METHODOLOGY

METHODOLOGY FOR REDUCING METHANE EMISSIONS FROM COMBUSTION ENGINE EXHAUST

SDG 13

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SUMMARY

The methodology is applicable to projects and programmes that involve the installation of equipment for reducing methane slip, here meaning methane that escapes unburnt from marine (ship) and land-based (stationary) internal combustion engines using natural gas or other methane-rich fuel, including fuels derived from renewable sources. The equipment that reduces methane slip is installed in the exhaust gas stream and includes instruments for measuring the concentration and flow rate of methane and other gases before and after the component that reduces methane emissions, permitting an accurate quantification of methane emission reductions.

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1| Introduction

1.1.1 | The following table describes the key information for the application of the methodology.

Table 1. Key information

Typical mitigation activity (project) type	The activity that involves installation of devices on land and/or marine (ship) engines to measure and reduce methane emissions from their exhaust gases. * The terms 'Mitigation Activity', 'Activity' and 'Project' refer to project activity and are used interchangeably.
Activity requirement	Others
Mitigation activity (project) type	Others
Applicable GS4GG products	☒ GSVERs ☒ Certified impact statement
Geographical applicability	Global
Applicable activity (project) scale	☒ Micro scale ☒ Small scale ☒ Large scale A mitigation activity can claim emission reductions less than or equal to - 10,000 tCO_2 eq per year for Micro scale activity - 60,000 tCO_2 eq per year for Small scale activity
Mitigation type	☒ Emission reduction ☐ Emission removal
Project activity start date	The earliest date on which the project developer has committed to expenditures related to the implementation of mitigation activity.
Crediting period start date	The start date of Crediting Period is the date of start of operation (start of operation of 1st methane reduction device as part of mitigation activity) or a maximum of two years prior to the date of Project Design Certification, whichever occurs later.
Crediting period length	Ten years (maximum); the mitigation activity follows five-year renewal cycle per latest version of GS4GG requirements for renewal of crediting period. Crediting period ends if the engine reaches its end of life, even if the given project activity is within its approved original or renewed crediting period. Under no circumstances, shall the total crediting period of any project activity relying on this methodology exceed a maximum of 10 (ten) years.
Application limitations	The methodology can be applied to the activity involving the installation of the technology i.e., methane reduction devices,

	a. Where technology is installed with new engines, the activity shall be submitted for listing by 31/12/2030. b. Where technology is installed to old or existing engines, the activity may be submitted before or after 31/12/2030.

2| Definition

2.1.1 | The definitions contained in the Glossary of Gold Standard for Global Goals (GS4GG), along with the those provided in this methodology, apply to this methodology terms shall apply[1]:

Table 2. Terms and Definitions

TERM	DEFINITION
Absolute humidity	The ratio between the mass of H_2O (vapor phase) in the gas and the mass of the dry gas
Dry basis	A parameter that does not account for the H_2O present in the gas
Gaseous stream	A mixture of gaseous components which, for the purpose of this methodology, may contain different fractions of N_2, CO_2, O_2, CO, H_2, CH_4, N_2O, NO, NO_2, SO_2, and H_2O in the vapor phase and its absolute pressure must be below 10 atm or 1.013 MPa.[2] Other gases may be present (e.g. hydrocarbons) provided their total concentration represents less than 1% (v/v) of the total.[2] A dry gas or dry gaseous stream excludes the H_2O fraction and a wet gas or wet gaseous stream includes the H_2O fraction.
Methane slip	Refers to methane gas emitted unburned from an internal combustion engine. The sources[3] can be identified as follows: a) Escape of unburnt mixture via the exhaust valve, b) Incomplete combustion in the pre-chamber, c) Quenching of the flame on combustion chamber surfaces or crevices, d) Local flame extinction due to high turbulence.
Normal conditions	As 0°C (273.15 K, 32°F) and 1 atm (101.325 kN/m^2, 101.325 kPa, 14.69 psia, 29.92 in Hg, 760 torr)
Relative humidity	The ratio between the partial pressure of H_2O in the gas and the saturation pressure at a given temperature.

[1] These definitions are based, in part, on those provided in CDM Methodological Tool 8 "Tool to determine the mass flow of a greenhouse gas in a gaseous stream".

[2] This condition is required because it is assumed in the calculations that the gas stream behaves as an ideal binary mixture of water vapor and an ideal gas. If the gaseous stream contains larger fractions of other gases, such as hydrocarbons other than methane or HFCs, the gas cannot be considered to be an ideal gas mixture. Moderate pressures will assure that gases behave as ideal gases.

[3] Weisser et al., 2019; Greenhouse Gas (GHG) Emissions from LNG Engines. Review of the Two Stroke Engine Emission Footprint. 4 - Emission Reduction Technologies - What's in Store for the Future, CIMAC World Congress 2019

Saturation (absolute) humidity	The maximum amount of H_2O (vapor phase) that the gas can contain at a given temperature and pressure, expressed as mass of H_2O per mass of the dry gas.
Time interval	The inverse of frequency. Refers to the time interval between measurements.
Time period	The duration of time. Refers to the duration of each measurement.
Wet basis	A parameter that accounts for the H_2O present in the gas.

3| Scope, Applicability, and entry into force

3.1 | Scope

3.1.1 | This methodology is applicable to activities that involve installation of devices to measure and reduce methane emissions from the exhaust gases of land-based (stationary) and marine (ship) internal combustion engines using natural gas or other methane-rich fuel, including fuel from renewable sources.

3.2 | Applicability

3.2.1 | The table below presents the applicability conditions, and the means of verification used to ensure compliance with the applicability conditions of the methodology.

Table 3. Applicability Conditions and Means of Verification

Applicability Condition	Means of Verification
a. The activity comprises the installation of a new device to measure and abate methane emissions in the exhaust gas stream of an internal combustion engine burning natural gas or another methane-rich fuel.	The project design document (PDD) shall include a description of the device with details and supporting data on how methane emissions are measured and reduced.
b. For gas measurements, the recommended emission gas analyser is based on infrared (IR) absorption spectroscopy with a tunable Fabry-Perot filter, offering unique performance and stability and providing real-time gas analysis with no need for consumables. The analyser is to be designed for use with cold-dry extractive sampling systems.	Manufacturer specifications.

For measurement of water vapour, any hot/wet measurement procedure may be used.	
c. The engine shall be land-based (stationary) or installed in ships.	The PDD shall provide details on the geographical location of the land-based (stationary) installation or the ship identifiers, specifically the International Maritime Organization (IMO) number[4].
d. For both land-based (stationary) and marine (ship) applications, the engine(s) where the device is installed can be a new or an existing internal combustion engine.	The PDD shall provide a description of the engine, including make, model and (for existing engines) serial number, allowing the engine(s) where the methane abatement device is applied to be identified. See "Safeguards" section, Monitoring parameter section, and Annexes 1 and 2 on how to ensure that the activity does not extend the use of a fossil fuel.
e. Since the methodology is applicable to natural gas or other methane-rich fuel, which may be derived from a renewable source such as landfill gas or other biogenic methane, and the latter allows GHG emissions reduction, a fuel switch from a fossil to a non-fossil alternative at the time of the device installation or during the project period is allowed.	Records of fuel type and dates of fuel switching, if any, and any equipment changes associated with the fuel switch.
f. The methodology is applicable to both cases where the technology is installed on new and existing engines. The project activities/VPAs involving the installation of the technology to	PDD would describe if the activity includes new or existing engines with evidence referenced to objectively validate the same.

[4] The IMO number is a unique reference for a ship, registered ship owners and management companies. IMO numbers were introduced under the International Convention for the Safety of Life at Sea (SOLAS) to improve maritime safety and security and to reduce maritime fraud. For ships, the IMO number remains linked to the hull for its lifetime, regardless of a change in name, flag, or owner.

i. new engines must be submitted for listing prior to the end of 31/12/2030. ii. old/existing engines are eligible beyond 31/12/2030.	
g. To ensure that any activity applying this methodology does not lead to the long-term lock-in of emissions, the activity shall not claim GSVERs beyond the life of the engine to which the technology is applied. In other words, the crediting period ends if the engine reaches its end of life, even if the given activity is within its approved original or renewed crediting period.	The PDD shall - provide a description of the engine including make, model (for existing engines), serial number and remaining lifetime estimated using CDM TOOL 10. This shall allow confirmation of any engine replacement. - indicate the project start date and crediting period start and end date, which shall be checked at each verification.

3.2.2 | The project developer is responsible for fulfilling all data and monitoring requirements, including securing necessary monitoring data. Therefore, an agreement between the participants and the developer shall be established where necessary.

3.3 | Safeguards

3.3.1 | Activities applying this methodology shall adhere to most recent edition of the Safeguarding Principles & Requirements, throughout the entire project cycle.

3.3.2 | The activity using this methodology shall not undermine or conflict with any national, sub-national or local regulations or guidance for methane emissions or reductions, fuel supply or use. The project design document shall present:

a. a summary of existing the national, regional and local regulatory framework relevant for the proposed activity.

b. monitoring plan at the activity level to ensure that any activity is surplus to regulations during the crediting period (refer to para 5.3.1 |

3.3.3 | Any party, including but not limited to technology supplier, engine or ship owner and aggregator, may develop a project or Programme of Activities applying this methodology. Clear communication and agreement among all parties involved, including but not limited to technology supplier, engine or ship owner, and aggregator, is required to avoid potential double counting of carbon credits. Such an agreement, which covers carbon credit ownership, should be established if the project developer is not the fuel end user. This agreement should be private and confidential but subject to monitoring and verification during the project approval process and prior to the issuance of carbon credits.

3.4 | Entry into Force

3.4.1 | The date of entry into force of this methodology is the date of publication.

4| Normative References:

4.1.1 | This methodology refers to the latest approved versions of the following Clean development mechanism (CDM) methodological tools:

a. CDM Tool 01 – Tool for the demonstration and assessment of additionality
b. CDM Tool 03 – Tool to calculate project or leakage CO2 emissions from fossil fuel combustion.
c. CDM Tool 05 – Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation.
d. CDM Tool 08 – Tool to determine the mass flow of a greenhouse gas in a gaseous stream
e. CDM Tool 07 – Tool to calculate the emission factor for an electricity system
f. CDM Tool 10 – Tool to determine the remaining lifetime of equipment
g. CDM Tool 21 – Demonstration of additionality of small-scale project activities.

5| Baseline Methodology

5.1 | Project Boundary

5.1.1 | A project may include one or more engines, either land-based (stationary) or on ships, or both. The project boundary encompasses all engine installations for all locations in the project activity. At each location, the project boundary includes the engine or engines, with fuel and air entering and gases exiting. Each engine is an internal combustion engine that burns natural gas or other methane-rich fuel. Whether on a ship or a stationary land location, the project boundary only includes engines that will be impacted by the installation of project equipment to measure and reduce methane emissions.

5.1.2 | If the device installed for measuring and reducing methane emissions consumes electricity, the project boundary includes the generators or power plants that supply this electricity.

a. In marine applications, this electricity is sourced from on-board generators, which are included in the project boundary.
b. For land-based (stationary) applications, the electricity may be sourced from (a) a grid or (b) an off-grid source, which are included in project boundary including any onsite generators,

5.1.3 | The project boundary for a single engine is shown in Figure 1, below.

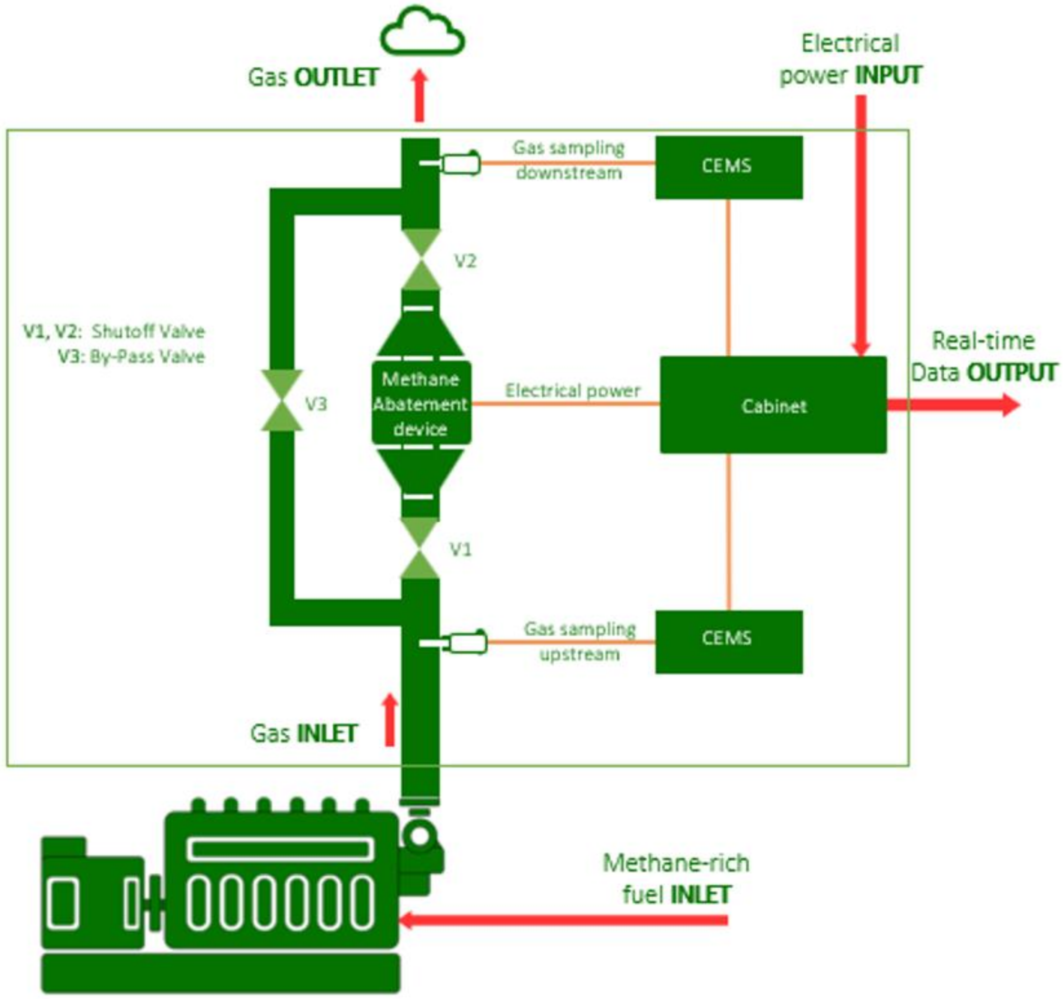

Figure 1. Installation showing engine, methane abatement device, monitoring points upstream (Baseline) and downstream (Project) of treatment device, gas analyser and project boundary (shown as a green box). CEMS: Continuous emissions monitoring system. Source: Daphne Technology SA

5.2 | Emissions sources included in the project boundary

Table 4. Emissions sources included in or excluded from the project boundary

Scenario	Source	Gas	Included	Justification/Explanation
Baseline scenario	GHG emissions in engine exhaust (upstream of any project device to reduce methane emissions)	CO_2	Yes	Major emission source
		CH_4	Yes	Main source of emissions from methane slip (unburnt methane in combustion products)
		N_2O	No	Excluded for simplification. This is conservative
Project scenario	GHG emissions in engine exhaust	CO_2	Yes	Major emission source
		CH_4	Yes	Remaining emissions following methane abatement device

	downstream of device to reduce methane slip	N_2O	No	Excluded for simplification. This is conservative
	Emissions from electricity consumption attributable to the methane abatement equipment installed in the project activity	CO_2	Yes	May be an important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small*
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small

*Note that if the electricity is generated by the same engine to which the methane abatement device is attached, these methane emissions are already included above, so that the emissions reductions are even more conservative.

5.3 | Demonstration of additionality

5.3.1 | Regulatory surplus: All activities, regardless of their scale, shall demonstrate regulatory surplus. It means showing that the proposed activity is not directly mandated by law or triggered by any legal requirements, such as legally binding agreements, covenants, consent decrees, or contracts with government agencies or private parties. If a legal mandate comes into effect during the crediting period, the activity can only claim credits until the day the legal requirements become effective.

5.3.2 | The project developer shall demonstrate additionality by conforming to additionality requirements of one of the options below,

a. CDM Tool 01 - Tool for the Demonstration and Assessment of Additionality;

b. CDM Tool 21 – Demonstration of additionality of small-scale project activities; (applicable to small-scale projects only)

c. An approved Gold Standard VER additionality tool

5.3.3 | The project developer shall provide transparent and documented evidence to demonstrate the additionality in line with applied additionality tool. Some aspects on the determination of additionality are discussed below in the section on Baseline scenario determination. These aspects shall be incorporated into the additionality analysis presented in the PDD.

5.4 | Baseline scenario

5.4.1 | For the project activity covered by this methodology, the alternatives to the project activity as possible baselines are:

a. For existing engines:

i. Continue operation without the installation of the methane measurement and abatement device.

ii. Installation of methane measurement and abatement device without carbon credits.

b. For new engines:

i. Installation of the new engine without the methane measurement and abatement device.

ii. Installation of the new engine and the methane measurement and abatement device, without carbon credits.

5.4.2 | In either case, there is a choice of installing the methane measurement and abatement device, with or without carbon credits. Whether such installation is warranted without carbon credits is determined by the additionality analysis.

5.5 | Selection and justification of the baseline scenario

5.5.1 | As part of identifying alternative baseline scenarios, the project developer shall demonstrate that alternatives to the project activity comply with current laws and regulations. These include, but are not limited to, regulations relevant to pollutant and methane emission reductions. For marine-based activities, for instance, a parent engine shall have an Engine International Air Pollution Prevention (EIAPP) Certificate from the Flag State and International Maritime Organization (IMO) reference numbers via a Technical File (TF). This file accompanies the engine's NOx-emissions (NOx Technical Code) throughout its operational life.

5.5.2 | Currently, there are no financial incentives to reduce methane emissions, but this could change in the future. Any impacts of potential future regulations aimed at methane reductions on a given project, and the financial or technical additionality demonstrations for that project, should be considered at the project or PoA, VPA level.

5.6 | Baseline Emissions

5.6.1 | Baseline emissions in year y (BEy) are calculated as follows:

$$BE_y = BE_{CH_4,y} + BE_{CO_2,y} = GWP_{CH_4} \times M_{B,CH_4,y} + M_{B,CO_2,y} \qquad \text{Eq. 1}$$

Where:

BE_y	=	Baseline emissions in year y, $tCO_{2\,eq}$
$BE_{CH_4,y}$	=	Baseline CH_4 emissions in year y, $tCO_{2\,eq}$
$BE_{CO_2,y}$	=	Baseline CO_2 emissions in year y, $tCO_{2\,eq}$
GWP	=	Global warming potential (GWP), based on 100-year GWP as per GS4GG requirements
$M_{B,CH_4,y}$	=	Mass flow rate of CH_4, tonnes/year
$M_{B,CO_2,y}$	=	Mass flow rate of CO_2, tonnes/year

5.6.2 | The concentration of nitrogen shall be determined from the mass flow balance, as indicated in the CDM Tool 8. Unrelated to the determination of GHG gases (CO_2 and CH4), a given project activity *could* extend the monitoring procedure to air pollutants such as NO, NO_2, and SO_2.

5.7 | Project emissions

5.7.1 | The project emissions include two components to project emissions:

a. CH_4 and CO_2 remaining in the gaseous stream leaving the device used for reducing methane in the exhaust gas;
b. Operation of the device for reducing methane emissions requires electricity, insofar as fossil fuels are used for electricity generation.

5.7.2 | The project emissions are calculated as follows:

$$PE_y = PE_{CH_4,y} + PE_{CO_2,y} = GWP_{CH_4} \times M_{P,CH_4,y} + M_{P,CO_2,y} + PE_{EC,CO_2,y} \qquad \text{Eq. 2}$$

Where PE_y, $PE_{CH_4,y}$, $PE_{CO_2,y}$, $M_{P,CH_4,y}$, and $M_{P,CO_2,y}$ are defined as for baseline emissions in Eq. 1 above, with “P” (Project) replacing “B” (Baseline) and

$PE_{EC,CO_2,y}$	=	Project CO_2 emissions resulting from the electricity consumption of the methane abatement device

5.7.3 | The determination of the mass flow rate of CO_2 and CH_4 upstream of the methane abatement device (Baseline) and downstream of the methane abatement device (Project) requires the measurement of the concentrations of CO_2, CH_4, and humidity, as well as the flow rate. These input parameters are calculated following the latest version of CDM Tool 08, with the following requirements.

a. The mass flow of CO_2 and CH_4 shall be determined following CDM Tool 8 Option B or Option E
b. The absolute humidity of the CO_2 and CH_4 shall be determined following CDM Tool 08 Option 1: Calculation using measurement of the moisture content.

5.7.4 | For land-based (stationary) engines, the project emissions due to electricity consumption ($PE_{EC,CO_2,y}$) by the methane abatement device are calculated applying the latest approved version of CDM Tool 05 as follows.

a. If the electricity is sourced entirely from a renewable electricity source, the project emission shall be considered as zero.
b. If the electricity is sourced from the grid, the project developer may apply option A1 or option A2 of CDM Tool 05.
c. If the electricity is sourced from an off-grid captive power plant, the project developer may apply option B1 or option B2 of CDM Tool 05

5.7.5 | For ship-based engines, the project emissions due to use of electricity ($PE_{E,CO_2,y}$) by the methane abatement device are calculated applying the latest approved version of CDM Tool 05. The following requirements are applied for application of CDM Tool 05 for such cases

a. If the electricity is sourced entirely from a renewable electricity source the project emission shall be considered as zero.
b. If the electricity is sourced from the ship's fossil fuel-based generator, the project developer may apply option B1 or option B2 of CDM Tool 05. In such cases, average technical transmission and distribution losses for providing electricity to methane abatement device ($TDL_{j,y}$) may be assumed to be zero.

5.8 | Procedure for the ex-ante determination of baseline and project emissions

5.8.1 | In instances where a methane measurement and abatement system, which is the project activity, *has already been installed*, a trial run of the system is conducted to collect upstream and downstream emission data. The system's operational stability shall be ensured for a representative period for the trial run. The performance data is used as the basis for ex-ante estimates, following the procedures detailed in the above section.

5.8.2 | In order to ensure that the baseline measurements are conservative – do not lead to higher emissions reduction, the measurements shall be compared to the literature for methane slip, from independent sources. Where measurements lead to higher emissions reductions, the conservative values sourced from relevant literature shall be applied.

5.8.3 | For marine applications, methane slip depending on the type of engine may vary, as shown in Table 5 **Table 4**.

Table 4. Methane emissions for different types of marine engines using Liquefied Natural Gas (LNG)

Engine type	Methane emissions		Source table in reference
	g/kWh	%	
Two-stroke, low-speed engine, Diesel, dual fuel	0.23	0.17	5.7
Two-stroke, low-speed engine, Otto, dual fuel	2.14	1.5	5.7
Four-stroke, medium speed, Otto, spark ignition	2.00	1.3	5.8
Four-stroke, medium speed, Otto, dual fuel	3.98	2.6	5.8
Four-stroke, high speed, Otto, spark ignition	3.25	1.7	5.9
Gas turbine, simple cycle	0.08	0.04	5.10

Source: Sphera (2021)

5.8.4 | For land-based stationary applications, typically for gas compression in natural gas pipelines, Vaughn et al. (2021) published results of measurements.

Table 5. Methane emissions from measurements by Vaughn et al. (2021) and U.S. EPA compilation of air pollutant emission factors, denominated AP42, original values in pounds (lb) per million Btu (MM Btu) of fuel.

Engine type	Methane emissions	
	lb/MMBtu	g/kWh
2 SLB: Two-stroke, lean burn, AP42	1.45	2.24
2 SLB: Two-stroke, lean burn, Vaughn et al. (2021)	--	--
4 SLB: Four-stroke, lean burn, AP42	1.25	1.93
4 SLB: Four-stroke, lean burn, Vaughn et al. (2021)	1.15	1.78
4 SRB: Four-stroke, rich burn, AP42	0.23	0.36
4 SRB: Four-stroke, rich burn, Vaughn et al. (2021)	0.10	0.15

Source: adapted from Vaughn et al. (2021), Table 1

5.8.5 | In instances where a methane measurement and abatement system, which is the project activity *has not been installed*, then ex ante estimates may be determined assuming a baseline methane emissions level taken from **Table 4**, **Table 5**, or other relevant third-party reference.

5.8.6 | The procedure is as follows:

a. *Ex-ante* baseline methane emissions (methane slip, g/yr) = Engine power (kW) x (hours of operation on natural gas or other methane-rich fuel per year) x methane slip (g/kWh) from above table, according to engine type. This value may be compared with ex-post determination of methane slip, as determined in Eq. (1) above, using monitoring parameters specified further below.

b. *Ex-ante* project emissions may be estimated from laboratory measurements of methane abatement potential, with respect to the Baseline methane emissions. For ex-ante project emissions associated with the electricity consumption of the measurement and abatement device, manufacturer measurements or estimates of the electricity consumption could be used, together with the emissions factor of the electric power system that would be supplying the equipment, including any Transmission and Distribution (T&D) losses as per CDM Tool 05 described above.

5.9 | Leakage emissions

5.9.1 | There are no leakage emissions considered for this methodology.

5.9.2 | There are no other GHG emissions included in this methodology. Note, however, that project developer shall include NOx (NO and NO_2) and SO_2 emissions since the methane measurement device is able to accurately measure such emissions. Note that NOx and SO_2 are not GHGs.

5.10 | Emission reductions

5.10.1 | The emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \text{Eq. 1}$$

Where:

ER_y = Emission reductions in year y (t CO_2e/yr)

BE_y	=	Baseline emissions in year y (t CO_2e/yr)
PE_y	=	Project emissions in year y (t CO_2e/yr)
LE_y	=	Leakage emissions in year y (t CO_2e/yr)

5.11 | Changes required for 2nd crediting period

5.11.1 | When the project developers apply for crediting period renewal, the developer shall apply the latest available version of the methodology and:

a. Reassess the continued validity of the baseline in line with any changes in the relevant national and/or sectoral regulations and incorporate the impact of new regulations on baseline.

b. Update the baseline emissions using the new data available, where needed.

c. Update the ex-ante parameters value (not updated during the crediting period).

d. Incorporate any relevant updates of the GS4GG requirements as applicable to the project activity

5.12 | General requirements for data and information sources

5.12.1 | Describe and specify in the PDD all monitoring procedures, including the type of measurement instrumentation used, the responsibilities for monitoring and QA/QC procedures that will be applied. Where the methodology provides different options (e.g. use of default values or on-site measurements), specify which option will be used. Meters should be installed, maintained and calibrated according to equipment manufacturer instructions and be in line with national standards, or, if these are not available, international standards (e.g. IEC, ISO).

5.12.2 | All data collected as part of monitoring should be archived electronically and be kept at least for 2 years after the end of the last crediting period. 100% of the data should be monitored if not indicated differently in the comments in the tables below.

5.12.3 | When multiple sources are available and fulfil the requirements for defining or cross-checking a parameter, the most relevant source shall be chosen. Criteria for relevance include geographical (e.g., more specific to the project boundary location), temporal (e.g., more recent), and others. The VVB shall assess the relevance of the source applied compared with the other sources available. While conservativeness is a guiding principle for selecting data, the source applied to define or cross-check the parameter may not be the most conservative if it can be shown to be the most relevant.

5.13 | Data and parameters not monitored

5.13.1 | In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Parameter ID	**RMCE 1**
Data/Parameter:	Ship identification numbers
Data unit:	n/a
Description:	Unique ship identification numbers assigned by the International Maritime Organization (IMO). Include all ships in a given project.
Source of data:	Ship owner/operator, IMO, third party websites
Measurement procedures (if any):	-
Any comment:	Each IMO number is a unique reference for a ship, registered ship owners and management companies. IMO numbers were introduced under the International Convention for the Safety of Life at Sea (SOLAS) to improve maritime safety and security and to reduce maritime fraud. For ships, the IMO number remains linked to the hull for its lifetime, regardless of a change in name, flag, or owner. Applicable only to ship-based projects.

Parameter ID	**RMCE 2**
Data/Parameter:	Project location
Data unit:	As for geographical coordinates
Description:	Project location
Source of data:	Project proponent, GPS data
Measurement procedures (if any):	-
Any comment:	Other geographical indicators could be the company and/or plant name, address, other government land Applicable only to land-based (stationary) projects

Parameter ID	**RMCE 3**
Data/Parameter:	Engine make, model and (for existing engines) serial number
Data unit:	None
Description:	Engine identifier
Source of data:	Manufacturer and/or equipment nameplate
Measurement	None

procedures (if any):	
Any comment:	Crediting period ends at the end of remaining life of the engine where the methane abatement devices have been added

Parameter ID	**RMCE 4**
Data/Parameter:	GWP_{CH4}
Data unit:	t CO_2eq/t CH_4
Description:	Global warming potential of CH_4
Source of data:	IPCC Default value as per GS4GG requirements.
Measurement procedures (if any):	-
Any comment:	-

6| Uncertainty Quantification

6.1.1 | Potential sources of uncertainty, along with the associated Quality Assurance/Quality Control (QA/QC) requirements to minimize them, are summarized in monitoring parameter tables below.

6.1.2 | The uncertainties associated with the parameters would be aggregated into uncertainty estimates for emission reductions. A 95% confidence interval will be employed for quantifying uncertainty due to random errors, following the statistical approaches provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (propagation of errors method), unless otherwise required in the applied tool or guidelines. When the uncertainty in the estimated value of emission reductions or removal is expected to be at a 95% confidence interval (within +/-10% range when applicable), the activity may exclude such random errors; while, in case of being outside +/-10% range at a 95% confidence interval, the activity should include such random errors.

7| Monitoring methodology

7.1 | Data and parameters monitored

7.1.1 | In addition to the parameters listed in the tables below, the provisions on data and parameters monitored in the tools referred to in this methodology apply.

Parameter ID	**RMCE 5**

Data/Parameter:	Regulations and policies related to methane emissions or reductions, fuel supply or use in a jurisdiction where project is located
Data unit:	N/A
Description:	It is possible that some jurisdictions where the project boundary lies may institute laws and regulations. In these cases, the project developer shall monitor the development of such regulations and assess the eligibility for issuance of GSVERs for each verification event.
Source of data:	Monitoring
Measurement procedures (if any):	-
QA/QC procedures:	-
Monitoring frequency:	Annual
Any comment:	N/A

Parameter ID	**RMCE 6**
Data/Parameter:	$V_{t,db}$
Data unit:	m³ dry gas/h
Description:	Volumetric flow of the gaseous stream in time interval *t* on a dry basis
Source of data:	On-site measurements
Measurement procedures (if any):	Volumetric flow measurement should always refer to the actual pressure and temperature. Calculated based on the wet basis flow measurement plus water concentration measurement
Monitoring frequency:	Continuous if not specified in the underlying methodology
QA/QC procedures:	Periodic calibration against a primary device provided by an independent accredited laboratory is mandatory for all projects applying large scale methodology(ies). Calibration and frequency of calibration is according to manufacturer's specifications
Any comment:	This parameter will be monitored in CDM Tool 8, Option A, which is used in this methodology

Parameter ID	**RMCE 7**

Data/Parameter:	$v_{i,t,db}$
Data unit:	m³ gas *i*/m³ dry gas
Description:	Volumetric fraction of greenhouse gas *i* in a time interval *t* on a dry basis
Source of data:	On-site measurements
Measurement procedures (if any):	Continuous gas analyser operating in dry-basis. Volumetric flow measurement should always refer to the actual pressure and temperature
Monitoring frequency:	Continuous if not specified in the underlying methodology
QA/QC procedures:	Calibration should include zero verification with an inert gas (e.g. N_2) and at least one reading verification with a standard gas (single calibration gas or mixture calibration gas). All calibration gases must have a certificate provided by the manufacturer and must be under their validity period.
Any comment:	From CDM Tool 8

Parameter ID	**RMCE 8**
Data/Parameter:	$EC_{PJ,j,y}$
Data unit:	MWh/yr
Description:	Quantity of electricity consumed by the project electricity consumption source *j* in year *y*
Source of data:	Direct measurement or calculated based on measurements from electricity meters
Measurement procedures (if any):	Use electricity meters installed at the electricity consumption sources.
Monitoring frequency:	Continuous measurement and at least monthly recording
QA/QC procedures:	In cases where electricity meters are regulated (e.g. the electricity is supplied by the electric grid), the electricity meter will be subject to regular maintenance and testing in accordance with the stipulation of the meter supplier and/or as per the requirements set by the grid operators or national requirements. The calibration of meters, including the frequency of calibration, should be done in accordance with national standards or requirements set by the meter supplier or requirements set by the grid operators. The accuracy class of the meters should be in accordance with the stipulation of the meter supplier and/or as per the requirements set by the grid operators or national requirements. In cases where

	electricity meters are not regulated (e.g. the electricity is supplied by captive power plants), the electricity meter will be subject to regular maintenance and testing in accordance with the stipulation of the meter supplier or national requirements. The calibration of meters, including the frequency of calibration, should be done in accordance with national standards or requirements set by the meter supplier. The accuracy class of the meters should be in accordance with the stipulation of the meter supplier or national requirements. If these standards are not available, and meter supplier does not specify, calibrate the meters every 3 years and use the meters with at least 0.5 accuracy class (e.g. a meter with 0.2 accuracy class is more accurate and thus it is accepted).
Any comment:	In case of missing data due to meter failure or other reasons for a certain period of time, the following options to estimate electricity consumption may be applied: a. A conservative value based on rated capacity and full operational hours (8760 hours); or b. Estimation of electricity consumption as highest daily value among the daily monitored values multiplied by the number of days' data were missing. This option is applicable for missing data of up to 7 consecutive days within three consecutive months.

Parameter ID	**RMCE 9**
Data/Parameter:	$FC_{n,i,y}$
Data unit:	Mass or volume unit at Normal conditions per year (in m^3, ton or litres)
Description:	Quantity of fuel type *i* fired in the captive power plant *n* in *year y*
Source of data:	Annual data during the crediting period: On-site measurements; Historical data: Historical records / on-site measurements
Measurement procedures (if any):	Use either mass or volume meters. In cases where fuel is supplied from small daily tanks, rulers can be used to determine mass or volume of the fuel consumed, with the following conditions: The ruler gauge must be part of the daily tank and calibrated at least once a year and have a book of control for recording the measurements (on a daily basis or per shift);
Monitoring frequency:	Historical data or monitored data aggregated annually
QA/QC procedures:	The consistency of metered fuel consumption quantities should be cross-checked with an annual energy balance that is based on purchased quantities and stock changes.
Any comment:	Note: The requirements for this monitoring parameter have been simplified since the parameter is only needed for determining the

	emissions factor for electricity generation, and historical data may be sufficient, as indeed indicated in the item "Source of data"

7.2 | General requirements for sampling

7.2.1 | Not applicable to this methodology.

7.3 | Considerations in case of applying methodology in PoA

7.3.1 | The methodology may be applied to standalone projects or a programme of activities (PoA).

7.3.2 | The following conditions apply for using the methodology in a PoA:

a. The PoA can contemplate both land-based (stationary) projects or marine (ship-based) projects.

b. The individual real case VPA or regular VPA within the PoA may comprise either a set of land-based (stationary) installations or set of ships, but not the combination of land-based (stationary) installations and ships

c. VPAs comprising marine, ship-based installation needs to consider IMO and other internationally binding regulations in establishing additionality.

d. There should be an agreement in place establishing the arrangements for ownership of carbon credits generated in each VPA, so that there is no double counting or doubts on the ownership of the carbon credits.

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ANNEX 1: LNG IN SHIPPING

LNG is an important transition fuel in shipping. LNG ships currently make up only ~1% of the entire fleet of ships. In the sustainable development scenario prepared by the International Energy Agency (IEA, 2020a), cited by Bureau Veritas (2022), the use of LNG would grow up to around 2040 (*see Figure 2*), with ammonia and hydrogen which can be made from renewable energy becoming relevant only in 2040 and beyond. It needs to be emphasized that shipping, while the most energy efficient and low carbon transportation mode, is also the hardest to decarbonize. LNG dominates the market for alternative low-emission fuels in new ships, with the rest being almost entirely Heavy fuel oil (HFO) (see Figure 3). Moreover, since the LNG vessel market share is increasing (see Figure 3 and Figure *4*), methane slip is projected to increase over the coming years[5] without encouraging or facilitating new technologies such as that which the methodology is proposing.

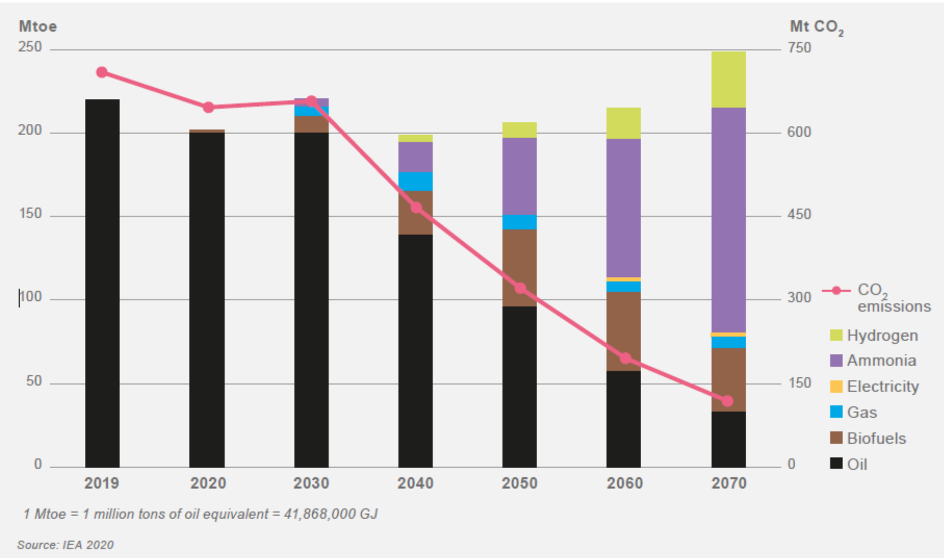
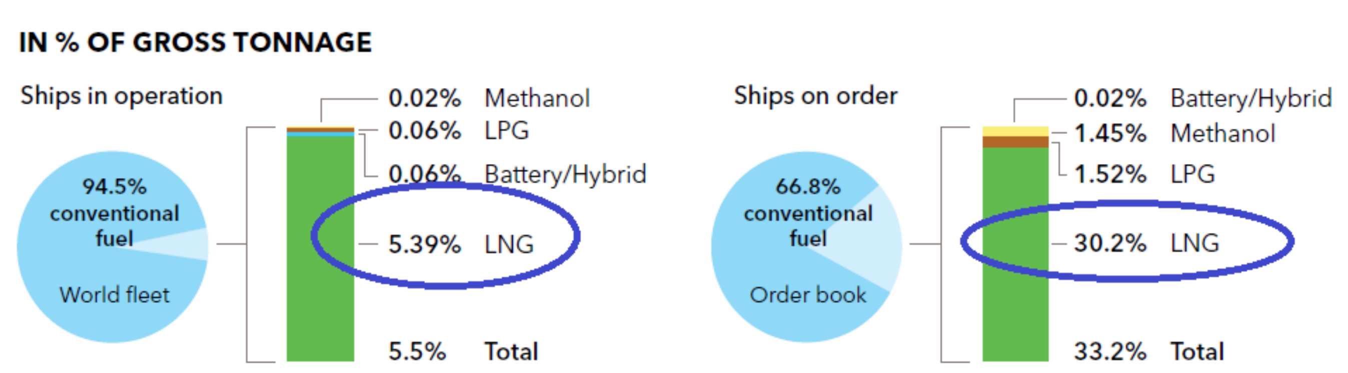


Figure 2. Energy consumption and CO_2 emissions of international shipping in the sustainable development scenario 2019-2070. Source: IEA, 2020a



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[5] This conclusion is also reached by DNV in their Alternative Fuel Insights March 22, see, e.g. https://safety4sea.com/number-of-ships-using-lng-scrubbers-to-increase-from-2020/

Figure 3. Alternative fuel uptake in the world fleet by gross tonnage. Note that while LNG ships represent only 5.39% of ships in operation, it represents almost a third of ships on order.
Source: DNV, 2022, Maritime Forecast to 2050. Energy Transition Outlook 2022. Fig. 3.2.

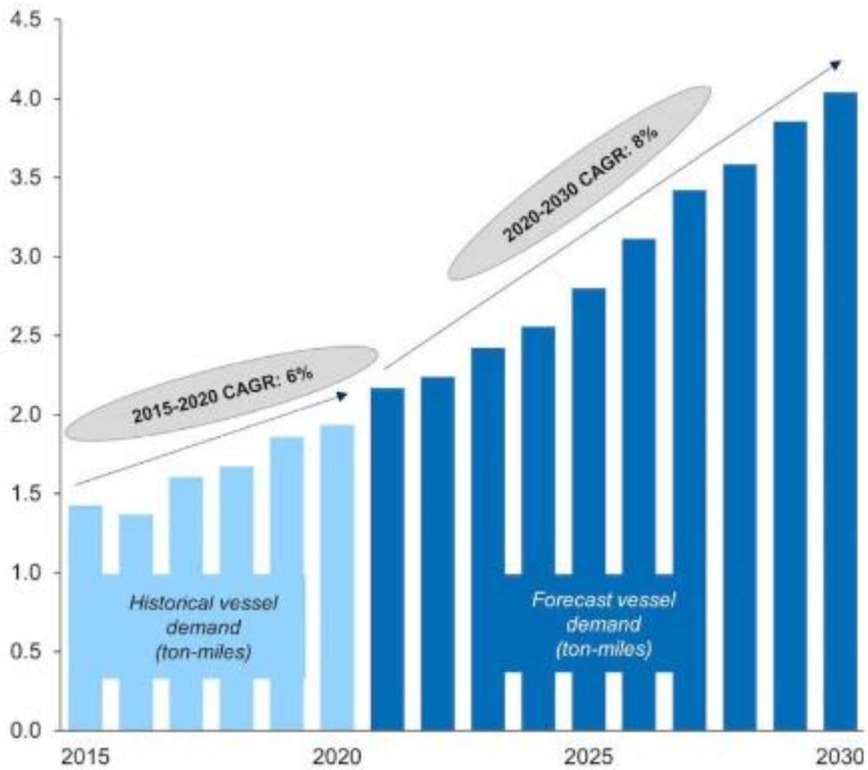

Figure 4. LNG vessel demand, in trillion ton-miles of transport, 2015-30
Source: splash247.com[6]

LNG is also a fuel-in-transition. Methane is the principal component of natural gas as well as biogas. In the future, LNG vessels would continue to operate with biogenic LNG.
LNG is a low-emissions fuel. Even fossil LNG provides substantial GHG emissions reduction compared to LSHFO (Figure 5). The benefits are expected to increase in the future, with improvements in LNG engines, especially for Otto-cycle dual-fuel engines (Table 6).

[6] https://splash247.com/lng-vessel-demand-forecast-to-double-this-decade/ citing Rystad Energy Vessel Analytics.

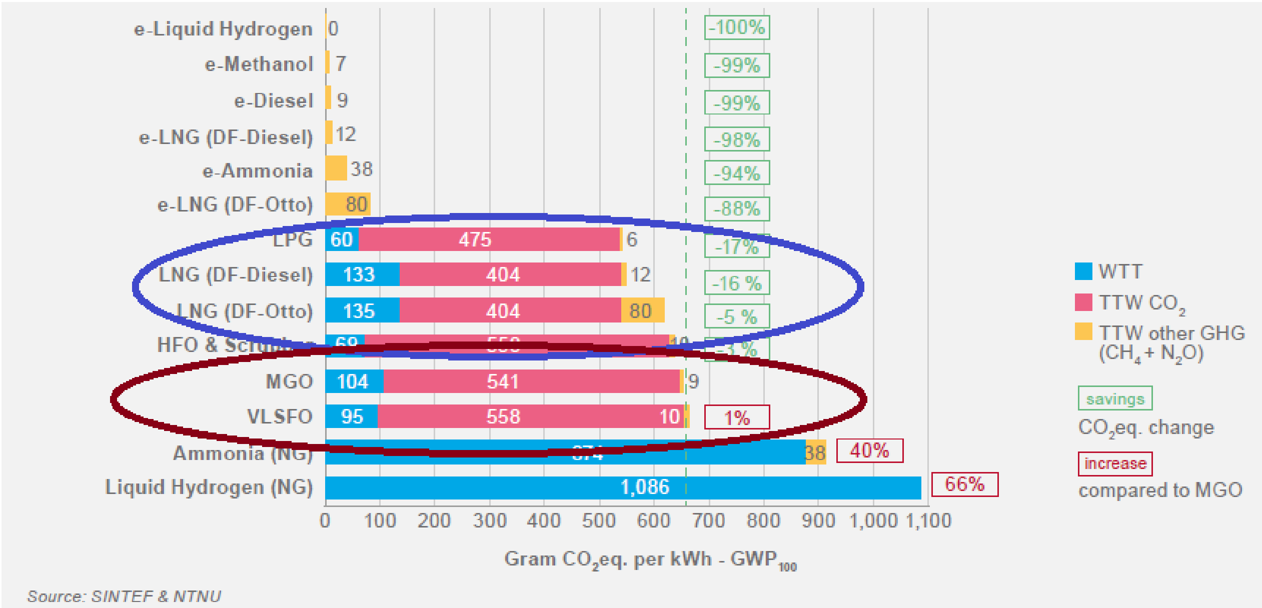

Figure 5. Life-cycle ("well-to-wake") emissions of different marine fuels

Table 6. Emissions benefits of today's and 2030 LNG-fuelled engines compared with LSFO

g CO_2-eq/kWh	2-stroke slow speed		4-stroke medium speed	
	Diesel-DF	Otto-DF	Otto-DF	Otto-SI
Benefit compared with $VLSFO_{0.5}$				
Today	23 %	14 %	6 %	14 %
2030	24 %	24 %	22 %	21 %

Source: Sphera, 2021, Table 5.

Retrofitting methane-slip reduction technology is more difficult on a vessel than installing on a newbuild due to space issues. The measure is an after-treatment system, so can measure the presence of pollutants before and after the system and/or the system can be disconnected and measurements without abatement are possible. This way, it is always possible to establish the baseline, even for newbuilds and new engines.

LNG is substantially more expensive than low sulphur heavy fuel oil HFO, which is currently the most common fuel used in international shipping. Bureau Veritas (2022) provides a comparison of the production cost of different fuels used for shipping in recent years (Figure 6). As can be seen, LNG (blue oval) is substantially more expensive per unit energy than HFO and Low-sulphur heavy fuel oil (LSHFO) (brown oval).

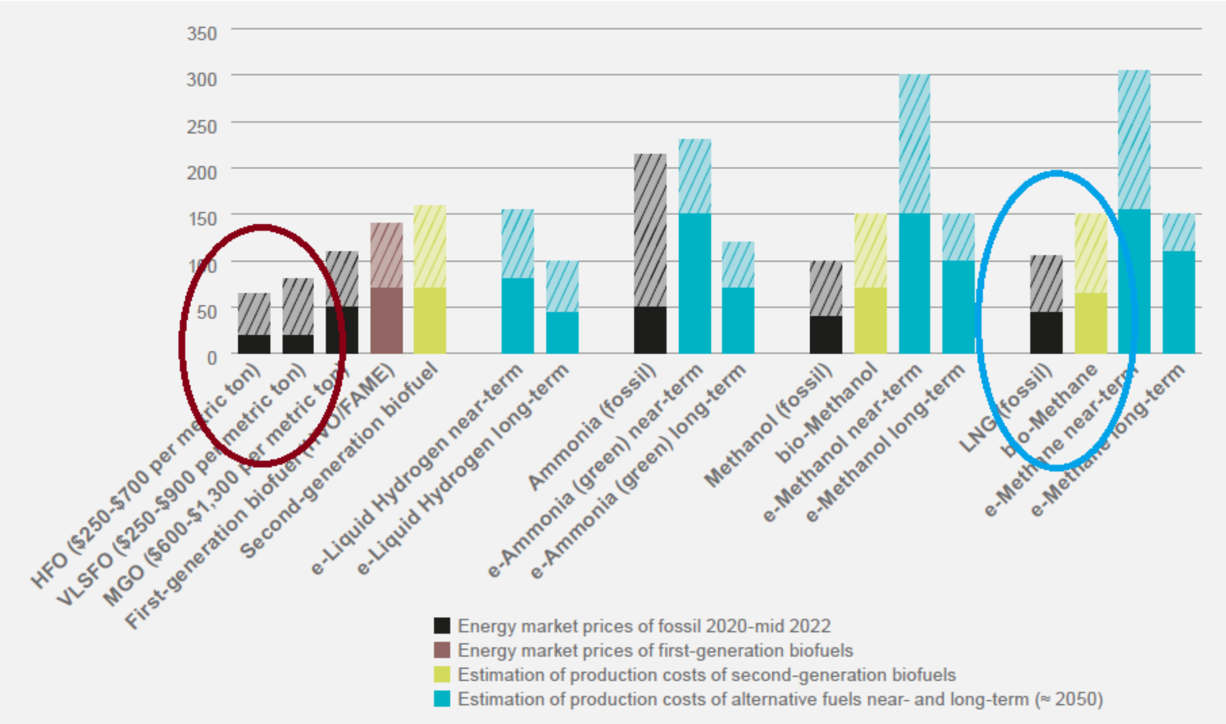

Figure 6. Production cost estimation of alternative fuels vs. Fossil fuels market prices (US $/MWh)
Source. Bureau Veritas, 2022, Fig. 58.

Further evidence on the continuing and growing use of LNG in ships appears regularly. For instance, a shipping industry news article reported on Sept. 29, 2023[7]:

“The main driver for change in vessel design and operation will remain the need for fuel optimisation through to 2030 and beyond. There is little availability for cargo capacity improvement and so the only other avenue may be autonomous functions in navigation and other maritime activities.

“The search for the silver bullet fuel solution remains enticing but elusive, with hydrogen, ammonia and even methanol not being realistic on a large scale, at least before 2030. LNG seems to be becoming more accepted as the transition fuel and we can see this in the numbers for LNG-powered vessels uptake with a global fleet of 251 LNG-fuelled vessels in operation, and 403 more on order, according to 2022 DNV statistics. Dual fuel HFO/LNG provides an accessible option for many shipowners.” (Emphasis added)

[7] https://splash247.com/ship-concept-2030-the-case-for-lng/

ANNEX 2. METHANE RICH FUELS IN STATIONARY ENGINES

Applicability to stationary engines

The main use of the methane abatement device would be at compression stations in natural gas pipelines. The implementation of the methane abatement device will in no way prolong or extend the use of fossil fuels and is in fact applicable to any methane rich fuel including those derived from renewable or bio sources.

Pipelines use a part of the natural gas (NG) they are transporting to operate the compressors that are located at specific distances along the pipeline. Insofar as there is methane slip in the NG engines, the methane abatement device would reduce these methane emissions. This is clearly beneficial for existing pipelines, as well as being beneficial for new pipelines that are under construction or even those that are planned. The addition of a methane abatement device at compression stations would not prolong the use of natural gas, only ensure that methane slip from engines used as compressors in such pipelines are minimized. Eventually, some of these pipelines would be used to transport methane/biomethane blends and even 100% biomethane. The methane abatement device would continue to ensure that methane emissions from biomethane transport are reduced.

Below we review studies on future supply and demand for natural gas in general and LNG in particular. We summarize information on methane emissions in the oil and gas sector in general, from data by the International Energy Agency, as well as methane emissions in the natural gas supply chain, and the need for both improved monitoring of methane emissions and its abatement.

Global Gas output, supply and demand

As per a global study carried out by McKinsey[8], "…gas will be the strongest-growing fossil fuel and will increase by 0.9 percent from 2020 to 2035. It is the only fossil fuel expected to grow beyond 2030, peaking in 2037. From 2035 to 2050, gas demand will decline by 0.4 percent. This relatively moderate decline is due to hard-to-replace gas use in the chemical and industrial sectors, which limits the impact of an accelerating decline in gas used for power. Meanwhile, LNG is set for stronger growth, as domestic supply in key gas markets will not keep up with demand growth. Demand is expected to grow 3.4 percent per annum to 2035, with some 100 million metric tons of additional capacity required to meet both demand growth and decline from existing projects. LNG demand growth will slow markedly but will still grow by 0.5 percent from 2035 to 2050, with more than 200 million metric tons of new capacity required by 2050."

[8] McKinsey and Co., 2021. Global Gas Output to 2050, Summary report 2021.

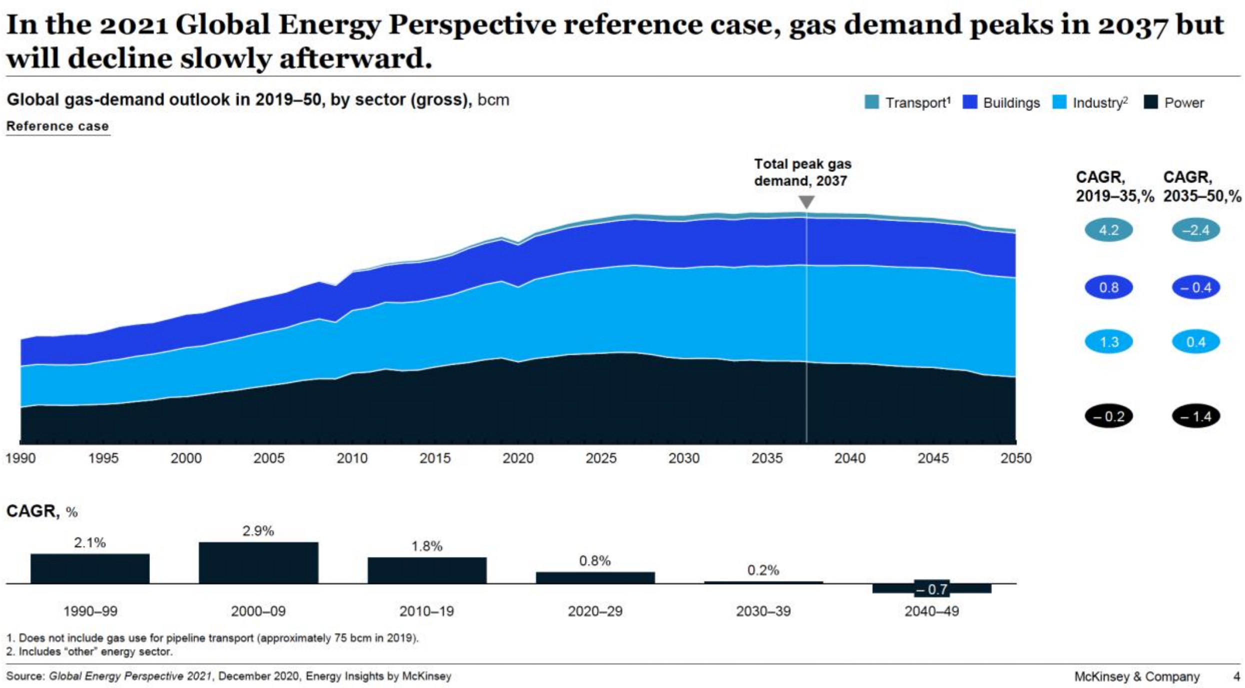

Figure 7. Global gas demand outlook, 2019-2050.
(Source: McKinsey, 2021. Global Energy Perspectives 2021. McKinsey Energy Insights)

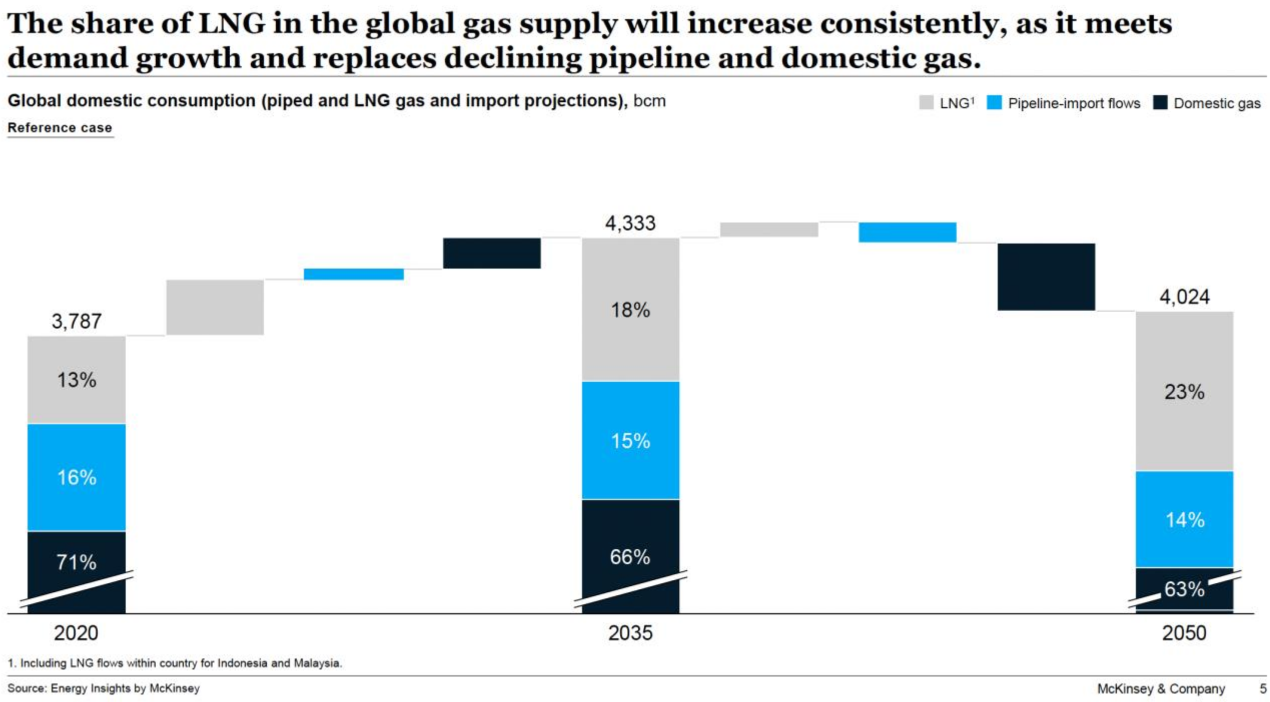

Figure 8. Share of LNG in global supply chains, 2020-2050
(Source: McKinsey, 2021. Global Gas Outlook to 2050.)

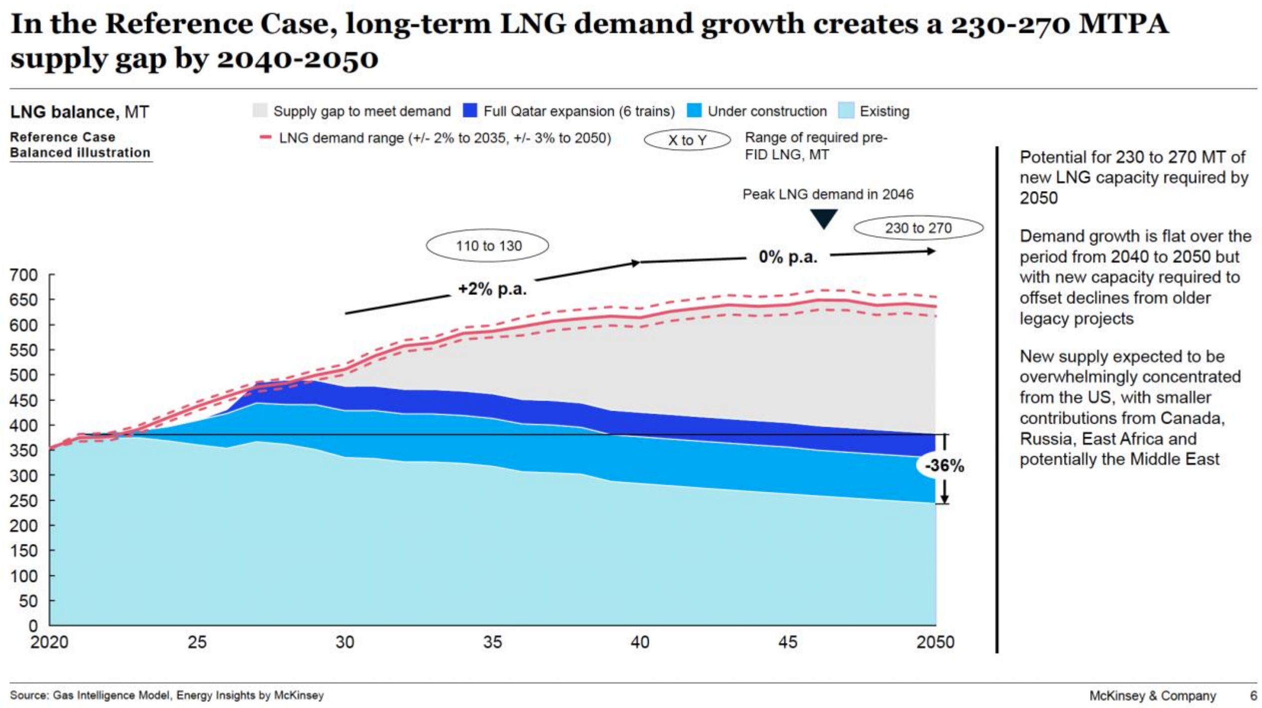

Figure 9. Reference case: Long-term LNG demand creates a supply gap
(Source: McKinsey, 2020. Global Gas Outlook to 2050)

LNG - a fuel in transition

According to the Center on Global Energy Policy at Columbia University (CGEP, 2019), "…some in the sector have started to embrace "green" gas – low-carbon substitutes for conventional methane….However each of these technological pathways is fraught with difficulties."

One of the most common pathways includes biomethane production from landfill gas, animal manure and other agricultural waste products. However, this option faces "serious scalability constraints" due to land and feedstock availability and the biomethane production is still likely to involve methane leakage.

Methane emissions in the oil and gas sector

Methane emissions are generated by both natural sources, such as microbes in wetlands, and human activity. According to the International Energy Agency, the largest source of anthropogenic methane emissions is agriculture, followed by the energy sector, cited in BNEF (2022).

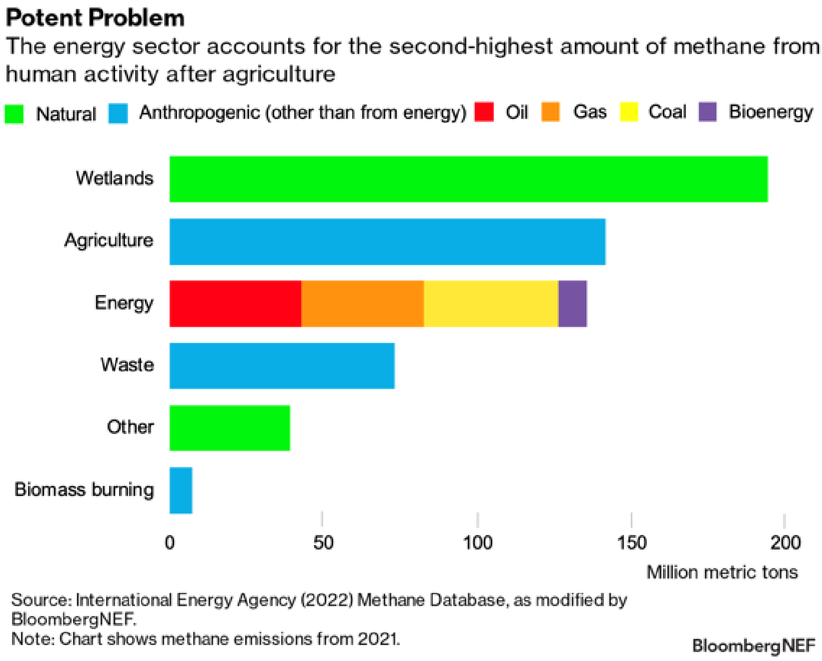

Figure 10. Methane emissions from different sources. The Energy sector is the third largest, with about half of that coming from oil and gas.
(Source: BNEF, 2022, based on International Energy Agency (2022) database. Bloomberg New Energy Finance.)

The oil and gas industry was responsible for 82.5 million metric tons of methane emissions in 2021, about a quarter of the manmade total, according to data from the International Energy Agency, which is an increase from 80.4 million tonnes in 2015. Methane is more than 80 times as potent in climate terms as CO_2 over a 20-year timeframe, so any emission reductions can make a big and quick impact.

Growing recognition of methane's role in the climate crisis culminated in over 100 countries signing the Global Methane Pledge, launched at COP26 in Glasgow in 2021. It is a non-binding commitment to cut collective methane emissions by 30% by the end of the decade, compared to 2020 levels.

At the corporate level, the Oil and Gas Climate Initiative (OGCI, n/d), whose members include BP and Chevron, has laid out a target for companies to lower the 'methane intensity' of their operations to under 0.2% by 2025. This refers to emissions as a percentage of natural gas that goes to market and is a stepping stone to generating "near zero" methane emissions by 2030. OGCI says "Reducing methane emissions from oil and gas operations is one of the quickest ways to help meet the Paris Agreement objectives…." OGCI is focused on developing "programs and tools to monitor and measure methane emissions and identify abatement potential", which is the intention of the technology covered under this methodology.

Methane emissions in the NG supply chain

According to MiQ (n/d) an independent not-for-profit established by Rocky Mountain Institute (RMI) and SYSTEMIQ, a Certified B Corporation, which is aiming to facilitate a rapid reduction in methane emissions, methane emissions do not just occur at one point in the natural gas supply chain:

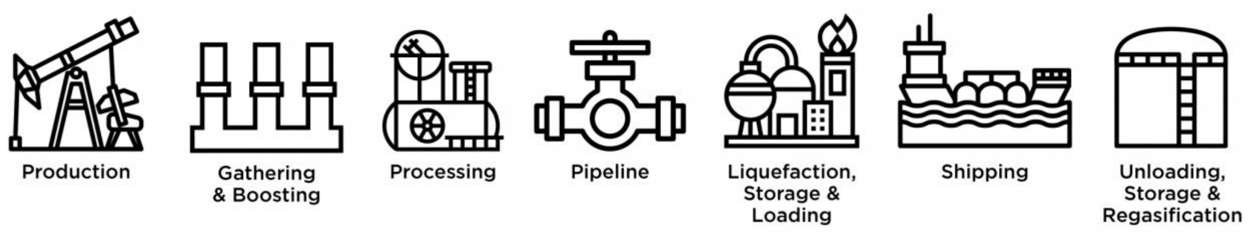

Figure 11. Natural gas supply chain emissions.
(Source: MiQ,n/d. "Assessing methane emissions across the natural gas supply chain". https://miq.org/technical-information/applying-the-standard/)

Methane emissions remain a persistent problem for oil and gas companies and, unlike CO_2, are almost entirely Scope 1 emissions from their own operations. Approximately 80% of the sector's methane emissions come from the upstream segment, from onshore and offshore oil and gas production, with three main sources: venting, flaring and so-called fugitive emissions.

Natural gas is often a by-product of oil extraction and when the gas is uneconomical to use or sell, developers can opt to burn this gas or vent it into the atmosphere, while some gas is also flared for safety and maintenance reasons. While burning gas converts it into carbon dioxide and water, defective or inefficient flaring equipment can see methane released directly into the air instead. Moreover, some unburnt methane remains following gas combustion, which is called methane slip, and this methodology refers to a technology for reducing methane slip.

According to BNEF (2022), for oil and gas companies to address this methane problem, a first step must be the ability to accurately quantify the scale of the problem. This will require investment in advanced methane detection and quantification technologies, such as that included in this methodology. Thereafter, these companies will need to invest in new technologies to reduce the methane slip or recover methane, however there are very few such technologies available or commercialized today. Incentive such as carbon revenues or climate finance can help to accelerate the adoption of such technologies in the short term as they are currently cost prohibitive for most companies.

DOCUMENT HISTORY

Version	Date	Description
1.0	04/09/2024	First version