Recommended Guideline for Greenhouse Gas and Carbon Intensity Accounting frameworks for LNG/Hydrogen/Ammonia Projects (JOGMEC CI Guideline)

Version 2

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Japan Organization for Metals and Energy Security

(JOGMEC)

Abbreviation

In this guideline, we aim to standardize units and abbreviations as follows:

Abbreviation	Formal name
AGRU	Acid Gas Removal Unit
CCS	Carbon dioxide Capture and Storage
CCU	Carbon dioxide Capture and Utilization
CFP	Carbon Footprint of a Product
CO2e	Carbon Dioxide Equivalent
GHG	Greenhouse Gas
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Assessment
LHV	Low Heating Value
LNG	Liquefied Natural Gas
PSA	Pressure Swing Adsorption
SMR	Steam Methane Reformer
SRU	Sulfur Recovery Unit

Definition of terms

Definitions of terms used in this guideline and their reference sources are listed as follows:

用語	定義	参照元
Output	Product, material or energy flow from a unit process.	ISO 14040:2006
Input	Product, material, or energy flow to a unit process.	ISO 14040:2006
Inventory	A list of calculated GHG emissions and sources by an organization.	2004 GHG protocol
Engineering Calculation	The general calculation using engineering methods such as material balance calculations and process simulation tools.	API Compendium of GHG Emissions Methodologies for the oil and natural gas industry

Cut-Off Criteria	Specification of the amount of material or energy flow or the level of significance of GHG emissions associated with unit processes or the product system to be excluded from a CFP study.	ISO 14067:2018
System Expansion	The concept of extending a product system by adding the function of co-product is also called system extension or system boundary extension.	ISO 14040:2006/AMD 1:2020
System Boundary	Set of criteria specifying which unit processes are part of a product system.	ISO 14040:2006/AMD 1:2020
Data Quality	Characteristics of data that relate to their ability to satisfy stated requirements.	ISO 14040:2006
Process	Set of interrelated or interacting activities that transforms inputs into outputs	ISO 14044:2006
Primary Data	Quantified value of a process or an activity obtained from a direct measurement or a calculation based on direct measurements.	ISO 14067:2018
Secondary Data	Data which do not fulfill the requirements for primary data.	ISO 14067:2018
Operating data	Data related to an operation activity obtained from instruments, etc. while operating.	
Greenhouse Gas Emission Factor	Coefficient relating activity data with the greenhouse gas emission.	ISO 14067:2018
CFP (Carbon Footprint of a Product)	Sum of GHG emissions and GHG removals in a product system, expressed as CO2 equivalents and based on a life cycle assessment using the single impact category of climate change.	ISO 14067:2018
Emission Factor Approach	A method of calculating GHG emissions by accumulating activity data and emission factors.	API Compendium of Greenhouse Gas Emissions Methodologies for the oil and natural gas industry, 3.1
CFP study	All activities that are necessary to quantify and report a CFP or a partial CFP.	ISO 14067:2018
Sensitivity Analysis	Systematic procedures for estimating the effects of the choices made regarding methods and data on the outcome of a CFP study.	ISO 14067:2018
Functional Unit	Quantified performance of a product system for use as a reference unit.	ISO 14040:2006, 3.20
Co-Product	Any of two or more products coming from the same unit process or product system.	ISO 14040:2006, 3.10

e-methane	Alternate natural gas, which is synthesized from CO2 and hydrogen (e.g., green hydrogen).	Ministry of Economy, Trade, and Industry, "Public and private councils for the promotion of Methanation", Nov. 2022 メタネーション推進官民協議会(2022.11)
Emitter	Original emitters of CO2 captured from the combustion of fossil fuel, which is the feedstock for e-methane.	Ministry of Economy, Trade and Industry, "Interim report on CO2 counting during combustion of synthetic methane", Mar. 2022 メタネーション推進官民協議会 CO2 カウントタスクフォース中間整理 (2022.3)
Actual measurement data	Data obtained from direct measurements. E.g., leaked methane concentration, volume of methane leak, exhaust gas composition, etc.	
Product System	Collection of unit processes with elementary and product flows, performing one or more defined functions, and which models the life cycle of a product.	ISO 14044:2006, 3.28
Product Flow	Products entering from or leaving to another product system	ISO 14040:2006
Global Warming Potential, GWP	Index, based on radiative properties of GHGs, measuring the radiative forcing following a pulse emission of a unit mass of a given GHG in the present-day atmosphere integrated over a chosen time horizon, relative to that of carbon dioxide.	ISO 14067:2018
Intermediate Flow	Product, material or energy flow occurring between unit processes of the product system being studied.	ISO 14040:2006
Intermediate Product	Output from a unit process that is input to other unit processes that require further transformation within the system.	ISO 14040:2006
Transparency	Open, comprehensive and understandable presentation of information.	ISO 14040:2006
Carbon Dioxide Equivalent	Unit for comparing the radiative forcing of a GHG to that of carbon dioxide	ISO 14067:2018
Waste	Substances or objects which the holder intends or is required to dispose of.	ISO 14040:2006, 3.35
Emission Factor	A factor for estimating GHG emissions from available activity data (fuel consumption, product production, etc.) and units of absolute GHG emissions.	2004 GHG protocol (Chapter 6)

Allocation	Partitioning the input or output flows of a process or a product system between the product system under study and one or more other product systems.	ISO14040:2006
Uncertainty	Parameter associated with the result of quantification that characterizes the dispersion of the values that could be reasonably attributed to the quantified amount.	ISO 14067:2018
Uncertainty Analysis	Systematic procedure to quantify the uncertainty introduced in the results of a life cycle inventory analysis due to the cumulative effects of model imprecision, input uncertainty and data variability.	ISO 14040:2006
Fugitive Emissions	Emissions resulting from the intentional or unintentional release of GHGs without physical controls. Fugitive emissions often arise from joints, seals, packings, gaskets, etc. during the production, processing, transportation, storage and use of fuels and other chemicals.	2004 GHG protocol (Chapters 4,6)

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Preface

1. Background and purpose

1.1. JOGMEC initiative for Carbon Neutrality

JOGMEC’s mission is to ensure energy security by supporting affordable and stable energy sources. In November 2022, JOGMEC expanded its functions to include equity investments in hydrogen and fuel ammonia production and storage, as well as carbon dioxide capture and storage (CCS) projects and sub-bottom profiling surveys related to those areas. Consequently, the official name of the organization was changed to "Japan Energy and Metals National Corporation".

In addition to liquefied natural gas (LNG), which plays an important role in the energy transition due to its lower greenhouse gas (GHG) emissions than fossil fuels, the "Green Growth Strategy for Carbon Neutrality by 2050" supports hydrogen, ammonia, and synthetic fuel businesses, as they are also considered to be one of the 14 key areas where efforts are indispensable when aiming for carbon neutrality.

1.2. GHG emissions and CI calculation for LNG, hydrogen, ammonia, and synthetic fuels

For a clean fuel, one of the key factors is the amount of GHG emitted from raw material production, liquefaction, reforming, etc. of LNG, hydrogen, ammonia, and synthetic fuel production. From the viewpoint of procuring clean energy resources for the future, calculating GHG emissions and visualizing their environmental value as carbon intensity (CI) have become even more important. Australia, the United States, and other countries are studying mechanisms to certify GHG emissions during production, while in Europe, efforts are ongoing to set CI thresholds for defining clean resources. However, the calculated value of GHG emissions varies depending on the selected calculation method. Even if existing international standards are invoked, the calculation values vary because of differences in the system boundary settings and calculation methods, such as whether to calculate using general emission factors as secondary data or emission factors based on actual measurements and operation data as primary data; therefore, the search for a consistent and highly transparent calculation method is in progress.

1.3. Features of this CI Guideline

Considering the social situation related to the calculation of GHG emissions, to support the promotion of LNG, hydrogen, ammonia, and synthetic fuel businesses by Japanese operators, JOGMEC has compared and verified multiple existing international standards and formulated recommendation guidelines for GHG and CI calculations that hardly get impacted by operations.

This guideline is in harmony with existing international standards and does not define any new calculation methods; however, it has the following features:

1) Various conditions, such as system boundaries, are clearly and appropriately set to enhance transparency and comparability with other guidelines and standards.

2) For the major GHG emission sources and types of GHGs that significantly impact calculation results, use of primary data (actual measurements, operating data, business-specific emission factors, etc.) is recommended in the calculation of GHG emissions that could reflect actual business conditions.

3) The guideline suggests a highly transparent method for calculating GHG emissions and CI containing methane (CH_4), which can also accurately reflect the environmental value of energy resources.

Consequently, it is expected that these guidelines will possibly cooperate with the Guarantee of Origin (GO) and certification mechanisms for hydrogen and ammonia in each country and region. The application of these guidelines can be verified in joint studies and technological development and demonstration projects supported by JOGMEC, and the calculation method can be continuously reviewed to ensure that it meets the internationally required standards while minimizing its impact on actual operations. Although the examination items or criteria necessary for conducting a selection review of JOGMEC's investment and debt guarantee businesses are not indicated, references to these guidelines can be considered for examination.

To formulate these guidelines, a group of external experts solicited opinions on published proposals. Review meetings with external experts were held twice from November to December 2021, where experts from energy developers, engineering companies, and consulting companies provided opinions and comments. On January 24, 2022, a draft of this guideline was published on the JOGMEC website and solicited a wide range of opinions (public comment period: January 24 to February 18, 2022). The main contents of the discussion included matters related to the definitions and threshold values of "color" in products such as blue and green, information on how to handle CO_2 when using CO_2 for manufacturing chemical products instead of CCS, and the origin of raw materials such as seeking hydrocarbon sources other than natural gas. We express our sincere gratitude to everyone who cooperated and provided their opinions. We respect their comments and will link them to future discussions and revisions.

1.4. Major revisions from the first edition

JOGMEC has strengthened the functions of its existing operations by adding risk money support services for the production and storage of hydrogen, ammonia, synthetic fuels, and CCS, and geological structure survey services for offshore wind power generation; thereby, the official name of the organization has been changed to "Japan Organization for Metals and Energy Security".

Based on the strengthening of functions and JOGMEC's technical verification project, the following outlines are added to the second edition:

1.4.1. Addition of specific methods for CI calculation (refer to Chapter 2, 2～4 and Chapter 3,1)

To improve the quality of data, prioritizing the use of available primary data is necessary. Through research projects and literature surveys, JOGMEC identified the main emission sources that accounted for the majority of GHG emissions at LNG and ammonia plants, as listed them in Chapter 2. In addition, CI calculation examples with noteworthy points are described in Chapter 3.

1.4.2. Addition of e-methane (refer to Chapter 2, 5.2)

The CH_4 synthesized from captured CO_2 and hydrogen is called e-methane, which is a synthetic fuel used as an energy source. As it is expected to make effective use of the existing infrastructure for LNG and natural gas, such as city gas pipelines and LNG carriers, demonstration tests were conducted at pilot facilities. Technological development is progressing to further increase the size and efficiency of facilities, and consideration of overseas commercialization has begun. IPCC Sixth Assessment Report (AR6) also mentions "power to fuels", indicating that e-methane has a high affinity with existing gas systems.

However, to popularize e-methane, it is necessary to develop systems and rules for recording the inventories of each entity regarding the procurement of inexpensive hydrogen, the emission of CO_2 as raw material, and at the consumption stage.

These guidelines describe the CI calculation for the e-methane production stage and the stages of mixing and liquefying e-methane and natural gas (see Chapter 3.1). It was assumed that e-methane produced overseas will be imported as LNG utilizing the existing infrastructure, and when introduced, it will be produced by mixing e-methane and natural gas.

1.4.3. Addition of hydrogen by the electrolysis of water (refer to Chapter 2, 5.4.2)

As a backdrop to recent debates on clean hydrogen production, hydrogen production by water electrolysis was added to the process using natural gas as a raw material. The concept of calculating GHG emissions in this guideline is in accordance with the International Partnership for the Hydrogen Economy (IPHE).

Acknowledgement:
Considering the second edition of this guideline, JGC Global Co., Ltd. contributed to the commissioned project by JOGMEC "FY2022「Greenhouse gas and carbon intensity accounting framework for LNG/Hydrogen/Ammonia production". We would like to thank them.

Chapter 1　Scope of the guidelines and handling of data

This guideline does not provide new calculation methods for GHG emissions of target products (LNG, e-methane, hydrogen, and ammonia), but provides an approach to calculating GHG emissions using existing methods, criteria, and standards based on international discussions. This chapter shows the scope of this guideline by organizing the boundary of the target system, concept of the target system flow, and position of the calculation report.

1. Reference standards

This guideline covers the calculation of GHG emissions, carbon footprint of a product (CFP), and CI of products. The criteria and standards generally represented in this field are as follows:
＜Criteria and standards for life cycle assessment (LCA) evaluation, GHG emissions calculation, and CFP calculation＞

- ISO 14040：2006 Environmental Management Life Cycle Assessment Principles and Framework
- ISO 14044：2006 Environmental Management Life Cycle Assessment Requirements and Guidelines
- ISO 14067：2018 Greenhouse gases – Carbon footprint of products – Requirements and guidelines for quantification
- PAS 2050：2011　Specification for the assessment of the life cycle greenhouse gas emissions of goods and services
- GHG Protocol Product Life Cycle Accounting and Reporting Standard (2011)
- Ministry of Environment, "LCA Guidelines for Assessing the Effect of Greenhouse Gas Emissions Reduction in Renewable Energy, etc." *(2021)（脚注）
- 環境省, "令和 3 年度　再生可能エネルギー等の温室効果ガス削減効果に関する LCA ガイドライン"（2021 年）

Additionally, because this guideline covers products in the oil and gas sectors, we referred to the following standards for calculating GHG emissions in these industries:

＜Criteria and standards for calculating GHG emissions in the oil and natural gas sectors＞

- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry (November 2021)

Regarding LNG and hydrogen products, attention has been focused on GHG emissions in recent years. Therefore, the following guidelines were referred to:

＜Standards and specifications for the CFP calculation of LNG and hydrogen＞

- GIIGNL (International Group of Liquified Natural Gas Importers), “MRV and GHG Neutral LNG Framework” (Version 1.0, November 2021)
- IPHE (International Partnership for Hydrogen and Fuel Cells in the Economy), Production Analysis Task Force, “Working Paper: Methodology for Determining the Greenhouse Gas Emissions Associated With the Production of Hydrogen” ” (Version 1, October 2021)
- Ministry of Environment, “LCA Guidelines for Assessing the Effect of Greenhouse Gas Emissions Reduction in the Hydrogen Supply Chain, Version 2.1” ＊(2020)

（脚注）
環境省，“水素サプライチェーンにおける温室効果ガス削減効果に関する LCA ガイドライン Ver. 2.1”（2020 年）

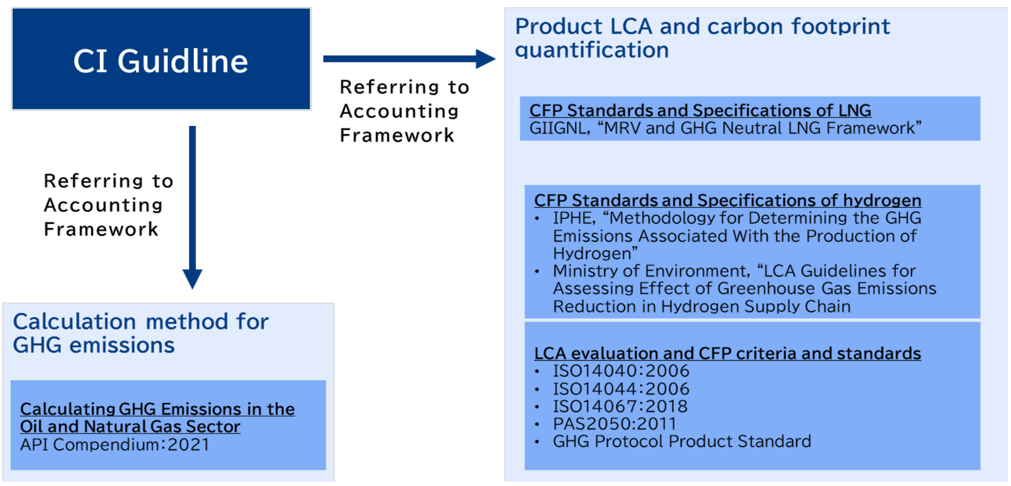


Figure 1: Relationship between referenced criteria and standards

2. Setting boundaries

2.1. Concept of System Boundary

This guideline establishes system boundaries that enable the calculation of GHG emissions in each process between the production of feedstock and the shipping point (well-to-gate) in the product manufacturing facility. The infrastructure (e.g., storage, transportation, and supply) after the shipping point (gate) of the product manufacturing facility and processes related to the consumption area are not covered in this guideline.

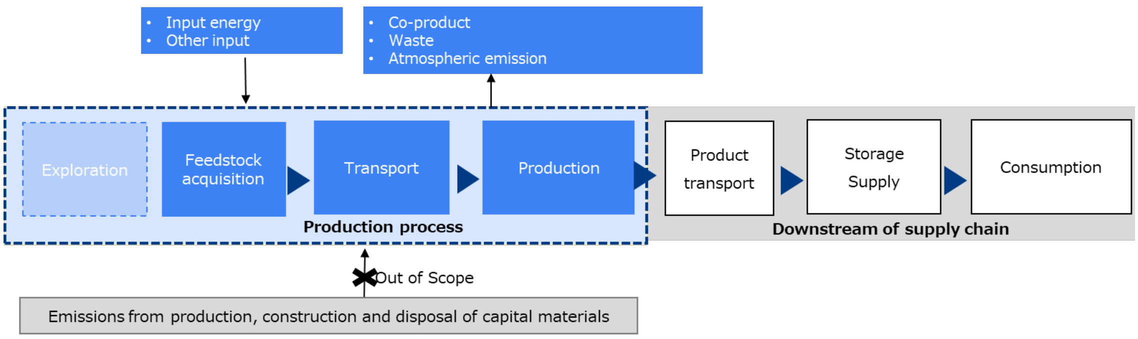


Figure 2 : Target production system boundary and process

As the main emission process, feedstock acquisition, transport, and production are included in the "Well-to-Gate" boundary, as shown in Figure. 2. For each target process, the consumption of energy, inputs for each process, and the amount of waste and atmospheric emissions were clarified. Data should be collected to compare the total amount of input and output and to confirm the validity of the data. The following items correspond to the collected data:

- Energy and other inputs supplied in the target process
- All co-products in the target process
- Wastes and direct atmospheric emissions from the target process

Exclusions in the CO2 calculation for natural gas are specified as follows:

・GHG emissions during exploration are not considered in calculations as they are temporary and have a small amount within the scope of the well-to-gate.

・Emissions associated with the manufacture, construction, and disposal of capital goods (e.g., production equipment) used in each of the processes of "raw material production", "raw material transportation", and "product manufacturing" are a small emission source compared to the GHG emissions from the target process over several decades. It is recommended to check whether emissions from capital goods have not been large emission. In case of the international or national reporting requirements change in future, it is updated to include these emissions.

2.2. Target Process and Flow

These guidelines cover LNG, e-methane, hydrogen, and ammonia as the target products, and the process flows listed in Table 1 were subject to calculations.

Table 1：Target Process and Flow

Stage	Process	Flow
(Common over products) Feedstock acquisition	Separation / purification Compression	Feedstock Fuel Electricity Co-product Waste Atmospheric emission
(Common over products) Transport	Pipeline Vessel (on the sea)	Feedstock Fuel Electricity Co-product Atmospheric emission
Production (LNG)	gas reception Separation Acid gas removal Dehydration / Demercury Liquefaction Nitrogen and helium removal On-site storage CCS(※1)	Feedstock Fuel Electricity Co-product Waste Atmospheric emission
Production (Hydrogen)	Desulfurization Modification CO shift Hydrogen refining On-site storage CCS(※1)	Feedstock Fuel Electricity Co-product Waste Atmospheric emission
Production (Ammonia)	Desulfurization Modification CO shift Synthesis Refining Compression Separation On-site storage CCS(※1)	Feedstock Fuel Electricity Co-product Waste Atmospheric emission

(※１) CCS is calculated according to CCS guidelines

2.3. Cut off criteria

The cut-off criteria are the criteria for GHG emission processes, or the amount of material or energy flows that were not included in the calculation of GHG emissions. In the calculation of GHG emissions in this guideline, efforts were made to include all processes and flows resulting from the target production. However, it is desirable to perform calculations using alternative data without cutting off the data.

Individual material or energy flows may be excluded if they do not need to be considered in a particular process or flow. If a process that is partially within the system boundary is excluded in this manner, the process must be identified and the reason reported.

As the criteria for whether or not to cut off processes, flows, and emission sources that are less than 1% of the total GHG emissions within the product system boundary covered by this guideline can be cut off. Additionally, it must be confirmed that the total cut-off emissions are less than 5% of the total GHG emissions.

2.4. Concept of allocation

If multiple products are produced in a target project, the method of allocating GHG emissions between the product subject to CFP accounting and the co-products needs to be determined.

When calculating GHG emissions through these guidelines, it is necessary to consider the subdivision of target processes and the expansion of system boundaries following ISO 14044 before considering the allocation between product systems and co-products.

In the subdivision of target processes, when two types of products are produced from one process, it is possible to divide the process and flow to avoid allocation by grasping inventory data in detail.

In expanding the system boundary, co-products are regarded as alternative products to other products in the market, and the same environmental load as the alternative products is allocated. As a specific calculation method, the co-product is compared with other substitute products, and "the environmental load of the alternative product (e.g., production energy X [MJ])" is converted to "the environmental load of the product system under the investigation."

For example, when LNG is produced, the associated liquefied petroleum gas (LPG) is also produced. The environmental load of LNG production was calculated by subtracting the environmental load of general LPG production from that of LNG production.

If allocation is unavoidable after considering the subdivision of the target process and the expansion of the system boundary, it is necessary to apply and explain an appropriate allocation method.

In addition to energy allocation, it is possible to allocate energy by weight.

3. Calculated data

3.1. Data collection

For each process within the product system boundary covered in this guideline, it is necessary to collect data on input (energy consumption) and output (waste and air emissions) for each process. It is also necessary to cover the specific period required to set time boundaries such that the calculated GHG emissions are representative and consider aging and changes in aging (refer Chapter 3, 1. CI calculation).

To calculate the GHG emissions, it was necessary to collect all available data from the calculator. For example, if the calculator is a product manufacturer, it is desirable to request that the developer supply the feedstock and the feedstock supplier disclose and share data on GHG emissions per feedstock. However, if it is difficult for the developer and feedstock supplier to disclose and share data, other documents and databases could be used while paying attention to data quality. However, it is desirable to pay attention to the data conditions to represent the actual GHG emissions.

3.2. Data quality

When calculating GHG emissions, the bias and the uncertainty should be reduced by using the best available quality data. In particular, it should be taken care of to improve the quality of the data collected for processes that have a large impact on the calculated GHG emissions.

In addition, it is recommended to check the items described in the following relevant parts of ISO 14044 for the requirements that characterize the quality of the data.

[referring to：ISO 14044:2006, 4.2.3.6]

3.3. Data uncertainty

The use of highly uncertain data may adversely affect the overall quality of these guidelines. Therefore, an uncertainty analysis must be performed through a quantitative evaluation of the calculated values and a qualitative evaluation of the sources of uncertainty. The uncertainty can be considered in calculation factors (emission factors, measurement methods, source variability, etc.), co-product allocation methods, and inherent uncertainties in the model that were used when activity data were not available. Table 2 shows examples of uncertainty evaluation.

Table 2:Methods of uncertainty consideration

Method	Content	Accuracy of consideration
Qualitative Consideration	List and discuss about sources of uncertainty Hypothetical discussion	Low
Subjective data quality ratings	Evaluation based on uncertainties already assigned to emission factors, etc.	Low
DARS (Data Attribute Rating System)	A system developed by the U.S. EPA that can calculate the reliability of emissions required from emission factors and activity data.	Medium
Expert estimation method	Statistical analysis of mean values, standard deviations, etc. by experts	Medium
Direct simulation method	Emission uncertainty assessment using statistical analysis such as the Monte Carlo method	High

(Created by JOGMEC, based on information from IPIECA)

It is also recommended to conduct an uncertainty evaluation at site-level emission using satellites, drones, etc., as specified in Oil and Gas Methane Partnership (OGMP 2.0).

3.4. Data Priority

To improve the quality of the data, it is necessary to collect primary data, such as the designed values of processes and actual measurement values for each relevant facility, regarding data related to processes and facilities owned by manufacturers that have a significant impact on the calculation of GHG emissions. It is recommended that primary data be obtained for the calculation of large emission sources. But if it is difficult to collect primary data, data collection methods based on considerations in GIIGNL, "MRV and GHG Neutral LNG Framework-D" are recommended to calculate the GHG Footprint according to the following data priorities.

<Data collection priority>

- Primary data (direct): Operational and actual measurement data obtained from the target project. Specifically, flow measurement by meter, gas fuel sampling, product flow measurement, etc.
- Primary data (indirect): Equipment-specific data obtained from projects subject to calculation, engineering assumptions based on design data, composition of gaseous fuel modeled based on specific processes, etc. The normalized leak rate becomes the indirect primary data in the case where it is corrected based on the primary direct gas composition.
- Secondary data (direct): De facto values based on product processes and specific regions. It also includes the calculated values from the LCA models that can be input into the primary data.
- Secondary data (indirect): Emission factors for stages not related to product characteristics, sources, or values calculated by LCA models that cannot be input to the primary data. Although it is practical to estimate emissions from small sources, extensive use of nonspecific secondary data should be avoided as much as possible.

It is also desirable to report the percentage of primary data (emissions criteria) used in the GHG emissions calculations based on the above data categories.

Regarding the CFP survey required before starting the target project, it is expected that the emission sources should be identified, and emissions calculated assuming the production process, at the project planning stage. At this time, the proportion of secondary data is expected to increase (see Chapter 3, Table 10);

however, it is desirable to report the emission sources and process flow in the plan by collecting primary data during project implementation. In addition, it is possible to investigate in detail the boundaries and calculation methods that were decided before the project's implementation.

Chapter 2 Calculation methodology for eligible GHG emission sources

This chapter presents the methodology for calculating GHG emissions from the sources of the products covered in this guideline.

1. GHGs subjected

Combustion, flaring, venting, and leakage are the main sources of emissions during the lifecycle of the products covered in this guideline, and the main GHGs are CO2, CH4, and dinitrogen monoxide. However, the following seven gases are covered because refrigerant leakage, etc., are also effective in causing global warming.

- Carbon dioxide (CO2)
- Methane (CH4)
- Dinitrogen monoxide (N2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFC)
- Sulfur hexafluoride (SF6)
- Nitrogen trifluoride (NF3)

To ensure consistency in the calculation of the CFP, this guideline uses the global warming potential (GWP) of the gases listed in Table 3, together with the emission values. GWP 100-year value (GWP100) in the IPCC Fifth Assessment Report is currently used in the GHG Protocol Initiative and will be used in future reports under the Paris Agreement.

Table 3：Typical GHG Global Warming Potential (GWP)

GHGs	GWP100
CO2	1
CH4	28
N2O	265
HFC-32	677
HFC134a	1,300

PFC-14	6,630
Sulfur hexafluoride (SF6)	23,500
Nitrogen trifluoride (NF3)	16,100

Source: IPCC, 2013; Climate Change, 2013; Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F.; Qin, G.-K. Plattner, M. Tignor, S. K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex, and P. M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535. (Appendix 8.A)。
The GWP for CH4 was set to 28, which is normally used to align with the GHG Protocol and COP resolutions (Decision-CMA/CMA.3 Guidance operationalizing the modalities, procedures, and guidelines for the enhanced transparency framework referred to in Article 13 of the Paris Agreement).

For the GHG emissions of the target gas in this guideline, both the amount of target gas (ton/year) and the CO2 equivalent (tonCO2e/year) should be reported. Additionally, this guideline recommends CFP calculations using the CO2 equivalent value according to the following formula:

GHG emissions subjected [tonCO2e] = *Mass of GHG gas* [ton] × *GWP100*

2. GHG emission sources

Table 4 lists the types of GHGs emitted from plants and their major sources.

Table 4: Representative Emission Sources by Source Type

Category		Major emission sources
Direct Emission		
Combustion	Stationary combustion	Boilers, heaters, furnaces, internal combustion engines (e.g., gas turbines and emergency generators), etc.
	Mobile combustion (Transportation equipment, etc.)	Ships, trucks, and other vehicles, etc.
Flare and Vent	Flare	Flare systems, separation, and recovery processes, etc.
	Process vents	Tank vents, acid gas removal equipment, etc.

	Other flare vents (Routine maintenance and non-routine activities)	Sampling, product shipping, safety valves and depressurization valves, etc.
Leak	Raw material transportation and product manufacturing processes	Installed parts such as valves, flanges, compressor seals, etc. and mechanical leaks, etc.
	Other flare vents	Air conditioning and fire suppression systems, etc.
Indirect Emission		
Energy from outside System Boundary	Emissions from electricity, heat, and steam production	Leakage mainly from stationary combustion and transportation

The emission sources listed in Table 4 account for 80% of the total GHG emissions and are considered major sources in the value chain (well-to-gate); e.g., LNG and ammonia production plants in North America and Southeast Asia and their upstream gas processing plants. The unit names in parentheses refer to the items in Figure 3.

・Natural gas feedstock production plant (Transmission / Processing / G&B[1] / Production)

- Vent from compressors and emissions from their driving machines.
- Vent to the atmosphere from an acid gas removal unit.
- Combustion emissions from flare stacks at an upstream gas plant.

・LNG (Liquefaction)

- Emissions from refrigerant compressor drivers and internal engines for power generation.
- Vent to the atmosphere from an acid gas removal unit.

・Ammonia plant

[1] Oil and gas fields has treatment facilities for collecting oil and gas produced from production wells and separating and removing water, salt, acid gas, etc.; metering facilities for determining the amount of crude oil, condensate, gas, etc. produced; and boosting facilities for storing or sending off products.

- Vent to atmosphere from acid gas removal unit.
- Emission from a primary reformer.
- Emissions from boilers.
- Emissions from internal combustion engines for power generation.

The above emission sources are also listed in the paper written by Cheniere, showing the major emission sources from the upstream gas-processing plant to the LNG plant, as shown in Figure 3. This study was conducted by Cheniere, an LNG operator, in collaboration with an academic organization to conduct LCA assessments.

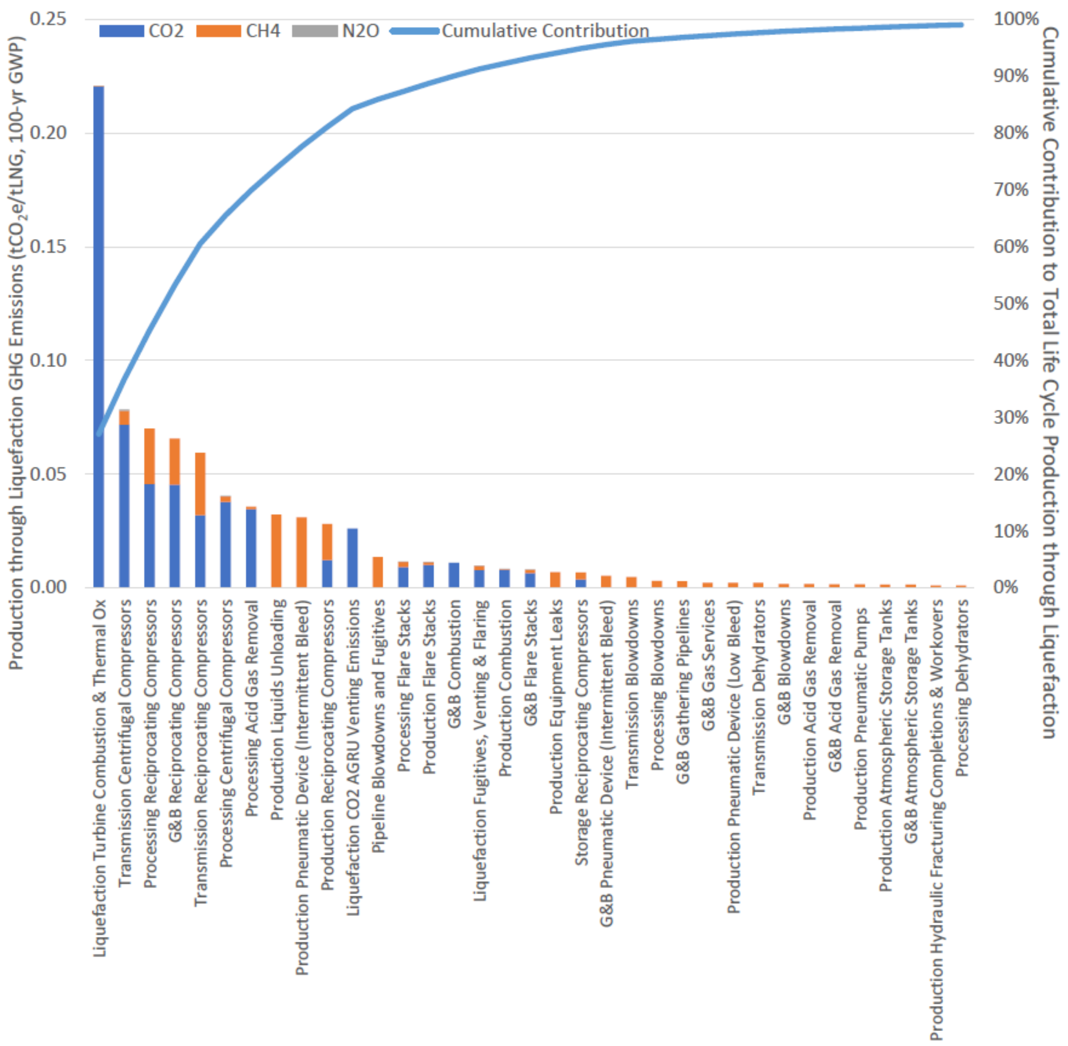


Figure 3. Distribution of GHG emissions in an LNG plant

Source: Selina A. Roman-White, James A. Littlefield, Kaitlyn G. Fleury, David T. Allen, Paul Balcombe, Katherine E. Konschnik, Jackson Ewing, Gregory B. Ross, and Fiji George, LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting, ACS Sustainable Chemistry & Engineering 2021, 9 (32), 10857-10867, Supporting Information, Figure S16.

2.1. Combustion

(1) Stationary combustion

Combustion of fuel in stationary equipment.

Main GHGs：

- CO_2, CH_4, and N_2O

Major emissions sources：

(2) Emissions are mainly from combustion equipment (furnaces, boilers, etc.), gas turbines, and internal combustion engines such as emergency generators.

(3) CH_4 and N_2O are contained in trace amounts in emissions from combustion equipment.

(4) Mobile combustion

Combustion of fuel in transportation equipment.

Main GHGs：

- CO_2, CH_4, and N_2O

Major emissions sources：

- Emissions from combustion equipment for the transportation of raw materials (ships, vehicles, etc.).

2.2. Flare and Vent

(1) Flare

Combustion gas is sent from the equipment or systems to the flare system during plant operation.

Main GHGs：

- CO_2, CH_4, and N_2O

Major emissions sources：

- The main gases that enter the flare system include the off-gases generated during the separation and distillation processes in the upstream gas plant before being sent to the pipeline.

- Surplus gas is mainly generated by operational fluctuations in LNG, hydrogen, and ammonia production plants.

(2) Process vent

Process vents are gases released from equipment or systems during plant operation. These guidelines consider them to be vented directly into the atmosphere and not sent to a flare system.

Main GHGs：

- CH_4 and CO_2

Major emissions sources：

- Some vents, such as those of tanks and acid gas removal units, are vented directly into the atmosphere from the equipment or systems.

(3) Other flare vents

Due to planned maintenance and unexpected activities in businesses.

Main GHGs：

- CH_4 and CO_2

Major emissions sources：

- GHG emissions are derived from the depressurization and blowdown of piping during maintenance, startup, and shutdown of equipment like compressors, and GHGs are released from safety valves and depressuring valves when the pressure in the tanks or piping increases.
- In upstream gas plants, some facilities do not have pneumatic or electrical instrumentation because of their remote location, resulting in the release of gas from the control valves and chemical feed pumps that are driven by the gas produced.

2.3. Fugitive emissions

(1) Raw material transportation and product manufacturing processes

Main GHGs：

- CH4 and CO2

Major emissions sources：

- Piping components such as valve bonnet flanges and pipe joint flanges.
- Fugitives from valves and flanges are also often detected in gas pipelines that deliver raw gas to LNG, hydrogen, and ammonia plants.

(2) Equipment components

Main GHGs：

- Fluorocarbons, etc

Major emissions sources：

- HFC and PFC are used in air-conditioning, refrigeration processes, fire extinguishing systems, etc.
- SF6 is used as an insulating gas inside switchgear, which opens and closes power circuits.

2.4. Indirect emissions

The GHG emissions stem from the use of electricity, heat, and steam supplied from outside the system boundary.

3. Calculation of GHG emissions

3.1. Outline of calculation method

In many criteria and standards, the method of calculating GHG emissions is not adopted to measure emissions directly; rather, it uses secondary data that multiplies activity data, such as production, with a general emission factor. The method using secondary data is simple, but when the calculated values are different from the actual operating conditions of the plant, concerns regarding the GHG emissions calculation presenting the actual state of the project arise.

Engineering calculations of GHG emissions from primary data, such as actual operating data, yield more accurate values than methods that use emission factors.

Furthermore, for a method that best reflects the actual state of the project, primary data obtained from the actual measurement of GHG emissions and concentrations from some emission sources is required. Among the calculation methods given in Chapter 2: 3.2, an example of the calculation of the emission factor based on primary data is presented.

CH4 may be emitted, even though it is unspecified and uncalculated. Therefore, it is difficult to accurately calculate emissions using general emission factors, despite the magnitude of the GWP. Consequently, in efforts such as the OGMP led by Europe and the United States regarding the calculation of CH4 emissions, it is necessary to report the emissions for each emission source and include some actual measurements from the site.

The general methods for calculating GHG emissions are listed in Table 5.

Table 5 : Calculation method by GHG type and its characteristics

Classification of methods by data	Calculation method	CO2	Methane Nitrous oxide
Method using primary data	Calculations using specific emission factors on a project	• CO2 emission depends on the fuel type than the equipment type • Emission factor values recommended by manufacturers are based on type of combustion equipment, air and fuel ratio and fuel type	• Emissions strongly depend on equipment characteristics
	Engineering calculations using operating data	• Able to be applied to many sources but depends on methodologies and assumptions used • Sometimes detailed data is required	• Sometimes detailed data is required
	Calculated using activity data such as emission factors from actual measurement data and operating data	• Calculation accuracy is considered to be less different from engineering calculation	• It is possible to calculate an emission factor that matches the actual situation

	Calculation of emissions using measured data (Actual measurements for all target emission sources and for all periods)	• Calculation accuracy is considered to be less different from engineering calculation • Generally impractical given the huge number of sources of emissions in product manufacturing plants	• Calculation accuracy is high, but it takes a lot of cost and time
Method using secondary data	Calculations using general emission factors	• Based on average carbon content of various fuels • Fuel composition is determined by fuel type	• Emissions depend on equipment type • Uncertainty contributes less to overall emissions calculations

Source: Revised from API, 2021: Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry, USA, 138 pp. (Table 4-1)

Examples of measured and operational data as primary data are shown below.

- Actual measurement data: concentration and volume of leaked CH4, and composition of exhaust gas
- Operating data: feedstock input and fuel consumption

When calculating GHG emissions based on this guideline, use of primary data from major emission sources is recommended.

3.2. Calculation method

This guideline suggests the calculation of GHG emissions for both direct and indirect emissions using the following formula:

GHG Emission [tonCO2e]＝*Activity data*×*GHG Emission Factor*×*calculation factor* ×*GWP*

- Activity data : Quantitative data representing the volume over a period. Primary data are preferred; however, estimated values can also be used.
- GHG emission factor : GHG emissions data per unit activity. Emission factors are either values based on measured primary data (such as gas composition analysis) or default values specific to the type of fuel or equipment.

- Calculation factor：An additional factor is used to calculate the GHG emissions. For example, the conversion of units, adjustment of predetermined emission factors or composition, and calorific value based on the same basis as selected emission factors.
- GWP: Follow Chapter 2: 1 "Target GHG".

Several approaches exist for setting GHG emission factors, depending on the availability of data.

<Option A: Emission factors specific to the fuel or equipment in question>

GHG Emission factor = Unit calorific value (LHV) ×Emission factor per unit calorific value

※Eigenvalues are quoted from fuel supply suppliers, national inventories, IPCC guidelines, etc.

<Option B: Emission factors based on measured carbon weight ratio>

GHG Emission factor = Carbon weight ratio×44/12 or Carbon weight ratio× Density×44/12

(※When consumption is based on volume：Emission factor
= Carbon weight ratio×Density×44/12)

<Option C: Emission factors from actual measurement data>

GHG Emission factor = Emission factor based on the actual measurement

Option C:An example of a calculation based on the emission factor from actual measurement and activity data, such as driving data, is as follows:

While calculating emissions, general emission factors could be used; however, since these emission factors were set considering general emission conditions, they may not reflect the actual state of emissions.

When calculating based on primary data, the following method can be used for calculating emission factors from actual measurement and operational data (Figure 4)：

① Collection of actual measurement and operating data under typical operating conditions

② Examples of actual measurement data include the GHG concentration, exhaust gas volume, and GHG leakage volume, which can be obtained by sampling.

③ Examples of operating data: feedstock input volume and fuel consumption volume

④ Analysis of actual measurement and operation data.

⑤ Calculation of emission factors and emissions based on measured data.

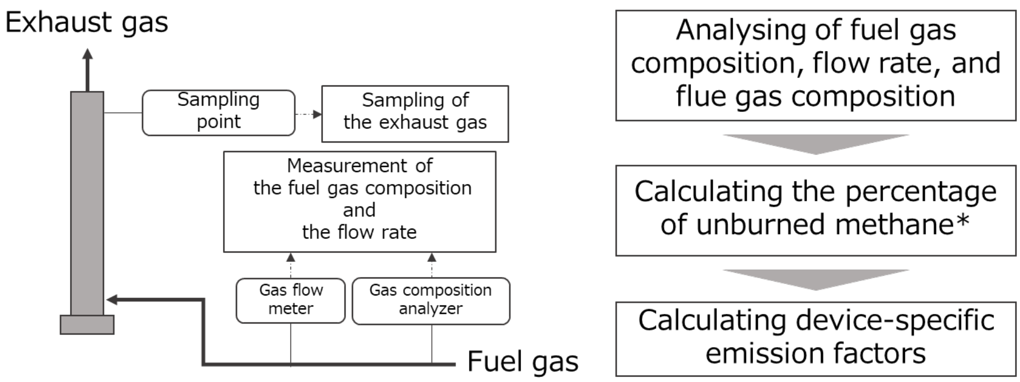


Figure 4 : Emission factor calculation procedure for combustion equipment.

Note: CO2 and nitrous oxide can also be obtained by the analysis of exhaust gas composition, similar to CH4 emissions.

3.3. Combustion

(1) Stationary combustion (stationary equipment)

In combustion equipment, such as gas turbines and heating equipment, the fuel is sufficiently mixed with combustion air, and almost all the carbon in the fuel is oxidized and converted to CO2. Therefore, the CO2 emissions can be calculated using operational data, assuming that the carbon in the fuel becomes CO2, regardless of the type of combustion equipment.

However, CH4 and nitrous oxide emissions vary depending on the combustion equipment type and combustion conditions, which means that emission factors should be used for calculation. For CH4 and N2O, the emission factors should be calculated from primary data, such as the operating and measured emission gas data. Additionally, if e-methane is combusted, appropriate emission factors should be used referring to Chapter 2: 5.2.1 “GHG Emissions in e-methane production.” If this is not appropriate, use the emission factors specified by the manufacturer or the existing emission factors from the secondary data is recommended.

Following examples explain calculation of the emissions of stationary combustion equipment with primary data: for CO2, engineering calculations using operational data and for CH4 and N2O, project-specific emission factors were used. API Compendium method is recommended to be used to calculate emissions.

Example:

The calculation of CO2, CH4, and N2O emissions for heating equipment burning natural gas as fuel at 800 mmscf/year is shown.

The calculation is exemplified with primary data such as composition data of natural gas as fuel collected by sampling, fuel consumption data measured by flowmeters, and heating equipment-specific emission factors for CH4 and N2O.

Table 6 Composition of natural gas

Composition	**molar fraction**	**Molecular weight**	**weight fraction**
	Mole%.	MW	Wt%.
Carbon dioxide (CO2)	0.8	44	2.1
Methane (CH4)	95.3	16	90.6
Ethane (C2H6)	1.7	30	3.0
Propane (C3H8)	0.5	44	1.3
Butane (C4H10)	0.1	58	0.3
Nitrogen (N2)	1.6	28	2.7
total amount	100	16.84	100

Calculate the carbon fraction per unit weight of natural gas.

The carbon fraction of CH4 is calculated as follows:

$$Wt\%C_{\mathrm{CH4}} = \frac{12\left(\mathrm{kg\ C}/_{\mathrm{kgmole\ C}}\right)\times 1\left(\mathrm{kgmole\ C}/_{\mathrm{kgmol\ CH4}}\right)}{16\left(\mathrm{kg\ CH4}/_{\mathrm{kgmole\ CH4}}\right)} \times 100 = 75\%$$

Similarly, calculating the carbon fraction for CO2, ethane, propane, and butane yields the following:

$Wt\%C_{\mathrm{CO2}} = 27\%$, $Wt\%C_{\mathrm{C2H6}} = 80\%$, $Wt\%C_{\mathrm{C3H8}} = 82\%$, $Wt\%C_{\mathrm{C4H10}} = 83\%$

The carbon fraction of the whole natural gas is calculated using that of each composition.

$$Wt\%C_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{components}(Wt\%_i \times Wt\%C_i) = 72.2\%$$

CO2 emissions E_{CO2} are calculated as follows:

$$E_{CO2} = FC \times \frac{1}{molar\ volume\ conversion} \times MW_{\text{Mixture}} \times Wt\%C_{\text{Mixture}} \times \frac{44}{12} \times \frac{1}{100}$$

Fuel consumption FC : 800mmscf/year = 22.7 x 10^6 m^3/year (@ 15.6°C, 101.325kPa)
Molar volume conversion: 23.685m^3/kg-mole (@ 15.6°C, 101.325kPa)
MW_{Mixture} : Natural gas molecular weight 16.84 kg/kg-mole
$Wt\%C_{\text{Mixture}}$: 72.2% (calculated value)

$$E_{CO2} = 42,727 \text{ ton/year}$$

CH4 and nitrous oxide emissions E_{CH4}, E_{N2O} are calculated with emission factors specific to heating equipment, as shown below.

CH4 emission factor EF_{CH4} : 37 kg/10^6 m^3 of fuel gas

Nitrous oxide emission factor EF_{N2O} : 10 kg/10^6 m^3 of fuel gas

$$E_{CH4} = FC \times E_{CH4} = 22.7 \times 10^6 \times 37/10^6 = 840 \text{ kg/year}$$
$$E_{N2O} = FC \times E_{N2O} = 22.7 \times 10^6 \times 10/10^6 = 227 \text{ kg/year}$$

(2) Mobile combustion (transportation equipment)

Existing emission factors, which serve as secondary data corresponding to the combination of fuel type and combustion equipment, should be used for the calculation because the composition and emissions of CO2, CH4, and N2O vary depending on the combination of fuel type and combustion equipment. If e-methane is combusted by means of fuel for transportation, appropriate emission factors should be used referring to Chapter 2: 5.2.1, "GHG Emissions in e-methane production."

3.4. Flare and vent

(1) Flare

The flow rate and composition of the gas flow vary greatly depending on the operating conditions, i.e., steady-state operation, operational fluctuations during plant startup and shutdown, and emergencies, as the gas flowing into the flare system is a surplus gas that exhausts during plant operation.

CO2 emissions should be calculated using emission factors from primary data, such as operating and measured data.

The emission factor is basically calculated based on the measured emission data as primary data because CH4 is emitted as unburned content during flare combustion. However, obtaining data is difficult, therefore calculations are done using test data from equipment manufacturers.

N2O is produced by the combustion of flare gas and is calculated using test data from equipment manufacturers and existing emission factors from secondary data.

Following is an example of the calculation of the emissions from a flare system:

Example.

The calculations of CO2, CH4, and N2O emissions from the heating equipment burning natural gas at a fuel rate of 800 mmscf/year are shown below.

It is assumed here that the CH4 and hydrocarbon emission factors (the amount of unburned hydrocarbons emitted from the flare) are determined by direct measurements at the flare stack, for example, using a drone or infrared camera.

<u>CO2 emissions from flare systems</u>

$$E_{\mathrm{CO2}} = \left(HC \times CF_{\mathrm{HC}} \times FE \times \frac{44}{12}\right) + M_{\mathrm{CO2}}$$

E_{CO2} = CO2 emissions from flares (mass basis)

HC= number of hydrocarbons burned in a flare (mass-based hydrocarbons calculated from flare events estimated from operational data over a period)

CF_{HC} = Carbon mass fraction in hydrocarbons burned in a flare (carbon mass fraction calculated based on flare events estimated from operational data over a period)

FE= Combustion efficiency of flare (measured directly or using vendor data)

44/12 = Mass ratio of Carbon to CO2

M_{CO2} = Amount of CO2 in gas flowing into flare (mass basis)

CH4 emissions from flare systems

$$E_{\mathrm{CH4}} = (CH4_{\mathrm{in}} \times (1 - FE))$$

E_{CH4} = Methane emissions from flare system

$CH4_{in}$ = mass flow rate of methane entering a flare

FE= combustion flare rate in the flare system (measured directly or using vendor data)

Dinitrogen monoxide emissions from flare systems

$$E_{\mathrm{N2O}} = \left(E_{CO2} \times \frac{EmF_{\mathrm{N2O}}}{EmF_{\mathrm{CO2}}}\right)$$

E_{N2O} = Dinitrogen monoxide emissions from flare system

E_{CO2} = CO2 emissions from flare system

EmF_{N2O} = default emission factor (common fuel gas:3 x 10^{-3} kg N_2O/MMBtu, natural gas:1 x 10^{-3} kg N_2O/MMBtu)

EmF_{CO2} = default emission factor (60 kgCO2/MMBtu)

(2) Process vent

Process vents emit directly into the atmosphere from equipment or systems, and there are various methods for calculating GHG emissions using actual measured data, operating data for engineering calculations, and emission factors.

Emissions should be determined based on direct measurements or using emission factors from measured data, as CH_4, which has a high GWP, is directly emitted into the atmosphere. However, obtaining primary data is difficult, therefore existing emission factors from secondary data can be considered for determining emissions.

For certain equipment or systems, calculations using operational data can be adopted instead of actual measurements, if sufficient accuracy needs to be obtained from such calculations.

One example is the CO_2 emissions from an acid gas removal system that emits acidic gas into the atmosphere. Here, the difference between the amount of CO_2 in the gas before and after treatment was calculated as the emissions.

However, the amount of CH_4 absorbed in the emitted acid gas should be calculated using the emission factor from primary data, such as actual or measured data on emissions from the acid gas removal unit. Since obtaining primary data is difficult, emissions are determined by considering existing emission factors as secondary data.

Following is an example of emission calculation in an acid gas removal system:

<u>Calculation of CO_2 emissions in acid gas removal unit</u>

The CO_2 emissions in acid gas removal unit can be determined by the difference between the CO_2 content in the inlet and outlet gases. The CO_2 fraction should be determined by a gas analyzer installed in the inlet and outlet gases.

$$E_{CO2} = \left[\left(\frac{Volume}{time} \times CO_2 mole\%\right)_{\text{before treatment}} - \left(\frac{Volume}{time} \times CO_2 mole\%\right)_{\text{after treatment}}\right] \times \frac{44}{molar\ volume\ conversion}$$

E_{CO2} = CO_2 emissions in acid gas removal system

$Volume$= gas volume flow rate before or after acid gas removal (calculated using a flow meter or design information on the percentage of feedstock gas entering the amine solution)

CO_2 mole% = CO_2 molar content in inlet or outlet gas (measured by sampling or analyzer)

molar volume conversion = molar volume to mass conversion factor (379.3 scf/lbmole or 23.685 Sm^3 /kgmole)

(3) Other flare vents

Emissions can be calculated for each emission event, as emissions from maintenance activities and unexpected activities at a facility are temporary. For example, if a part or the entire plant system is depressurized to atmospheric pressure during maintenance, GHG emissions are calculated by assuming that the volume of gas in the pipes and equipment at the target location is flared or released into the atmosphere.

3.5. Fugitives

Fugitive emissions include leaks from the valves and flanges. The leakage amount is the sum of all measurements, as the actual amount of leakage differs for each leakage source. However, checking all the leakage sources for leakage is unrealistic. Therefore, the emission factors obtained from the measured GHG leakage data for the representative components should be used in the calculation. If primary data are difficult to obtain, existing secondary emission factors may be used in combination with the primary data to determine the emissions from the leakage of the relevant equipment.

3.6. Indirect emissions

Indirect emissions are the GHG emissions generated by the production of utilities, such as electricity, heat sources, and other utilities supplied from outside the system boundary in plant operations. These emissions are based on the emission factors from each supplier or the existing emission factors per heating value.

Additionally, the emission factor for each supplier can use the "Greenhouse Gas Reporting System (e.g., Japan's Greenhouse Gas Accounting, Reporting, and Publication System)" or "GHG Protocol Scope 2 Guidance" for the country or region concerned. In this case, the emission factor should be the latest value, and the source should be clearly stated.

4. Methane emission management

4.1. Methane emission management and measurement methods

Many projects producing CH4, such as LNG and e-methane, and hydrogen/ammonia projects that use CH4 as feedstock have been designed to reduce CH4 leaks. However, in some cases, CH4 leaks into the atmosphere, and appropriate management methods are required.

It is expected to become an important issue in the future to establish monitoring and management methods using CH4 measurement technology, and to calculate GHG emissions after showing that there are no unspecified or uncalculated CH4 leaks in the project.

CH4 measurement methods can be roughly divided into bottom-up and top-down methods.

- Bottom-up measurements (using gas sampling, optical gas imaging with an infrared camera, high-flow sampler, and drone)

  It can measure emissions from individual sources. The emission factors calculated from the measured data described in Chapter 2 were derived from the results of bottom-up measurements. The lower measurable limits and uncertainties are relatively low; however, the possibility of missing emissions from unexpected sources is high. Table 7 summarizes the measurement methods used for each emission source.

- Top-down measurement (using satellite and drone):

  Since emissions are measured at the site level, it is generally not possible to obtain emissions from individual emission sources; however, obtaining comprehensive emissions for sites or regions is possible. Furthermore, a difference in the lower measurable limits and uncertainties exists due to the difference in the measurement methods, and in general, the uncertainty in the lower measurable limits is higher in the top-down measurement.

Table 7：Methane measurement methods for each emission source

Emission source classification		Methane measurement method (※1)
Combustion	Stationary combustion	Gas sampling, Infrared camera, Drone
Vent	Flare/Vent	Infrared camera, Drone
	Process vent	Infrared camera, Drone、High flow sampler
	Other flares and vents	Infrared camera, Drone、High flow sampler
Leak	Feedstock transportation and product manufacturing process	Infrared camera, High flow sampler
Over the facility subject to methane emission control		Satellite, Drone

※1：This table is revised based on the results of technical verification.

※2：For a more detailed explanation of each methane measurement method, see the Appendix at the end of the book.

<u>Measurement of CH4 emissions at an ammonia plant</u>

In JOGMEC, GHG emissions from LNG, hydrogen, and ammonia plants were calculated using the first version of this guideline and actual plant measurements to investigate the actual conditions of GHG emissions from these plants. Through the JOGMEC in FY2022, no significant CH4 leakage from the facility in the plants was verified through top-down measurements. Bottom-up measurements have also enabled the accurate detection of CH4 leaks from sources dispersed in the plant. This measurement confirmed that CH4 emissions accounted for less than 2% of the total GHG emissions, including CO2, and CH4 leaks from the valves, which accounted for approximately 0.8% of the total CH4 emissions. However, there was also a difference between the emission factor for CH4 leakage with the secondary data and the emissions calculated from the measurements. We will continue to verify the CH4 emission management and measurement methods using top-down and bottom-up measurements in CI calculations. As part of this project, JOGMEC will work with JGC Global to build the first CH4 management test facility in Japan and conduct technical verification of CH4 measurement equipment using infrared cameras and drones.

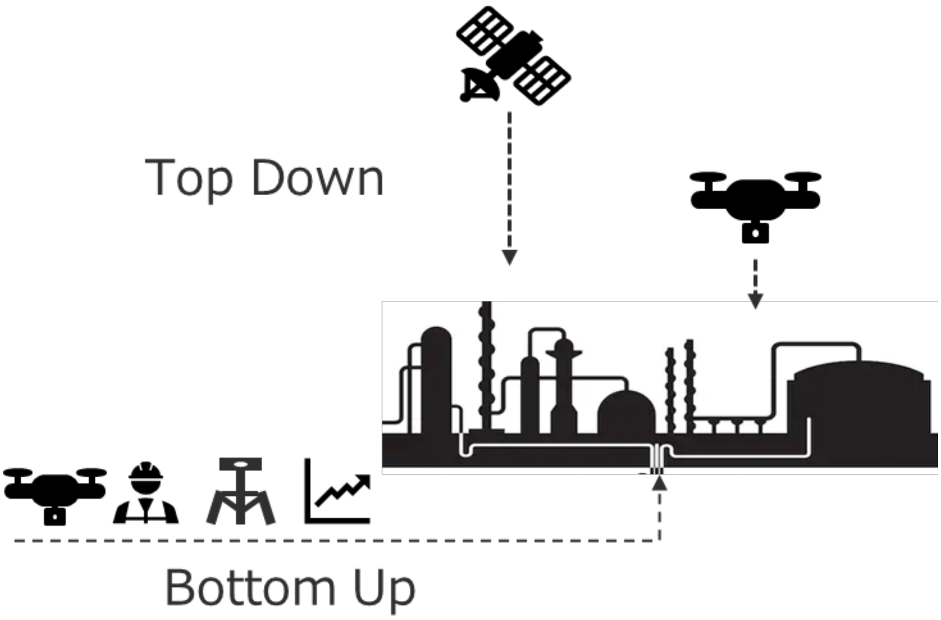


Figure 5 : Image of CH4 measurement

5. Product manufacturing process and process flow

The block flow of the product manufacturing process for LNG, e-methane, hydrogen, and ammonia as targeted by this guideline is presented in this section. The processes and flows described in this section are typical. Therefore, the processes and flows in plants should be defined appropriately when these guidelines are applied.

5.1. Natural gas feedstock production process

In the ″ "natural gas feedstock production process," after exploration and mining in upstream operations, the feedstock gas is extracted from the production wells, and the feedstock gas and coproducts are separated and recovered before transport.

Co-products (e.g., natural gas liquids such as ethane, propane, butane, pentane, oil, and condensate) generated during gas processing are usually separated from the product gas stream owing to their high added value.

If the gas treatment process is followed by the LNG production facility, the product gas is extracted in the gas treatment process before being directly transported to the LNG production facility and processed.

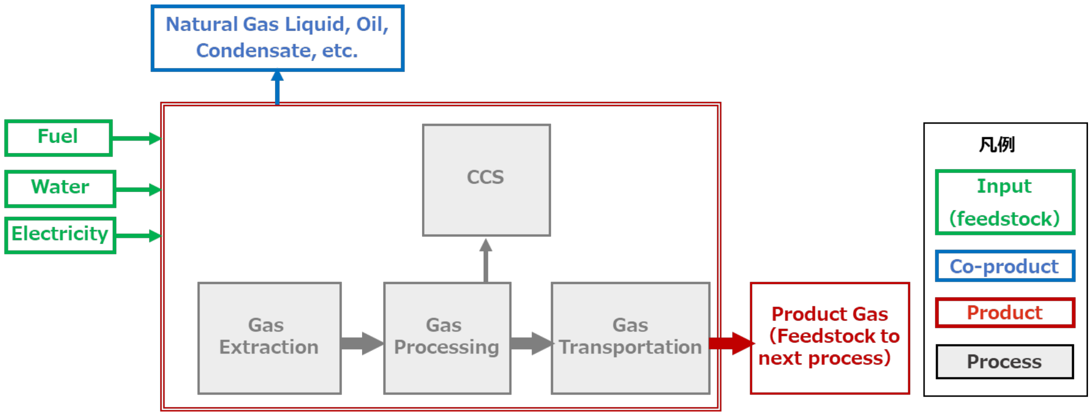


Figure 6 : Block flow diagram of upstream gas operation

5.2. E-methane production process

E-methane is produced through a synthesis reaction (methanation), the feedstock of which is hydrogen from renewable energy resources and recovered CO2, before being heated and pressurized. After distillation, e-methane is either sent to an LNG plant or shipped as a product.

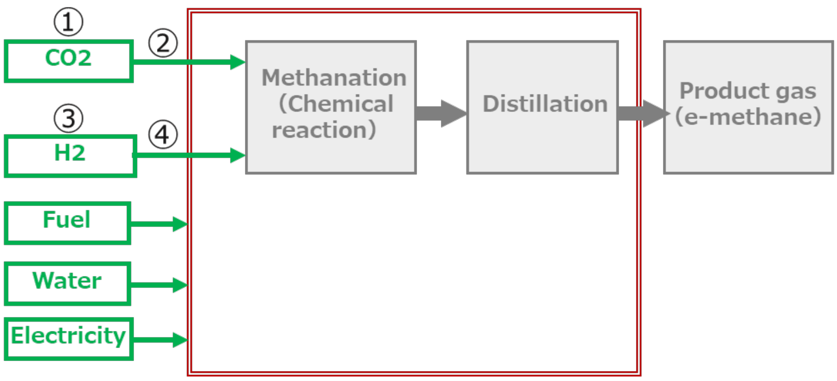


Figure 7 : Block flow diagram of e-methane production process

5.2.1. GHG emissions from e-methane production

In the case of direct air capture (DAC) or biomass technology, in which CO2 is captured from the atmosphere, the captured CO2 is used as a chemical feedstock for e-methane production. Although CO2 is emitted when burned, emissions from e-methane combustion are considered zero in the CI calculation (elaborated in Chapter 3), because CO_2 is captured from the atmosphere and does not change the concentration of CO_2 in the atmosphere.

Furthermore, if CO_2 is derived from the combustion of fossil fuels, the CO_2 count is based on the assumption of Proposal No. 1 of "Public and private councils for the promotion of methanation", mentioned in the appendix at the end of this document. This assumption is subject to change in future after discussion with the committee. Proposal No. 1 assumes that GHG emissions from e-methane combustion at the e-methane producer are considered zero to prevent double counting when CO_2 is accounted for as emissions at the emitter.

If e-methane is mixed during LNG production and shipped, the emission factor can be calculated as a weighted average based on the ratio of e-methane to natural gas. In addition, when e-methane is emitted due to fugitives or incomplete combustion in a furnace, the conventional GWP value of CH_4 should be used.

5.2.2. GHG emissions of CO2 and hydrogen as feedstock

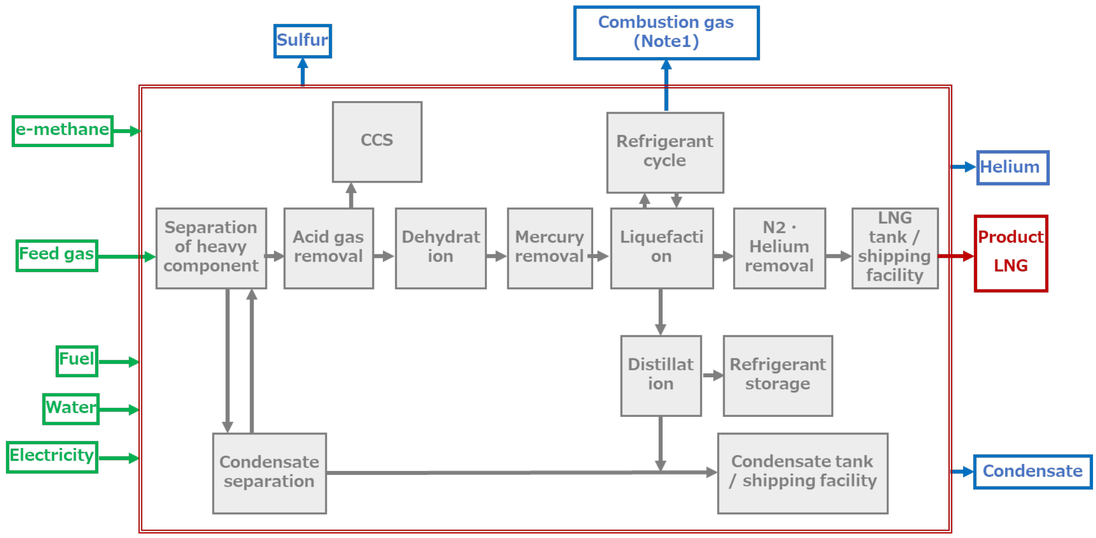
To prevent double counting in the CI calculation in Chapter 3 for GHG emissions of feed CO_2 and feed hydrogen, it is necessary to discuss and agree on which side of the emitter, or e-methane producer, will calculate GHG emissions.
It is desirable to consider using a guaranteed origin.

- Feedstock CO_2
  - GHG emissions from feed CO_2 capture (① in Figure 7)
  - GHG emissions from feed CO_2 transport (② in Figure 7)
- Feedstock H_2
  - GHG emissions from hydrogen production process (③ in Figure 7)
  - GHG emissions from hydrogen transportation (④ in Figure 7)

5.3. LNG

The LNG plant receives feed gas from the upstream gas facility and purifies it through acid gas removal, mercury removal, and dehydration units before being sent to the liquefaction process. In the liquefaction process, the feed gas is cooled to around -160 °C to obtain LNG. The product, LNG, is sent to LNG tanks and loaded onto LNG carriers for shipments. The co-products include liquid hydrocarbons (condensate) and LPG, which are present in trace amounts in the feed gas sent to the plant. Sulfur and helium can also be removed and shipped as co-products, depending on the composition of the feed gas.

The block flow diagram of the LNG plant is shown in Figure 8.



Note1: If e-methane is mixed during LNG production, the emission factor should be calculated using a weighted average based on the ratio of e-methane to natural gas.

Figure 8 : Block flow diagram of LNG process

5.4. Hydrogen

Hydrogen production can be divided into two categories: processes that use natural gas as feedstock; and water electrolysis processes derived from renewable energy sources.

5.4.1. Natural gas feedstock

Processes that use natural gas as feedstock are those that receive natural gas, undergo desulfurization, and then obtain syngas (a mixture of hydrogen and carbon monoxide) by steam methane reforming (SMR) or autothermal reforming (ATR), followed by a carbon monoxide shift reaction, pressure swing adsorption (PSA), to obtain the product hydrogen.

Figure 9 shows the block flow of hydrogen production using natural gas as the feedstock.

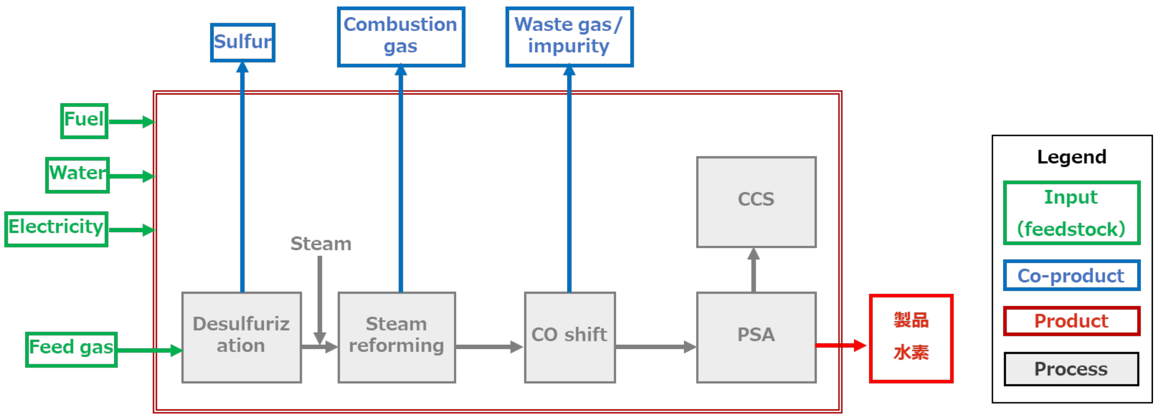


Figure 9: Block flow diagram of steam reforming

5.4.2. Water electrolysis process

Figure 10 shows a block flow diagram of hydrogen production by water electrolysis.

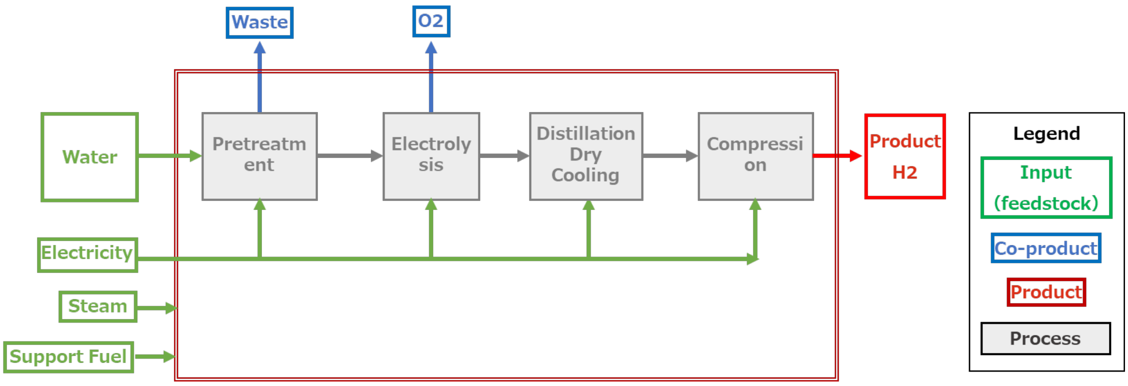


Figure 10: Block flow diagram of water electrolysis

GHG emissions need to consider not only electrolysis but also emissions derived from the production of electricity, heat, and steam used in the pretreatment and downstream processes such as distillation, drying, cooling, and compression. Particularly when electricity, heat, and steam are supplied from outside the system boundary or when they are produced by fuel combustion within the system boundary, the GHG emissions should be considered, as shown in Table 8. If electricity from renewable energy resources is produced and used within the system boundary, GHG emissions from electricity use can be considered zero. It should be noted that GHG emissions from electricity use may also be calculated with a proof of generation source (using GO).

Table 8 GHG emission sources in water electrolysis process with renewable energy

Process	Major emission source	Other emission sources (*1)
Pretreatment	Impurity removal equipment	-
Electrolysis Distillation・ Dry・Cooling・ Compression	Each equipment	External equipment which supplies electricity, heat or steam. Equipment which produces electricity, heat and steam by fuel combustion within the system boundaries.

(*1) when applicable

5.5. Ammonia

The ammonia plant receives natural gas as feedstock, obtains synthesis gas (a mixture of hydrogen and carbon monoxide) by SMR and ATR, removes carbon by the carbon monoxide shift reaction and decarbonation, and then removes residual carbon monoxide and oxygen by methanation. Consequently, a mixture of hydrogen and nitrogen is prepared and sent for synthesis to produce ammonia. Then, the unreacted gas and ammonia are sent for cryogenic separation to obtain liquid ammonia.

Figure 11 shows a block flow diagram of ammonia production with natural gas feedstock.

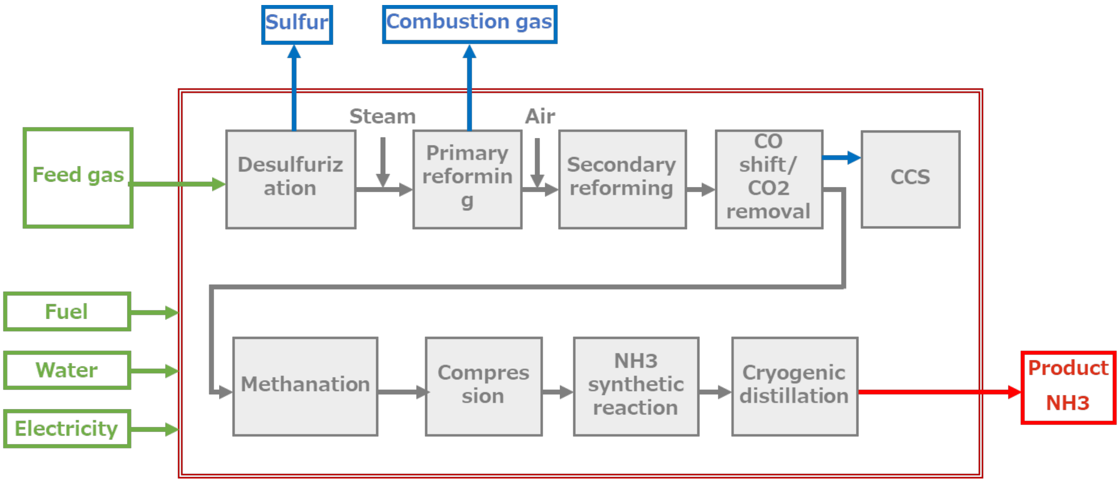


Figure 11: Block flow diagram of ammonia plant with natural gas feedstock

The process of producing ammonia from hydrogen derived from water electrolysis (as described in Chapter 2, 5.4.2) and nitrogen separated from air is receiving increasing attention, as shown by the block flow in Figure 12.

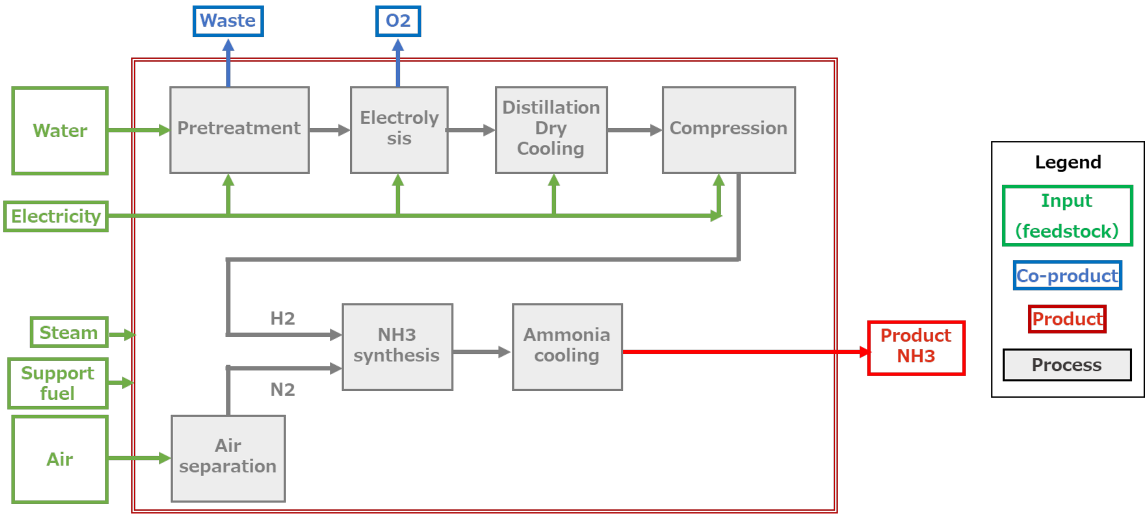


Figure 12: Block flow diagram of ammonia plant with water electrolysis

6. Selection of GHG emissions calculation method

This guideline recommends that primary data be used as major emission sources to obtain representative values of GHG emissions.

Even when primary data are used, it is desirable to select an appropriate calculation method for each emission source and target gas.

Table 9 shows the appropriate calculation method for each emission source, classified as combustion, venting, leakage, and supply from outside the system boundary. For each target gas, such as CO2, CH4, and nitrous oxide, this table provides a reference summary that exemplifies the calculations at the operational stage.

Table 9 : Calculation method selection

Source Classification		Target gas	Primary data: Calculate emission factors from actual measurements	Primary data: Engineering calculation	Primary data: Use project-specific emission factors	Secondary data: Use general emission factors	Example of calculation method selection (✓✓Recommended, ✓Alternative)
Combustion	Stationary combustion	CO2	–	✓✓	✓	–	✓✓: [Engineering calculations] Calculations using primary data such as fuel gas flow rates and facility operating hours. ✓: [Use project-specific emission factors] Calculated by fuel type or by combustion equipment type.
		CH4	✓✓	–	✓	–	✓✓: [Calculate emission factor from actual measurement] Measure the methane concentration in the emission gas and calculate the emission factor. Calculate the emission factor by the product of the emission factor and the fuel gas flow rate. ✓: [Use project-specific emission factors] Calculated by fuel type or by combustion equipment type.
		N2O	–	–	✓✓	–	Calculations using general emission coefficients determined by fuel type or combustion equipment type.
	Mobile combustion	CO2	–	–	–	✓✓	Use of general emission factors] Calculated by fuel type or by combustion equipment type.
		CH4	–	–	–	✓✓	Use of general emission factors] Calculated by fuel type or by combustion equipment type.
		N2O	–	–	–	✓✓	Use of general emission factors] Calculated by fuel type or by combustion equipment type.
Vent	Flare Vent	CO2	–	✓✓	–	✓	✓✓: [Engineering calculations] Calculations using primary data such as gas flow rate and composition of gas delivered to the flare. ✓: [Use general emission factor] Calculation using a general emission factor for flares determined by the type of flare plant for each project.

		CH4	✓✓	–	–	✓	✓✓: [Calculate emission factors from actual measurements] Engineering calculations using primary data such as unburned methane concentration in flue gas emitted from the flare and gas flow rate delivered to the flare are recommended. ✓: [Use general emission factor] Calculation using a general emission factor for flares determined by plant type.
		N2O	–	–	✓✓	✓	✓✓: [Use project-specific emission factors] Calculated using emission factors specific to the flare system used for the project. ✓: [Use a general emission factor] Calculated using a general emission factor determined by the type of plant.
	Process Vent	CO2	–	✓✓		✓	✓✓: [Engineering calculations] Calculate the gas flow rate being vented to the atmosphere based on the opening of the vent valve and the difference in flow rate before and after the vent, and by the product of the CO2 concentration in the gas. ✓: [Use of general emission factor] Calculation using a general emission factor for venting determined by plant type.
		CH4	–	✓✓		✓	✓✓: [Engineering calculations] Calculate the gas flow rate being vented to the atmosphere based on the opening of the vent valve and the difference in flow rate before and after the vent, and by the product of the methane concentration in the gas. ✓: [Use of general emission factor] Calculation using a general emission factor for venting determined by plant type.
		N2O	–	–		–	-

Source Classification		Target gas	Primary data			Secondary data	Example of calculation method selection (✓✓Recommended, ✓Alternative)
			Calculate emission factors from actual measurements	Engineering calculation	Use project-specific emission factors	Use general emission factors	
Vent	Other flare vents	CO2	–	✓✓		✓	✓✓: [Engineering calculations] Calculate the gas flow rate sent to the flare or vent based on the opening of the vent valve and the difference in flow rate before and after the vent, and the product of the CO2 concentration in the gas. ✓: [Use general emission factors]] Calculations using general emission factors for flare and vent determined by plant type.
		CH4	✓✓	✓✓		✓	For gas drive valves ✓✓: [Calculate emission factors from actual measurements] Measure the actual natural gas content emitted from gas-driven valves and use this as the emission factor for gas-driven valves to calculate GHG emissions. ✓: [Use general emission factor] Calculate using a general emission factor determined by the type of valve. For other vents ✓✓: [Engineering calculations] Calculate the gas flow rate sent to the flare or vent based on the opening degree of the vent valve and the difference in flow rate before and after the vent, and then calculate by the product of the CO2 concentration in the gas. ✓: [Use of general emission factors] Calculation using general emission factors for flare and vent determined by plant type.
		N2O	–	–		–	-
Leakage	Transportation and	CO2	–	–	✓✓	✓	✓✓: [Use project-specific emission factor] For the process/equipment that is the source of leakage, use the leakage amount indicated by the manufacturer as the factor. ✓: [Use general emission factor] Calculation using a general emission factor determined by the leakage source.

		CH_4	–	–	✓	✓✓	✓✓: [Calculation using a general emission factor] Calculation using a general emission factor determined by the leakage source. ✓: [Using project-specific emission factors] Calculation using primary data by the supplier.
		N_2O	–	–		–	-
	Leakage from equipment components	CO_2	–	–	✓✓	✓	✓✓: [Use project-specific emission factor] Use the leakage amount indicated by the manufacturer as a factor for the component that is the source of leakage. ✓: [Use general emission factor] Calculation using a general emission factor determined by the leakage source.
		CH_4	–	–	✓✓	✓	✓✓: [Use project-specific emission factor] Use the leakage amount indicated by the manufacturer as a factor for the component that is the source of leakage. ✓: [Use a general emission factor] Calculation using a general emission factor determined by the leakage source.
		N_2O	–	–		–	-
Supply from outside the system boundary	Emissions by electricity, heat and steam	CO_2	–	–	✓✓	✓	✓✓: [Use project-specific emission factors] Calculation using primary data from the supplier. ✓: [Use general emission factor] Calculation using a general emission factor determined by the production process of electricity, heat, and steam.
		CH_4	–	–	✓✓	✓	✓✓: [Use project-specific emission factors] Calculation using primary data from the supplier. ✓: [Use general emission factor] Calculation using a general emission factor determined by the production process of electricity, heat, and steam.
		N_2O	–	–	✓✓	✓	✓✓: [Use project-specific emission factors] Calculation using primary data from the supplier. ✓: [Use general emission factor] Calculation using a general emission factor determined by the production process of electricity, heat, and steam.

Chapter 3 Calculation of carbon intensity (CI) of target product

This chapter presents the calculation method for CI, the figure of which is likely to be reported, and the concept of reducing GHG emissions through CCU/CCS and carbon credits.

1. CI calculation

According to the CFP calculation approach for products, this guideline calculates the product CI to compare different life cycle stages among GHG reporters or target products.

Common criteria should be established for the target product to allow a transparent and consistent assessment.

A product's CI is obtained by dividing the CFP value of the product by the reduction in GHG emissions based on the energy content (low heating value (LHV) basis) or weight (metric ton basis) of the product. In particular, this guideline recommends that both energy content and weight bases be converted, as shown in the results sheet.

The definition of product CI is as follows:

$$\text{CI : Carbon Intensity} = \frac{\text{Product GHG emissions} - \text{Reduction in GHG emissions}}{\text{Product energy content or weight}}$$

- Product GHG emissions :
  Calculations were divided into feedstock production, feedstock transport, and production processes.

- Reduction in GHG emissions :
  Refer to "Chapter 3: 2, Reduction in GHG emissions."

- Product energy content :
  Units to be unified on an LHV basis in the form of megajoules (MJs) or million British thermal units (MMBtu).

- Product weight：
  Units to be unified on a metric ton basis.

The product CI calculation for a project plays an important role in making investment decisions and understanding the environmental impact of the project in advance, not only for plants in operation but also for projects under planning or construction. However, in the early stages of a project, such as during feasibility studies (FS), the calculation could use both secondary data based on emission factors by plant type and primary data based on plant inlet/outlet information. However, in the basic design phase (front-end engineering design (FEED)), performing engineering calculations based on primary data are possible, such as heat and material balance and vendor information, as equipment selection for major large equipment (e.g., gas turbines) is often completed at the FEED stage.
Table 10 summarizes the information available for CI calculations for each project phase.

Table 10: Data available for CI calculation as per project phase

Plant Phase		Feasibility Study	Frond End Engineering Design	Operation
Available data	**Primary data (direct)**	No data	No data	· Operational data · Measurement data
	Primary data (indirect)	· Block Flow Diagram · Plant capacity and unit capacity · Plant feedstock and product information	· Process Flow Diagram · Heat and Material Balance (H&MB) · Piping and Instrument Diagram without Vendor information (P&ID) · Process Data Sheet · Mechanical Data Sheet · Emission factor specified by Vendors of equipment or unit	· Piping and Instrument Diagram with Vendor information (P&ID) · Data sheet issued by Vendor · Instrumentation data sheet · Piping 3D layout diagram · Maintenance activity log · Emission factor reflecting maintenance and operational data · Emission factor specified by Vendors of equipment or unit
	Secondary data (direct)	·Emission factor per plant type	·Emission factor per plant type	·Emission factor per plant type
	Secondary data (indirect)	· Emission factor specified by equipment or unit	· Emission factor specified by equipment or unit	· Emission factor specified by equipment or unit

Following are examples of CI calculations for hydrogen and ammonia produced from natural gas:

■Hydrogen CI (CI_{H2})

$$CI_{\mathrm{H2}}\left[\frac{\mathrm{tonCO2e}}{\mathrm{tonH2}}\right]$$

$$= \frac{\begin{array}{c}\text{GHG emissions from Natural gas feedstock production process [tonCO2e](See Chapter 2.5.1)} \\ \text{+GHG emissions from Hydrogen production process [tonCO2e](See Chapter 2.5.4)}\end{array}}{\text{Product hydrogen weight [ton]}}$$

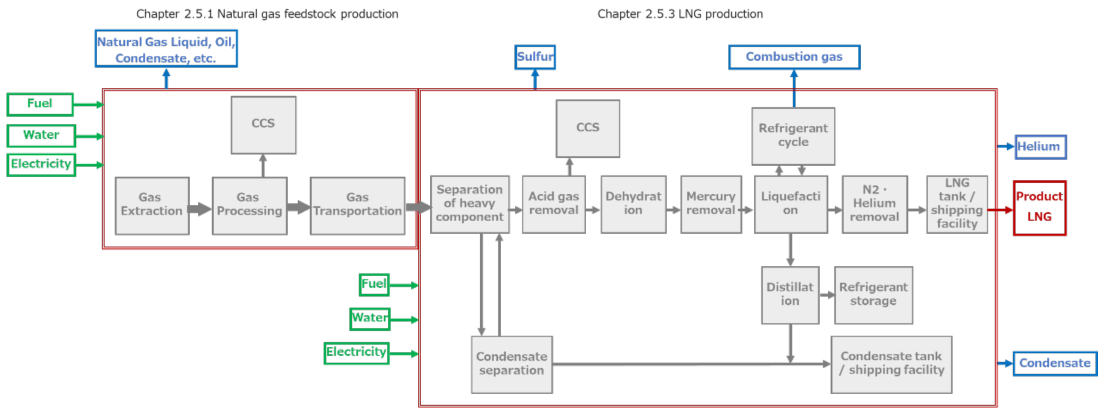
■Ammonia CI (CI_{NH3})

$$CI_{\mathrm{NH3}}\left[\frac{\mathrm{tonCO2e}}{\mathrm{tonNH3}}\right]$$

$$= \frac{\begin{array}{c}\text{GHG emissions from Natural gas feedstock production process [tonCO2e](See Chapter 2.5.1)} \\ \text{+GHG emissions from Ammonia production process [tonCO2e](See Chapter 2.5.5)}\end{array}}{\text{Product hydrogen weight [ton]}}$$

The following are examples of CI calculations for LNG, e-methane, and e-methane when e-methane is mixed into the LNG production process and shipped.

■LNG CI (CI_{LNG})



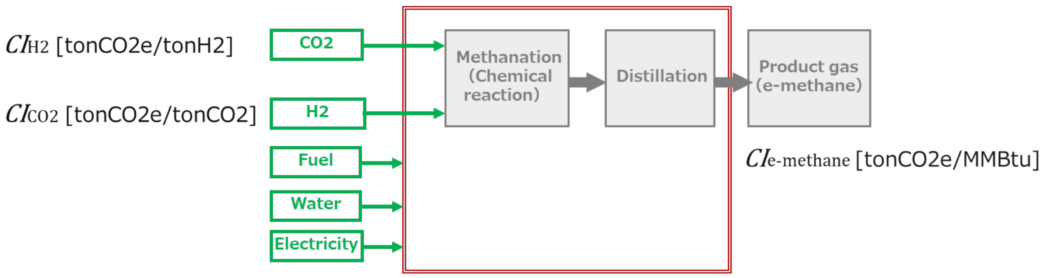
$$CI_{\mathrm{LNG}}\left[\frac{\mathrm{tonCO2e}}{\mathrm{MMBtu}}\right]$$

$$=\frac{\begin{array}{c}\text{GHG emissions from Natural gas feedstock production process [tonCO2e](See Chapter 2.5.1)}\\ \text{+GHG emissions from LNG production process [tonCO2e](See Chapter 2.5.3)}\end{array}}{\text{Product LNG energy content [MMBtu]}}$$

・Product LNG energy content = M_{LNG}[ton-LNG]* $\mathrm{LHV}_{\mathrm{LNG}}$ [MMBtu/ton-LNG]

■e-methane CI ($CI_{\text{e-methane}}$)

Chapter 2.5.2 e-methane production



$$CI_{\mathrm{e-methane}}\left[\frac{\mathrm{tonCO2e}}{\mathrm{MMBtu}}\right]=\frac{\begin{array}{c}\text{GHG emissions of feedstock Hydrogen [tonCO2e]}\\ \text{+GHG emissions of feedstock CO2 [tonCO2e]}\\ \text{+GHG emissions of e}-\text{methane process [tonCO2e] (See Chapter 2.5.2)}\end{array}}{\text{e}-\text{methane energy content [MMBtu]}}$$

・GHG emissions of feedstock Hydrogen = CI_{H2} [tonCO2e/ton-H2] × M_{H2} [ton-H2]

・M_{H2} = Hydrogen weight entering the system during the calculation period

・GHG emissions of feedstock CO2 = CI_{CO2} [tonCO2e/tonCO2] × M_{CO2} [tonCO2]

・M_{CO2} = CO2 weight entering the system during the calculation period

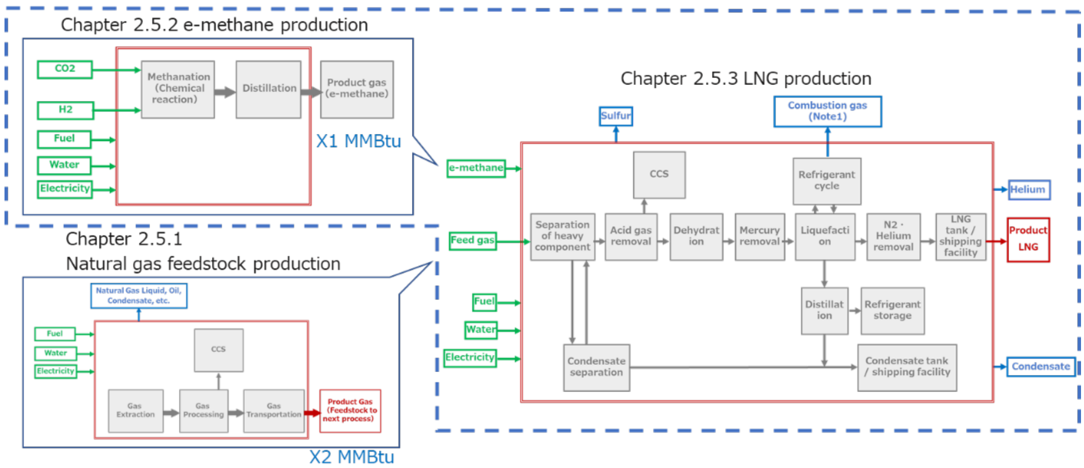
・Feedstock hydrogen CI was assumed to have certificates such as GO.

・Feedstock CO2 CI shall avoid double counting of GHG emissions. (See Chapter 2.5.2 e-methane production)

・Fugitive emissions of e-methane downstream of methanation need to be recognized as GHG emissions at the general CH4 GWP.

■e-methane CI （$CI_{\text{e-methane}}$） when e-methane is mixed into the LNG production process and shipped

In this case, the area indicated by the blue box is the LNG CI derived from e-methane; the GHG emissions of the LNG process are allocated on a heating value basis according to the ratio of e-methane and natural gas supplied. The allocation value α is indicated in the equation below.



$$CI_{\text{LNG(e-methane derived)}}\left[\frac{\text{tonCO2e}}{\text{MMBtu}}\right]$$

$$=\frac{\begin{array}{c}\text{GHG emissions of e}-\text{methane process [tonCO2e] (See Chapter 2.5.2)}\\ +\text{GHG emissions of LNG production process }\times\ \alpha\ \text{[tonCO2e] (See Chapter 2.5.3)}\end{array}}{\text{Product LNG(e}-\text{methane derived) energy content [MMBtu]}}$$

$$(\alpha=\frac{x_1}{x_1+x_2})$$

・Chapter 2.5.2 GHG emissions of e-methane process ＝ $CI_{\text{e-methane}}$ [t-CO2e/MMBtu] × $LHV_{\text{e-methane}}$ [MMBtu/ton-methane] × $M_{\text{e-methane}}$ [ton-methane]

・$M_{\text{e-methane}}$ = e-methane weight entering the system during the calculation period

・Product LNG energy content = M_{LNG}[ton-LNG]* LHV_{LNG} [MMBtu/tonLNG]

・Note(*1): If e-methane is mixed before being combusted in the LNG production process, the emission factor is calculated as a weighted average based on the ratio of e-methane to natural gas. If e-methane is released unburned from a furnace or leaked, the fugitive emissions of e-methane need to be recognized as GHG emissions at the general CH4 GWP.

Notes for the CI calculation of products:

① Based on the operational data logs, unexpected activities that occurred during the CI calculation period, as described in Table 4 and Chapter 2: 2.2, should be identified. Subsequently, GHG emissions must be calculated for each applicable event and considered in the total GHG emissions for the calculation period.

② Calculations should be in accordance with actual shipping operations. For example, in the case of LNG, products from a liquefaction plant are stored in storage tanks and periodically shipped by LNG cargo to the final destination. Here, the product CI should be calculated for each cargo based on the latest measured emission factor and the average operating data for the cargo. The actual measurements should be conducted appropriately, considering the operating conditions of the facility, including the unexpected activities described in Section ①, and should be conducted at least once a year.

2. Treatment of emission credits

Regarding global warming countermeasures in the production of LNG, e-methane, hydrogen, and ammonia, appropriate determination of the environmental values of clean fuels is important. Moreover, calculations and reporting of GHG emissions must be in line with the actual state of the project. This guideline presents the current thinking on how to handle CCS/CCU and carbon credits to reduce GHG emissions; however, the terms and effectiveness of their application will continue to be considered.

2.1. Carbon capture and storage (CCS)

When captured and stored CO2 is emitted from sources within the boundary of the target system, emission reductions are based on an appropriate accounting method that can cut off the emissions in the calculation of the production CI. Regarding the method of calculating the emission reduction due to CCS projects, referring to Chapter 3 of the "Recommended guideline for the implementation of carbon dioxide capture and storage projects (CCS guideline)" and "Recommended guideline for safe and long-term CO2 containment with CO2-EOR (CO2-EOR Guideline)" stipulated by JOGMEC is recommended.

In addition, in the CCS project, when using carbon credits with policies and systems, it is necessary to subtract the cut-off from CI and add back the emission reductions to prevent double counting.

2.2. CO2 recovery and effective use (CCU)

In the case of capturing and replacing (effectively using) CO2 emitted from emission sources within the boundary of the target system, it is possible to cut emissions off from in the product CI calculation by setting appropriate calculation methods and various terms. For example, in the case of effectively manufacturing carbon-recycled products using CO2, it is necessary to satisfy various conditions to prevent the release of products derived from natural gas or CO2 into the atmosphere.

2.3. Carbon credits

Regarding carbon credits, which are created from the activities of reducing emissions from emission sources, they do not exist in the processes of products handled in this guideline for CI calculations. Therefore, we will continue to consider the effectiveness of the system of cutting off the credits by transferring the value of the credit to the product CI and emissions deduction. The study will be continued to clarify various existing limitations. However, carbon credits that are created based on appropriate methodologies and management, such as credit mechanisms, are legalized in many countries and regions and may be given a certain degree of credibility.

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