APPENDIX F
NORTH WEST SHELF PROJECT EXTENSION GREENHOUSE GAS BENCHMARKING REPORT

Revision 1

Woodside

Appendix F

NWS Project Extension Proposal

Woodside Energy Ltd

Greenhouse Gas Benchmarking

| Revision 4

October 17, 2019

Greenhouse Gas Benchmarking

JACOBS

NWS Project Extension Proposal

Project No: IW207800
Document Title: Greenhouse Gas Benchmarking
Revision: Revision 4
Date: October 17, 2019
Client Name: Woodside Energy Ltd
Project Manager: Lisa Dumbrell
Author: Michelle Hall

Jacobs Australia Pty Limited

11th Floor, Durack Centre
263 Adelaide Terrace
PO Box H615
Perth WA 6001 Australia
T +61 8 9469 4400
F +61 8 9469 4488
www.jacobs.com

Document history and status

Revision	Date	Description	By	Review	Approved
0	11 July 2019	For Client	M Hall	J Moore	M Goodwin
1	29 July 2019	For Client	M Hall	S Blackford	M Goodwin
2	20 Aug 2019	For Client	M Hall	L Dumbrell	M Goodwin
3	2 Oct 2019	For Client	M Hall	L Dumbrell	M Goodwin
4	17 Oct 2019	For Client	M Hall	L Boulden	M Goodwin

Greenhouse Gas Benchmarking

JACOBS

Contents

Greenhouse Gas Benchmarking

JACOBS

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to complete a greenhouse gas emissions benchmark assessment for the North West Shelf Project Extension Proposal in accordance with the scope of services set out in the contract between Jacobs and the Client, Woodside Energy Ltd.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report using various information sourced from Woodside Energy Ltd and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project, subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context.

This report has been prepared on behalf of, and for the exclusive use of Woodside Energy Ltd and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and Woodside Energy Ltd. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

Greenhouse Gas Benchmarking

JACOBS

1. Introduction

1.1 Background

Woodside Energy Ltd (Woodside), as operator for and on behalf of the North West Shelf Joint Venture (NWSJV), is proposing to continue and extend the operating life of the North West Shelf (NWS) Project through the long-term processing of third-party gas and fluids. This proposal is referred to as the NWS Project Extension Proposal (the Proposal).

This greenhouse gas (GHG) benchmarking study has been prepared to support the environmental approvals for the Proposal which includes the following:

- Emissions of up to 7.7 million tonnes per annum (mtpa) of carbon dioxide equivalent (CO_2-e);
- Potential changes to feed gas composition including changed content of inerts, hydrocarbons and other components;
- Changes to the composition of environmental discharge and emissions, although annual volumes of emissions and discharges are expected to be in line with current levels;
- Modifications to the onshore receiving facilities to accommodate third-party gas and fluids; and
- Potential construction of additional operational equipment to accommodate changes to feed gas composition or management of environmental discharge and emissions.

The Proposal requires environmental approval under the *Environmental Protection Act 1986* (WA) (EP Act) and *Environment Protection and Biodiversity Act 1999* (Commonwealth) (EPBC Act).

This GHG benchmarking assessment has been prepared in accordance with the NWS Project Extension Proposal Environmental Scoping Document (Woodside, 2019) to support the development of the NWS Project Extension Proposal Environmental Review Document.

1.2 Objective

The objective of this report is to benchmark the GHG emissions performance of the Karratha Gas Plant (KGP) (which is a component of the Proposal) against that of other comparable Australian and international Liquified Natural Gas (LNG) facilities. This information will assist in assessing the performance of the Proposal in accordance with Woodside's Climate Change Policy.

1.3 Scope of this Assessment

The scope of this benchmarking assessment is Scope 1 emissions, as defined by the NGER Regulations (AG, 2018) definition[1], from the KGP and associated utilities.

The following are out of scope:

- GHG emissions from upstream operations associated with the extraction and compression of raw gas, i.e. upstream of the Trunkline Onshore Terminals (TOT1 and TOT2)
- Scope 2 emissions
- Scope 3 emissions.

Emissions associated with handling, transport and use of gas product downstream of the fiscal product meter are excluded from the benchmarking scope.

[1] NGER Regulation 2008 (AG, 2018) definition: Scope 1 emission of greenhouse gas, in relation to a facility, means the release of greenhouse gas into the atmosphere as a direct result of an activity or series of activities (including ancillary activities) that constitute the facility.

2. Overview of Approach

A benchmark is a standard of performance that is used to inform trends and typical conditions in a given industry, for the purposes of assessing relative impact. For GHG assessments, benchmarking is a tool which can compare the performance of activities or facilities within the same industry, using the same assessment parameters and boundaries. For the benchmarking of LNG facilities, the comparison parameter most commonly used is 'GHG intensity'; this term is defined as the tonnes of GHG emitted per tonne (t) of LNG produced and has been applied to this GHG benchmarking assessment. GHG emissions are expressed in t CO_2-e, where the CO_2-e emissions are an aggregate of GHG emissions including carbon dioxide, methane and nitrous oxide, calculated as an equivalent CO_2 emission by factoring in the global warming potential (GWP) of each constituent gas.

The CO_2-e estimates are required to reflect the GWP values at the time of reporting, as specified in the *National Greenhouse and Energy Reporting* (NGER) *Regulations 2008* (AG, 2018). In 2015-16, the GWP values were amended based on the findings of the Intergovernmental Panel on Climate Change's Fourth Assessment Report. A summary of the changes to the GWP as applied in the NGER calculations for the key gases (CO_2, methane and nitrous oxide) are shown in Table 2-1. For the KGP benchmarking data, both the maximum capacity data and the current operational data as per the NGER report data for 2017-18 were included and the amended (i.e. post 2015-16) GWP values were used for each.

Table 2-1: Changes in GWP for Scope 1 emission calculations (CER, 2019c)

Greenhouse gas	GWP pre 2015-16	GWP 2015-16 onwards
Carbon dioxide	1	1
Methane	21	25
Nitrous oxide	310	298

2.1 Selection of Facilities for Comparison

The selection of LNG facilities for comparison with the NWS Project Extension Proposal was based on:

- Location – LNG facilities in Australia as well as selected facilities internationally were selected to represent comparable operating conditions (including climatic conditions) and facility designs.
- Age – the most recent LNG facilities, planned or recently started up, have been included in the assessment as these plants are more likely to have the most recent energy efficient technology and designs, thereby are expected to have the lowest emissions intensity associated with the liquefaction process.
- Capacity – the LNG production capacity of a facility will impact the type of equipment used and the energy efficiency achievable. Including facilities in the benchmarking with a similar capacity to the KGP is important to ensure comparison of facilities with the same or similar ability to achieve energy efficiency savings. The KGP is considered a large facility with annual LNG production in FY2017/18 of 16.6 mt and maximum capacity of 18.5 mtpa.
- Available data – to enable assessment of the GHG intensity, sufficient emissions and production data must be available, including details of emission sources (e.g. upstream, liquefaction facility, etc.) in the public domain. To this end, the majority of data used has been obtained from publicly available environmental impact assessments (EIA), or similar. This is acknowledged to be a short-coming (see Section 5.2) as the data is representative of expected emissions for full planned LNG capacity as determined during the design phase, and not current operational rates.

In total, 10 Australian and 8 international LNG facilities were selected for benchmarking and comparison with the KGP. These facilities are shown in Table 2-2. The table includes individual LNG trains (T) for KGP and some other facilities where data was available, enabling a more detailed comparison of emissions.

Table 2-2: Summary of Benchmarked LNG Facilities

LNG facility	Location	Year commissioned	LNG production (mtpa)[1]	Reservoir CO_2 content (mol%)[1]
Australian facilities				
Barossa-Caldita LNG	Offshore Northern Territory (NT)	Design phase. Expected to commence operation in 2023	3.6	16 - 20
Prelude LNG	Offshore WA	2018	3.6	9
Ichthys LNG	Offshore WA, with 890 km pipeline to Darwin, NT	2016	8.4	Brewster: 8, Plover: 17
Gorgon LNG	WA	2016	15.6	Gorgon 15, Jansz 0.5
KGP T1 – T3	WA	1989-92	8.2	2.4
Darwin LNG	NT	2006	3.6	6
KGP T1 – T5	WA	1989-2004	18.5 [3] Current operation: 16.6	2.4
Wheatstone Project	WA	2017	25 [4] Current capacity: 8.9	"low" [2]
Pluto LNG	WA	2012	4.8	2
KGP T4 and T5	WA	2004	8.4	2.4
Gladstone LNG	Queensland	2015	10	0.3
Australia-Pacific LNG (APLNG)	Queensland	2016	18 [4] Current capacity: 9.0	1
Queensland Curtis LNG	Queensland	2015	11	< 1
International facilities				
Cove Point	Maryland, USA	2017	5.75	Not applicable
Qatargas 1 (T1 – T3)	Qatar	1997	10	2.1

LNG facility	Location	Year commissioned	LNG production (mtpa)[1]	Reservoir CO_2 content (mol%)[1]
Qatargas 2 (T4 and T5)	Qatar	2009	15.6	2.1
Qatargas 3 (T6)	Qatar	2010	7.8	2.1
Qatargas 4 (T7)	Qatar	2011	7.8	2.1
Qatargas TOTAL	Qatar	1997 - 2011	41.2	2.1
RasGas	Qatar	1999	6.4	2.3
PNG LNG	Papua New Guinea	2014	6.3	0.7 - 2.0
Nigeria LNG	Nigeria	2000	6.1	1.8
Snohvit LNG	Norway	2007	4.3	8
Oman LNG	Oman	2001	6.9	1.0
Sabine Pass	Louisiana, USA	2016	16	0.1 - 4.8

1. Production rates are as reported in publicly available information, typically environmental approval documentation, and therefore represent planned rates, i.e. those expected at the time of the preparation of approval documentation. For the Australian LNG facilities, the current capacities from the Australian Government Resources and Energy Quarterly, March 2019 (AG, 2019), are also shown.
2. The publicly available reservoir CO_2 content reported in the Draft Environmental Impact Statement for the Wheatstone Project (Chevron, 2010) is described as 'low' and no CO_2 mol% is provided.
3. The LNG production rate for KGP T1 – T5 of 18.5 mtpa is the current maximum production rate.
4. Planned capacity.

2.2 Basis of Comparison

In addition to using the same parameters for comparison of LNG facility GHG emissions performance, i.e. the GHG intensity (t CO_2-e / t LNG), emissions within the same 'boundaries' have been used for each facility to ensure meaningful comparison. The emission source information and data for LNG facilities is often not transparent within environmental assessment reports available in the public domain and this introduces uncertainty to the comparisons.

Although the standard benchmarking parameter, GHG intensity, is based on the production rate of LNG, it is acknowledged that data provided also include emissions associated with other co-produced products such as LPG and condensates. This has the potential to introduce differences in the basis of comparison of emissions intensity data for the benchmarked facilities.

Typically, the numerator in benchmarking LNG facility emissions intensity will include only emissions associated with the gas processing facility, e.g. emissions from the acid gas removal unit (AGRU), combustion for fuel gas, flaring and venting at the LNG production plant. These are Scope 1 emissions for the processing facility, i.e. downstream of the raw gas extraction and transfer operations, and upstream of the product custody transfer points. Scope 2 emissions are excluded from this assessment. Emissions from the upstream processing operations, e.g. production wells and platforms, and downstream operations, i.e. piping, distribution, transport, and third-party consumption (Scope 3) are also excluded from the calculations. This approach has been applied for the current benchmarking.

Although the intent of defining the emissions boundary is to achieve a 'like for like' comparison of facility performance, this is not always possible due to the variation in design and operation of LNG facilities. For example, the extent of processing raw gas upstream from an LNG plant, i.e. at or near the point of extraction, will impact the magnitude of the emissions attributable to the LNG plant. A number of the facilities included in the benchmarking utilise subsea production systems. This tends to increase the GHG emissions at the gas processing plant site, making direct comparisons of actual emission intensity of the LNG processing operations more difficult.

As discussed in Section 2.1, publicly available data for other Australian and international LNG facilities is largely representative of planned maximum capacity. Operational data, i.e. LNG production and associated GHG emissions following approval and commissioning, is not typically available. The benchmarking comparisons have therefore included the KGP planned capacity data, as well as the current operational data.

3. Overview of KGP GHG Emissions

3.1 Introduction

The primary CO_2-e emissions from a typical LNG facility are shown in Table 3-1.

Table 3-1: Key GHG Emission Sources associated with LNG Production [1]

Process area	Typical CO_2-e emission sources (API, 2015)
Upstream – gas extraction and production	Flaring Fuel use for compression Fuel use (gas and diesel) for power generation Fugitive emissions Minor process venting, e.g. from tanks Electricity purchase
LNG liquefaction plant – gas treatment, liquefaction and storage	Flaring Fuel use for refrigeration compressors Fugitive losses (leaks from equipment, including tanks and pipelines) Fuel use for power generation Fuel use for any fired process heat generators Venting from AGRU Nitrogen venting (containing methane)
Downstream – transport of facility products (pipeline, shipping, etc.)	Fuel use for compression Fugitive emissions Flaring due to ship gas up and cool down Boil-off gas

1. The emissions shown represent the key emissions which are expected as part of a typical LNG facility. There will be other minor emissions which are dependent of the gas quality, e.g. condensate stabilisation after separation from the gas phase.

The emissions from each of the three process areas shown in Table 3-1 can fall into Scope 1, Scope 2 or Scope 3 emission categories, depending on the facility operation. Typically, the ‘upstream’ and ‘LNG liquefaction plant’ emissions will be predominantly Scope 1 emissions. However, at some sites, Scope 2 emissions may also be relevant, e.g. if electricity is imported. In addition, if raw gas is imported from another facility (owned and operated by others), then these emissions may be considered Scope 3. The ‘downstream’ processes typically constitute Scope 3 emissions as they are indirect emissions which occur outside of the gas processing premises. The most significant of these are emissions from product combustion by end users. For the GHG intensity benchmarking assessment, Scope 1 emissions associated with the LNG liquefaction plant are compared.

The break-down of the CO_2-e emissions for the KGP for year 2017-18 is shown in Table 3-2. These represent Scope 1 emissions, consistent with reporting requirements under NGER Regulations (AG, 2018). The largest sources of GHG emissions at KGP is from the fuel gas consumed for driving the refrigeration compressors, followed by the CO_2 released via the AGRU vents. The category ‘fuel gas use – other stationary’ includes fuel consumed in furnaces, non-LNG related compressors and the combustion of non-LNG products (Liquified Petroleum Gas [LPG], greases, oils, etc.). ‘Other’ includes fugitive leaks from tanks and pipeline, diesel combustion (vehicle transport, electricity generation) and emissions associated with wastewater treatment at site.

Table 3-2: Indicative Break-down of CO_2-e emissions for KGP

KGP CO_2-e emission source	Indicative % of total CO_2-e emissions
Fuel gas use – electricity generation	15%
Fuel gas use – refrigerant compressor gas turbines	55%
Fuel gas use – other stationary	< 1%
AGRU	22%
Venting and flaring	7%
Other	< 1%
Total, KGP	100%

3.2 Emissions Related to Design

GHG emissions are influenced by the design of the LNG facility and selection of equipment. Key technology and process factors which influence GHG intensity are:

- Selection of liquefaction technology
- Choice of power generation equipment and configuration
- Use of waste heat recovery
- Acid gas removal process.

3.2.1 Liquefaction technology and power generation

Typically, the largest source of emissions at an LNG facility is from the fuel consumption associated with the operation of the refrigeration compressor and power generator drivers. There are two main options for selection and design of the drivers:

- Direct drive – These are the most common type used in liquefaction plants. Natural gas being delivered to the site is used to fuel gas-turbine driven compressors. The gas turbines can be conventional heavy-duty industrial or aeroderivative types. Aeroderivative gas turbines usually have higher efficiencies than conventional gas turbines, resulting in lower GHG emissions intensity per MWhr of energy produced. For some LNG facilities, aeroderivative gas turbines are used for both the refrigerant compressors and power generation.
- Electric drive – These systems use an electric motor to drive the compressors, which are less common, but can achieve higher efficiencies and hence lower GHG emissions (Kleiner, 2005). If the electricity is from renewable or low-emissions sources, then this can offer a lower intensity method of driving the compressors. In some cases, electricity is provided within the LNG facility by combined cycle gas turbine (CCGT) plants using natural gas at the site. These use waste heat effectively to achieve high thermal efficiencies.

With any drive type (for both liquefaction and power generation), it is important to match the design and selection of the drivers with the production rates and operating conditions to maximise operating efficiency (GPN, 2014). Operating equipment items at sub-optimal performance levels can result in poor reliability and reduced energy efficiency.

As part of the KGP Expansion Project, Train 4 (T4) was implemented in 2004 and Train 5 (T5) in 2008 with new high-efficiency Frame 7 gas turbine with power recovery via hydraulic turbines, as well as four new aeroderivative gas turbines (Frame 7) for electrical power generation. The power generation turbines have higher efficiency (i.e. lower GHG emissions per unit energy output) than the older industrial gas turbines which are also used for power generation at KGP. The electrical power system is integrated and therefore the more efficient aeroderivative turbines are loaded preferentially to industrial turbines.

3.2.2 Waste heat recovery

The use of waste heat recovery at an LNG facility can offer significant reductions in fuel use and GHG emissions. This technology is currently used at several of the newer LNG facilities, including each of the five trains (T1 – T5) at the KGP. Waste heat from the gas turbine compressor drivers is used to supply process heat to other areas of the plant, e.g. via a heated water system. Recovered process heat means that the need to generate heat via fuel fired burners is reduced, thereby reducing GHG emissions. The process items which require the highest amount of heat within an LNG facility are often the AGRU and dehydration media regeneration. For sites where the reservoir CO_2 levels are low, the process heat requirements for the AGRU is also relatively low. For such sites, the potential savings in GHG emissions are lower than those which have higher reservoir CO_2 levels.

At KGP, waste heat recovery units (WHRUs) use the exhaust stream from the gas turbines driving the propane compressors to provide process heating via the heated water system. The WHRUs also provide process heat to a slipstream of dried feed gas to regenerate the molecular sieve adsorber beds used for dehydration of the feed gas. Waste heat is also shared with the Domgas unit.

3.2.3 Acid gas removal

CO_2, as well as other co-absorbed substances, including a small amount of methane, is removed from the liquefaction plant inlet gas stream via the AGRU to avoid it freezing at low temperatures. As the stripped gases are typically vented to atmosphere, minimising the non-CO_2 components released, including methane, is important. Most recent LNG facilities use the solvent, activated methyldiethanolamine (aMDEA), for absorption of CO_2 in the AGRU. The use of aMDEA has been demonstrated to reduce co-absorption of hydrocarbons which may otherwise be vented to atmosphere and is used at the KGP for CO_2 removal at the AGRU.

3.2.4 Other process design options

Other process designs which can influence GHG emissions are:

- Routing gas vents from start-up operations to the flare system, instead of direct venting to atmosphere.
- Use of dry gas seals on gas turbine compressors which have been intrinsically designed for minimal venting.
- Avoiding flare emissions by ensuring adequate boil-off gas compressor capacity (and redundancy) is incorporated in the design.
- The design and selection of process items with high reliability to minimise the number of shut-downs and process upsets, during which gas streams are released to atmosphere (via flare or venting).
- Flash gas streams, e.g. from the AGRU, are recovered back in to the process instead of venting to atmosphere.
- Combustion of co-absorbed hydrocarbons in the AGRU vent stream via a regenerative or recuperative thermal oxidiser.

- The extent of process integration, i.e. the efficient use of hot and cold process streams across different processing areas, to reduce the amount of fuel use at the site can reduce the site's GHG emissions. This is most applicable to larger scale plants which have more stable energy requirements and flexibility in design.

3.3 Emissions Related to External Factors

In addition to the impact of the design of the LNG facility, 'external' factors, i.e. inherent to the site location, also have the potential to affect the environmental performance of a facility. Common external factors which affect the level of GHG emissions are discussed in the following sections.

3.3.1 Ambient temperatures

The ambient temperature at the LNG facility location will impact the system energy demand and subsequent GHG emissions. For sites with cooler ambient temperatures, less energy is required for liquefaction, as the efficiency of the gas turbines (for refrigeration compressor and power generation drivers) increases at lower temperatures, reducing fuel use and GHG emissions per unit of power output. For every one-degree Celsius reduction in ambient operating temperature, LNG process capacity increases by approximately 0.6% (Chevron, 2015).

3.3.2 Reservoir gas composition

The concentration of CO_2 and other inert gases in the reservoir will affect the GHG emissions for the LNG facility. CO_2 needs to be removed from the raw gas stream as it will freeze at the low operating temperatures in the liquefaction process. If the CO_2 concentration is high, this translates directly to high emissions of CO_2 (with small amounts of methane) which are vented to atmosphere at the AGRU, upstream of the liquefaction process. Emissions from fuel combustion associated with energy use at the AGRU will also occur. These incremental GHG emissions can be reduced by the use of waste heat for power generation.

3.3.3 Geosequestration Opportunities

Geosequestration offers opportunities to capture the CO_2 vented to atmosphere from the AGRU. Geosequestration, whereby the CO_2 gas stream stripped from the natural gas feed stream to the liquefaction plant is injected into an underground reservoir (such as the Dupuy Formation underneath Barrow Island), has been incorporated into the design and construction of the Gorgon LNG facility in Western Australia. Reinjection of CO_2 has recently (August 2019) commenced. The Ichthys LNG facility has been designed as "CCS (carbon capture and storage) ready" meaning that provisions have been made in the design to be able to retrofit the facility with CCS capability in the future (APPEA, 2018). The Snohvit LNG facility in Norway reduces its CO_2 emissions by injecting the CO_2 stream into an offshore reservoir (see Section 5.3.2).

4. NWS Project Extension Proposal GHG Emissions

As part of the Proposal, the feed gas composition to the KGP may change as a result of third-party gas and liquids and changing NWSJV field resources. However, importantly, there will be no change to the current and future projected level of GHG emissions and/or the LNG production capacity at the KGP. Although the future projected GHG emissions and LNG production rates are expected to vary from year to year, and consequently the GHG intensity will also be variable, the changes to the plant inlet gas under the Proposal will not alter the projected GHG intensity for the Proposal.

A summary of the NWS Project Scope 1 CO_2-e emissions (including upstream emissions), production rates and calculated emission intensities for the last four years is provided in Table 4-1. The table shows the calculated GHG intensity representing the KGP LNG plant GHG emissions as part of the NWS Project, i.e. excluding upstream operations. This metric is used for benchmarking with other LNG facilities (see Section 5). The highest GHG intensity over the last 4 years has been 0.41 t CO_2-e / t LNG.

Table 4-1: Summary of NWS Project GHG Emissions and LNG Production for the KGP LNG plant, FY2015-2018[1]

NWS GHG parameter	Units	FY2014/15	FY2015/16	FY2016/17	FY2017/18
CO_2-e emissions					
Fuel combustion[2]	t CO_2-e / yr	5,162,500	4,986,900	5,188,600	5,165,700
Venting	t CO_2-e / yr	1,520,400	1,477,500	1,563,000	1,685,300
Other[3]	t CO_2-e / yr	100	100	100	100
Total KGP LNG plant CO_2-e (excluding upstream)	t CO_2-e / yr	6,683,000	6,464,500	6,751,700	6,851,100
LNG production rate	mtpa	16.29	15.95	17.35	16.62
GHG intensity (Scope 1 KGP only)	t CO_2-e / t LNG	0.41	0.41	0.39	0.41

1. The NWS Project emissions and LNG production data shown is based on the supporting data from the annual NGERs submissions to the Clean Energy Regulator.
2. Fuel combustion includes flaring emissions.
3. 'Other' emissions include those associated with wastewater handling and emissions of hydrofluorocarbons and sulphur hexafluoride gases.

JACOBS

5. Benchmarking Results and Discussion

5.1 Overview

Figure 5-1 provides a summary and comparison of the GHG intensities for various Australian and international LNG facilities (selected as described in Section 2.1).

The total column for each facility depicts the GHG intensity for the emissions attributable to the LNG plant. As detailed in Section 1.3, emissions from upstream processing associated with gas extraction and off-shore processing are not included. Similarly, Scope 2 and Scope 3 emissions are excluded.

Within the LNG plant emissions, the graph shows the distinction between the emissions released via the AGRU which are directly related to the reservoir CO_2 concentration, and the remaining emissions attributable to the LNG plant, i.e. emissions from refrigeration compressors, power generation, flaring, fugitive emissions, etc. The amount of CO_2 removed at the LNG facility may not be representative of the total reservoir CO_2; some may be removed upstream. Additionally, emissions data is inclusive of the processing of other products in addition to LNG due to limitations of available data.

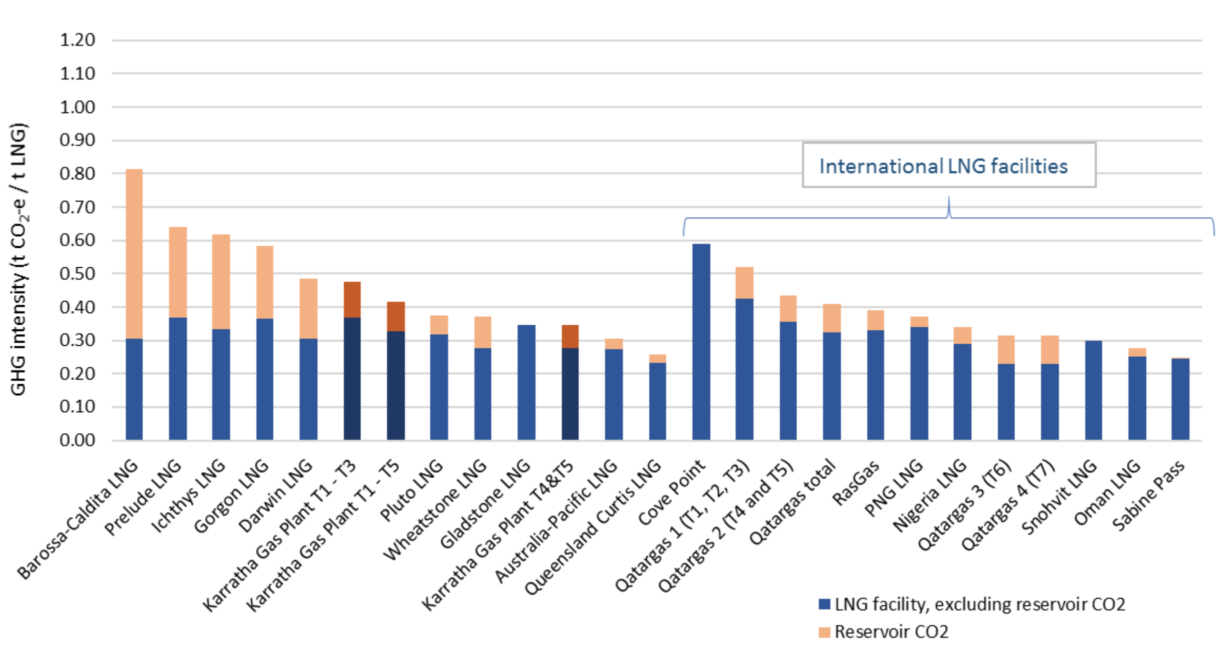

Figure 5-1: GHG Intensity of Australian and International LNG Facilities (KGP facilities shown in darker colour)

For the KGP LNG and Pluto LNG facilities, the maximum approved CO_2-e emission rates and LNG production data have been applied in Figure 5-1. The following are relevant to the interpretation of Figure 5-1:

1. The Barossa-Caldita LNG is a proposed off-shore floating production storage and offloading (FPSO) facility. The data shown includes emissions associated with CO_2 removal (reservoir CO_2) at the FPSO. The LNG facility emissions, excluding reservoir CO_2, have been assumed to be the same as the downstream Darwin LNG facility where the gas will be processed.

2. For the Gladstone LNG facility, the GHG emissions attributable to reservoir CO_2 are not provided in available data and are instead included in the total for the LNG facility. However, the CO_2 reservoir content for the Gladstone feed gas is very low at 0.3 mol%. As a result, the associated CO_2-e emissions are expected to also be low.

3. The CO_2-e emissions attributable to reservoir CO_2 are not available for the Snohvit LNG facility. Several previous assessment reports have stated a GHG intensity of 0.22 t CO_2-e / t LNG. However, a study undertaken for the Government of British Columbia, Canada (Delphi Group, 2013) highlighted that this figure is a 'pre-production' estimate as the Snohvit facility was then currently under construction. This report provided a newer estimate of 0.3 – 0.35 t CO_2-e / t LNG due to problems with geosequestration. The reservoir CO_2 content is 8 mol%.

4. The CO_2-e emissions attributable to reservoir CO_2 for the Sabine Pass LNG are very low due to CO_2 removal undertaken as part of upstream processing (see further information below).

GHG intensities calculated using the 2017/18 NGER data have been provided in Table 5-1 for comparison.

Table 5-1: KGP LNG facility GHG intensity data for current operations

LNG facility	LNG production rate (2017-18), mtpa	GHG intensity (t CO_2-e / t LNG)		
		Reservoir CO_2	LNG facility, excluding reservoir CO_2	Total LNG facility
Karratha Gas Plant T1 - T5	16.6[2]	0.09	0.32	0.41
Karratha Gas Plant T1 - T3	8.22	0.09	0.40	0.49
Karratha Gas Plant T4 -T5	8.40	0.09	0.26	0.35

5.2 Limitations

For the non-Woodside operated facilities, the emissions data has been obtained from publicly available information. The majority of this information has been extracted from EIA reports and for some cases there is limited amount of data break-down and definition of reporting boundaries. Uncertainties associated with the use of data and information available from these sources include:

- In some cases, the definition of 'LNG production' is not clear. Some reports may also include other co-produced products such as LPG and condensates.
- The extent of processing at the upstream facilities, e.g. at the point of raw gas extraction, varies from site to site. For example, if some CO_2 removal is carried out at upstream facilities instead of at the AGRU within the LNG facility, the CO_2 emissions reported for the LNG liquefaction facility will be reduced accordingly.
- A number of the facilities benchmarked utilise subsea production systems (e.g. Gorgon LNG, Snohvit LNG) and this may inflate the emissions at the gas processing plant site, further obscuring the actual emissions intensity of the LNG processing operations.
- The data available from EIA reports is based on concept or detailed phase designs and not operational data. The emissions data is therefore not based on current operation and would not reflect any plant

[2] Actual KGP capacity is 18.5mpta

modifications or operating condition changes carried out since the EIA. This has the potential to introduce significant variation from actual current operational GHG intensity data.

5.3 Discussion

5.3.1 Benchmarking against Australian LNG facilities

The data for the five KGP LNG trains, T1 – T5 in Figure 5-1, shows the improved performance of train T4 and T5, commissioned in 2004 and 2008, compared to that of the original trains T1, T2 and T3 (commissioned 1989 – 1992), with the GHG intensity decreasing from 0.47 to 0.35 t CO_2-e / t LNG, respectively. This is a result of the following mitigation measures implemented for the newer T4 and T5 LNG trains (Woodside, 2004):

- Use of higher-efficiency Frame 7 gas turbines with power recovery via hydraulic turbines.
- Use of higher-efficiency aero-derivative gas turbines for electrical power generation.
- Routing flash gas from the horizontal three phase separator of the AGRU to the low pressure fuel gas system.
- Routing the start-up vent from the AGRU to the flare system, rather than direct venting of the gas stream to atmosphere.
- Utilisation of dry gas seals, that have minimal venting, or double oil seals, with seal gas losses routed back to compressor suction, to reduce seal gas losses from the gas and refrigerant compressors.

Of the Australian LNG facilities, the emissions for the KGP T4 and T5, and for the entire LNG facility (i.e. T1 – T5), are lower than the average for the Australian facilities analysed of 0.44 t CO_2-e / t LNG [3]. Facilities with GHG intensities lower than KGP T4 and T5 are Australia-Pacific LNG (APLNG) and Queensland Curtis LNG. Wheatstone Project and Gladstone LNG have GHG intensities similar to that of KGP T4 and T5, but slightly lower than KGP T1 – T5. Each of these facilities have relatively high LNG production capacities and have been commissioned recently, i.e. in the last 5 years. Emissions from these facilities are discussed below. Interestingly, the GHG intensities for large and recently commissioned plants, i.e. Ichthys LNG, Prelude LNG and Gorgon LNG, are higher than that of KGP T1 – T5. This indicates that the higher reservoir CO_2 content for these facilities more than off-sets the improvements made by the implementation of more recent LNG technologies.

Comparisons of GHG intensity values which exclude emissions attributable to the reservoir CO_2 content are useful as these emissions are inherent to the fields which supply the facility. The GHG intensity of KGP T4 and T5, excluding CO_2 reservoir emissions, is lower than the average for the Australian facilities analysed of 0.31 t CO_2-e / t LNG, and is comparable to Wheatstone LNG and APLNG. The GHG intensity, excluding CO_2 reservoir emissions, for the entire KGP LNG facility (T1 – T5) is 0.33 t CO_2-e / t LNG which is slightly higher than the average for the Australian facilities.

The KGP has GHG intensity comparable to the Wheatstone Project, which is a new facility. The GHG intensity of the LNG facility, excluding emissions attributable to the CO_2 reservoir, is slightly lower for Wheatstone compared to the KGP (T1 – T5). Influencing factors may be the use of aero-derivative turbines for both the refrigeration process and power generation at Wheatstone (compared to the use of aero-derivative turbines for power generation for the KGP T4 and T5 only) and the use of the Optimised Cascade refrigeration process. The use of this process has been reported to offer efficient liquefaction and operational flexibility (APLNG, 2010) which is supported by its application in recent LNG facility installations.

[3] The calculated average excludes the Barossa-Caldita LNG GHG intensity as the data are preliminary estimates only based on early reservoir modelling and early engineering designs (ConocoPhillips, n.d).

The Gladstone LNG and APLNG facilities are major Australian facilities, with significant LNG production rates, as reported in the respective environment approval documentation, of 10 mtpa and 18 mtpa, respectively. It is noted however, that the nameplate capacities for these facilities are less than the planned rates shown in the approval documentation (see Table 2-2). The Gladstone LNG facility GHG intensity, excluding CO_2 reservoir emissions, is similar to that for the whole KGP (T1 – T5), and the intensity for APLNG is lower. However, the intensity for the KGP T4 and T5 trains is slightly lower than that of Gladstone LNG and similar to that of APLNG when CO_2 reservoir emissions are excluded. Potential contributors to the APLNG intensity being lower than that of KGP T1 – T5, excluding emissions attributable to CO_2 reservoir venting emissions, are the use of the Optimised Cascade refrigeration process, and reduced energy requirements at the AGRU due to the low reservoir CO_2 levels for APLNG (1 mol%, which islower than 2.4 mol% for KGP).

The Queensland Curtis LNG facility has the lowest GHG intensity of the major Australian facilities, both with and without CO_2 reservoir emissions. The Queensland Curtis LNG facility employs the following design features:

- Aero-derivative gas turbines used within the Optimised Cascade liquefaction process, with inlet air chilling.
- Use of aero-derivative gas turbines for electricity generation.
- Use of waste heat recovery units for process heat requirements.

The use of aero-derivative turbines for both refrigeration compression and power generation contribute to the lower emissions for the Queensland Curtis Island facility. In addition, the lower reservoir CO_2 content means that the power requirements for handling the CO_2 will be lower than that of KGP T1 – T5, although this is a relatively minor influence to total CO_2-e emissions.

All other Australian facilities are more recent installations compared to the KGP. It is therefore expected that these LNG facilities would have more advanced processing equipment and designs which would result in better energy efficiency, thereby resulting in lower GHG intensities. Interestingly, the older KGP LNG facility compares well with the performance of several of the more recent LNG facilities, e.g. Gorgon LNG, Prelude LNG and Ichthys LNG, with and without CO_2 reservoir emissions. This is considered to be a result of the ongoing changes implemented at the site to mitigate emissions as described above, as well as ongoing continuous improvement projects. However, the CO_2 content of the raw gas to KGP may vary in the future and associated variation in GHG emissions may occur.

Of the Australian facilities assessed, the Darwin LNG plant, commissioned in 2006, provides the closest comparison to the KGP in terms of age with KGP T4 and T5 commissioned in 2004 and 2008. The GHG intensity for Darwin LNG is 0.49 t CO_2-e / t LNG which is higher than that of KGP T1 – T5 (0.42 t CO_2-e / t LNG). This is possibly a result of the higher reservoir CO_2 content for Darwin LNG. Excluding emissions attributable to the feed gas CO_2, the GHG intensity for the Darwin LNG is similar to that of the KGP T1 – T5 and higher than that for KGP T4 and T5.

The proposed Barossa-Caldita LNG FPSO has the highest reservoir CO_2 GHG intensity. This is due to the high CO_2 reservoir content of 16 – 20%. It should be noted that the GHG estimates for the facility are preliminary only as the project is currently in the design phase with a final investment decision not due until end 2019.

An Australian LNG facility not included in the assessment is a small facility in Kwinana, Perth. This facility processes 175 t /day LNG (0.064 mtpa) and has an estimated emissions intensity of 0.20 t CO_2-e / t LNG. However, there is insufficient publicly available information to determine the emission sources which are included in the reported emissions. Due to the scale of the facility and the lack of information, this site has therefore not been included in the Australian facilities for benchmarking.

5.3.2 Benchmarking against international LNG facilities

The Sabine Pass LNG facility in Louisiana, USA, has the lowest GHG intensity, with and without consideration of reservoir CO_2 emissions. This is a large capacity LNG facility (16 mtpa, compared to KGP FY2017/18 LNG production of 16.6 mtpa) which uses the ConocoPhillips Optimised Cascade technology for the liquefaction process. Aeroderivative turbines are used for the refrigeration compressors. Gas is supplied to the LNG facility by a network of pipelines which can deliver gas from various conventional and unconventional gas fields across the United States. In 2010, the most likely sources of gas to the Sabine Pass LNG facility were the Gulf Coast Texas and Louisiana onshore conventional gas fields, the gas fields (Permian, Anadarko, and Hugoton basins), and the emerging unconventional gas fields (Barnett, Haynesville, Eagle Ford, Fayetteville, Woodford, and Bossier basins) (Cheniere, 2013). The pipeline CO_2 concentration for these gas fields varies from 0.1 to 4.8 mol%. Due to the very low reported emissions from the AGRU, previous studies (Delphi Group, 2013) have estimated the pipeline feed CO_2 content at 0.01 mol% and have concluded that the gas delivered to the LNG facility must have already undergone acid gas removal upstream. This low level of CO_2 in the raw gas entering the LNG plant is expected to contribute to the reported low GHG intensity.

Oman LNG has the second lowest GHG intensity of 0.28 t CO_2-e / t LNG, with and without consideration of reservoir CO_2 emissions. A contributor is expected to be the use of water cooling instead of air cooling at the facility. This leads to more efficient heat exchange and more consistent production rates that are less susceptible to variance in ambient air temperature. Another contributor may be the low inlet gas CO_2 content and consequent low power requirements for the AGRU.

The Snohvit LNG project is located in northern Norway, just above the Arctic Circle. A very low GHG intensity of 0.22 t CO_2-e / t LNG has been reported for this facility within various EIA and GHG assessment documents for other projects. However, a study undertaken for the Government of British Columbia, Canada (Delphi Group, 2013) highlighted that this figure is a ‘pre-production’ estimate as the Snohvit facility was then currently under construction. However, the report provided a newer estimate of 0.3 – 0.35 t CO_2-e / t LNG as it appears there have been problems with CO_2 injection at the Snohvit facility due to reservoir pressure buildup, so the plant has not been performing as well as initially planned. In any case, contributing factors to the relatively low GHG intensity for this facility are:

- The GHG intensity is based on the re-injection of reservoir CO_2 into the subsurface
- The cold operating temperatures (compared to the Australian facilities) mean less energy is required for refrigeration and the gas turbines run more efficiently, increasing power and reducing relative fuel gas use.
- The facility is connected to the local electrical grid, removing the requirement for spinning reserve electrical power generation.

It is noted that the Snohvit facility uses subsea production systems, i.e. there is no offshore gas platform. Although there will be no emissions related to gas production, there may be a slight increase in emissions for the onshore facility (Chevron, 2015).

Of the international LNG facilities, the Qatargas facility is most easily compared with the KGP T1 – T5 as it is a large facility of similar age (1997 – 2011 for the progressive implementation of liquefaction trains) and has a similar reservoir CO_2 content. This facility comprises four LNG plants, with a total of 7 liquefaction trains (T1 – T7). The GHG intensity for this facility (combined T1 – T7) is 0.41 t CO_2-e / t LNG which is very similar to that of KGP T1 – T5. When reservoir CO_2 emissions are excluded, the GHG intensities are also similar for the two facilities. Like the KGP, the GHG intensity has decreased progressively as newer liquefaction trains have been added over the years.

Overall, the GHG performance of the KGP is comparable with both Australian and international LNG facilities. The GHG intensity for KGP is lower than the average intensity for the 10 Australian facilities assessed (excluding the Barossa-Caldita LNG FPSO). Excluding CO_2 emissions attributable to reservoir CO_2 content, the GHG intensity for the KGP facility (T1 – T5) is similar to the average intensity for the Australian facilities, and the intensity for T4 and T5 is slightly lower than the average.

When assessed against international LNG facilities, the GHG performance of the KGP was found to be very similar to those facilities located in a similar climate and of similar age.

6. Conclusion

In conclusion this benchmarking study shows that the GHG performance of KGP compares well against other LNG facilities. Although the older infrastructure (T1-T3) contains older technology the overall facility compares well against some of the newest LNG facilities in Australia. Overall, the current and future projected GHG performance of the Proposal is similar to both Australian and international LNG facilities. The GHG intensity for KGP is lower than the average intensity for the ten Australian facilities assessed. When assessed against international LNG facilities, the GHG performance of the Proposal was found to be very similar to those facilities located in a similar climate and of similar age.

Whilst there are a number of limitations associated with this benchmarking study, largely due to the availability of GHG emission data from other facilities, the assessment provides a useful understanding of how the Proposal GHG emissions compare to other facilities for the purpose of supporting the NWS Project Extension Proposal Environmental Review Document.

7. Terms

Term	Definition
AGRU	Acid gas removal unit
aMDEA	Activated methyldiethanolamine
APLNG	Australia-Pacific LNG
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CO_2-e	Carbon dioxide equivalent emissions
EIA	Environmental impact assessment
FPSO	Floating production storage and offloading facility
GHG	Greenhouse gas
GWP	Global Warming Potential
KGP	Karratha Gas Plant
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
mt	Million tonnes
mtpa	Million tonnes per annum
MWhr	Mega (x10^6) watt hours
NGER	National Greenhouse Energy and Reporting
NT	Northern Territory, Australia
NWS	North West Shelf
NWSJV	North West Shelf Joint Venture
t	Tonnes
T	Train
TOT	Trunkline Onshore Terminal
T1, T2, T3, T4, T5	KGP LNG processing trains #1, #2, #3, #4 and #5
WA	Western Australia, Australia
WHRU	Waste heat recovery unit

Greenhouse Gas Benchmarking

JACOBS

8. References

AG, 2018: National Greenhouse and Energy Reporting Regulations, 2008, Australian Government, Environment and Energy, registered August 2018

AG, 2019: Resources and Energy Quarterly March 2019, Department of Industry, Innovation and Science, Australian Government, March 2019

AP LNG 2010: Australia Pacific LNG Project, Vol 5, Attachment 3 Greenhouse gas Assessment - LNG Facility, Worley Parsons, Mar 2010

API, 2015: Liquefied Natural Gas (LNG) Operations, Consistent Methodology for Estimating Greenhouse Gas Emissions, v 1.0, America Petroleum Institute, May 2015

APPEA, 2018: NT Climate Change Discussion Paper, Australian Petroleum Production and Exploration Association (APPEA), Dec 2018

CER, 2019a: Safeguard baselines tables, 2017/18 and 2016/17, Clean Energy Regulator, http://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/Safeguard-baselines-table, website accessed May 2019

CER, 2019b: LEPID for the 2013-14 financial year, Clean Energy Regulator, Australian Government, http://www.cleanenergyregulator.gov.au/Infohub/CPM/Liable-Entities-Public-Information-Database/LEPID-for-the-2013-14-financial-year, website accessed May 2019

CER, 2019c: Global warming potential table, Clean Energy Regulator, Australian Government, http://www.cleanenergyregulator.gov.au/NGER/The-safeguard-mechanism/Baselines/Reported-baseline/global-warming-potentials, website accessed September 2019

Cheniere, 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, March 2013

Chevron, 2010: Draft Environmental Impact Statement/Environmental Review and Management Programme for the Proposed Wheatstone Project, Chevron, July 2010

Chevron, 2015: Gorgon Gas Development and Jansz Feed Gas Pipeline: GHG Abatement Program, Chevron, 2015

ConocoPhillips: Barossa Offshore Project Proposal, Section 4, ConocoPhillips Australia (date not available)

Delphi Group, 2013: LNG Production in British Columbia: Greenhouse Gas Emissions Assessment and Benchmarking, Delphi Group, May 2013

FERC, 2014: Cove Point Liquefaction Project Environmental Assessment, Federal Energy Regulatory Commission, Office of Energy Projects, May 2014

GPN, 2014: Benchmarking GHG emissions from cryogenic gas processing, K. Chow et al, from website www.gasprocessingnews.com/features/201412/benchmarking-ghg-emissions-from-cryogenic-gas-processing.aspx.

IGU, 2018: 2018 World LNG Report, International Gas Union (IGU), 2018

Kewan Bond, 2008: Greenhouse Gas Assessment, Papau New Guinea Liquefied Natural Gas Project, Kewan Bond Pty Ltd, December 2008

Kleiner, 2005: All Electric Driven Refrigeration Compressors in LNG Plants Offer Advantages, Fritz Kleiner, Siemens AG, Industrial Applications, Oil & Gas Business Unit, and Steve Kauffman, Shell Development (Australia) Pty. Ltd., LNG & GTL, Gastech 2005

OEH, 2002: Darwin 10 MTPA LNG Facility (Wickham Point), Environmental Assessment Report and Recommendations, Office of Environment and Heritage, Department of Infrastructure, Planning and Environment, Northern Territory Government, May 2002

Qatargas, 2016: Sustainability Report 2016, Qatargas

QGC, 2009: Queensland Curtis LNG, Draft Environmental Impact Statement, QGC Limited, July 2009

Santos, 2009: GLNG: Supplementary EIS, Greenhouse Gas Management, Santos Petronas, October 2009

URS, 2002: Darwin 10 MTPA LNG Facility, Public Environmental Report, URS, March 2002

West Australian, 2019: Article “Chevron delays underground storage of carbon dioxide for Gorgon”, West Australian, March 2019, website https://thewest.com.au/business/oil-gas/chevron-delays-underground-storage-of-carbon-dioxide-for-gorgon-ng-b881125789z

Woodside 2004: LNG Expansion Project Greenhouse Gas Management Plan, Woodside Energy, 2004

Woodside, 2006: Pluto LNG Development, Draft Public Environment Report / Public Environmental Review, Woodside, December 2006

Woodside, 2011: Pluto LNG Project Greenhouse Gas Abatement Program, Woodside, June 2011

Woodside 2018: 2018 North West Shelf Optimisation Reference Plan 2018 – 2011, Woodside, Jun 2018

Woodside 2019: North West Shelf Project Extension Proposal Draft Environmental Scoping Document, Woodside, May 2019

Woodside 2019a: MSExcel spreadsheet “Emission Forecast Data for NWS Project Extension.xls”, provided May 2019

Woodside 2019b: Woodside Policy: Climate Change Policy, Woodside, Feb 2017

Woodside 2019c: Woodside NGER calculation spreadsheets for 2015, 2016, 2017 and 2018, provided May 2019