# Brief description of the source

Energy and heat generation processes are required throughout the oil and gas value chain. When gas is burned in stationary and, in some cases, portable heaters, boilers, furnaces, engines, generators, turbines, thermal oxidizers, incinerators and other combustion equipment, the entirety of the fuel is not transformed to $CO_2$. When gas is used as a fuel for such equipment, this incomplete combustion of methane and release into the atmosphere from the equipment exhaust stack is known as methane slip. The extent of this methane slip is dependent on the type and operation (mainly, load) of the emission source.

# System boundaries

All stationary and mobile sources of methane emissions related to incomplete combustion of natural gas (heaters, boilers, furnaces, engines and turbines), as described above, are considered herein. For OGMP reporting, these incomplete combustion sources should be reported under incomplete combustion. Combustion for waste gas elimination in flares and incinerators, including thermal oxidizers, also occurs across the value chain and should be reported under Flaring (see *Incomplete combustion from gas flaring TGD*). For guidelines on materiality, please refer to the [*General guidance TGD*].
Some widely used reference materials also assume methane emissions from the combustion of other liquid (other than LNG) and solid hydrocarbon fuels. The associated methane emissions from equipment that burn these fuels is considered negligeable and need not be reported as incomplete combustion.

Guidance on materiality is presented in the *General principles TGD.* De minimis combustion sources are excluded from this TGD.(e.g. : domestic boilers in the facilities buildings…)

# Level 3 Quantification Methodologies

## Emission factors

Accepted emission factors, as defined in the *General Principles TGD,* or those prescribed by local regulation are considered as providing Level 3 estimates, provided they are specific for the type of equipment and consider fuel quantity (flow), methane content of the fuel (composition), and destruction efficiency. Practitioners should use quantification methodologies that best represent conditions and practices (in particular, type of fuel – including dual fuels, type of device, size, load) of their equipment and where warranted, adjust the quantification method, to more accurately estimate emissions accounting for differences between the reference system on which the methodology is based, and their systems.

To accommodate the variation in destruction efficiency across the operating range of the equipment, operating pattern of the equipment, which can impact destruction efficiency can be considered (for example hours at low, medium and high load),

The resources noted below aid in providing emissions estimates from incomplete combustion.

Some generic emission factors provide methane emissions estimates that take into account the fuel composition and the destruction efficiency for different types of fuel and combustion equipment. The following non-exhaustive list provides some examples of such emission factors:

| Example emission factors from *API, Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, 2009* | | | | |
|---|---|---|---|---|
| Emission source (natural gas) | Emission factor | Emission factor - converted | Emission factor - converted | Reference |
| Boilers/Furnaces/heaters | 2.3 lb/$10^6$ scf | 0.0009 kg/$10^6$ Btu (HHV) | 3.1 kg/ GWh | Table 4-7 |
| IC engines – 2 cycle lean | 1.45 lb/$10^6$ Btu (HHV) | 0.66 kg/$10^6$ Btu (HHV) | 2244.2 kg/ GWh | Table 4-9 |
| IC engines – 4 cycle lean | 1.25 lb/$10^6$ Btu (HHV) | 0.57 kg/$10^6$ Btu (HHV) | 1934.6 kg/ GWh | Table 4-9 |
| IC engines – 4 cycle rich | 0.23 lb/$10^6$ Btu (HHV) | 0.104 kg/$10^6$ Btu (HHV) | 356 kg/ GWh | Table 4-9 |
| Turbines ( ≥ 80% load) | 0.0086 lb/$10^6$ Btu (HHV) | 0.0039 kg/$10^6$ Btu (HHV) | 13.3 kg/ GWh | Table 4-9 |
| Natural gas vehicles | 0.009 g/L | $2.2*10^{-7}$ kg/Btu (HHV) | 0.00075 kg/kWh | Table 4-17 |

Other references, such as local regulations or academic papers, also provide emission factors which can be used to quantify methane emissions from incomplete combustion at level. A few non-exhaustive examples are:

- No Author, *Del B Veiledning til SFTs Retningslinjer,* 2001 - Table 19 – Emission factor for incomplete combustion in gas turbines on the Norwegian Continental Shelf Link
- IPCC – default emission factor for gaseous fuels
- US EPA Greenhouse Gas Reporting Rule, Title 40, Chapter I, Subchapter C, Part 98, Subpart W-Petroleum and Natural Gas Systems, §98.233(z), Equation W-39B. Link
- 2012 Guidelines to Defra/DECC's GHG Conversion Factors for Company Reporting, Annex 6 – Table 6a Link
- EEMS – UK, *Atmospheric Emissions Calculations,* 2008

### Manufacturer estimates

If available, methane emission factors presented in manufacturer documentation can be used to estimate combustion efficiency, provided they are specific for the type of equipment provided by the manufacturer.

## Level 4 Quantification Methodologies

### Direct measurement and Measurement-based Emission factors

Measurements (including continuous or periodic monitoring), or emission factors developed from representative measured emissions (including predicted emissions) are considered Level 4 emissions quantification. When quantifying methane emissions resulting from incomplete combustion using direct measurement and measurement-based emission factors, measurements must be taken that consider the mass or volume and methane content of the exhaust gases.

The following are considered as providing Level 4 estimates:

| Parameters | **Continuous or Intermittent Combustion** |
|---|---|
| Mass of exhaust gases | Direct measurement or calculated based on fuel quantity and inlet air flow (where relevant) measurements, or volume of exhaust determined through the application of correlations based on representative sampling |
| Methane content of exhaust | Measurement-based methane content in the exhaust gas or methane content determined through the application of correlations based on representative sampling |

Level 4 emissions quantification shall be based on measurements conducted on a representative sample considering parameters that affects the content of methane in the exhaust (e.g.  load and other parameters). System configurations and operating conditions should be considered in determining 'like' systems that carry common parameter value Each system that is not 'like' will require determination of a separate parameter value (mass and methane content of the exhaust) 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.

Measurement-based emission factors derived from a representative sample expressed in terms of emission per volume of fuel combusted allow for easy adjustment of activity data.

The methane content of the exhaust can also be derived from techniques that combine measured fuel and airflow parameters combined with other equipment metrics (such as temperature) and kinetic models, such as predictive emissions monitoring (PEMS) techniques. For such systems, there needs to be clear validation and calibration with physical measurements.

### Mass of exhaust

Measurement-based methane mass of exhaust, mass of exhaust determined through the application of correlations based on representative sampling, or in some cases engineering calculations (as discussed below) are considered Level 4 emissions quantification. Measurement of volume of exhaust, converted to mass, using measured gas density can also be used for Level 4 emissions quantification.

Accepted measurement equipment and techniques, as defined in the *General Principles TGD,* for determining the volume of exhaust gas are to be employed. Following is a non-exhaustive list of such measurement solutions:

- Ultrasonic Flowmeters
- Thermal Flowmeters
- Differential Pressure Flowmeters
- Turbine meters
- Dynamic pressure measurement
- Impeller anemometer

The volume of exhaust gas can also be calculated based on the measured fuel and air flows that are combusted, depending on the load at which the engine is running. Similarly, the total exhaust flow rate can be determined based on fuel flow rate and exhaust $O_2$ or $CO_2$ content using combustion stoichiometric.

### Methane content of the exhaust

Measurement-based methane content of the exhaust or methane content of the exhaust determined through the application of correlations based on representative sampling are considered Level 4 emissions quantification.

Accepted measurement equipment and techniques, as defined in the *General Principles TGD,* for determining methane content in the exhaust are to be employed. Following is a non-exhaustive list of methodologies/approaches/technologies to measure methane content:

- Differential Absorption Lidar (DIAL) Link (Measures directly methane content in the exhaust, removes the requirements for composition of the fuel and if continuous monitoring, gas flow does not have to be measured either)
- ORSAT Methane Analyzer
- Heated Flame Ionization Detector
- Fourier transform infrared (FTIR)
- Tracer gas in combination with Fourier transform infrared (FTIR) for mass flow determination Link

When measuring methane content in the exhaust, it is important to take ambient methane content into consideration and to quantify the delta between the ambient methane and the methane present in the exhaust to accurately quantify methane emissions from unburned fuel. Ambient methane can be disregarded, as it leads to conservative estimates.

An alternative to quantifying these two parameters separately is to determine gas flow, methane content and destruction efficiency, similarly to the methodology described in the Flare Efficiency *TGD.*