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TECHNICAL ASSOCIATION
OF THE EUROPEAN NATURAL GAS INDUSTRY

Assessment of methane emissions for gas Transmission and Distribution system operators

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1 INTRODUCTION

In an international context where greenhouse gas (GHG) emissions, and more specifically methane (CH_4) emissions are considered to have an important impact on Climate Change, it is crucial for the industry to assess and to mitigate the methane emissions in order to support and contribute actively to the European goal of achieving the Paris targets.

Methane emissions management and reduction is the top priority for the European natural gas industry which has to address this challenge by putting in place systems to ensure a high level of transparency and reliability when reporting its emissions of methane.

MARCOGAZ detected a lack of harmonized standards to address the quantification of methane emissions from the natural gas industry and, therefore, developed the present document that describes a methodology, based on a bottom-up approach, to identify and to quantify all types of methane emissions from transmission and distribution systems.

This document should be a technical guideline for gas companies across Europe to support fast and harmonized implementation of methane emissions quantification process.

This document will be submitted to CEN in order to be used as technical reference to prepare a European standard on methane emissions quantification in transmission and distribution grids.

2 SCOPE

This document describes a methodology to identify different types of methane emissions from the natural gas infrastructure and it explains, step by step, how to quantify each (type of) emission.

Two parts of the natural gas value chain - transmission and distribution systems – are covered, but the general principles can also be applied to other parts of the chain.

The present document specifies a bottom-up method of quantification of identified methane sources. This quantification method requires splitting the gas infrastructure into groups of assets and indicating categories of emission that can be expected from these groups to determine the emission factors (EF) and the activity factors (AF) for each group.

Finally, a general method to calculate the uncertainties associated with the quantified amounts of emitted methane is described.

Note: Parts of the methods of this document are retrieved by an international research program initiated by GERG for DSO [ref. (1)*]. At the time of writing this document, there is another GERG programme investigating the performance of different techniques of methane emissions measurement.*

3 TERMS AND DEFINITIONS

For the purposes of this document, the following terms and definitions apply:

★ **Activity Factor - AF**

A numerical value describing the size of the population of emitting equipment's such as length of pipelines, number of valves (per type), number of pneumatic devices (per type), or the frequency of emitting events such as number of operating vents, multiplied, if relevant, by the duration of the emission.

★ **Block valve**

A valve used to isolate a segment of the main transmission pipeline for tie-in or maintenance purposes. Block valves typically are located at distances of 10 km along each line to limit the amount of piping that may need to be depressurized for tie-ins and maintenance, and to reduce the amount of gas that would be lost in the event of a line break.

★ **Blow down valve**

A valve used to empty a gas pipeline section or a whole installation and, when activated, initiates the gas blowdown (e.g. when gas compressor units are shut down).

★ **Connection**

Area of contact between two or more linked parts, normally sealed by mechanic means in order to keep tightness.

★ **Devices**

Any equipment (active or passive) related to a gas system and needed in order to keep the normal operation of the network. It can be found as in-line equipment (like valves) or auxiliary equipment (like analysers). Methane emissions can appear from devices in unexpected way or as consequence of its function.

★ **Control valve**

Modulating valve that controls either the flow rate or pressure through the pipeline. In the latter case, this facility is often referred to as a regulator station. Usually, high pressure gas from the pipeline is used as the supply medium needed to energize the valve actuator.

★ **Discharge Coefficient - C_D**

C_D coefficient, which relates the actual flowrate to the theoretical flowrate through an opening and accommodates the friction of the real flow as well as boundary layer effects (jet contraction). Needs to be determined experimentally and is nearly one for well-rounded openings.

Remark: According to several data sources, a value of about 0.6 can be applied for sharp edged holes, welding cracks or ruptures (ref. (2), (3), (4)).

★ **Emission Factor - EF**

The emission factor describes typical methane emissions of a component or part of the gas system (e.g. valve, pipeline section) and can have units like [m^3/km] or [m^3/event].

★ **Fugitive emission**

Leakages due to tightness failure and permeation.

★ **Gas compressor station *[ref.* (5)*]***

Installation used for:
- transporting gas in pipelines;
- compressing gas from a pipeline to a gas storage facility or vice versa

More than one of the above functions could be done simultaneously or alternatively.

★ **Gas distribution system *[ref.* (6)*]***

Mains and service lines including piping above and below ground and all other equipments necessary to supply the gas to the consumer.

★ **Gas transmission [ref. (7)]**

Transmission' means the transport of natural gas through a network, which mainly contains high-pressure pipelines, other than an upstream pipeline network and other than the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to its delivery to customers, but not including supply;

Remark: Transport from production companies to the distribution companies and to the industry. Transmission lines transport natural gas across long distances and occasionally across interstate boundaries. They are connected to the distribution grid via city gate stations.

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

★ **Gate station**

A distribution facility located adjacent to a transmission facility where pressure reduction first occurs and the natural gas flows through a splitter system for distribution to different districts or areas. The gas is often metered, heated, and odourised at this point. These stations may have multiple metering and pressure regulating runs. Gate stations are also typically the custody transfer point between transmission and distribution.

★ **Incident *[ref.* (5)*]***

Unexpected occurrence, which could lead to an emergency situation.

★ **Incident emission**

Methane emissions from unplanned events. This will normally be from failures of the system due to third party activity and external factors.

★ **Incomplete combustion emissions**

Unburned methane in the exhaust gases from gas turbines, gas engines and combustion facilities and flaring.

★ **Installation *[ref.* (8)*]***

Equipment and facilities for the extraction, production, chemical treatment, measurement, control, storage or offtake of the transported gas.

★ **Methane emission**

Any release of methane to the atmosphere, whatever is the origin, reason and duration.

★ **Main lines of distribution *[ref.* (9)*]***

Pipework in a gas supply system to which service lines are connected.

⋆ Operational emission

Methane emissions from normal or planned operating activities where often significant volume of natural gas is released to the atmosphere from the gas network. This includes release through stacks; blow off valves, pressure release and purging of turbines and emissions due to normal maintenance inspection and control. Operational vents comprise planned venting and purging of pipelines, which is usually done during commissioning, decommissioning, renewal and maintenance of pipelines for safety reasons to prevent the risk of explosions. Pneumatic emissions are also operational emissions.

⋆ Permeation

Penetration of a permeate (such as a liquid, gas, or vapour) through a solid. In case of natural gas through polyethylene pipelines, it is directly related to the pressure of the gas and polyethylene intrinsic permeability.

⋆ Pipeline components *[ref. (6)]*

Elements from which the pipeline is constructed. The following are distinct pipeline elements:
pipes, including cold formed bends;

- fittings;

EXAMPLE 1 Reducers, tees, factory-made elbows and bends, flanges, caps, welding stubs, mechanical joints

- ancillaries;

EXAMPLE 2 Valves, expansion joints, insulating joints, pressure regulators, pumps, compressors

- pressure vessels

⋆ Pneumatic emission

Emissions caused by gas operated valves, continuous as well as intermittent emissions

⋆ Point of delivery *[ref. (6)]*

Point where the gas is transferred to the user. This can be at a means of isolation (e.g. at the outlet of an LPG storage vessel) or at a meter connection. For this document the point of delivery is typically nominated by the distribution system operator and can be defined in National Regulations or Codes of Practices.

⋆ Porosity *[ref. (10)]*

Volume of the pore space (voids) within a formation expressed as a percentage of the total volume of the material containing the pores.

⋆ Pressure regulating station *[ref. (9)]*

Installation comprising all the equipment including the inlet and outlet pipework as far as the isolating valves and any structure within which the equipment is housed, used for gas pressure regulation and over-pressure protection.

⋆ Purge factor

f_{purge} : Factor, which accounts for the emissions caused by purge operations. Purging of the air inside a pipeline or facility is necessary to mitigate the risk of explosions. The purge factor herein not refers to the amount of purge gas used but to the amount of the gas vented.

Example: If purging is done with 1.5 times the pipeline volume, one volume stays in the pipe and 0.5 volumes are vented to the atmosphere. The purge factor is in this case 0.5. If the actual purge factor is not known for an operation, country specific factors should be used.

★ **Purging *[ref.* (6)*]***

Process for safely removing air or inert gas from pipework and/or pipeline components and replacing it with gas, or the reverse process.

★ **Regulator *[ref.* (11)*]***

Device which reduces the gas pressure to a set value and maintains it within prescribed limits.

★ **Service lines *[ref* (9)*]***

The pipework from the main lines to the point of delivery of the gas into the installation pipework.

Remark: Service line is usually a short, small diameter pipeline that delivers gas from distribution main or transmission pipeline to the customer. They are usually made of steel pipe or steel tubing (either cathodically protected or not), or plastic (usually polyethylene, but sometimes PVC or other plastic), although copper tubing was also used in the past. Service lines can be installed under or above ground.

★ **Uncertainty (of measurement) *[ref* (12)*]***

Parameter, associated with the result of a measurement, that characterizes the dispersion of the values that could reasonably be attributed to the measurand.

NOTE 1: The parameter may be, for example, a standard deviation (or a given multiple of it), or the half-width of an interval having a stated level of confidence.

NOTE 2 Uncertainty of measurement comprises, in general, many components. Some of these components may be evaluated from the statistical distribution of the results of series of measurements and can be characterized by experimental standard deviations. The other components, which also can be characterized by standard deviations, are evaluated from assumed probability distributions based on experience or other information.

NOTE 3 It is understood that the result of the measurement is the best estimate of the value of the measurand, and that all components of uncertainty, including those arising from systematic effects, such as components associated with corrections and reference standards, contribute to the dispersion.

★ **Vented emissions**

All emissions due to operations and incidents.

4 SYMBOLS AND ABBREVIATIONS

Table 4-1 Symbols applied within this report

Symbol	Description	Unit (if not specified otherwise)
A	Area	m^2
AF	Activity factor (used in combination with EF)	km or $-$.
β	Forchheimer coefficient	m^{-1}
c	Concentration	$vol\,\%$
C_D	Discharge coefficient	$-$
d	Diameter	m
E	Methane emission	$\frac{kg_{CH4}}{yr}$
EF	Emission factor (used in combination with AF)	$\frac{kg_{CH4}}{yr}, \frac{kg_{CH4}}{km\,yr}, \frac{kg_{CH4}}{event}$
F_{pv}	Super compressibility factor	$-$
f_{purge}	Purge factor	$-$
k	Permeability of the soil	m^2
$\kappa;\ \gamma$	Adiabatic index of natural gas	$-$
l	Length of pipelines	km
M	Molar mass	$\frac{kg}{kmol}$
µ	Dynamic viscosity of the gas	$Pa \cdot s$
n	Number (e.g. of leaks, incidents, events, etc.)	$\frac{leaks}{yr}$ or $\frac{leaks}{km \cdot yr}$, etc.
PC	Permeation coefficient	$\frac{cm^3}{m \cdot bar \cdot d}$
P	Absolute pressure	$bar(a)$
Q_m	Mass flow rate	$\frac{kg}{yr}$
Q_v	Volume flow rate	$\frac{m^3}{yr}$
R	Ideal gas constant	$\frac{J}{mol \cdot K}$
r	Radius	m
ρ	Density	$\frac{kg}{m^3}$
SDR	Standard Dimension Ratio	$-$
s	Wall thickness	m
T	Temperature	K
U	Uncertainty	-
t	Duration of gas escape	h
V_{geo}	Geometric volume of the pipeline	m^3
x	Fraction	$-$
Z	Compressibility factor	$-$

Table 4-2 Indices applied within this report

Symbol	Description
0	Universal
atm	Atmospheric
CH_4	Methane
eq	Equivalent
ext	External
i, j	Specific
inc	Incident
int	Internal
m	Mass
NG	Natural gas
n	normal conditions (0°C, 101,325kPa)
op	Operational
$perm$	Permeation
$purge$	Purging
ss	Start / stop
$survey$	Survey
$total$	Total
v	Volume
$vent$	Venting

Table 4-3 Abbreviated terms applied within this report

Abbreviation	Description
AF	Activity Factor
DN	Nominal Diameter
DSO	Distribution System Operator
TSO	Transmission System Operator
EF	Emission Factor
EPA	Environmental Protection Agency (USA)
FID	Flame Ionization Detector
GERG	European Gas Research Group
HFS	High Flow Sampler
HP	High Pressure
LNG	Liquefied Natural Gas
LP	Low Pressure
MEEM	Methane Emission Estimation Method
MP	Medium Pressure
MOP	Maximum Operating Pressure
PN	Nominal Pressure
PRMS	Pressure Regulating and Metering Station
PRS	Pressure Regulating Station
SDR	Standard Dimension Ratio. The ratio between the outside diameter and the wall thickness.
UGS	Underground Gas Storage
UNFCCC	United Nations Framework Convention on Climate Change

5 ASSESSMENT OF METHANE EMISSION SOURCES

5.1 Strategy for assessment of methane emission from a natural gas system

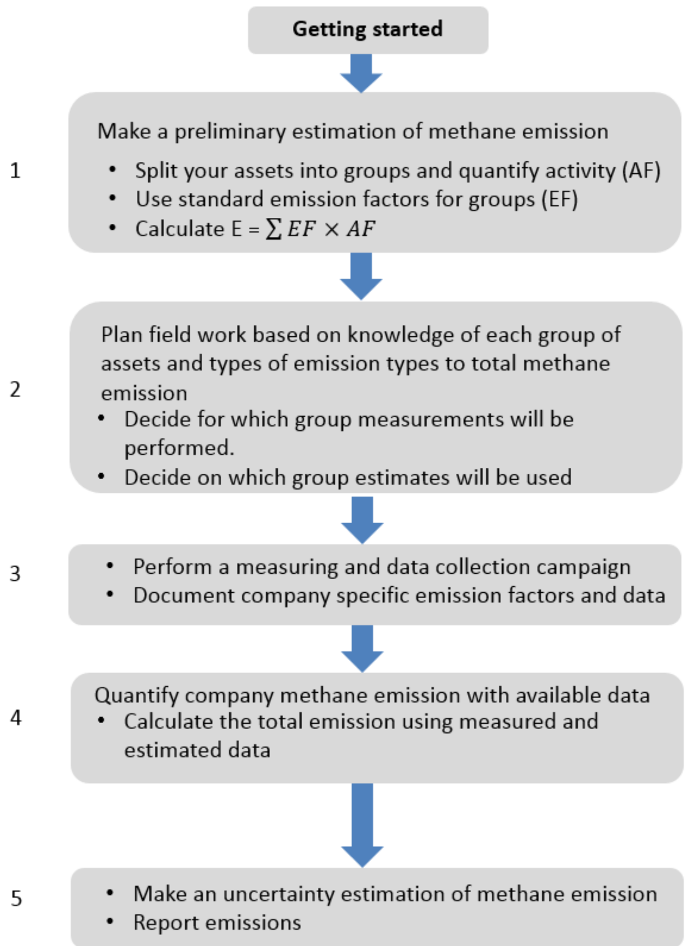
This chapter aims to give the reader an overview of the process of developing methane emission estimation for a pipeline transmission or distribution system. The process is the same whether managing a large complex system or just a small simple one. The overview is given in two figures depending on the starting point in the process, and the accompanying paragraphs will give a brief process description and guide to the paragraphs where further information are given.

Starting point

If no previous estimation of the methane emission from the gas network system exists.

Figure 5-1 gives an overview and provides a systematic approach for methane emission estimation. The following sub-paragraphs provide further information on each step in the process.

Figure 5-1 Process for getting started to estimate methane emission from a gas grid.



1. *Preliminary estimation of methane emission*

First step is to establish a preliminary estimation of the methane emission from the gas grid system. This is done in order to find out from which particular part of the system the emission is likely to be most important. This will vary from DSO to TSO and will vary among these according to their pipeline system, design of the infrastructure and the technologies used.

Figure 5-2 gives an overview of the gas grid for TSO and DSO. For all the group of assets of the grid, emission sources have to be identified.

The first thing to consider is the assets and how these can be divided into manageable groups. The aim is to build asset groups, in which the assets are expected to behave similarly with respect to different types of methane emissions. Examples of asset groups are: steel pipeline, PE pipeline, and metering and pressure regulation stations. It is important that the assets groups are quantifiable groups (e.g. the length of pipeline, the number of stations). § 5.3 includes the list of different assets groups to consider.

Secondly, available knowledge on emissions of methane for each of the asset groups will be needed. If measurements of methane emissions are available for some parts of the system, such data might be able to provide emissions factors for some of the assets groups. Note that some assets have different ways of contributing to the emissions, and make sure that measurements / estimates include all possible emission types. Table 5-2 (§ 5.3) provides information on emission types from different assets. If, for some assets groups no company information is available, it is possible at this stage to use information generated by others. MARCOGAZ provides emission factors ranges *[ref.* (13)*,* (14)*,* (15)*,* (16)*]*.

Finally, combine the asset groups with the emission factors to generate the estimate of methane emissions from the gas grid system. This will provide an overview of the methane emission of the whole system, and which parts give the largest contribution to the total methane emission.

Based on the knowledge from the first step on which assets groups that contribute the most to the total methane emissions, it is possible to reorganise the assets into other groups and to go into more detail in certain segments, or continue with the current asset division.

2. *Planning field work*

Next step is to make a plan for which assets groups the methane emission measurements shall be performed. It might be wise to focus on asset groups that gives the largest contribution to the preliminary estimated methane emissions. Other aspects to take into consideration are budget limitations, planned maintenance activities, and practical limitations.

When making the planning, it is important to consider the type of emissions for the asset group (see Table 5-2, § 5.3) and the measuring techniques which are suitable for those types of emissions (see §7). During the planning, it should also be ensured that the reporting from field measurements on methane emissions includes data on sampling and method uncertainties.

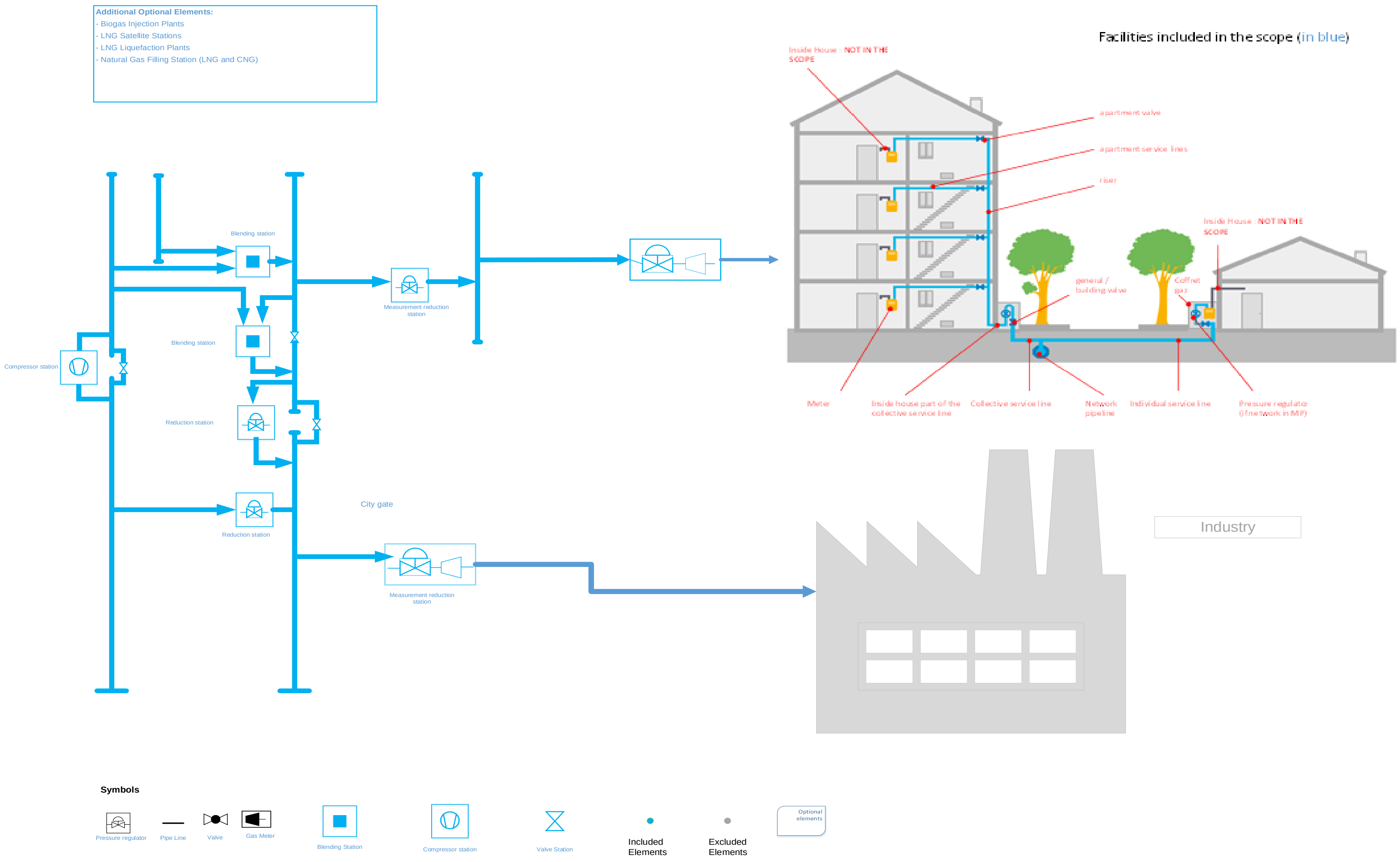


Figure 5-2: Overview of the gas grid

3. Perform a measuring and data collection campaign

Perform the measuring and data collection campaign on the asset groups planned and perform quality assurance for each data set. Collect accepted methane emission datasets in a database. When the measuring campaign has been performed, calculate new emission and activity[1] factors for the relevant asset groups, see paragraph 6 for guidelines.

4. Quantify company methane emission with available data

When the emission factors have been reviewed and accepted, a new estimation of the total methane emissions can be performed combining the data of the measurements and estimates of the asset groups.

5. Reporting methane emission results and uncertainty calculation

A report on the methane emission shall contain a description of the gas system considered, a description of asset division into groups and emission types, documentation on which standard emission factors have been used, and reference to documentation of own determination of group emission factors and their uncertainty. Paragraph 8 provides a guideline for uncertainty calculations. An uncertainty analysis for the total emission of methane will provide detailed knowledge about which assets groups contribute most and where future improvements are possible for the methane emission estimation.

Other issues

Be aware that the process generates knowledge on assets considering maintenance standard and risk of leakage and emissions. This might give valuable clues when companies are planning asset maintenance. We recommend to share this knowledge with the asset management team.

Building further knowledge of methane emissions

Following-up on a previous estimation of the methane emission from the gas network system, companies might want to improve their assessment of the methane emission. This paragraph gives guidelines to how this can be achieved.

Figure 5-3 provides an overview of the ongoing process of improvement and can be used as a work plan. Based on the obtained results for methane emissions the previous years it is possible to make an informed decision on which efforts or improvement will provide most new information.

Evaluate if the assets groups are adequate, or whether more detail is needed.

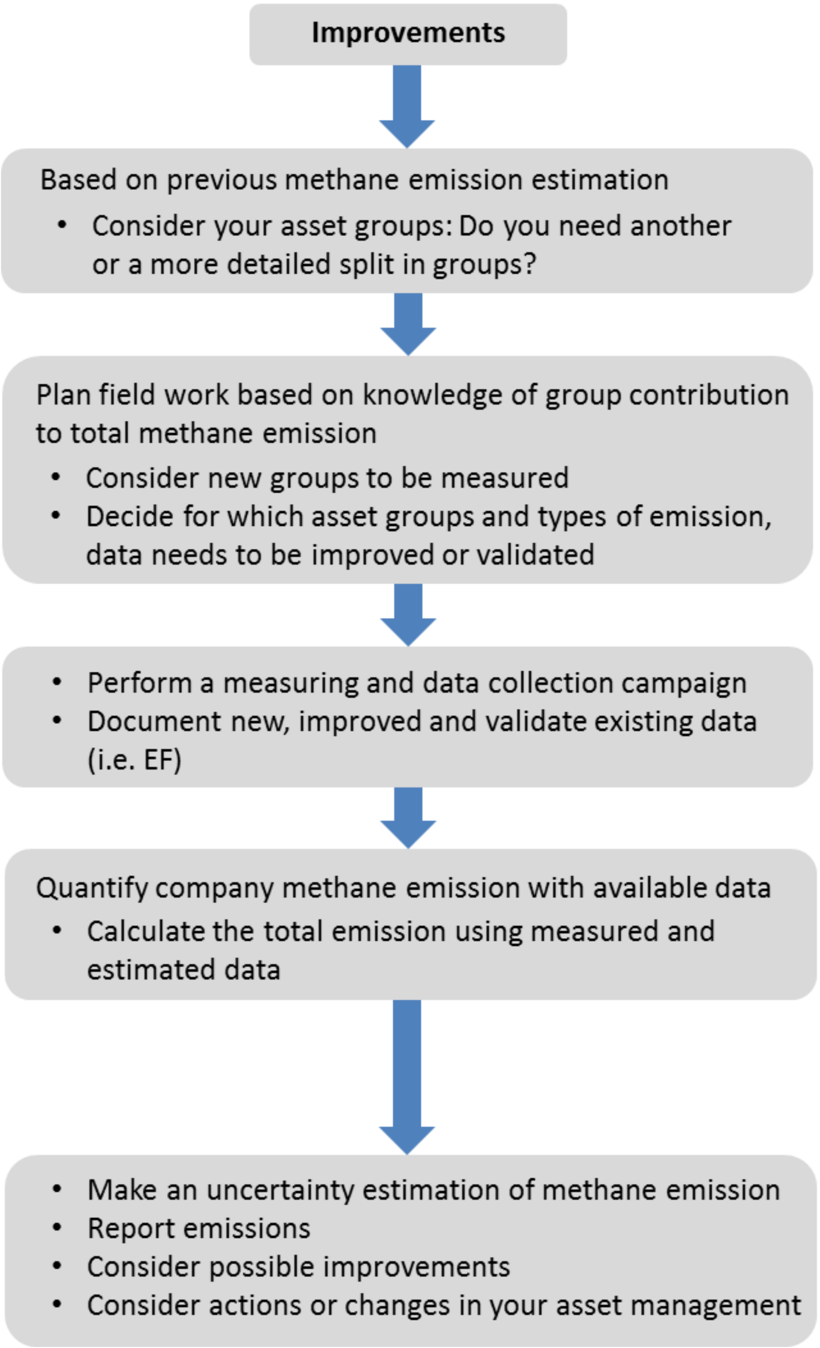
Note: There might be knowledge collected in the previous data showing that an asset group considered rather uniform in emission comprises actually two groups with different emission behaviour. This could be old and non-renovated valves compared to renovated or new valves or similar. It might also be worth considering splitting the major emitters into more detailed groups to be able to better understand and mitigate the emissions, e.g. take a compressor station asset group and split it into a group of compressors and a group for all the piping on the compressor stations.

Note: Having data for more years gives the opportunity to develop trends and to analyse these for company total and for asset groups, which have been divided or improved by renovation. If the company has a methane emission reduction target, it will be possible to evaluate progress and also to suggest which

[1] Emission factors as well as activity factor may need adjustment. E.g. the emissions of pressure regulators are dependent of their mode of operation (stand by position or open regulating position). This might reflect the emission factor as well as the activity factor.

asset groups need to contribute to reach the target, thereby providing strategic information for the future efforts in maintenance and renovation.

Figure 5-3: Process work plan improving the methane emission estimation.



5.2 Emission types for gas networks

Emission assessment procedures often have a similar approach in how to measure and/or estimate the emission sources. In this document methane emission is categorized in 3 types of emissions (see Table 5-1). A method to measure or estimate each emission type is given in the next paragraphs.

Table 5-1: Types of methane emissions

Methane emissions			
Types of emissions			**Examples**
Fugitives	**Leaks due to connexions**		Tightness failure
	Permeation		
Vented	**Operational emissions**	**Purging/venting for works, commissioning and decommissioning**	Works, maintenance
		Regular emissions of technical devices	Pneumatic emissions actuators, flow control valves, …
		Starts & stops	Emissions from start and stops of compressors, …
	Incidents		Third party, corrosion, construction defect/material failure, ground movement, failure of installation
Incomplete combustion			Unburned methane in exhaust gases from combustion installations.

5.3 Identification of emission sources.

Table 5-2 gives an overview of the type emissions to be expected from different groups of assets in the gas network. The paragraphs in the table refers to the paragraphs where a description is given on how to assess the methane emissions. One asset type can have multiple types of emission. The system operator shall assess all the assets and emissions sources of Table 5-2.

Fugitive and vented emissions from Table 5-2 shall be evaluated for all categories of asset where these emissions can occur (see Table 5-2).

marcogaz TECHNICAL ASSOCIATION OF THE EUROPEAN NATURAL GAS INDUSTRY		Types of emissions						
		Fugitives		Vented				Incomplete combustion
				Operational emissions				
		Permeation	Leaks due to connections	Purging/venting for works, commissioning and de-commissioning	Regular emissions of technical devices (e.g. pneumatic)	Start & Stop	Incidents	
Groups of assets	Main lines & service lines	§ 6.4.1	§ 6.4.2	§ 6.5.2.1			§ 6.6	
	Connections (flanges, seals, joints)		§ 6.4.2					
	Measurement devices (chromatographs, analysers …)		§ 6.4.2		§ 6.5.2.2			
	Valves[2] (regul. stations, blending stations, compressor stations, block valve stations)		§ 6.4.2	§ 6.5.2.1	§ 6.5.2.2			
	Pressure / Flow regulators		§ 6.4.2		§ 6.5.2.2			
	Safety valves		§ 6.4.2				§ 6.6	
	Combustion devices (turbines, engines, boilers…)		§ 6.4.2	§ 6.5.2.1		§ 6.5.2.3		§ 6.7
	Compressors & compressor seals		§ 6.4.2	§ 6.5.2.1	§ 6.5.2.2	§ 6.5.2.3	§ 6.6	
	Flares					§ 6.5.2.3		§ 6.7

Table 5-2: Applicable emission types for assets

[2] All types of valves shall be considered: e.g. regulating valves, blow down valves, block valves regulating valves, open-ended line valves

6 QUANTIFICATION

6.1 General concept of quantifications

The bottom-up approach used in this document is a source-specific quantification approach. Methane emission from each identified source shall be quantified. The total methane emissions can be calculated by summing all emissions of the individual sources.

Quantification comprises measurements of the amount of methane emitted from leaks of different origin, estimation of emissions from groups of assets or calculation based on available data.

The general idea on how to quantify total methane emissions is given by equation 6-1.

$E = \sum_{i}^{n} E_i = \sum_{i}^{n} (EF_i \, . AF_i)$	*6-1*

Where:

E	Total methane emission, in [kg]
E_i	Methane emissions of source i, in [kg] Remark: E_i can be directly measured, derived from measurements, calculated or estimated, see §6.2.
EF_i	Emission factor typically expressed as a mass flow rate (Q_m) in kg per time unit and per "i" event (or device or group of assets)
AF_i	Activity factor typically expressed as a result of multiplying number N of "i" events (or devices or group of assets) by duration of methane leakage t_i
n	number of all considered emission sources

AF_i is calculated as:

$AF_i = N_i \, . t_i$	*6-2*

Where:

N_i	Number of "i" events or devices or group of assets. Depending on category of emission, they can be: length of pipeline, number of leaks, number of vents, number of incidents, number of start & stops, number of devices.
t_i	Duration of methane leakage due to "i" event (or device or group of assets). Duration is expressed in a year or in an hour, depending on the category of emission and units of the Q_m.

Table 6-1: Examples of EF and AF units for different types of emission

Types of emissions			EF	AF
Fugitive emissions	**Pipeline permeation**		Q_m in [kg/km*yr]	N = length of pipelines, in [km] t = duration of the leak expressed in [year] (for new pipeline, t can be < 1)
Fugitive emissions	**Leaks due to connexions (flanges, pipe equipment, valves, joints, seals)**		Q_m in [kg/leak*yr]	N = number of assets of each group t = duration of the leakage expressed in [year]
Vented	**Operational emissions**	**Purging/venting for works, maintenance, commissioning and decommissioning**	Q_m in [kg/event]	N = number of vents or purges t is not relevant (t=1)
Vented	**Operational emissions**	**Regular emissions of technical devices (e.g. pneumatic)**	Q_m in [kg/h*device]	N = number of devices of each type t = duration in [hour]
Vented	**Operational emissions**	**Start & Stop**	Q_m in [kg/(start/stop)]	N = number of starts & stops t is not relevant (t=1)
Vented	**Incident emissions**	**Distribution grid**	Q_m in [kg/incident] or [kg/km]	N = number of incidents or km of pipeline t is not relevant(t=1)
Vented	**Incident emissions**	**Transmission grid**	Q_m in [kg/incident]	N = number of incidents t is not relevant(t=1)
Incomplete combustion			Q_m in [kg/h]	N = number of combustion installations in service t = duration in running [hour]

Conversion of volume flow rate into mass flow rate

Equation to calculate the mass flow rate Q_m based on the volume flow rate Q_v.

$Q_m = Q_v . x_{CH4} . \rho_{CH4}$	*6-3*

Where:

- Q_m mass flow rate of methane in kg/time unit
- Q_v volume flow rate of gas in $m^3{}_n$/time unit
- x_{CH4} methane concentration in the gas (in %) based on the gas composition
- ρ_{CH4} density of methane (i.e. 0,7175 kg/m³ in normal conditions)

In Table 6-2 some examples of emission factors and the corresponding activity factors are given.

Table 6-2: Examples of emission estimation/calculation

Examples	EF	AF	E
Pipelines	0,1 kg km^{-1} yr^{-1}	1.000 km	100 kg / yr
Venting due to overpressure (exceeding MOP)	500 kg / vent	100 vents / yr	50.000 kg / yr
Single incident	1.000 kg	1 incident	1.000 kg
Incidents for a given period of time.	1.000 kg/incident	12 incidents	12.000 kg

6.2 Determination of Emission Factors (EF)

Emission factors (EF) shall be determined for all assets (e.g. main lines, service lines and facilities like pressure regulating stations) and for all events (e.g. leakages on pipelines, maintenance operations on pipelines or on facilities, etc.). Further distinction can be made among materials, pressure levels, locations (above ground or underground), diameters, etc (see § 5.3).

Emission factors can be determined directly by measurement, estimated or calculated:

Measurements
Emission measurements can be made using methods listed in §7. Measured data can be used directly for quantification or for estimation of EF's for different group of assets.

Estimations

The EF used describes a typical methane emission from a component or an emission event, established from academic publications, field measurement campaigns on a device population sample, gas industry R&D research, or equipment supplier data, so that the EF are at the closest of the company equipment reality. The relevant EF is then applied to a population of emitting sources.

Calculations
The EF used is directly calculated from field data or/and design data.
For example, in the case of the vents, the amount of methane emitted can be accurately derived from the pipe section volume (length and diameter) and the pressure condition in that particular pipe section. An AF in this case may be the number of vents at Operating Pressure (OP) during the events or if no information about pressure is available by default the Maximum Operating Pressure (MOP) can be used.

6.3 Determination of Activity Factor (AF)

In general, activity factor (AF) needs to fit to the respective emission factor (EF). AF is typically expressed as the number of leaks per year (absolute or per km) or the number of incidents or events (see also Table 6-1) or the operating time. Usually activity factors are provided from asset management databases of the operators which includes master data and incident registrations.

6.4 Quantification of fugitive emissions

6.4.1 Fugitive emissions from permeation of pipelines

Permeation, in terms of gas flow through pipeline walls, is a physical property related to polymers (e.g. polyvinylchloride (PVC), polyethylene (PE), polyamide (PA).

Note: Permeation emission of pipelines made of steel/cast iron is considered to be zero and therefore does not need to be taken into account.

The emission of a pipeline group "i" is estimated by the general equation 6-4 and total emission of all the groups by the equation 6-5.

$E_i = EF_i . AF_i = Q_{m_{i,}} \cdot l_i \cdot t_i$	*6-4*
$E = \sum_{i=1}^{n} E_i$	6-5

Where:

$Q_{m_{i,}}$	The emission rate in [kg_{CH4}/(km.yr)] of a pipeline group "i". It depends on material, diameter, thickness and pressure. Figures come from external studies. Equations to use for the calculation of Q_m are given in Annex A and Annex B).
l_i	The length of pipeline group "i" of a specific material, diameter, thickness and pressure, in [km]. Figures come from operator's inventories.
t_i	The duration of the permeation during the period of evaluation, in [year].
i	The reference of a pipeline group: "i = 1 → n". Grouping can be performed on basis of material, diameter, thickness and pressure.

6.4.2 Fugitive emissions due to connections (e.g. flanges, pipe equipment, valves, joints, seals)

Natural gas grids are inspected regularly to detect leaks and to ensure safe operations.

The emissions of leaks which are detected by survey are categorized as fugitive emissions and can be quantified through three approaches (that can be combined): direct measurement (§6.4.2.1), estimation derived from survey (§6.4.2.3) or estimation based on emission factor (§6.4.2.2). These 3 approaches can be applied to all type of assets when quantifying the total fugitive emissions.

Fugitive emissions due to connections are grouped according to Table 5-2. Sub grouping is also possible based on materials or other properties.

6.4.2.1 Quantification by direct measurement

Leak detection and measurement (see measurement methods in §7), are performed to derive the total emission of a group of asset (e.g. station, compressor, equipment type), measuring the emission of each single leak.

In this case, the total emission is the sum of all the individual (measured) leaks.

6.4.2.2 Quantification using emission factors (estimation)

Different EF shall be defined for different (sub-)groups and multiplied by the respective AF.

Total emissions for fugitive leaks should be estimated using equations 6-6 and 6-7.

$E_i = \mathrm{EF_i} \cdot \mathrm{AF_i}$	*6-6*
$E = \sum_{\mathrm{i=1}}^{\mathrm{n}} \mathrm{E_i}$	*6-7*

Where:

$\mathrm{E_i}$ Emission related to fugitive leak of group of assets "i", in [kg]

$\mathrm{EF_i}$ Emission factor related to fugitive leak of group of assets "i"

$\mathrm{AF_i}$ Activity factor related to fugitive leak of group of assets "i"

E Emissions related to the fugitive leaks from all the groups of assets "i=1 → n", in [kg/yr]

Note: EF is in that case commonly established by measurement on a representative sample of assets, during leak detection and measurement campaigns.

6.4.2.3 Quantification derived from survey

Emissions of leaks, which are detected by survey (through a systematic by vehicle or pedestrian leak monitoring, mainly for pipelines systems operated by DSOs) are classified as fugitive emissions and can be estimated by equations 6-8 or 6-9.

$E = Q_m \cdot t \cdot n$	*6-8*

Where:

E Methane emission of leaks detected by survey, in $\left[\frac{kg}{yr}\right]$

Q_m Average emission (mass flow) rate of a leak, in $\left[\frac{kg}{leak \cdot h}\right]$

t Average duration of gas escape of a leak, in $[h]$

n Number of leaks detected per year, in $\left[\frac{leaks}{yr}\right]$

$E = Q_m \cdot t \cdot n \cdot l$	*6-9*

Where:

E	Methane emissions of leaks detected by survey, in $\left[\frac{kg}{yr}\right]$
Q_m	Average emission (mass flow) rate of a leak, in $\left[\frac{kg}{leak \cdot h}\right]$
t	Average duration of gas escape of a leak, in $[h]$
n	Number of leaks detected per year, in $\left[\frac{leaks}{km \cdot yr}\right]$
l	Length of main lines, in $[km]$.

These emissions are the sum of the emissions from all leakages detected by the operator surveys during the year.

6.4.2.3.1 **Emission rate Q_m**

First, a distinction should be made between underground leaks and above ground leaks. The emission rates of above ground fugitive leaks are generally larger than for the underground leaks since there is no soil acting as a barrier.

For underground leaks four approaches to determine emission rates are available (see also §7):

1. By constant pressure method (determination of the emission rate of a pipe section);
2. By pressure decay method (determination of the emission rate of a pipe section);
3. Determination of the emission rate of each single leak;
4. Determination of Soil Coefficients and calculation of the Emission Rate from Leak Size and Pipeline Pressure

If the number of leaks decreases, the results of an application of the indirect approaches (1 and 2) are not influenced by this, without doing new measurements, since there is no reference to the leak survey data. Therefore, this standard focuses on the direct approaches 3 and 4.
A description of the approaches available to determine emission rates q_m for underground leaks is given in Annex C.

6.4.2.3.2 Duration of gas escape (t)

The duration of a gas escape needs to be determined in order to estimate emissions of leaks (equation 6-10).

$t = t_1 + t_2$	*6-10*

Where:

t	Duration from the beginning of the gas escape until the gas flow is stopped (at least by provisional measures), in [hour].
t_1	Duration from the beginning of the gas escape until it is detected, in [hour].
t_2	Duration from the detection of the gas escape until the leak is stopped (at least by provisional measures), in [hour].

The determination of t_1 is difficult since the network operator does usually not know when the gas escape exactly started. The determination of t_2 depends on the urgency of repair and may be determined by various factors, e.g.:

- Location of the gas leak (distance to buildings, cellars, canalisation …)
- Concentration of methane measured

Two basic approaches are in place to determine t, and are described in Annex D.

6.4.2.3.3 Number of leaks

The emission rate Q_m and the duration of gas escape t (equation 6-9 or 6-10) should be multiplied by the number of leaks n (absolute or per km). Different categories of leaks (e.g. leaks on low pressure plastic pipelines) can be defined by taking into account different Q_m and t and multiplying them with the respective number of leaks of the group.

6.5 Quantification of vented emissions

6.5.1 General considerations

Vented emissions comprise of operational emissions and incidental emissions.
Operational emissions include venting and purging, which is usually done during commissioning, decommissioning, renewal and maintenance of pipeline systems, regular emissions of technical devices and emissions from start-stop operations.

In the cycle to start a compressor in some cases methane is emitted to the atmosphere. For safety reasons, the content of the pipeline connected to the compressor is released to the air when a compressor is set off. The associated emissions can be significant and need to be taken into account in the methane emission calculation as vented emissions.

If detailed data is available, operational data should be determined with an event-based approach by summing up the venting, purging and start-stop emissions of each operation.
If the detailed data for the event-based approach is not available, a simplified approach can be used instead.

An incident vent can be caused by a system failure, like an overpressure. This will release gas via safety valves to the surrounding to ensure safe operations of the installations.
In the case of a distribution grid, EF may be estimated per incident, or per length of a pipeline section.
In the case of a transmission grid, EF is usually related to a single event and is a matter of fact an amount of CH_4 emitted.

Note: The amount of gas released caused by an incidental vent can be estimated from inner pressure and orifice diameter. Duration of the escape is also usually known.

6.5.2 Operational emissions

The total operational emissions shall be calculated by summing up emissions from purging, venting, regular emissions of technical devices and start-stop operations which took place during the year (other time periods may be also used) according to equation 6-11:

$E_{op} = E_{vt} + E_{devices} + E_{pr} + E_{ss}$	*6-11*

Where:

E_{op}	Total operational methane emission during a year, in $[kg]$
E_{vt}	Emission from venting during a year, in $[kg]$
$E_{devices}$	Emission from technical devices during a year, in [kg]
F_{pr}	Emission from purging during a year, in $[kg]$
F_{ss}	Emission from start-stop operations during a year, in $[kg]$

6.5.2.1 Venting and purging

Emission from venting operations E_{vt} shall be calculated according to Equation 6-12. It was assumed, that all vents are split into "n" groups, and that each group of vents has its own Emission Factor (EF) and Activity Factor (AF).

$$E_{vt} = \sum_{i=1}^{n} (EF_{vt(i)} \,.\, AF_{vt(i)})$$	*6-12*

Where:

$\boldsymbol{EF_{vt(i)}}$	The emission factor for "i" group of vents, in $\left[\frac{\boldsymbol{kg}}{\boldsymbol{vent}}\right]$
$\boldsymbol{AF_{vt(i)}}$	The number of vents, within group "i" in [vent]
n	The number of groups of vents per year

Emission from purging operations shall be calculated according to Equation 6-13. It was assumed, that all purges are split into "k" groups, and that each group of purges has its own Emission Factor (EF) and Activity Factor (AF).

$$E_{pr} = \sum_{i=1}^{k} (EF_{pr(i)} \,.\, AF_{pr(i)})$$	*6-13*

Where:

$\boldsymbol{EF_{pr(i)}}$	The emission factor for "i" group of purging, in $\left[\frac{\boldsymbol{kg}}{\boldsymbol{event}}\right]$
$\boldsymbol{AF_{pr(i)}}$	The number of purges of group "i" in [event]
k	The number of groups of purging per year

6.5.2.2 Regular emissions of technical devices

Regular emissions from technical devices are, among others, emissions from pneumatic controllers/actuators but also emissions from sampling of measurement equipment, or emissions from compressor on which gas seals are installed.
Regular emissions have the following properties:

- Emissions can be continuous or intermittent;
- The rate of emissions depends on the design and the operational conditions of the device.

The regular emissions are estimated by the following steps:

1. Perform inventory of the regular emitting technical devices like valves, positioners, regulators ...
    a. Identification of the device type
    b. Function of the device (e.g. distinction between regulation valve and safety valve)
2. Determination of an EF (m_n^3 per hour or per movement or mode of operation[3])
    a. Emitted volume based on direct measurement on a (representative) number of devices of each type

[3] Emission factor of devices may be dependent on their mode of operation (e.g. standby or regulating) and sometimes are not constant over their operating range.

    b. Alternative: emitted volume based on manufacturer's documentation
    c. Alternative: emitted volume from the literature
3. Determination of an AF
    a. For devices (e.g. valves) with few emissions' occurrence (e.g.: operational movements) on yearly base, it can be an option to consider the real amount of occurrence or total operational time [hours] per year. In these cases, occurrence / hours have to be registered.
    b. For devices with continuous or even with intermittent emissions, the activity factor is commonly calculated for a full year operation.

Pneumatic emissions are calculated with equation 6-14.

$E_{pneum} = \sum_{i=1}^{n}(EF_i . AF_i)$	*6-14*

Where:

EF_i	The emission factor of group "i" (might depend on: e.g. pressure, geometry of device)
AF_i	The activity factor of group "i"

6.5.2.3 Start/stop operations

Emission from start/stop operations on equipment like compressor units and boilers shall be calculated according to equation 6-15. It is assumed that all start/stop operations are split into "s" groups, and that each group of start/stop operations has its own Emission Factor (EF) and Activity Factor (AF).

Emission factors not always relates to the number of starts and stops reported. A start/stop of a specific combustion engine does not always emit the same amount of methane since it depends on the operational modes (e.g. starting sequences, emergency shut down).

$E_{ss} = \sum_{i=1}^{n}(EF_{ss(i)} . AF_{ss(i)})$	*6-15*

Where:

$\boldsymbol{EF}_{ss(i)}$	Emission factor for "i" group of start/stop operations, in $\left[\frac{\boldsymbol{kg}}{\boldsymbol{event}}\right]$
$\boldsymbol{AF}_{ss(i)}$	Number of start/stop operations of group "i", in [event]
n	Number of groups of start/stop operations per year

6.5.2.4 Operational emissions: simplified approach (applicable for DSO)

If no detailed information is available on single operations which cause emissions, a simplified approach for estimating the emissions from all operations should be used.

This approach is based on an estimated share of all pipelines that are renewed, commissioned or decommissioned.
A distinction between venting and purging emissions should be made also in the simplified approach since the operating pressures for venting or purging activities can differ significantly. In this case, instead of equations 6-12 and 6-13, equations 6-16 and 6-17 shall be used.

$E_{vt\_simp} = V_{geo} \cdot \frac{\overline{p_{vt}} . T_n . Z_n}{P_n . \overline{T_{int}} \cdot \overline{Z_{vt_{int}}}} \cdot \overline{\rho_n} . \overline{x_{CH_4}} \approx V_{geo} \cdot \frac{\overline{p_{vt}} . 269{,}6}{\overline{T_{int}} \cdot \overline{Z_{vt_{int}}}} \cdot \overline{\rho_n} . \overline{x_{CH_4}}$	*6-16*
$E_{pr\_simp} = V_{geo} \cdot \frac{\overline{p_{pr}} \cdot T_n . Z_n}{P_n . \overline{T_{int}} \cdot \overline{Z_{pr\_int}}} \cdot \overline{\rho_n} . \overline{x_{CH_4}} \approx V_{geo} \cdot \frac{\overline{p_{pr}} \cdot 269{,}6}{\overline{T_{int}} \cdot \overline{Z_{pr\_int}}} \cdot \overline{\rho_n} . \overline{x_{CH_4}}$	*6-17*
$V_{geo} = \frac{\pi}{4} \cdot \overline{d_{int}^2} \cdot (x_{op} \cdot l_{total})$	*6-18*

Where:

$\overline{p_{vt}}$	Weighted average operating pressure for all pipelines existing in an operators or countries grid, in $[bar]$
$\overline{p_{pr}}$	Weighted average operating pressure for all purge operations including atmospheric pressure, in $[bar]$
$\overline{d_{int}}$	Average diameter of all pipelines of a distribution grid, in $[m]$
$\overline{Z_{vt\_int}}$	Average compressibility at venting condition ($\overline{p_{vt}}$ and $\overline{T_{int}}$), [-]
$\overline{Z_{vt\_int}}$	Average compressibility at purging condition$\overline{p_{pr}}$ and $\overline{T_{int}}$,[-]
x_{op}	Share of pipelines which are renewed, commissioned or commissioned per year, $[-]$
$\overline{x_{CH_4}}$	Mass fraction of methane in natural gas [-]
$\overline{\rho_n}$	Density of natural gas at normal conditions
l_{total}	Total length of the pipelines in the distribution grid, in $[m]$
$\overline{T_{int}}$	Average gas temperature in a distribution grid, in [K]

6.6 Emissions from incidents

Emissions due to incidents on a pipeline system can have several causes as:

a) External interference (i.e. third-party damage)
b) Corrosion
c) Construction defect / material failure
d) Hot tap made by error
e) Ground movements
f) Venting caused as the consequence of a system failure (e.g. over pressure)

In this document, the treatment of the methane emissions related to these kinds of incidents is dependent on the type of leak. Leaks on the pipelines found by inspection are treated as fugitive emissions (§6.4.2.3). The present paragraph describes how incident emissions are calculated.

Yearly totals of incident emissions are calculated on an individual basis or as grouped incidents. The calculation of the incidents on an individual basis is preferred; however incident grouping can be used.

An incident emission can be caused by a failure of the system, like an overpressure, that releases gas by means of safety valves.
The amount of gas released by an incidental vent can be measured because of the known conditions that apply to the gas flowrate. Otherwise, it can be calculated from inner pressure and orifice diameter. Duration of the escape is also usually known.

Incidents can lead to an uncontrolled and continuous gas emission that requires to be put in safety and repaired urgently. Most typical incidents are third-party damages. Other incidents not caused by third parties have to be quantified as well.

6.6.1 Incidents on an individual basis

The total emission as the consequence of incidents can be calculated on the basis of single events. In this case, all incidents with gas release shall be reported and summed using equation 6-19 or other documented methods.

$$E_{inc} = \sum_{i=1}^{n} Q_{m_i} \cdot t_i$$	*6-19*

Where:

E_{inc} Total incident emission, in [kg]
Q_{m_i} Emission rate of incident i, in $\left[\frac{kg.}{h}\right]$
t_i Duration of incident i, in [h]
n Number of incidents per year

6.6.2 Incidents grouping

If data for all individual incidents are not available, grouping of incidents shall be applied.

Different emission factors / flowrates have to be defined by the operator for different types of incidents.
Two different kinds of emissions are associated with incidents and shall be calculated per group:

1. Gas escape due to the damage itself
2. Gas release as consequence of the repair required for the damage

The emissions caused by incidents shall be estimated by equation 6-20 or 6-21

$E_{inc} = \sum_{i=1}^{s} E_{inc_i} = \sum_{i=1}^{s} (\overline{Q_{m_i}} \cdot \overline{t_i} \cdot n_i)$	*6-20*

$E_{inc} = \sum_{i=1}^{s} E_{inc_i} = \sum_{i=1}^{s} (\overline{Q_{m_i}} \cdot \overline{t_i} \cdot n_i . l_i)$	*6-21*

Where:

E_{inc}	Total incident emission, in $\left[\frac{kg}{yr}\right]$
E_{inc_i}	Methane emissions of incidents of group i, in $\left[\frac{kg}{yr}\right]$
$\overline{Q_{m_i}}$	Average emission rate of incident group i, in $\left[\frac{kg}{inc \cdot h}\right]$
$\overline{t_i}$	Average duration of gas escape of incident group i, in $[h]$
n_i	Number of incidents of group i (absolute or per km), in $\left[\frac{inc.}{yr}\right]$ or $\left[\frac{inc.}{km \cdot yr}\right]$
l_i	Length of main lines of group i, in $[km]$

6.6.3 Emission rate Q_m

The emission rate Q_m can be determined for each incident or for different groups of incidents.

A distinction should be made between underground leakages and above ground leakages.

Different Q_m can also be defined depending on the cause of the incident. DSO companies often apply incidents caused by third parties as a special group. In case of third-party damages, incident mainly occur due to digging. For this reason, the pipelines damaged by a third party are usually not covered by soil anymore. The missing barrier of the soil should be taken into account to determine the emission rate of that category of incidents.

If the emission rate is calculated, it can be important to determine if the leak flow is supersonic or subsonic, and the size of the damage. For a detailed description of the calculation of the flow types, see Annex E.

6.6.4 Duration of gas escape

Duration of the gas escape needs to be determined in order to estimate emissions after the incident. Three different time periods can be distinguished, see equation 6-22:

$t = t_1 + t_2 + t_3$	*6-22*

Where:

t	Duration from the beginning of the gas escape until the gas flow is stopped (at least by provisional measures), in [h]
t_1	Duration from the beginning of the gas escape until the incident is reported to the operator, in [h]
t_2	Duration from the call until arrival on site, in [h]
t_3	Duration of onsite activity until the gas flow is stopped (at least by provisional measures), in [h].

In case of reported third-party damage, the beginning and the duration of the gas escape is well known.

Generally, the times t_1, t_2 and t_3 are known by the DSO and TSO. If the exact times are not known, an operator-specific or country-specific t should be used.

In case of other incidents (e.g. reported due to gas smell), the beginning of the gas escape is not always known, thus assumptions can be made, for instance depending of the location of the incident and the frequency of the survey.

6.6.5 Number of Incidents

The number of incidents shall be counted over the reporting period. It is usually exactly known as each incident is expected to be logged and categorized.
Attention needs to be paid to the number of incidents: it needs to be ensured, that the related emissions are not estimated in another category (e.g. fugitive leaks) to avoid double-counting.

6.7 Methane emissions from incomplete combustion

Methane emissions from combustion are normally estimated or measured.
Direct measurement (e.g. measurement with a sensor directly into the stack) or on-line estimations (e.g. indirect measurement based on other parameters) of methane in the exhausts should be used to measure unburned methane in the waste gasses of the combustion engines.

6.7.1 Measurement

When direct measurements or online estimations are performed, the total yearly emissions are calculated as:

$E_{combustion} = \int Qm_t.dt$	6-23

Where:

$E_{combustion}$	Total unburned methane from combustion, in $[\frac{kg}{yr}]$
Qm_t	Emission rate during a time interval dt, in $[kg]$
dt	Time interval

6.7.2 Emissions based on emission factor

Unburned methane emissions from combustion shall be calculated from an emission factor and activity factor if no direct or indirect measurement is available. Emission factors can be

retrieved from literature or measurement if available. Grouping shall be done on the bases of type or even manufacturer of the combustion engines. E.g. emission factors can be based on the fuel input of a type of combustion engine.
The total emission of unburnt methane from combustion process can be calculated with equation 6-24 :

$E_{combustion} = \sum_{i=1}^{n} E_i = EF_i . AF_i$	*6-24*

Where:

$E_{combustion}$	Total unburned methane from combustion, in $[\frac{kg}{yr}]$
EF_i	Emission factor of group i
AF_i	Activity factor of group i

7 METHODS FOR DETECTION AND/OR QUANTIFICATION (INFORMATIVE)

This paragraph gives an overview of the methods which are currently available for the determination of methane leakages. In Annex F, more detailed description of the methods is also given.

Table 7-1: Techniques for quantification.

Technique	Description of technology /operation	Advantages	Disadvantages	Device
Pressure decay / Flow fluctuation	The pressure decay method can be used as a quantitative leak measurement technique, where the methane emission over a known length of pipeline is measured. Method can be applied to isolated parts of a distribution and transmission network. Pressure inside a pipeline is measured during a specific time interval and leakage is calculated from the pressure drop and using the known (estimated) volume of the pipeline section. The sensitivity of the pressure monitoring method depends on the leak location. Near the inlet and the outlet of the pipeline a leak leads to little or no change in pressure.	• Simple and requires no telemetry.	• Uncertainty associated with unknown changes of gas temperature during the measurement. • It does not provide any leak localization • It is only useful in steady state conditions. • Pipeline section needs to be isolated from the rest of the network.	Pressure sensors, flowmeters
Refraction wave method (acoustic pressure waves)	The acoustic pressure wave method analyses the refraction waves produced when a leak occurs. When a pipeline wall breakdown occurs, gas escapes in the form of a high velocity jet. This produces negative pressure waves which propagate in both directions within the pipeline and can be detected and analyzed. The amplitude of a pressure wave increases with the leak size.	• Ability to detect small damages (less than 3 mm) • It is able to indicate the location of the leak in a few seconds with accuracy less than 50 m.	Unable to detect an ongoing leak after the initial event.	Pressure sensors

	Technique	Description of technology /operation	Advantages	Disadvantages	Device
	Balancing methods	These methods base on the principle of conservation of mass. In steady state, the mass flow entering the leak-free pipeline will balance the mass flow leaving it. Mass imbalance indicates leak.	• Require at least two flow meters, one at the inlet and the other at the outlet.	Provide leak detection, but no leak location	Flowmeters
Leak Flow capturing	***Point-source measurements***	Measurement of emissions from fixed source points based on flow rate and methane composition. Engines and compressors represent typical point-source emissions.	• Measures total methane emissions from individual point sources (e.g., compressor seals, valves). • Captures temporal trends if deployed for extended time periods.	• Labor intensive to quantify spatial and temporal variability (requires many individual measurements to capture variability).	HI Flow Sampler (HFS)
	Suction method (aspiration method)	Capturing as much of the leakage by partially enclosing the leaking components, diluting the leakage using suction. The method is suitable for measurement of small to medium size leaks in shallow buried pipelines (typically less than 2 m depth) and of moderate to low pressure (typically 16 bar to 30 mbar).	• Not usable for leaks with a large surface area. • Small measurement uncertainties	• Require a previous detection of the leaks, e.g. by carpet probe (see Annex F)	High volume sampler with pump and FID analyzer
	Bagging	A leak rate is measured by enclosing an equipment piece in a bag to determine the actual mass emission rate of the leak to determine a fugitive or vented flow rate.	• Accurately measures emissions from individual or small groups of leaks in a controlled environment.	• Labor intensive to measure the variability of emissions over large source areas • Single bagging may not capture all variability in emissions. Provides an measurement that must be repeated to capture temporal trends.	Calibrated bags
	Flux chamber	Method in which natural gas escaping from earth surface is measured using chambers of special construction. Static chambers quantify emissions by multiplying the change in methane concentration over short	• Accurately measures emissions from individual or small groups of leaks in a controlled environment. • Does not rely on atmospheric modelling to derive leaks.	• Quantifies diffusive emission rates from a small source area (typically 1 m^2 or less). • Labour intensive	Chambers of different volumes

Technique	Description of technology / operation	Advantages	Disadvantages	Device
	monitoring periods by the chamber volume/area ratio. Dynamic chambers quantify emissions using inlet/outlet methane concentrations with a known rate of the flux.	• Can measure the variability of emissions over large source areas	• Provides measurement that must be repeated to capture temporal trends	
External tracer	Release of tracer gas (C_2H_2, N_2O) at known rate from source area. Measurement of methane and tracer concentrations across well-mixed downwind plumes to derive emission rate. The correct emission measurement depends on sensors layout and meteorological conditions	• Measures total methane emissions from source area. • Measures complex sources	• Difficult to isolate individual sources • Vulnerable to bias if the locations of tracer release differ significantly from the location of methane release. • Labor intensive to measure the spatial and temporal variability of emissions over many sources.	Fourier Transform Infrared Spectroscopy (FTIR), Laboratoire des Sciences du Climat et de l' Environnement (LSCE) FTIR , Cavity Ring Down Spectroscopy (CRDS), Weather station
Perimeter facility line measurements	Measurement of path-integrated methane along boundaries of a source area (e.g., ppm methane along with wind characteristics to estimate an emission rate.)	• Measures total methane emissions from variable-sized source areas. • Allows long-term continuous monitoring to capture temporal trends in emissions	• Difficult to isolate the different sources in source area depending on distribution and meteorological conditions. • Appropriate topographic and meteorological conditions are necessary. • Difficult to determine the area contributing to leakage	Open-path spectrometers (infrared, tunable diode laser)

Table 7-2: Methods for methane detection

Method	Description	Technical Specifications
Flame ionisation detection	The operation is based on the ionization of the detected gas in the hydrogen flame that is generated inside the FID. It enables to detect the methane concentrations from very low levels, but reacts not only to methane, but to other hydrocarbons as well.	The sensitivity of a GC-FID machine is around 0.1 ppm[4] and a maximum range of about 2000 ppm.
Semiconductor based detection	In the presence of the detected gas, the semiconductor's resistance decreases due to the oxidation, or reduction, of the gas on the metal oxide surface. The method is not selective, as some other gases, such as ozone, volatile organic compounds (VOC), may give false alarms. Because the sensor must come in contact with the gas to detect it, semiconductor sensors work over a smaller distance than infrared point or ultrasonic detectors.	Detection concentration: 200-10.000 ppm (Natural gas / Methane), Operating temperature: 14 to 122°F (-10 to 50°C)
Optical gas imaging	OGI infrared cameras are equipped with sensors to detect hydrocarbons. The equipment may be hand-held or remotely operated from ground-mounted installations or through mobile deployment (vehicular & aerial). Hand-held units are a recommended solution for a broad range of components. The camera is simpler to use thanks to point and detect function. An operator can scan the leak area in real time by viewing a live image of visible gas plumes on a screen. No calibration required, some cameras not ATEX compliant.	Min. detectable leak rate (methane) – 0,35 g/h

[4] GC Analysis of Greenhouse Gases and Optional Headspace Automatic Sample Introduction, Shimadzu – accessed on 19 May 2016.

Method	Description	Technical Specifications
Acoustic leak detection	Acoustic leak detectors capture the acoustic signal of pressurized gas escaping from 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 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. 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. 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.	Sensitivity: Detects a leak of 0,1 mm at 3 bars at 20 m Temperature range: - 10°C to + 50°C
Laser leak detection	A popular detector is the Remote Methane Leak Detector (RMLD), which uses a tunable diode-infrared laser that is tuned to a frequency which is specifically absorbed by methane. As the laser beam from an RMLD device passes through a gas plume (and is reflected back to the camera) it will detect if methane is present in the beam path by comparing the strength of the outgoing and reflected beams. Simple to operate, especially handheld versions, 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) require a background surface to reflect back laser beam (not applicable for open fields).	Measurement Range: 1-50k ppm
Combustible gas detection	When gas that is aimed to be detected goes through the catalyst it is combusted what heats up the catalyst and changes the resistance, which subsequently enables detecting of the searched gas. The catalyst poisoning may be an issue decreasing its reliability.	Measurement Range: 1ppm-100%

Method	Description	Technical Specifications
Thermal dispersion	Gas leak rate is estimated based on the size of the cloud observed from thermograms. The amount of gas released depends of the upstream pressures and leak sizes.	
Electrochemical detection[5]	Electrochemical detectors use the porous membrane through which the detected gas goes to the electrode on which it is either oxidized or reduced, resulting in the change of the electric current.	
Soap Bubble Screening	It is easy, quick and low cost to detect leaks with a soap solution. Soap bubble screening consists to spray all the junctions with a mixture of water and soap (or with a specific commercial foaming product). All the junctions (even the junctions inserted in a coating) are targeted (the actuator of the valves, flanges, fitting, caps, insulating joints, …). It is necessary to stay a short time in front of each junction to watch the creation of bubble. This technology can be used for an efficient and fast leak detection and repair campaign, operational team are familiar with that very well know historical methodology. Not effective on large openings. Cannot be used on equipment above the boiling point or below the freezing point of water.	-

[5] Dosi, Manan & Lau, Irene & Zhuang, Yichen & Simakov, David & W. Fowler, Michael & Pope, Michael. (2019). Ultra-Sensitive Electrochemical Methane Sensors based on Solid Polymer Electrolyte-Infused Laser-Induced Graphene. ACS Applied Materials & Interfaces.

8 UNCERTAINTY CALCULATIONS (INFORMATIVE)

8.1 Introduction

Calculating the uncertainty of the estimated methane emission value from the gas system is important in order to provide the user with some knowledge of the accuracy of the work performed[6].

In general, the total annual methane emission from a system is calculated using equation 8-1.

$\mathrm{E} = \sum_{i}^{n} E_i$	*8-1*

Where

E Total methane emission, in [kg]

E_i Total emission of group i, in [kg]

In its most simple form, this refers to one group where the activity can be the pipeline length [km], and the emission factor is the emission of methane for the whole system for each km of pipeline. This factor does not need to be measured on the current system but can be taken from other studies of a similar pipeline system. In a more sophisticated approach, more groups can be defined and specific emission measurements can be performed on group elements to establish the emissions factor for each group.

In general, using a simple approach and standard emission factors without using any measured data will result in a rather high uncertainty of the total emission of methane.

In order to calculate the uncertainty of the estimated methane emission value for the system, knowledge of the uncertainty of the emission factors and activity factors needs to be provided.

Normally the activity factor (AF) is quite accurately determined as the gas system is constructed from a known number of valves, heaters, flanges, km of pipes of specific type, instruments emitting gas, pneumatic valves, or whatever other groups are chosen.

The emission factor (EF) is either chosen from a table using standard values, or it is derived from emission measurements. It is important when doing measurements also to collect knowledge on the accuracy of the measurements.

8.2 Uncertainty calculation based on deterministic calculation

From equation 8-1 the total uncertainty U(E) [ref. (12)] can be calculated with equation 8-2.

$\mathrm{U(E\,)} = \sqrt{\sum_{\mathrm{i=1}}^{n} \left[\frac{\partial(\mathrm{E})}{\partial(E_i)} \times \mathrm{U}(E_i)\right]^2}$	*8-2*

Where:

$\mathrm{U(E\,)}$ Uncertainty of the total emission, in [kg]

$\mathrm{U}(E_i)$ Uncertainty of the emission of group i, in [kg]

[6] The level of uncertainty will depend on the quantification strategy (e.g. TIER I, Tier II, Tier III (see ANNEX H)

Assuming statistical independence among the asset groups and normal behaviour of U, equation 8-3 will be a good approximation of the uncertainty.

$\mathrm{U(E)} = \sqrt{\sum_{\mathrm{i=1}}^{n}[AF_i \times \mathrm{U}(EF_i)]^2}$	*8-3*

To estimate $\mathrm{U}(EF_i)$, σ_{EF_i} can be used:

$\mathrm{U}(EF_i) = \sigma_{EF_i}$	*8-4*

Where:

σ_{EF_i} Estimate of the variance of the emission factor of population EF_i, in [kg]

$\mathrm{U}(EF_i)$ Uncertainty of the emission factor of group i (one sigma, *the half-width of an interval having a stated level of confidence*), in [kg]

For a one-sided test, leaving an uncertainty of 5% ($\alpha = 0{,}05$) in the upper tail, σ_{E_i} shall be calculated with equation 8-5:

$\sigma_{EF_i} = \sqrt{\frac{(n-1).S_{EF_i}^2}{\chi^2_{(n=1),(1-\alpha)}}}$	*8-5*

Where:

$\sigma_{EF_i}{}^2$ Variance of the population EF_i

α Width of a rectangular distribution of possible values of an input quantity

S_{EF_i} Experimental standard deviation of the emission factor of group i

χ^2 Chi squared value (normally from table of statistical books) with $n-1$ degrees of freedom

n Number of measurements

The standard deviation of the emission factor of group i can be calculated as:

$S_{EF_i}{}^2 = \frac{1}{n-1}\sum_{j=1}^{n}(EF_{i,j} - \overline{EF_i})^2$	*8-6*

Where:

S_{EF_i} Experimental standard deviation of emission factor of group i

$EF_{i,j}$ j[th] individual measurement of emission factor i

EF_i Average emission factor of group "i"

Examples of calculation are provided in Annex G.

Note:

- *In some cases, a standard deviation of the emission factor from direct measurements is not available. In this case, the standard deviation shall be estimated using best guess assumptions or could be based on publications.*
- *If the reporting is incomplete, the error introduced by this should be taking into account in the uncertainty calculations.*
- *Measurement uncertainty can be quite large and not random.*
- *All the bullets above could result in a higher total uncertainty.*

Other statistical approaches such as Monte Carlo simulation [ref. (17)] can be used to calculate the total uncertainty of the emissions.

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10 ANNEXES

Annex A: Permeation coefficients

Permeation emission is quantified by calculation. The single parameter that needs to be determined by measurements is the permeation coefficient, which describes the ability of a certain gas (e.g. methane) to permeate through a certain material at a certain temperature. Equations 10-1 and 10-2 shall be used to calculate emission rate. These equations are already applied by many countries in Europe and can be regarded as the best available method.

$q_V = PC_{CH4} \cdot \pi \cdot SDR \cdot p_{CH4}$	*10-1*

Where:

q_V	Emission rate (e.g. per leak), in $\left[\frac{kg}{leak \cdot hr}\right]$
PC	Permeation coefficient of methane through the material, (e.g. PE100) at a certain temperature (e.g. 20 °C), in $\left[\frac{kg}{m \cdot bar \cdot d}\right]$
SDR	Standard Dimension Ratio, in $[-]$
p_{CH4}	Partial pressure of methane in the pipeline, in $[bar]$

The Standard Dimension Ratio (SDR) is defined by equation 10-2.

$SDR = \frac{d_e}{s}$	*10-2*

Where:

d_e	External diameter of the pipeline, in $[mm]$
s	Wall thickness of the pipeline, in $[mm]$

Various permeation coefficients are given in literature.

Permeation Coefficient (original)		Unit	Reference	Permeation Coefficient (converted)	
Value	**Material, temperature**			**Value**	**Unit**
0.019	PE100, 20°C	$cm^3_{CH4}/(m \cdot bar \cdot d)$	(18 p. 60)	1.90E-08	$m^3_{CH4}/m \cdot bar \cdot d$
0.056	HDPE, 20°C	$cm^3_{CH4}/(m \cdot bar \cdot d)$		5.60E-08	$m^3_{CH4}/m \cdot bar \cdot d$
34.1	PE100, 20°C	$(ml \cdot mm)/(m^2 \cdot bar \cdot d)$		3.41E-08	$m^3_{CH4}/m \cdot bar \cdot d$
1.11E-09	PE80, 8°C	$cm^2_{CH4}/(bar \cdot s)$		9.59E-09	$m^3_{CH4}/m \cdot bar \cdot d$
0.006	PE100, 8°C	$cm^3_{CH4}/(m \cdot bar \cdot d)$		6.00E-09	$m^3_{CH4}/m \cdot bar \cdot d$
0.29	Plastic, 8°C	$m^3_{CH4}/(km \cdot bar \cdot yr)$		2.30E-08	$m^3_{CH4}/m \cdot bar \cdot d$

Table 10-1: Permeation coefficients from different studies

If there is no information about the SDR of the pipes, the assumption can be made that pipelines with a MOP ≤ 5 bar[7] are SDR17[8] and pipelines with a MOP > 5 bar are SDR11[9].

[7] Absolute pressure = 6 bar
[8] Pipelines with a MOP ≤ 5 bar can also be SDR11 but for a conservative consideration, SDR17 should be taken.
[9] The SDR is the ration between pipe diameter and wall thickness (e.g. the wall thickness of a SDR11 pipe with a diameter of 500 mm is 500:11=45,45 mm.

The influence of the soil temperature around a pipeline on permeation is often neglected but was assessed to be significant in a recent study, since the permeation rates drop significantly with decreasing temperatures (more detailed information in Annex B).

Annex B: Permeation – Influence of the soil temperature

Summary of a research project of DBI Gas- und Umwelttechnik GmbH Leipzig on behalf of E.ON Metering GmbH Essen (Source: (19), (20))

The currently used permeation coefficients for the examination of permeation from gases through plastic pipes are usually valid for an ambient temperature of 20 °C. The monthly mean temperature of the soil is often lower. Due to the fact, that the quantity of plastic pipes and the future feed-in of hydrogen are increasing in the German distribution grid, the permeation and its reliable examination are of high importance for grid operators.
The project analysed four different modern pipe materials (polymer pipe, multi-layer composite pipe and two polymer pipes with aluminium barrier layer). The samples were filled with three different gas compositions (Table 10-2) and this summary focuses on the results for 100 vol-% methane.

Table 10-2: Technical facts about the project

Technical facts about the project	
Pipe materials	PE100 RC, HexelOne®, HexelOne® + barrier layer of aluminium, SLA Barrier® Pipe
Pipe dimension	DN110 and SDR11
Test gas composition	100 vol-% CH_4, 70 vol-% CH_4, and 30 vol-% H_2, 100 vol-% H_2
Test temperatures	20 °C and 8 °C
Duration	1 yr
Pressure	10 bar (11 bar absolute) and 16 bar (17 bar absolute)

Source: (19) (translated)

As the measurement results show, the amount of permeating gas depends very much on the temperature. For practical applications, the permeating volume per year is related to real soil temperatures. Since the selected examination temperatures (8 °C and 20 °C) do not reflect the real soil temperatures in Germany over one year, an average soil temperature for Germany of the last 120 years in one-meter depth was taken into account. From the determined specific permeation coefficients for 8 °C and 20 °C a compensation function was generated based on experience from investigations (Table 10-3).
This compensation function represents an assumption but was confirmed by a control measurement (at 14 °C for PE100 RC, 100 vol-% CH_4).

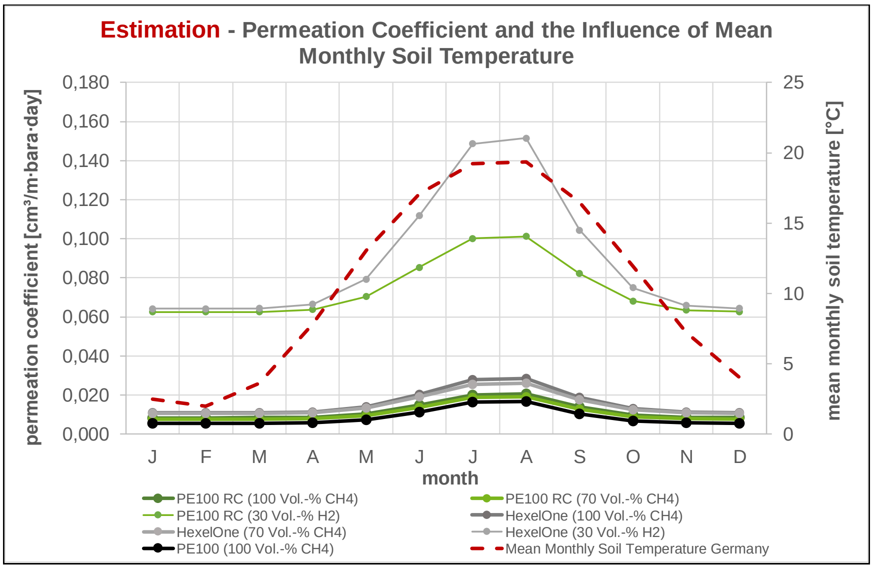
Table 10-3: Compensation function for the test materials

Material (test gas)	**Compensation function[1,2]**
HexelOne (100 vol.% CH_4)	$f(x) = 0{,}010866 \cdot e^{0{,}00003x^{3{,}549}}$
PE100 RC (100 vol-% CH_4)	$f(x) = 0{,}008307 \cdot e^{0{,}00002x^{3{,}549}}$
PE100 (100 vol-% CH_4)	$f(x) = 0{,}005550 \cdot e^{0{,}00003x^{3{,}549}}$
Explanation 1. "x" refers to the temperature in [°C] 2. The respective compensation function was determined based on expert experience with the permeation rates for 8 °C and 20 °C and confirmed with a control measurement at 14 °C. It is only valid for the tested specimens but has a similar structure for other specimens/materials.	

Source: (20) (translated)

With the compensation function from Table 10-3, temperature-specific permeation coefficients could be determined. The temperature-specific permeation coefficients related to the monthly average soil temperature for Germany are shown in Figure 10-1.

Figure 10-1: Permeation coefficient and influence of mean monthly soil temperature



Source: (19) (translated)

Annex C: Approaches to determine emission rates Q_V for underground leaks

1. Direct measurement of the emission rates

The leak first needs to be identified with a gas detector, e.g. carpet probe [ref. (21)] or a car with optical methane detection [ref. (22)]. The detector measures a concentration of methane in the air. This concentration is only loosely related with the actual emission rate, because the concentration measured above ground is influenced by many factors (e.g. wind, the distribution of leaking gas in the soil). Thus, the emission rate needs to be determined with another measurement device (e.g. a suction measurement device, see Annex F).
Not all leaks can be measured directly, for example, if the location is not well accessible.

In general, it is not necessary to measure the emission rates of all leaks occurring in the pipelines of a gas system. A representative selection is sufficient, which leads to average emission rates for a group of assets.

2. Determination of soil coefficients and calculation of the emission rate from leak size and pipeline pressure

Emission rates from underground leakages can be determined by using soil properties and calculating the emission rates depending on the size (radius) of the leak and the pipeline pressure (10-3).

$q_V(T,p) = 3600 \cdot \frac{6\pi\mu r_{eq}^2}{\rho(T,p)k\beta} \cdot \left[-1 + \sqrt{1 + \frac{k^2}{\mu^2} \cdot \frac{2\beta}{3r_{eq}R_iT_{int}} \cdot (p_{abs}^2 - p_{atm}^2)}\right]$	*10-3*

Where:

q_V	Volume flow rate of a leak at reference conditions, in $\left[\frac{m^3}{leak \cdot h}\right]$,
r_{eq}	Equivalent radius of the leak, in $[m]$,
ρ	Density of the natural gas at reference conditions, in $[kg/m^3]$,
k	Permeability of the ground, in $[m^2]$,
β	Forchheimer coefficient [(ref) p],) in $[m^{-1}]$, (ref. (23)
μ	Viscosity of the gas in the pipeline, in $[Pa \cdot s]$,
R_i	Specific gas constant of the natural gas, in $\left[\frac{J}{kg \cdot K}\right]$,
T_{int}	Temperature of the gas in the pipeline, in $[K]$
p_{abs}	Absolute pressure in the pipeline, in $[Pa]$, and
p_{atm}	Atmospheric pressure, in $[Pa]$

The specific gas constant can also be expressed as $R_i = \frac{R_0}{M_i}$.

Where:

R_0	Ideal gas constant = $8.31448\ [\frac{J}{kg \cdot K},]$
M_i	Specific molar mass of natural gas, in $\left[\frac{kg}{kmol}\right]$.

The permeability k and the Forchheimer coefficient β of representative types of soil should be determined experimentally. Alternatively, a ground environment coefficient K_{sol} is used instead of the Forchheimer coefficient. K_{sol} is related to the permeability and calculated by equation (10-4).

$K_{sol} = \frac{0.3}{\sqrt{k}}$	*10-4*

Where:

K_{sol} Ground environment coefficient, in $[m^{-1}]$
k Permeability of the soil, in $[m^2]$

The equivalent radius r_{eq} corresponds to the radius which a sphere of the same surface as the leak would have and is calculated by equation (10-5).

$r_{eq} = \sqrt{\frac{A}{4\pi}}$	*10-5*

Where:

r_{eq} Equivalent radius of the leak, in $[m]$
A Area (surface) of the leak, in $[m^2]$

The mass flow rate is calculated by multiplying the volume flow with the density ρ of the escaping natural gas at reference conditions (equation 10-6).

$q_m = q_V(T,p) \cdot \rho(T,p)$	*10-6*

Annex D: Fugitive emissions of pipelines: Approaches to determine leak duration

1.) Leak duration depending on the monitoring period and the maximum repair time [ref. (24)]. The time t_1 is derived from the maximum time between two surveys. For t_2 it is assumed that the leak can be repaired immediately or at the end of the allowed time frame. Assuming the average value of the extremes of the two time periods, t_{total} is calculated as:

$t = \frac{t_{1,max} + t_{2,max}}{2} = \frac{t_{mon} + t_{rep}}{2}$	*10-7*

2.) Leak duration by verified expert estimations
Assumes a duration of leaks detected by survey of $t = 8.760\ h$ based on the assumption that leaks keep growing continuously during their existence and a leak would not exist longer than one year without being reported as an incident.

Annex E: Estimating volume flow rate for different types of flow conditions.

The first step is to determine if the gas flow from a leak is supersonic or subsonic. For this evaluation, the critical pressure ratio is used (25). The critical pressure ratio is determined by equation 10-8. For natural gas ($\kappa \approx 1{,}3$), a critical pressure ratio of about 0.54 is valid.

$\left(\frac{p_{atm}}{p_{abs}}\right)_{crit} = \left(\frac{2}{\kappa + 1}\right)^{\frac{\kappa}{\kappa - 1}}$	*10-8*

Where:

p_{atm} Atmospheric pressure, [bar]
p_{abs} Absolute pressure, [bar]
κ Adiabatic index of natural gas

If the pressure ratio $\frac{p_{atm}}{p_{abs}}$ is equal or greater than the critical pressure ratio, the flow is subsonic (equation *10-9*). If it is smaller, the flow is supersonic (equation *10-10*)

$\frac{p_{atm}}{p_{abs}} \geq \left(\frac{p_{atm}}{p_{abs}}\right)_{crit} \quad \rightarrow \; subsonic\ flow$	10-9
$\frac{p_{atm}}{p_{abs}} < \left(\frac{p_{atm}}{p_{abs}}\right)_{crit} \quad \rightarrow \; supersonic\ flow$	10-10

To determine an emission rate (subsonic as well as supersonic), the area of the damage A needs to be determined. The respective equations are valid for circular holes. To apply them also for holes with a non-circular shape, the hydraulic diameter needs to be considered (equation 10-11).

$d_h = \frac{4A}{P}$	*10-11*

Where:

d_h Hydraulic diameter, in $[m]$
A Area of the damage (described below), in $[m^2]$
P Perimeter of the damage, in $[m]$

The area A and the perimeter P used within equation 10-11 depends on the shape of the damage and on the dimensions.

Equations for Subsonic Flow

Emissions related with incidents with a pressure ratio greater than or equal the critical pressure ratio are calculated with equation 10-12. This equation is broadly applied among the partners contributing to this report and can be seen as the best available approach. The symbols in the equation were chosen in accordance with ISO 5167 (26).

$q_V(T,p) = 3600 \cdot \frac{C_D}{\rho_{(T,p)}} \cdot \frac{\pi}{4} d_h^2 \cdot \left(\frac{p_{atm}}{p_{abs}}\right)^{\frac{1}{\kappa}} \cdot \sqrt{2 \cdot \frac{\kappa}{\kappa - 1} \cdot p_{abs} \cdot \rho_{int} \cdot \left(1 - \left(\frac{p_{atm}}{p_{abs}}\right)^{\frac{\kappa-1}{\kappa}}\right)}$	*10-12*

Where:

q_V	Volume flow rate of an incident, in $\left[\frac{m^3}{h}\right]$, at reference conditions
C_D	Discharge coefficient [-] (see paragraph 3)
ρ	Density of the natural gas, in $\left[\frac{kg}{m^3}\right]$
d_h	Hydraulic diameter, in $[m]$
p_{atm}	Atmospheric pressure, in $[Pa]$
p_{abs}	Absolute pressure of the pipeline, in $[Pa]$
κ	Adiabatic index of natural gas, in $[-]$
ρ_{int}	Density of the natural gas in the pipeline, in $\left[\frac{kg}{m^3}\right]$

The density of the gas in the pipeline can be expressed with equation 10-13.

$\rho_{int} = \frac{p_{int}}{R_i \,.\, T_{int}}$	*10-13*

Where

R_i	Specific gas constant of the natural gas, in $\left[\frac{J}{kg \cdot K}\right]$, of the escaping natural gas at reference conditions.
T_{int}	Temperature of the gas in the pipeline in $[K]$.

The mass flow rate is calculated by multiplying the volume flow with the density ρ of the escaping natural gas at reference conditions (equation 10-6).

Equations for Supersonic Flow

Emissions with a pressure ratio smaller than the critical pressure ratio are calculated with equation 10-14.

$q_V(T,p) = 3600 \cdot \frac{C_D}{\rho(T,p)} \cdot \frac{\pi}{4} d_h^2 \cdot \left(\frac{2}{\kappa + 1}\right)^{\frac{1}{\kappa-1}} \cdot \sqrt{\frac{2\kappa}{\kappa + 1} \cdot p_{abs} \cdot \rho_{atm}}$	*10-14*

The mass flow rate is calculated by multiplying the volume flow with the density ρ of the escaping natural gas at reference conditions (equation 10-6).

Annex F: Technologies for measurements on pipelines

Three measurement methodologies are considered for direct measurements on underground pipelines:

- Tracer Method
- Suction Method
- High Flow Sampler (HFS)

The tracer method is more often applied for measurements on facilities and is therefore described in greater detail in the section about technologies for measurements on facilities. However, it is used in (27) for underground pipeline leak measurements as quality assurance.

The suction method and the HFS are both based on a similar principle. The suction method uses probes in the area surrounding a pipe leak, which aspirate the gas from the soil (Figure 10-2). After a certain volume has been extracted and discarded, the concentration of CH_4 is measured in the sucked gas flow. This ensures that only emissions that have not accumulated earlier in the soil surrounding the leak are measured. The high flow sampler uses a surface enclosure to capture the leakage (Figure 10-4) with a high flow rate. Both measurement principles are suitable for determining emission rates but require a previous detection of the leaks, e.g. by carpet probe.

Figure 10-2: Emission rate measurement with suction method in Amsterdam

Source: Kiwa Technology B.V (28)

<u>Technologies for Measurements on Facilities</u>

Five measurement principles are considered for direct measurements on facilities:

- ✓ Tracer Method
- ✓ Method of EN 15446
- ✓ Air Flow measurements
    - o Bagging
    - o High Flow Sampler (HFS)
    - o Combination of blower with flow measurement and FID measurement

Tracer method

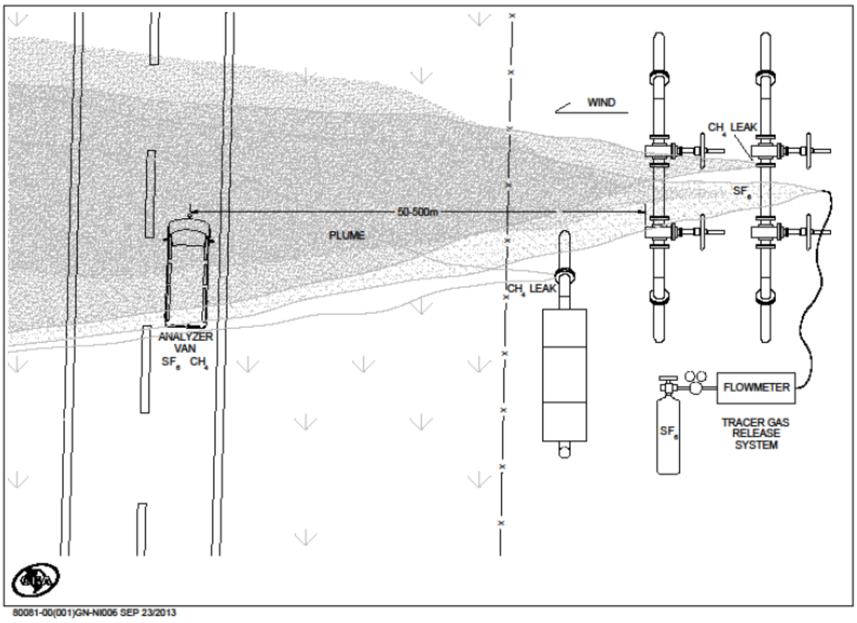
The tracer method is based on the release of an inert gas (e.g. sulphur hexafluoride SF_6) with a controlled emission rate near the leak (Figure 10-3). The concentrations of CH_4 and the tracer are both measured downwind and the emission rate of the leak. is determined by equation *10-15*.

$$q_{m,i} = \frac{(c_i - c_{i,background})}{c_{tracer}} \cdot q_{m,tracer}$$	10-15

Where:

$q_{m,i}$	Emission rate (mass flow) of the substance i [kg/s] (e.g. CH_4),
c_i	Concentration of the substance i [%w/w] (e.g. CH_4),
$c_{i,background}$	Background concentration of the substance I [%w/w] (e.g. CH_4),
c_{tracer}	Concentration of the tracer gas [%w/w]
$q_{m,tracer}$	Emission rate (mass flow) of the tracer gas [kg/s] (e.g. SF_6).

Figure 10-3: Scheme of tracer measurement



Source: Lamb et al. (27)

The tracer method can measure various sources of emissions on a facility at the same time and can deliver one emission rate for the whole facility but is rather unsuitable for the measurement of single emission sources (e.g. one flange) on a facility. The "method works best when a facility is relatively isolated from other interfering sources and when there are suitable roads or areas upwind and downwind for making cross-plume measurements" (27). The environmental impact of the measurements should be considered, since SF_6 is a potent greenhouse gas.,

All other measurement principles are suitable for the determination of emission rates, as is the tracer method, but require the previous detection of the leak, e.g. by infrared camera or sniffing method.

Method of EN 15446 - Direct Measurement of the Emission Rates

The method of EN 15446 is based on gas concentration values which are obtained with portable screening instruments, usually a FID Flame Ionisation Detector.

The detector measures a concentration of methane in the air, the screening values (in ppm) that shall be converted into leak rates (in kg/h per leak) by using correlations.

The most frequently used sets of correlations are these published by the EN 15446 standard "Fugitive and diffuse emissions of common concern to industry sectors. Measurement of fugitive emission of vapours generating from equipment and piping leaks", namely the SOCMI correlations (developed for the Chemical industry) and the Petroleum Industry correlations, described in Annex C of the standard. Measurements according to the method described in this standard can be executed in a relative short time compared to other methods. Due to the large number of elements (e.g. flanges, couplings, valves) in the gas facilities the speed of taking concentrations measurements is an advantage of this standardized method. Gas companies usually use the SOCMI correlation factors to estimate and report its fugitive emissions because it's a conservative approach.

For screening values exceeding the range of measurements (most frequently 100000 ppm), a fixed emission factor (so-called "pegged" factor) is prescribed by this standard.

However, in 2010 the GERG project „Inventory of Natural Gas Emissions Measurement Method" concluded that there is no correlation of the values suggested in the standard and of reference values obtained by measurements on open ended pipes, threaded connections, flanges and valves (29). For this reason, the method of EN 15446 seems not well suitable for the natural gas industry. In contrast to that, the measurements with the HFS had a "good correlation with reference values" (29).

In general, flow measurements are considered the most useful direct methods for the natural gas industry. This includes bagging, HFS and also the combination of blower with flow and FID measurement. All of them are based on the measurement of a controlled air flow rate as well as the measurement of the concentration of CH_4 in this flow rate (Figure 10-4 as example for the HFS).

A combination of the two methods, the screening values with the use of equation of correlation as general approach and real flow measurements instead of applying the pegged value (a fixed value in case of detector overload) is the best approach to measure emission rates.

Figure 10-4: High Flow Sampler measurement on a facility

Source: Heath Consultants Incorporated (30)

Leak Selection

There are no specific requirements on how many measurements are needed for obtaining representative emission factors for one operator or a whole country.

Generally, a representative sample of a given population is obtained from random sampling. Since several studies showed that most of the emission sources are small and only a few have large emission rates, a stratified sampling[10] seems accurate. For instance, the study of Lamb, et al. "focused on the top eight emitting categories from the current EPA methane inventory" and selected randomly the leaks from a list of leaks provided by the distribution companies (31).

Another large measurement campaign conducted at natural gas production facilities (32) believed to ensure representative sampling by

- Selecting a large number of participant companies
- Selecting a range of geographic areas to sample
- Setting minimum number of sampling targets in each area

The following might have an influence on the emission rate:

- Diameter of pipe line or joint type
- Material
- Soil type
- Location (above ground, underground)
- Pressure level
- Size area of damage
- Size of facility
- Weather data

At the moment there is no measurement data available providing full information on all identified parameters. The available data shows possible tendencies, but they could be caused by underlying parameters. For instance, the operating pressure of a pipeline was found to have an influence on the emission rate but it could be, that the pressure influence is not observed, if there is a very dense soil above the leak.

Preliminary investigations should be made either in field or in laboratory measurements which can identify the attributes that have to be taken into account for the sampling in large measurement programmes to avoid biased sampling.

[10] A stratified sampling is "A sampling strategy based on known information about the distribution of emissions designed to yield a data base that minimized any bias and addressed the most significant source categories while accounting for current emission factors (EF) with large uncertainties." (27 S. S108)

Annex G: Examples uncertainty calculation

Example 1:

In this example it is shown how to calculate the variance from a sample.

First, we calculate the average and the mean of the measured emissions on compressor stations:

Table 10-4: Example 1- Calculation of uncertainty

Compressor station	Emission [kg/yr]
1	131.400
2	114.600
3	140.000
4	120.000
5	145.300
6	131.400
7	109.900
8	150.100
9	139.900
10	131.400
Average	131.400
Standard deviation	13.181

Using equations 8-6 and 8-4

$$\sigma_{E_i} = \sqrt{\frac{(n-1)S_{E_i}^2}{\chi^2_{(n=1),(1-\alpha)}}} = \sqrt{\frac{(10-1).13.181^2}{0,059105}} = 16.646\ kg/yr$$

$$\mathrm{U}(E_i) = \sigma_{E_i=16.646}\ kg/yr$$

Example 2:

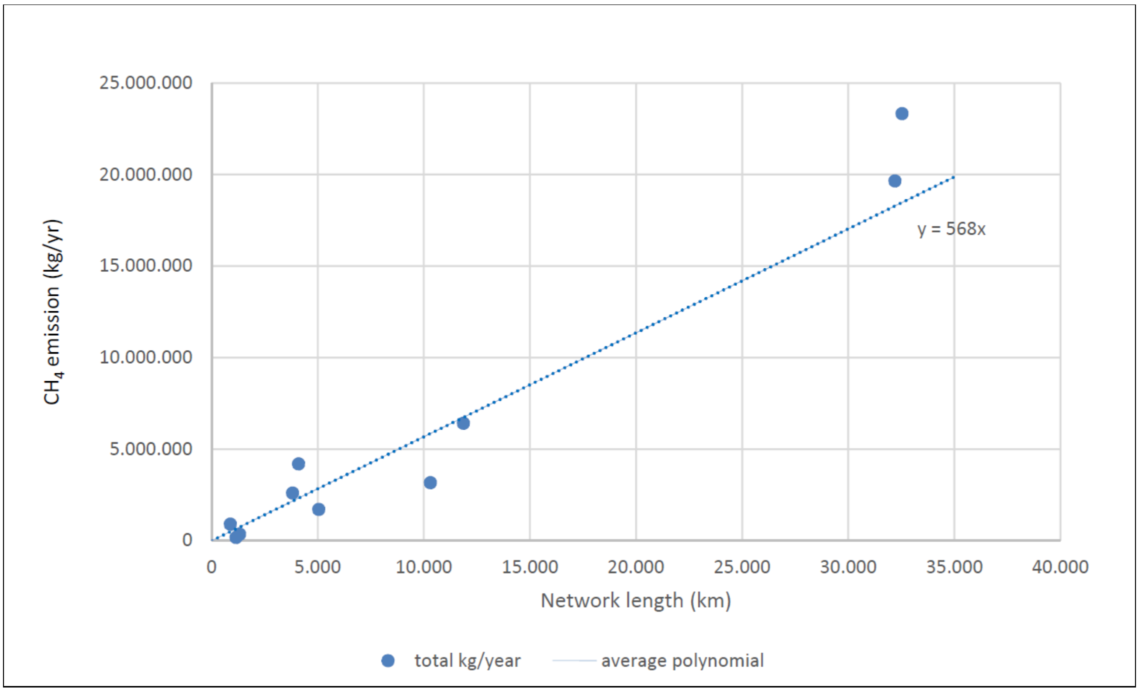
An example gas company has the following assets shown in the below table:

Table 10-5: Example 2 - Assets

Asset	Activity Factor (AF)
Steel transmission pipeline	10.000 km
Compressor stations of same type	20
Metering and pressure regulating stations	100
Block valve stations	1.000

Using a very simplified Tier (I) approach (see Annex H) all emissions are assigned to the pipeline length, and the MARCOGAZ emission factor for this is taken from ref. (16) on www.marcogaz.org.

Figure 10-5: Example Tier I approach for TSO pipelines [ref. (16)]



Hence: The Tier (I) approach gives an annual emission of 10.000 km pipeline ☐ 568 kg/km pipeline equal to 5.680.000 kg of methane annually.
The uncertainty on the Marcogaz emission factor for pipelines is estimated to be ± 340 kg/year (60 %) which then gives an uncertainty of 5.680 ± 3.400 tons methane annually.
The next year the company has estimated the emission of methane using emission factors derived from local measurements. For the asset groups of Table 10-6 the following was established:

For the **steel transmission pipeline** itself only very small emissions were found during a survey of 500 km of pipeline, and an annual emission factor of 25 kg/(km year) pipeline was documented with an uncertainty of ± 12 kg/(km year).

A sample of 10 **compressor stations** were measured using a laser-based method using tracer gas to quantify the emissions. The emission factor for the compressor stations varied significantly, but on average it was 131.400 kg/(compressor station year) and the square root of the variance of the measured emissions of the compressor stations was found to be ± 25,000 kg/(compressor station year).

A sample of ten **metering and pressure regulation stations** (MR-station) was measured using a bottom up method to quantify the emissions. The emission factor was on average 16,000 kg/(MR station year) and the square root of the variance of the measured emission of the compressor stations is found to be ± 4.000 kg/(MR-station year).

A sample of 100 **block valve stations** were measured and showed an emission factor of 170 kg/(block valve station year). The square root of the variance of the measured emissions was ± 50 kg/(block valve station year).

It is assumed that the uncertainty in the measurements is small compared to the variation in emission of the individual samples. The calculation of annual emission and uncertainty is then performed as in the following tables assuming statistically independence of the groups:

Table 10-6: Example 1 - Calculation annual emissions.

Asset	**AF_i**	**EF_i**	**AF_i x EF_i**
Steel transmission pipeline	10.000	25	250.000
Compressor stations of same type	20	131.400	2.628.000
Metering and pressure regulating stations	100	16.000	1.600.000
Block valve stations	1.000	170	170.000
Total emission of methane			4.648.000

Hence the Tier (II) approach gives an annual emission of methane of 4.648 tons /year.

Uncertainty estimation (kg/year):

Table 10-7: Example 1 - Calculation of uncertainty

Asset	**AF_i**	**$U(EF_i)$**	$AF_i \times \mathrm{U}(EF_i)$	$[AF_i \times \mathrm{U}(EF_i)]^2$
Steel transmission pipeline	10.000	12	120.000	1.4400.000.000
Compressor stations of same type	20	16.646	332.920	110.835.726.400
Metering and pressure regulating stations	100	4.000	400.000	160.000.000.000
Block valve stations	1.000	50	50.000	2.500.000.000
			Sum	287.735.726.400
			Square root (sum)	536.410

Hence the uncertainty is ± 536 tons/year.

Compared to tier (I) result of 5.680 ± 3.400 tons methane annually, the tier (II) approach gave 4.648 ± 536 tons methane annually (1 sigma).

Example 3: Estimation of fugitive emission of distribution pipelines.

A specific distribution system consists of 100 km PE SDR17 pipeline of diameter 90 mm. Each year 20 km (20%) of the network is surveyed and the (repaired) leaks are counted. The average methane leak rate is estimated as: 0,02 kg/h with an uncertainty of 100% = 0,02 kg/h. In this example the time between survey is 5 years. During the survey 4 leaks are detected.

Calculation of the estimate of the methane emission during a year proceeds as follows:

$$E = Q_m \times t \times n$$

The uncertainty can be assessed by:

$$\text{U(E)} = \sqrt{\left(\frac{\sigma Q_m}{Q_m}\right)^2 + \left(\frac{\sigma n}{\langle n \rangle}\right)^2 + \left(\frac{\sigma t}{\langle t \rangle}\right)^2} . E$$

Number of leaks (n) and the uncertainty of the number of leaks.
During the survey period 4 leaks are detected in 20 km of the total network of 100 km.

The estimated number of leaks in the network per year is:

$$n = \frac{100}{20} . 4 = 20\ leaks$$

The uncertainty is based on the 4 known leaks in the surveyed part of the network and an estimate of the number of leaks in the other parts of the network.
The uncertainty in the detected leaks (4 leaks) is 0. The uncertainty in calculated leaks (16 leaks) follows the Poisson-distribution https://en.wikipedia.org/wiki/Poisson_distribution

The uncertainty of these 16 leaks can be calculated as:

$$\sigma_n = 0 + \sqrt{16} = 4\ leaks$$

Uncertainty leak rate (Q_m)
The methane leak rate of an individual leak is estimated as: 0,02 kg/h with a standard deviation of 0,02 kg/h.
The average leak rate uncertainty of 20 leaks can be calculated as:

$$\sigma_{\overline{Q_m}} = \left(\frac{S_{Q_m}}{\sqrt{n}}\right) = \left(\frac{0{,}02}{\sqrt{20}}\right). = 0{,}0045\ \text{kg/h}$$

Duration (t) of a leak and the uncertainty of duration.
It is not known how long detected leaks exists. In this example it is dependent on the time between two surveys. The time between two surveys is 5 years. Therefore, it is assumed that the average duration of a leak is t = 5/2 = 2,5 years.

The standard deviation of duration of a single leak is:

$$S_t = \frac{2.t}{\sqrt{12}} = \frac{2 \times 2{,}5}{\sqrt{12}} = 1{,}44\ yr$$

Note: $\sqrt{12}$ is the consequence of the assumption that the duration of a leak is derived from an uniform distribution (https://en.wikipedia.org/wiki/Uniform_distribution_(continuous)).

Since there are 20 leaks per year the **average** standard deviation of the duration is calculated as:

$$S_{\bar{t}} = \left(\frac{1,44}{\sqrt{20}}\right) = 0,32\ yr$$

Total emission and uncertainty

The total emission of the reporting period is:

$$E = Q_m \times t \times n = 0,02 \times 2,5 \times 20 \times 8760 = 8.760 \text{ kg}$$

The emission uncertainty (1 sigma) over the reporting period is:

$$\text{U(E)} = \sqrt{\left(\frac{\sigma_{Q_m}}{\langle Q_m \rangle}\right)^2 + \left(\frac{\sigma AD}{\langle AD \rangle}\right)^2 + \left(\frac{\sigma t}{\langle t \rangle}\right)^2} . E = \sqrt{\left(\frac{0,0045}{0,02}\right)^2 + \left(\frac{4}{20}\right)^2 + \left(\frac{0,37}{2,5}\right)^2} . 8.760 = 2.939 \text{ kg}$$

Annex H: Examples uncertainty calculation

Table 10-8: Levels of uncertainty

Tier (I)	The tier (I) approach is based on standard values for emission factors and a simple approach for the activity ranging from treating the whole system as one group to a few groups.
Tier (II)	The tier (II) approach is based on a group approach for the activity combined with some emission factor knowledge originating in measured values on the specific system.
Tier (III)	The tier (III) approach is based on a group approach for the activity combined with a substantial amount of emission factor knowledge originating from measured values on the specific system.

* * * * * *