements, information from technology provider, other type of documentation) are required, although no third-party audit or verification standard is specified.  According to Article 22 of the **Russian** Federal Law #96 on “Protection of the atmosphere” (last amended on 13th July 2015), operators are obliged to compile inventories of the pollutant emissions at least once every five years and to provide annual actual data as a basis for pollutant emission payments. For fugitive methane emissions however, it is not required to use facility-specific emission factors and it is only the calculation methodology that is verified. Nevertheless, companies can base their emissions monitoring and reporting based on the technical guidelines developed internally (and approved by the authorities).  As the result, there is no single established methodology for estimating emissions of pollutants from oil and gas operations in Russia. Instead, there are a number of guidance documents that are approved by the government to be used when estimating and reporting company’s emissions.[[53]](#footnote-54) |

## **MRV at the national level and international reporting**

Calculation and reporting of national methane emissions are important for knowledge, awareness and inciting action. It forms a fundamental basis for the design and implementation of effective policies and measures, and for monitoring progress from mitigation efforts. This section summarizes key aspects of the methodologies and practical guidelines for calculating methane emissions at the national level and how this information should be presented and used in a national context and internationally as required according to UNFCCC decisions.

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

### 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 is from 2006.[[54]](#footnote-55) A process for the refinement of the 2006 IPCC Guidelines began in 2017 with the Refinement document scheduled for adoption by the Panel in May 2019.[[55]](#footnote-56)

**[Here will follow a summary of 2006 Guidelines and the 2019 Refinement. It should be noted that** , **developed country Parties to the UNFCCC are currently required to use the 2006 GL, and many developing countries also use them. All Parties to the Paris Agreement will be required to use the 2006 Guidelines when reporting starts in 2024**.

**Since the 2019 Refinement is still being reviewed by relevant governmental institutions (expected to be released in May 2019) it will be included once it has been made public. The following main points to be included are (2-3 pages):**

* Presentation of main methodological features; activity data, emission factors and tiers, see Box 2-1 above.
* Scope and specification Oil and Natural Gas System segments covered
* Emission factors and uncertainty ranges (as provided in Guideline and IPCC Emissions Factor Database
* Completeness and quality control (e.g. way to ensure that no segments are omitted or double counted)
* Tools and practical guidelines for preparation of GHG inventories (e.g. IPCC inventory software, various national GHG capacity building tools and guidelines)

### National Inventory Reports

Improving national inventories, through a progression towards higher tier approaches, is essential in order to reduce the knowledge gap and create a sound foundation for mitigation policies and measures. In practice, improving national inventories for oil and gas methane emissions requires collaboration with oil companies, researchers, and others who can provide important essential inputs, such as emissions factors and activity data. Task forces involving company and public institutions staff can therefore be an important means to improve the quality of national oil and gas methane inventories. Several countries have had broad collaborative processes which have resulted in greatly improved national inventories for oil and gas methane emissions. Three examples are summarized in Box 3-2.

|  |
| --- |
| **Box 3-2: Improving national inventories reports (NIR) for oil and gas methane emissions**  The United States, Canada and Norway have over the past xx year improved the quality and level of details on methane in their NIRs. This has been achieved through active collaboration with the industry and other non- governmental institutions.  In **Norway** a two years study (2014-16) was initiated by the Norwegian Environmental Agency to survey methane emission sources at offshore installations.[[56]](#footnote-57) The objective was to quantify emissions, improve the methodology for quantification (which had been unchanged for more than 20 years) and to undertake BAT assessments and identify suitable mitigation measures. The detailed analysis was conducted by a consultant but with active participation (and data inputs) from operating companies on the Norwegian Continental Shelf, as well as the oil industry association and other relevant regulatory institutions. The work resulted in revisions and a more detailed breakdown of emissions by source (see Table 2.5, Chapter 2 above), and specific recommendations for methodology improvements. Revised emissions levels where found to be lower than previous estimates but with considerable variations between emission sources. The emission abatement potential was found to be modest (around 10%).  In preparing annual NIR the US EPA collaborates with a large number of experts and institutions. 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 has been incorporated into the US estimates across all segments of the oil and gas supply chain.  In **Canada** [to be added] |

The process of moving towards 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 Oil and Natural Gas Systems, but there is no internationally recognized categorization of emissions subcategories relevant for Tier 3 quantification. The emissions categories from Norway or USA are two examples of categories of emission components being used in detailed Tier 3 based methane inventories. [[57]](#footnote-58),[[58]](#footnote-59)
* Definition of the approach to emission estimate for each emission category: An emission estimation approach is then selected for each emission sources, depending on the data (potentially) available.
* Data collection: The data collection process can then start. Two types of data can be collected: (i) activity data and (ii) emission factors. The data may be collected from oil and gas companies (in particular activity data) but research studies may be performed in parallel to e.g. improve the understanding of emission factors
* 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 needs also to be developed to keep the inventory updated over time. This will include updating the activity data each year as well as refining emission factors and improving the management uncertainty in estimates. It is in this regard also important that improved knowledge is being used consistently across time series.

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

For policy purposes it is also important to have in place procedures and capabilities so that results and progress of mitigation efforts can be monitored over time. As noted above this is very demanding because it requires that reliable quantification of how emissions intensities are affected by improvements in technologies and operational practices.

### International reporting and the Paris Agreement “Rulebook”

The variable and often poor quality of UNFCCC methane emissions data were illustrated in Chapter 2 above. In light of the recent decision providing detailed guidance on Paris Agreement reporting it is important that this data quality is improved. As already covered in some detail, the IPCC Guidelines are here important.

All ECE member states are signatories to the UNFCCC and prepare national GHG emissions inventories as obliged under the Convention. Currently so-called Annex 1 Parties submit National Inventory Reports (NIRs) on an annual basis, based on the 2006 IPCC Guideline. [[59]](#footnote-60) So-called non-Annex 1 Parties report their inventories with less regularity and often as part of the National Communications (NCs).[[60]](#footnote-61)

With the focus on higher-quality reporting under the Paris Agreement, the call on countries to improve the quality of estimates of emissions from methane and other GHGs, as well as reporting on mitigation actions undertaken, will become greater. The role played by national authorities in data compilation both for the purposes of international reporting and in support of policies and regulations to curb methane emissions will be even more important. Issues specifically related to the NDCs are further discussed in Chapter 4.

An important step to make the Paris Agreement operational was achieved in December 2018 with adoption of the Paris Agreement “Rulebook”.[[61]](#footnote-62) The part of the Rulebook particularly relevant here are the modalities, procedures and guidelines (MPGs) for the Transparency Framework (Article 13) of the Paris Agreement.[[62]](#footnote-63) The MPGs include a robust and common system that all parties to the Paris Agreement must use in accounting of their emissions.

The Transparency Framework is at the heart of the Paris Agreement. It relates to sharing of comprehensive and comparable information. The MPGs build on the reporting requirements developed under the Convention but set in place common guidelines for reporting and review. This includes greater expectations for the frequency, scope, and level of detail for developing countries, many of which have reported infrequently using less detailed guidelines. . Of note, 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 need in order to fully meet the MPGs of the Transparency Framework.

1. All Parties will report using the same MPGs. While reporting requirements so far have been different for Annex 1 and non-Annex 1 countries, this differentiation does not exist in the MPGs. There are, however some time limited flexibilities for developing countries that need it in the light of their capacities.
2. All Parties will use common reporting formats.
3. Biennial transparency reports (BTRs) and national inventory reports (NIRs) (can be one report) are to be submitted biennially starting from end 2024.
4. Two aspects with the biennial transparency reports particularly relevant to this report:
   1. The National Inventory Report consistent with the 2006 IPCC Guidelines.
   2. Information necessary to track progress in implementing and achieving the NDCs.

Some ECE member states (those being non- Annex 1 to the UNFCCC) may need substantial additional capacity to be able to report according to transparency reporting requirements, particularly for the part that relates to oil and gas sector methane in the national inventory report. Whether methane is included in reporting on progress relative to 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). However as will be further explained elsewhere in this document many countries have large opportunities for cost-efficient methane mitigation, and may wish to include some of these opportunities in their NDCs. This would require the countries to implement IPCC methodologies and procedures for monitoring and reporting methane emissions on a regular basis, and with focus on providing consistent time series. The use of national activity data and emissions factors, combined with detailed, regular reporting, greatly facilitates the quantification of impacts of mitigation efforts. Fortunately, the international community is now very focused on providing capacity building assistance to countries seeking to improve the quality of their reporting under this new enhanced transparency framework.

### 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 which consists of a basic comparison of the reporting format, overall consistent, completeness check; and ***(ii)*** Review by expert review teams that examine the data, methodologies and procedures used in preparing the national inventory against UNFCCC reporting guidelines, with a particular focus on key categories, areas where issues have been identified and recommendations made in the previous reviews.

The MPG document for the Transparency Framework of the Paris Agreement has a detailed description of the scope of work for the Technical Expert Review Team to review the national inventory reports and biennial transparency reports. Relevant to this report, two areas under review will be reporting on the NIRs and information on progress relative to NDC targets. The Technical Expert Review Team will provide recommendations for improvements, and assess the need for capacity building support for those developing country Parties that have used a flexibility provision in the light of their capacity. To the extent that oil and gas sector methane emissions represent a large part of GHG emissions and are explicitly covered in the NDCs, this part will obviously be included in the Technical Expert Review.

# Mitigation

### Key messages

* Methane emissions can be reduced effectively with large near-term climate change mitigation impacts at low capital expenditures. An important part of the emission reduction can be achieved without imposing any net cost to investors.
* Barriers, such as lack of knowledge, awareness and financial incentives, as well as regulatory factors, hinder many of these opportunities from being implemented. Understanding the barriers is essential for planning and implementing mitigation measures and policy instruments
* In addition to motivation to prioritize methane management and implement cost-efficient action companies must acquire knowledge about emission sources, a good overview of abatement options/technologies and establish sound procedures to execute projects and monitor results.
* National circumstances imply that policies and regulations for methane emission can vary greatly between countries. Effectiveness and cost-efficient can be achieved with different approaches but there are some general principles and examples of good practices, regulations and policies which countries should consider. Importantly new technologies for detection and measurement will increase the scope for and efficiency of regulations.
* As countries increasingly focus on the achievement of national targets under international frameworks like the UNFCCC, methane mitigation may provide an attractive opportunity to enhance action. Methane emission reductions could be more explicitly covered in each country’s Nationally Determined Contribution (NDC) to the Paris Agreement. International carbon and climate finance, is one element of carbon pricing that can also play a role in incentivizing mitigation.

## 4.1 Abatement opportunities and barriers to action

A number of empirical studies have documented that oil and gas methane emissions can be substantially reduced at no or low costs. Since methane is a powerful GHG and short-term climate pollutant emission reductions measures can offer large near term climate mitigation benefits and are among the most cost-efficient opportunities of emission reduction efforts.

*Table 4.1 Methane emissions abatement potential in selected countries*

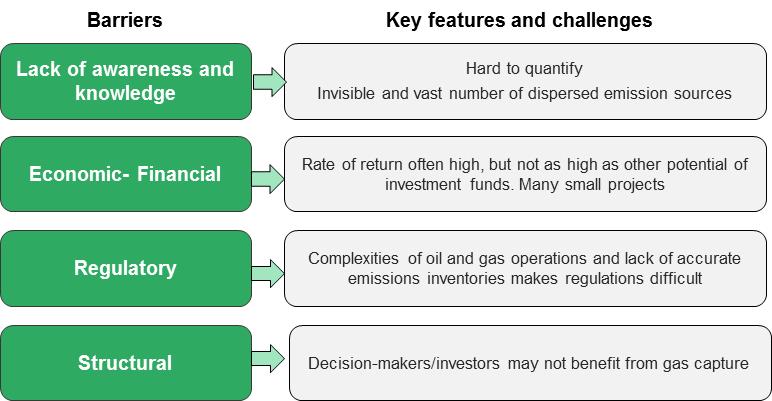
|  |  |  |
| --- | --- | --- |
| **Country /Region** | **Reduction potential** | **Further details** |
| Global[[63]](#footnote-64) | **50%** | Can be mitigated with positive net present value |
| USA[[64]](#footnote-65) | **40%** from onshore installations | Net costs ≤ 0.01 US$/Mcf of natural gas produced  Most of the potential and largest cost savings in Centrifugal Compressors (wet seals) and High Bleed Pneumatic Devices |
| Canada[[65]](#footnote-66) | **45%** from onshore installations | Costs ≤ 0.01 CAD/Mcf of natural gas produced |
| Mexico[[66]](#footnote-67) | **54%** of from onshore and offshore installations | Costs ≤ 0.01 $MXn/Mcf of natural gas produced  More than half the potential in Oil Tanks |
| Kazakhstan[[67]](#footnote-68) | **50%** from onshore installations | Positive net present value for operating companies  2/3 of the potential at Tank Farms and Centrifugal Compressors |

Note: The methodologies for the cost calculations and assumptions (particularly gas prices) of the analyses are better documented in the studies for the US, Canada and Mexico (all commissioned by the international nonprofit organization Environmental Defense Fund) than the global estimates provided by the IEA.

A number of studies have highlighted the importance of oil and gas methane mitigation in international climate policies.[[68]](#footnote-69) Table 4.1 presents results from a selection of methane abatement cost studies. The potential for profitable abatement measures are in the range 40-54 % direct measurement, engineering calculations, or emission factors. In some cases, operators have a choice of calculation methods for an emission source

Limited information is available about the causes for this large, persistent and unexploited potential for economic emission reductions. Barriers to action may vary from country to country and across companies, but there are some common features which are summarized in Figure 4.1 and further explained below.

*Figure 4.1: Overview of barrier to methane emission mitigation*



#### Lack of awareness and knowledge

Methane emissions are largely not visible, and often unknown to the public. Additionally, CO2 emissions have been considered the dominant contributor to GHG emissions, despite the high share of GHG emissions in the Oil and Natural Gas system. Even if awareness exists, there may still 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.

Lack of basic inventories for methane both at the national and company level hinder mitigation actions, and even when methane emission inventories exist, uncertainties in the estimates can halt decision making at the corporate level and may confuse and alienate participants in the political debate and prevent consensus building.

#### Economic - Financial

Even when companies have the knowledge of the scale and nature of emissions, and have identified profitable mitigation opportunities, this may not be enough to spur action. Not all profitable projects are undertaken or invested in, due to lack of human resources and capital to pursue all project propositions reported as profitable. Unless there are specific guidelines or policy reasons (e.g., “Licence to Operate”) to prioritise methane management practices and investments, they will often not be selected in the internal competition for resources.

The financial return on methane emission reduction projects depend critically on the price being paid for the gas captured and brought to markets. If prices used in investment analyses are those observed in relevant gas markets, and prices are kept artificially low through regulations or subsidy schemes, then the incentives for capturing gas otherwise wasted would be too weak. Another and perhaps even more serious hindrance exist if the gas market is “demand constrained” implying that the additional supplies brought about by gas capture does not lead to increased gas sales, but only result in less production. In such cases the gas supplied may not see a near term benefit to justify the costs of gas capture.

#### Regulatory

Oil and gas sector methane emissions have in many jurisdictions have received little political attention and with limited regulatory measures being imposed. A number of factors can explain this:

* As largely invisible and originating in relatively moderate volumes from a huge and dispersed number of sources, methane emissions have not attracted the attention of policy makers and the public. Focus has been on large and visible point sources, as flare stacks.
* Given the complexity of oil and gas sector methane emissions, there are major challenges in developing and implementing good regulations, including the demanding task of establishing competent regulatory institutions.
* In many countries climate change mitigation has only recently emerged as a political priority. It may be perceived as a threat to oil and gas sector revenues, jobs and industrial activity.

The capacity and capabilities of regulatory institutions are important factors, particularly since methane emissions from oil and gas industries are new on the policy agenda and given the complexities of these emissions and the measures to reduce them. More fundamentally, in some countries there are independent regulatory institutions and/or policy making branches that regulate energy, environment, and commercial activities separately.

#### Structural

Structural barriers are related to framework conditions for operators and other partners in 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 Agreement 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 the gas which offers poor incentives to operators to develop and manage gas handling facilities. As a consequence, considerable gas volumes are flared or otherwise wasted with significant economic losses on top of the environmental damages. With the increased focus on flare reduction many countries have or are taking steps to change legal and regulatory conditions with the aim to incentivize gas utilization.

In the downstream segment of the gas value chain a common problem is a lack of incentives for distribution companies to prevent gas losses. Often companies do not purchase and sell the gas, but are merely paid by the volume of gas distributed, as measured at inlet stations. Consequently, their revenues are not sensitive to the rate of losses and their incentives to undertake maintenance and leak detection and repair may be dictated by safety considerations and avoidance of supply disruptions only.

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. Actions by companies, national authorities and international fora are discussed in the three next sections.

## Company strategies and actions

Ultimately decisions and actions to reduce emission of methane emissions are made at the company level. Companies will typically establish strategies and action plans for investments and improvements to operational practices. A good potential starting point is to have available a company-wide inventory of methane emissions (see Chapter 3) which can be leveraged to prioritize the effort and select sites for measurement campaigns. Existing measurement campaigns can directly be used to identify discrete emission reduction projects. Then follow a three-step process, as illustrated in Figure 4.2.

Figure 4.2 Steps in implementation of a methane mitigation strategy and plan



### Evaluate abatement potential and costs

There are currently a large number of best practices and technologies that can be applied to reduce methane emissions from the oil and gas value chain. These practices have been documented in a number of publicly available reports.[[69]](#footnote-70) An overview of the main abatement options by emission sources categories are summarized in Table 4.1 and presented in more details (including links to other sources of information) in the Annex 1.

Table 4.2 Main abatement option by emission source

|  |  |  |
| --- | --- | --- |
| **Emission source** | **Abatement option** | **Emission reduction** |
| **1. Hydraulic fracturing & well completion** | Green completion system | Up to 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 |
| **3. Liquids unloading from gas wells** | Install plunger lift systems in gas well | Up to 95% |
| Capture casing head gas and compress/connect to low-pressure line (VRU) | Up to 98% |
| Smart Well technology to plunger lift systems | 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 | Up to 98% |
| 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/intermittent 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 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 50% |
| Replacement by zero emission options (electric or air driven) | 100% |
| **6. Wet-seal centrifugal compressors** | Re-route gas at atmospheric pressure to VRU 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 | Typically, 50-65% |
| Re-route vents points to VRU or fuel gas system | Up to 95% |
| Re-route vents points to flare | Up to 99% |
| **8. Venting associated gas at upstream oil production facilities** | Flaring without energy recovery instead of venting[[70]](#footnote-71) | Up to 98% |
| Capturing vent gas for gas utilization | up to 100% |
| Install flare ignition systems[[71]](#footnote-72) | Variable |
| **9. Hydrocarbon liquid storage tank, loading & transportation, produced water discharge** | Reduce operating pressure upstream[[72]](#footnote-73) | Up to 30% |
| Increase tank 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 | 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 |
| 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) or low-pressure header (fuel gas or gathering system) |
| Minimise the number of starts ups |
| 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 |
| 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 |
| **Emission source** | **Abatement option** | **Emission reduction** |
| **11. Component and equipment leaks** | Perform LDAR | Depends on frequency |
| Distribution pipeline: Replace cast iron, and unprotected steel pipeline | 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 |
| Improve combustion efficiency by Change flare tip / installing flare ignition systems[[73]](#footnote-74) | Increase to up 98% Combustion efficiency |

A couple of key emissions sources can be highlighted:

* Component and equipment leaks: Systematic and regular LDAR is typically a central part of methane mitigation. It is described in the chap 2 and below
* Compressor vents: Compressor vents contribute a large share of the emission in a number of countries. Various mitigation approaches can be considered including (i) retrofitting to dry seal compressor (ii) re-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.)

Overall, many of the methane mitigation technologies and practices are mature and have been used by the industry, sometimes for decades, though not necessary in every country. A few technologies are more recent, this includes electric controllers and new methane detection technologies.[[74]](#footnote-75)

Based on the emission inventory developed and/or based on measurement surveys performed, companies can identify which mitigation options are most relevant to evaluate. A detailed inventory, with emissions broken down by emission source subcategories represents a significant advantage to effectively identify program with large abatement potential and to focus the effort. Discrete projects are typically identified through specific facilities assessment or measurement campaigns.

For each potential abatement project, an investment analysis can then be performed to estimate the potential emission reduction and the project’s expected cost/profitability. A number of considerations should be highlighted when performing this analysis:

* Investment costs: Project investment capital costs typically include engineering, drafting, site preparation, materials, equipment, instrumentation, utilities, logistics (in particular when technologies need to be imported), labor, construction management, and commissioning costs. Though the actual costs for project implementation vary significantly from site to sites, the investment required to implement each project is typically very modest (compared to other oil and gas investments). For example, replacing a gas driven pneumatic controller costs between a few hundreds and a few thousands USD, while installation of a VRU on a tank farm costs a few hundred thousand USD. However, as described below, projects can be implemented in the form of large programs which combined represent substantial investment.
* Change in operational costs: The (positive or negative) impact of the mitigation technologies on the operational costs needs to be assessed carefully as experience has demonstrated that this impact can be quite substantial. For example, electronic controllers are reported to reduce significantly maintenance costs in particular compared to wet gas driven controllers[[75]](#footnote-76).
* Emission reduction estimate: Emission reduction estimates are typically derived from measurement campaigns and/or from engineering calculation.[[76]](#footnote-77) In some cases, the volume of gas that can be saved by the implementation of a mitigation technology needs to be assessed carefully, through the use of models (for example, to quantify vapor emissions from an un-stabilized liquid storage tank). Annual and short-term variations should also be considered when estimating the benefit (e.g. a compressor used only during the winter). Finally, the lifetime of the abatement measure is also taken into account in the assessment.
* Value of the gas saved: As direct emission of gas is reduced/eliminated, the conserved natural gas can in theory be sold and generate revenue for most of the abatement technologies. Some of the abatement options (e.g., re-routing a vent to a gas flare) do not however provide any gas savings. Depending on the specific ownership or contractual circumstances, it is not always possible for the company that implements projects to benefit fully from the gas saved (see discussion of barriers in section 4.1). As a result, some projects which are economic from a societal perspective are not economic for the owner of the infrastructure.[[77]](#footnote-78)

### Payback period and abatement cost: The payback and the abatement cost for methane emission reduction projects are highly site specific. Given most notably the important variation in terms of emission factors[[78]](#footnote-79), the abatement cost for the same technology can vary significantly for the same abatement options. These indicators should thus always be assessed for each discrete project. Past studies[[79]](#footnote-80) have however demonstrated that a large share of the abatement potential can be implemented at no-net cost, with payback period varying from a few months to a few years.

### Select abatement project

Companies typically select projects based on a combination of criteria including economic considerations (net present value, internal rate of return, etc.), methane emission reduction and practical considerations. A number of points should be highlighted when selecting methane abatement projects:

* The specific role of LDAR: LDAR sits at the intersection between inventory development and mitigation. Emissions sources are first detected and measured (allowing to improve the understanding of the emission rates), and when relevant, repairs are performed. Detection and measurement campaigns are an important part of any methane mitigation strategy and inventory development. Experience has demonstrated that it is virtually always economic to repair a leak once it has been detected[[80]](#footnote-81). Regular LDAR thus represents a natural pillar in a methane emissions management program and, when relevant, can/ and should be integrated into regular HSE activities. Details on the design of LDAR program are presented in Box 4-1.
* Focus on large emission sources: A small number of emissions points typically represent the vast majority of the emissions (see Box 4-2). Focusing in priority on these emission points (often denoted super-emitters), can provide substantial emission reductions and can also be cost effective (due to the large volume of gas wasted).[[81]](#footnote-82)
* Program of projects instead of individual projects: Given the nature of methane emissions (a large number of relatively small sources of emission), it is natural to evaluate program of projects (e.g. install VRU on all the un-stabilized liquid storage tanks within a region). A bundle of investments has the attraction of offering important economies-of-scale. Procurement and installation costs will generally be lower, both because better prices can be obtained for equipment and as a result of more streamlined and efficient installation (experience shows that installation costs can be divided by up to five).[[82]](#footnote-83) There will also be costs savings in planning and execution of monitoring and results. For standalone projects such costs can be significant. The success in achieving efficiency in program implementation typically involves a sequential approach, where experiences and results of the previous installations provide a learning experience for a subsequent scale up. It is however important to note that each system should be properly engineered based on the specific operating conditions and activity levels.

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| **Box 4-1 Leak Detection and Repair (LDAR)**  Detection and measurements is often part of a so-called leak detection and repair (LDAR) or ‘Directed Inspection and Maintenance (DI&M) campaign (hereafter called LDARs) with the primary objective of mitigation, and as such could have been covered in the next chapter. [[83]](#footnote-84) However, LDARs also serve important MRV purposes. They are typically performed on a regular basis with each new campaign allowing for identification of new emission sources that have appeared since the last inspection. Increasing the frequency of LDAR has a positive impact on the overall emission as new emission sources are detected and fixed earlier. On the other hand, increasing the frequency increases the costs, which in turn impacts the cost effectiveness of LDAR surveys. Past studies have showed that the abatement costs (USD spent per ton of emission reduced) increases with increased frequency.[[84]](#footnote-85) In addition, given the variable nature of many of the emission sources, repeat surveys decreases the uncertainty in the emissions estimate. A minimum LDAR frequency is imposed in some jurisdictions. For other countries, the relevant frequency can be determined on a case by case basis. The most relevant inspection frequency depends on:   * The facility size/type: It is cost efficient to inspect a large facility more regularly 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. It may be interesting to plan a LDAR just before a large maintenance to identify additional repair which can be performed, and just after the maintenance to check the tightness of the repairs. * Results of past inspections: Results of past inspections provide valuable information on the past sources of emissions.[[85]](#footnote-86) It is important to note that leaks can develop even in a facility which has demonstrated very limited emissions in past inspections.   Finally, continuous monitoring can also be considered, for example through the deployment of fixed IR camera. This type of approach allows detection of new emission sources (and in particular new super-emitters) early. A maintenance crew is then sent on-site to identify the specific emissions source (depending on the continuous monitoring approach) and to fix it.  Existing document, notably those prepared by the US EPA summarizes elements of best practices for LDARs.[[86]](#footnote-87) They typically include:   * Written program that includes a (measurable) objective for the program, procedures for leak identification and quantification, procedures for repairing and keeping track of leaking equipment, role and responsibilities of personnel involved.[[87]](#footnote-88) * 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 to ensure 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**  Recent research has documented that a small number of sites and components are the major sources of methane emissions.[[88]](#footnote-89) The figure below, taken from 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 CH4 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».[[89]](#footnote-90)  Distribution of measurement of CH4 emissions from natural gas production sites in the Barnett Shale region[[90]](#footnote-91)    There is currently limited published scientific literature on the main causes for the existent of these sources of emissions there are clear indications that equipment age, gas composition, and maintenance practices play a key role. Super-emitters can occur along the entire value chain of oil and gas from upstream production to downstream transmission and distribution. 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), though large emitters can be found in all types of facilities and for all types of components.[[91]](#footnote-92) Typical examples may include faulty devices (such as stuck open valves or continuously emitting intermittent controller). Human errors probably also 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. This means that addressing the larger emitters is not only very efficient from a climate mitigation perspective, but it is also often (but not always) cost-effective (i.e., the savings from the gas recovered are significant).[[92]](#footnote-93)  Super-emitters tend to also be transient both in time and in location, making them relatively unpredictable when it comes to locating these exceptionally large sources of leaks and vents. Systematic and frequent (or continuous) surveys allow identifying and addressing these sources of emissions as soon as possible. Given the magnitude of the super emitters, less-sensitive and cheaper detection technologies can be used for this emission source category. |

### Execute abatement projects

Once an abatement project has been selected, the project execution phase can then start. Companies have internal processes and decision gates which typically include project development (including feasibility), project implementation and project monitoring stages. The focus of this paragraph will be to describe only the specific elements related to methane emission mitigation projects:

* Organizational considerations: Implementing emission reduction program are at times perceived as complex due to the large number of actors involved (for example, installing VRU on all un-stabilised liquid storage tanks involve the coordination with a number of operational teams). Decisions and project implementation involve a number of departments and actors (due to the number of sources) including subcontractors and often overseas internal stakeholders/subcontractors. Local operations always have a key role in ensuring the success of the projects.
* Coordination with other maintenance operations: While many emissions points can be fixed outside of scheduled facility turnarounds, a number of 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. In addition, LDAR surveys could, for example, be run in parallel to other environmental surveys to reduce costs.
* The importance of monitoring: Experience (for example with VRU or low bleed controllers) has demonstrated that emission reduction needs to be verified after the project implementation to evaluate the project’s success over time or to identify and fix implementation issues.[[93]](#footnote-94)
* Greenfield/new infrastructure project: Implementing methane emissions management best practices during the early stages of a project design can significantly decrease the abatement costs compared to retrofit projects.

## National policies and regulations

### National authorities have several options for imposing policies and regulations to reduce oil and gas sector methane emissions. In this section we distinguish between three categories:

1. **Standards** include requirements for use of specific technologies and/or operational practices, and quantifiable emission limits. As standalone tools, technical standards are most common (often denoted as BAT). Emission limits are often used in conjunction with technical standards (e.g. to determine the BAT) or combined with economic instruments (e.g. emission charges or fines). Requirements for regular leak detection and repair (LDAR) programs are also part of this category.
2. **Economic instruments** cover emission charges and emission fines (for emissions above a permitted level), emission trading systems and so-called offset credit scheme, and tax rebates and financial grants for specific emission reduction investments. Tax rebates and grants normally do not require quantification of emissions and therefore have lower administrative costs than the other economic instruments. Gas price and gas price reforms can also be considered as part of this category.
3. **Public-private partnerships and negotiated agreements** between the industry and political authorities or the regulator, can take different forms, from loosely defined partnership with noncommittal targets to formalized agreements with threat of subsequent mandatory regulations of specific quantitative targets are not met. Negotiated agreements may include: i) emission reduction targets negotiated and agreed between the regulator/political authorities and companies, ii) an institution with the mandate to manage and coordinate emission reduction measures to be implemented by companies, and iii) procedures for monitoring, reporting and verification of compliance and eventual enforcement measures.

### Even if there has been little of active policies and regulations for methane across most countries, all the three categories are in use, see Box 4-3.

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| **Box 4-3 Examples of national policies and regulations**  **Standards** for practices (e.g. LDARs) and equipment (e.g. green completion) are currently perhaps the most important measures implemented, primarily in North America. For example, Canada has as part of ambitious methane emission reduction targets (40 to 45% from 2012 levels by 2025) imposed stringent performance standards on compressors and pneumatic devices (e.g. new pneumatic controllers and pumps they should have low/no bleed devices by 2020 and high bleed controllers need to be replaced by 2023).[[94]](#footnote-95) There are also at the provincial level requirement for periodic inspection of leaks and leak detection and repair (LDAR) programs, and offset schemes.  In many ECE member states **Best Available Techniques (BAT) standards** increasingly make reference to methane emissions. Russia, for example, is planning a pilot transition BAT for 300 companies from 2019, which will help reduce emissions from the oil and gas sector. A number of BAT covering methane emissions are included in the sector guidance documents – vapor recovery from storage tank farms, increased durability of pipelines, compressor station optimization. Another example is the European Commission which in September 2018 a draft document (“Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production), where BAT for onshore flaring and venting, and management of fugitive emissions are presented.  **Economic instruments** have not been much in use. Methane emission sources rarely covered by emissions trading schemes and other type of “carbon pricing” largely due to MRV difficulties. This is however in the process of changing with offset schemes for methane now in place on several provinces in Canada, with MRV protocol to take care of accounting issues, see Table 3-1 above. Russia and other republics of the Commonwealth of Independent States (CIS)have for a long time regulated methane as a hazardous pollutant, from a health and safety perspective. Emission limits are set and penalties apply for volumes exceeding the limits. Emission charges are set according to emissions quantification methodologies which will vary and only in some cases be adjusted to local circumstances and may therefore have weak incentives to improve performances. Still, two specific developments in Russia are interesting: i) steps are taken to improve methodologies for quantification of GHG emissions by enterprises ii) emissions charges for air pollutants are used as a powerful policy measure to curb emissions from associated gas[[95]](#footnote-96), [[96]](#footnote-97)  **Agreements and public-private partnership** have been important in 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 and recently updated with a “Methane Challenge” component in 2018. It has been estimated that the program from its inception until 2016 resulted in cumulative methane emissions reductions in the United States of over 39 billion cubic meters.[[97]](#footnote-98) Canada also has a long tradition in fostering agreements with the oil and gas industry on environmental matters, for the major part through initiatives taken by provincial regulatory authorities[[98]](#footnote-99). Since 2016 Norway has had a close collaboration between regulatory authorities and most oil and gas operators to identify and develop measures to reduce emissions, see Box 3-2. |

### Oil and gas sector policies and regulations for methane emissions, to the extent that they exist, vary across countries as do other part of oil and gas sector policies and regulations. 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. These are discussed here, making reference to three main assessment criteria:

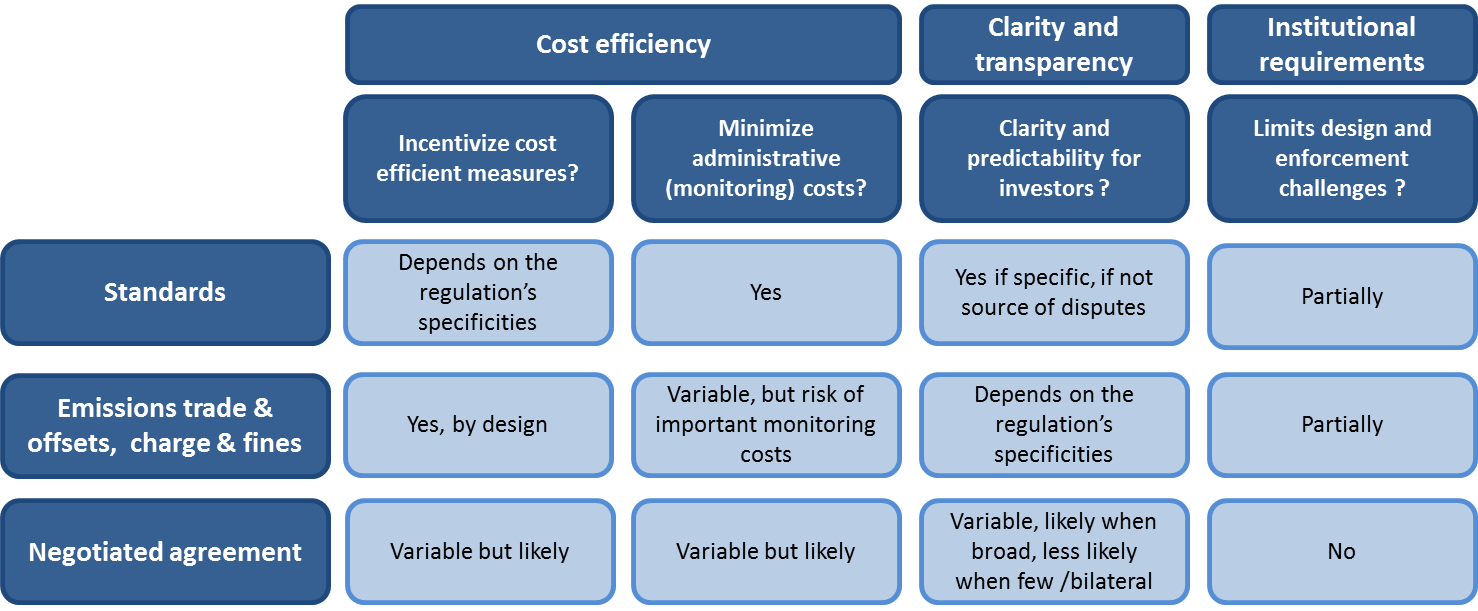
1. **Cost-efficiency**.Measures with low abatement costs should be implemented before measures with higher costs. Due to the sensitivity of emission reduction (abatement) costs to site specific conditions there are considerable practical challenges with ensuring cost-efficiency. Perhaps the most difficult part is to acquire adequate and unbiased information on emissions and cost of mitigation. The administrative costs of compliance and enforcement, both those covered by the companies and the regulatory agencies, can be significant (particularly monitoring and verification costs) and must be taken into account when cost-efficiency considerations are made. It should be noted, however, that compliance and enforcement costs can be significantly reduced with new emerging monitoring technology.
2. **Clarity and transparency**.Rules and procedures for approval of emission limits, technology standards and other regulatory measures should be clear and transparent, and the same goes for compliance and enforcement mechanisms. Predictability in the use of regulatory tools and enforcement is also important, not the least for the purpose of reducing the risk associated with investments in new and efficient technologies.
3. **Institutional capability.** Regulatory ambitions must be attuned to the capacity and capability of regulatory institutions. Again, the complexity of oil and gas sector operations and emissions is a challenge. Regulatory institutions must have staff with adequate sector specific competence, otherwise the principles of cost-efficiency and clarity/transparency will be undermined. More fundamentally, regulatory staff must act impartially and without risk of corruption/mismanagement. Regulatory requirements, data reporting and enforcement procedures that are flexible (e.g. for the sake of cost-efficiency) will generally be more susceptible to corruption than rigid and simple rules. So again, 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 have its practical challenges in the case of methane and black carbon emissions since these emissions cause concern for climate change, local environmental damages, safety and health as well as resource conservation. All these issues are rarely handled by one regulatory institution or by one set of coordinated regulatory measures

It can be misleading to give regulations a score according to the three criteria, for example by giving technical standards a low score on cost-efficiency and a high score on clarity and transparency. Some of the regulatory approaches will by design “pick” the emission reduction with the lowest abatement cost first (e.g. economic instruments such as emissions trading and offset schemes and emission charges) while cost efficiency for others will depend on the specificities of the regulation.

Another complication with a comparative analysis is that the approaches/tools often will be used in combination, and the fact that regulations serve different and sometime conflicting targets (e.g. local versus global environmental concerns, environment versus economic returns). In the practical design and implementation of regulations there are therefore difficult trade-offs to be made, and for this reason it is also difficult to make specific recommendations for regulatory measures here.

Despite these caveats we list in Figure 4.4 a schematic overview of three broad categories of regulations with an indicative assessment of how these categories score against the listed criteria above.

Figure 4.4: Illustrative assessment of regulatory tools



Some further considerations are summarized below:

#### ***Technical standards and emission limits***

Technical standards offer a transparent and simple mechanism to reduce emission; in particular since this option in most cases does not involve the need for cumbersome monitoring. However, to be cost-effective, the technical standards must be based on a detailed understanding of the variety of specific conditions in the oil and gas sector. Therefore, it represents a considerable burden on the regulator for the design, the update and the enforcement of the regulation. Leak detection and repair programs can be considered as standards, and empirical studies suggest that they can be cost-efficient. However, empirical analysis of emission sources and survey & repair costs should be conducted before such programs are designed and operationalized to determine amongst other the relevant monitoring frequency. This was done in the United States and Canada before standards were imposed.

The increased focus on methane emissions in many locations also means that there is 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.

#### ***Economic instruments***

The most obvious and cost-efficient measure under this category is gas price reform so that prices reflect actual costs and market conditions. In some countries, prices are set through political interventions and kept at an artificially low level. Reform of these interventions would help to make gas capture more economical.

In the context of climate policy, carbon pricing is receiving increased attention. It is also interesting to note that some oil and gas companies are increasingly applying carbon pricing in their investment analysis and decision processes, i.e., a cost is attached to every tonne of GHG emissions and investments which reduce emissions will be rewarded according to the cost reductions they create. As policy measures, the suitability and effectiveness of economic instruments depend critically on the ability to monitor and verify emissions. As we know this can be complicated and expensive for methane emissions. Costs and accuracy of emissions quantification must therefore be carefully considered in order to determine whether economic instruments should be applied and how it might be designed. Emissions trading system or emission charges for all methane emissions are difficult due to the large number and great variety of emission sources, which make monitoring, reporting and verification difficult. The cost-efficiency often attributed to economic instruments may therefore be undermined by MRV costs. The most important emissions trading scheme, EU ETS, has been in operations since 2005 and has on a few occasions increased the sectoral scope, but methane emissions are still not included.

However, methane emissions are part of the project-based emissions trading mechanisms (see Section 4.5 below) and these emission reductions can, under certain conditions be used as “offsets” into ETS’s, or methane offsets can in other ways be used as compliance tools under regulatory GHG emissions commitments as already being implemented in Canada. Developing an offset scheme for methane in conjunction with emissions trading has also been considered for implementation in Kazakhstan.[[99]](#footnote-100)

Further development of such offset schemes can give important incentives for emission reductions, both in a national/region context, and through international emissions trading related to the UNFCCC (see Section 4.4). Monitoring, reporting and verification issues required for a credible offset scheme will give insight of great value for regulation of oil and gas sector methane emissions.

#### ***Negotiated agreements***

Public-private partnerships have been successfully been applied in North America and Europe, see Box 3-2 and 4-1. Such partnerships may include negotiated agreements between companies and political authorities/regulators. Agreements are interesting approaches with the promise of being effective and cost efficient, but some conditions are important: i) there must be strong institutions both on the industry and regulatory/political side who 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.

The regulator, companies and their industry associations can jointly develop a report which summarizes common knowledge of emission sources and level (including relevant emission factors and uncertainty levels) drawing both on available company data, national statistics and international data sources. Relevant research institutions etc. may also be involved in this work.

Public private partnerships are potentially a cost efficient measure and there are a number of active national and international partnerships. They are clearly important and effective in creating knowledge and awareness and it remains to be seen what their role can have to spur 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 at international public-private partnerships and industry initiatives which are already making a notable impact. Some of them are surveyed in Box 3-1 and there are a number of others which may become significant in creating awareness and spur action, see Box 4-3.

|  |
| --- |
| **Box 4-3 Overview of international partnerships on oil and gas methane management**  To be completed based on survey to be published by IPIECA |

With the Paris Agreement soon entering its operational phase, and with major part if the Paris Agreement “Rulebook” now adopted by parties to the Agreement (see section 3.3 above), international 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. Emission reductions targets and related plans for policies and measures to be submitted by national governments as part of the Nationally Determined Contribution (NDC) documents.
2. Carbon and climate finance mechanisms, which can help remove barriers and accelerate mitigation efforts.

### NDCs and the Paris Agreement “Rulebook”

Parties to the Paris Agreement are obliged to submit on a regular basis their NDCs. Intended Nationally Determined Contrinutions (INDCs), were already submitted just prior to or after the Paris COP21 meeting in 2015; these were converted into Nationally Determined Contributions as each Party joined the Paris Agreement unless a revised NDC was submitted. Each Party is next required to recommunicate or update its NDC by 2020.

Most NDCs are brief and include little information on planned policies and measures. Many contain little information on sectoral contributions. Of the ECE member states only the submission from Azerbaijan includes details on oil and gas methane emissions reductions[[100]](#footnote-101).

The Paris Agreement Rulebook contains guidance for the information that should accompany an NDC for clarity, transparency, and understanding, as well as guidance on accounting for NDCs. Both sets of guidance must be applied to the second and subsequent NDCs (starting in 2030 for most Parties), but are encouraged to be applied to the first NDCs. These guidelines[[101]](#footnote-102) 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 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 and scope and coverage of the NDC target. As with the MPGs for the Transparency Framework (see section 3.3), there are no differentiation between developed and developing countries, although it is states that capacity building support will be granted to developing countries.

An important issue is the scope and coverage of sectors and emission sources in the NDCs that each Party selects as part of its target. On the one hand there are currently large shortcomings with accounting for methane emissions for many countries, as explained throughout this document, and hence major challenges with target setting and credible methods and procedures for monitored for progress. On the other hand, methane emission reductions are in many ECE member states among the most cost-efficient mitigation opportunities (see section 4.1 above), and many countries may wish to include this mitigation in its NDC.

Quantitative coverage of emissions in NDCs is also a condition for any emission reductions, including for methane, being eligible under cooperative approaches involving the international transfer of mitigation outcomes under the Paris Agreement (Article 6) and other schemes for emissions trading. Without solid accounting of emissions and emission reductions such trading will lack credibility and 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 programmes are summarized in the next section

### Climate finance and carbon market mechanisms

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

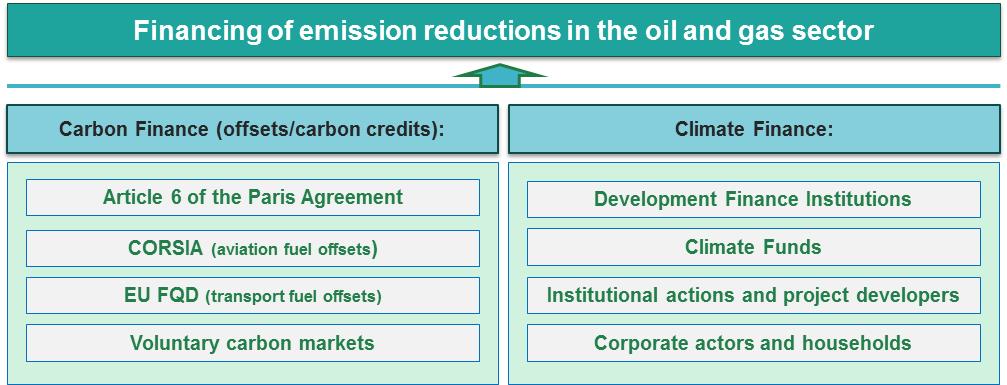
1. *Climate finance refers to local, national or transnational financing—drawn from public, private and alternative sources of financing—that seeks to support mitigation and adaptation actions that will address climate change.[[102]](#footnote-103)*
2. *Carbon market mechanisms, also sometimes referred to as “carbon finance,” which involves trade in verified emission reduction (carbon credits)*

Although many methane mitigation options appear to be financially viable, there exist economic barriers which hinder implementation. Climate finance can be a means to overcome economic barriers (see section 4.1 above) that may hinder implementation of methane mitigation projects, particularly in cases where small projects can be bundled into large programmes with significant GHG emission reduction impacts. The financing can in the form of commercial “green financing/bonds”, or financing on concessional terms. The latter is part of the transfers to developing countries which is an important part of climate change policies addressed under the UNFCCC. Climate finance is seen by developing countries as an important means to reach (conditional) targets set in the NDCs.

Carbon market mechanisms offer payment for emission reduction units as a commodity, and as such is part of a 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 4.5.

Figure 4.5: Overview of carbon market mechanisms and climate finance sources

**

#### Carbon market mechanisms

**Article 6 of the Paris Agreement** has as its objective to achieve higher ambitions in mitigation through voluntary cooperation. Article 6.2 introduces the concept “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 to sell these emission reduction commitments. In other words, there is an “opportunity cost” to selling emission reductions. To ensure that emission reductions are only used for one purpose, the decision on Article 6.2 calls for “corresponding adjustments” when emission reduction units are transferred (i.e. adding back these emissions to the host country’s GHG inventory or decreasing their allowable emissions budget). Article 6.4introduces a new international mechanism which will have similarities with the CDM of the Kyoto Protocol, with 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 has been plagued with onerous rules and procedures. Negotiations on rules and procedures for Article 6 were not concluded and having the schemes operational is therefore delayed. Nevertheless, a number of countries have started “pilot projects” to test bilateral ITMO schemes.

Linked to processes under the Convention, the UN special agency **ICAO (International Civil Aviation** **Organization)** has agreed with the international aviation industry to achieve zero growth in GHG emissions from 2020. A principal means to achieve it 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 industry and may create a demand of 300-400 mill tons CO2 eq. From 2026 and onwards demand is expected to be considerably higher, but is yet not clear what sources supply that will be allowed. Reducing emissions from deforestation and forest degradation (REDD) may become a significant source of supply, but there should also be opportunities for methane emission reduction from oil and gas and other sectors.

Another scheme, outside the Convention and the Paris Agreement, is the **Fuel Quality Directive (FQD)** [[103]](#footnote-104) offsets introduced by the European Union (EU) as a mechanism with which transport fuel suppliers in the EU can meet part of their obligations to reduce the GHG intensities 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 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 now being transposed into national law of all EU countries and will be operational from 2020, albeit as it seems now only for the year 2020, with the exception of Germany where the scheme is expected to last until 2030.

Then there are so-called **voluntary carbon market schemes**. This covers 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. Oil and gas sector emission reductions has only to a very limited degree been channelled to voluntary carbon markets

This section has highlighter the important role the Paris Agreement can play in promoting methane mitigation action, particularly the NDCs and the international cooperation mechanism (Article 6). In many countries, methane emissions hold a large potential for costs efficient mitigation options and can therefore be important. Article 6 of the Paris Agreement was established to “allow for higher ambitions in mitigation”.[[104]](#footnote-105) This is directly related to implementation of the NDCs and accounting procedures and guidelines in the Paris Agreement “Rulebook”. In the context of international cooperation on methane emissions reductions MRV requirements and mitigation are therefore interrelated.

# 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 implemented policies and measures and by market competition wherein the costs and sustainability attributes of energy alternatives are decisive factors. The enduring role of oil and gas obliges increased attention on methane emissions from the entire oil and gas value chain from exploration and extraction to end use.

The current level of methane emissions from oil and gas sector installations represents a significant resource waste and causes environmental damages. Recent research shows that methane emissions are responsible for about one fourth of manmade global warming. Oil and gas sector operations account for one fourth of current global anthropogenic methane emissions, and there are several projections indicating that emissions could increase significantly.

A major part of oil and gas methane emissions is technically feasible to eliminate. Empirical studies suggest that almost 50% can be reduced with no net costs. A number of barriers, including lack of awareness and knowledge, have hinder exploitation of this potential. This document provides guidance for developing and implementing effective monitoring, reporting and verification practices MRV), as well as mitigating methane emissions. The term MRV covers three categories of activities: i) encompass direct measurements and other methods for 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 strongly related. Mitigation can be most effective and cost-efficient when based on sound MRV practices. Further, MRV and mitigation practices conducted at the facility and company level are often interrelated with those developed at national level, and they are again influenced by international guidelines and commitments, 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, with the purpose of contribution to sound MRV practices and effective and cost-efficient mitigation. 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 oil and gas operations**. Data reported to the UNFCCC is the main source of global and country estimates of emissions of GHGs, including methane. The quality of methods and primary data used for these estimates vary significantly by country. There are other (independent) estimates of global, regional and country emissions. Estimated emission levels from the independent sources typically diverge, and countries and sector estimates can be twice or half the level of the official UNFCCC reports. Improving the practices for estimating national methane emissions data is an essential for enhanced methane emissions management.
2. **Quantification of methane emissions is difficult**. Unlike CO2 emissions, methane emissions typically comes from very large number of dispersed emission sources, which often are difficult to detect and measure. Quantification cannot be based purely on continuous monitoring. Procedures should be in place to combine measurements with calculations based methods. Technologies to assist in methane detection and measurement are emerging and should by adopted by companies and authorities in their MRV activities.
3. **Oil and gas companies are making progress in quantifying and mitigating emissions.** Increase recognition of methane management as important for resource efficiency and environmental protection has led a number of large companies to take action unilaterally and/or through industry associations and public private partnerships. Knowledge and best practices are being shared and results are gradually emerging. Still, 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.
4. **The Paris Agreement “Rulebook” calls for scale up of national MRV effort.** This should improve knowledge about the scale and nature of methane emissions and the benefits of mitigation, but many countries may find it difficult to adapt to new accounting and reporting requirements set in the Paris Agreement “Rulebook”. Considerable support is to build the institutional and technical capacity required for reporting biennially on emissions and on progress in mitigation efforts. Sharing of knowledge and best practice experiences, nationally between public institutions and companies, and internationally between a broad set of institutions, will be essential.
5. **Regulatory standards, economic instruments and agreements between the industry and national authorities can all be part of effective and cost-efficient policies to address oil and gas methane emissions.** Current policies and regulations vary across countries as do other parts of oil and gas sector policies and regulations. 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. The suitability of different approaches must be considered in light of national circumstances, including the nature of emissions and related infrastructure. Technological developments and improvement in MRV practises can open up new approaches in use of all the three categories of policy instruments mentioned here.
6. **Enhanced methane emission reductions efforts can result from the Paris Agreement becoming operational**. The significant, near term and cost-efficient mitigation impacts of methane emission reductions call for these being explicitly and quantitatively covered in the Nationally Determined Contributions (NDCs). This requires careful planning and implementation of policies and measures, supported by sound MRV practices. Several of the countries with large methane emission potentials will need support in order to establish the capabilities and capacity the required for MRV and mitigation planning activities. Further, for some countries will also be able to achieve more ambitious reduction through investment support. Investment support would typically be granted based on documented results based on sound MRV methods and practices.

# Case studies

### Case study 1: Public private partnership to improvement knowledge about methane emissions and mitigation options – Norway

[this is a sample to show suggested format and content of case studies, text to this case study may be extended and modified for the public version of this document]

**Initial condition:**

The methodologies and practises for quantification of methane emissions from offshore oil and gas installations on the Norwegian Continental Shelf has been in use for use for 20 years and were perceived to be incomplete and inaccurate. Moreover, with increased political attention given to GHG emissions from the oil and gas industry there was a need to identify new cost- efficient measures to reduce emissions from oil and gas operations on the Norwegian Continental Shelf.

**Process:**

A two years study was initiated by the Norwegian Environmental Agency to survey methane emission sources at offshore installations.[[105]](#footnote-106) The study aimed to identify and categorize emission sources, quantify emissions, improve the methodology for quantification, and make recommendations for possible mitigation measures, including implementation of new BAT standards. The detailed analysis was conducted by a consultant but with participation (and data inputs) from operating companies on the Norwegian Continental Shelf, as well as the oil industry association and the Norwegian Petroleum Directorate and the Petroleum Safety Authority. Operators contributed significantly to practical work and management of the study.

**Results**

The study confirmed that quantification according to existing methodologies and practises were incomplete and inaccurate from some sources. Nevertheless the overall revised estimates were found to be lower than previously calculated. Significant variations between sources were found, with several new sources identified. It was recognized that significant uncertainties are associated with the new estimates. The uncertainty is particularly high for gas leaks. Still it is considered a sound assumption that the total share of leaks is relatively low at 10% of total methane emissions.

Based on the outcome of the study new approaches for methane quantification have been proposed. Specific methods are recommended for individual emission sources and sub-sources. In some cases installation specific methods are recommended.

BAT waste gas recovery standards were recommended for new installations and number of proposal were made for technical modifications to processing units at existing installations.

The emission abatement potential was found to be modest at around 10%.

### Case study 2: Process to establish an inventory for methane emissions at a large state-owned oil company – country in Eurasia

[will be added together with 5-6 other cases]

# 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.[[106]](#footnote-107) For each emission sources, the following information are presented:

* A brief description of the emission sources
* A list of typical mitigation techniques. 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 ion 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.[[107]](#footnote-108) The resulting uncertainty varies significantly depending on the approach selected.

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| * **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 subsequently capture it. In addition, gas can seep to the surface in other locations than the wellbore when the hydrocarbon bearing reservoir is “fracked”. | | | | | | | | | | | * Image Source: http://www.USGS.gov | | | | | | | | | | | | | |
| * **Mitigation Techniques:** * Adopting "green completion" practices to capture gas at the wellhead 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[[108]](#footnote-109)** | | | | | * **Applicable** **Emission Quantification equipment[[109]](#footnote-110)** | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | |
| * Optical Gas Imaging | | | | | * Turbine Meter * Hotwire anemometer * Vane anemometer * Orifice meter | | | | | * Direct measurement and calculation methodology[[110]](#footnote-111) * Default emission factors (Sm3/completion/year) | | | | | | | | | | | | | | |
|  | | | | |  | | | | |  | | | | | | | | | | | | | | |
| * **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 in the annular wellbore space between the tubing and casing, particularly in marginal oil wells with a low GOR. Usually beneficial, casing head gas forces the produced oil up the tubing. However, in mature oil wells equipped with a beam pump or electric submersible pump, this gas can begin restricting 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 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 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[[111]](#footnote-112)** | | | * **Applicable** **Emission Quantification equipment[[112]](#footnote-113)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | |
| * Optical Gas Imaging | | | * Turbine Meter * Hotwire anemometer * Vane anemometer | | | | | | * Direct measurement * Engineering calculation[[113]](#footnote-114) * Default emission factors (e.g. Sm3/well or Sm3/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 accumulating 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 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 * Furthermore, install Smart Well technology to plunger lift systems, an automated system that determines when a plunger lift cycle need to be actuated to determine optimally when liquids should be unloaded. * 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> | | | | | | | | | | | | |
|  | | | | | | | | | | |  | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[114]](#footnote-115)** | | | | | * **Applicable** **Emission Quantification equipment[[115]](#footnote-116)** | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | |
| * Optical Gas Imaging | | | | | * Turbine Meter * Hotwire anemometer * Vane anemometer | | | | | * Direct measurement * Engineering calculation[[116]](#footnote-117) * Default emission factors (Sm3/well or Sm3/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 distillation still vent off-gas. | | | | | | | | | | | * 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 (e.g. desiccant) dehydrators, up to 100% emission reductions achievable[[117]](#footnote-118), [[118]](#footnote-119) * 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 achievable. | | | | | | | | | | | **Further Information:**  <http://www.ccacoalition.org/en/resources/technical-guidance-document-number-5-glycol-dehydrators> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[119]](#footnote-120)** | | | | * **Applicable** **Emission Quantification equipment[[120]](#footnote-121)** | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | | | |
| * Optical Gas Imaging | | | | * Vane Anemometer * Hotwire Anemometer * Turbine meter | | * Direct measurement (but challenging) * Engineering calculation with software * Default emission factors (e.g. Sm3/MM Sm3 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 CH4 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. In addition to emissions by design, pneumatic controller loops and pneumatic pumps can tend to frequently emit gas due to a defect or maintenance issue. | | | | | | | | | | | * Image Source: CCAC | | | | | | | | | | | | |
| * **Mitigation Techniques:** * Replacement or retrofit from high/intermittent bleed to low bleed devices, up to 97% emission reductions achievable. Actual emission rate must be monitored on a regular basis. * Ensure intermittent bleed controller only vents/emits during the de-actuation portion of a control cycle with no emission when the valve is in a stationery position. * Replace with non-methane emitting controller[[121]](#footnote-122) * Routing emissions to an existing combustion device or vapor recovery unit, up to 95% emission reductions achievable. | | | | | | | | | | | **Further Information:**  <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[[122]](#footnote-123)** | | | | | * **Applicable** **Emission Quantification equipment[[123]](#footnote-124)** | | | | | * **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[[124]](#footnote-125) * Default emission factors (in Sm3/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 absorbed by the oil. The seal oil is purged of the absorbed 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 fugitive emissions compared to the wet seals. | | | | | | | | | | | * Image Source: Siemens.com | | | | | | | | | | | | |
| * **Mitigation Techniques:** * Re-route gas at atmospheric pressure to 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[[125]](#footnote-126)** | * **Applicable** **Emission Quantification equipment[[126]](#footnote-127)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | | |
| * Optical gas Imaging | * Vane Anemometer * Hotwire Anemometer * Turbine meter * High volume sampler | | | | | | * Direct measurement[[127]](#footnote-128) * Default emission factors (in Sm3/compressor/year) depending on the type of compressor[[128]](#footnote-129), [[129]](#footnote-130) | | | | | | | | | | | | | | | | |
|  |  | | | | | |  | | | | | | | | | | | | | | | | |
| * **Emission source categories along the value chain** | | | | | | | | | | | * **P** | | * **G&P** | | | | | * **T&S** | | | | * **D** | |
| **7. Reciprocating rod-packing compressors** | | | | | | | | | | | * • | | * • | | | | | * • | | | |  | |
| Though there are 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 replacing packing rings and, in some cases, the piston rods. | | | | | | | | | | | * 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[[130]](#footnote-131)** | * **Applicable Emission Quantification equipment[[131]](#footnote-132)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | | |
| * Optical gas Imaging * Acoustic Detection Device (for through-valve leaks) | * Vane Anemometer * Hotwire Anemometer * Turbine meter * Calibrated Vent Bag * High volume sampler * Orifice meter (vent flow measurement device) | | | | | | * Direct measurement[[132]](#footnote-133) * Default emission factors (in Sm3/compressor/year or Sm3/cylinder/year) depending on the compressor conditions[[133]](#footnote-134), [[134]](#footnote-135) | | | | | | | | | | | | | | | | |
| * **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[[135]](#footnote-136) * Capturing vent gas for gas utilization, emission reductions up to 100% at location[[136]](#footnote-137) | | | | | | | | | | | **Further Information:**  <http://article.sciencepublishinggroup.com/pdf/10.11648.j.ijema.20160406.13.pdf> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[137]](#footnote-138)** | | **Applicable Emission Quantification equipment[[138]](#footnote-139)** | | | | | | **Typical quantification Methodologies** | | | | | | | | | | | | | | | |
| * Optical gas Imaging | | * Vane Anemometer | | | | | | * Direct measurement * Site specific emission factor based on past measurement (in % of throughput) | | | | | | | | | | | | | | | |
| * **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), 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 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 upto 98% * Reducing operating pressure upstream, Increasing tank pressure, Changing the geometry of the loading pipe[[139]](#footnote-140) * 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. 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>  Hydrocarbon loading / unloading:  <https://www.globalmethane.org/m2mtool/files/inddesc/Loading%20and%20Unloading%20Evaporation%20Losses%20-%20Rev%200.doc>  Produced water discharge:  <https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/produced-water.pdf> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[140]](#footnote-141)** | | * **Applicable Emission Quantification equipment[[141]](#footnote-142)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | |
| * Optical gas Imaging * Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) | | * Turbine Meter * Calibrated vent bag\* * Vane anemometer\* * Hotwire anemometer\* * High volume sampler\* | | | | | | * Direct measurement in conjunction with vent gas composition analysis[[142]](#footnote-143) * Estimation method through calculation with software (AspenTech HYSYS, E&P TANKS)[[143]](#footnote-144) * Lab analysis of hydrocarbon liquid * Emission factors (e.g. Sm3/bbl depending on the type of tank) | | | | | | | | | | | | | | | |
|  | |  | | | | | |  | | | | | | | | | | | | | | | |
| * **Emission source categories along the value chain** | | | | | | | | | | | **P** | | | **G&P** | | | | **T&S** | | | | **D** | |
| * **10. Equipment depressurization and blowdowns from pipelines and facilities** | | | | | | | | | | | • | | | • | | | | • | | | | • | |
| * 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. | | | | | | | | | | | * Image Source: Pipeliner Channel | | | | | | | | | | | | |
| * **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. | | | | | | | | | | | **Further Information:**  <http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[144]](#footnote-145)** | | * **Applicable** **Emission Quantification equipment[[145]](#footnote-146)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | |
| * Optical Gas Imaging | | *(When the blowdown is purged through a vent stack or pipe):*   * Vane Anemometer * Hotwire Anemometer * Turbine meter * Calibrated Vent Bag | | | | | | * Direct measurement (but difficult) * Engineering calculation based on throughput * Emission factors (Sm3/event depending on the type of event) | | | | | | | | | | | | | | | |
| * **Emission source categories along the value chain** | | | | | | | | | | | **P** | | | **G&P** | | | | **T&S** | | | | **D** | |
| * **11. Component and equipment leaks** | | | | | | | | | | | • | | | • | | | | • | | | | • | |
| * The potential variety of components or sources of unintentional leaks 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, open-ended lines, 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. Methane Emissions from equipment designed to vent as part of normal operations, such as gas-driven pneumatic controllers, are not considered leaks. | | | | | | | | | | | * **I**mage Source: EDF.org | | | | | | | | | | | | |
| * **Mitigation Techniques:** * Leak detection and repair (LDAR), variable emission reductions | | | | | | | | | | | **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> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[146]](#footnote-147)** | | * **Applicable** **Emission Quantification equipment[[147]](#footnote-148)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | |
| * Optical gas Imaging * Laser leak detector * Soap Bubble Screening * Organic Vapor Analyzers (OVAs) and Toxic Vapor Analyzers (TVAs) * Acoustic Leak Detection | | * Calibrated Vent Bag * High volume sampler * Vane anemometer * Hotwire anemometer * Turbine meter * Acoustic Detection Device (for through-valve leaks) | | | | | | * Leak screening and direct emission rate measurement * Emission factors per component (in Sm3/component) or per throughput[[148]](#footnote-149) | | | | | | | | | | | | | | | |
| * **Emission source categories along the value chain** | | | | | | | | | | | **P** | | | **G&P** | | | | **T&S** | | | | **D** | |
| * **12. Incomplete combustion (including Associated petroleum gas (APG) flaring, engines, turbines, fired heaters)** | | | | | | | | | | | • | | | • | | | | • | | | |  | |
| 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.[[149]](#footnote-150) | | | | | | | | | | | * Image Source: Sparrows group | | | | | | | | | | | | |
| * **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)[[150]](#footnote-151) | | | | | | | | | | | **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> | | | | | | | | | | | | |
| * **Applicable emission detection equipment[[151]](#footnote-152)** | | * **Applicable Emission Quantification equipment[[152]](#footnote-153)** | | | | | | * **Typical quantification Methodologies** | | | | | | | | | | | | | | | |
| * Not relevant | | * Direct quantification difficult or for research only | | | | | | * Engineering calculation based on throughput | | | | | | | | | | | | | | | |

# Annex 2 Mature detection and quantification technologies

This Annex presents a very brief overview of various methane detection and quantification technologies currently available. This is primarily based on Climate and Clean Air Coalition’s Technical Guidance Document and EPA’s Star Program.[[153]](#footnote-154), [[154]](#footnote-155)

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| --- | --- | --- |
| * **Table 1: Mature detection equipment** | | |
| * **1. Optical Gas Imaging (Infrared Cameras)** | | |
| * **Technology**   OGI infrared cameras are able to detect the presence of methane emissions from components and equipment at oil and gas facilities. They are equipped with catalytic oxidation and thermal conductivity sensors designed to detect hydrocarbons which absorb infrared light at specific wavelengths.  **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. 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. | | **Handheld Infrared Optical Gas Imaging Camera[[155]](#footnote-156)**      **Investment Costs**  approx. $85,000 - $115,000 for handheld versions |
| **Method of Usage:** | Generally simple to operate, especially handheld versions. Remotely operated versions from mounting poles or for mobile deployment (vehicular & aerial) also available | |
| **Applicability:** | Leaks and vents of all sizes, typically scans at a distance up to 500m away (small leaks can be detected only from short distance)).[[156]](#footnote-157) A wide variety of hydrocarbon compounds can be detected using OGI cameras (not just methane) and knowledge of equipment may be required to specifically identify methane leaks | |
| **Detection Speed:** | Scans area in real time, capable of 100`s of components / hour | |
| **Climatic Constraints:** | Generally applicable for hot and cold environments, however climatic conditions affect the detection efficiency (temperature & humidity)[[157]](#footnote-158) | |
| **Safety Concerns:** | Generally considered safe, however some cameras not certified intrinsically safe if hydrocarbon presence is significant (battery exposure) | |
| **Service Requirements:** | No calibration required | |
| **Cost Considerations:** | High initial purchase price | |
|  |  | |
| * **2. Laser Leak Detector** | | |
| * **Technology**   Laser leak detectors are a proven method for locating methane emission sources in the oil and gas industry. A popular detector is the Remote Methane Leak Detector (RMLD), which uses a tuneable 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 device uses an invisible infrared laser to detect the presence of methane coupled with a visible green spotter laser to help the operator 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. | | * **Laser Remote Methane Leak Detector[[158]](#footnote-159)** |
| **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).[[159]](#footnote-160) 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 (No cross-sensitivity[[160]](#footnote-161)) | |
| **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), not affected by wind. | |
| **Safety Concerns** | Safe method of leak detection; measurements can be made remotely, keeping operators out of harm`s way. Most models certified intrinsically safe[[161]](#footnote-162). | |
| **Service Requirements** | Calibration is minimal.[[162]](#footnote-163) Most models feature built-in self-test and calibration function which verifies operation and adjusts laser wavelength for maximum sensitivity[[163]](#footnote-164) | |
| **Cost Considerations** | Relatively low-cost solution for methane leak detection | |
| * **3. Soap Bubble Screening** | | |
| * **Technology**   Soap bubble screening is a simple but relatively time-consuming process to detect methane 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. | | * **Soap Bubble Screening[[164]](#footnote-165)**     **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, however some cameras not certified intrinsically safe if hydrocarbon presence is significant (battery exposure) | |
| **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. The devices consist of a flame ionization detector (FID) which is particularly sensitive to methane, and which is capable of measuring organic vapor concentrations ranging from 9 to 10000 ppm. TVAs furthermore 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 10000ppm.  **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 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. | | * **OVA / TVA Screening[[165]](#footnote-166)**     **Investment Cost**  under $10,000[[166]](#footnote-167) |
| **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[[167]](#footnote-168) | |
| **Climatic Constraints** | Cannot be used below freezing point (temperature range of 0 C to 50 C)[[168]](#footnote-169) | |
| **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 | |
| **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. 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 a 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. 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.[[169]](#footnote-170) Ultrasonic leak detectors can also be installed on mounting poles typically around 2m above the ground around a facility and send a signal to a control system indicating the onset of a leak. | | * **Acoustic leak screening[[170]](#footnote-171)**     **Investment Costs**  $1,000 - $20,000 depending on instrument sensitivity, size, and any associated equipment or associated parts[[171]](#footnote-172) |
| **Method of Usage** | Manual operation requiring an operator to test each component with hand-held units. Available in remotely operated models on mounting poles (with automated alarm upon detection). | |
| **Applicability** | Particularly useful for inaccessible components, larger leaks and pressurized gas. Not as useful for smaller leaks or low-pressure gas (150 psi is required for ultrasonic leak detectors).[[172]](#footnote-173) | |
| **Detection Speed** | With hand-held models, speed depends on man-power. Automated pole-mounted systems available with rapid response speed and will sound alarm instantly upon detection. | |
| **Climatic Constraints** | Particularly suitable for windy conditions as the technology is not affected by wind effects. Sensitive to background noise, however can be tuned to specific frequencies of a leak. | |
| **Safety Concerns** | Hand-held 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. | |
| * **7. Spectrometer Sensors** | | |
| **Technology**  Spectrometer sensors are able to detect large methane concentrations from the air by measuring the wavelengths of reflected sunlight 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 any emissions sources. 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[[173]](#footnote-174)**   **(Investment) Cost**  High cost and depends on several factors including location and areal 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 super-emitters. Also useful for surveying pipelines over a long distance and 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. | |
| **Climatic Constraints** | 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, however provide the ability to screen unsafe-to-monitor components that may otherwise be rarely surveyed[[174]](#footnote-175) | |
| **Service Requirements:** | N/A (service providers) | |
| **Cost Considerations:** | May provide maximum impact at minimum cost for detecting large leaks, nonetheless expensive method for screening for methane leaks. | |

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| **Table 2 Mature quantification equipment** | | |
| **1. Calibrated Vent Bag** | | |
| * **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. 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[[175]](#footnote-176)**     **Investment Cost**  Approximately $50 each[[176]](#footnote-177) |
| **Method of Usage** | Operator manually places vent bag around a vent pipe and rate is measured by operator directly at source. Stop-watch and manual measurement of gas temperature also required at source. | |
| **Applicability** | * Requires access to emission source and useful for quantifying large methane leaks/vents ranging from 17m3 / hour to 408 m3 / hour with an accuracy of +/- 10%.[[177]](#footnote-178) Not suitable for smaller emission points | |
| **Quantification Speed** | * Requires operator to record the time required to fill the vent bag using a stop-watch. Not time effective and only capable of quantifying a few leaks per hour. | |
| **Climatic Constraints** | * Can measure over a range of 0°C to 49°C, difficult to use in adverse weather conditions, particularly windy conditions.[[178]](#footnote-179) | |
| **Safety Concerns** | * Requires operator to be located in close proximity to the leak. | |
| **Service Requirements** | * Not required, vent bag can be used approximately 100 times if handled with care. | |
| **Cost Considerations** | * Low cost method, approximately US$ 50 purchase cost per bag and available in various sizes, main expense lies in labour cost (usually 2 operators required). | |
| **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.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.  **Measurement**  The operator places the suction pump on a component, which sucks in the air and analyses if any traces of hydrocarbon is present by measuring the concentration. A thermal anemometer is also inserted directly into the main sample line which 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[[179]](#footnote-180)**   **Investment Costs:**  Approx. $17,500 + $1,200 (calibration kit)[[180]](#footnote-181) |
| **Method of Usage** | Operator manually places suction pump over suspected leak and rate is measured directly at source. Care needs to be taken to ensure against increased dilution of the emission with ambient air | |
| **Applicability** | * Requires access to emission source and useful for quantifying small leaks/vents ranging from 0.02m3 / hour to18 m3 / hour with an accuracy of +/- 10%.[[181]](#footnote-182) Measures combustible hydrocarbon concentrations in the captured air stream ranging from 0.01% to 100% with a reliable range of uncertainty.[[182]](#footnote-183) Does not distinguish between methane and heavier hydrocarbons. | |
| **Quantification Speed** | * Relatively time effective and essentially capable of quantifying multiple leaks per hour, however still requires manual operation of each measurement which can be relatively time consuming. | |
| **Climatic Constraints** | * Can measure over a temperature range of 0°C to 50°C, ideally suited to usage in favorable weather conditions.[[183]](#footnote-184) | |
| **Safety Concerns** | * Device is intrinsically safe (equipped with grounding wire to dissipate any static charge). Requires operator to be located in close proximity to the leak. | |
| **Service Requirements** | Considerable calibration & maintenance required. Calibration prior to each measurement campaign. | |
| **Cost Considerations** | * Relatively expensive method for quantifying leaks, especially when also considering labour costs. | |
| **3. Flow Meters** | | |
| **Technology**  There are several flow meter technologies that can be used including:[[184]](#footnote-185)   * **Positive displacement flow meters** which measures volumetric flow by requiring gas to mechanically displace components * **Thermal mass flow meters** which measures mass flow based on heat transfer from a heated element * **Turbine flow meters** measure volumetric flow based on the gas flowing passed 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)[[185]](#footnote-186)**     **Investment Cost**  Dependent on type of meter (e.g. turbine meter approximately US$4,000, thermal mass flow meter US$4,500- US$8,500)[[186]](#footnote-187) |
| **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 can be in some types even be clipped on 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 leaks (e.g. flanges and valves). Depending on technology used, flow meters are able to measure smaller gas flows (e.g. from 8m3/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. | |
| **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** | * Doesn`t require operator to be close to source, unless for taking manual reading in some meter types (e.g. some turbine meters) | |
| **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 meter, but generally considered cost efficient especially for high flow measurement. | |
|  |  | |
| **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 inserting 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[[187]](#footnote-188)**     **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).[[188]](#footnote-189) 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[[189]](#footnote-190) | |
| **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 | |
| **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 m2. | | * **Hotwire anemometer in use[[190]](#footnote-191)**     **Investment Costs**  Approx. $1,400 to $5,500[[191]](#footnote-192) |
| **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).[[192]](#footnote-193) 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. | |
| **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. Furthermore, 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 | |
| **6. Method 21 (and using correlation equations to estimate emission rates)** | | |
| **Procedure**  The EPA method for “Determination of volatile organic compound leaks” or Method 21 was introduced in the 1990s as a standard by the US Environmental Protection Agency for leak detection and monitoring fugitive emissions.  **Quantification**   1. Screen components to get screening values (SV) in parts per million (ppm).   Only concentration is directly measured by method 21. The size of the leak is not considered, and different leak rates could have the same concentration, and vice versa.   1. Apply correlations to estimate emission rates (ER)   Empirical equations based on field data (SV vs. ER from bagging tests).   1. Report Emission rates in kilogram per hour (kg/hr)   High uncertainties and method 21 can only give an estimate of emission rates. | | * **Correlation curves[[193]](#footnote-194)** |
| **Method of Usage** | Required the concentration of methane emissions of the regulated 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 initially recorded using laser leak detectors or 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 (pegged value, e.g.: 10´000 or 100´000 ppm | |
| **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 | |
| **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. | |

1. The term MRV covers three categories of activities: i) monitoring, which encompasses direct measurements and other methods for quantifying emissions; ii) reporting, which covers compilation of estimated emissions in specific formats for internal use or external circulation; and iii) verification of emissions and/or emission reductions, often by a third party, for internal purposes or as required by public regulations. [↑](#footnote-ref-2)
2. <https://www.iea.org/weo2017/> [↑](#footnote-ref-3)
3. IPCC fifth assessment reports Chapter 8. <https://www.ipcc.ch/report/ar5/wg1/mindex.shtml> [↑](#footnote-ref-4)
4. See for example <https://www.iea.org/weo2017> page 432 [↑](#footnote-ref-5)
5. <https://www.globalmethane.org/documents/gmi-mitigation-factsheet.pdf> [↑](#footnote-ref-6)
6. <https://www.earth-syst-sci-data.net/8/697/2016/essd-8-697-2016.pdf>, and IEA World Energy Outlook 2017. [↑](#footnote-ref-7)
7. See Chapter 10 Figure 10.13 in the IEA World Energy Outlook 2017 [↑](#footnote-ref-8)
8. See Section 10.4 of the IEA World Energy Outlook 2017 [↑](#footnote-ref-9)
9. <http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents> [↑](#footnote-ref-10)
10. <https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf> [↑](#footnote-ref-11)
11. *Id.* [↑](#footnote-ref-12)
12. <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> [↑](#footnote-ref-13)
13. 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 reefing and distribution to end use consumers. [↑](#footnote-ref-14)
14. It is important to note that the year for the emission estimates varies in different studies, which in itself will lead to differences in methane emission estimates. Although many of the studies rely on nationally reported data (including information about methane emissions reported to the UNFCCC), the other data inputs used, for instance certain activity data (e.g. production or throughput volumes, volumes of gas vented and flared), as well as default emission factors might differ in different studies. Default emission factors alone (prescribed by the IPCC 2006 Guidelines) have a range of uncertainty of several hundred per cent. [↑](#footnote-ref-15)
15. <https://www.iea.org/weo2017/> (Figure 10.5 page 441) [↑](#footnote-ref-16)
16. 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) [↑](#footnote-ref-17)
17. <http://science.sciencemag.org/content/early/2018/06/20/science.aar7204> [↑](#footnote-ref-18)
18. Data are from 2015 for most countries, otherwise for the most recent year estimated have been submitted (see Table 2.1). [↑](#footnote-ref-19)
19. 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 [↑](#footnote-ref-20)
20. UNFCCC data for 2015 for annex 1 countries and latest available for non-annex 1 countries [↑](#footnote-ref-21)
21. See Figure 10.7 in IEA WEO 2017. [↑](#footnote-ref-22)
22. It follows from this that IEA estimates of total upstream emissions are 6 percentage points higher than UNFCCC data (78% against 72%). [↑](#footnote-ref-23)
23. <http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents> [↑](#footnote-ref-24)
24. <http://ccacoalition.org/en/resources/oil-and-gas-methane-partnership-ogmp-third-year-report> [↑](#footnote-ref-25)
25. <https://carbonlimits.no/project/statistical-analysis-leak-detection-and-repair-canada/> [↑](#footnote-ref-26)
26. There are over 1.7 million active oil and gas wells in the United States alone (<https://www.fractracker.org/2015/08/1-7-million-wells/>) [↑](#footnote-ref-27)
27. «Quantifying cost effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras”, Carbon Limits report CL-13-27 (2014) [↑](#footnote-ref-28)
28. *Id.* [↑](#footnote-ref-29)
29. Odorized natural gas and sour gas will have noteworthy odor potential. [↑](#footnote-ref-30)
30. Vents are in theory easier to identify than leaks. [↑](#footnote-ref-31)
31. Emission rates are typically variable over time. Variation can occur over very short timeframe (for example with a natural gas driven intermittent bleed controller actuating with variable frequency) or over longer timeframe (for example storage tanks emissions vary depending on the external temperature). [↑](#footnote-ref-32)
32. In addition, some sources of emissions are not easily measured (ref Annex 1) [↑](#footnote-ref-33)
33. <http://www.ccacoalition.org/en/resources/technical-guidance-document-number-7-well-venting-liquids-unloading> [↑](#footnote-ref-34)
34. Including labor and travel costs [↑](#footnote-ref-35)
35. More information on the limitations of IR camera in the Annex 3 [↑](#footnote-ref-36)
36. Note that Stanford University has created a model which can be used by operator to compare a set of 4 detection approaches: <https://ngi.stanford.edu/sites/default/files/Adam_Brandt.pdf> [↑](#footnote-ref-37)
37. Operator can find detailed guidelines in the OGMP technical guidance documents (including reference to relevant software): <http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-technical-guidance-documents> [↑](#footnote-ref-38)
38. The engineering calculation (including the use of models) are particularly for some specific sources of emissions (e.g. storage tanks, ref to annex 1). [↑](#footnote-ref-39)
39. The first approach will not allow to identify emission reductions opportunities or to assess progress over time for example. [↑](#footnote-ref-40)
40. There is currently very limited number of information sources for emission factors in particular for some emissions sources (e.g. Blowdown) [↑](#footnote-ref-41)
41. <http://ccacoalition.org/en/resources/oil-gas-methane-partnership-ogmp-overview> [↑](#footnote-ref-42)
42. <http://www.ccacoalition.org/en/resources/reducing-methane-emissions-across-natural-gas-value-chain-guiding-principles> [↑](#footnote-ref-43)
43. <https://oilandgasclimateinitiative.com/> [↑](#footnote-ref-44)
44. <http://ccacoalition.org/en/content/oil-and-gas-methane-partnership-reporting> [↑](#footnote-ref-45)
45. <https://oilandgasclimateinitiative.com/oil-and-gas-climate-initiative-sets-first-collective-methane-target-for-member-companies/> [↑](#footnote-ref-46)
46. <https://oilandgasclimateinitiative.com/blog/methodological-note-for-ogci-methane-intensity-target-and-ambition> [↑](#footnote-ref-47)
47. <https://www.iso.org/standard/66453.html> [↑](#footnote-ref-48)
48. 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 which 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 guidances on materiality of emissions.

    [↑](#footnote-ref-49)
49. Definition is based on ISO 14064 [↑](#footnote-ref-50)
50. <https://www.epa.gov/ghgreporting/ghgrp-methodology-and-verification> [↑](#footnote-ref-51)
51. <https://www.capp.ca/-/media/capp/customer-portal/publications/252792.pdf?modified=20180526213237> [↑](#footnote-ref-52)
52. <https://www.canada.ca/en/environment-climate-change/services/national-pollutant-release-inventory/data-quality.html> [↑](#footnote-ref-53)
53. Standard programme for natural gas emissions assessment at Gazprom facilities (2006) are available at <https://ohranatruda.ru/upload/iblock/bfa/4293788169.pdf> [↑](#footnote-ref-54)
54. <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> [↑](#footnote-ref-55)
55. <https://www.ipcc-nggip.iges.or.jp/home/2019refinement.html> [↑](#footnote-ref-56)
56. <http://www.miljodirektoratet.no/no/Publikasjoner/2016/Juni-2016/Cold-venting-and-fugitive-emissions-from-Norwegian-offshore-oil-and-gas-activities--summary-report/> [↑](#footnote-ref-57)
57. <http://www.miljodirektoratet.no/no/Nyheter/Nyheter/2016/Juni-2016/Vellykket-samarbeid-om-a-redusere-utslipp-til-luft-fra-norsk-sokkel/> [↑](#footnote-ref-58)
58. <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2016> [↑](#footnote-ref-59)
59. Industrialized countries and countries with economies in transition (including the Russian Federation), as listed in Annex 1 to the UNFCCC. [↑](#footnote-ref-60)
60. Developing countries, including those not listed in Annex 1 to the UNFCCC. [↑](#footnote-ref-61)
61. 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). [↑](#footnote-ref-62)
62. The full text of MPGs for the transparency framework can be found at <https://unfccc.int/sites/default/files/resource/l23_0.pdf> [↑](#footnote-ref-63)
63. <https://www.iea.org/weo2017/> page 426 [↑](#footnote-ref-64)
64. <https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf>. [↑](#footnote-ref-65)
65. <https://www.edf.org/sites/default/files/content/canada_methane_cost_curve_report.pdf> [↑](#footnote-ref-66)
66. <https://www.edf.org/sites/default/files/content/mexico_methane_cost_curve_report.pdf> [↑](#footnote-ref-67)
67. <https://www.carbonlimits.no/project/methane-emissions-from-oil-and-gas-systems-in-ebrd-region/> [↑](#footnote-ref-68)
68. For example, The International Energy Agency stated already in its 2015 World Energy Outlook that oil and gas sector methane emissions reductions as one of five effective measures to more quickly towards an energy path consistent with a 2oC limit for global temperature increase. The three others measures were: energy efficiency in industry, buildings and transport; progressive reduction in least-efficient coal power plants; increased investments in renewable energy technology; phase-out of energy subsidies. See <https://www.iea.org/newsroom/news/2015/november/world-energy-outlook-2015.html> [↑](#footnote-ref-69)
69. Including CCAC OGMP 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. [↑](#footnote-ref-70)
70. CO2 emissions increase with this measure. However overall the GHG emissions decrease

    As the gas is not conserved (i.e. it is burned instead of vented) this mitigation option typically has no economic benefits.

    Flaring is more visible than venting [↑](#footnote-ref-71)
71. 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. [↑](#footnote-ref-72)
72. Needs to be combined with other mitigation upstream or downstream as the emission will happen at a different point in the value chain. [↑](#footnote-ref-73)
73. As the gas is not conserved (i.e. it is burned instead of vented) this mitigation option typically has no economic benefits. [↑](#footnote-ref-74)
74. <https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/> [↑](#footnote-ref-75)
75. <https://carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/> [↑](#footnote-ref-76)
76. Rarely from emission factors which are too uncertain for investment analysis [↑](#footnote-ref-77)
77. A number of mechanisms can be implemented to address this barrier and are discussed in the section 4.4. [↑](#footnote-ref-78)
78. Implementation costs are of course also site specific as highlighted above. [↑](#footnote-ref-79)
79. ICF abatement costs studies for Mexico, US and Canada. IEA WEO 2018. [↑](#footnote-ref-80)
80. “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/> [↑](#footnote-ref-81)
81. There is currently no one single definition for large or super emitters. Whilst 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. [↑](#footnote-ref-82)
82. Based on interviews with Canadian operators on their experiences [↑](#footnote-ref-83)
83. For definition of LDARs and DI&Ms see <http://www.ipieca.org/resources/awareness-briefing/methane-glossary/> [↑](#footnote-ref-84)
84. See for example <https://carbonlimits.no/project/quantifying-cost-effectiveness-of-systematic-leak-detection-ldar-using-infrared-cameras/> [↑](#footnote-ref-85)
85. See for example some work on the analysis of past inspections. <https://carbonlimits.no/project/statistical-analysis-of-leak-detection-and-repair-in-europe/> [↑](#footnote-ref-86)
86. For example: <https://www.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf> [↑](#footnote-ref-87)
87. In the case of a LDAR program [↑](#footnote-ref-88)
88. For example: <http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133> <https://www.nature.com/articles/ncomms14012.pdf> [↑](#footnote-ref-89)
89. <http://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133> [↑](#footnote-ref-90)
90. *Id.* [↑](#footnote-ref-91)
91. <https://carbonlimits.no/project/statistical-analysis-leak-detection-and-repair-canada/> [↑](#footnote-ref-92)
92. Brandt, et. al., Methane Leaks from Natural Gas Systems Follow Extreme Distributions, Environ. Sci. Technol., 2016, pp 12512-12520 [↑](#footnote-ref-93)
93. For example, a number of recent measurement studies have reported higher emissions from low-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](http://www.pnas.org/content/early/2013/09/10/1304880110.full.pdf+html) [↑](#footnote-ref-94)
94. <https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=FF677357-1&offset=2&toc=hide> [↑](#footnote-ref-95)
95. 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 CO2e/year) do not have to be reported [↑](#footnote-ref-96)
96. 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” [↑](#footnote-ref-97)
97. <https://www.epa.gov/natural-gas-star-program/natural-gas-star-program#tab-3> [↑](#footnote-ref-98)
98. e.g. the Alberta Energy Regulator [↑](#footnote-ref-99)
99. <https://www.ebrd.com/documents/climate-finance/the-domestic-emissions-trading-scheme-in-kazakhstan.pdf> [↑](#footnote-ref-100)
100. 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 [↑](#footnote-ref-101)
101. https://undocs.org/FCCC/CP/2018/L.22 [↑](#footnote-ref-102)
102. See <https://unfccc.int/topics/climate-finance/the-big-picture/introduction-to-climate-finance> [↑](#footnote-ref-103)
103. For further information see <http://ec.europa.eu/clima/policies/transport/fuel_en> [↑](#footnote-ref-104)
104. <https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement> [↑](#footnote-ref-105)
105. <http://www.miljodirektoratet.no/no/Publikasjoner/2016/Juni-2016/Cold-venting-and-fugitive-emissions-from-Norwegian-offshore-oil-and-gas-activities--summary-report/> [↑](#footnote-ref-106)
106. The list build on the 9 core emissions sources defined in the CCAC OGMP Technical documents [↑](#footnote-ref-107)
107. Including OGMP reporting guidelines, EPA GHG inventory approach etc… [↑](#footnote-ref-108)
108. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-109)
109. *Id.* [↑](#footnote-ref-110)
110. 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>) [↑](#footnote-ref-111)
111. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-112)
112. *Id.* [↑](#footnote-ref-113)
113. An engineering calculation relies on a representative sample of well production taken with no casinghead gas venting: i.e. capture all gas and oil entering the well casing. 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 [↑](#footnote-ref-114)
114. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-115)
115. *Id.* [↑](#footnote-ref-116)
116. 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> [↑](#footnote-ref-117)
117. 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. [↑](#footnote-ref-118)
118. <https://www.epa.gov/sites/production/files/2016-06/documents/ll_desde.pdf> [↑](#footnote-ref-119)
119. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-120)
120. *Id.* [↑](#footnote-ref-121)
121. <http://www.catf.us/resources/publications/files/Zero_Emitting_Pneumatic_Alternatives.pdf> [↑](#footnote-ref-122)
122. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-123)
123. *Id.* [↑](#footnote-ref-124)
124. 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 per year 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. [↑](#footnote-ref-125)
125. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-126)
126. *Id.* [↑](#footnote-ref-127)
127. 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 [↑](#footnote-ref-128)
128. 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. [↑](#footnote-ref-129)
129. 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> [↑](#footnote-ref-130)
130. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-131)
131. *Id.* [↑](#footnote-ref-132)
132. 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 [↑](#footnote-ref-133)
133. 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. [↑](#footnote-ref-134)
134. 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> [↑](#footnote-ref-135)
135. Gas flaring results of course in significant CO2 emissions. [↑](#footnote-ref-136)
136. Other emissions points may appear on the utilization route. [↑](#footnote-ref-137)
137. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-138)
138. *Id.* [↑](#footnote-ref-139)
139. Also applies to methane emissions from water discharge (reducing to the lowest pressure possible before discharge) [↑](#footnote-ref-140)
140. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-141)
141. *Id.* [↑](#footnote-ref-142)
142. However, standing and working losses are less accurately quantified by direct measurement and with changes in crude oil from multiple wells. [↑](#footnote-ref-143)
143. In addition, emissions from scrubber dump valve need to be estimated [↑](#footnote-ref-144)
144. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-145)
145. *Id.* [↑](#footnote-ref-146)
146. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-147)
147. Same as above [↑](#footnote-ref-148)
148. 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 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. [↑](#footnote-ref-149)
149. 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/> [↑](#footnote-ref-150)
150. 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/ [↑](#footnote-ref-151)
151. From the CCAC OGMP document: Conducting emission detection and quantification equipment [↑](#footnote-ref-152)
152. *Id.* [↑](#footnote-ref-153)
153. <http://www.ccacoalition.org/en/file/3385/download?token=vTrJd-N5> [↑](#footnote-ref-154)
154. <https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf> [↑](#footnote-ref-155)
155. Image source: Carbon Limits measurement campaign [↑](#footnote-ref-156)
156. <https://ngi.stanford.edu/sites/default/files/acs.est_.6b03906.pdf> [↑](#footnote-ref-157)
157. *Id.* [↑](#footnote-ref-158)
158. 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. [↑](#footnote-ref-159)
159. <https://thehazmatguys.com/thmg141-laser-methane-detectors/> [↑](#footnote-ref-160)
160. *Id.* [↑](#footnote-ref-161)
161. <http://www.hetek.com/wp-content/uploads/RMLD-Brochure.pdf> [↑](#footnote-ref-162)
162. <https://thehazmatguys.com/thmg141-laser-methane-detectors/> [↑](#footnote-ref-163)
163. <http://www.hetek.com/wp-content/uploads/RMLD-Brochure.pdf> [↑](#footnote-ref-164)
164. Image source: Natural Gas STAR Technology Transfer Workshop, Houston, Texas, September 22, 2004: “Methane Emissions Management at TransCanada Pipe Lines,” presented by TransCanada [↑](#footnote-ref-165)
165. Image source: CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: “Fugitive Equipment and Process Leaks,” presentation by UNEP [↑](#footnote-ref-166)
166. 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> [↑](#footnote-ref-167)
167. *Id.* [↑](#footnote-ref-168)
168. <https://www.enviroequipment.com/rentals/thermo-tva-1000-fidpid-rental> [↑](#footnote-ref-169)
169. 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> [↑](#footnote-ref-170)
170. Image source: CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: “Fugitive Equipment and Process Leaks,” presentation by UNEP [↑](#footnote-ref-171)
171. *Id.* [↑](#footnote-ref-172)
172. <http://s7d9.scene7.com/is/content/minesafetyappliances/07-8313-MC_UltrasonicGasLeakDetectWP> [↑](#footnote-ref-173)
173. Image source: <http://kairosaerospace.com/methane-detection/> [↑](#footnote-ref-174)
174. <http://kairosaerospace.com/methane-detection/> [↑](#footnote-ref-175)
175. Image source: Carbon Limits measurement campaign [↑](#footnote-ref-176)
176. CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: “Fugitive Equipment and Process Leaks,” presentation by UNEP [↑](#footnote-ref-177)
177. *Id.* [↑](#footnote-ref-178)
178. *Id.* [↑](#footnote-ref-179)
179. Image source: Carbon Limits measurement campaign [↑](#footnote-ref-180)
180. A major high-volume sampler product (Hi-Flow SamplerTM) is being discontinued [↑](#footnote-ref-181)
181. CCAC Oil and Gas Methane Partnership - webinar April 7, 2015: “Fugitive Equipment and Process Leaks,” presentation by UNEP [↑](#footnote-ref-182)
182. *Id.* [↑](#footnote-ref-183)
183. *Id.* [↑](#footnote-ref-184)
184. <https://sagemetering.com/knowledge-base/topics/greenhouse-gas-emissions-monitoring-using-thermal-mass-flow-meters/> [↑](#footnote-ref-185)
185. Image source: CCAC Oil and Gas Methane Partnership: webinar March 12, 2015: “Hydrocarbon Liquid Storage Tanks and Casinghead Gas Venting,” presentation by UNEP [↑](#footnote-ref-186)
186. <https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf> [↑](#footnote-ref-187)
187. 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 [↑](#footnote-ref-188)
188. <https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf> [↑](#footnote-ref-189)
189. *Id*. [↑](#footnote-ref-190)
190. 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 [↑](#footnote-ref-191)
191. <https://www.epa.gov/sites/production/files/2016-04/documents/mon7ccacemissurvey.pdf> [↑](#footnote-ref-192)
192. *Id.* [↑](#footnote-ref-193)
193. Image source: ISA [↑](#footnote-ref-194)