Brief description of the source

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

Following is a non-exhaustive list of examples of potential components and equipment and their associated leak points:

Component[1]		Leak Point examples
Connections*		flanges (gasket), threaded connections, tube fittings, and other types of joints/seals
Open Ended Lines		closed valve leak directly to the atmosphere or through an open vent pipe
Blow-down open ended line		Through blow-down valves.
Valves and control valves		stem, gland, bonnet, (all that is related to valve shaft sealing)
Pressure Relief Valves		rupture disk, valve seat (or outlet),
Others	LNG Pumps, Rotary Compressors and Agitators	shaft seal such as rotary screw, rotary vane and scroll compressors, excluding design emissions
	Covers	Manways, boilermakers, blind flanges, access hatches.
	others	Grease nipples,…

* Connections means flanged, screwed, or other joined fittings used to connect two pipelines, a pipeline and a piece of process equipment or two pieces of equipment... Joined fittings welded completely around the circumference of the interface are not considered connectors.

Scope boundaries

Natural gas leaks which can occur in above ground (including below ground equipment which is physically accessible) equipment including indoor and vaults at any point along oil and gas value chains, are considered herein. These cover all emissions from equipment leaks in natural gas service. Unintended emissions arising from incidents, as defined in Incidents TGD, is to be reported under that category.

Unintended emissions from leaks are considered to be any unintended emissions which would typically be detected through a robust detection survey.

[1] A glossary of the main components presented in the table can be found out at https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-A

In upstream segments, streams with low methane content, e.g. <10 wt. % methane content – all facilities downstream from a methanizer in a processing plant, are not within scope.

Emissions from equipment specifically designed to release methane (i.e. vents), including emissions from compressor seals, are not included herein (see series of venting related TGDs). Excess venting emissions from malfunctioning equipment is also not considered herein.[2] For guidance on determining emissions from equipment malfunctions, please refer to the *Incidents and malfunctions TGD*.

Emissions from underground pipelines (see *Fugitive emissions from underground pipes TGD*) are also not included herein.

Guidance on materiality is presented in the *General principles TGD*.

Level 3 Quantification Methodologies

Level 3 quantification for leaks relies on component count and emission factors, with the option to either quantify emissions using population emission factors or leak/no-leak emission factors in combination with leak detection. Accepted component-level emission factors (see examples below) or those prescribed by local regulation to the component level are considered as providing Level 3 estimates. Component count can rely on physical count, P&ID/desktop count or equipment-based activity factors. Measurement of emissions from individual leaking components is not required at Level 3.

Population emission factors

Population emission factors take into account an average share of leakers and non-leakers within the population or directly, an average of emissions from the population. Depending on how these emissions factors were established, they can also account for other parameters such as weight fraction and number of hours of operation.

Accepted component-level emission factors, as defined in the *General Principles TGD*, (see references below) are considered as providing Level 3 estimates, provided they are specific for the component type. Practitioners are encouraged to use emission factors that best represent conditions and practices at their facilities and adjust the factors, where warranted, to estimate emissions more accurately from leaks given differences between the reference system on which the emission factor is based, and their systems.

Additional examples which may also be used as references for emission factors are:

- EPA. *Greenhouse Gas Reporting Rule.* Title 40, Part 98 Subpart W-Petroleum and Natural Gas Systems. February 6, 2017. Tables W-2, W-3B, W-4B, W-5B and W-6B. Link
- For companies having implemented an LDAR program – CAPP, *Update of fugitive equipment leak emission factors* – Table 10, 2014, Link
- A. P. Pacsi et al., *Equipment leak detection and quantification at 67 oil and gas sites in the Western United States* – Tables S13 and S14, 2019, doi: 10.1525/elementa.368 Link

[2] Where the regulatory or company reporting requirements asks for reporting as fugitive, then it is permissible to report them as such.

The above steps can be represented by the following formulas:

$$ER_{Type} = \left(EF_{Population} \text{ x } N_{Types} \text{ x } WF_{CH4} \text{ x } t\right)$$

Where:

ER_{Type} = Methane emission leak rate (kg/year) for components of a particular type
N_{Types} = Number of all components of a particular type
WF_{CH4} = Weight Fraction of methane in line/stream
t = number of hours in the year when the unit/equipment is in operation or under pressure and the component is considered as a Leaker
$EF_{Population}$ = population emission factor for components of a particular type (kg/h)

$$ER_{Total} = \sum_{i=type}^{n} ER_{Type}$$

And where:

ER_{Total} = the total emission rate for all component types (kg/year)

Leak/no leak emission factors

Leak emission factors represent the average emissions from a population of a leaking component of similar type. No-leak emission factors consider the fact that, even if not detectable, over the population, some small leaks might still exist.

To determine the number of leaking components, it is necessary to conduct a survey using robust detection to identify the number of leaking components for each component type. Fixed mounted LEL detectors are typically not suitable for determining whether leaks exist but portable may be suitable. This count then needs to be multiplied with the corresponding leaker emission factor, the share of methane within the gas stream for whole gas emission factors and the number of hours of operation or under pressure. In some reference sources, the share of methane is already taken into account in the emission factor, in which case it is presented as a weight or volume of methane per hour.

Accepted component-level emission factors, as defined in the *General Principles TGD*, (see references below) or those prescribed by local regulation are considered as providing Level 3 estimates, provided they are specific for the component type. Practitioners are encouraged to use emission factors that best represent conditions and practices at their facilities and adjust the factors, where warranted, to more accurately estimate emissions from leaks given differences between the reference system on which the emission factor is based, and their systems.

Following are some examples of leaker emission factors which can be used to determine methane emissions from leaks:

- EPA. Greenhouse Gas Reporting Rule. Title 40, Part 98 Subpart W-Petroleum and Natural Gas Systems. February 6, 2017. Tables W-1E, W-3A, W-4A, W-5A and W-6A Link

- Norsk olje & gas (Norog), Appendix B – Guideline 044 – ver. 16 – Handbook for quantifying direct methane and NMVOC emissions, 2018 – Table 15 – also provides a more detailed description of the leak/no-leak method as well as examples of leak/no-leak emission factors depending on detection limits

The above steps can be represented by the following formulas:

$$ER_{Type} = ((EF_{Leakers} \times N_{Leakers} \times WF_{CH4}) + (EF_{Non-leakers} \times N_{Non-Leakers} \times WF_{CH4})) * t$$

Where:

ER_{Type} = Methane emission leak rate (kg/year) for components of a particular type
$EF_{Leakers}$ = emission factor for leaking components of a particular type (kg/h)
$N_{Leakers}$ = Number of components of a particular type identified as leaking
$EF_{Non\text{-}leakers}$ = emission factor for non-leaking components of a particular type (kg/h)
$N_{Non\text{-}leakers}$ = Number of components of a particular type identified as non-leaking
WF_{CH4} = Weight Fraction of methane in line/stream
t = number of hours in the year when the unit/equipment is in operation or under pressure

$$ER_{Total} = \sum_{i=type}^{n} ER_{Type}$$

And where:

ER_{Total} = the total emission rate for all component types (kg/year)

Activity factors

Activity factors can also be used to determine the number of components in each category depending on the number and type of equipment present at asset-level. Practitioners can determine the component count using activity factors for facilities with similar design as those for which the activity factors were established. Some examples of such activity factors can be found at:

- EPA. *Greenhouse Gas Reporting Rule.* Title 40, Part 98 Subpart W-Petroleum and Natural Gas Systems. February 6, 2017. Tables W-1B and W-1C.
- API, *GHG compendium,* 2009, Tables C-8 and C-9

Practitioners can also develop their own activity factors determined based on the component count of 'like' systems.

Level 4 Quantification Methodologies

Methane emissions from leaks can be quantified using different methodologies: direct measurement, measurement-based emission factors or a combination of the two. Other quantification methodologies could also be considered under the conditions presented in the

General Principles TGD. Emissions from natural gas leaks is the sum of the leak rate from all leaks, adjusted to reflect the number of operating hours per year, where applicable.

Direct measurement and Measurement-based Emission factors

Measurements (including continuous and periodic monitoring) or emission factors developed based on representative measured emissions are considered Level 4 emissions quantification[1 2].

Measurements must be taken that represent the total flow or methane concentration of each measured leak. For measurements considering the total flow, the associated methane content can be determined in line with the *General Principles TGD*, in which case a conservative gas composition can be applied (e.g. assume higher methane content). Surveys of the system relying on robust detection programs (i.e. performed by trained personnel – internal staff or external service provider, using appropriate equipment, at a suitable frequency) are necessary to ensure emission points are properly identified.

To determine methane emission from unintended leaks, the leaking components first need to be identified. To do so, accepted detection technologies, as defined in the *General Principles TGD,* with a sufficient level of performance and accuracy, or, detection equipment prescribed by local regulation[3 4]. If the detection technology used identifies methane emissions, from a distance which allows individual components to be identified, it should be considered as a leak, in line with the scope boundaries defined above. The leak should then be quantified, using an accepted quantification methodology[1 2], as defined in the *General Principles TGD*.

Measurement-based emission factors, developed from a representative sample, can be applied on a leaker-basis, combined with robust detection, or on a population-basis, considering a rate of leaking component determined through a representative sample or an average leak rate per component population.

Sampling strategy for measurement-based emission factors

Level 4 emission factors should be based on measurements conducted on a representative sample. Component type, environmental and operating conditions (e.g. age, model, frequency of LDAR) should be considered in determining ‘like’ systems that carry a common emission factor. Each component that is not ‘like’ will require determination of a separate emission factor for that system based on the appropriate measurement studies. For guidelines on the methodology to develop a statistically representative sample, please refer to the [Uncertainty and reconciliation guidance]. Detection frequency does not necessarily need to be aligned with measurement frequency. Over time, the emission factor should naturally adapt to shifts in LDAR practices.

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[3] More details on various detection equipment can be found at CCAC, *Conduction Emissions Surveys, Including Emission Detection and Quantification Equipment – Appendix A of the OGMP Technical Guidance Document,* 2017

[4] More details on Identification, Detection, Measurement and Quantification best practice can be found in Methane Guiding Principles, *Reducing Methane Emissions: Best practice guide - Equipment leaks,* 2019 https://methaneguidingprinciples.org/best-practice-guides/

Leak duration

Leaks randomly occur throughout facilities and it can be challenging to identify precisely when each one started to emit. To determine total methane emissions from leaks through direct quantification, it is however necessary to attribute a duration between the emergence of the leak and its repair. Several leak duration quantification methodologies exist and can be used to estimate leak duration. These methodologies can be either backward looking, estimating the point in time when the leak started and considering emissions since, or forward looking, considering the leak rate measured during a detection survey to be the basis for future emissions. Within these two methodologies, it is also possible to account for emissions reduction from leak repairs. Each methodology has its own bias, and will typically over- or underestimate emissions, depending on the situation. However, all of the following methodologies are accepted.

When looking back at emissions having occurred from identified leaks, a leak can be considered to have started emitting from the previous detection campaign when it was not detected as a conservative approach, from half-time since the previous survey or using other leak duration estimate methodologies, provided the methodology can be explained and justified. If this is the first leak detection campaign conducted at a facility, the leaks can be considered as having been there from the beginning of the reporting period and until repair for quantification purposes. Alternatively, it can be assumed for the first detection campaign, that the leak started emitting from the time of first detection. This will tend to lead to an underestimation of emissions for the first reporting period. If leak detection and repair (LDAR) is performed, all repairs should be verified using a leak detection method to ensure the component has been properly repaired and no longer releases gas. If a leak is detected, it can be assumed to leak until it is repaired and verified.

If leak detection frequency spans more than one reporting period, the leak can be assumed to start from the previous survey as a conservative approach, from half-time since the previous survey or using other leak duration estimate methodologies, provided the methodology can be explained and justified. It is then assumed to be leaking until it is repaired or the end of the current reporting period. If a leak is detected but not repaired before the end of the reporting period, it is assumed to leak until the end of the reporting period. At the start of the following reporting period, it is still assumed to be leaking, up until it is repaired, or a new detection campaign is performed, and the leak is no longer present. The second option will tend to over-estimate emissions if repairs are performed.

To limit restatement, for leak detection intervals spanning over more than one reporting period, Practitioners can allocate all emissions from leaks from the start of the reporting period. If large, material leaks are uncovered, previously reported emissions from leaks may be restated, in line with company practices. This approach will typically lead to an underestimation of emissions from leaks over the years when surveys are taken early in the reporting period and to an overestimation of emissions when surveys are taken later in the reporting period.

Alternatively, forward looking approaches can be considered to determine leak duration, assuming the measured leak rate is constant until the following detection campaign or considering a leak duration equal to the reporting period in which it was quantified. Where emissions from leaks increase over time, this will tend to underestimate emissions. This tendency will be reinforced if emissions reduction from leak repairs are considered. On the other hand, emissions will tend to be overestimated if repairs are performed but not considered in the forward-looking emission rate.

Average leak duration is not necessary to determine the total emissions when relying on measurement-based emission factors. When quantifying methane emissions from leaks using emission factors, emission factors are typically developed based on a leak rate, which can be adjusted to reflect the number of operating hours. In this case, the duration of the leak does not impact the quantification.

When measurements are used to determine emission factors for ‘like’ systems, the emission factor may either be applied to all ‘like’ systems, independently of which systems the measurements have been performed on or the emission factor may be applied only to systems which have not undergone measurements. The first approach increases the uncertainty of emissions quantification at the level of individual facilities. Emission factors will tend to vary over time, as additional measurements are performed and integrated to calculate emission factors.