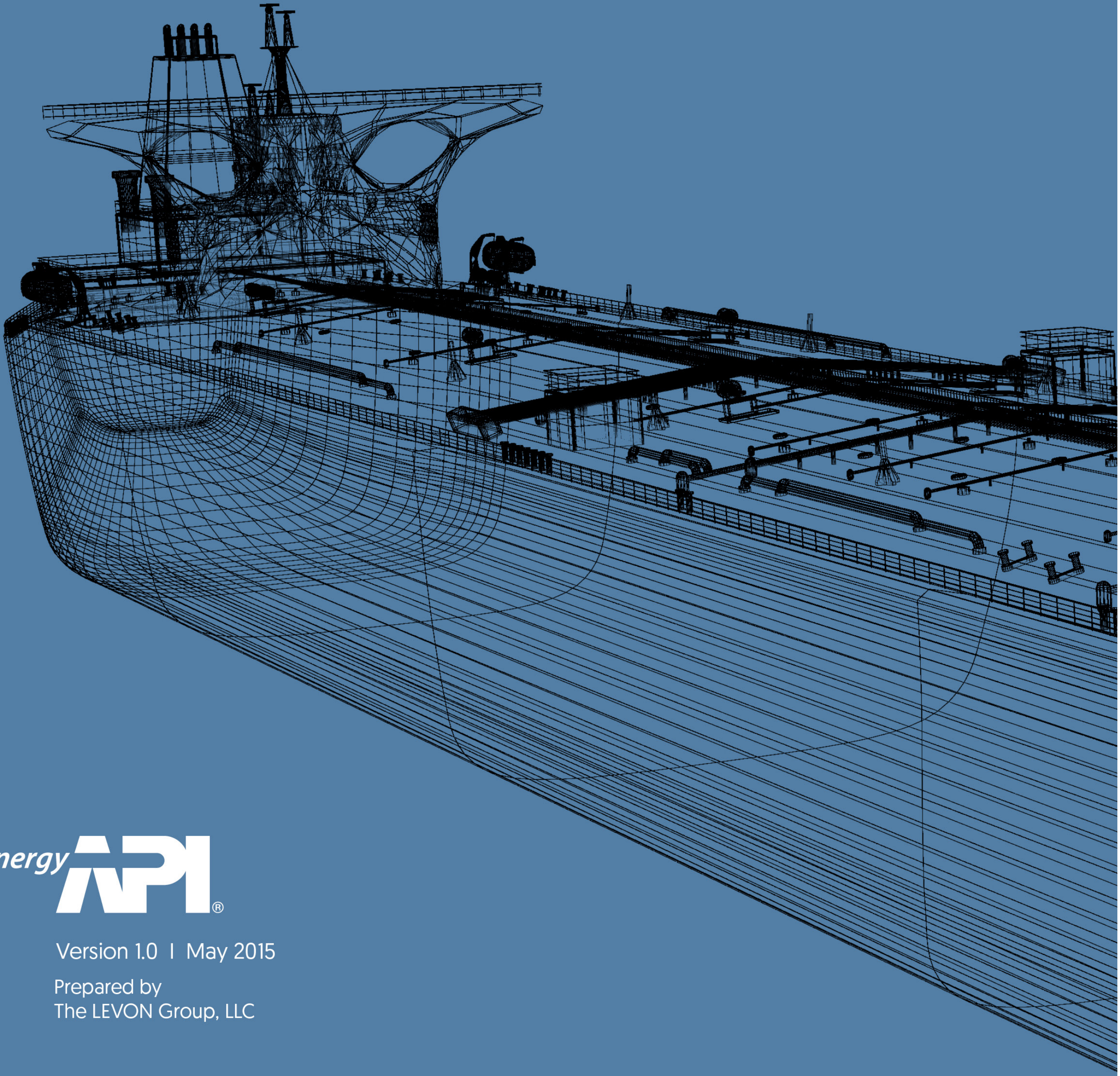

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Prepared by
The LEVON Group, LLC

Liquefied Natural Gas (LNG) Operations

Consistent Methodology for Estimating Greenhouse Gas Emissions

FOREWORD

The American Petroleum Institute (API) has extensive experience in developing greenhouse gas (GHG) emissions estimation methodology for the Oil and Natural Gas industry. API's Compendium of GHG Emissions Methodologies for the Oil and Gas Industry (API Compendium) is used worldwide by the industry and is referenced in numerous governmental and non-governmental protocols and procedures for calculating and reporting GHG emissions.

The API Compendium includes methods that are applicable to all sectors of the Oil and Natural Gas Industry from the exploration and production at the wellhead through transmission, transportation, refining, marketing and distribution. API has developed this document in order to enable consistent and comprehensive internationally-accepted methodologies to estimate GHG emissions from the liquefied natural gas (LNG) operations segment including its specialized facilities, processing techniques, and associated infrastructure.

API's objectives in developing this guidance document are:

- Develop and publish technically sound and transparent methods to estimate GHG emissions from LNG operations, accounting for the diversity of operations;
- Align methodologies with API Compendium structure and organization;
- Maintain consistency with globally recognized GHG accounting systems and those in LNG importing and exporting countries.

The guidance document is organized around four main chapters:

1. LNG Overview
2. LNG Sector Background
3. GHG Emissions Inventory Boundaries
4. Emission Estimation Methods

Supplemental information is provided in five appendices:

A - Glossary of Terms

B - Unit Conversions

C - Acronyms

D - Global Warming Potential (GWP)

E - Emission Factors Tables for Common Industrial Fuels

This document is released now as a “Pilot Draft” for one year to encourage broad global testing of the approach and to gather feedback from early users. API is also seeking comments through participation in public forums and presentation of the methodology. Following this ‘pilot’ period of feedback collection API will revise the relevant chapters of the document and publish a final guidance document based on feedback received.

API has initiated this effort as part of its contribution to the Asia Pacific Partnership for Clean Development and Climate Change, where it participated in the Cleaner Fossil Energy (CFE) Task Force as part of a project that aimed to evaluate GHG emissions from LNG operations that may lead to technological fixes to minimize natural gas wastage, reduce GHG emissions, and improve energy efficiency.

ACKNOWLEDGEMENT

API would like to acknowledge the invaluable technical contribution of API’s U.S. Experts Working Group and to the thorough review and comments by the Technical Committee of the U.S. Center for LNG.

Many thanks also to APPEA (Australian Petroleum Producers and Exploration Association) and its member companies for their review and comments.

American Petroleum Institute

Washington DC

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May 2015

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1.0 OVERVIEW

With increased scrutiny of greenhouse gas (GHG) emissions from the consumption of fossil fuels, there is a growing realization that the consumption of natural gas, including its use as a fuel for electricity generation, is set to rise. Growing global need for liquefied natural gas (LNG) to supplement regional natural gas supplies will lead to increased levels of activities to liquefy, ship, store and regasify LNG for its ultimate use. LNG – as a clean energy alternative – will play an increasingly important role in helping nations improve their air quality and ensure a secure and diverse energy supply in the coming years.

1.1 LNG Applications

There are a diverse range of applications that can use LNG, and in its liquefied form it is ideal for transporting natural gas over large distances to bring it to consumers. Important applications of LNG include power generation; industrial and residential demand; storage of natural gas to balance out peaks in market demands; fuel for road, rail, and marine transportation.

1.1.1 Power Generation

Sourcing of LNG for power generation enables many regions and countries to switch their power generation systems to natural gas. LNG as a globally traded commodity is being made available over long distances by efficient transportation of an energy-dense liquid from its point (or country) of origin to be regasified and used in the natural gas delivery system throughout intended power markets globally. This global reach makes it possible to increase the use of natural gas while lessening reliance on more carbon-intensive fossil fuels. According to the U.S. EPA[1] burning of natural gas results in lower quantities of nitrogen oxides, carbon dioxide and methane emissions, where the latter two are greenhouse gases.

Global transport of LNG is predicated on close attention to the regional difference of the heating values of distributed natural gas with which the regasified LNG must be compatible:

- Asia (Japan, Korea, Taiwan – distributed gas typically has an HHV that is higher than 1,090 BTU/SCF (40.6 MJ/m^3)[2],

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[1] U.S. EPA, Clean Energy, Natural Gas, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html

[2] Multiply BTU/SCF by 0.037259 to get MJ/m^3

- U.K. and the U.S. - distributed gas typically has an HHV that is less than 1,065 BTU/SCF (39.7 MJ/m^3),
- Continental Europe - the acceptable HHV range is quite wide: 990 – 1,160 BTU/SCF (36.9 to 43.2 MJ/m3).

Several methods may be used to modify the heating value of regasified LNG so it can be adjusted to the desired level. For example, increasing heating value can be accomplished by injecting propane and butane into the gas. Conversely, to decrease natural gas heating value, nitrogen can be injected. Blending different gas or regasified LNG streams can also lead to adjustment of the heating values to the desired levels.

The regional differences in heating value of the natural gas would need to be taken into consideration when accounting for GHG emissions from power generation using natural gas with varied carbon compositions and GHG emissions intensity per unit of thermal or electrical power production.

1.1.2 Natural Gas Storage (Peak-Shaving) Facilities

In the U.S., natural gas utilities and interstate pipeline companies operate "peak shaving" facilities where they liquefy and store pipeline natural gas for use during high demand periods. Such "peak shaving" typically relies on either trucking LNG for storage at local utilities, or drawing from natural gas transmission or distribution pipelines during low demand periods for local liquefaction, storage, and later regasification when demand peaks. LNG from peak shaving facilities can be regasified for injection into the transmission or distribution grids when natural gas demand is high, or used directly as liquid fuel for transportation.

According to the EIA there are 105 "peak shaving" plants in the U.S that serve also as LNG storage facilities. These facilities primarily serve areas of the U.S. where pipeline capacity and underground gas storage are insufficient for periods of peak natural gas demand. These facilities are divided into two categories, those with and without liquefaction capabilities. The EIA lists 59 such facilities with the capacity to liquefy natural gas and store the LNG. This category of liquefaction facilities tend to be larger than the remaining "satellite" facilities that are located in 31 states across the U.S. and which rely on receiving LNG for storage directly in its liquid form.

The LNG peak-shaving facilities with liquefaction equipment are typically built to allow continuous liquefaction at a relatively low rate, and regasification amounting to about 10% of storage capacity every day of operation, thus increasing the natural gas delivery capacity of the system (storage and transmission pipelines) during high demand periods such as for winter cold snaps. The main sources of GHG emission from these facilities are expected combustion devices used for regasification and compressors operation.

1.1.3 Road, Rail and Marine Vessels

Over the past 15 years, the role of LNG as a fuel for heavy-duty vehicles has grown due to the emergence of economic incentives for alternative-fuel vehicles and tighter vehicle emission standards. Because of LNG's increased driving range relative to compressed natural gas, it is used in heavy-duty vehicles, typically vehicles that are classified as "Class 8" (33,000 - 80,000 pounds, gross vehicle weight). LNG is used primarily as fuel for refuse haulers, local delivery (grocery trucks), and transit buses.

LNG is an alternative fuel for the heavy-duty vehicle market, including delivery trucks, transit buses, waste collection trucks, locomotives, and multiple off-road engines. When compared to other fuels, LNG fueled heavy duty vehicles produce fewer emissions of nitrogen oxides (N_2O and NOx), particulate matter (PM), sulfur oxides (SOx), and carbon dioxide (CO_2). Nitrous Oxide (N_2O) is a greenhouse gas, whereas the mixture of nitrogen oxides denoted as NOx (primarily NO and NO_2) contribute to the formation of ground level ozone and are not considered greenhouse gases. A typical LNG-fueled truck will have 90% lower NOx and PM emissions than a diesel-fueled truck, 100% lower SOx emissions, and 30% lower CO_2 emissions.

The growing global concern over air pollution and greenhouse gas emissions from ships has driven regulatory change at the international level. The International Maritime Organization (IMO) has adopted regulations that (a) limit the sulfur content in marine fuels to reduce SOx emissions; (b) specify standards for new marine diesel engines to reduce NOx emissions; and (c) require new ships to meet an Energy Efficiency Design Index to reduce GHG emissions. These three changes, along with the price advantage of LNG over marine fuels, have driven a strong interest in LNG fueled vessels as a viable alternative to meet these new standards.

As of 2008 shipping emissions accounted for 2-4% of CO_2, 10-20% of NOx and 4-8% of SOx global emissions. LNG-fueled ships, in the gas burning mode, result in the elimination of essentially all SO_2 emissions, and leads to reduced NOx, CO_2, and PM emissions when compared to the emissions from a typical vessel powered by marine diesel. Consequently, the number of LNG-fueled non-carrier vessels is growing globally. These vessels represent all ship classes for a variety of applications such as: ferries, offshore service vessels, tugs, barges, patrol vessels, and tankers.

Due to LNG's high energy density its use is growing globally in many areas demanding high horsepower applications, including rail locomotives, tug boats, platform support vessels, inland waterway tow boats, mine trucks, hydraulic fracturing pumps and well drilling rigs.

1.2 LNG Greenhouse Gas Emissions

In 2006, the U.S. EPA commissioned a study to assess the contribution of LNG operations to methane emissions in the U.S[3]. The study concluded that current emission estimation methods might be over-estimating GHG emissions from LNG operations, and that despite some similarities between natural gas processes and LNG operations, there is a growing need to more fully characterize GHG emissions from the various segments of LNG operations.

As LNG becomes a more substantial fraction of the overall natural gas market, the need to characterize GHG emissions from the LNG operations chain is becoming more evident. The development of robust emission estimation methods for the different operational segments of the LNG sector would contribute to consistent assessment and reporting of GHG emissions for LNG operations.

For example, the 2011 U.S. GHG Inventory estimates that the contribution of methane from LNG operations amounts to close to 1.9 million metric tonnes (MMT) in units of CO_2 equivalent emissions (CO_2e), which represents 1.3% of methane emissions from all the segments that make up the Natural Gas Systems[4]. These emissions are due to fugitive emissions from station operations, along with venting and fugitive emissions from operating LNG compressors and engines. The LNG methane emissions is comprised of 1.5 MMT CO_2e from seventy (70) LNG

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[3] ICF, 2006, "Methane Emissions from LNG Operations", Discussion Paper, November 7, 2006, Virginia, USA

[4] U.S. EPA, National Greenhouse Gas Emissions Data, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011", Annex 3, Washington DC, April 2013; http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html

storage stations (including peak-shaving plants with liquefaction capacity), and 0.4 MMT CO_2e from the operation of eight (8) imports/export terminals.

This document is designed to provide guidance for the quantification of GHG emissions associated with operations along the LNG value chain, i.e. liquefaction; shipping; loading/unloading; regasification; and storage. The guidance provided includes:

- Mapping out of the GHG emission sources associated with the LNG operations chain;
- Compilation and description of relevant methods for estimating GHG emissions including generic emission factors that may be useful when site specific information is lacking.

The main GHGs considered in this document are CO_2 that is primarily associated with process heat and combustion emissions, and CH_4 that is primarily associated with venting, leakage and fugitive emissions. All other GHGs are of lower significance though they should be considered if they are relevant for specific circumstances or are subject to local requirements.

2.0 LNG SECTOR BACKGROUND

This section provides a brief description of LNG, its properties along with the “LNG operations chain.” The material presented here defines the boundaries for this industry sector and the corresponding emission sources that will be included when estimating GHG emissions from LNG operations.

2.1 What is LNG?

Liquefied natural gas, or LNG, is simply natural gas in its liquid state. When natural gas is refrigerated to a temperature of about minus 160°C (or minus 260°F) at atmospheric pressure, it becomes a clear, colorless, and odorless liquid. This reduces its volume by a factor of more than 600, allowing it to be efficiently stored for multiple uses and transported in tanks by sea or land. LNG is non-corrosive and non-toxic but requires storage in specially-designed cryogenic tanks in order to maintain it in its liquid state. The density of LNG is roughly 0.41 to 0.50 kilograms per liter (kg/L), depending on temperature, pressure and composition, which is about half that of water (1.0 kg/L). Produced natural gas is composed primarily of methane (80 – 99 mol%) and generally contains up to 20 mole% total of ethane, propane and heavier hydrocarbons, and other minor non-hydrocarbon substances. Prior to the liquefaction process, natural gas is treated to remove essentially all of its non-hydrocarbon components (carbon dioxide, mercury, sulfur compounds, and water) with the exception of nitrogen, and some heavier hydrocarbons contained within the natural gas, resulting in an LNG composition that is typically over 95% methane and ethane with less than 5% of other hydrocarbons (ethane, propane, and butanes) and nitrogen. The nitrogen content of the LNG is reduced to typically one percent or less prior to storage at the liquefaction facility.

The composition of LNG is a function of the production formation from where the liquefied gas originates, and the market for which the LNG is intended. Its ultimate composition and heating value will depend on the processing (or gas “conditioning”) steps employed for the removal of pentanes and heavier hydrocarbons to very low levels, and the natural gas heating value specifications for the intended markets of the LNG, which drives the decision of whether to include natural gas liquids (e.g. ethane, propane and butanes) removal capabilities in the overall liquefaction plant design. Many hydrocarbons in the hexane or heavier range are normally solids at LNG temperatures, and are relatively insoluble in LNG; hence, components such as benzene must be removed to a few parts per million to prevent them from freezing during the liquefaction process. Similarly, some pentane range hydrocarbons may also form solids at LNG temperatures and have limited solubility in LNG. When designing LNG liquefaction plants, great care is taken to make sure that solubility limits are considered for a range of possible feedstocks.

The data presented in Table 1 provides examples of selected compositions and heating values for LNG originating from different locations around the world[5].

Table 1. Selected LNG Compositions and Higher Heating Values for Different Origins (mole %)

SPECIES	ABU-DHABI	ALASKA	ALGERIA	AUSTRALIA	BRUNEI	INDONESIA	MALAYSIA	OMAN	QATAR RICH	TRINIDAD
N_2	0.11%	ND	0.28%	0.01%	0.00%	0.09%	0.32%	0.00%	0.19%	0.00%
CH_4	87.07%	99.80%	91.40%	87.82%	89.40%	90.60%	91.15%	87.66%	89.87%	92.26%
C_2H_6	11.41%	0.10%	7.87%	8.30%	6.30%	6.00%	4.28%	9.72%	6.65%	6.39%
C_3H_8	1.27%	ND	0.44%	2.98%	2.80%	2.48%	2.87%	2.04%	2.30%	0.91%
i-C_4H_{10}	0.06%	ND	0.00%	0.40%	ND	ND	0.70%	0.29%	0.41%	0.21%
n-C_4H_{10}	0.08%	ND	0.00%	0.48%	1.30%	0.82%	0.66%	0.30%	0.57%	0.22%
i-C_5H_{12}	0.00%	ND	0.00%	0.00%	0.00%	ND	0.01%	0.00%	0.01%	0.00%
n-C_5H_{12}	0.00%	ND	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	99.90%	100.00%	100.00%	99.80%	100.00%	100.00%	100.00%	100.00%	100.00%
HHV Gas (Btu/SCF)	**1,123.00**	**1,010.80**	**1,078.40**	**1,142.90**	**1,121.00**	**1,110.80**	**1,118.50**	**1,127.60**	**1,115.60**	**1,082.10**

Source: D. McCartney, Black & Veatch Pritchard, Inc., 2002

ND = Not Determined

For gas entering the LNG liquefaction facility, key quality concerns include CO_2 and sulfur content, in addition to nitrogen, water, and mercury. Due to the sensitivity of liquefaction facilities to mercury, gas sent to a liquefaction process is treated to ensure that it contains an extremely low concentration (sub-parts per billion) of this element. The specifications for pre-processing the gas feeding a liquefaction plant are more stringent than for pipeline gas; all impurities must be removed to levels much lower than needed for pipeline gas to prevent problems in the liquefaction process. Additionally, there is typically no gas treating facilities at

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[5] D. McCartney, Gas Conditioning for Imported LNG, 82nd Annual Convention Gas Processors Association, San Antonio, Texas, March 11, 2002

LNG receiving terminals, so the LNG should be compatible with the specification of the sales gas at the receiving terminal.

For the product LNG that is shipped, or otherwise transported, quality specifications are primarily designed to address end-use considerations. For LNG that is intended to be blended with pipeline natural gas, consideration of the interchangeability of the gases distributed is important. The interchangeability of different natural gas streams can be represented using the Wobbe Index[6], which is coming into wider use in the U.S. as in the rest of the world.

2.2 LNG Operations Chain

The LNG operations chain consists of several interconnected elements as shown schematically in Figure 1. However, the figure depicts the gas fields as being closely connected to the liquefaction plants, which is not uniformly the case. Similarly the LNG operations chain does not always terminate in transfer to a pipeline system.

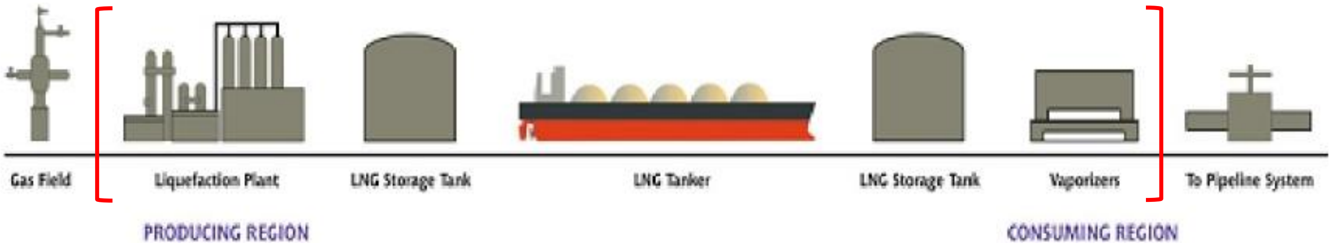

Figure 1. LNG Operations Chain ***Source***: CMS Energy

For the purpose of this document we structured the discussion of LNG operations and its associated GHG emissions into five stages, as illustrated by the operations depicted within the brackets in Figure 1. These operations include:

- **Liquefaction -** Plants where natural gas is treated to remove impurities and higher molecular weight hydrocarbons, and then liquefied and stored for subsequent shipment;

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[6] The Wobbe Index is defined as the higher heating value of the gas divided by the square root of the specific gravity of the gas, i.e. its molecular weight relative to air. If two fuels have the same Wobbe Index, then at a given combustor inlet pressure and valve setting, the flame stability resulting from combustion of the two fuels will be identical.

- **Storage -** Storage tanks that are designed to store LNG at atmospheric pressure;
- **Loading and Unloading -** Marine or inland terminals designed for loading LNG onto tankers, or other carriers or unloading it for regasification;
- **Shipping -** LNG tankers used for transporting LNG;
- **Regasification -** Plants, typically co-located with unloading terminals, where LNG is pressurized, regasified, and injected into pipelines, or other receiving systems, for delivery of natural gas to end users.

The GHG estimation methods to be discussed in this document pertain to the sources in the LNG operations chain and encompass those operations extending from the point of entry of the natural gas into a liquefaction plant and through to the regasification stage, where the vaporized natural gas enters either a transmission pipeline system or other mode of conveyance to the ultimate users. Methodologies for estimating GHG emissions associated with routine gas processing operations that are designed to bring the natural gas directly to the market are addressed in the API GHG Methodology Compendium[7] and are not repeated in this document. Similarly, the API Compendium includes methods that are relevant to natural gas pipeline transmission and distribution along with methods that may be relevant to LNG plants that would augment the methods provided in Section 4.0 of this document.

The sub-sections below provide brief descriptions of the operations and equipment associated with each of the five interconnected LNG operations elements, and start to outline potential GHG emission sources in each of these stages.

2.2.1 Liquefaction

Natural gas arriving at a liquefaction plant may either be raw material from dedicated gas fields, or, in some cases, has already been through some initial processing. Prior to liquefaction, the natural gas is further treated to remove water, sulfur-containing species (primarily hydrogen sulfide), and any residual CO_2 that might be present. It is also treated to remove other components that could freeze (e.g., benzene) under the low temperatures needed for liquefaction, or that could be harmful (e.g. mercury) to the liquefaction facility.

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[7] API, "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry", 3rd Edition, Washington DC, August 2009

Figure 2 illustrates an example liquefaction process, including recovery of Boil-Off Gas (BOG) during LNG ship loading[8]. The BOG can either be routed to the plant's fuel gas system, or compressed and returned to the inlet of the process. LNG typically contains at least 90% methane, along with smaller and decreasing amounts of ethane, propane, and butanes. Even when producing a high heating value (rich) LNG, the LNG contains no more than 0.5 mole% pentanes and heavier hydrocarbons. The liquefaction process entails treating the natural gas followed by chilling it using refrigerants, which are typically hydrocarbons, although non-hydrocarbons (e.g. nitrogen) may also be used as refrigerants. The liquefaction plant uses multiple compressors, condensers, pressure expansion valves, isentropic expanders and evaporators. The natural gas goes through stages of pre-cooling, liquefaction and sub-cooling until it reaches the desired temperature, and is then stored as LNG in near-atmospheric pressure tanks prior to ship loading.

Liquefaction process GHG emissions are primarily due – but not limited - to:

- **(a)** Fuel gas combustion to power refrigeration compressors and electrical generators;
- **(b)** Fired heaters, flares, incinerators, and other fired process heat generators;
- **(c)** Venting of low pressure carbon dioxide;
- **(d)** Fugitive losses of natural gas from the process due to leakage; and
- **(e)** Fugitive losses of other GHG's used in the facility (i.e., SF_6 used for switchgear).

The liquefaction process may consist of one or more 'LNG trains' and can be designed to produce a rich (high in heating value) or lean (low in heating value) LNG, as desired, even approaching 100% methane depending upon the composition of the feed gas and the level of hydrocarbon recovery practiced. It is important to note some LNG facilities produce a Domestic Gas stream as a product, where they may also produce surplus power for export to local areas. Similarly if the facility extracts a natural gas liquids stream and fractionates it for sale of ethane, propane, butane, and pentane plus products these ought to be accounted for in the overall material balance as products and not emission sources.

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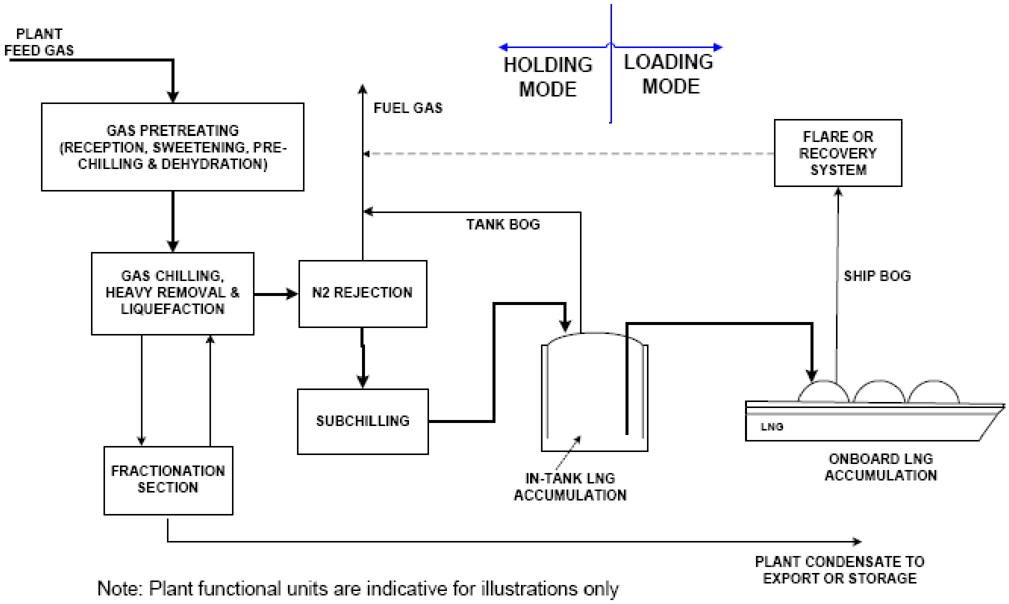
[8] Huang, S. H., Hartono, J., Shah, P., "Recovering BOG during LNG Ship Loading", Paper presented at GPA 86th National Convention in San Antonio, Texas, March 11-14 (2007).



Source: Huang et al, 2007

Figure 2. Schematics of an Example Liquefaction and Vessel Loading Process

2.2.2 Storage

LNG storage tanks are located at liquefaction plants to store LNG prior to loading onto tankers. Receiving terminals also have storage tanks to hold LNG prior to regasification. In addition, LNG storage tanks may be used in natural gas distribution systems for surge capacity to help meet peak demand; such tanks are part of a “peak-shaving” facility.

LNG storage tanks are typically double-walled tanks (i.e., a tank within a tank), with the annular space between the two tank walls filled with insulation. The inner tank, in contact with the LNG, is made of material suitable for cryogenic service such as 9% nickel steel or aluminum. The outer tank includes a dome that, with the outer tank wall and floor, and its lining, provides containment for the vapor that exists in equilibrium with the LNG. The outer tank wall is typically constructed of carbon steel (in the case of single containment or double containment design) or reinforced concrete that is lined with a combination of 9% nickel steel (up to a certain height) and carbon steel in the case of a full containment design. LNG storage tanks are operated at essentially atmospheric pressure. The annular space, typically a meter or more thick, is filled with insulation.

Greenhouse gas emissions from LNG storage tanks are minimal since:

(a) There is no systematic venting from the tanks: gas is fully contained within the outer container of the overall tank design;

(b) Gas displaced during tank loading or boiled off due to heat leakage is captured and either used for fuel gas onsite; compressed and sent to a transmission or distribution system pipeline; or reliquefied and returned to the storage tank;

(c) Most piping connections associated with LNG tanks are welded rather than flanged;

(d) LNG storage tanks are operated near atmospheric pressure with a slight overpressure so there is minimal pressure differential between the tank and the atmosphere to drive leaks;

(e) The tanks are double-walled and heavily insulated to minimize evaporative losses, while their tank in a tank design minimizes the potential for liquid leaks.

In addition to the double wall design, storage tanks also have different containment provisions for handling emergencies. Most LNG storage tanks in the United States are built above ground; they are commonly used both in liquefaction and in regasification plants. These tanks are cheaper and faster to construct relative to in-ground tanks because minimal site excavation and drainage systems are required. In-ground tanks are more common at receiving terminals located at seismically sensitive areas with limited land area like Japan, South Korea, and Taiwan. At these locations, in-ground tanks can be spaced closely together. Also, in-ground tanks have minimal visual impact (i.e., they can be totally invisible to the public), and landscaping can be used for camouflage[9]. Table 2 provides a summary of the types of LNG tanks' containment design as used globally with an indication of the U.S. market share of these tanks.

The GHG emissions methodology that is the scope of this document (and discussed in Section 4.0 below) considers storage emissions but does not address emissions during highly unlikely storage failures. Fugitive emissions (gas leakage) from LNG storage tanks are primarily determined by the number and type of piping and valve connections used. LNG vaporization within the tanks is due to heat gain from the surroundings, and from energy input from the pumping process. Ambient heat gain is a function of the type and amount of insulation used.

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[9] Huang, S., Chiu, C.-H., Elliot, D., "LNG: Basics of Liquefied Natural Gas", University of Texas, Continuing Education, Petroleum Extension Services (PETEX), Austin, Texas (2007).

The resulting gas from such heat input to the LNG is called boil-off gas (BOG). Stored LNG will stay at the same temperature in spite of such heat input because of the "auto refrigeration" process[10]. BOG production is managed with BOG compressors and interconnecting piping.

Table 2. Types of LNG Storage Tanks In-Use Globally (a)

	PRIMARY CONTAINMENT	MAX D.P. (mbar) (B)	MARKET SHARE (C)
Single-Containment	Self-support	160	64%
Double-Containment	Self-support	190	18%
Full-Containment	Self-support	210/290	
PC/PC (d)	Self-support	300	1%
Above-ground Membrane	Supported	300	6%
In-ground Membrane	Supported	300	11%

(a) Huang, S., Chiu, C.-H., Elliot, D., "LNG: Basics of Liquefied Natural Gas", University of Texas, Continuing Education, Petroleum Extension Services (PETEX), Austin, Texas (2007).
(b) D,P. = Delta Pressure (or pressure differential); mbar = millibars
(c) Data estimates for global market share
(d) PC = pre-stressed concrete construction

Figure 3 provides schematics for the three basic containment types for above-ground LNG tanks[11], including:

- **Single-containment tanks** are the lowest cost option if sufficient plot space is available for earthen dikes as secondary containment. The primary containment is the inner shell that is made of 9% nickel steel. The outer shell is made of carbon steel, which is incapable of withstanding the low temperature of LNG, but which serves as the gas-tight container for BOG and keeps the insulated space dry. In the unlikely event of failure of the inner shell,

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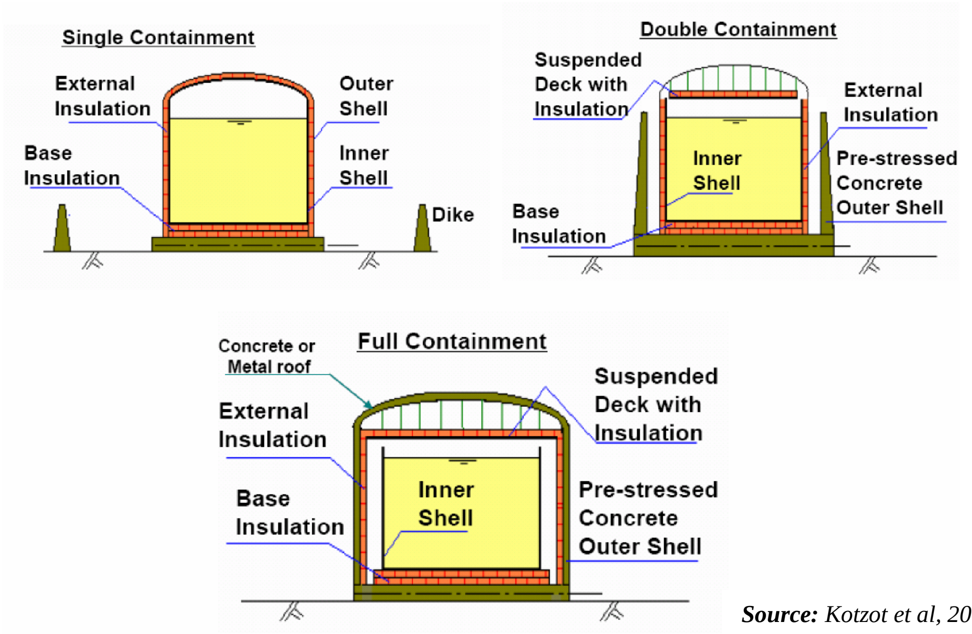
[10] **Auto refrigeration** is the process in which the LNG is kept at its boiling point so that any added heat is countered by energy lost from *boil-off* of the stored liquid.

[11] Kotzot, H. J., "Overview of the LNG Industry – Gas Treatment, Liquefaction, and Storage", paper presented in GPA Annual Convention, San Antonio, TX (2003).

liquid will be impounded within the dike, where the LNG would evaporate. Therefore, the open space requirements around single containment tanks are greater than those for other categories of containments.

- **Double containment tanks** are only required to provide liquid tightness in case of an LNG spill from the inner tank, and gas tightness to contain BOG. The existence of an outer wall that is capable of containing LNG significantly reduces the traveling distance and dispersion of vapors should the inner tank fail.
- **Full-containment tanks** are designed such that the outer tank can contain both the liquid and the vapor. In the event of inner tank failure, the outer wall is capable of sustained containment of the liquid while retaining vapor tightness. In the unlikely event of an inner tank failure, some of the vapor generated as the outer tank cools to LNG temperature might be released through the tank relief vents if the tank's primary gas management system, the BOG compressors, and its secondary system, a flare, are not able to handle the excess.



Source: *Kotzot et al, 2003*

Figure 3. Schematics of Above Ground LNG Storage Tanks Containment Design

2.2.3 Loading and Unloading

Marine loading terminals are located adjacent to liquefaction plants where LNG is initially stored, while unloading takes place at receiving terminals prior to LNG regasification. LNG loading arms, typically constructed from pipe with cryogenic swivels, are used to transfer LNG between onshore or offshore facilities and LNG tankers, both in liquefaction and regasification plants. LNG is maintained at cryogenic temperature throughout the loading and unloading process. Specially designed and well-insulated loading racks and vessel connectors are used to minimize generation of boil-off gas and to ensure safety of the LNG transfer process. Figure 4 shows articulated LNG loading arms at a terminal.

The handling capacity of a marine loading arm varies between 4,000 and 6,000 m^3/hr. A loading or unloading terminal would normally consist of two or three loading arms in liquid transfer service, a vapor return arm and a common liquid/vapor spare.

Courtesy: FMC
Technologies, *SA*

Figure 4. Articulated LNG Loading Arms

With the emergence of offshore LNG operations, different designs are used for loading and offloading LNG under different conditions, such as from regasification or liquefaction plants in environments that are more severe than the protected harbors typically employed with onshore liquefaction plants and receiving terminals. New types of loading arms have been designed for

‘Side by Side’ LNG transfer between a floating production storage and offloading (FPSO) terminal and a ship, a floating storage and regasification unit (FSRU) and an LNG carrier, or a gravity-base LNG receiving terminal and an LNG ship. These systems can be used in moderate sea states. ‘Tandem’ LNG transfer systems have been designed for use between an FPSO or an FRSU and a dedicated LNG carrier, e.g. the Boom to Tanker (BTT) system[12]. The latter will be used in more severe environmental conditions.

The operations at a loading or unloading terminal are comprised of the following steps:

(a) Moorage of an LNG vessel at the terminal;

(b) Connection of cryogenic loading arms, arranged for continuous recirculation of LNG from the plant storage tanks;

(c) Transfer of LNG via the cryogenic loading arms between the LNG storage tanks on board the LNG carrier and the LNG storage tanks at the liquefaction plant site or the receiving terminal; the initial LNG transfer rate onto a ship depends on the temperature of the tanks within the ship upon its arrival;

(d) Compressing boil-off gas, with or without flaring and/or venting of displaced tank gas during loading;

(e) Discontuation of the LNG transfer operation, followed by draining of the liquid-filled loading arms;

(f) Disconnection of the LNG vessel from the loading arm for its onward sea journey.

Fugitive emissions associated with the ship loading or unloading process are minimal, due primarily to the welding of all associated piping systems.

2.2.4 Shipping

LNG is shipped in double-hulled vessels that are specially designed and insulated to enable safe and reliable transport of LNG from liquefaction facilities to receiving terminals, while minimizing the amount of LNG that boils off. The tankage and BOG management systems are designed to maintain the cargo tank pressure below the maximum allowable relief valves (MARVS) settings or to safely utilize or dispose of the natural LNG boil-off gas at all times, including while in port, maneuvering or standing.

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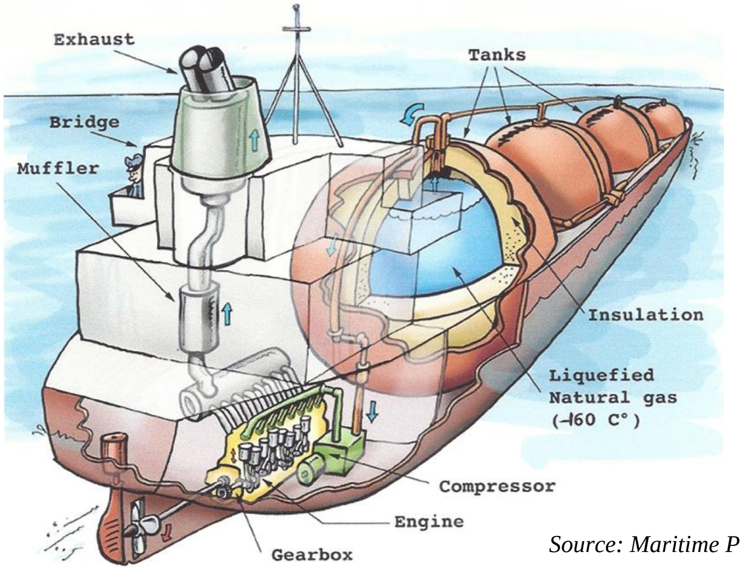
[12] Pashalis, C., *Latest Developments for Offshore FMC Loading Systems*, LNG Journal, July/August 2004

LNG tankers typically burn the natural gas boiled off from the stored LNG as fuel, supplemented by fuel oil, to power their propulsion system. Many of the new LNG tankers, including the Q-Flex (capacity to 216,000 m^3) and Q-Max LNG carriers (capacity to 266,000 m^3), both first delivered in 2007, are much larger than the LNG carriers in service prior to that point in time. These newer ships utilize slow speed diesel-powered propulsion systems and have onboard reliquefaction facilities to reliquefy boil-off gas and return it to the ship's LNG tanks as LNG.

The LNG containment system designed in LNG carriers can be categorized as either a spherical (Moss) design; a membrane design; and a structural prismatic design. Although the spherical design is the most identifiable one for LNG ships, the majority of recently built ships have employed the membrane design.

Figure 5 shows a cut-away view of an LNG tanker with Moss spherical storage tanks, and offers insights into potential GHG emission sources from the shipping portion of the LNG value chain. As discussed above, during the voyage, the main source of GHG emissions from an LNG ship is the combustion of boil-off gas (BOG) and other fuels used for vessel propulsion and gas compression.



Source: Maritime Propulsion

Figure 5. LNG Tanker Cross-Section (Moss Design)

Prevalent propulsion systems on LNG carriers include: steam, dual-fuel, slow speed diesel with reliquefaction and gas turbines. Dual-fuel electric propulsion systems have become the preferred design for new-built LNG carriers in the range from 140,000 m^3 to 200,000 m^3, with slow speed diesel propulsion with reliquefaction becoming more popular for vessels over 210,000 m^3 capacity. All these different propulsion systems require high-voltage power plants, either to supply only the cargo handling (tank unloading) pumps and/or reliquefaction plant or combined with electric propulsion[13]. The choice of the specific propulsion type, its design, capacity and rate of utilization will impact GHG emissions associated with LNG ship voyages.

LNG ship operations generate GHG emissions while traveling at sea, while berthing and/or un-berthing from the docks, and while loading and unloading their cargo. One should account for the GHG emissions associated with any routine operations at dock (i.e.'hoteling' operations), the duration of operation, and the power demand of the cargo transfer pumps, in addition to the loading/unloading operations discussed in Section 2.2.3 above.

For berthing and unberthing operations the LNG ships use specialized couplings to ensure safe LNG transfer, which are known as quick coupling (QC) and quick release (QR). Vessels also are equipped with powered quick release couplings for emergency disconnects of products transfer if it becomes necessary. Figure 6 shows examples of such couplings, which are located at the mating point between the loading arms and the ship.

Courtesy: Chevron

Figure 6. Loading arm couplings: QC/QR (left**), and Powered Emergency Release coupling (**right**)**

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[13] J. F. Hansen, R. Lysebo, "Comparison of Electric Power and Propulsion Plants for LNG Carriers with Different Propulsion Systems ",ABB AS, Oslo, Norway, www.abb.com/marine

To estimate GHG emissions during LNG ship voyages one has to evaluate emissions associated with each of the typical systems that may be present onboard. Such systems may include one or any combination of the following, with aggregate capacity for BOG utilization or disposal that is no less than the ship's normal boil-off rate (NBOR)[14]:

(a) A steam boiler with a common propulsion steam turbine and steam dump system;
(b) A slow speed diesel or dual fuel diesel engine plant for propulsion and power generation;
(c) A gas turbine plant for propulsion and power generation;
(d) A re-liquefaction system;
(e) A gas combustion unit;
(f) Other units, such as an auxiliary steam boiler capable of burning boil-off vapors.

2.2.5 Regasification

Regasification plants, which return the LNG back into the gaseous state, are typically incorporated into LNG receiving terminals. Figure 7 provides a schematic of a composite example of a regasification plant. Most plants do not have all of the processing capabilities shown on the chart. For example, the ethane-plus extraction step shown in the figure is an option that is used at very few potential locations due to the lack of local infrastructure or markets. Most LNG receiving terminals are only capable of pumping and vaporizing LNG. Some have the ability to blend nitrogen into the send out gas to reduce its heating value, or to blend in propane and/or butanes into the LNG to increase its heating value. A limited number of receiving terminals have facilities to separate higher hydrocarbons from rich LNG, or are considering adding the facilities needed to effect that separation.

For all LNG regasification plants, LNG is initially pumped from the LNG ship into the receiving terminal's LNG storage tanks. Subsequently, LNG is either transferred further in its liquid phase, e.g. loaded onto trucks for transport to smaller storage facilities at a customer's site, or pumped to higher pressure through in-tank and high pressure pumps, vaporized at high pressure, and delivered into the send out gas pipeline.

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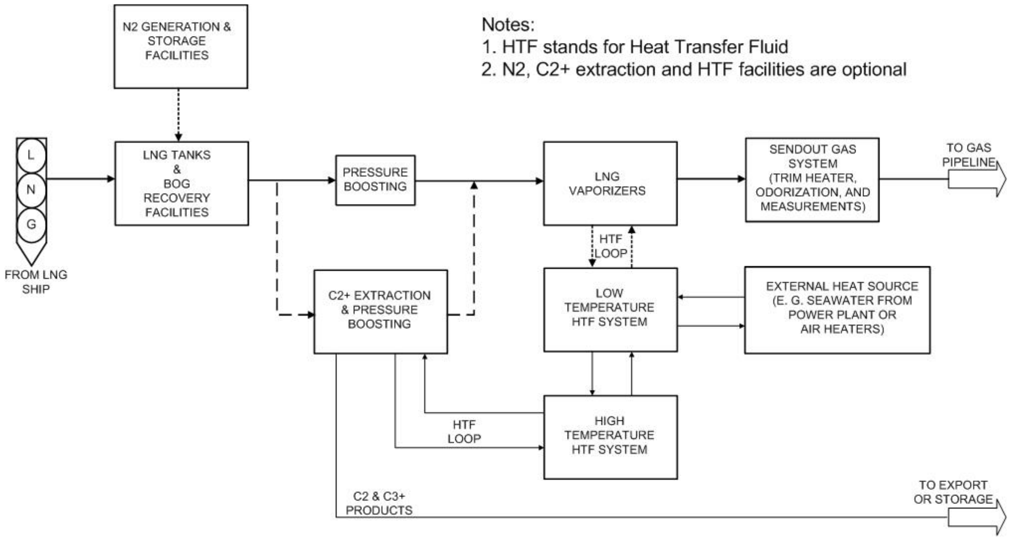
[14] American Bureau of Shipping (ABS), "Guide for Propulsion System for LNG Carriers", September 2005 (Updated February 2011), New York, NY, USA



Source: Huang et al, 2007

Figure 7. Schematic of a Composite LNG Receiving Terminal

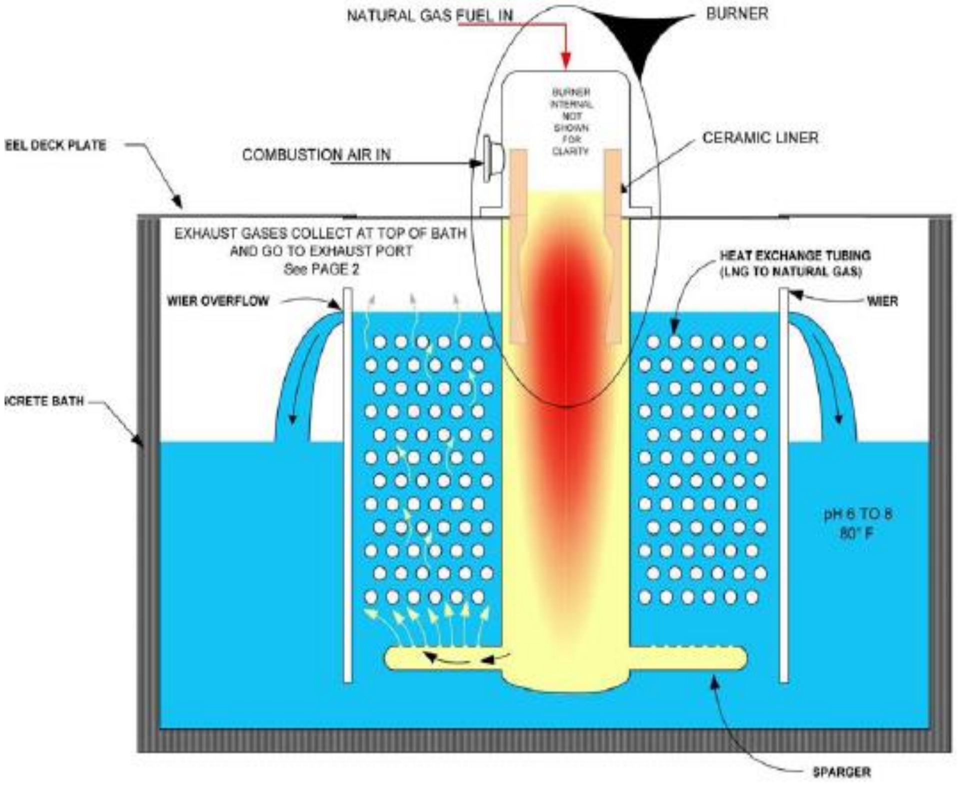
The vaporizers commonly in use throughout the world are summarized in Table 3. The table includes a brief description of the operating mode for each type.

Vaporizers presently in use in the U.S. are mostly submerged combustion or shell and tube design. Elsewhere in the world, other types like open rack seawater type and intermediate fluid type are in use. The pressurized natural gas from the regasification process is either delivered to adjacent consumers, or enters into a natural gas pipeline transmission and distribution system.

Table 3. Summary of Common Types of LNG Vaporizers

VAPORIZER TYPE	MODE OF OPERATION
Submerged Combustion Vaporizers (SCV)	▪ Pressurized LNG is vaporized in stainless steel tube coils immersed in a hot water bath that is heated by combusting natural gas. ▪ The combustion takes place in a distributor duct immersed in the water bath, into which the combustion products are directly sparged. The water in the bath serves as the heat transfer media for vaporizing the LNG in the tube coil. ▪ The pressurized and vaporized natural gas can go directly to a transmission pipeline without further compression.
Open Rack Vaporizers (ORV)	▪ An ORV consists of two horizontal headers connected by a series of vertical finned heat transfer tubes made of aluminum alloy that use seawater as the heat source. ▪ LNG enters the bottom header and moves upward through the vertical tubes. Meanwhile seawater flows downward along the outer surface of the tubes. The vaporized gas is collected and removed from the top header.
Shell & Tube Vaporizers (STV)	▪ The STVs can be categorized as either direct or indirect heating. Different designs offer different solutions to prevent the possible consequences of freeze-up, as follows: 1. **Direct heating:** The LNG flows on the tube side, with seawater on the shell side. The design utilizes the partially heated LNG as a buffer fluid between seawater and the cold inlet LNG. 2. **Indirect heating:** In this category of STVs an intermediate liquid is used as the heat transfer media for vaporization. They are known as: – <u>Traditional Intermediate Fluid Design</u> – typically uses a 36% ethylene glycol/fresh water solution as the intermediate fluid in a circulating loop for vaporizing LNG, while the cooled solution can be reheated by direct heat exchange with seawater or ambient air. – <u>Double Tube Bundle Shell and Tube Vaporizer</u> – comprised of a lower and an upper set of tube bundles, and uses an intermediate heat transfer fluid (e.g. propane, iso-butane, Freon, or NH_3) between the LNG (upper tubes) and the seawater or glycol water (lower tubes).
Ambient Air Vaporizers (AAV)	▪ This vaporization system design takes heat from ambient air to vaporize the LNG. ▪ The AAVs also come in two categories: direct and indirect heat exchange with air. Since the LNG temperature is dramatically lower than the dew point temperature of ambient air, different designs offer different solutions to prevent the possible icing-up: **1.** **Direct heating with ambient air**. AAVs use two modes for drawing ambient air: natural draft, or forced draft. They typically are designed as either single units or multiple units arranged in banks with common interconnecting piping. **2.** **Indirect heating with ambient air**. LNG exchanges heat with a circulating intermediate fluid that is heated by ambient air. The selection of the intermediate fluid is based on its freezing point and good heat transfer properties.

Figure 8 shows a schematic of a typical submerged combustion vaporizer in which the LNG flows through the tube bundle that is submerged in the water bath together with the gas burner flue gas tube. The gas burner discharges the combustion flue gases into the water bath, thus heating the water and providing the heat for the vaporization of the LNG.



Courtesy: *Dominion*

Figure 8. Submerged Combustion Vaporization of LNG

Open rack vaporizers use seawater as a heat source for the vaporization of LNG. These vaporizers use once-through seawater flow on the outside of a heat exchanger as the source of heat for the vaporization, and are widely used in Japan. Their use in the U.S. and Europe is less common due to environmental permitting limitations.

Vaporizers of the intermediate fluid type use a refrigerant like Freon or Propane with a low melting point to transfer heat from a warm water stream to the LNG. Here a liquid refrigerant "reboiler" type heat exchanger is used in conjunction with ambient once-through water in the tube bundle. The process is based on the heat of condensation of the refrigerant to provide the heat of vaporization of the LNG. These type vaporizers have some of the same permitting constraints in the U.S. as the open rack types.

Other types of vaporizers include ambient air vaporizer systems that utilize ambient air to provide the heat for the vaporization process. Such systems can also include supplemental heaters for heating the cooled water from the heat exchanger. These systems are designed to extract heat from the environment for the vaporization of large quantities of LNG with reduced fuel gas usage relative to submerged combustion vaporizers. This also results in reduced effect on the environment and on marine and terrestrial life.

As presented earlier in Table 1, the composition of LNG varies based on the originating production formation and the level of separation and processing at the liquefaction plant. Additional processing or dilution steps may be required after regasification in order to meet national or local gas quality specifications and the needs of end-users. These additional processing steps could also lead to additional GHG emissions, which would have to be assessed based on the local operational boundaries for the regasification plants. For many regasification facilities, the vast majority of GHG emissions stem from combustion processes, with minimal venting due to compressor operations. Yet, one should note that some regasification plants also have power generating capability, with its associated emissions.

3.0 GHG EMISSIONS INVENTORY BOUNDARIES

Generic guidance for establishing GHG emissions inventories at the facility or company level is available from the joint initiative of the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD)[15]. Industry relevant guidance for establishing GHG emissions inventory boundaries for the petroleum and natural gas sector is provided in the Petroleum Industry Guidelines for Greenhouse Gas Reporting[16]. The Industry Guidelines recognize that GHG emissions may be aggregated across a range of dimensions including organizational and operational boundaries, geographic boundaries, industrial sectors, company divisions, facilities, and source types. Companies typically set their overall organizational boundaries for reporting either on the basis of operational control, financial control, or by equity share. For reporting LNG GHG emissions companies could include emissions from their LNG operations as part of a comprehensive GHG emissions report, or as a separate report highlighting emissions from their LNG operations chain.

At the most basic level, a GHG emissions inventory is comprised of calculated and estimated emissions from individual emission sources that are aggregated to produce the inventory. Emissions information is typically obtained either through direct on-site measurement of emissions, or the combination of an emission factor and some measure of the activity that results in the emission (referred to as the activity factor). Emission factors describe the emission rate associated with a given emission source, which may be either based on site-specific measurements or published data. Activity factors are generally a measured quantity, such as a count of equipment or amount of fuel consumed.

When selecting methods for quantifying GHG releases to the atmosphere, a four stage hierarchy is usually used for selecting appropriate approaches consistent with data availability,

(a) Direct Measurements;

(b) Mass Balance;

(c) Emission Factors;

(d) Engineering Calculations.

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[15] WRI/WBCSD, GHG Protocol Initiative, *A Corporate Accounting and Reporting Standard*, Revised June 2004

[16] API/IPIECA/OGP, *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions, Revised Edition, London, October 2011*

One of the major challenges for complex GHG emission inventories, such as those for oil and natural gas companies, is the identification of the specific emission sources associated with each facility and the appropriate methods for estimating these emissions. The guidance provided in this document is designed to aid in estimating GHG emissions from the LNG sector and its chain of operations. It is not intended to supplant guidance provided by local regulators or other climate schemes that have jurisdiction over the applicable LNG operations. The LNG sector is expected to have multiple reporting challenges due to its complexity and the fact that its operations typically cross jurisdiction lines such as national, provincial or state boundaries.

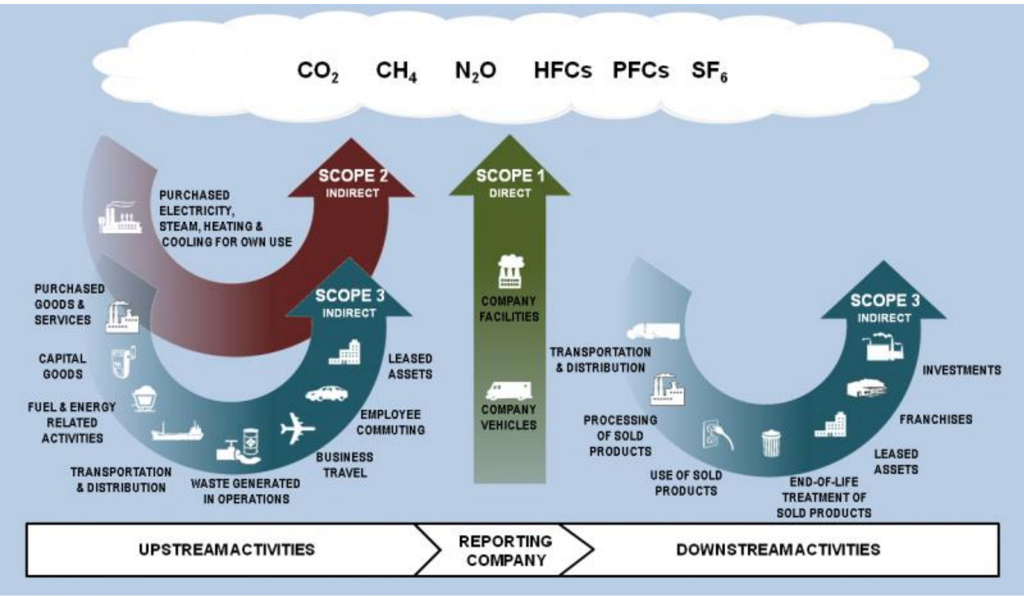
The data provided in this document serves to augment existing oil and natural gas industry method compilations by presenting data and guidance that is applicable for emitting sources within the LNG operations chain. This document is not intended to replace local requirements or other mandatory protocols for various GHG programs.

3.1 Operational GHG Emissions

In defining the scope for developing a GHG emissions inventory, companies must first determine which emission sources should be included within the selected organizational boundary for the inventory. This process is referred to as setting the operational boundaries of the GHG emissions inventory. A key step in setting the operational boundaries is the categorization of GHG emission sources as either direct or indirect. The distinction is that direct GHG emission are those that are due to sources that are either operated or under the control of the organization compiling the inventory, while indirect GHG emissions are a consequence of the activities of the reporting organization, but occur from sources owned or controlled by a third party.

Over the past decade, a global practice has emerged leading to categorizing GHG emissions into three major ’scopes’, as depicted in Figure 9 and which comprise of:

- **Direct GHG Emissions (Scope 1) -** Direct GHG emissions that occur from sources that are owned or controlled by the company. Such sources are further categorized into: stationary combustion; process/equipment venting; fugitive emissions; and operated mobile sources (vessels, aircraft, cars, trucks, construction equipment, etc.).



Source: GHG Protocol

Figure 9. Categories of Company's Operations by Scopes

- **Indirect GHG Emissions from Purchased and Consumed Energy (Scope 2**) - Indirect GHG emissions attributable to purchased electricity; purchased heat/steam; and purchased cooling water.
- **Other Indirect GHG Emissions (Scope 3)** – Indirect emissions due to emission sources that are not owned or operated by the company but are essential for conducting the company's business and are not accounted for in Scope 1 and 2.

The emission estimation methods provided in this document pertain primarily to direct emissions from operations that are part of the five stages of the LNG value chain with emphasis on operations where companies have operational control and can obtain the needed information to calculate GHG emissions.

If companies wish to account for their contribution to indirect GHG emissions, which are due to operations undertaken by others on their behalf, similar estimation methods to the ones described here may apply. If such is the case, companies ought to be cognizant of the potential of "double counting" of emissions that may be independently reported by the company's supply-chain providers. The final content of companies' emissions inventories and their extent will be dependent on applicable requirements and specifications along with the intended data use.

3.2 GHG Emission Sources

Devices and processes being used throughout the LNG operations chain consist both of equipment used in other segments of the oil and natural gas industry as well as specially designed equipment for the liquefaction, storage, loading, shipping, offloading, and revaporization of the LNG. Since there is some similarity in equipment and operating characteristics, certain emissions estimating methods provided in other industry guidance can be used in addition to the methods provided in Section 4.0 below for LNG operations.

The rate and extent of GHG emissions for the LNG sector are primarily attributable to the quality and quantity of the fuels used, thermal efficiency of the process design, feedstock throughput, "boil-off" rate, and extent of recovery of "boil-off" gases (BOG) generated due to energy input to and heat ingress into the chilled product. Therefore, emissions could also be affected by the volatility of the compounds handled, inspection/maintenance operations along with equipment design for control and containment.

3.2.1 Emission Sources Categories

Per United Nations' guidance, all non-combustion emissions, including flaring and venting (both intentional and unintentional) are defined as fugitive emissions. However, this definition is counter-intuitive and contravenes established regulatory definitions used for controlling emissions of volatile organic compounds in many countries around the world, including the U.S. Therefore, this document follows the format established by the API Compendium[7] and includes flaring emissions with combustion sources and distinguishes fugitive emissions clearly from vented emissions.

Emissions from sources in the LNG operations chain can be classified into the following main categories:

- **Combustion-related emissions -** Emissions resulting primarily from fuel fired equipment. This may include fuel use in engines or turbines that provide power to compress gases, pump liquids, or generate electricity; and for firing heaters and boilers. Combustion of gases in flares and incinerators is included with combustion-related emissions in the API Compendium but it is more routinely reported with 'vented emissions', which is more consistent with the IPCC recommended format.

- **Vented Emissions** - Designed releases of CH_4 and/or CO_2 including but not limited to process emissions where vented gas streams are not recovered, or rerouted back to the fuel gas system. It also includes operations such as blowdown from compressors or other equipment for maintenance, and direct venting of gas used to power equipment such as pneumatic controllers. According to the IPCC recommendations for national GHG inventories, this category includes also all gas flaring in addition to emergency venting that is not routed to a flare.
- **Fugitive emissions -** Emissions that occur unintentionally and could not reasonably pass through a flare or exhaust stack, chimney, vent, or other functionally-equivalent opening. This would include leaks from piping components and other equipment.
- **Transportation-related emissions -** Emissions associated with operations of a wide variety of mobile sources operated by the company including ships, barges and tank trucks, along with transfers into transmission or distribution pipelines.
- **Non-routine emissions -** Non-routine emissions associated with LNG operations are primarily a result of start-up, shut-down, or plant upset. These emission sources are generally routed to the flare system.

3.2.2 Emission Sources in the LNG Operations Chain

A descriptive list of GHG emission sources associated with each of the segments of the LNG operations-chain (as discussed in Section 2.2) is provided below, mapping them to the main source categories discussed above. The specific emitting equipment to be accounted for in each of these segments would ultimately depend on facility design. For example, some aspects of natural gas processing are hard to separate from an LNG liquefaction facility, due to integrated design and operation, as may also be the case for on-site power generation at regasification facilities.

- **Liquefaction** - Sources include primarily combustion emissions from mechanical drive turbines, power generators, or other process drivers; combustion emissions from fired heaters, flares, and other heat generation sources; emissions from the CO_2 removal process; venting from compressors used for cryogenic cooling; venting from the "cold box" where liquefaction occurs (applicable for some but not all liquefaction processes); fugitive emissions from LNG pumps and compressors; venting from LNG storage (in extreme upset conditions only); and fugitive emissions from flanges, valves, and fittings within the process. If the facility inlet is integrated with natural gas production additional GHG emission sources would have to be accounted for in the overall inventory to address such integrated operations.

- **Storage -** Sources include flaring and venting of excess BOG from storage tanks; combustion emissions and venting from compressors used to recover BOG; and fugitive emissions from compressors;
- **Loading and Unloading** - Sources include combustion emissions from power generation facilities needed to provide electricity to a ship's cargo pumps; venting when ship loading connection is broken; venting when connection to other means of conveyance such as barges or trucks are broken; and fugitive emissions from piping flanges, valves, and fittings.
- **Shipping** - Sources include venting of unconsumed and un-reliquefied BOG during voyage, combustion emissions from power generation, venting from compressors used to recover BOG, fugitive emissions from compressors, emissions from fuel combustion used for ship propulsion or for other carriers used to transport the LNG; and combustion emissions from the power plant used to power the ship's other systems, e.g. its living quarters.
- **Regasification -** Sources include fugitive emissions from flanges, valves, and fittings in the piping used within the terminal, venting emissions from LNG pumps during maintenance, flaring of BOG from storage tanks during ship unloading (if BOG rate exceeds BOG compressor capacity), emissions from fuel combustion used for the vaporization process, venting from the vaporization process during maintenance, venting from BOG compressors during maintenance, and fugitive emissions from compressors. If the facility is integrated with on-site power generation the emission sources associated with power generation would also have to be accounted for.

Mapping of these emission sources is provided in the tables below. Table 4 presents a list of stationary combustion-related emissions sources for each of the LNG operations segments.

Table 4. Mapping of Combustion Emission Sources in the LNG Operations Chain [(a)]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE[(B)]	SHIPPING	REGASIFICATION
Boilers/Heaters	Process heaters • Submerged combustion vaporizers • Glycol-water heaters	X			X
	Line heaters		X		X
	Water heaters, e.g. Submerged Combustion Vaporizers				X
Compressors	Gas Turbine driven compressors	X	X	X	X
	Engine driven compressors	X	X	X	X
Generators	IC engine generators	X	X	X	X
	Turbine generators	X	X	X	X
Flares and Incinerators *(could be included with vented sources)*	Flares	X	X		X
	Thermal oxidizers	X	X	X	X
	Catalytic oxidizers	X	X	X	X
Miscellaneous	Fire water pumps (diesel)	X		X	X
	Power generation	X	X	X	X

[(a)] This table lists sources that might be of interest for LNG operations. For most of these sources, estimation methods are already identified in the 2009 revision of the API compendium. Specific methods and Emission Factors applicable to LNG sources will be provided in the sections that follow.

[(b)] Storage includes sources from Loading and Unloading of LNG.

The GHG emissions sources associated with LNG operations for vented and fugitive emissions are listed in Tables 5 and 6. This is followed by a list of transportation related emission sources in Table 7.

Table 5. Mapping of Vented Emission Sources in the LNG Operations Chain [(a)]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE[(B)]	SHIPPING	REGASIFICATION
Pumps & Compressors	Compressor venting and blowdowns	X	X	X	X
	Pump venting and blowdowns	X	X	X	X
	Compressor starts	X	X	X	X
Process Vents	CH_4 from processing	X			X
	CO_2 from processing	X			
	Cryogenic Exchangers	X			X
	Vaporization				X
Storage Tanks	BOG venting	X	X	X	X
	Vapor recovery units	X	X	X	X
Vessel docking	Coupling connectors		X	X	
Safety	Pressure Relief Valves (PRVs)	X	X	X	X
	Emergency vents	X	X	X	X
Miscellaneous Vents	Gas sampling and analysis	X	X		X

[(a)] This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

- GHG emissions from these sources consist primarily of CH_4,
- Venting of CO_2 will depend on its content in the feed gas and the acid removal process utilized and whether it is vented or injected into a disposal well
- If gas flaring and incineration is reported with the vented emissions – in accordance with IPCC guidance - these emissions will consist primarily of CO_2.

[(b)] Storage includes sources from Loading and Unloading of LNG.

Table 6. Mapping of Fugitive Emission Sources in the LNG Operations Chain [a]

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE (B)	SHIPPING	REGASIFICATION
Compressors	Rod packing	X	X	X	X
	Dry Seals	X	X	X	X
Pumps	Mechanical seals	X			
	Barrier fluid seals	X			
Valves	Gas service	X	X	X	X
	Light liquid service	X	X	X	X
	Heavy liquid service			X	
Pressure Relief	Pressure relief valves	X	X	X	X
	Misc. devices	X	X	X	X
Air Separation Units	Flanges	X		X	X
Refrigeration and A/C Systems	Flanges	X	X	X	X
Instrumentation	Meter connectors	X	X	X	X
	M&R Stations		X		X
Spills	Startup & Shutdown	X	X	X	X
	Accidental	X	X	X	X

[a] This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

– GHG emissions from these sources consist primarily of CH_4,

[b] Storage includes sources from Loading and Unloading of LNG.

Table 7. Mapping of Transportation Related Sources in the LNG Operations Chain (a)

SOURCE CATEGORY	POTENTIAL EMISSION SOURCES	LIQUEFACTION	STORAGE(B)	SHIPPING	REGASIFICATION
LNG carriers	Propulsion systems, On-board power plants			X	
Rescue Boats	Propulsion systems		X	X	X
Coast guard escort	Propulsion systems		X	X	X
Support Vessels	Propulsion systems		X	X	X
Helicopters	Propulsion systems			X	X
Tugs	Propulsion systems		X	X	X
Bathymetric survey boats	Propulsion systems		X	X	
Dredging equipment	Propulsion systems		X	X	

(a) This table follows the source categorization used in the API Compendium (Version 3.0, August 2009), which provides guidance and calculation methods for many similar sources.

- GHG emissions from these sources consist primarily of CO_2,
- Limited emissions of CH_4 and N_2O for different engines and catalysts.

(b) Storage includes sources from Loading and Unloading of LNG.

The equipment classification in Tables 4 through 7 are similar to the ones used in the API Compendium[13] with the sources listed cross-referenced to the specific segments within the LNG operations chain. Based on local requirements companies may include gas flaring and incineration emissions with vented emissions, which is consistent with IPCC guidance.

3.2.3 GHGs Emitted from LNG Operations

The most commonly recognized and globally reported GHGs are those covered by the Kyoto Protocol:

(a) Carbon Dioxide, CO_2
(b) Methane, CH_4
(c) Nitrous Oxide, N_2O
(d) Hydrofluorocarbons, HFCs
(e) Perfluorocarbons, PFCs
(f) Sulfur Hexafluoride, SF_6

Notably, GHG emissions from the LNG segments are likely to consist primarily of CO_2 CH_4 and N_2O. The other listed GHGs would potentially be contributing a very minor amount. The main sources for the GHG emissions are:

- **Carbon Dioxide (CO_2) -** from process CO_2 in addition to combustion of fuels in engines, boilers, heaters, turbines and other and compressor drivers;
- **Methane (CH_4) –** from venting and equipment leaks in all segments of the LNG operations chain;
- **Nitrous Oxide (N_2O)** - from combustion devices, of primary importance for stationary engines including gas turbines and combustion of non-gaseous fuels;
- **Other GHGs** – these typically include SF_6, HFCs and PFCs as required by international GHG reporting frameworks, and should be included if they are germane to company's LNG operations.

Quantification of respective GHG emissions from each of the sources within the source categories in each of the LNG operations segments, as listed in Tables 4, 5, and 6, can be complicated by the variability of site operations and the potential lack of information about the quantity and quality of the fuels consumed especially since some of the fuels combusted are self-generated either during processing or as 'boil off' during storage and shipping. In most cases, they are rerouted to combustion devices used in the facilities, and in rare cases, they are flared or vented as a safety precaution. Such fuels tend to be variable in composition which makes it hard to characterize their GHG emissions using average emission factors that are based on an assumed average composition for the combusted fuels.

Similar to other sectors of the oil and natural gas industry operations, CO_2 emissions from combustion devices are typically the largest contributors to total GHG emissions from the LNG operations-chain. These are followed by methane emissions, which although may be smaller in absolute terms, are important due to methane's higher Global Warming Potential (GWP). Other very high GWP GHGs such as SF_6, hydrofluorocarbons (HFCs) or perflurohydrocarbons (PFCs) can also be important in special instances if their use is part of the facility design.

Global warming potentials are a comparative index of cumulative radiative forcing of targeted GHGs as compared to CO_2, over a specified time horizon. The 100-year time horizon is most commonly used for national GHG emission inventories and for corporate GHG reporting.

Appendix D provides GWPs from both the IPCC Second Assessment Report (SAR), which is currently used for national GHG inventories and is recommended for corporate reporting. The recalculated GWPs provided in the IPCC Fourth Assessment Report (4AR) are shown for comparison and for use by local or regional programs that mandate their use. The reference to HFCs and PFCs denotes potential emissions from any of a family of compounds, as presented in Appendix D. The Appendix also includes recommended GWPs for selected commercial blends of commonly used refrigeration liquids.

In order to enable comparison of the relative impact of emissions from different GHGs, and to ultimately sum them, an international metric measure termed "carbon dioxide equivalents" (CO_2e) is used. The CO_2e for a gas is derived by multiplying the metric tons of the emitted gas by its associated GWP, and then summed over all the GHGs included in the summary.

$$\textbf{EMISSIONS}\ (\mathrm{MMTCO_2e}) = \sum_i (\mathrm{MMT\ GHG_i}) * (\mathrm{GWP_i})$$

Where,
GHG_i is the applicable mass of the i^{th} GHG, and
GWPi is its corresponding 100-years' time horizon GWP

4.0 EMISSIONS ESTIMATION METHODS

As discussed in Section 3.0 GHG quantification methods selected will depend on data availability and the intended use of the data. A typical method selection hierarchy (which could also be associated with increased uncertainty) consists of direct measurements including mass balance approaches; emission factors including those provided by equipment manufacturers; and engineering calculations that are based on process knowledge.

It practice, overall plant GHG emissions would be estimated using a combination of the methodologies briefly listed below:

- **Calculations using Emission Factors -** For calculating CO_2 combustion emissions when using commercial fuels, a valid approach is to use published emission factors that are based on known fuels properties including their carbon content and heating values. This Emission Factor approach requires valid information about the amount of fuel used. Such information could be obtained from on-site measurements or from a third-party meter of the fuel supplier.

  For calculating CH_4 non-combustion emissions one would primarily use published or manufacturers' emission factors based on equipment type and its expected leakage rate. This would be especially suitable for estimating emissions from pneumatic controllers using natural gas as the controller's gas source (not common in LNG operations), or for assessing fugitive emissions from piping component leaks.

- **Measurements, Sampling and Analysis over a Range of Conditions -** Calculating CO_2 emissions from stationary combustion sources can be performed with a high degree of certainty when using site specific fuel consumption data along with its carbon content or heating value, especially for operations that use fuels with varied characteristics. This is a highly reliable method for distinct emission sources that contribute substantially to overall emissions, though it might not be practical for all smaller combustion sources.

  For CH_4 emissions from non-combustion sources vented emissions could be calculated based on periodic vent volume and duration measurements or knowledge of inlet and outlet concentrations, and total flow rate, for calculating a total material mass balance. Such approaches would be useful for large process or blow-down vents that are key contributors to facility emissions but would generally not be practical for many small sources.

- **Engineering calculations -** For both CO_2 and CH_4 emissions, engineering calculation methods based on process knowledge could be reliable for specific emission sources. However many process simulations may require detailed input data which might not be readily available.

  Engineering calculation could be most useful for estimating emergency venting and flaring emissions, based on process design and atmospheric release settings for emergency relief devices. They could also inform the calculations of CH_4 emissions from storage tanks ‘cool down’ at terminals and on-board ships. For example, engineering specification can be used to estimate the large amount of BOG (mainly CH_4) generation as cold LNG is sprayed into a warm ship’s storage tanks.

As discussed above, although measurements could be an essential component of obtaining robust emissions data, they are expected to be applied only for sources that have a significant contribution to the overall inventory. Direct emissions measurements are only relevant for facilities with existing monitoring systems that were installed either for process control or to meet regulatory requirements.

Regardless of the approach employed, it is essential that entities report consistently over time to ensure the comparability of temporal emissions data and to allow for trends analysis. Emission inventories are advised to list periodic changes made in order to have it documented and to ensure data transparency.

The methods described here represent extracts from the API Compendium yet do not reproduce all of the methods provided therein[7]. The user is referred to the API Compendium for a more expanded discussion of methodology and other technical considerations, especially when LNG operations are integrated with other sectors of the oil and natural gas industry.

4.1 Stationary Combustion Emissions Estimation

This section is designed to be complementary to Section 4.0 of the API Compendium[7] and it is intended to augment that methodology as applicable to combustion emissions for the LNG operations chain. The approaches presented here are applicable to a wide range of geographically diverse LNG operations representing a range of fuel heating values, carbon content and ultimate applications.

Carbon dioxide (CO_2) and water (H_2O) are produced and/or emitted as a result of combustion of hydrocarbon fuels. The combustion stoichiometry follows the general formula below, assuming complete combustion of a generic hydrocarbon (with or without embedded oxygen):

$$\mathrm{C_xH_yO_z} + \left(x + \frac{y}{4} - \frac{z}{2}\right)\mathrm{O_2} \rightarrow (\mathrm{x})\,\mathrm{CO_2} + \left(\frac{\mathrm{y}}{2}\right)\mathrm{H_2O}$$

Where,
x represents the number of carbon atoms in the combusted molecule
y represents the number of hydrogen atoms in the combusted molecule
z represents the number of oxygen atoms (if any) in the combusted molecule

During the combustion process, nearly all of the fuel carbon is converted to CO_2, and this conversion is relatively independent of the fuel or firing configuration. Incomplete combustion of the fuel may result in a portion of that fuel remaining in the exhaust, along with generation of other products of incomplete combustion such as carbon monoxide (CO). The presence of nitrogen in the combustion air, especially when catalysts are not used to limit NO_x emissions, could lead to the emission of small quantities of nitrous oxide N_2O. The methodology described below is somewhat conservative since it is assumes that all the carbon in the fuel is transformed into CO_2 while at the same time it allows for calculating emissions of some minor trace constituents due to incomplete combustion.

Typically the conditions that favor formation of CH_4 emissions (assuming methane is the primary hydrocarbon in the fuel used) may also lead to CO, N_2O, and NO_x formation, and these emissions tend to vary with the type of fuel and firing configuration. Overall, CH_4, CO, N_2O, and NO_x emissions from combustion sources are many times lower than CO_2 emissions.

Options for calculating CO_2 emissions from stationary combustion devices:

(a) Using an emission factor that is multiplied by the annual fuel use, with a default heating value for that fuel; or

(b) Using an emission factor that is based on average carbon content for a given type of fuel along with a measured or estimated annual fuel use; or

(c) Using measured fuel use with periodic measurements of the carbon content of that fuel.

Options for calculating CH_4 emissions from stationary combustion units:

(a) Using an emission factor that is based on annual fuel use and heating value of fuel;

(b) Using an applicable equipment/technology-based emission factors.

4.1.1 CO_2 Emissions Estimation using Emission Factors

Emissions for a particular source or device are calculated as the product of the applicable emission factor (EF) and the activity factor (AF). Emissions for a particular facility or operation are the sum of these individual products:

$$\textbf{Emissions} = \sum \mathbf{AF_i * EF_i}$$

Where,

Emissions is the estimated emissions for all sources

EF_i represents the emission factor for source i

AF_i represents the activity factor for source i (e.g., source heat load, or fuel consumption per year)

Appendix E provides copies of Table 4.3 and Table 4.5 from the API Compendium (Version 3.0, August 2009). These tables list emission factors for estimating CO_2 and CH_4/N_2O, respectively, for common industry fuels. The data are presented both in US and SI units for ease of application globally. The emission factors used for these calculations could either be those provided in the tables in Appendix E or by other applicable reporting programs.

Each company or project may also develop specific emissions factors based on knowledge of the BOG and LNG hydrocarbon species profiles and their properties. Fuel properties in terms of heating values and carbon content are provided in Table 3-8 of the API Compendium (Version 3.0, August 2009)[7] for commercial fuels. As stated above, the convention used to calculate CO_2 emissions are based on the assumption of full oxidation (i.e. conversion of 100% of the fuel carbon content to CO_2).

Other important considerations when estimating emissions using emission factors include:

- **Standard Gas Conditions -** When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are 14.696 psia and 60°F (101.325 kPa and 15.6°C). At standard conditions one pound-mole has a volume of 379.3 cubic feet. Similarly, one kg-mole occupies 23.685 m^3 at standard conditions.

- **Heating Value Specifications -** When converting between fuel volume and energy, higher heating value (HHV) or gross calorific value is the preferred North America convention. However, lower heating value (LHV) or net calorific value can also be used, and the conversion convention adopted internationally[17] is that LHVs are 10% lower than HHVs for gaseous fuels. Care should be taken to use the heating value that is consistent with the way the emission factor is expressed.
- **Units -** Calculations may be performed in either English or SI units. Users should take care to use a consistent set of units throughout the emissions estimation process in order to ensure that the results are expressed in metric tons (or 'tonnes'). Appendix B of this document summarizes unit conversions that are applicable for LNG operations. Additional guidance on conversions that are generally applicable for emission estimation is available in Section 3.6 of the API Compendium (version 3.0, August 2009)[7], which provides a tabulation of unit conversions useful for such calculations.

The API Compendium documents the carbon contents for natural gas and similar gaseous fuels in different heating value ranges. In the United States, pipeline quality natural gas is classified as having an HHV greater than 970 Btu/scf but less than 1,100 Btu/scf[18], although many pipelines in the U.S. have broader specifications than these heating value ranges. Globally, LNG streams consist of mixtures of hydrocarbons that contain different percentages of hydrocarbon species as shown by the compositional profiles of LNG from different origins presented earlier in Table 1.

Table 8 presents carbon content and emission factors data for use when estimating CO_2 emissions from the combustion of LNG fuels based on information about their higher heating values ranges. LNG streams with higher heating values tend to have a higher content of higher molecular weight hydrocarbons which affects the carbon content of the gas and its emissions per unit of energy consumed.

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[17] IPCC, *2006 Guidance for National GHG Emission Inventories*, Volume 2, Chapter 2, Table 2.6, 2007

[18] Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Annex A, Table A-38, April 15, 2009.

Table 8. Natural Gas Carbon Contents and Emission Factors for Different Higher Heating Value Ranges [(a)]

HIGHER HEATING VALUES	Carbon Content [a] g C/10^3 Btu	CO_2 EMISSION FACTOR tonnes $CO_2/10^6$ Btu	tonnes CO_2/TJ
U.S. Average [(b)]	14.47	0.05306	50.29
1,000 to 1,025 Btu/scf	14.43	0.05291	50.15
1,025 to 1,050 Btu/scf	14.47	0.05306	50.29
1,050 to 1,075 Btu/scf	14.58	0.05346	50.67
1,075 to 1,100 Btu/scf	14.65	0.05372	50.92
1,100 to 1,125 Btu/scf	15.07	0.05526	52.38
1,125 to 1,150 Btu/scf	15.09	0.05533	52.44
1,150 to 1,175 Btu/scf	15.15	0.05555	52.65
1,175 to 1,200 Btu/scf	15.27	0.05599	53.07
1,200 to 1,225 Btu/scf	15.38	0.05639	53.45
1,225 to 1,250 Btu/scf	15.52	0.05691	53.91
Greater than 1,250 Btu/scf	16.33	0.05988	56.76

(a) Based on data from worldwide LNG operations including U.S. produced gas. The data is provided on an HHV (higher heating value) basis.
(b) The gas compositions included in this analysis does not include H_2.

4.1.2 CO_2 Emissions Estimation using Fuel Composition

This section discusses estimating CO_2 emissions from information about fuel properties and its quantity. This approach is based on a material balance in which the metered, or estimated, fuel consumption data is used together with information about fuel composition to derive CO_2 emissions.

LNG streams are mixtures of different hydrocarbons. The carbon content of a fuel mixture is a weighted average of the individual component carbon contents. This is determined by first calculating the weight percent carbon of each of the fuel components, which is accomplished by multiplying the molecular weight of carbon by the number of moles of carbon and dividing by the molecular weight of the compound.

Table 9 below lists the carbon content, molecular weights and higher heating values (HHV) for species that are typical components of LNG streams, and which are the building blocks for deriving emissions based on LNG composition. The data are provided both in U.S. and international units at standard conditions of 60°F (15.6°C) and 1 atmosphere.

Table 9. Carbon Content and Higher Heating Values for LNG Constituents [(a)]

Compound	Moles Carbon per Mole	Carbon Content (Wt. %)	MW	HHV (Btu/scf)	HHV MJ/standard-m^3
Nitrogen	0	0.0%	28.01	0	0
Carbon Dioxide - CO_2	1	27.3%	44	0	0
Methane - CH_4	1	74.8%	16.04	1,010	37.620
Ethane - C_2H6	2	79.8%	30.07	1,770	65.904
Propane - C_3H_8	3	81.6%	44.1	2,516	93.799
Iso-Butane - i-C_4H_{10}	4	82.6%	58.12	3,252	121.17
n-Butane - n-C_4H_{10}	4	82.6%	58.12	3,262	121.54
Iso-Pentane - i-C_5H_{12}	5	83.2%	72.15	4,001	149.07
n-Pentane - n-C_5H_{12}	5	83.2%	72.15	4,009	149.39
n-Hexane - n-C_6H_{14}	6	83.5%	86.18	4,756	177.21

(a) Higher Heating Value at 60°F, 1 atm. Data taken from *API MPMS* Chapter 14, Section 5, Table 1; Gas Processors Suppliers Association *Engineering Data Book*, Figure 23-2,; Perry's *Chemical Engineers' Handbook*, Table 3-207..

The following steps are used to perform these calculations:

- **(a)** Speciation for the mixture (for gaseous and light liquid fuels)using gas chromatography to obtain the compositional analysis for each fuel component in mole percent;
- **(b)** Calculation of the weight percent of the hydrocarbon constituents for the mixture by multiplying the mole percent of each component by its molecular weight;
- **(c)** If complete speciation of the mixture is not available, an average molecular weight, $MW_{Mixture}$, may be estimated from species profiles tables for similar LNG streams.

Table 10 provides examples of a range of LNG streams with their species profiles, which were used to derive the $MW_{Mixture}$, fuel weight percent C, mixture HHV and conversion factors (in different units) for calculating CO_2 emissions from the combustion of these LNGs.

One of the features of LNG operations is that the carbon content of the combusted fuel fractions may vary throughout the operations chain - from processing to shipping and on to regasification. During liquefaction, the fuel used to fire the combustion devices typically has lower carbon content and heating value than the feed stream used for producing the LNG, since it consists mostly of lower molecular weight boil-off gas and most of the inlet gas stream's inert nitrogen.

The carbon content and heating value of the finished LNG differs from the feed gas due to removal of excess trace contaminants, e.g. CO_2, H_2S, and nitrogen and higher molecular weight hydrocarbons. During LNG shipping, if BOG is used as ship's fuel, the carbon content of the fuel that is used for propulsion and compression consists also of the lighter hydrocarbon fraction that is captured as boil-off gas (BOG), and is enriched in nitrogen due to nitrogen's low boiling point relative to methane, making its composition somewhat different from that of the LNG being transported. For regasification operations, the fuel used would again have somewhat different carbon content due to removal of the BOG during the voyage.

Table 10. Compositions and Emission Factors for Select LNG Streams (a)

LNG COMPOUNDS	CHEMICAL FORMULA	EXAMPLES OF LNG STREAMS COMPOSITION (WT %)					
		(A)	(B)	(C)	(D)	(E)	(F)
Nitrogen	N_2	0.05%	0.43%	0.10%	0.02%	0.31%	ND
Methane	CH_4	92.07%	84.55%	91.43%	92.63%	91.02%	99.80%
Ethane	C_2H_6	6.89%	10.93%	7.42%	6.89%	7.53%	0.10%
Propane	C_3H_8	0.97%	3.21%	0.87%	0.35%	0.95%	ND
iso-Butane	i-C_4H_{10}	0.00%	0.47%	0.08%	0.02%	0.08%	ND
n-Butane	n-C_4H_{10}	0.00%	0.38%	0.09%	0.03%	0.08%	ND
iso-Pentane	i-C_5H_{12}	0.02%	0.02%	0.01%	0.02%	0.01%	ND
n-Pentane	n-C_5H_{12}	0.00%	0.00%	0.01%	0.04%	0.01%	ND
	TOTAL	100.00%	99.99%	100.00%	100.00%	100.00%	99.90%
Fuel mixture MW		17.30	18.89	17.42	17.16	17.48	16.04
Fuel weight % C		75.53%	75.93%	75.54%	75.50%	75.31%	74.82%
Heating Values							
HHV (Btu/scf)		1,077.40	1,156.70	1,082.90	1,070.60	1,082.80	1,009.80
HHV (MJ/std-m^3)		40.13	43.09	40.35	39.89	40.35	37.62
LHV (TJ/Gg)		48.75	52.35	49.01	48.45	49.01	45.70
Emission Factors							
Lbs CO_2 /10^6 Btu		117.25	119.89	117.46	117.01	117.54	114.88
tonnes CO_2 /10^6 Btu		0.0532	0.0544	0.0533	0.0531	0.0533	0.0521
tonnes CO_2 / TJ		50.41	51.54	50.50	50.31	50.53	49.39
Tg C / QBtu		14.50	14.83	14.53	14.48	14.54	14.21

(a) Examples consist of six LNG streams and are based on confidential data

(b)) Units: MJ = 10^6 Joules; TJ = 10^{12} Joules; Gg = 10^9 grams; TG = 10^{12} grams = million tonnes; QBtu = 10^{15} Btu

Due to the strict dependence and tight correlation between the CO_2 emissions factors and the heating values of the constituents comprising the LNG product, it is possible to derive empirical relations to represent this correlation. These correlations were derived both for the North America convention of specifying fuels in terms of HHV and energy throughput in terms of

Btu/scf (Figures 10) and also in Standard International (SI) units where fuel heating value is specified in terms of LHV and energy throughput in terms of units of TJ/Gg (Figure 11).

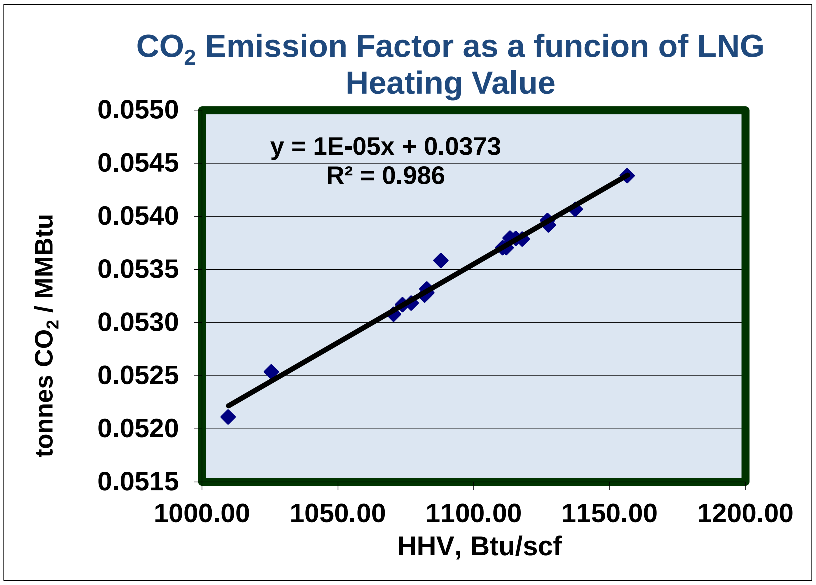

Figure 10. CO_2 Emission Factors (EF) as a Function of LNG Higher Heating Values (HHV)
[EF ($TCO_2/10^6$ Btu) = $1*10^{-5}$ HHV(Btu/Scf) + 0.0373]

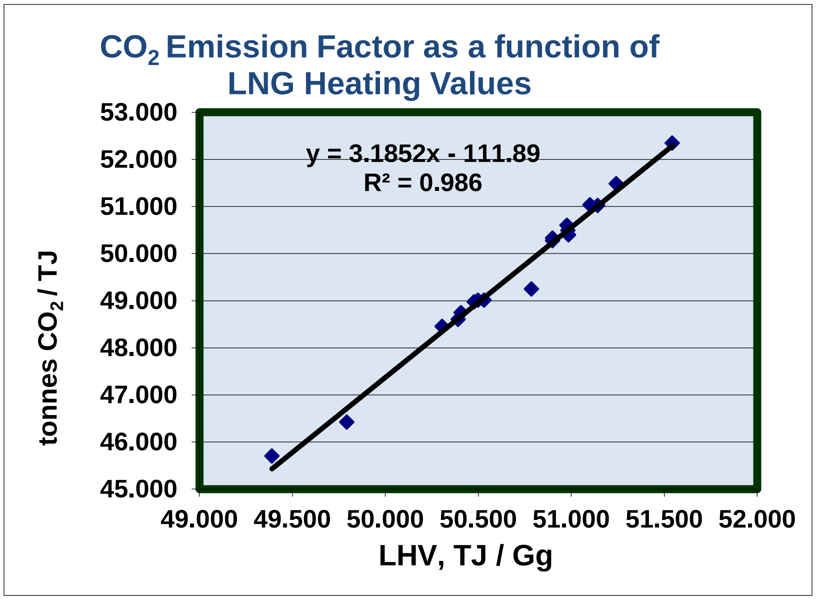

Figure 11. CO_2 Emission Factors (EF) as a Function of LNG Lower Heating Values (LHV)
[EF (TCO_2 /TJ) = 3.185 LHV(TJ/Gg) – 111.9]

The correlation equations provided above may be used for deriving site-specific emission factors, on either an HHV or an LHV basis respectively, for estimating CO_2 emissions from the combustion of the produced LNG. This approach will allow companies to tailor their calculations to their specific circumstances based on the availability of data on the heating values of the LNG fractions produced, transported, stored and used. For example, for LNG production, the higher the LNG product HHV, the **less** energy it takes to liquefy it, and therefore, fuel consumption and CO_2 emissions are reduced relative to a lower HHV LNG product, which is exactly the opposite of what happens when combusting a higher HHV LNG product. .

Using actual fuel consumption data in conjunction with its composition is the preferred method for estimating combustion emissions.

When metering all of the streams to measure fuel consumption is not practical, alternative approaches are needed for engineering estimates of fuel consumption. Equipment fuel consumption rates could be estimated by the following:

(a) Equipment rating (horsepower) using actual horsepower is the most accurate approach. Manufacturer or maximum horsepower rating and load can be used to estimate fuel usage, recognizing that these may overestimate emissions.

(b) Operating hours can be based on recorded monthly operating hours from which yearly operating hours can be calculated. Alternatively, an estimator for total operating hours may be percent run time or downtime hours;

(c) Equipment thermal efficiency allows the estimation of required heat input per energy output, with conversion factors that are usually available from equipment vendors. A list of conversion factors that may be used for this calculations are available in Table 4-2 of the API Compendium (version 3.0, August 2009)[7].

4.1.3 Emissions from Flares

Flares are used in all segments of the oil and natural gas industry to manage the disposal of unrecoverable gas via combustion of hydrocarbon products from routine operations, processing, upsets, or emergencies. A wide variety of flare types are used in the industry, ranging from small open-ended pipes at production wellheads, to large horizontal or vertical flares with pilots and air- or steam-assist, such as in processing plants. Emissions of CO_2, N_2O, and NO_x are formed as products of combustion, and CH_4 emissions may result from incomplete combustion or from time periods where there is no flame at the flare tip due to operational problems.

Flares have been documented to achieve 98% combustion efficiency, and where no site-specific data is available, the IPCC[19] recommends using this destruction efficiency in conjunction with "generic" gas composition at gas processing plants to calculate GHG mass emission rates for flares.

Table 11 presents emission factors that are applicable to estimate flaring emissions for sweet and sour gas processing, and could also be applicable to LNG processing and liquefaction plants. For classifying gas streams into sweet and sour, the most common specification is based on the hydrogen sulfide content of 0.25 grain H_2S per 100 cubic feet of gas, or approximately 4 ppmv. The data in Table 11 follows the IPCC guidance and recommends also that different sets of emission factors be applied to operations in developed countries vs. other countries (such as developing countries and countries with economies in transition) to reflect different levels of flaring based on presumed local practices.

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[19] IPCC. 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions), Table 4.2.4, 2006 Revised November 2008.

Table 11. GHG Emission Factors for Gas Flares in Gas Processing and Liquefaction (a)

Flare Source	Units (b)	CO_2	CH_4	N_2O
Developed Countries				
Sweet Gas Processing (H_2S < 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$1.8*10^{-3}$	$1.2*10^{-6}$	$2.5*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	$5.1*10^{-2}$	$3.4*10^{-5}$	$7.1*10^{-7}$
Sour Gas Processing (H_2S > 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$3.6*10^{-3}$	$2.4*10^{-6}$	$5.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	0.10	$6.8*10^{-5}$	$1.5*10^{-6}$
Other Countries				
Sweet Gas Processing (H_2S < 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$1.8*10^{-3}$ – $2.5*10^{-3}$	$1.2*10^{-6}$ – $1.6*10^{-6}$	$2.5*10^{-8}$ – $3.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	$5.1*10^{-2}$ – $7.1*10^{-2}$	$3.4*10^{-5}$ – $4.5*10^{-5}$	$7.1*10^{-7}$ – $9.6*10^{-7}$
Sour Gas Processing (H_2S > 4ppm)	$Gg/10^6\ m^3$ (raw gas feed)	$3.6*10^{-3}$ – $4.9*10^{-3}$	$2.4*10^{-6}$ – $3.3*10^{-6}$	$5.4*10^{-8}$ – $7.4*10^{-8}$
	tonnes/ 10^6 scf (raw gas feed)	0.10 – 0.14	$6.8*10^{-5}$ – $9.3*10^{-5}$	$1.5*10^{-6}$ – $2.1*10^{-6}$

(a) IPCC, 2006 IPCC Guidelines (footnote 19)
(b) Extracted from Tables 14-11 and 14-12 of the 2009 API Compendium which converted the metric units presented by the IPCC to English Units
(c) Per IPCC designation this refers to developing countries or countries with economies in transition

4.2 Vented Emissions

Vented emissions are releases to the atmosphere as a result of the process or equipment design or operational practices. Vented emissions may come from a variety of non-fired stacks and vents, which tend to be very specific to the type of operation. A broader discussion of emission sources and estimation methods that apply in general to vented emission sources in the oil and natural gas industry are presented in Section 5.0 of the API Compendium (Version 3.0, August 2009). However, for LNG operations the primary design characteristic is that all BOG is captured and returned to storage tanks, consumed as fuel, or fed into a boil-off gas recondenser. As a consequence routine continuous venting from operations is minimized, as discussed in the subsections below, which provide a brief recap of some of the key vented sources that are applicable to LNG operations.

4.2.1 Gas Treatment Processes

To optimize effectiveness and efficiency of developing an emissions inventory, operators may choose to use a mix of estimation approaches relying on methods presented here, additional methods that are available in the API Compendium or specific company information that is available for a particular operation. Whatever the method selected, it is important to document the specific method used for each vent source, and to ensure consistency in the application of methods among similar sources for a given inventory period.

(i) Dehydration Emissions

These include emissions attributable to glycol dehydrators, glycol pumps, solid bed desiccant dehydrators and other dehydration alternatives. Glycol dehydrators are used to remove water from gas streams by contacting the gas with a liquid glycol stream in an absorber. The liquid glycol absorbs the water from the gas stream, and the water is driven from the glycol by heating the glycol in the reboiler (or regenerator). A small amount of CH_4 is absorbed by the glycol; most of the absorbed methane is removed from the glycol upstream of the regenerator in a flash drum (common to all glycol units) and used as fuel in the glycol reboiler. A much smaller proportion is driven off to the atmosphere in the glycol regeneration step. Methane emissions from uncontrolled glycol dehydration units occur because the CH_4 that is not removed from the glycol stream in the upstream flash drum passes directly through the regenerator and is vented to the atmosphere. Additional methane emissions can occur if stripping gas is used to reduce the residual water content of the regenerated glycol.

Combustion emissions from the glycol reboiler are responsible for most of the CO_2 emissions, and those are accounted for separately using one of the combustion methods discussed in Section 4.1 above. Similarly, if the dehydration vents are routed to a flare, these emissions should be estimated separately using applicable techniques.

Dehydration within natural gas liquefaction plants is generally performed via solid bed desiccant systems (molecular sieve). These systems typically have lower CH_4 (and CO_2) emissions than glycol-based systems. Molecular sieves remove water from natural gas by surface adsorption. Molecular sieve units use granules of a porous material comprised primarily of alumina and silica. Wet gas is passed over the granules, which are contained inside a vertical pressure vessel. Water contained in the gas is adsorbed onto the surface of the desiccant materials. Once loaded, i.e. saturated with water, the beds are regenerated by passing hot gas through the bed of granules to drive the water off the surface of the granules. GHG emissions are limited by cooling the regeneration gas to condense the desorbed water, separating the condensed water from the regeneration gas, and returned the regeneration gas to the process. CO_2 emissions from the molecular sieve regeneration process are typically minimized by using a waste heat source, e.g. gas turbine exhaust, to heat the regeneration gas.

Estimating emissions from each glycol or solid bed desiccant dehydrator will require the following data for the period of interest:

- **(a)** Glycol dehydrator feed natural gas flow rate in 10^6 scf;
- **(b)** Glycol dehydrator absorbent circulation pump type;
- **(c)** Whether stripper gas is used in glycol dehydrator;
- **(d)** Whether a flash tank separator is used in glycol dehydrator;
- **(e)** Total time the glycol dehydrator is operating in hours;
- **(f)** Type of absorbent used;
- **(g)** Temperature (degrees Fahrenheit) and pressure (psig) of the wet natural gas;
- **(h)** Concentration of CH_4 and CO_2 in wet natural gas;
- **(i)** Efficiency of vent gas controls used, if any.

A more detailed description of the emission estimation methods for glycol dehydrators, glycol pumps, solid bed desiccant dehydrators or alternative dehydrators are provided in Section 5.1.1, 5.1.2, 5.1.3, and 5.1.4, respectively, in the API Compendium (Version 3.0, August 2009)[7].

(ii) Acid Gas Removal/Sulfur Recovery Units

Natural gas (which contains H_2S and CO_2), must be treated to reduce their concentration to a level that allows for continuous LNG production and meets LNG product specifications, typically less than 50 ppmv for CO_2 and 4 ppmv for H_2S. Acid Gas Removal (AGR) units remove H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). AGR units have similar equipment to those in glycol dehydrator units (an absorber, liquid circulation pump, and a reboiler to regenerate the absorber liquid), although the solvent regeneration system in an AGR generally employs additional equipment relative to the regeneration system in a glycol unit.

Sulfur Recovery Units (SRUs) can also be used to recover elemental sulfur from H_2S and other organic sulfur species, e.g. mercaptans. The most commonly used sulfur recovery process is the Claus process, in which the H_2S undergoes thermal and catalytic oxidation processes, both of which form elemental sulfur through the conversion of H_2S to sulfur and water. During the thermal oxidation process, H_2S is partially combusted by intentionally providing insufficient air for complete combustion. In so doing, only some of the H_2S is converted into sulfur, water, and SO_2. The SO_2 is then consumed in the catalytic process steps downstream of the thermal oxidation step (typically multiple reactor beds in series), reacting with remaining H_2S to form sulfur and water. A tail gas treating unit is typically used with Claus units to maximize total sulfur recovery. It does so by converting all non-H_2S sulfur species back into H_2S, then using another amine unit to capture that H_2S and recycle it back to the inlet of the Claus unit.

If hydrocarbons are present in the H_2S-rich stream feeding the Claus unit, those hydrocarbons are combusted in the thermal oxidation step, producing incremental CO_2 emissions. CO_2 present in the feed to the Claus unit is an inert that does not participate appreciably in the Claus reaction.

Many LNG facilities vent CO_2 removed from the feed gas to the atmosphere; depending on the feed gas concentration of CO_2, this can be a very significant contributor to total facility GHG emissions. In some LNG plants, the CO_2-rich acid gas stream, which can include appreciable quantities of H_2S, is sequestered using compressors to inject the gas into a disposal well.

When there is only trace quantities of H_2S in the feed gas to an LNG facility, any H_2S or other sulfur species removed from the feed gas in the AGR unit is generally either combusted by routing it to an incinerator, or sequestered in a disposal well.

For each acid gas removal unit the preferred emissions estimation approach relies on a mass balance that is based on the following data:

- **(a)** Throughput of the acid gas removal unit using either a meter or engineering estimate, in 10^6 scf;

(b) Average volumetric fraction of CO_2 content of the natural gas into and out of the acid gas removal unit.

A more detailed description of the emission estimation methods applicable for acid gas removal or sulfur recovery units are provided in Section 5.1.5 in the API Compendium (Version 3.0, August 2009). Use of Acid Gas Injection should be accounted for by subtracting those injected volumes from the calculation.

(iii) Other Generic Process Vents

These vents represent a generic class of process vents through which gas may be vented, or released, without combustion. As a result, these emission sources are more likely to contain CH_4 than CO_2. These emission sources may include small, miscellaneous vents that occur on an intermittent basis, or may encompass an overall process vent. Normally all but small vented gas streams are routed to a flare system and would be included in the combustion emissions.

Due to the wide variability of sources that could be considered, there are no emission factors or default values for estimating CH_4 and/or CO_2 emissions. A general material balance approach is required, based on source-specific measurements or estimates of the vent rate and concentrations.

For estimating emissions from such vents one has to assess the following during the period of interest for developing an emissions inventory:

(a) Is the venting continuous or periodic?
(b) Rate of continuous venting or duration and number of periodic venting;
(c) Unique physical volumes that are characteristic for each event (or categories of events);
(d) Average CO_2 and CH_4 content of each physical volume vented (or categories of such events);
(e) Total CO_2 and CH_4 vented associated with these events expressed in terms of mass CO_2e.

A more detailed description of emission estimation methods from such non-combustion vents is provided in Section 5.3 of the API Compendium (Version 3.0, August 2009).

4.2.2 Compression, Storage, Loading and Unloading

Throughout the LNG operations chain, there are nominal methane emissions due to the liquefaction and revaporization of natural gas. LNG being a cryogenic liquid requires maintenance of a thermodynamic equilibrium near its boiling point. For example, for LNG storage tanks, BOG may be either flared or (less commonly) vented, if the vapor generation rate exceeds BOG compressor(s) or reliquefaction unit capacity. Similarly, during LNG loading or unloading, compression is required to capture BOG which is either returned it to a storage tank, used as fuel, reliquefied, or routed it to a recondenser.

In this section we will address such potential methane emission sources targeting primarily emissions associated with compressors blowdown and loading/unloading of LNG.

(i) Compressors Venting

Emissions from reciprocating compressors are typically associated with rod packing and unflared blowdown venting in its operating mode; blowdown venting in its pressurized standby mode; and leakage through its isolation valve in its shut-down depressurized mode.

Centrifugal compressors may either include oil seals that require periodic degassing, or dry seals that pump gas between the seal rings creating a high pressure barrier to leakage. Emissions are associated with blowdown venting in its operating mode, wet-seal degassing in its operating mode and leakage through the isolation valves in its shut-down depressurized mode.

In LNG facilities most, if not all, of the venting is either captured and rerouted to storage vessels or else is sent to a flare to minimize release of cryogenic liquid vapor to the atmosphere. If atmospheric venting does occur emissions could be estimated based on the following information:

(a) Rate of venting in scf/hour;

(b) Vent time (hours) for each venting event;

(c) Mole fraction of GHG in the vent gas;

(d) Total mass emissions in terms of CO_2e corresponding to the emissions inventory period.

(ii) Pipeline Transfers

Methane and potentially small amounts of CO_2 are also vented or lost to the atmosphere if the BOG is not captured during pipe transfer of LNG, either during loading for transport, off-loading for storage or vaporization, or from gathering lines at terminals and peak-shaving plants.

Table 12 lists typical loss rates for storage, loading and unloading of LNG if BOG is not captured during any of these operational steps (note this is the exception, not the normal design approach). The listed loss rates provided in Table 12 and the composition of the LNG stream being handled, should be used to estimate potential CH_4 and CO_2 emissions only if these emissions are not captured or routed to flare. The data in Table 12 could also be useful to assess the potential for GHG emission reductions when operational changes are being implemented.

Table 12. Storage, Loading and Unloading: Typical Loss Rates

Source	Typical Venting or Loss Rate	Units
BOG from storage tanks [(a)]	0.050%	Of total tank volume per day
BOG from vessels during shipping [(b)]	0.15%	Of total ship storage volume per day
Transfer pipe loss - foam insulation [(c)]	0.0012%	per km LNG transfer pipe[(d)]
Transfer pipe loss - powder insulation [(c)]	0.0006%	per km LNG transfer pipe[(d)]
Transfer pipe loss – vacuum insulation [(c)]	0.00012%	per km LNG transfer pipe[(d)]

[(a)] D. Féger, "An innovative way of reducing BOG on existing or 'new built' LNG storage tanks", , Proceedings LNG16 Congress, Algeria, April 2010

[(b)] Sempra LNG, "GHG life-cycle emissions study: U.S. Natural Gas Supplies and International LNG", November 2008

[(c)] B. Kitzel, "Choosing the right insulation", LNG Industry, Spring 2008

[(d)] Based on LNG transfer rate of 228m^3/min and heat transfer coefficient of pipe wall insulation, U(w/m^2k) = 0.26 (foam), 0.13 (powder), and 0.026 (vacuum),

[(e)] EPA, Natural Gas Star, "Liquefied Natural Gas Emissions Reduction Opportunities: Lessons Learned" Natural Gas STAR Technology Transfer Workshop, Alaska, May 2006

4.3 Fugitive Emissions

Fugitive emissions are defined as unintentional emissions that could not reasonably pass through a flare or exhaust stack, chimney, vent, or other functionally-equivalent opening. Any pressurized equipment has the potential to leak where two surfaces meet in a non-welded or otherwise non-bonded manner; these leaks generally occur through valve stems, flanges, threaded connections, pump or compressor shaft seals, or related equipment. Fugitive emissions also originate from non-point evaporative sources. Section 6.0 of the API Compendium (Version 3.0, August 2009) presents a thorough discussion of the different methods available for the quantification of fugitive emissions at the installation, equipment or leaking component level. Systems handling LNG generally require welded rather than flanged or threaded connections, thereby minimizing fugitive emissions.

This section presents a list of the available approaches with a compilation of published emission factors for estimating emissions from LNG operations. The discussion focuses primarily on estimating CH_4 emissions with CO_2 emissions being of secondary consideration with the exception of gas processing for the removal of CO_2 when the gas is sourced from CO_2-rich reservoirs.

Options for estimating fugitive GHG emissions include:

(a) Component counts and emission factors;

(b) Monitoring to detect leaking components; and

(c) Engineering calculations using process model simulations.

4.3.1 Component Counts and Emission Factors

This method is based on counts (or estimates) of the population of different component types (e.g. threaded connectors, valves, etc.) and applying the corresponding emission factors to the components population (without distinction between leakers or non-leakers) to derive total emissions. Emission factors that are provided in terms of total hydrocarbon may be scaled based on knowledge of stream composition to obtain CO_2 and CH_4 fugitive emissions.

This method is easy to apply since it requires only knowledge of the counts of valves, threaded connectors, etc. The disadvantage of using these population factors is that they only provide an estimate of potential emissions, not actual emissions. This approach is also inadequate for providing trends in changes in emissions over time, since the only variable is equipment/ component count, which in most operations does not change significantly.

Table 13 presents a set of default CH_4 emission factors for components and devices in LNG storage and loading or unloading at import/export terminals. These factors represent average emissions per hour per component. For quantifying total fugitive CH_4 emissions for these operations, the number of components in each of the specified categories and their hours of operation will have to be taken into account. The component counts should be applied to all ‘non-vapor recovery compressors’ for which a separate integrated emission factor is provided. Table 13 also presents separately an emission factor for vapor recovery compressors based on the compressors (and not component) counts.

These emission factors should not be used for LNG terminals with supplies of inert gas (such as nitrogen), which typically use the inert gas – rather than natural gas - for seals and packing. Most natural gas liquefaction plants and LNG receiving terminals have such nitrogen systems. Also, it is important to note that in LNG service when a PRV leaks the leakage will typically be into the relief header going to a flare, which may result in CO_2 being emitted to atmosphere, but no hydrocarbons.

Table 13. Default Methane Emission Factors per Component Population For LNG Storage and Import/Export Terminals

Component/ Device	Emission Factor [a] (scf/hour/component)
Valve	**1.19**
Pump Seal	**4.00**
Connectors (*flanges and threaded fittings*)	**0.34**
Other[b]	**1.77**
Vapor Recovery Compressors [c]	**4.17** *(per compressor)*

[a] See Reference 20; based on an assumed methane content of 93.4%
[b] Emission factor is in terms of scf/hour/compressor
[c] Emission factor is in terms of scf/hour/compressor

4.3.2 Monitoring to Detect Leaking Components

Emissions may be estimated by conducting a survey to identify leaking components and 'leaker' emission factors to those sources found to be emitting hydrocarbon above a given threshold. Estimating emissions using leaker emission factors is more accurate than population factors because leaker factors are applied to leaks once they are identified. Since equipment leaks occur randomly within a population of components, determining the number of actual leaking component improves the emissions estimate and can be used to improve site performance by accelerating maintenance on known leak sources.

For applying this method for LNG service, emissions can be calculated by a simplified approach outlined by the U.S. EPA[20]:

(a) All applicable components are monitored at least once during the inventory period,

(b) Components classified as 'leakers' (>10,000ppm) in each of the component categories are counted and multiplied by the respective 'leaker' emission factors and hours of operation to derive total emissions

(c) Additional emissions from the vapor recovery compressors should be accounted for by applying to population emission factor to the total vapor recovery compressor count.

Table 14 provides a set of generic emission factors that can be used to estimate fugitive emissions from identified leakers at natural gas processing plants[21]. These factors are applicable for LNG facilities including liquefaction and regasification of LNG and could also be applied for leakers at gathering pipelines and compressors.

These factors also assume that facilities are monitored periodically to detect leaking components (> 10,000ppm) using an appropriate screening device. The emission factors in Table 14 are provided in terms of total hydrocarbon and should be converted to CO_2 and CH_4 emissions and ultimately summed up as CO_2e based on site-specific gas composition data.

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[20] US Environmental Protection Agency, Federal Register, Volume 76, page 80594, December 23, 2011 and amended at Volume 77, 51495, August 24, 2012 ; Tables W-5 and W-6

[21] US Environmental Protection Agency, Federal Register, Volume 76, page 80594, December 23, 2011; Table W-2

Table 14. Default Total Hydrocarbon Emission Factors for Detected Leaking Components in Gas Processing (a)

	Natural Gas Processing Service (scf/hour/component)
Compressor “Leaker” Components	
Valve (b)	14.84
Connectors (*flanges and threaded fittings*)	5.59
Open-ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Other “Leaker” Components, Non-Compressor, Gas Service	
Valve (b)	6.42
Connectors (*flanges and threaded fittings*)	5.71
Open-ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Gathering Pipelines (c)	2.81 *(scf/hour/mile)*

(a) See Reference 21
(b) Valves include control valves, block valves and regulator valves
(c) Only this factor is in units of "scf/hour/mile"

4.4 Transportation Emissions

Transportation GHG emissions associated with motor vehicles, vessels, barges, tank trucks, rail cars or tankers, should be accounted for in an overall GHG emissions inventory when they are germane to company operations. Emissions from such mobile sources are due to the type of fuels used to propel them.

Table 15 provides a collection of emission factors that are applicable to the transportation of LNG by land or sea, while utilization a variety of fuels, including LNG or BOG, to propel the transport carriers. The emission factors listed are based on GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation), which is a full life-cycle model sponsored by the Argonne National Laboratory (U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy). It is designed to fully evaluate energy and emission impacts of advanced and new transportation fuels and their fuel cycle from well to wheel and more. The emission factors in Table 15 are those embedded in version 1.8b of the model as updated by the California Air Resources Board (CARB) for estimating the carbon intensities of transportation fuels as part of the Low Carbon Fuels Standard (LCFS) rule[22]. The GREET modeling approach has also been integrated by the U.S. EPA into their Motor Vehicle Emissions Simulator (MOVES) to account for the fuel cycle “well to pump” energy use and contribution to emissions[23].

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[22] CARB, Low Carbon Fuel Standard, http://www.arb.ca.gov/fuels/lcfs/lcfs.htm#modeling; updated May 23, 2013

[23] U.S. EPA, Office of Transportation and Air Quality, MOVES (Motor Vehicle Emission Simulator); http://www.epa.gov/otaq/models/moves/index.htm; updated May 30, 2013

Table 15. GHG Emission Factors for Combustion of Fuels for LNG Transportation [(a)]

	Fuel	CO_2	CH_4	CO_2	CH_4
		tonnes/ 10^6Btu	tonnes/10^6Btu	tonnes/TJ	tonnes/TJ
Ocean Tanker					
	Bunker Fuel	0.0845	0.0000046	80.11	0.00434
	Diesel	0.0776	0.0000046	73.59	0.00434
	Natural Gas/BOG	0.0576	0.0000916	54.57	0.08684
Barge					
	Residual Oil	0.0848	0.0000019	80.37	0.00180
	Diesel	0.0779	0.0000019	73.85	0.00180
	Natural Gas	0.0579	0.0000381	54.90	0.03610
Locomotive					
	Diesel	0.0777	0.0000039	73.62	0.00374
	Natural Gas	0.0577	0.0000788	54.65	0.07469
	LNG	0.0583	na	55.29	na
Trucks Class 8B)					
	Diesel	0.0778	0.0000015	73.75	0.00144
	LNG	0.0593	0.0000305	56.24	0.02889
Trucks (Class 6)					
	Diesel	0.0779	0.0000015	73.85	0.00145
	LNG	0.0594	0.0000307	56.29	0.02909

(a) Extracted from the California GREET adaptation (CA-GREET 1.8b) that is a modified version of the latest GREET 1.8b model (released 9/05/2008) by Argonne National Laboratory

4.5 Non-routine Emissions

Non-routine emissions associated with LNG operations are primarily associated with start-up or shut-down emissions along with flaring during plant upset. There is very minimal open literature data on this topic; therefore the data provided in Table 16 should be viewed only as an example. Site specific data that better reflects an entity's facility design and operating practices are more suitable for calculating GHG emissions for specific inventory applications. The data presented in Table 16 is only for combustion/flaring emissions; it does not account for any direct venting during plant upset, start-up, or shutdown. It should be noted that peak rate CO_2 emissions associated with flaring during an emergency event could exceed 3000 tonnes/hour, but this will be only for a short period (5 – 20 min). Hence, using a single emission factor for an inherently transient event like flaring is not very accurate. Emissions can be estimated from the number of events, and total CO_2 emissions per event. A better approach would be to install flow meters in the flare headers and measure the total volume of the flared gas.

Table 16. Example of Emission Factors for Non-routine Emissions (per million tons per year capacity) (a)(b)

Source	CO_2 (Tonnes/hour)	CH_4 (Tonnes/hour)	N_2O (Tonnes/hour)
Heaters			
Start-up regeneration gas heater	0.282	0.0000242	0.0000005
Start-up hot oil heater	3.25	0.00028	0.0000060
Marine Flares			
Warm ship cool-down	12.17	0.015	0.000025
Cold ship cool-down	5.70	0.0069	0.000011
Maintenance	0.000927	0.00113	0.0000019
Plant Upset			
Wet flare	53.10	0.059	0.000098
Dry flare	44.51	0.050	0.000083

(a) Based on Darwin LNG public environmental report; values are rounded-off and normalized per 1 MTPA capacity to provide an indication of the order of magnitude of the respective GHG emissions.

(b) Assumption: all emissions are due to combustion/flaring of natural gas and LNG with no direct venting

5.0 METHODOLOGY IMPLEMENTATION AND IMPROVEMENTS

Improving the estimation of GHG emissions from the LNG operations chain would require improved data availability of relevant information of activity patterns such as volume of gas liquefied, number and duration of ship loadings/unloadings, storage, emergency equipment counts, etc. A more detailed list of potential emission sources in the LNG operations chain is provided Tables 4 – 7. Knowledge of these equipment counts and activities, along with the applicable emission factors, are needed for the quantification of actual emissions. Caution should be exercised when using activity data for new and existing sources from publicly available permit applications or EIS studies, since actual emissions would likely vary from values stated in permits that are designed to enable operation at full capacity.

5.1 Implementation Considerations

When implementing the methodology described in this document one has to consider the following for the different source categories:

- **Combustion Sources -** Activity factors and emissions for combustion sources generally depend on the size and the operating time of the equipment. Compressor exhaust emissions require knowledge of the compressor power and operating time. Fired vessels such as vaporizers require knowledge of the heat rate. These factors can incorporate some of the specifics of the way in which equipment is operated at LNG facilities. For example, a large ‘boil off gas’, or BOG, compressor may operate only during ship loading or unloading at LNG terminals. The activity factor will have to incorporate the shortened operating time of such a compressor and differentiate it from something like a transmission compressor that is run continuously throughout the year. It is also important to account for additional fired vessels and electricity generation equipment that are present at a given facility.
- **Methane Emissions from Fugitive Leaks -** Activity factors for potential fugitive emissions from equipment leaks could be obtained either from generic models relying on gross counts of sources e.g. number of plants, number of reciprocating compressors, number of centrifugal compressors, or number of pumps. Additionally compressor counts could be estimated by applying an average number of compressors per facility for each type of LNG operation.

Although such an approach would be less burdensome when developing a GHG inventory it may result in the estimation of very high emissions due to the conservative assumptions embedded in many of the generic equipment counts models. It is advisable to conduct actual surveys of facility equipment and components to more realistically represent the fugitive emission leaks from a given facility.

- **Methane Emissions from Venting -** Activity factors for vented emissions will depend on the number of upsets, compressors and other equipment blowdowns, and LNG loading/unloading activities. LNG facilities in operation need to keep track of the frequency and number of upsets that result either in gas flaring or venting on an annual basis. Documentation is also required of the number of LNG vessels and trucks loading and unloading activities. The truck loading/unloading operations is especially important for 'Peak Shaving' plants and satellite storage facilities. It could also become a factor if LNG is used to fuel heavy duty trucks and railcars.

5.2 Recommended Areas for Improvement

The document provides a compilation of current methods for estimating LNG emissions. Since the methods listed are based to a large extent on other natural gas GHG emission estimates additional research is needed to improve the emission estimating methods for the types of activities that are unique to the LNG operations chain.

Emission sources for which improved emission estimation methods and emission factors may be required include:

(a) Liquefaction – emission associated with dehydration systems, venting or leakage due to tank overpressure**,** displacement of uncombusted vapors during operations;

(b) Storage - venting from pressure relief valves not connected to a flare system, venting from BOG compressors, and fugitive emissions from flanges, valves, and fittings.

(c) Loading/unloading operations – flaring or venting from excess BOG generation during a loading or unloading operation or from storage tank balancing, venting when vessel loading connections are broken, fugitive emissions from BOG compressor seals and rod packing;

(d) **Regasification -** venting from maintenance within the regasification process, venting and fugitive emissions from the BOG compressors, fugitive emissions from the flanges, valves, and fittings, and venting from maintenance on LNG pumps;

(e) **Start-up and Malfunctions -** flaring during liquefaction process start-up, chilling of storage tanks and regasification equipment, pressure relief (essentially all of which route to a flare system) and related venting, and upset events

(f) **Transportation -** leakage during transfer to an LNG transport truck or other means of LNG conveyance to a direct consumer of LNG.

It is expected that the GHG intensity of the various stages of the LNG value chain will be reduced as new technologies and more energy efficient technologies are implemented. Hence, updates of emission factors will be required as part of the continual improvement process.

APPENDICES

Appendix A

Glossary of Terms [(a,b,c)]

TERM	**DEFINITION**
BCF	Billion s cubic feet of natural gas at standard conditions. One BCF is equivalent to roughly 2.64 million pound-moles of natural gas.
Boil-off	LNG that is lost from storage during transport or storage due to revaporization resulting from heat gain (from the ambient surroundings through insulation, or from energy input by pumping the fluid)
British Thermal Unit (BTU)	The amount of heat required to change the temperature of one pound of water one degree Fahrenheit.
Carbon Dioxide	A product of combustion and a greenhouse gas.
Cryogenics	Refers to low temperature and low temperature technology. There is no precise temperature for an upper boundary but -50°F is often used.
Cryogenic liquid	A liquefied gas that is kept in its liquid form at very low temperature and has a normal boiling point below -50°F (- 46°C)
Density	Mass per unit volume of a fluid. The energy industry usually relies on two expressions of liquid density: specific gravity (density of the fluid divided by the density of water) and degrees API. The larger the specific gravity and the smaller an API number, the denser the liquid.
Fahrenheit degrees (F)	A temperature scale at which water boils at 212° and freezes at 32° Fahrenheit. Convert to degrees Celcius (C) by the following formula: (°F-32)/1.8= °C.
Greenhouse Gases	Gases in the atmosphere that absorb and emit radiation within the thermal infrared range. This process is the fundamental cause of the greenhouse effect. The main greenhouse gases in the atmosphere are water vapor, carbon dioxide, methane, nitrous oxide and ozone.
Heat Content	The amount of useful energy measured in British Thermal Units (BTU) or Joules (J)
Higher Heating Value (HHV)	The amount of energy released when a specific volume of gas is combusted completely and all resulting water vapor is condensed. Commonly measured in units of Btu/scf or MJ/m^3
Hydrocarbon	Chemical compound containing carbon and hydrogen
Impoundment	Spill control for tank contents designed to limit the liquid travel in case of release. May

	also refer to spill control for LNG piping or transfer operations.
Joule	Metric (SI) unit of work and energy. One Joule is equivalent to 0.2390 calories, and 1 Btu is equal to 1,055 Joules.
Liquefaction	The process of altering the state of a gas into a liquid by cooling the gas. For methane, this requires decreasing its temperature to approximately -260˚F (-162˚C) at atmospheric pressure.
Liquefied Natural Gas (LNG)	Natural gas that is stored and transported in liquid form, at essentially atmospheric pressure, at a temperature of approximately -260˚F (-162˚C).
Methane	The main component of natural gas. Methane also is a potent greenhouse gas.
Mole Percent	A mole is a standard number of molecules: 6.022×10^{23}. Mole fraction or mole percent is the number of moles of a component of a mixture divided by the total number of moles in the mixture.
MTPA	Million Tonnes per Annum.
MW	Molecular Weight
Natural Gas	A combustible gaseous mixture of simple hydrocarbon compounds, primarily methane.
Natural Gas Liquids	Hydrocarbons heavier than methane found in raw natural gas. The term is generally used to include ethane, propane, and butanes, but can also include pentanes and heavier.
Peak-shaving LNG Facility	A facility for both storing and vaporizing LNG intended to operate on an intermittent basis to meet relatively short term peak gas demands on a distribution system. A peak-shaving facility may also have liquefaction capacity, which is usually quite small compared to its vaporization capacity.
Regasification	The process of altering the state of natural gas from liquid to gas by warming it and converting it back into a gaseous state.
Standard Cubic Foot	One cubic foot of gas at standard conditions of 60 degrees Fahrenheit and 14.696 pounds per square inch absolute, containing 1/379.3 = 0.00264 pound-moles of gas.
Stranded Gas	Gas is considered stranded when it is not near a market, and a pipeline to market is not economically justified.
Sweetening	Gas treating to remove sulfur compounds. Aqueous amine solutions, for instance, can be used to absorb H_2S and other sulfur species, e.g. mercaptans, from natural gas to produce a sweet liquefaction feed.

Well	A hole drilled into the earth’s surface to access a specific resource.
Wobbe Index	A measure of the interchangeability of different fuel gas streams. It is defined as the gross calorific value (higher heating value) of a gas divided by the square root of the ratio of the molecular weight of the gas to that of air.

[a] Phillips Petroleum Company;

[b] Poten & Partners

[c] Understanding Today’s Global LNG Business, Enerdynamics

Appendix B

Unit Conversions

From …	Multiply by	To obtain …
1 tonne LNG	**46,467**	**cubic feet gas**
1 cubic meter LNG	**21,189**	**cubic feet gas**
1 cubic meter LNG	**23.3079**	**million Btu**
1 cubic meter LNG	**0.4560**	**tonne LNG**
1 tonne LNG	**2.1930**	**cubic meter LNG**
1 tonne LNG	**14.04**	**Barrels LNG**
1 tonne LNG	**51.1138**	**million Btu**
1 tonne LNG	**78.827**	**cubic feet LNG**
1 million cubic feet gas	**21.5206**	**tonnes LNG**
1 million cubic feet gas	**47.1943**	**cubic m LNG**
1 nautical mile	**1.1508**	**statute miles**
1 horsepower (HP)	**0.7457**	**kW**
1 kW	**1.3410**	**horsepower (HP)**
1 million cubic feet gas per day	**7,885**	**tonnes LNG per year**
1 tonne	**1.1023**	**short (US) tons**
1 kg	**2.2046**	**lb**
1 tonne CO_2	**18,314**	**cubic feet gas**
1 cubic meter	**35.3147**	**cubic feet**
Average Emissions(a)		
Combustion of 1 Bcf	**54,602**	**tonnes CO_2**
Combustion of 1 cubic meter LNG	**1.1570**	**tonnes CO_2**
Combustion of 1 tonne LNG	**2.5372**	**tonnes CO_2**

(a) Averages based on: *U.S. Dept of Energy (2005) "Liquefied Natural Gas: Understanding the Basic Facts";* Detailed methods incorporating actual fuel properties are provided in Section 4.0 of this document

Appendix C

Acronyms

Bcf	Billion standard cubic feet
Btu	British thermal units
BOG	Boil-off Gas
C	Celsius (Centigrade)
Cf	Cubic feet
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
F	Fahrenheit
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GJ	Gigajoule
GTL	Gas-to-Liquid
GWP	Global warming potential
IMO	International Maritime Organization
J	Joule
LDAR	Leak detection and repair
LDC	Local distribution company
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
m^3	Cubic meter
Mcf	Thousand standard cubic feet
MMBtu	Million British thermal units
MMcf	Million standard cubic feet
MTPA	Million tonnes per annum
NO_x	Nitric oxide (NO, NO_2)
N_2O	Nitrous oxide
NGL	Natural gas liquids
ORV	Open rack vaporizer
Psi	Pounds per square inch
Psig	Pounds per square inch gauge
PUC	Public Utilities Commission
SCV	Submerged combustion vaporizer
Tcf	Trillion standard cubic feet

Appendix D

Global Warming Potential (GWP)

I. List of Commonly Reported GHGs and their 100-year GWPs

Greenhouse Gas	SAR [(a)] GWP	AR4 [(b)] GWP
Carbon Dioxide (CO_2)	1	1
Methane (CH_4)	21	25
Nitrous Oxide (N_2O)	310	298
HFCs		
HFC-23	11,700	14,800
HFC-32	650	675
HFC-125	2,800	3,500
HFC-134a	1,300	1,430
HFC-143a	3,800	4,470
HFC-152a	140	124
HFC-227ea	2,900	3,220
HFC-236fa	6,300	9,810
HFC-4310mee	1,300	1,640
PFCs		
CF_4	6,500	7,390
C_2F_6	9,200	12,200
C_3F_8	7,000	8,830
C_4F_{10}	7,000	8,860
C_5F_{12}	7,500	9,160
C_6F_{14}	7,400	9,300
Sulfur Hexafluoride (SF_6)	23,900	22,800

(a) IPCC Second Assessment Report (SAR), 2001; used for reporting through 2012
(b) IPCC, Forth Assessment Report (4AR), 2007; for reporting in 2013 and beyond

II. List of Common Commercial Refrigeration Liquid Blends and their GWPs

Designation	Blend Content	GWP [(c)]
R404A	52:44:4 blend of HFC-143a, -125 and -134a	3,260
R407C	23:25:52 blend of HFC-32, -125 and -134a	1,526
R408A	47:7:46 blend of HCFC-22, HFC-125 and HFC-143a	2,795
R410A	50:50 blend of HFC-32 and -125	1,725
R507	50:50 blend of HFC-125 and HFC-143a	3,300
R508B	46:54 blend of HFC-23 and PFC-116	10,350

(c) UK Defra / DECC's, "2011 Guidelines: GHG Conversion Factors for Company Reporting", Version 1.2, August 19, 2011 (Annex 5)

Appendix E

Emission Factors Tables for Common Industrial Fuels

(from API GHG Compendium, Version 3.0, August 2009)

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

	Carbon Emission Factor from Original Source Document		CO_2 Emission Factor[a, b], US Units		CO_2 Emission Factor[a,b], SI Units	
Fuel	**Emission Factor**	**Source**	**tonnes/10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Aviation Gas	18.87 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0728	0.0692	69.0	65.6
Bitumen	22.0 kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0851	0.0809	80.7	76.6
Coke	31.00 kg C/MMBtu	Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.1199	0.1139	113.7	108.0
Coke (Coke Oven/Lignite/Gas)	29.2 kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.1130	0.1073	107.1	101.7
Crude Oil	20.33 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7
Distillate Fuel (#1,2,4)	19.95 MMTC/10^{15} Btu or Tg C/10^{15} Btu	Table 6-1, EIA, 2007 Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Electric Utility Coal	25.98 MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.1003	0.0953	95.0	90.3
	25.76 Tg C/10^{15} Btu	Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0994	0.0945	94.2	89.5
Ethanol[c]	19.3 kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0747	0.0709	70.8	67.2
Flexicoker Low Btu Gas	278 lb CO_2/10^6 Btu (LHV)	Petroleum Industry Data	0.1261	0.1135	119.5	107.6
Fuel Oil #4	45.8 lb C/10^6 Btu	Derived from fuel property data in Table 3-8	0.0802	0.0762	76.0	72.2
Gas/Diesel Oil[d]	20.2 kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0781	0.0742	74.1	70.4
Jet Fuel	19.33 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Kerosene	19.72 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0761	0.0723	72.1	68.5
Lignite	26.30 MMTC/10^{15} Btu; kg C/MMBtu	Table 6-2, EIA, 2007; Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.1015	0.0964	96.2	91.4
LPG	16.99 MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0656	0.0623	62.2	59.0
	17.23 Kg C/MMBtu	Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.0665	0.0632	63.0	59.9
Butane (normal)	17.71 MMTC/10^{15} Btu	Table 1-5, EIA, 2007	0.0684	0.0649	64.8	61.5
	17.72 Tg C/10^{15} Btu	Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0684	0.0650	64.8	61.6

Table -4-3. CO$_2$ Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types (continued)

Fuel	Carbon Emission Factor from Original Source Document			CO$_2$ Emission Factor[a, b], US Units		CO$_2$ Emission Factor[a, b], SI Units	
	Emission Factor		Source	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Ethane	16.25	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0627	0.0596	59.4	56.5
Isobutane	17.75	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008	0.0685	0.0651	64.9	61.7
Propane	17.20	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2007; Table A-40, EPA, 2008; Table 12.1, TCR, 2008.	0.0664	0.0631	62.9	59.8
Miscellaneous Product[d,e]	20.33	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0785	0.0745	74.4	70.7
Motor Gasoline (Petrol)	19.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Naphtha (<401°F)	18.14	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0700	0.0665	66.4	63.0
Nat. Gas Liquids	17.5	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0677	0.0643	64.2	61.0
Natural Gas (Pipeline)[f]	14.47	MMTC/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2007; Table B-1, EPA, 2008b; Table 12.1, TCR, 2008.	0.0590	0.0531	55.9	50.3
Natural Gas (Flared)	14.92	MMTC/10^{15} Btu	Table 6-1, EIA, 2007	0.0608	0.0547	57.6	51.8
Other Bituminous Coal	25.8	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0998	0.0948	94.6	89.9
Other Oil (>401°F)	19.95	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Pentanes Plus	18.24	Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0704	0.0669	66.7	63.4
Petroleum Coke[g]	27.85	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.1075	0.1021	101.9	96.8
Refinery Gas	15.7	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007	0.0607	0.0577	57.6	54.7
Residual Oil #5	46.9	lb C/10^6 Btu	Derived from fuel property data in Table 3-8	0.0821	0.0780	77.8	73.9
Residual Oil #6	21.49	MMTC/10^{15} Btu or Tg C/10^{15} Btu	Table 6-1, EIA, 2007 Table A-32, EPA, 2008; Table 12.1, TCR, 2008.	0.0829	0.0788	78.6	74.7

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types (continued)

	Carbon Emission Factor from Original Source Document		CO_2 Emission Factor[a, b], US Units		CO_2 Emission Factor[a, b], SI Units	
Fuel	**Emission Factor**	**Source**	**tonnes /10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Special Naphtha	19.86 Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0767	0.0728	72.7	69.0
Still Gas	17.51 Tg C/10^{15} Btu	Table A-29, EPA, 2008; Table 12.1, TCR, 2008.	0.0713	0.0642	67.6	60.9
Sub-bituminous Coal	26.48 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-2, EIA, 2007; Table A-33, EPA, 2008; Table 12.1, TCR, 2008.	0.1022	0.0971	96.9	92.0
Unfinished Oils[d,e]	20.33 MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2007; Table A-33, EPA, 2008; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7

Sources:

Energy Information Administration (EIA). *Documentation for Emissions of Greenhouse Gases in the United States 2005*, DOE/EIA-0638(2005), October 2007.

Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006*, Annexes. EPA 430-R-08-005, April 15, 2008.

Environmental Protection Agency (EPA), Climate Leaders. *Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Stationary Combustion Sources*. EPA 430-K-08-003, May 2008 (2008b).

Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.

The Climate Registry (TCR). *General Reporting Protocol*, Version 1.0, March 2008.

[a] CO_2 emission factors shown are based on the default *Compendium* assumption of 100% oxidation.

[b] To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

[c] Theoretical number. Under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2.

[d] Term is defined in the Glossary.

[e] Carbon content assumed to be the same as for Crude Oil (EIA, 2007).

[f] Natual gas carbon coefficient is based on a weighted U.S. national average.

[g] Note that catalyst coke is not the same as petroleum coke/marketable coke. Catalyst coke refers to coke formed on catalysts while petroleum/marketable coke is coke that is the "final product of thermal decomposition in the condensation process in cracking" (EIA, 2007b). Carbon dioxide emissions from catalyst coke are discussed in Section 5.

[h] Values are for Residual Fuel, which is defined in the text of the reference document as No. 6 fuel oil.

Table 4-4. CH_4 and N_2O Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

Fuel	CH_4 Emission Factor[a], US Units		CH_4 Emission Factor[a], US Units		N_2O Emission Factor[a], US Units		N_2O Emission Factor[a], SI Units	
	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Aviation Gasoline/Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Biogasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Biodiesels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Bitumen	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Coke Oven and Lignite Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Crude Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Ethane	1.06E-06	1.00E-06	1.00E-03	9.50E-04	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Gas Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.06E-07	1.00E-07	1.11E-13	9.50E-05
Gas/Diesel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Jet Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Lignite	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Liquified Petroleum Gases	1.06E-06	1.00E-06	1.00E-03	9.50E-04	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Motor Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Naphtha	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Natural Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.11E-13	9.00E-05
Natural Gas Liquids	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Biogas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.11E-13	9.00E-05
Other Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Liquid Biofuels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Petroleum Products	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Other Primary Biomass	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.45E-12	3.80E-03
Paraffin Waxes	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Petroleum Coke	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Residual Fuel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.68E-13	5.70E-04
Sub-Bituminous Coal	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.67E-12	1.42E-03
Wood/Wood Waste	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.45E-12	3.80E-03

[a] Converted from original units of kg/TJ (LHV). To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV). Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.