LNG Production in British Columbia:

Greenhouse Gas Emissions Assessment and Benchmarking

Client: BC Climate Action Secretariat

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In 2011, the Government of British Columbia developed a vision and strategy to build a new industry in Liquefied Natural Gas (LNG). Liquefaction of natural gas enables transportation to markets overseas, thereby increasing the market potential of British Columbia's supply of natural gas. By exporting LNG, BC intends to supply markets in Asia where demand growth for energy sources is expected to continue in future years. In September 2011, the Government of BC released *Canada Starts Here: The BC Jobs Plan*, which included a target to bring at least one natural gas pipeline and LNG terminal online by 2015, with three LNG facilities in operation by the year 2020.

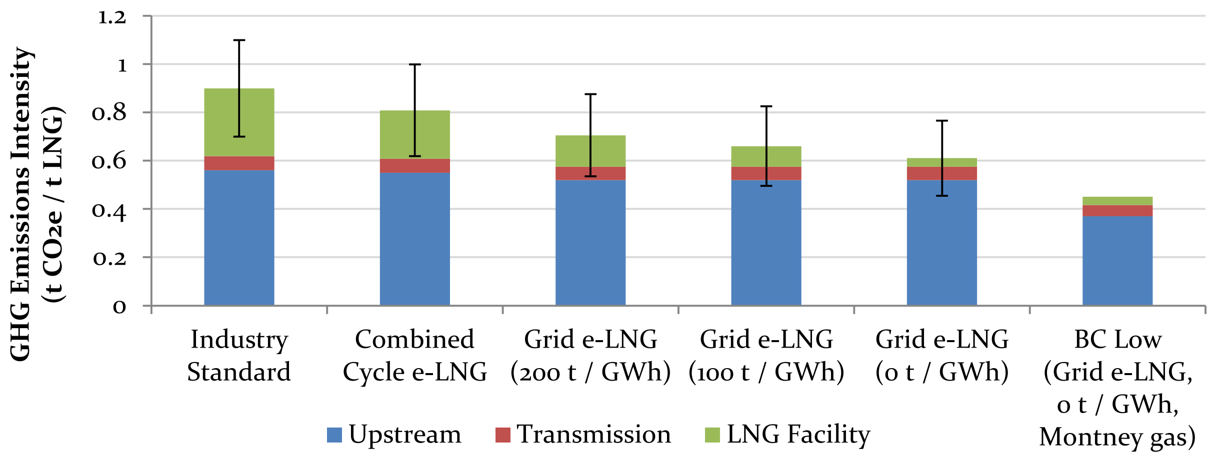
The objective of this report is to calculate and compare greenhouse gas (GHG) emissions from a hypothetical BC LNG value chain (including natural gas extraction and processing, pipeline transmission, and liquefaction) with LNG value chains worldwide.

This report quantifies the GHG emissions associated with a hypothetical BC value chain, consisting of: gas extraction, processing, and production at plays in northeast BC; transmission of produced gas via pipeline to coastal BC; and, gas liquefaction at a LNG facility with 2 trains producing 12 million tonnes per annum (mtpa) LNG. The GHG emissions associated with various natural gas supply options (gas from Montney and Horn River) and LNG facility power options have been calculated and are reported and discussed in this report. Two power supply options were considered when calculating the emissions from a hypothetical BC LNG facility, including:

- **e-LNG** –LNG facility powered entirely by electricity. Two different electricity supply options are considered: (1) the BC electricity grid at three different GHG emission intensities (200, 100, and 0 t CO_2e / GWh)[1] and (2) a site-located combined-cycle natural gas power plant.
- **Industry standard** – direct-drive refrigeration compressors powered with natural gas and electricity generated with natural gas generators.

The calculated GHG emissions intensities of five hypothetical BC LNG value chains are displayed in the figure below. The figure also shows a 'BC Low' value chain, which represents a scenario where the LNG facility is powered by grid electricity with an emission factor of 0 tCO_2e / GWh. In this scenario, the gas may be sourced in two ways: (1) entirely from Montney; or (2) from a combination of Montney and Horn River, but CCS must be used at Horn River due to the significantly higher reservoir concentration of CO_2. This 'Low' value chain is included for discussion in the benchmarking section.

[1] BC Hydro, the crown corporation operating the BC electricity grid, has estimated that it could provide a hypothetical grid-connected LNG facility with electricity having a GHG emission factor of 200 tCO_2e / GWh without changing the GHG intensity of the grid used to meet the province's other electricity requirements.

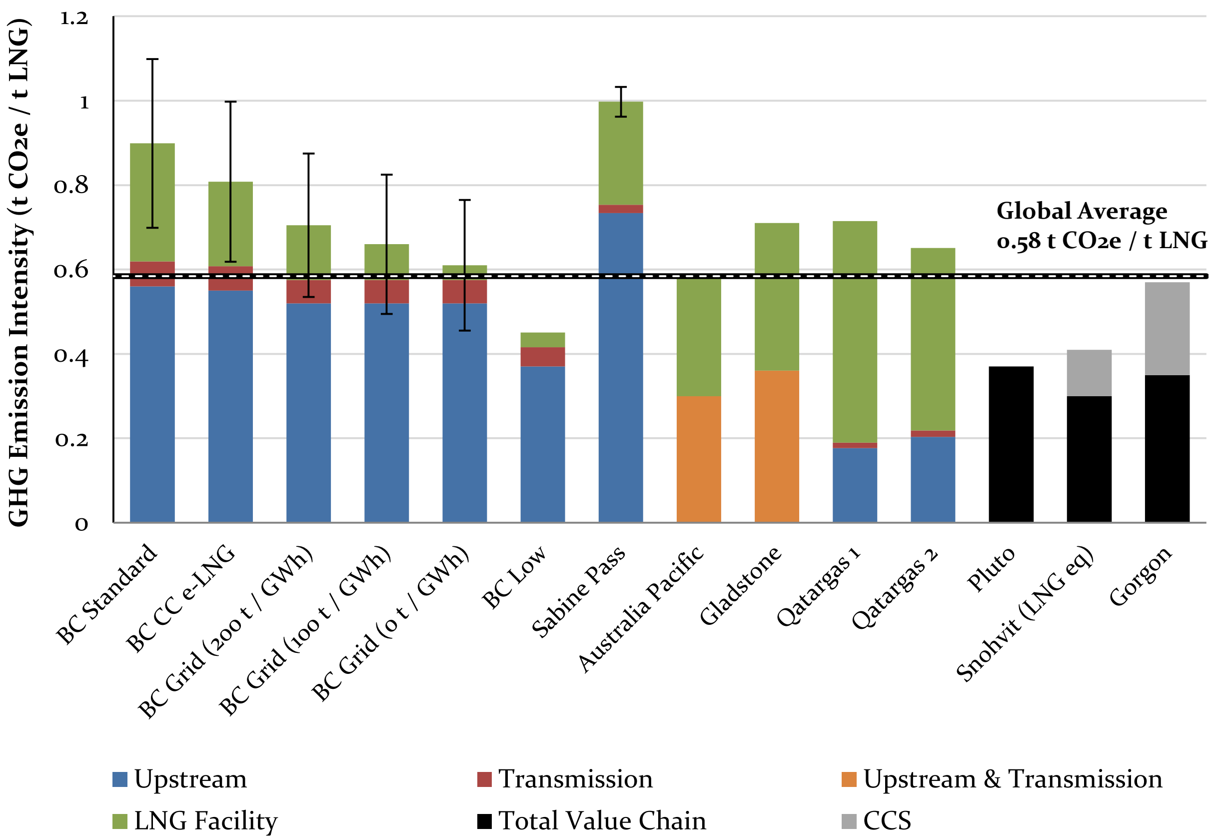


From the figure above, two important observations may be drawn: (1) upstream emissions make up the highest proportion of total value chain emissions for all hypothetical BC facility types; and (2) the significant difference in upstream emissions associated with Montney and Horn River gas accounts for the majority of the GHG intensity range. The Horn River play has a significantly higher concentration of CO_2 (12%) than the Montney play (1%). The higher concentration of CO_2 results in higher volumes of CO_2 venting during acid gas removal. Facilities receiving natural gas extracted entirely at the Montney play could have GHG intensities closer to the lower end of the range, while facilities receiving natural gas extracted entirely at the Horn River play could have GHG intensities closer to the higher end of the range.

A benchmarking exercise was conducted in order to compare the GHG intensities of the hypothetical BC value chains with operational, under construction, and proposed global LNG value chains. The value chains selected cover a broad range of upstream gas resource and LNG facility characteristics. A list of the value chains included in the benchmarking exercise is shown in the table below.

Value Chain Name	Country	Rationale for Inclusion
Sabine Pass	U.S.	This under construction value chain has a very low proposed LNG facility intensity.
Australia Pacific	Australia	Facilities under construction that incorporate efficient processes and GHG mitigation measures.
Gladstone	Australia	
Qatargas 1 and Qatargas 2	Qatar	Qatar is the largest producer of LNG worldwide and has been included as a reference for the typical emission intensity from LNG production.
Pluto	Australia	Recently commissioned LNG plant with a very low value chain GHG intensity.
Snohvit	Norway	Some studies have claimed that Snohvit has the lowest GHG intensity of any value chain currently in operation. The Snohvit facility also includes CCS.
Gorgon	Australia	Very low GHG intensity value chain that plans to incorporate CCS.

The GHG intensities of the hypothetical BC value chains, along with the intensities of the global LNG value chains, are shown in the figure below. For most value chains, the total value chain GHG intensity is disaggregated into three intensities – upstream emissions, transmission emissions, and LNG facility emissions. However, for some global value chains it was not possible to disaggregate the total value chain intensity to this extent because of data gaps in the reference documents.



The proportion of the total value chain intensity that is comprised of upstream vs. LNG facility emissions varies significantly among the various value chains. To explain this observation, the value chains may be grouped into four categories:

1. *Upstream Intensive Value Chains (Hypothetical BC & Sabine Pass)* – in these value chains, the upstream emissions account for a greater proportion of the total value chain emissions. This is primarily a result of the gas formation type from which natural gas is extracted and supplied to the LNG facility (refer to Section 2.1.1 for a discussion of emissions from various gas formation types). The hypothetical BC and Sabine Pass value chains both involve the extraction, production, and processing of shale gas, which is GHG intensive. Therefore, even when the LNG facility has a low GHG intensity, as is the case with the hypothetical grid-connected BC facilities, the total value chain emissions intensity could be above average.

2. *LNG Facility Intensive Value Chains (Qatargas 1 & 2)* - in these value chains, the LNG facility emissions account for a greater proportion of the total value chain emissions. The Qatargas value chains fit into this category as a result of having access to a low emitting natural gas source (offshore gas) and containing less up-to-date LNG facilities that do not make use of the energy efficiency and GHG mitigation options common to newer facilities.

3. *Proportional Value Chains (Australia Pacific & Gladstone)* - in these value chains, the LNG facility emissions and upstream emissions account for approximately the same proportion of the total value chain emissions. The LNG facilities are supplied with gas from a medium emitting source (coal bed methane at Australia Pacific and Gladstone) and also employ some energy efficiency and GHG mitigation options.

4. *Low Intensity Value Chains (Pluto, Snohvit & Gorgon)* – in these value chains, both upstream and LNG facility emissions are very low. Pluto, Snohvit, and Gorgon all receive natural gas extracted offshore with a sub-sea gathering system, which results in very low GHG emissions. The Snohvit and Gorgon value chains also employ CCS to reduce emissions from the venting of CO_2 contained in the LNG facility feed gas. As shown in the figure, this may have a significant impact on the overall value chain GHG intensity. In addition to having low upstream emissions, these value chains also have very low LNG facility emissions.

The average GHG intensities of the hypothetical BC value chains all fall above the global average value chain intensity of 0.58 tCO_2e / t LNG[2] due to the higher upstream emissions intensity. However, the range of hypothetical BC value chain emissions intensities (shown by the error bars in the figure) indicates that hypothetical BC value chains with grid-connected LNG facilities could have GHG intensities lower than the global average if upstream emissions are mitigated (using gas from the Montney play or by incorporating CCS at Horn River). The 'BC Low' value chain (the lower bound of the 0 t/GWh grid e-LNG value chain) could have an emissions intensity closer to, but still approximately 20% greater than, the lowest global GHG intensity value chains. This indicates that global 'low intensity value chains', which have access to natural gas from low emissions intensive formation types, would likely have lower emissions intensities than any hypothetical BC value chain considered in this report.

[2] Note that this average only includes the global value chains surveyed in Section 4. It is not an average of every LNG value chain currently in operation, under construction, or being planned in the world.

1 INTRODUCTION

In 2011, the Government of British Columbia developed a vision and strategy to build a new industry in Liquefied Natural Gas (LNG). Liquefaction of natural gas enables transportation to markets overseas, thereby increasing the market potential of British Columbia's supply of natural gas. By exporting LNG, BC intends to supply markets in Asia where demand growth for energy sources is expected to continue in future years.

1.1 The Global LNG Market

The global natural gas market consists of a collection of distinct regional markets, each characterized by location, availability of local natural gas resources, pipeline infrastructure, accessibility to natural gas from other regions of the world, and rate of demand growth. Regions may be interconnected via pipelines or by import/export LNG shipping facilities, while some operate relatively autonomously. In general, regions will meet their natural gas demands first with local resources, then with gas deliveries via pipelines, and finally with LNG imports.[3] The major LNG exporting regions are the Middle East (primarily Qatar) and Asia-Pacific (Malaysia, Indonesia, and Australia), with the major LNG importing regions being Asia (Japan, Korea, China, and India) and Europe (the UK and Spain).[4] A summary of LNG imports and exports by country as a percent of total world LNG trade is shown below in Figure 1.

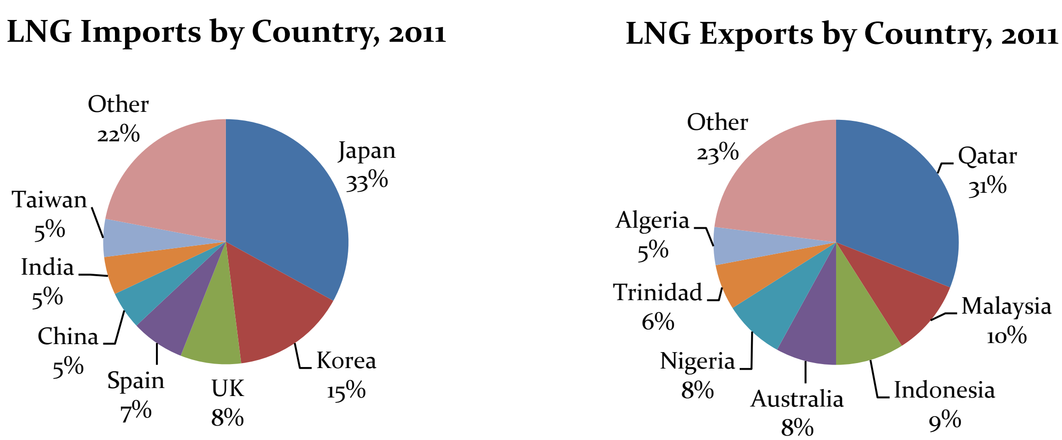


Figure 1 – LNG imports and exports by country as a percent of total supply or demand.[5]

[3] NERA Economic Consulting. (2012). Macroeconomic impacts of LNG exports from the United States. Available online: http://1.usa.gov/13mLsLL.
[4] International Gas Union. (2012). World LNG report 2011. Available online: http://bit.ly/134SKVt
[5] Adapted from International Gas Union (2012).

By the end of 2011, 18 countries were exporting their natural gas resources as LNG. Qatar is the largest LNG exporting country, supplying approximately 76 million tonnes (mt) of LNG to the market in 2011, followed by Malaysia at 25 mt, Indonesia at 21 mt, and Australia at 19 mt. On the demand side, 25 countries imported LNG in 2011. Japan imported approximately 79 mt of LNG, followed by Korea at 36 mt, the UK at 19 mt, Spain at 17 mt, and China at 13 mt.[6]

From 2006 to 2011, the global volume of LNG traded grew from approximately 159 mt to 242 mt, which is equivalent to a growth of 52%. The increase in global LNG trade from 1980 to 2011 is shown below in Figure 2. The majority of the supply increase over this period was met by countries that have historically been LNG exporters, such as Qatar, with the remainder originating in countries that had not previously exported LNG. Demand growth was strongest in countries already importing LNG, with Japan, the United Kingdom, China, and India absorbing most of the growth in LNG supply.

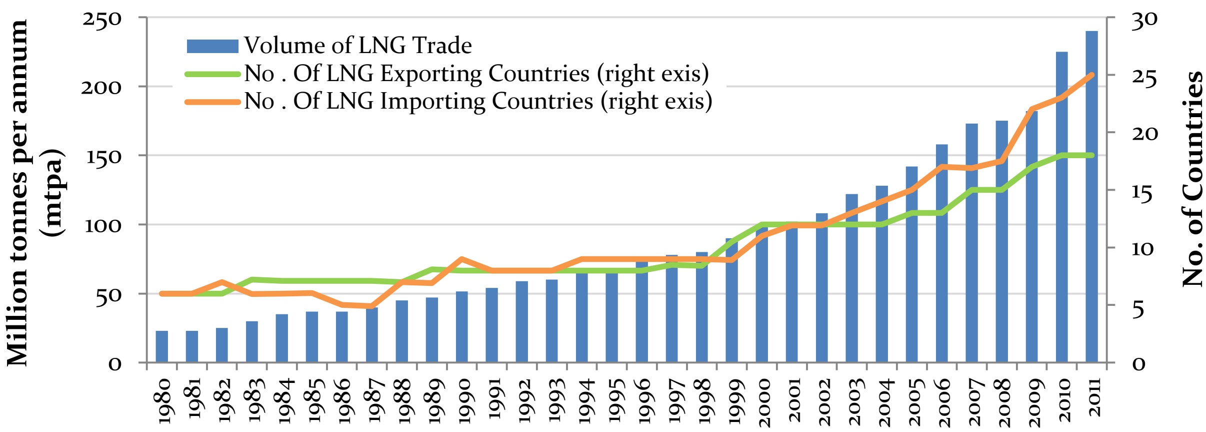


Figure 2 – Global LNG trade volumes, 1980 – 2011.[7]

1.2 The Opportunity for British Columbia

In September 2011, the Government of BC released *Canada Starts Here: The BC Jobs Plan*. According to the plan, economic growth in BC will be achieved by focusing on the province's competitive advantages, including its natural resources and proximity to growing markets in Asia. *The BC Jobs Plan* included a target to bring at least one natural gas pipeline and LNG terminal online by 2015, with three LNG facilities in operation by the year 2020. To achieve this goal, the Government of BC developed an LNG strategy, outlined in *Liquefied Natural Gas: A Strategy for B.C.'s Newest Industry*.[8]

The strategy outlines a plan to extract BC's reserves of natural gas located in unconventional fields in the northeast part of the province. This gas is then to be transmitted via pipeline to coastal BC, where LNG

[6] International Gas Union (2012).
[7] Adapted from International Gas Union (2012).
[8] British Columbia Ministry of Energy and Mines. (2011). Liquefied natural gas: a strategy for B.C.'s newest industry. Available online: http://bit.ly/10JTRqj.

plants will liquefy the natural gas for export. According to the strategy, liquefying natural gas for export will allow BC to supply new markets with natural gas, especially Asia, which is expected to have growing demand over the next number of years. As a result, the strategy claims that new jobs will be created, local economies will be more diversified, new skills training will be developed, 'economic spinoffs' will be generated, and the province will receive more revenues to pay for public services.

Recent growth in LNG trade suggests that there is an expanding global market for LNG. A fulsome analysis of LNG supply and demand, LNG pricing, and/or BC Government revenue generation is outside of the scope of this report. Refer to the references section of this report for a list of studies providing an economic analysis of LNG production in BC.[9]

1.3 Overview and Current Status of BC LNG Facilities

As of April 11, 2013, the BC government had received ten LNG project proposals, with at least two others that are in the preliminary stages of consideration.[10] Specific plans for LNG facility construction include:

- Shell announced plans to build LNG Canada with joint venture partners KOGAS, Mitsubishi and PetroChina. TransCanada was later selected to build supportive pipeline infrastructure. LNG Canada recently submitted a project description to the Canadian Environmental Assessment Agency (CEAA) and the BC Environmental Assessment Office (BC EAO) as a first step in initiating the environmental assessment process, which typically takes two years to complete.[11]
- The BG Group, a major company with an established LNG portfolio, announced a partnership with Spectra Energy to jointly develop a new transportation system. The proposed pipeline will move natural gas from BC's northeast and will serve the BG Group's planned LNG facility on Ridley Island in the Port of Prince Rupert.
- PETRONAS, an experienced LNG operator, announced the Pacific Northwest LNG facility along with their acquired partnership of Progress Energy. TransCanada has been chosen to build supportive pipeline infrastructure for this plant also.
- Chevron Canada purchased an operating interest in the Kitimat LNG plant and the Pacific Trail Pipeline. Chevron will now build and operate this project along with Apache.
- Douglas Channel Energy Partnership plans to construct and operate a small scale LNG facility on the west bank of the Douglas Channel in the District of Kitimat. The project has received LNG export authorization from the National Energy Board and has executed purchase/sale agreements to provide LNG to Pacific Rim markets.

In addition to these LNG proposals, there are other industry players who are actively looking into the possibility of projects of their own, including a partnership between Nexen (recently acquired by CNOC Limited) and Inpex, as well as a recently announced partnership between AltaGas and Idemitsu Kosan.

[9] For example, see: Angevine and Oviedo (2012), Henderson (2012), and NERA (2012).
[10] Simpson, S. (April 11, 2013). Four more LNG project proposed for B.C. *The Vancouver Sun*. Available online: http://bit.ly/10ZUOfg.
[11] Project description files are available on LNG Canada's website: http://bit.ly/11cm4LP.

1.4 Objective of this Report

The objective of this report is to compare greenhouse gas (GHG) emissions from a hypothetical LNG value chain in BC with LNG value chains worldwide. This report quantifies the GHG emissions associated with the value chain in BC from cradle to LNG facility gate. Emissions quantified include those associated with extraction, production, and processing of natural gas, transmission of natural gas to the LNG facility via pipeline, and the natural gas liquefaction process, excluding construction and shipping emissions. The GHG intensity of the hypothetical BC value chain is then benchmarked against other LNG value chains worldwide, including both facilities currently in operation and those still in the planning or construction phase.

2 THE LNG VALUE CHAIN

This report presents GHG emissions associated with LNG production in a cradle to gate model, where the cradle is considered to be underground natural gas deposits, and the gate is the outlet of the LNG plant. In this model, production of LNG involves three primary steps, including the following: natural gas extraction, production and initial processing; transmission of natural gas to the LNG plant via pipeline; and, natural gas liquefaction at the LNG plant. Each step consists of unique activities, processes, and energy sources, which result in emissions of GHGs.

2.1 Natural Gas Extraction, Production and Processing

Upstream gas operations, including extraction, production, and processing, involve taking raw natural gas from underground formations, and stripping out impurities and other hydrocarbons and fluids to produce pipeline grade natural gas that meets specified gas composition requirements. A diagram of typical upstream natural gas activities, including extraction of gas from an underground reservoir, purification and processing, and finally transmission to a gas pipeline is shown below in Figure 3.[12] The figure also shows GHG emissions sources associated with each upstream activity.

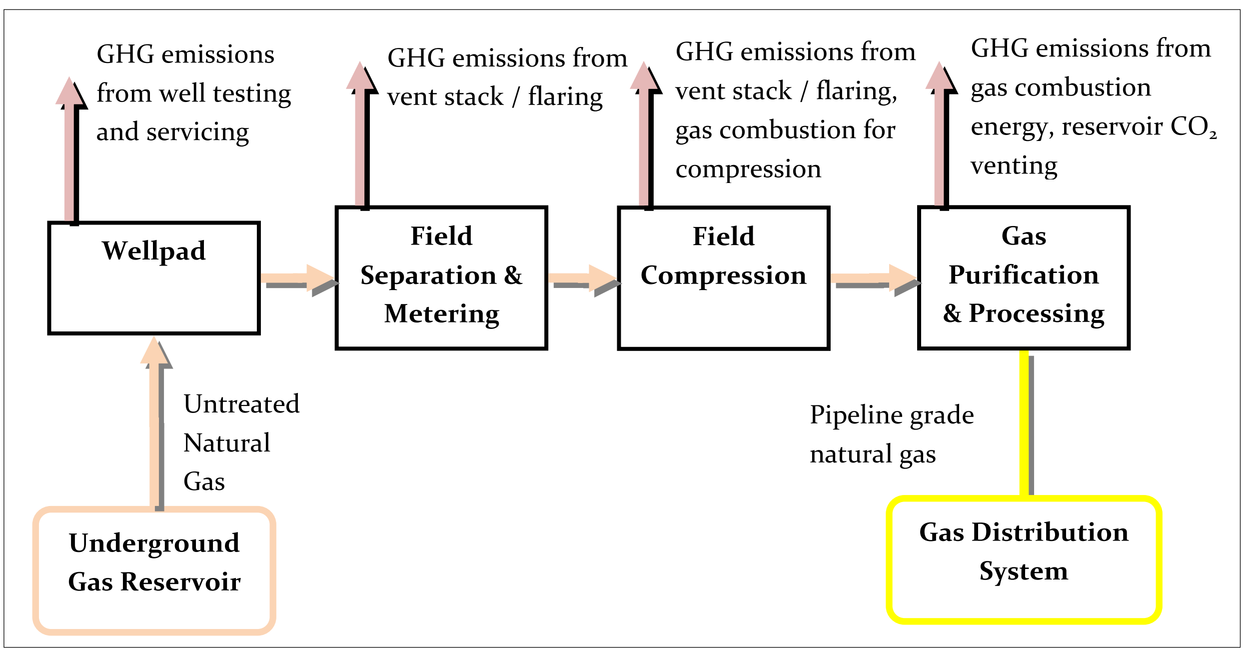


Figure 3 – Schematic of natural gas extraction, production and processing with main emission sources.[13]

[12] Note that this figure displays the activities involved in the extraction and production of wet gas and is more relevant to the facilities surveyed in this report than extraction and production of other gas types.

[13] Canadian Association of Petroleum Producers. (2004). A national inventory of greenhouse gas (GHG), criteria air contaminant (CAC) and hydrogen sulphide (H2S) emissions by the upstream oil and gas industry. Volume 1, overview of the GHG emissions inventory. Available online: http://bit.ly/10hR8Iu.

GHG emissions from upstream gas activities primarily result from: equipment leaks, venting and flaring, fuel combustion by process equipment, and venting of formation CO_2, which is typically extracted from the raw gas at gas processing plants. A chart showing the breakdown of GHG emissions by source for the entire Canadian upstream natural gas industry is shown below in Figure 4.

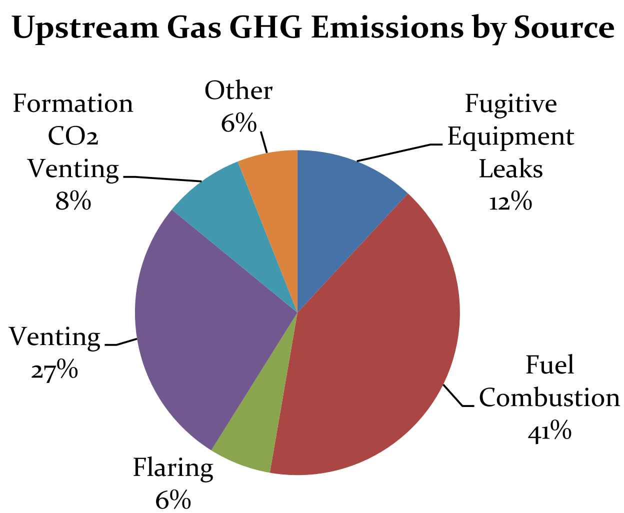


Figure 4 – GHG emissions from natural gas extraction, processing, and production by source category.[14]

GHG emissions from venting formation CO_2 may vary significantly for extraction of gas from different fields, depending on the composition of gas at a particular field. Natural gas typically contains 0-8 mol% CO_2;[15] however, some gas may contain a greater percentage of CO_2, such as the gas processed by the Gorgon LNG plant in Australia, which contains up to 15 mol% CO_2. Before natural gas is allowed to enter the pipeline system, the CO_2 content must be reduced to approximately 2 mol% or lower, depending on the specifications of the pipeline operator. When natural gas is later processed into LNG, the CO_2 content must be further reduced to near 0 mol%. CO_2 removed from raw natural gas before the gas enters the pipeline system and later liquefied is typically vented to the atmosphere, with the magnitude of these GHG emissions determined by the CO_2 composition of gas from a particular field.

2.1.1 Upstream GHG Emissions by Natural Gas Formation Type

The type of formation from which natural gas is extracted is an important determinant of GHG emissions arising from upstream natural gas extraction and production activities. An illustration of common on-shore natural gas formation types (non-associated, coal bed methane, associated, shale, and tight) is shown below in Figure 5. This illustration also applies to off-shore formation types, with the main difference being that the gas formation is located under the sea-bed, rather than under the land surface.

[14] Adapted from Canadian Association of Petroleum Producers (2004).
[15] Natural Gas Supply Association. (2011). Overview of natural gas, background. Available online: http://bit.ly/m7jTK

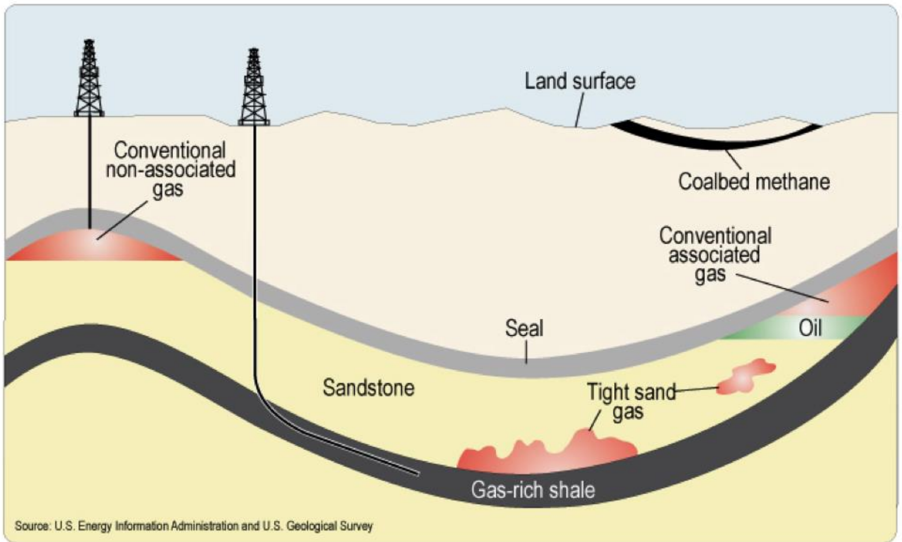


Figure 5 – Illustration of common natural gas formation types.[16]

In general, natural gas extraction methods, technologies, and energy use vary by formation type, and therefore so do the GHG emissions associated with extraction activities. Other factors dependent on formation type, which influence upstream GHG emissions, include: flaring rate; venting of gas during well completions and workovers; venting of gas during liquids unloading; and, fugitive emissions from valves and other sources. The GHG intensity for extraction, production, and processing of natural gas from common formation types is shown below in Figure 6.

As shown below in Figure 6, upstream emissions associated with natural gas extraction, processing, and production are dependent on the gas formation type and vary significantly between the different deposit types. Conventional onshore, shale, and tight gas have the greatest GHG emissions, which are all similar within error. Coal bed methane (CBM) and associated gas have the next lowest GHG emissions, with offshore conventional having the lowest GHG emissions of any US formation type with data available (the sub-sea emissions are an estimate, not based on US operations data). GHG emissions from offshore extraction and production are low as a result of very high gas production rates per well, as well as stringent safety measures on offshore production platforms aimed at reducing fugitive and episodic venting emissions.[17]

An estimate of GHG emissions from gas extracted with sub-sea gathering systems is also shown in Figure 6, with this type of gas potentially having the lowest emissions of any deposit type. The GHG intensity shown in the figure is not based on actual operations data, but was calculated from information contained in the

[16] National Energy Technology Laboratory. (October 3, 2012). Unconventional natural gas: an LCA with a conventional answer. Available online: http://1.usa.gov/11bJREv.
[17] National Energy Technology Laboratory (October 3, 2012).

Gorgon facility reference documents.[18] The Gorgon environmental impact statement indicates that the use of sub-sea gathering systems instead of offshore platforms reduces LNG value chain emissions by 0.04 t CO_2e / t LNG (0.75 g CO_2e / MJ natural gas). Transmission emissions are also typically very low with this type of system, as pipeline are of short length, powered by electricity, and designed for near-zero fugitive emissions.[19]

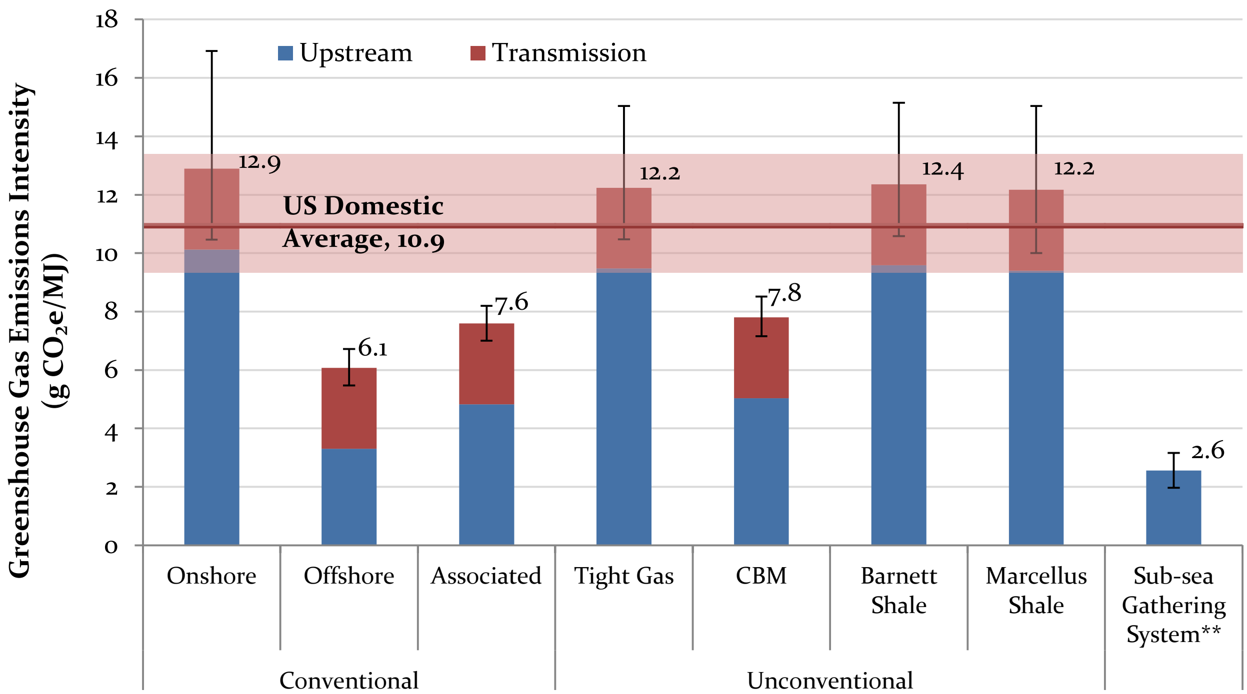


Figure 6 – Average GHG emissions by natural gas deposit type (US data).[20]

2.2 Natural Gas Transmission

Natural gas transmission systems conduct pipeline quality natural gas from the gas producers to market, or in the case of a LNG value chain, to the LNG production facility. A typical transmission system will contain straddle plants, which remove any natural gas liquids that have accumulated in the system, and a number of natural gas storage facilities located along the gas transmission pipeline system. Storage facilities accommodate fluctuating differences between gas supply and demand rates. GHG emissions associated with natural gas transmission arise primarily from fugitive natural gas leaks along the transmission pipeline

[18] Chevron Australia. (2009). Gorgon Gas Development and Jansz Feed Gas Pipeline: Greenhouse Gas Abatement Program. Available online: http://bit.ly/J8smlp.

[19] Transmission emissions are also typically low for LNG facilities supplied with natural gas from offshore platforms, since the LNG facility is usually located within close proximity to the point where gas arrives onshore, resulting in a short pipeline transmission distance. In the case of the Qatargas facilities discussed in Section 4, transmission emission intensities are significantly lower than shown in Figure 6 for offshore gas due to short pipeline transmission distances.

[20] National Energy Technology Laboratory (October 3, 2012).

** Sub-sea gathering system emissions based on offshore US data and Gorgon EIS document, not actual US data. See discussion in the body of this report.

and fossil fuel combustion, which provides power to the compressors used to push natural gas along the pipeline. These compressors typically combust natural gas, although electric compressors are also used in some situations. When electric compressors are powered with a low GHG emitting electricity grid, natural gas transmission emissions are typically reduced.

2.3 Natural Gas Liquefaction Process

The natural gas liquefaction process involves two primary steps: treatment of the inlet natural gas to remove impurities followed by cooling and refrigeration to transform the natural gas into a liquid (LNG). In the first step, impurities such as water, hydrogen sulphide, and carbon dioxide are removed to prevent potential freezing problems in the refrigeration process and to meet LNG product quality specifications. In the refrigeration step, natural gas is cooled to approximately -162°C in a heat exchange cycle using compressed refrigerant(s), such as propane, ethane, and methane. A simplified illustration of the LNG production process is shown below in Figure 7.

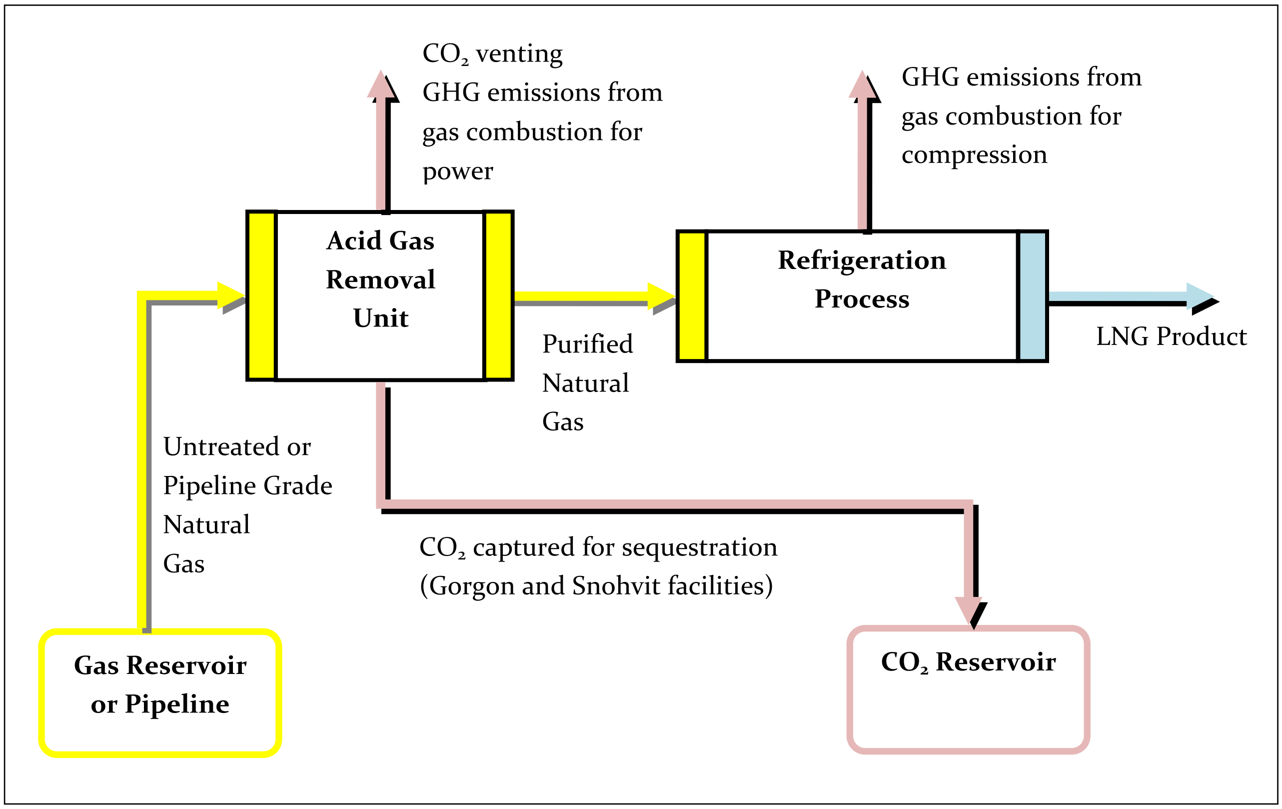


Figure 7 – Schematic of LNG production process with main emission sources.

Figure 7 above shows a high-level diagram of the natural gas liquefaction process, beginning with a natural gas inlet directly from gas fields or a pipeline on the left. The inlet natural gas first enters a unit to remove CO_2 contained within this stream. The process of acid gas removal is sometimes done in two steps, with the first step occurring upstream, bringing the reservoir natural gas to pipeline quality, with the second step

occurring within the LNG facility. In most LNG plants this CO_2 is vented to atmosphere, and is thus one major source of emissions at the LNG facility.

Figure 7 also shows the path taken by this CO_2 if it is to be injected in an underground reservoir – note that only one installed and operating plant in the world (Snohvit, Norway) currently incorporates carbon capture and storage (CCS). The Gorgon plant in Australia, currently in the planning phase, anticipates using CCS.

After leaving the CO_2 removal unit, the natural gas will pass through removal units for other impurities and then enter the refrigeration process. The refrigeration process may be divided into 'trains', which are processes operating in parallel to handle the total facility production capacity (the refrigerant compressors can only be sized to refrigerate a maximum amount of natural gas).

Worldwide, all currently operating plants but one (Snohvit, Norway[21]) use 'direct drive', which means that natural gas is used directly by the plant in the refrigeration step to drive the compressors. The proportion of GHG emissions from a 'typical' LNG plant, which receives natural gas that has undergone some initial processing, is shown below in Figure 8. The refrigeration/compression step is the largest consumer of energy and hence the largest producer of GHG emissions.

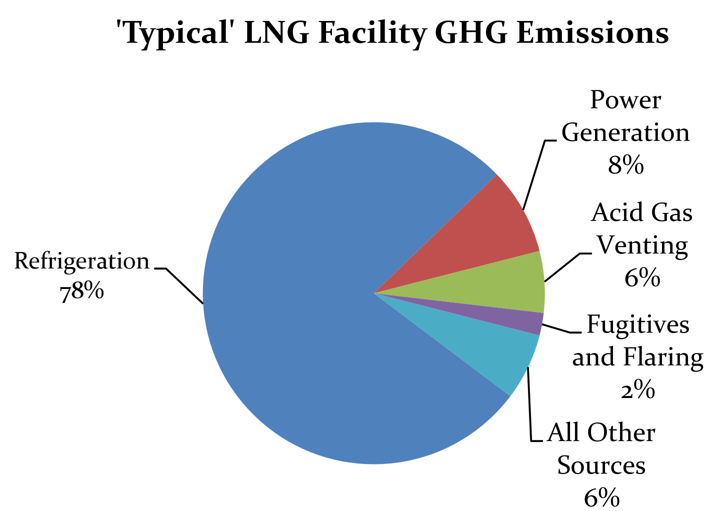


Figure 8 – GHG emissions allocations from a natural gas powered LNG facility.[22]

[21] The Snohvit plant uses natural gas generated electricity with grid electricity back-up.

[22] This emissions breakdown represents the average of the Sabine Pass, Australia Pacific, and Gladstone facilities. These three facilities receive natural gas that has undergone initial processing to meet pipeline gas quality specifications. Emissions from facilities that receive gas directly from the gas field without any initial processing will have a somewhat different emissions profile. The main difference being that a higher percentage of emissions will be allocated to power generation, as these facilities will run equipment to process natural gas at the LNG facility, rather than upstream.

Other sources of GHG emissions include electricity generated on-site (through natural gas combustion) to be used in the process, methane that is released as part of the removal of nitrogen from the LNG product and other various smaller sources including flaring and on-site heating.

2.3.1 LNG Process Technologies

A number of different refrigeration processes are currently in use in operating LNG plants around the world. The most common processes are: ConocoPhillips' Optimized Cascade®; Air Products and Chemicals Inc.'s C3/MR™, Split MR™, and AP-X™; and, the Linde Mixed Fluid Cascade (MFCP™). These processes primarily differ in the number of cycles (heat exchange steps) and the type refrigerant(s) used. Figure 9 below shows the total worldwide installed capacity of various refrigeration processes. The C3/MR™ process was most commonly used in LNG plants until recently, when plants began utilizing other processes such as the Optimized Cascade®, AP-X™, and Split MR™.

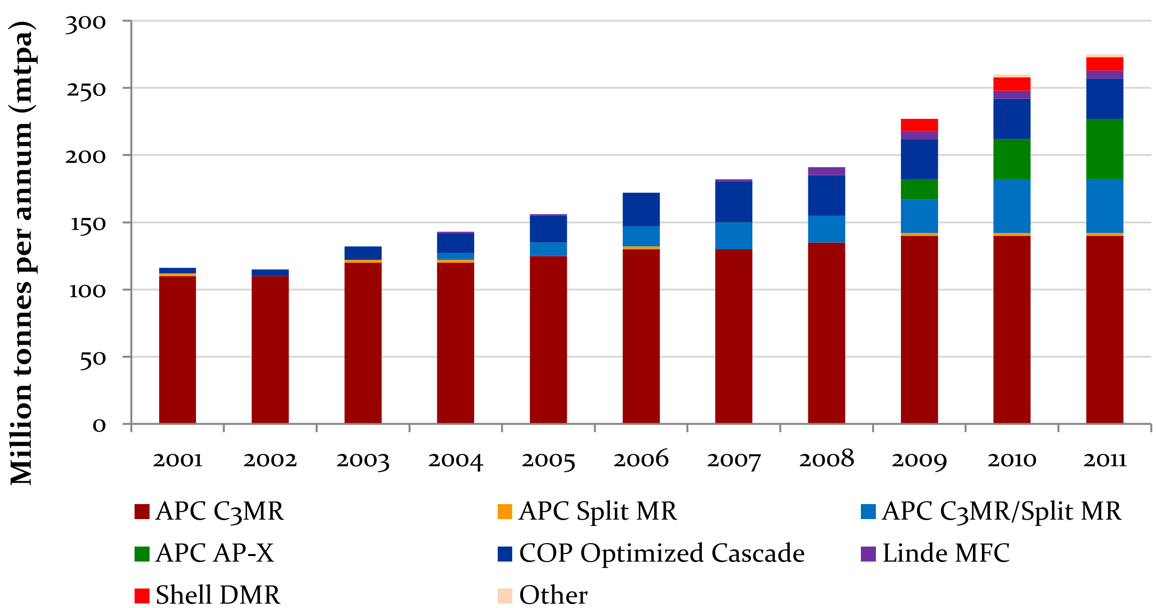


Figure 9 – LNG liquefaction capacity by type of process technology, 2001-2011[23].

Differences in efficiency – energy used per tonne LNG produced – between the various processes do exist; however, these differences are generally not significant. Further, a simple comparison of the efficiencies of the various process technologies can be misleading. This is because the overall efficiency of a particular LNG plant is dependent on both the process technology choice and the selection of process equipment, such as refrigeration compressors. When designing an LNG plant, the selection of process technology and equipment are interrelated, as the process technology must be able to work hand-in-hand with the process

[23] Adapted from International Gas Union (2012).

equipment to result in a reliable LNG plant.[24] Therefore, the overall efficiency of a particular plant is a more meaningful metric than process technology efficiency.

When designing a LNG plant, there are three main strategies for reducing GHG emissions: incorporating energy efficient equipment and heat recovery processes; pumping CO_2 back into the ground that would have been vented (CCS); and, using a low GHG emitting power source. For the first strategy, there are a number of options including high-efficiency compressors, high-efficiency power generation turbines, less energy-intensive CO_2 stripping processes and waste heat recovery. CCS can have a particularly large impact when the facility is processing an inlet gas with a high CO_2 concentration. The third strategy involves the electrification of the plant with the use of low emission electricity (e.g., from renewables).

[24] Caswell, C., Durr, C., Kotzot, H., and D. Coyle. (2011). Additional myths about LNG. Available online: http://bit.ly/12iBKO2.

3 GHG Emissions from a Hypothetical BC LNG Value Chain

This section presents the GHG emissions from a hypothetical BC LNG value chain consisting of: gas extraction, processing, and production at plays in northeast BC; transmission of produced gas via pipeline to coastal BC; and, a LNG facility with 2 trains producing 12 million tonnes per annum (mtpa) LNG. The GHG emissions associated with various natural gas supply options (Montney and Horn River) and LNG facility power options have been calculated and are reported and discussed in this section. Two power supply options were considered when calculating the emissions from a hypothetical BC LNG facility, including:

- **e-LNG** –LNG facility powered entirely by electricity. Two different electricity supply options are considered: (1) the BC electricity grid at three different GHG emission intensities (200, 100, and 0 t CO_2e / GWh)[25] and (2) a site-located combined cycle natural gas power plant.
- **Industry standard** – direct-drive refrigeration compressors powered with natural gas and electricity generated with natural gas generators.

The GHG emissions reported in this section include emissions associated with upstream natural gas extraction, production and processing, transmission of natural gas from the site of extraction to the LNG facility, and natural gas liquefaction at the LNG plant. In the absence of publicly available BC facility designs, it was necessary to make a number of assumptions in the GHG calculations, and thus there is significant uncertainty in the GHG emissions reported. Given this uncertainty, the purpose of this section is not to provide a single value for GHG emissions, but rather to explore a range of potential GHG emissions for various LNG plant designs and upstream gas supply options.

Estimations for the emissions intensity of the LNG facility portion of the value chain are based on publicly available emissions estimates from proposed and recently constructed international LNG facilities (further discussion of these facilities is presented in Section 4). In some cases, there is a lack of data relevant to the specific operating conditions of the hypothetical BC LNG value chain. For example, data is not readily available for LNG facilities powered by grid electricity. In these cases, the available data is leveraged as much as possible, with associated uncertainty reflected in the GHG emissions range reported.

3.1 Upstream Natural Gas Extraction, Production, and Processing

The sources of upstream natural gas GHG emissions are described in Section 2.1. For this report, it has been assumed that natural gas supplied to the hypothetical LNG plant in BC will be extracted from the shale gas plays in the Horn River basin and Montney formation in northeast BC. These shale gas plays have the

[25] BC Hydro, the crown corporation operating the BC electricity grid, has estimated that it could provide a hypothetical grid-connected LNG facility with electricity having a GHG emission factor of 200 tCO_2e / GWh without changing the GHG intensity of the grid used to meet the province's other electricity requirements. The 0 and 100 tCO_2e / GWh scenarios have been added to demonstrate the effect of the grid emission factor on LNG facility emissions.

potential to provide a significant portion of BC's natural gas production in the future, and may therefore be a major supplier of natural gas to any future LNG facilities.

GHG emissions associated with shale gas extraction and production have received considerable attention in recent years. Howarth[26] published a high-profile study claiming that upstream emissions from shale gas are significantly higher than from conventional gas. This study used the same data sources that were used by the US EPA to calculate emission factors for unconventional gas production[27]. However, the methodology used by the US EPA in calculating its emission factors have been disputed by CERA,[28] and the applicability of both the Howarth and US EPA results to the Canadian context has been disputed by $(S\&T)^2$ consultants for NRCAN[29]. Pembina[30] has also acknowledged that the Howarth work was not representative of conditions in BC, mainly because it assumes methane venting that would not be allowable under BC regulations.

For this report, the upstream emissions for the hypothetical BC value chain were calculated using GHGenius, a model for the lifecycle assessment of fuels developed for NRCAN. The GHGenius emissions calculations are based on data received from Canadian shale gas well drilling operations. Therefore, the emissions calculated with the GHGenius model appear to be the most relevant for gas extracted in northeast BC. However, it should be noted that the calculations in the model are built with data from just two operations. This is a very small sample and therefore the emissions estimates reported in this section contain uncertainty.

Assumptions made when calculating upstream shale gas GHG emissions in the GHGenius model are outlined in Table 1.

The amount of natural gas that must be extracted and transmitted to the LNG facility varies among the different power supply options. It has been assumed that all BC facilities will have a 'base' natural gas demand of 12 mtpa, which is required to produce 12 mtpa of LNG.[31] The industry standard and combined cycle e-LNG facilities both require additional natural gas for electric power generation. Additional natural gas is also required by the industry standard facility for compression power generation. The amount of additional natural gas required by these facilities was calculated (see subsections 3.3.3 and 3.3.4 for further details) and added to the 'base' natural gas requirement of 12 mtpa when calculating upstream GHG emissions. The natural gas demands of the various LNG facilities were calculated to be: 12 mtpa for grid powered e-LNG; 12.7 mtpa for combined cycle e-LNG; and, 13.0 mtpa for industry standard LNG.

[26] Howarth, R., Santoro, R., and A. Ingraffea. (2011). Methane and greenhouse-gas footprint of natural gas from shale formations. *Climatic Change Letters.* Available online: http://bit.ly/1az3CeM.
[27] $(S\&T)^2$ Consultants Inc. (August 31, 2011). Shale gas update for GHGenius. Available online: http://bit.ly/117DVow.
[28] CERA. (2011). Mismeasuring methane: estimates for greenhouse gas emissions from shale gas production are significantly overstated. Available online: http://bit.ly/1335dIG.
[29] $(S\&T)^2$ Consultants Inc. (August 31, 2011).
[30] The Pembina Institute. (September 2011). Shale gas in British Columbia: risks to B.C.'s climate action objectives. Available online: http://bit.ly/uvXQWv.
[31] This does not factor in transmission and LNG process gas losses arising from fugitive emissions and episodic flaring or venting. However, it is expected that these losses will not be significant and so their exclusion from the total 'base' mass of natural gas supplied will not materially affect the upstream emissions calculations.

Table 1 – Assumptions and parameters used in GHGenius.

Parameter/Assumption	Value
Gas formation type	Shale[32]
Montney gas CO_2 concentration (mol%)	1
Horn River gas CO_2 concentration (mol%)	12
Extraction Technology	Unconventional drilling with hydraulic fracturing
Extraction and Processing Energy Source(s)	Natural gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	Assumed to be 1
Natural gas pipeline distance (km)	Montney – 863 (Pacific Trails Pipeline plus distance from Summit Lake to Fort St. John) Horn River – 1,088 (Pacific Trails Pipeline plus distance from Summit Lake to Fort Nelson)
Power source for pipeline transmission	Natural gas

The GHGenius calculation results for emissions associated with the extraction, production, and processing of natural gas from the Montney and Horn River plays are presented in Table 2 and Table 3 below. These are the emissions associated with producing and transmitting the mass of natural gas (tpa) required by each facility, as mentioned above.

Table 2 – Emissions from extraction and production of natural gas from the Montney play.

GHG Source	Emissions (t CO2e, Grid Powered e-LNG)	Emissions (t CO2e, Combined Cycle e-LNG)	Emissions (t CO2e, Industry Standard LNG)
Natural gas production and processing	1,680,000	1,780,000	1,820,000
Natural gas extraction	1,850,000	1,950,000	2,000,000
Fugitive emissions, venting, and flaring	954,000	1,010,000	1,030,000
Reservoir CO_2 venting and H_2S Removal	0 (All formation CO_2 vented at LNG facility)	0 (All formation CO_2 vented at LNG facility)	0 (All formation CO_2 vented at LNG facility)
TOTAL	**4,490,000**	**4,740,000**	**4,860,000**
Emissions Intensity (tCO2e/tLNG)	0.37	0.39	0.40

[32] Some conventional natural gas is still produced at Montney, with an approximate CO_2 concentration of 5%. The GHG emissions associated with producing this gas are approximately 26% greater than the emissions from producing Montney shale gas, primarily because of the higher CO_2 content. If the hypothetical BC facilities are supplied with any Montney conventional gas, this will be captured in the range of emissions reported below, as emissions from this gas are higher than Montney shale gas, but lower than Horn River gas.

Table 3 – Emissions from extraction and production of natural gas from the Horn River play.

GHG Source	Emissions (t CO2e, Grid Powered e-LNG)	Emissions (t CO2e, Combined Cycle e-LNG)	Emissions (t CO2e, Industry Standard LNG)
Natural gas production and processing	1,810,000	1,910,000	1,960,000
Natural gas extraction	1,980,000	2,100,000	2,150,000
Fugitive emissions, venting, and flaring	967,000	1,020,000	1,050,000
Reservoir CO_2 venting and H_2S Removal	3,280,000	3,460,000	3,550,000
TOTAL	**8,040,000**	**8,490,000**	**8,700,000**
Emissions Intensity (tCO2e/tLNG)	0.67	0.71	0.73

3.2 Natural Gas Transmission

GHG Emissions arising from natural gas transmission from the Montney and Horn River plays were also calculated using the GHGenius model. Sources of emissions included in these calculations include: natural gas combustion for compression; fugitive emissions from the pipeline system; and, fugitive emissions from storage points along the pipeline. Note that GHG emissions from natural gas transmission may be lower if the gas transmission pipeline is run by electric compressors; however, this report does not calculate GHG emissions for this scenario because it is not standard practice in the natural gas industry. The results of the GHGenius emission calculations are shown below in Table 4 and Table 5.

Table 4 – Emissions from transmission of natural gas extracted from the Montney play.

GHG Source	Emissions (t CO2e, Grid Powered e-LNG)	Emissions (t CO2e, Combined Cycle e-LNG)	Emissions (t CO2e, Industry Standard LNG)
Natural gas transmission and storage	555,000	586,000	601,000
Emissions Intensity (tCO2e/tLNG)	0.046	0.049	0.050

Table 5 – Emissions from transmission of natural gas extracted from the Horn River play.

GHG Source	Emissions (t CO2e, Grid Powered e-LNG)	Emissions (t CO2e, Combined Cycle e-LNG)	Emissions (t CO2e, Industry Standard LNG)
Natural gas transmission and storage	761,000	804,000	824,000
Emissions Intensity (tCO2e/tLNG)	0.063	0.067	0.069

3.3 Natural Gas Liquefaction Plant

As explained above, individual LNG plants have varying power requirements based on site characteristics and design specifications. However, for the hypothetical BC LNG plant under consideration, such characteristics and specifications are currently unknown. Therefore, in order to determine the energy consumption of the BC plant, it was necessary to estimate this from the data published by other LNG facilities.

GHG emissions from the hypothetical BC LNG facility are discussed in this section under four areas:

- Acid gas venting
- N_2 purge, flaring and fugitive emissions
- Power generation for non-compression activities
- Compression

3.3.1 Acid Gas Venting

Acid gas venting emissions are estimated from the amount of CO_2 present in the pipeline gas. The energy requirement for the acid gas removal unit is estimated as part of the facility electricity requirement in Section 3.3.3.

Emissions for CO_2 venting have been estimated for pipeline quality gas sourced from the Montney and Horn River fields. Assuming a concentration of CO_2 in LNG facility inlet gas of 1 mol% (approximately 2.6 mass%), the mass of CO_2 vented is approximately 312,000 tCO_2e for a 12 mtpa plant, or 0.026 tCO_2e/t LNG. This estimate is valid for e-LNG and standard LNG facilities as the additional natural gas transported to site for energy purposes would not be sent through the acid gas removal unit.

3.3.2 N_2 Purge, Flaring and Fugitive Emissions

Minor sources of GHG emissions at the LNG facility include methane vented in the process of removing nitrogen from LNG, small leaks from process equipment and piping (fugitives), and flaring of natural gas during process upsets when it cannot be captured or retained within the process. A summary of emissions from these sources for the international facilities surveyed in this report (that report emissions in these specific categories) is shown below in Table 6.

Table 6 – GHG emissions from N2 purge, flaring, and fugitive emissions at international LNG facilities.

Facility	Sabine Pass	Australia Pacific	Pluto	Gorgon
Methane in N_2 Purge (tCO_2e / mtpa LNG)	*N/A*	13,333	1,395	*N/A*
Flaring (tCO_2e / mtpa LNG)	215	6,667	6,744	2,733
Fugitive emissions intensity (t CO_2e / mtpa LNG)	5,600	889	930	1,265
TOTAL (tCO_2e / mtpa LNG)	**5,815**	**20,889**	**9,069**	**3,998**
Percent of Total LNG Facility Emissions (%)	2.4	7.5	2.4	1.1

Australia Pacific and Pluto are the only facilities that have reported emissions from methane vented during nitrogen purging. Most recently designed or constructed LNG facilities use a recycle compressor to recover methane released during nitrogen purging and recycle it to be used as process fuel gas. [33] This process is used in the Pluto plant, resulting in emissions from nitrogen purging being less than 1% of total facility emissions. The Australia Pacific plant does not appear to use recycle compressors to recover methane released during nitrogen purging, which may explain the relatively high GHG emissions reported for this category (approximately 5% of total facility emissions).

GHG emissions for the hypothetical BC facilities were calculated using the emissions intensity for the Pluto facility, as this includes all three categories of emissions and represents the most likely practice that will be used at a BC facility (methane recycling). GHG emissions were calculated to be 108,828 t CO_2e for a 12mtpa plant. It has been assumed that this emissions estimate will apply to the e-LNG and industry standard LNG facility types, as the activities described in this subsection are not expected to vary significantly among the different facility types.

3.3.3 Electricity for Non-Compression Activities

Electrical power consumption for non-compression activities in an LNG design will depend on many factors, some of which may be controlled by the process design, while others are related to the specific project site. In the absence of more detailed BC site information, power consumption was estimated from information available about existing or planned LNG plants in other jurisdictions. GHG emissions were estimated directly from the power generation GHG intensity of international facilities.

For the industry standard LNG facility, the reported GHG emissions of international facilities were used to estimate the GHG emissions directly, since it is likely that the performance of this hypothetical BC facility

[33] Chevron Australia. (2005). Draft environmental impact statement/environmental review and management programme for the Gorgon development, Section 13: Greenhouse gas emissions – risks and management. Available online: http://bit.ly/Xb7Ent.

would be similar to these facilities. A summary of the emissions associated with power generation from international LNG facilities is shown below in Table 7.

Table 7 – GHG emissions from power generation at international LNG facilities.

Facility	Sabine Pass	Australia Pacific	Pluto	Gladstone	Gorgon
Emissions from Power Generation (tCO2e)	293,000	400,000	528,000	319,196	2,091,184
Capacity (mtpa LNG)	16	18	4.3	10	15
Emissions Intensity (tCO2e/tLNG)	0.018	0.022	0.12	0.032	0.14

Not all of the conditions at these facilities are likely to be relevant to the conditions at a BC LNG facility. Of the five facilities, both Pluto and Gorgon process gas that has not been subjected to upstream processing, and hence there is a higher energy demand for gas processing. Gorgon also proposes to incorporate CCS, which further increases power generation requirements. The Sabine Pass facility has very low power requirements for acid gas removal when compared to the pipeline quality gas that would likely be used at a BC facility. Therefore, GHG emissions intensity from the Australia Pacific and Gladstone facilities were used to provide a range of potential GHG emissions from non-compression power generation.

Industry Standard GHG Emissions

The calculated GHG emissions from power generation for the industry standard plant are shown below in Table 8.

Table 8 - GHG emissions from power generation at a 12mtpa BC industry standard facility.

Facility	Industry Standard
Emissions from Power Generation (tCO_2e)	264,000 – 384,0000
Emissions Intensity (tCO_2e / t LNG)	0.022 – 0.032

e-LNG GHG Emissions

In order to estimate the emissions from power generation at the e-LNG facilities, the GHG emissions data from Australia Pacific and Gladstone were used to calculate the energy of the natural gas combusted for power generation at these facilities. The electricity required for the e-LNG facilities was then estimated using a simple cycle turbine efficiency of 36%[34] and a combined cycle turbine efficiency of 55%.[35] GHG

[34] GE's LM2500 series aeroderivative turbines, which are commonly used in LNG plants, range in efficiency from approximately 34-40%. See: GE Power & Water. (2011). Fast, flexible, power: aeroderivative product and service solutions. Available online: http://invent.ge/10CRtEL.

[35] US Energy Information Administration. (2013). Assumptions to the AEO 2013: electricity market module. Available online: http://1.usa.gov/OJha1a.

emissions from electricity generation were then calculated with the BC grid emission factors (for the grid connected facilities) and a natural gas combustion emission factor (for the combined cycle facility). The results of the GHG emission calculations are shown below in Table 9.

Table 9 – GHG emissions from power generation at a 12mtpa BC e-LNG facility.

Facility	Grid e-LNG (0 t / GWh)	Grid e-LNG (100 t / GWh)	Grid e-LNG (200 t / GWh)	Combined Cycle e-LNG
Emissions from Power Generation (tCO_2e)	0	52,000 – 75,000	104,000 – 149,000	175,000 – 251,000
Emissions Intensity (tCO_2e / t LNG)	0	0.0043 – 0.0062	0.0087 – 0.012	0.015 – 0.021

3.3.4 Compression

Power consumption for refrigeration/compression activities in an LNG plant will depend on many factors such as compressor efficiency, power source (direct-drive gas or electric), operating conditions, and other process design and equipment choices. In the absence of more detailed BC facility information, compression GHG emissions were estimated from information available about existing or planned LNG plants in other jurisdictions.

For the industry standard LNG facility, the reported GHG emissions of international facilities were used to estimate the GHG emissions directly, since it is likely that the performance of this hypothetical BC facility would be similar to these facilities. A summary of the emissions associated with compression at international LNG facilities is shown below in Table 10.

Table 10 – Compressive power emissions at international facilities.

Facility	Sabine Pass	Australia Pacific	Pluto	Gladstone	Gorgon
Emissions from Compression (tCO_2e)	3,520,000	3,560,000	804,000	2,471,724	2,467,301
Capacity (mtpa LNG)	16	18	4.3	10	15
Emissions Intensity (tCO_2e/t LNG)	0.22	0.20	0.19	0.25	0.16

Industry Standard GHG Emissions

A range of GHG emissions from compressive power generation for a 12 mtpa industry standard LNG facility in BC was calculated using the data in Table 9. The Gorgon facility, which has the lowest compression emissions intensity, has been excluded from this range in the interest of providing a conservative estimate of compression emissions. The calculated GHG emissions are shown below in Table 11.

Table 11 - GHG emissions from compression at a 12mtpa BC industry standard facility.

Facility	Industry Standard
Emissions from Compression (tCO_2e)	2,280,000 – 3,000,000
Emissions Intensity (tCO_2e / t LNG)	0.19-0.25

e-LNG GHG Emissions

Electric-drive refrigeration/compression either uses electricity generated on-site or grid-electricity. The Snohvit facility uses electric drive from site-generated electricity with grid backup. However, the emissions from the facility are publicly reported as a total and are not disaggregated for comparison of the refrigeration/compression emissions only. Therefore, in the absence of performance or engineering design data for an electric-drive LNG facility, product literature was consulted to estimate the performance benefit from electrification. [36]

Using this literature, an estimate of compression efficiency was derived for the industry standard and BC e-LNG facilities. The compression efficiency for each facility type was calculated to be: 30% for the industry standard facility (based on a gas turbine efficiency of 36% and a compressor efficiency of 84%); 80% for the grid powered e-LNG facility (based on a electric motor efficiency of 95% and a compressor efficiency of 84%); and, 44% for the combined cycle e-LNG facility (based on a electric motor efficiency of 95%, a compressor efficiency of 84%, and a combined cycle plant efficiency of 55%).[37]

These efficiencies were then used in combination with the data above in Table 10 (excluding Gorgon) to determine a range of natural gas energy requirements for the e-LNG facilities. A natural gas combustion emission factor was then used to calculate the GHG emissions arising from the combustion of this amount of natural gas. Results of the calculations are shown below in Table 13.

[36] ABB. (2006). All electric LNG plants: better, safer, more reliable – and profitable. Available online: http://bit.ly/117SeST and Siemens. (Date unknown). Pushing the limits of productivity: the all-electric liquefaction plant concept. Available online: http://sie.ag/12OVrIp.

[37] The equipment and power plant efficiencies in the ABB (2006) reference were changed slightly when calculating compression efficiency since they appeared to be based on outdated efficiency values. ABB (2006) was only referenced for the electric motor efficiency. GE Power & Water (2011) was the reference used for gas turbine efficiency and US Energy Information Administration (2013) was referenced for the combined cycle plant efficiency. Compressor efficiency was estimated from: Pelagotti, A. (2013). Latest advances in LNG compressors. *LNG 17: International Conference & Exhibition on Liquefied Natural Gas*. Available online: http://bit.ly/10CXvoW.

Table 12 – GHG emissions from compression at a 12mtpa BC e-LNG facility.

Facility	Grid e-LNG (0 t / GWh)	Grid e-LNG (100 t / GWh)	Grid e-LNG (200 t / GWh)	Combined Cycle e-LNG
Emissions from Compression (tCO_2e)	0	460,000 – 609,000	921,000 – 1,220,000	1,550,000 – 2,040,000
Emissions Intensity (tCO_2e/t LNG)	0	0.038 – 0.051	0.077 – 0.10	0.13 – 0.17

3.4 Carbon Capture and Storage (CCS)

Some international facilities make use of CCS to capture and store CO_2 contained within the source reservoir natural gas. The Snohvit facility currently captures and stores CO_2 in a sub-sea reservoir and the Gorgon facility plans to make use of CCS in a similar manner (these facilities are discussed further in Section 4). While an in-depth study on the applicability of CCS to the hypothetical BC LNG value chain is not presented in this report, it should be noted that reducing value chain emissions through the use of CCS is a possibility. The most applicable point in the BC value chain to apply CCS would be at the Horn River gas processing plants, where a large amount of CO_2 is separated from extracted natural gas and released to atmosphere. If CCS was used at Horn River, then the upstream CO_2 venting emissions associated with gas supplied from this play could be significantly reduced. However, the CCS process requires power for capturing CO_2, transmission via pipeline, and injection underground, which results in power generation GHG emissions. Also, some CO_2 venting emissions will still occur with CCS, as the CCS process is not 100% efficient (in terms of the ratio between the volume of CO_2 entering the CCS process to the volume of CO_2 eventually injected). Therefore, the magnitude of emissions reductions arising from the use of CCS will depend on the power source selected and the CCS process efficiency.

3.5 Summary

A summary of the average GHG emission intensities of the hypothetical BC value chains surveyed in this section is displayed in Figure 10 below. The error bars in the figure represent the range of intensities calculated for each value chain. In practice, the actual specific GHG intensity of a particular value chain could fall within this range.

Specific GHG intensity values for particular value chains will be determined by a number of factors, but the most important factor appears to be the natural gas supply source. This is for two reasons: (1) upstream emissions make up the highest proportion of total value chain emissions for all facility types; and (2) the significant difference in upstream emissions associated with Montney and Horn River gas accounts for the majority of the GHG intensity range. Facilities receiving natural gas extracted entirely at the Montney play will have GHG intensities closer to the lower end of the range, while facilities receiving natural gas extracted entirely at the Horn River play will have GHG intensities closer to the higher end of the range.

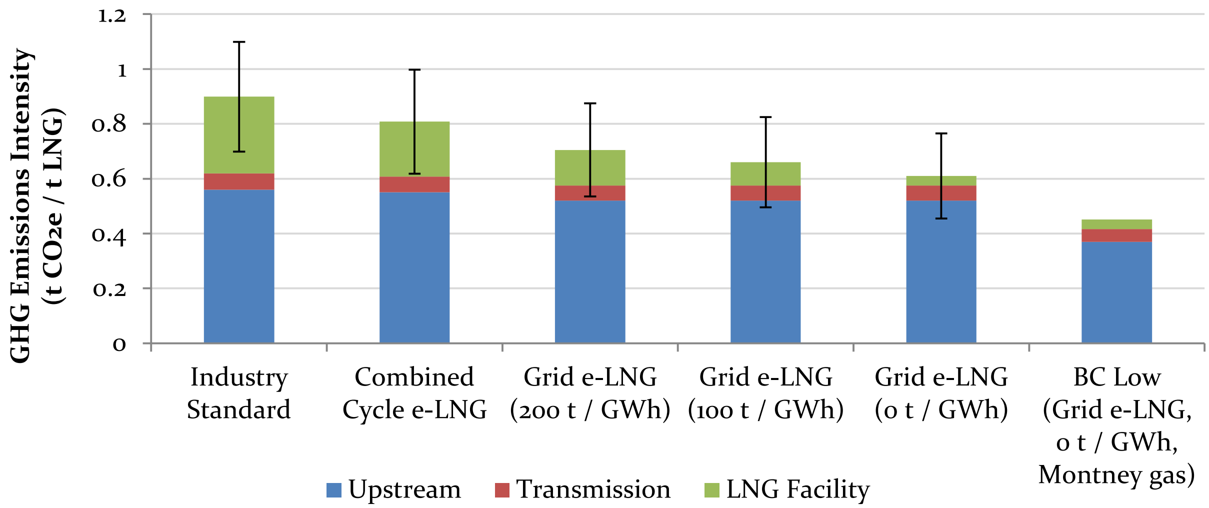


Figure 10 – Average GHG intensities of hypothetical BC facilities with various power supply options.

The GHG intensity that may be expected in the 'BC Low' value chain is also shown in the figure above (0.45 tCO_2e / t LNG). This represents the lowest emitting scenario considered in this report – a grid powered LNG plant supplied with electricity at 0 tCO_2e / GWh and natural gas from Montney. This intensity could also possibly be achieved with gas supplied by Horn River if CCS was found capable of capturing and storing approximately 92% of the CO_2 contained in the reservoir gas and the CCS process was powered with non-emitting electricity.

Comprehensive summaries of the GHG emissions and emissions intensities of the hypothetical BC facilities surveyed in this section are shown in Table 13, Table 14, and Table 15 below.

Table 13 – GHG emissions and emissions intensities for the industry standard 12mtpa BC facility.

Value Chain Stage	Emissions Range ($t\ CO_2e$)	Emissions Intensity Range ($t\ CO_2e/t$ LNG)	Average Emissions Intensity ($t\ CO_2e/t$ LNG)
Upstream Extraction and Processing	4,860,000 – 8,700,000	0.41 – 0.73	0.56
Transmission	601,000 – 824,000	0.050 – 0.069	0.059
LNG Facility (TOTAL)	2,960,000 – 3,800,000	0.25 – 0.32	0.28
• Acid gas venting	312,000	0.026	0.026
• N_2 purge, flaring, and fugitives	109,000	0.0091	0.0091
• Non-compressive power generation	264,000 – 384,000	0.022 – 0.032	0.027
• Compression	2,280,000 – 3,000,000	0.19 – 0.25	0.22
TOTAL	**8,420,000 – 13,300,000**	**0.70 – 1.1**	**0.91**

Table 14 – GHG emissions and emissions intensities for the combined cycle e-LNG 12mtpa BC facility.

Value Chain Stage	Emissions ($t\ CO_2e$)	Emissions Intensity Range ($t\ CO_2e/t$ LNG)	Average Emissions Intensity ($t\ CO_2e/t$ LNG)
Upstream Extraction and Processing	4,740,000 – 8,490,000	0.39 – 0.71	0.55
Transmission	586,000 – 804,000	0.049 – 0.067	0.058
LNG Facility (TOTAL)	2,140,000 – 2,720,000	0.18 – 0.23	0.20
• Acid gas venting	312,000	0.026	0.026
• N_2 purge, flaring, and fugitives	109,000	0.0091	0.0091
• Non-compressive power generation	175,000 – 251,000	0.015 – 0.021	0.018
• Compression	1,550,000 – 2,040,000	0.13 – 0.17	0.15
TOTAL	**7,470,000 – 12,000,000**	**0.62 – 1.0**	**0.81**

Table 15 – GHG emissions and emissions intensities for the grid-powered e-LNG 12mtpa BC facility.

Value Chain Stage	Emissions ($t\ CO_2e$)	Emissions Intensity Range ($t\ CO_2e/t$ LNG)	Average Emissions Intensity ($t\ CO_2e/t$ LNG)
Upstream Extraction and Processing	4,490,000 – 8,040,000	0.37 – 0.67	0.52
Transmission	555,000 – 761,000	0.046 – 0.063	0.055
LNG Facility			
0 t / GWh Grid (TOTAL)	421,000	0.035	0.035
100 t / GWh Grid (TOTAL)	933,000 – 1,100,000	0.078 – 0.092	0.085
200 t / GWh Grid (TOTAL)	1,450,000 – 1,790,000	0.12 – 0.15	0.13
• Acid gas venting	312,000	0.026	0.026
• N_2 purge, flaring, and fugitives	109,000	0.0091	0.0091
• Non-compressive power generation			
○ 0 t / GWh Grid	0	0	0
○ 100 t / GWh Grid	52,000 – 75,000	0.0043 – 0.0062	0.0053
○ 200 t / GWh Grid	104,000 – 149,000	0.0087 – 0.012	0.011
• Compression			
○ 0 t / GWh Grid	0	0	0
○ 100 t / GWh Grid	460,000 – 609,000	0.038 – 0.051	0.045
○ 200 t / GWh Grid	921,000 – 1,220,000	0.077 – 0.10	0.089
TOTAL (0 t / GWh Grid)	**5,460,000 – 9,220,000**	**0.46 – 0.77**	**0.61**
TOTAL (100 t / GWh Grid)	**5,970,000 – 9,900,000**	**0.50 – 0.83**	**0.66**
TOTAL (200 t / GWh Grid)	**6,490,000 – 10,600,000**	**0.54 – 0.88**	**0.71**

4 GHG Emissions from Global LNG Value Chains

This section presents GHG emissions from currently operational, under construction, and proposed global LNG value chains. The GHG emission sources discussed include: emissions associated with upstream natural gas extraction, production, and processing; emissions associated with the transmission of natural gas from the site of extraction to the liquefaction plant via pipeline; and, emissions from the LNG production facility. GHG emission intensities for each value chain are calculated in this section in order to facilitate the benchmarking comparison between global value chains and the hypothetical BC facilities subsequently presented in Section 5.

4.1 Included Value Chains

Table 16 lists the LNG value chains surveyed for this report, along with rationale for the inclusion of each value chain. The value chains selected cover a broad range of upstream gas resource and LNG facility characteristics (further discussed in subsequent subsections of Section 4). Operational, under construction, and proposed value chains have been included. The proposed and under construction value chains have been included because they generally employ the most up to date technologies and processes and may therefore be considered 'best practice' in the industry with respect to the mitigation of GHG emissions.

Table 16 – List of value chains included in the benchmarking analysis.

Value Chain Name	Country	Rationale for Inclusion
Sabine Pass	U.S.	This under construction value chain has a very low proposed LNG facility intensity.
Australia Pacific	Australia	Facilities under construction that incorporate efficient processes and GHG mitigation measures.
Gladstone	Australia	
Qatargas 1 and Qatargas 2	Qatar	Qatar is the largest producer of LNG worldwide and has been included as a reference for the typical emission intensity from LNG production.
Pluto	Australia	Recently commissioned LNG plant with a very low value chain GHG intensity.
Snohvit	Norway	Some studies have claimed that Snohvit has the lowest GHG intensity of any value chain currently in operation. The Snohvit facility also includes CCS.
Gorgon	Australia	Very low GHG intensity value chain that plans to incorporate CCS.

4.2 Overview of Methodology

GHG emissions were obtained for each of the value chains from publicly available GHG-specific or broader environmental impact reports. Benchmarking was conducted on an intensity basis in tonnes of CO_2 equivalent per tonne of LNG produced.

4.2.1 Key Assumptions and Limitations

GHG Reporting Scope

For some value chains, it was not always possible to determine the exact boundaries of the published GHG emissions. For example, Statoil has published the total GHG emissions for the Snohvit facility, but does not breakdown these emissions by source. It is therefore difficult to determine if the reported GHG emissions include upstream activities, gas transmission, and gas liquefaction, or if the reported emissions only include LNG facility emissions. In value chains where this type of uncertainty exists, a discussion has been included below in the corresponding subsection.

Differences also exist with respect to how emissions data are reported in public documents for each particular value chain. Some value chains present highly disaggregated data, whereas others aggregate emissions from different sources or processes. It is not always clear what sources or processes have been aggregated and therefore it is difficult to determine whether all value chains include the same emissions sources. This adds an amount of unknown or unquantifiable error when comparing value chains in the benchmarking exercise in Section 5, as there is some uncertainty as to whether the reported emissions from all value chains are commensurable.

Projected vs. Performance Data

This benchmarking exercise compares performance data from currently operational LNG value chains with projected data for value chains currently in the planning or construction phase. As with any projected data, it may not be representative of actual facility performance after commissioning, especially if design alterations occur during construction. The GHG emissions reported for these facilities should therefore be viewed as estimates containing a certain amount of unknown or unquantifiable error.

Calculations Performed by this Report's Authors

For value chains where GHG emissions intensities have not been reported, the authors of this report have calculated these intensities by dividing the total reported upstream, transmission, or LNG facility emissions by the total LNG produced in a particular value chain.

Where public documents have not reported upstream emissions associated with a particular value chain (Sabine Pass and Qatargas 1 & 2), these emissions have been estimated by the authors of this report. Standard GHG quantification procedures and emission factors were used to estimate these emissions. However, it was necessary to make a number of assumptions when performing these calculations, thereby adding a degree of unknown or unquantifiable error to the emissions estimates. Further discussion of these assumptions may be found in the relevant subsections below.

4.3 Sabine Pass Liquefaction Project, Cameron Parish, Louisiana

4.3.1 Description

In 2012, Cheniere Energy Partners started constructing a natural gas liquefaction plant at its currently operational LNG import terminal in Louisiana. The project is expected to be completed by 2015. It will allow the terminal to both import and export LNG, depending on market conditions. Cheniere Energy anticipates constructing the facility with four trains producing 16 mtpa of LNG.

4.3.2 Upstream Natural Gas Source and GHG Emissions

At the time of writing this report, the source of natural gas for the Sabine Pass plant remains uncertain. It is anticipated that natural gas will be supplied to the plant via the Creole Trail Pipeline, which Cheniere Energy has recently proposed expanding. This pipeline will connect the Sabine Pass facility to multiple interstate and intrastate pipelines, enabling it to purchase natural gas from multiple conventional and unconventional basins located across the United States. The Gulf Coast Texas and Louisiana onshore conventional gas fields (Permian and Anadarko) and the emerging unconventional gas fields (Barnett, Haynesville, Eagle Ford, Fayetteville, Woodford, and Bossier basins) are the most likely sources for natural gas supply at the Sabine Pass LNG plant.[38] A summary of the characteristics of the Sabine Pass natural gas supply and transmission pipeline is shown below in Table 17.

Table 17 – Sabine Pass upstream gas and pipeline characteristics.

Gas formation type	Onshore conventional and shale
Gas formation CO_2 concentration (mol%)	Barnett – 1.7, Fayetteville – 1.0, Haynesville – 4.8[39] Anadarko and Permian – 0.1[40]
Extraction Technology	Conventional drilling Unconventional drilling with hydraulic fracturing
Extraction Energy Source(s)	Natural Gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	0.01[41]
Natural gas pipeline distance (km)	120 miles (193 km)[42]
Power source for pipeline transmission	Natural Gas

[38] Cheniere Energy. (March 2013). Application of Sabine Pass Liquefaction, LLC for the long-term authorization to export liquefied natural gas. Application to the United States of America Department of Energy, Office of Fossil Energy Available online: http://bit.ly/13FOCYS

[39] Bryan Research and Engineering. (2008). Composition variety complicates processing plans for US shale gas. Available online: http://bit.ly/10jxUkG

[40] KGS Oil & Gas Reports. (2003). Gas compositions – Permian reservoirs in central Kansas. Available online: http://bit.ly/14OkjBK

[41] Calculated from the Sabine Pass environmental impact statement. This assumption has been included in the GHGenius calculations, resulting in virtually all of the reservoir CO_2 being vented before entering the transmission pipeline. This assumption essentially corrects for the very low reported Sabine Pass facility GHG emissions from acid gas venting by including the majority of these emissions in the upstream emissions calculation.

[42] Cheniere Energy. (2013). Creole trail pipeline. Available online: http://bit.ly/119E81X

Upstream GHG emissions from natural gas extraction, production, processing, and transmission have not been reported in the Sabine Pass environmental assessment document. To estimate these emissions, models were built in GHGenius v4.03 using the parameters outlined in Table 17 above. It was assumed that the natural gas supplied to the Sabine Pass facility will originate in the Barnett, Fayetteville, and Haynesville shale gas fields as well as the Anadarko and Permian fields. This assumption was based on the information provided in the Cheniere Energy application to the US DOE; however, the application does acknowledge that there is uncertainty with respect to natural gas supply options, which adds a degree of uncertainty to the upstream GHG emissions presented below.

To calculate emissions from the Barnett, Fayetteville, and Haynesville fields, a shale gas model was selected in GHGenius with input parameters including the average CO_2 concentration for the three fields (2.5 mol%) and a pipeline distance of 193km. GHG emissions associated with natural gas sourced from the Anadarko and Permian fields were also estimated in GHGenius. To calculate emissions from these fields, a conventional gas model was selected with input parameters including the average CO_2 concentration for the two fields (0.1 mol%) and a pipeline distance of 193km. GHG emissions from natural gas extraction, production, processing, and transmission of 17.3mtpa[43] of shale gas and 17.3mtpa of conventional gas supplied by these fields are shown below in Table 18 and Table 19.

Table 18 – Sabine Pass GHG sources and emissions for upstream operations.

GHG Source	Shale Emissions (t CO2e)	Conventional Emissions (t CO2e)
Natural gas production and processing	1,210,000	1,190,000
Natural gas extraction	4,060,000	4,010,000
Fugitive emissions, venting, and flaring	5,960,000	5,960,000
Reservoir CO_2 venting and H_2S Removal	1,070,000	38,000
TOTAL	**12,300,000**	**11,200,000**

Table 19 – Sabine Pass GHG sources and emissions for transmission activities.

GHG Source	Shale Emissions (t CO2e)	Conventional Emissions (t CO2e)
Natural gas transmission and storage	307,000	302,000

4.3.3 LNG Plant Configuration and GHG Emissions

[43] The mass of gas supplied to the Sabine Pass facility was calculated by assuming 16mtpa would be liquefied into LNG, with additional gas requirements for electricity and compression calculated using the GHG emissions reported in the Sabine Pass EIS.

A summary of the proposed Sabine Pass LNG plant configuration is shown below in Table 20.

Table 20 – Sabine Pass LNG plant configuration.[44]

Number of Trains	4
Inlet CO_2 Concentration	Calculated from emissions data as <0.01%.
Refrigeration Process Technology	ConocoPhillips Optimized Cascade.
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	General Electric PGT25+G4 aeroderivative gas turbine[45]
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	*Not Available*

The GHG emissions arising from the Sabine Pass facility are reported in a publicly available environmental assessment.[46] The majority of LNG plant GHG emissions arise from combustion of natural gas in the compressors driving the refrigeration process (approximately 92%) and from natural gas combustion for power generation (approximately 7.5%).

Table 21 – GHG sources and emissions for the Sabine Pass LNG plant.[47]

GHG Source	Emissions (t CO_2e for 16 mtpa plant)
Oil Heating	*Not Available*
Refrigeration Compressors	3,520,000
Power Generation	293,000
Power for Ship at Berth	*Not Available*
Backup Natural Gas Generators	824
Acid Gas Vent	688
Methane in N_2 Purge	*Not Available*
Fugitive Emissions	89,600
Flaring	3,440
TOTAL	**3,910,000**

This breakdown of GHG emissions is slightly different than for a typical for a LNG plant (refer to Figure 8). It seems likely, given the very low calculated inlet CO_2 concentration, that the reported GHG emissions have been calculated assuming that the natural gas inlet stream has already undergone acid gas removal to

[44] Federal Energy Regulatory Commission. (December 2011). Environmental assessment for the Sabine Pass liquefaction project. Available online: http://bit.ly/WqHtfr
[45] BusinessWire. (October 8, 2012). GE technology to power Cheniere Energy's LNG export facility in Louisiana. Available online: http://bit.ly/16vtlp7
[46] Federal Energy Regulatory Commission (December 2011).
[47] Federal Energy Regulatory Commission (December 2011).

an LNG standard prior to entering the facility gate. As a result, the facility has low CO_2 venting emissions and may also have a reduced energy demand for the acid gas removal unit. This would explain the relatively low emissions associated with acid gas venting and power generation, as shown in the summary of GHG emissions above in Table 21.

4.3.4 GHG Emissions Intensity

The GHG emission intensity of the Sabine Pass LNG value chain was calculated to be **0.96-1.03 tCO_2e/t LNG**. A summary of the total emissions and emission intensities for gas extraction, production, and processing, transmission, and liquefaction is shown in Table 22 below.

Table 22 – Summary of GHG emissions and emissions intensities for the Sabine Pass LNG value chain.

GHG Source	Emissions (t CO_2e for 16 mtpa plant)	Emissions Intensity (t CO_2e / t LNG)
Natural Gas Extraction, Production, and Processing	11,200,000 - 12,300,000	0.70-0.77
Natural Gas Transmission	302,000 - 307,000	0.019
Natural Gas Liquefaction	3,910,000	0.24
TOTAL	**15,400,000 – 16,500,000**	**0.96-1.03**

4.4 Australia Pacific LNG Project, Queensland, Australia

4.4.1 Description

Australia Pacific LNG Pty Limited (Australia Pacific LNG), a partnership between Origin, ConocoPhillips, and Sinopec, began construction in 2012 on a LNG liquefaction project that will utilize Australia's substantial coal seam gas resources in Queensland. The LNG plant is expected to become operational in 2015. It will include four LNG trains with an installed capacity of approximately 18 mtpa.

4.4.2 Upstream Natural Gas Source and GHG Emissions

LNG is produced by first extracting and processing coal seam gas (CSG) from Australia Pacific's gas fields, which is then transported to the LNG facility via a gas pipeline. The CSG is contained in onshore reserves located in the Surat and Bowen basins (specifically the Walloons gas fields' development area) located in Queensland, Australia. A summary of the characteristics of the natural gas supply and transmission pipeline is shown below in Table 23.

Table 23 – Australia Pacific upstream gas and pipeline characteristics.

Gas formation type	Onshore coal seam gas
Gas formation CO_2 concentration (mol%)	1
Extraction Technology	Conventional drilling Unconventional drilling with hydraulic fracturing
Extraction Energy Source(s)	Coal seam gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	1
Natural gas pipeline distance (km)	450
Power source for pipeline transmission	Coal seam gas

The emissions for upstream gas processing are shown in Table 24 below. Note that the reference document does not report emissions associated with power generation for natural gas transmission separately from power generation for other upstream operations. It is therefore not possible to calculate a unique GHG intensity for natural gas transmission independent of other upstream operations. A single intensity for extraction, production, processing, and transmission has been calculated and is reported below.

Table 24 – Australia Pacific GHG sources and emissions for upstream operations.[48]

GHG Source	Emissions (t CO2e for 18mtpa plant)
Natural gas production and processing	2,551,000
Natural gas extraction	*Included above*
Fugitive emissions, venting, and flaring	537,000
Reservoir CO_2 venting and H_2S Removal	*CO_2 venting included with LNG facility emissions*
Emissions from gas supplied by a third party	2,400,000
TOTAL	**5,488,000**

4.4.3 LNG Plant Configuration and GHG Emissions

A summary of the proposed Australia Pacific LNG plant configuration is shown below in Table 25.

Table 25 – Australia Pacific LNG plant configuration.[49]

Number of Trains	4
Refrigeration Process Technology	ConocoPhillips Optimized Cascade.
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	General Electric LM2500-G4+ aeroderivative gas turbine
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	Solar Titan 130

The majority of GHG emissions arise from combustion of natural gas in the gas turbines driving the refrigeration process (approximately 65%), power generation turbines (approximately 17%) and the acid gas CO_2 vent (approximately 11%). A summary of GHG emissions associated with the facility is shown below in Table 26.

[48] WorleyParsons. (March 2010a). Australia Pacific LNG Project, Volume 2: Gas Fields, Chapter 14: Greenhouse Gases. Available online: http://bit.ly/18lcLZ4
[49] WorleyParsons. (March 2010b). Australia Pacific LNG Project, Volume 5: Attachments, Attachment 31: Greenhouse Gas Assessment. Available online: http://bit.ly/Z7NGwD

Table 26 – GHG sources and emissions for the Australia Pacific LNG Plant.[50]

GHG Source	Emissions ($t\ CO_2e$ for 18 mtpa plant)
Oil Heating	70,000
Refrigeration Compressors	3,560,000
Power Generation	400,000
Power for Ship at Berth	520,000 *(Excluded)*
Backup Diesel Generators	400
Acid Gas Vent	580,000
Methane in N_2 Purge	240,000
Fugitive Emissions	16,000
Flaring	120,000
TOTAL	**4,986,400**

4.4.4 *GHG Emission Intensity*

The GHG emission intensity of the Australia Pacific LNG value chain was calculated to be **0.58 tCO_2e/t LNG**. A summary of emission intensities for gas extraction and production, transmission, and liquefaction is shown in Table 27 below.

Table 27 – Summary of GHG emissions and emissions intensities for the Australia Pacific LNG value chain.

GHG Source	Emissions ($t\ CO_2e$ for 18 mtpa plant)	Emissions Intensity ($t\ CO_2e$ / t LNG)
Natural Gas Extraction, Production, Processing, and Transmission	5,488,000	0.30
Natural Gas Transmission	*Included in line above*	*Included in line above*
Natural Gas Liquefaction	4,986,400	0.28
TOTAL	**10,474,400**	**0.58**

[50] WorleyParsons (March 2010b).

4.5 Gladstone LNG Project (GLNG), Queensland, Australia

4.5.1 Description

Santos Limited and its partners PETRONAS, Total, and Kogas began construction in 2010 on a LNG liquefaction and export facility on Curtis Island, near Gladstone, Queensland. The LNG facility will have an initial capacity of 3 - 4 mtpa with the potential for later expansion to 10 mtpa. The LNG facility operations are planned to commence in 2015.

Another project in the Gladstone area currently in the planning phase is the Gladstone LNG Project – Fisherman's Landing. This project is being developed by Liquefied Natural Gas Limited and will have a capacity of 3mtpa. An environmental impact statement prepared for this plant states that it will have an emissions intensity of 0.2 t CO_2e/t LNG, which would make it the least GHG intensive facility in the world.[51]

GHG intensity comparisons with the Fisherman's Landing project cannot be made as the environmental impact statement does not specify power generation requirements, the CO_2 content of the feed gas or the frequency and volumes of gas flared. Also, at the time of writing this report, the appendix to the impact statement detailing GHG emission calculations was not available on Liquefied Natural Gas Ltd.'s website.

4.5.2 Upstream Natural Gas Source and GHG Emissions

LNG is produced by first extracting and processing coal seam gas (CSG) from Australia Pacific's gas fields, then transporting the CSG to the LNG facility via a gas pipeline. The CSG is contained in reserves in the areas of Fairview, Roma, and Arcadia Valley located in Queensland, Australia. A summary of the characteristics of the natural gas supply and transmission pipeline is shown below in Table 28.

Table 28 – Gladstone upstream gas and pipeline characteristics.

Gas formation type	Onshore coal seam gas
Gas formation CO_2 concentration (mol%)	Not provided in reference documents.[52]
Extraction Technology	Conventional drilling Unconventional drilling with hydraulic fracturing
Extraction Energy Source(s)	Coal seam gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	Approximately 1 – see footnote below.
Natural gas pipeline distance (km)	435
Power source for pipeline transmission	Coal seam gas

The emissions from upstream gas extraction, processing, production and transmission are shown in Table 29 below. The reference document does not report emissions associated with power generation for natural

[51] WorleyParsons. (September 17, 2008). Gladstone LNG Project – Fisherman's Landing Environmental Impact Statement – Volume 1. Available online: http://bit.ly/ZRp64i
[52] Reference documents mention the reservoir CO_2 concentration is 'very low'. The APLNG reservoir has a CO_2 concentration of 1% and it may be assumed the Gladstone project reservoir will have a similar CO_2 concentration.

gas transmission separately from power generation for other upstream operations. It is therefore not possible to calculate a unique GHG intensity for natural gas transmission independent of other upstream operations. A single intensity for extraction, production, processing, and transmission has been calculated and is presented in the 'GHG Emission Intensity' subsection below.

Table 29 – Gladstone GHG sources and emissions for upstream operations.

GHG Source	Emissions (t CO2e for 10mtpa plant)
Natural gas production and processing	3,502,618
Natural gas extraction	*Included above*
Fugitive emissions, venting, and flaring	63,700
Reservoir CO_2 venting and H_2S Removal	*CO_2 venting included with LNG facility emissions*
TOTAL	**3,566,318**

4.5.3 LNG Plant Configuration and GHG Emissions

A summary of Santos Ltd.'s proposed LNG plant configuration is shown below in Table 30.

Table 30 – Gladstone LNG plant configuration.[53]

Number of Trains	3
Refrigeration Process Technology	ConocoPhillips Optimized Cascade
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	GE Aeroderivative, model unknown
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	*Not Available*

The major sources of greenhouse gas emissions for Gladstone LNG Project are fuel consumption in gas turbines for liquefaction and other process equipment (71%), all flaring and venting activities (20%) and power generation (9%). A summary of GHG emissions associated with the facility is shown below in Table 31.

[53] Santos. (October 2009). Supplementary EIS Greenhouse Gas Management. Available online: http://bit.ly/16vtWr4

Table 31 – GHG sources and emissions for the Gladstone LNG plant.[54]

GHG Source	Emissions ($t\ CO_2e$ for 10 mtpa plant)
Oil Heating	*Not Available*
Refrigeration Compressors	2,471,724
Power Generation	319,196
Power for Ship at Berth	*Not Available*
Backup Diesel Generators	*Not Available*
Acid Gas Vent (Reported as Flaring and Venting)	679,642
Methane in N_2 Purge	*Included in Acid Gas Vent Line*
Fugitive Emissions	1,959
Flaring	*Included in Acid Gas Vent Line*
TOTAL	**3,472,521**

4.5.4 *GHG Emission Intensity*

The GHG emission intensity of the Gladstone LNG value chain was calculated to be **0.70 tCO_2e/t LNG**. A summary of emission intensities for gas extraction and production, transmission, and liquefaction is shown in Table 32 below.

Table 32 – Summary of GHG emissions and emissions intensities for the Gladstone LNG value chain.

GHG Source	Emissions ($t\ CO_2e$ for 10 mtpa plant)	Emissions Intensity ($t\ CO_2e$ / t LNG)
Natural Gas Extraction, Production, Processing, and Transmission	3,566,318	0.36
Natural Gas Transmission	*Included in line above*	*Included in line above*
Natural Gas Liquefaction	3,472,521	0.35
TOTAL	**7,038,839**	**0.70**

[54] Santos (October 2009).

4.6 Qatargas 1 and 2, Qatar

4.6.1 Description

Qatargas Operating Company is a venture between Qatar Petroleum, Total, ExxonMobil, ConocoPhillips, Shell, Mitsui, Marubeini, Idemitsu Kosan, and Cosmo Oil. Qatargas currently operates 7 LNG facilities with a total capacity of 42 mtpa. This section only describes two of these facilities, Qatargas 1 and Qatargas 2, as GHG emission data are not available for the other facilities. Qatargas 1 consists of three LNG trains with a total capacity of 10 mtpa and Qatargas 2 consists of 2 LNG trains with a total capacity of 15.6 mtpa.

4.6.2 Upstream Natural Gas Source and GHG Emissions

The natural gas supplied to Qatargas 1 and 2 is produced on offshore platforms at the Qatar North field and sent to shore via a short (80km) pipeline. A summary of the natural gas supply and transmission pipeline is shown below in Table 33.

Table 33 – Qatargas upstream gas and pipeline characteristics.

Gas formation type	Non-associated offshore
Gas formation CO_2 concentration (mol%)	2.1
Extraction Technology	Conventional offshore drilling
Extraction Energy Source(s)	Natural Gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	2.1
Natural gas pipeline distance (km)	80
Power source for pipeline transmission	Natural Gas

GHG emissions associated with natural gas extraction, production, and transmission are not reported in Qatargas' Sustainability Report and no information on upstream gas emissions in Qatar appears to be publicly available. In order to provide an estimate of upstream emissions, the US National Energy Technology Laboratory upstream emissions calculator was used.[55] This calculator is based on emissions data from US facilities and therefore may not provide an accurate representation of emissions from facilities in Qatar. However, it appears to be the best available tool for estimating emissions from offshore conventional natural gas extraction, production, and transmission.

The GHG emissions estimates calculated for Qatargas 1 and 2 are shown below in Table 34 and Table 35. The mass of natural gas supplied to the Qatargas plants is provided in the Qatargas Sustainability Report as 9.3 mtpa[56] of gas to Qatargas 1 and 16.8 mtpa of gas to Qatargas 2. These supply numbers were used when calculating upstream GHG emissions.

[55] The calculator is available online: http://1.usa.gov/12WQKwq.
[56] With this amount of supply, it may be assumed that the Qatargas 1 facility is operating under its stated capacity of 10mtpa. This may result in an underreported facility GHG intensity, as this intensity calculation is based on the

Table 34 – Qatargas 1 & 2 GHG sources and emissions for upstream operations.

GHG Source	Qatargas 1 (t CO2e for 10 mtpa)	Qatargas 2 (t CO2e for 15.6mtpa)
Natural gas production and processing	*Included in total*	*Included in total*
Natural gas extraction	*Included in total*	*Included in total*
Fugitive emissions, venting, and flaring	*Included in total*	*Included in total*
Reservoir CO_2 venting and H_2S Removal	*Included in total*	*Included in total*
TOTAL	**1,750,935**	**3,173,570**

Table 35 – Qatargas 1 & 2 GHG sources and emissions for transmission activities.

GHG Source	Qatargas 1 (t CO2e for 10 mtpa)	Qatargas 2 (t CO2e for 15.6mtpa)
Natural gas transmission	126,407	229,113

4.6.3 LNG Plant Configuration and GHG Emissions

A summary of the operating Qatargas LNG plants configuration is shown below in Table 36.

Table 36 – Qatargas 1 and 2 LNG plant configuration[57].

Number of Trains	Qatargas 1 – 3 Qatargas 2 – 2
Refrigeration Process Technology	AP-X Hybrid Liquefaction
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	Qatargas 1 – General Electric Frame 5 heavy duty gas turbine Qatargas 2 – General Electric Frame 9 heavy duty gas turbine
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	*Not Available*

The major sources of greenhouse gas emissions for Qatargas are combustion of natural gas in turbines for power generation liquefaction compressors (68%), reservoir CO_2 venting (18%), and natural gas flaring (14%). Emissions from Qatargas 1 and 2 are shown below in Table 37.

nameplate capacity of 10 mtpa, rather than the actual amount of LNG produced. The actual amount of LNG produced by the Qatargas 1 facility was not available in reference documents to correct for this situation.
[57] Qatargas. (2012). 2011 Sustainability Report. Available online: http://bit.ly/12U4qN6

Table 37 – GHG sources and emissions for the Qatargas 1 and 2 plants[58].

GHG Source	Qatargas 1 (t CO_2e for 10 mtpa plant)	Qatargas 2 (t CO_2e for 15.6 mtpa plant)
Oil Heating	*Not Available*	*Not Available*
Refrigeration Compressors	Included with Power Generation	Included with Power Generation
Power Generation	3,536,209	4,594,043
Power for Ship at Berth	*Not Available*	*Not Available*
Backup Diesel Generators	*Not Available*	*Not Available*
Acid Gas Vent	936,055	1,216,070
Methane in N_2 Purge	*Not Available*	*Not Available*
Fugitive Emissions	*Not Available*	*Not Available*
Flaring	728,043	945,832
TOTAL	**5,200,308**	**6,755,947**

4.6.4 *GHG Emission Intensity*

The GHG emission intensity of the Qatargas 1 and 2 LNG value chains was calculated to be **0.71 tCO_2e/t LNG** and **0.65 tCO_2e/t LNG**, respectively. A summary of emission intensities for gas extraction and production, transmission, and liquefaction is shown in Table 38 and Table 39 below.

Table 38 – Summary of GHG emissions and emissions intensities for the Qatargas 1 LNG value chain.

GHG Source	Emissions (t CO_2e for 10 mtpa plant)	Emissions Intensity (t CO_2e / t LNG)
Natural Gas Extraction, Production, and Processing	1,750,935	0.18
Natural Gas Transmission	126,407	0.013
Natural Gas Liquefaction	5,200,308	0.53
TOTAL	**7,077,650**	**0.71**

[58] Qatargas (2012).
Note that a breakdown of emissions by source for each individual plant was not available, so emissions by source were estimating using the breakdown of emissions for all plants combined.

Table 39 – Summary of GHG emissions and emissions intensities for the Qatargas 2 LNG value chain.

GHG Source	Emissions (t CO_2e for 15.6 mtpa plant)	Emissions Intensity (t CO_2e / t LNG)
Natural Gas Extraction, Production, and Processing	3,173,570	0.20
Natural Gas Transmission	229,113	0.015
Natural Gas Liquefaction	6,755,947	0.43
TOTAL	**10,158,630**	**0.65**

4.7 Pluto LNG Project, Western Australia, Australia

4.7.1 Description

The Pluto LNG Project is located immediately south of the Karratha Gas Plant (KGP) on the Burrup Peninsula, Western Australia. The project is a joint venture between Woodside, the operator, Tokyo Gas and Kansai Electric. Production of LNG in train 1 began in May 2012 with an estimated output of 4.3 mtpa.

4.7.2 Upstream Natural Gas Source and GHG Emissions

The Pluto LNG plant is supplied with coal seam gas from the Pluto and Xena gas fields, which are approximately 190km offshore of Dampier, Western Australia. Gas is extracted from these fields through an offshore sub-sea gathering system, and then transmitted to shore via pipeline for processing at the LNG plant. A summary of the natural gas supply and transmission pipeline is shown below in Table 40.

Table 40 – Pluto upstream gas and pipeline characteristics.

Gas formation type	Sub-sea coal seam gas
Gas formation CO_2 concentration (mol%)	2.0
Extraction Technology	Sub-sea gathering system
Extraction Energy Source(s)	Natural Gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	2.0 Gas transmitted directly from field to LNG plant without initial processing
Natural gas pipeline distance (km)	190
Power source for pipeline transmission	Coal seam gas

The environmental impact statement for the Pluto project does not appear to include emissions associated with upstream operations or transmission. However, Woodside has informed the authors of this report that all emissions from upstream and transmission activities have been included in the reported GHG emissions. Gas processing activities are included with the LNG plant emissions, as gas from the production fields is transmitted directly to the LNG facility where it undergoes processing such as liquids removal, CO_2 removal, H_2S removal, etc. Emissions from other upstream and transmission activities, such as fugitive emissions from the production platform, have also been aggregated with LNG facility emissions in the environmental impact statement reporting.

4.7.3 LNG Plant Configuration and GHG Emissions

A summary of the LNG plant configuration for the first phase of the Pluto project is shown below in Table 41.

Table 41 – Pluto LNG plant configuration.[59]

Number of Trains	1
Refrigeration Process Technology	Shell FosterWheeler Worley (SFWW) C3MR
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	General Electric Frame 7EA heavy duty gas turbine
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	General Electric Frame 6B gas turbine

The major sources of greenhouse gas emissions for Pluto LNG Project are gas turbines for liquefaction (50%), power generation (30%), and reservoir CO_2 venting (15%). Power generation accounts for a higher proportion of emissions than is the case with a typical LNG facility. This is likely a result of most gas processing occurring at the Pluto LNG plant, rather than at upstream facilities, as is typical of most LNG value chains. A summary of GHG emissions associated with the facility is shown below in Table 42.

Table 42 – GHG sources and emissions for the Pluto LNG plant.[60]

GHG Source	Emissions (t CO_2e for 4.3 mtpa plant)
Oil Heating	*Not Available*
Refrigeration Compressors	804,000
Power Generation	528,000
Power for Ship at Berth	*Not Available*
Backup Diesel Generators	10,000
Acid Gas Vent	242,000
Methane in N_2 Purge	6,000
Fugitive Emissions	4,000
Flaring	29,000
TOTAL	**1,610,000**

4.7.4 *GHG Emission Intensity*

The GHG emission intensity of the Pluto LNG value chain was calculated to be **0.37 tCO_2e/t LNG**. A summary of emission intensities for gas extraction and production, transmission, and liquefaction is shown in Table 43 below.

[59] Woodside. (June 20, 2011). Pluto LNG Project Greenhouse Gas Abatement Program, Revision 2. Available online: http://bit.ly/YuyYjb
[60] Woodside (June 20, 2011).

Table 43 – Summary of GHG emissions and emissions intensities for the Pluto LNG value chain.

GHG Source	Emissions ($t\ CO_2e$ for 4.3 mtpa plant)	Emissions Intensity ($t\ CO_2e$ / t LNG)
Natural Gas Extraction, Production, and Processing	*Included with Liquefaction Emissions*	*Included with Liquefaction Emissions*
Natural Gas Transmission	*Included with Liquefaction Emissions*	*Included with Liquefaction Emissions*
Natural Gas Liquefaction	1,610,000	0.37
TOTAL	**1,610,000**	**0.37**

4.8 Snohvit LNG Installation, Snohvit, Norway

4.8.1 Description

The Statoil owned Snohvit natural gas plant is located in Melkoya in northern Norway. Production of LNG at the Snohvit plant began in 2007. The plant has a capacity of 4.3 mtpa LNG. It also produces approximately 0.2 mtpa LPG (Liquefied Petroleum Gas) and 0.8 mtpa condensate (mostly hydrocarbons such as pentane, hexane, etc.).

4.8.2 Upstream Natural Gas Source and GHG Emissions

The Snohvit LNG plant is supplied by three offshore gas fields (Snohvit, Albatross, and Askeladd) located in the Barents Sea approximately 140km northwest of the LNG plant in Melkoya. Natural gas is extracted using a sub-sea gathering system and then transmitted to the plant in Melkoya via a 143km pipeline. A summary of the natural gas supply and transmission pipeline is shown below in Table 44.

Table 44 – Snohvit upstream gas and pipeline characteristics.

Gas formation type	Non-associated offshore
Gas formation CO_2 concentration (mol%)	8
Extraction Technology	Sub-sea gathering system
Extraction Energy Source(s)	*Not available*
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	8 Gas transmitted directly from field to LNG plant without initial processing
Natural gas pipeline distance (km)	143
Power source for pipeline transmission	*Not available*

GHG emissions arising from upstream natural gas activities have not been reported in any publicly available documents dealing with the Snohvit facility. Total LNG facility emissions have been reported as a single number (see discussion below) and it is therefore difficult to determine whether this number includes upstream emissions, as emissions are not disaggregated by source. In this report, it has been assumed that the reported emissions value does include upstream emissions. The rationale for this assumption is that in a LNG value chain of Snohvit's type, where natural gas is extracted and directly transmitted to the LNG facility, it is common to aggregate upstream emissions with LNG facility emissions (see discussion of Pluto). If this assumption is later found to be incorrect, the total value chain emissions intensity (calculated below) should not change significantly when this error is corrected. This is because sub-sea gathering systems and pipelines typically have very low GHG emissions from extraction and transmission. Other sources of upstream emissions, such as the energy used for impurities removal, will be accounted for in the reported LNG facility emissions as this is where the gas processing takes place. Any venting of reservoir CO_2 will also be accounted for in the facility emissions for this reason; however, note that most reservoir CO_2 is not vented in the Snohvit LNG value chain, but rather it is captured and injected in a subsea reservoir.

4.8.3 LNG Plant Configuration and GHG Emissions

The Snohvit plant utilizes a Mixed Fluid Cascade[61] refrigeration process and is powered by gas turbine electrical generators with back-up electricity provided by the grid. This set-up is different from the typical LNG plant in that the compressors run on electricity generated from natural gas, rather than energy from direct natural gas combustion. One benefit of this set-up is the decoupling of the train capacity from the drive sizes, because the electrical drive motors for the compressors can be operated almost step-less. If the compressors were to be driven directly by the gas turbines, there would be limitations because only certain sizes of gas turbines are available.

Another atypical feature of the Snohvit plant is that it captures CO_2 separated from the inlet natural gas and injects it into an underground reservoir. This offsets most of the emissions that would be associated with venting the CO_2 separated from the inlet gas in the acid gas removal unit. The Snohvit plant also benefits from the cold climate of northern Norway, which allows both the process gas turbines and the LNG process to operate more efficiently.[62]

A summary of the operating Snohvit LNG plant configuration is shown below in Table 45.

Table 45 – Snohvit LNG plant configuration.[63]

Number of Trains	1
Refrigeration Process Technology	Linde-Statoil Mixed Fluid Cascade
Refrigeration Compressor Turbine Energy Source	Electricity from Natural Gas Combustion with Grid-Electricity Backup.
Refrigeration Compressor Turbine Model	General Electric Nuovo Pignone MCL1404/1406 and BCL1007[64]
Electricity Generation Energy Source	Natural Gas Combustion with backup provided by the local electricity grid.
Gas Turbine Generator Model	General Electric LM 6000 gas turbine

A breakdown of GHG emissions from the LNG facility by source is not available in public documents. The total GHG emissions emitted by the facility are given in Statoil's sustainability reports for the years 2007-2011. Data from 2009 were used to calculate the GHG intensity presented below. This year was chosen since

[61] Berger, E., Forg, W., Heiersted, R.S., and P. Paurola. (2003). The MFC® (Mixed Fluid Cascade) process for the first European baseload LNG Production Plant, The Snohvit Project. Available online: http://bit.ly/10Nknjc

[62] The hypothetical BC facility may also benefit from a cooler climate in comparison to facilities in locations such as Australia and Qatar. This benefit has not been calculated for the BC facility due to a lack of available calculation methodologies. However, based on a rough estimate, the climate of BC may facilitate a reduction in value chain emissions of approximately 5%. This is based on the Gorgon EIS, which estimates that value chain emissions would be reduced by approximately 13% if this facility was located in an area with a climate similar to Norway. The reduction for the BC value chain will not be as great, since temperatures in coastal BC are 7-10°C higher than at the location of the Snohvit plant in Norway.

[63] Berger et al. (2003).

[64] Statoil Hydro. (Date unknown). Snohvit LNG, Rotating Equipment, Theory and main boosting. Available online: http://bit.ly/13YV6ak

data for carbon dioxide injection were available, making it possible to calculate the GHG intensity reduction arising from CCS.

According to Statoil's 2009 Sustainability Report, as 805,000 tonnes CO_2 and 744 tonnes CH_4 were emitted from the facility in 2009.[65] A summary of GHG emissions associated with the facility is shown below in Table 46.

Table 46 – GHG sources and emissions for the Snohvit LNG plant.

GHG Source	Emissions (t CO_2e for 4.3 mtpa plant)
Oil Heating	*Not Available*
Refrigeration Compressors	*Not Available*
Power Generation	*Not Available*
Power for Ship at Berth	*Not Available*
Backup Diesel Generators	*Not Available*
Acid Gas Vent	*Not Available*
Methane in N_2 Purge	*Not Available*
Fugitive Emissions	*Not Available*
Flaring	*Not Available*
TOTAL	**819,784**

It should be noted that these values include emissions associated with the production of condensate and liquefied petroleum gas (LPG), which are not included in the emissions estimates for the other facilities discussed in this report. This is addressed in the GHG intensity section below by calculating two intensities: one including the LPG and condensate produced on a LNG energy equivalent basis, and the other using only the LNG produced.

4.8.4 GHG Emission Intensity

A GHG emission intensity in terms of LNG production at the Snohvit plant is not available in Statoil's public documents. An intensity referenced in numerous benchmarking studies of 0.22 tCO_2e/tLNG was first reported in the Gorgon plant's draft environmental impact statement, released in 2005.[66] This was a pre-production estimate of GHG intensity, as the Snohvit facility was then currently under construction. It was also based on the assumption that all reservoir CO_2 contained in the inlet natural gas would be captured and re-injected into an underground reservoir. However, it appears there have been problems with CO_2

[65] Statoil. (2010). Annual Report 2009, Sustainability Reporting, Environmental Data. Available online: http://bit.ly/18l9uJn
[66] Chevron Australia (2005).

injection at the Snohvit facility due to reservoir pressure buildup, so the plant has not been performing as well as initially planned.[67]

When calculating Snohvit's emission intensity, there was no information available to allocate emissions to the three product streams, so a range of intensities were calculated. The upper bound was estimated by allocating all emissions to the LNG stream and the lower bound was estimated by allocating emissions on an energy of product basis. The emission intensity for LNG production was estimated to be **0.35 tCO_2e/t LNG** or **0.30 tCO_2e/t LNG equivalent**.[68]

The contribution of CCS to reducing the emission intensity was calculated using data for CO_2 injected in 2009. According to the reference, approximately 298,000 tonnes of CO_2 was injected in the underground reservoir in 2009.[69] This resulted in an emissions intensity reduction of **0.13 tCO_2e/t LNG** or **0.11 tCO_2e/t LNG equivalent**. Therefore, if the Snohvit plant did not capture and inject the CO_2 contained in the feed gas, the plant would have an emissions intensity of **0.48 tCO_2e/t LNG** or **0.40 tCO_2e/t LNG equivalent**

A summary of emission intensities for gas extraction and production, transmission, liquefaction, and CCS is shown in Table 47 below.

Table 47 – Summary of GHG emissions and emissions intensities for the Snohvit LNG value chain.

GHG Source	Emissions (t CO_2e for 4.3 mtpa plant)	Emissions Intensity (t CO_2e / t LNG)
Natural Gas Extraction, Production, and Processing	*Not Available* *Assumed to be included with liquefaction*	*Not Available* *Assumed to be included with liquefaction*
Natural Gas Transmission	*Not Available* *Assumed to be included with liquefaction*	*Not Available* *Assumed to be included with liquefaction*
Natural Gas Liquefaction	819,784	0.30 – 0.35
TOTAL	**819,784**	**0.30 – 0.35**
CCS	298,000	(0.11) – (0.13)
TOTAL WITHOUT CCS	**1,117,784**	**0.40 – 0.48**

[67] See: Stigset, M. (May 19, 2011). Statoil's reservoir for carbon injection full, Teknisk says. *Bloomberg*. Available online: http://bloom.bg/lZVtHh and Lund, P.C. (October 29, 2012). CCS in Norway Status Report. *Briefing to Global CCS Institute Japan Study Meeting*. Available online: http://slidesha.re/YuA2Ug.
[68] Tonnes of LNG equivalent were calculated by converting the mass of LPG and condensate produced to an LNG energy equivalent mass, using a higher heating value of 26 MJ/L for LPG and 29 MJ/L for condensate.
[69] Hanson, O. et al. (2011). Monitoring CO_2 injection into a fluvial brine-filled sandstone formation at the Snohvit field, Barents Sea. Paper from the SEG San Antonio 2011 Annual Meeting. Available online: http://bit.ly/10pUhS6

4.9 Gorgon LNG Project, Western Australia, Australia

4.9.1 Description

The Gorgon Joint Venture, which includes Chevron Australia, Shell Development Australia, Mobil Australia, Osaka Gas, Tokyo Gas, and Chubu Electric Power, is currently constructing the Gorgon LNG plant in Australia. Shipment of LNG from the facility is expected to commence in 2015. The Gorgon plant will consist of three trains with a production capacity of 15.6 mtpa LNG.

4.9.2 Upstream Natural Gas Source and GHG Emissions

Natural gas will be supplied from coal seam gas resources in the Gorgon and Jansz-lo gas fields, which are approximately 100km off the west coast of Barrow Island. Subsea gathering systems and subsea pipelines will be installed to deliver natural gas to an onshore LNG facility. A summary of the characteristics of the natural gas supply and transmission pipeline is shown below in Table 48.

Table 48 – Gorgon upstream gas and pipeline characteristics.

Gas formation type	Sub-sea coal seam gas
Gas formation CO_2 concentration (mol%)	Gorgon – 15 Jansz - 1
Extraction Technology	Sub-sea gathering system
Extraction Energy Source(s)	Electricity from natural gas
Pipeline CO_2 concentration (plant inlet natural gas CO_2 concentration, mol %)	Gorgon – 15 Jansz – 1 Gas is transmitted straight from field to LNG plant without initial processing
Natural gas pipeline distance (km)	84km from Gorgon field 135km from Jansz field
Power source for pipeline transmission	Electricity from natural gas

GHG emissions associated with upstream activities are not reported in the Gorgon environmental impact statement. However, gas processing activities are included with the LNG plant emissions, as gas from the production fields is transmitted directly to the LNG facility where it undergoes processing such as liquids removal, CO_2 removal, H_2S removal, etc. Other upstream emissions sources are not disaggregated in the reporting, but the Gorgon environmental impact report states that all emissions related to the offshore production of natural gas are included in the values reported.

4.9.3 LNG Plant Configuration and GHG Emissions

A summary of the proposed Gorgon LNG plant configuration is shown below in Table 49. Note that the Gorgon plant plans to capture CO_2 separated from the inlet natural gas and inject it into an underground reservoir. This will offset most of the emissions that would be associated with venting the CO_2 separated from the inlet gas in the acid gas removal unit.

Table 49 – Gorgon LNG plant configuration.[70]

Number of Trains	3
Refrigeration Process Technology	Split-MR Propane Pre-Cooled Mixed Refrigerant
Refrigeration Compressor Turbine Energy Source	Natural Gas Combustion.
Refrigeration Compressor Turbine Model	General Electric Frame 7 gas turbine
Electricity Generation Energy Source	Natural Gas Combustion.
Gas Turbine Generator Model	General Electric Frame 9 gas turbine

As with the Pluto plant, power generation accounts for a higher proportion of emissions than is the case with a typical LNG facility. This is likely a result of most gas processing occurring at the Gorgon LNG plant, rather than at upstream facilities, as is typical of most LNG value chains. The major sources of greenhouse gas emissions for the Gorgon LNG Project are gas turbines for liquefaction (45%), power generation (38%), and reservoir CO_2 venting (15%). Emissions and emission sources from the Gorgon plant are shown below in Table 50.

Table 50 – GHG sources and emissions for the Gorgon LNG plant.[71]

GHG Source	Emissions (t CO_2e for 15.6 mtpa plant)
Oil Heating	10,911
Refrigeration Compressors	2,467,301
Power Generation	2,091,184
Power for Ship at Berth	*Not Available*
Backup Generators	*Not Available*
Acid Gas Vent	847,724
Methane in N_2 Purge	*Not Available*
Fugitive Emissions	18,973
Flaring	41,047
TOTAL	**5,477,140**

4.9.4 *GHG Emission Intensity*

The GHG emission intensity of the Gorgon LNG value chain was calculated to be **0.35 tCO_2e/t LNG**. Note that CCS reduces the GHG intensity of the Gorgon LNG value chain by **0.22 tCO_2e/t LNG.** Therefore, if the Gorgon plant did not capture and inject the CO_2 contained in the feed gas, the plant would have an emissions intensity of **0.57 tCO_2e/t LNG.**

[70] Chevron Australia (2009).
[71] Chevron Australia (2009).

A summary of emission intensities for gas extraction and production, transmission, liquefaction, and CCS is shown in Table 51 below.

Table 51 – Summary of GHG emissions and emissions intensities for the Gorgon LNG value chain.

GHG Source	Emissions (t CO_2e for 15.6 mtpa plant)	Emissions Intensity (t CO_2e / t LNG)
Natural Gas Extraction, Production, and Processing	*Not available* *Processing included in LNG facility emissions* *Power included in LNG facility emissions*	*Not available* *Processing included in LNG facility emissions* *Power included in LNG facility emissions*
Natural Gas Transmission	*Not available* *Assumed to be included with LNG facility emissions*	*Not available* *Assumed to be included with LNG facility emissions*
Natural Gas Liquefaction	5,477,140	0.35
TOTAL	**5,477,140**	**0.35**
CCS	3,400,000	(0.22)
TOTAL WITHOUT CCS	**8,877,140**	**0.57**

5 GHG Benchmarking of LNG Value Chains

The GHG intensities of the hypothetical BC value chains calculated in Section 3, along with the intensities of the global LNG value chains surveyed in Section 4, are shown below in Figure 11. For most value chains, the total value chain GHG intensity is disaggregated into three intensities – upstream emissions, transmission emissions, and LNG facility emissions. However, for some global value chains it was not possible to disaggregate the total value chain intensity to this extent because of data gaps in the reference documents.

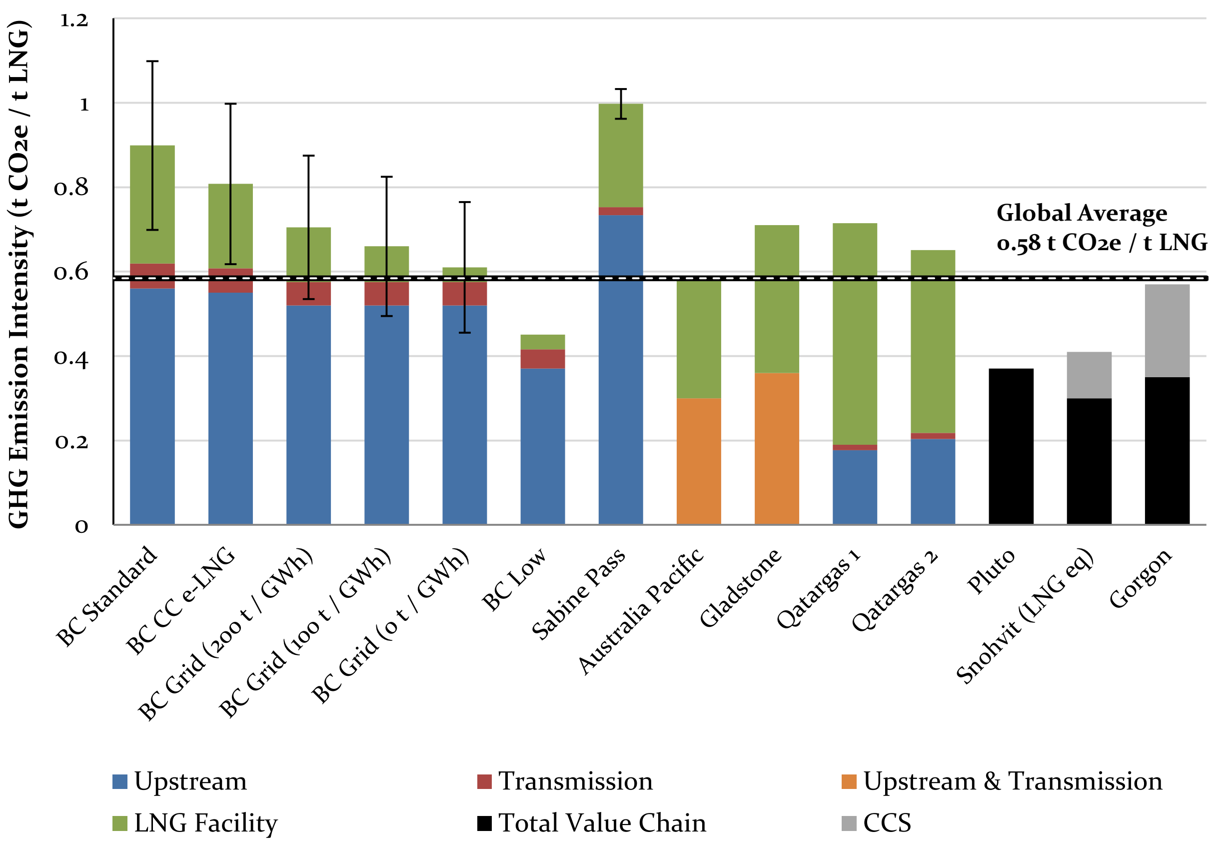


Figure 11 – GHG intensities for the LNG value chains surveyed in this report, t CO_2e/t LNG.

The Australia Pacific and Gladstone reference documents aggregated upstream and transmission emissions into a single value. This has been reflected in Figure 11 by including a category for 'Upstream & Transmission' emissions intensity, which represents the aggregated upstream and transmission emissions intensities. The Pluto, Gorgon, and Snohvit value chains reported emissions for the entire value chain without disaggregating into upstream, transmission, and LNG facility emissions. This has been reflected in Figure 11 by including a category for 'Total Value Chain' emissions, which represents the aggregated

upstream, transmission, and LNG facility emissions intensities. CCS is used at the Gorgon and Snohvit facilities to reduce emissions arising from the venting of CO_2 removed from the natural gas feed. This has been shown in Figure 11 by including a category, 'CCS', which represents the intensity of CO_2 captured and injected underground, i.e. t CO_2 injected per t LNG produced.

In general, Figure 11 shows that the Pluto, Gorgon, and Snohvit value chains have similar GHG intensities, which are the lowest GHG intensities of all value chains surveyed. The average intensity for these three value chains is approximately 0.34 t CO_2e / t LNG. Sabine Pass has the greatest GHG intensity at 1.0 tCO_2e / t LNG, with the remaining value chains having a GHG intensity either slightly above or below the average of 0.58 tCO_2e / t LNG.

The proportion of the total value chain intensity that is comprised of upstream vs. LNG facility emissions varies significantly among the various value chains. To explain this observation, the value chains may be grouped into four categories:

1. *Upstream Intensive Value Chains (Hypothetical BC & Sabine Pass)* – in these value chains, the upstream emissions account for a greater proportion of the total value chain emissions. This is primarily a result of the gas formation type from which natural gas is extracted and supplied to the LNG facility (refer to Section 2.1.1 for a discussion of emissions from various gas formation types). The hypothetical BC and Sabine Pass value chains both involve the extraction, production, and processing of shale gas, which is GHG intensive. Therefore, even when the LNG facility has a low GHG intensity, as is the case with the hypothetical grid-connected BC facilities, the total value chain emissions intensity could be above average.

2. *LNG Facility Intensive Value Chains (Qatargas 1 & 2)* - in these value chains, the LNG facility emissions account for a greater proportion of the total value chain emissions. The Qatargas value chains fit into this category as a result of having access to a low emitting natural gas source (offshore gas) and containing less up-to-date LNG facilities that do not make use of the energy efficiency and GHG mitigation options common to newer facilities.

3. *Proportional Value Chains (Australia Pacific & Gladstone)* - in these value chains, the LNG facility emissions and upstream emissions account for approximately the same proportion of the total value chain emissions. The LNG facilities are supplied with gas from a medium emitting source (coal bed methane at Australia Pacific and Gladstone) and also employ some energy efficiency and GHG mitigation options.

4. *Low Intensity Value Chains (Pluto, Snohvit & Gorgon)* – in these value chains, both upstream and LNG facility emissions are very low. Pluto, Snohvit, and Gorgon all receive natural gas extracted offshore with a sub-sea gathering system, which results in very low GHG emissions. The Snohvit and Gorgon value chains also employ CCS to reduce emissions from the venting of CO_2 contained in the LNG facility feed gas. As shown in the figure, this may have a significant impact on the overall value chain

GHG intensity. In addition to having low upstream emissions, these value chains also have very low LNG facility emissions.

The average GHG intensities of the hypothetical BC value chains all fall above the global average value chain intensity of 0.58 tCO_2e / t LNG[72] due to the higher upstream emissions intensity. However, the range of hypothetical BC value chain emissions intensities (shown by the error bars in the figure) indicates that hypothetical BC value chains with grid-connected LNG facilities could have GHG intensities lower than the global average if upstream emissions are mitigated (using the Montney play or incorporating CCS at Horn River). The 'BC Low' value chain (the lower bound of the 0 t/GWh grid e-LNG value chain) could have an emissions intensity closer to, but still approximately 20% greater than, the lowest global GHG intensity value chains. This indicates that global 'low intensity value chains', which have access to natural gas from low emissions intensive formation types, would likely have lower emissions intensities than any hypothetical BC value chain considered in this report.

[72] Note that this average only includes the global value chains surveyed in Section 4. It is not an average of every LNG value chain currently in operation, under construction, or being planned in the world.

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