Gorgon Gas Development and Jansz Feed Gas Pipeline:

Greenhouse Gas Abatement Program

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Terminology, Definitions, and Abbreviations

Terms, definitions and abbreviations used in this document are listed below. These align with the terms, definitions and abbreviations defined in Schedule 2 of the Western Australian Gorgon Gas Development Ministerial Statement No. 800 (Statement No. 800).

ABU	Australasia Business Unit
Additional Support Area	Gorgon Gas Development Additional Construction, Laydown, and Operations Support Area
AFAT	Average Feed Composition, Average Ambient Temperature
AGRU	Acid Gas Removal Unit
ALARP	As Low As Reasonably Practicable Defined as a level of risk that is not intolerable, and cannot be reduced further without the expenditure of costs that are grossly disproportionate to the benefit gained.
a-MDEA	Activated methyl di-ethanol amine
APCI	Air Products and Chemicals Incorporated
APLNG	Australia Pacific LNG
ARI	Assessment on Referral Information (for the proposed Jansz Feed Gas Pipeline dated September 2007) as amended or supplemented from time to time.
BOG	Boil-off Gas; vapours produced as a result of heat input and pressure variations that occur in association with LNG storage and loading operations.
BTEX	Benzene, toluene, ethylbenzene and xylene aromatic hydrocarbon compounds present in petroleum.
Carbon Dioxide (CO_2) Injection System	The mechanical components required to be constructed to enable the injection of reservoir carbon dioxide, including but not limited to compressors, pipelines, and wells.
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent

Construction	Construction includes any Proposal-related (or action-related) construction and commissioning activities within the Terrestrial and Marine Disturbance Footprints, excluding investigatory works such as, but not limited to, geotechnical, geophysical, biological and cultural heritage surveys, baseline monitoring surveys, and technology trials.
Cth	Commonwealth of Australia
DCC	Commonwealth Department of Climate Change
DEA	Di-ethanol amine
DEC	Former Western Australian Department of Environment and Conservation (now DER and the Department of Parks and Wildlife)
DER	Western Australian Department of Environment Regulation (formerly DEC)
DEWHA	Former Commonwealth Department of the Environment, Water, Heritage and the Arts (now Department of the Environment)
DLN	Dry Low NO_x
DMA	Decision-making Authority
DomGas	Domestic Gas
EEO Act	Commonwealth *Energy Efficiency Opportunities Act 2006*
EIS/ERMP	Environmental Impact Statement/Environmental Review and Management Programme (for the Proposed Gorgon Gas Development dated September 2005) as amended or supplemented from time to time.
EP Act	Western Australian *Environmental Protection Act 1986*
EPA	Western Australian Environmental Protection Authority
EPBC Act	Commonwealth *Environment Protection and Biodiversity Conservation Act 1999*
EPBC Reference: 2003/1294	Commonwealth Ministerial Approval (for the Gorgon Gas Development) as amended or replaced from time to time.
EPBC Reference: 2005/2184	Commonwealth Ministerial Approval (for the Jansz Feed Gas Pipeline) as amended or replaced from time to time.
EPBC Reference: 2008/4178	Commonwealth Ministerial Approval (for the Revised Gorgon Gas Development) as amended or replaced from time to time.
EPBC Reference: 2008/4469	Commonwealth Ministerial Approval (for the Wheatstone Project) as amended or replaced from time to time.
EPCM	Engineering, Procurement and Construction Management

ERF	Emissions Reduction Fund
FEED	Front End Engineering Design
FLNG	Floating LNG
FOB	Freight On Board
GHG	Greenhouse Gas
GI	Greenhouse Gas Intensity
Gorgon Gas Development	The Gorgon Gas Development as approved under Statement No. 800 and EPBC Reference: 2003/1294 and 2008/4178 as amended or replaced from time to time.
Greenfield	An undeveloped property or resource
Greenhouse Gases	Components of the atmosphere that contribute to the greenhouse effect. These include the six commonly reported greenhouse gases under the Commonwealth *National Greenhouse and Energy Reporting Act 2007* - methane (CH_4), carbon dioxide (CO_2), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
GT	Gas Turbine
GTG	Gas Turbine Generator
GWP	Global Warming Potential
H_2S	Hydrogen sulfide
ha	Hectare
HES	Health, Environment, and Safety
HFC	Hydrofluorocarbon
HIPPS	High Integrity Pressure Protection System
HVAC	Heating, Ventilation, and Air Conditioning
Hydrocarbons	A large class of organic compounds composed of hydrogen and carbon. Crude oil, natural gas, and natural gas condensate are all mixtures of various hydrocarbons.
Isentropic	Where the entropy of a system remains constant.
ISO	International Organization for Standardization
Jansz Feed Gas Pipeline	The Jansz Feed Gas Pipeline as approved in Statement No. 769 and EPBC Reference: 2005/2184 as amended or replaced from time to time.
JT	Joule-Thomson

km	Kilometre
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MCHE	Main Cryogenic Heat Exchanger
MEA	Mono-ethanol amine
MEG	Monoethylene glycol
MOF	Materials Offloading Facility
Mole %	The ratio of the number of moles of one substance to the total number of moles in a mixture of substances, all multiplied by 100 (to express the number on a percentage basis).
MR	Mixed Refrigerant
MRU	Mercury Removal Unit
MTPA	Million Tonnes Per Annum
MW	Megawatt
N_2O	Nitrous oxide
NGA	National Greenhouse Accounts
NGER	National Greenhouse and Energy Reporting
NGER Act	Commonwealth *National Greenhouse and Energy Reporting Act 2007*
NMVOC	Non-Methane Volatile Organic Compounds
NO_x	Nitrogen oxides (NO and NO_2)
NPI	National Pollutant Inventory; an Australian pollution database of emissions managed by the Australian Government on behalf of the Australian States and Territories.
OE	Operational Excellence
OEMS	Operational Excellence Management System
Operations (Gorgon Gas Development)	In relation to Statement No. 800 for the respective LNG trains, this is the period from the date on which the Gorgon Joint Venturers issue a notice of acceptance of work under the Engineering, Procurement and Construction Management (EPCM) contract, or equivalent contract entered into in respect of that LNG train of the Gas Treatment Plant; until the date on which the Gorgon Joint Venturers commence decommissioning of that LNG train.
p.a.	Per Annum; yearly

PER	Public Environmental Review for the Gorgon Gas Development Revised and Expanded Proposal dated September 2008, as amended or supplemented from time to time.
PFC	Perfluorocarbon
PGPA	Policy, Government and Public Affairs
Pig	Pipeline inspection gauge; a tool that is sent down a pipeline and propelled by the pressure of the product in the pipeline, or another fluid (usually during commissioning).
PM	Particulate Matter
ppmv	Parts per million by volume
Practicable	Means reasonably practicable having regard to, among other things, local conditions and circumstances (including costs) and to the current state of technical knowledge.
SF_6	Sulfur hexafluoride
Slug Catcher	A unit in the gas refinery or petroleum industry in which slugs at the outlet of pipelines are collected or 'caught'. A slug is a large quantity of gas or liquid that exits the pipeline.
SO_x	Sulfur oxides
Statement No. 748	Western Australian Ministerial Statement No. 748 (for the Gorgon Gas Development) as amended from time to time [superseded by Statement No. 800].
Statement No. 769	Western Australian Ministerial Statement No. 769 (for the Jansz Feed Gas Pipeline) as amended from time to time.
Statement No. 800	Western Australian Ministerial Statement No. 800 (for the Gorgon Gas Development) as amended from time to time.
Statement No. 865	Western Australian Ministerial Statement No. 865 (for the Gorgon Gas Development).
Statement No. 965	Western Australian Ministerial Statement No. 965, issued for the Additional Support Area, as amended from time to time. Statement No. 965 applies the conditions of Statement No. 800 to the Additional Support Area.
TAPL	Texaco Australia Pty Ltd
TJ	Terajoule
VOC	Volatile Organic Compounds; organic chemical compounds that have high enough vapour pressures under normal conditions to vaporise and enter the atmosphere.
WA	Western Australia

WAPET	West Australian Petroleum Pty Ltd
WAPET Landing	Proper name referring to the site of the barge landing existing on the east coast of Barrow Island prior to the date of Statement No. 800.
Wellhead	The surface termination of a wellbore that incorporates systems to provide pressure control, suspension of casing strings and provide sealing functionality for oil wells.
WHRU	Waste Heat Recovery Unit

1.0 Introduction

1.1 Proponent

Chevron Australia Pty Ltd (Chevron Australia) is the proponent and the person taking the action for the Gorgon Gas Development on behalf of the following companies (collectively known as the Gorgon Joint Venturers):

- Chevron Australia Pty Ltd
- Chevron (TAPL) Pty Ltd
- Shell Development (Australia) Pty Ltd
- Mobil Australia Resources Company Pty Limited
- Osaka Gas Gorgon Pty Ltd
- Tokyo Gas Gorgon Pty Ltd
- Chubu Electric Power Gorgon Pty Ltd

pursuant to Statement No. 800 and EPBC Reference: 2003/1294 and 2008/4178.

Chevron Australia is also the proponent and the person taking the action for the Jansz Feed Gas Pipeline on behalf of the Gorgon Joint Venturers, pursuant to Statement No. 769 and EPBC Reference: 2005/2184.

1.2 Project

Chevron Australia proposes to develop the gas reserves of the Greater Gorgon Area (Figure 1-1).

Subsea gathering systems and subsea pipelines will be installed to deliver feed gas from the Gorgon and Jansz–Io gas fields to the west coast of Barrow Island. The feed gas pipeline system will be buried as it traverses from the west coast to the east coast of the Island where the system will tie in to the Gas Treatment Plant located at Town Point. The Gas Treatment Plant will comprise three Liquefied Natural Gas (LNG) trains capable of producing a nominal capacity of five Million Tonnes Per Annum (MTPA) per train. The Gas Treatment Plant will also produce condensate and domestic gas. Carbon dioxide (CO_2), which occurs naturally in the feed gas, will be separated during the production process. As part of the Gorgon Gas Development, Chevron Australia will inject the separated CO_2 into deep formations below Barrow Island. The LNG and condensate will be loaded from a dedicated jetty offshore from Town Point and then transported by dedicated carriers to international markets. Gas for domestic use will be exported by a pipeline from Town Point to the domestic gas collection and distribution network on the mainland (Figure 1-2).

1.3 Location

The Gorgon gas field is located approximately 130 km and the Jansz–Io field approximately 200 km off the north-west coast of Western Australia. Barrow Island is located off the Pilbara coast 85 km north-north-east of Onslow and 140 km west of Karratha. Barrow Island is approximately 25 km long and 10 km wide and covers 23 567 ha. It is the largest of a group of islands, including the Montebello and Lowendal Islands.

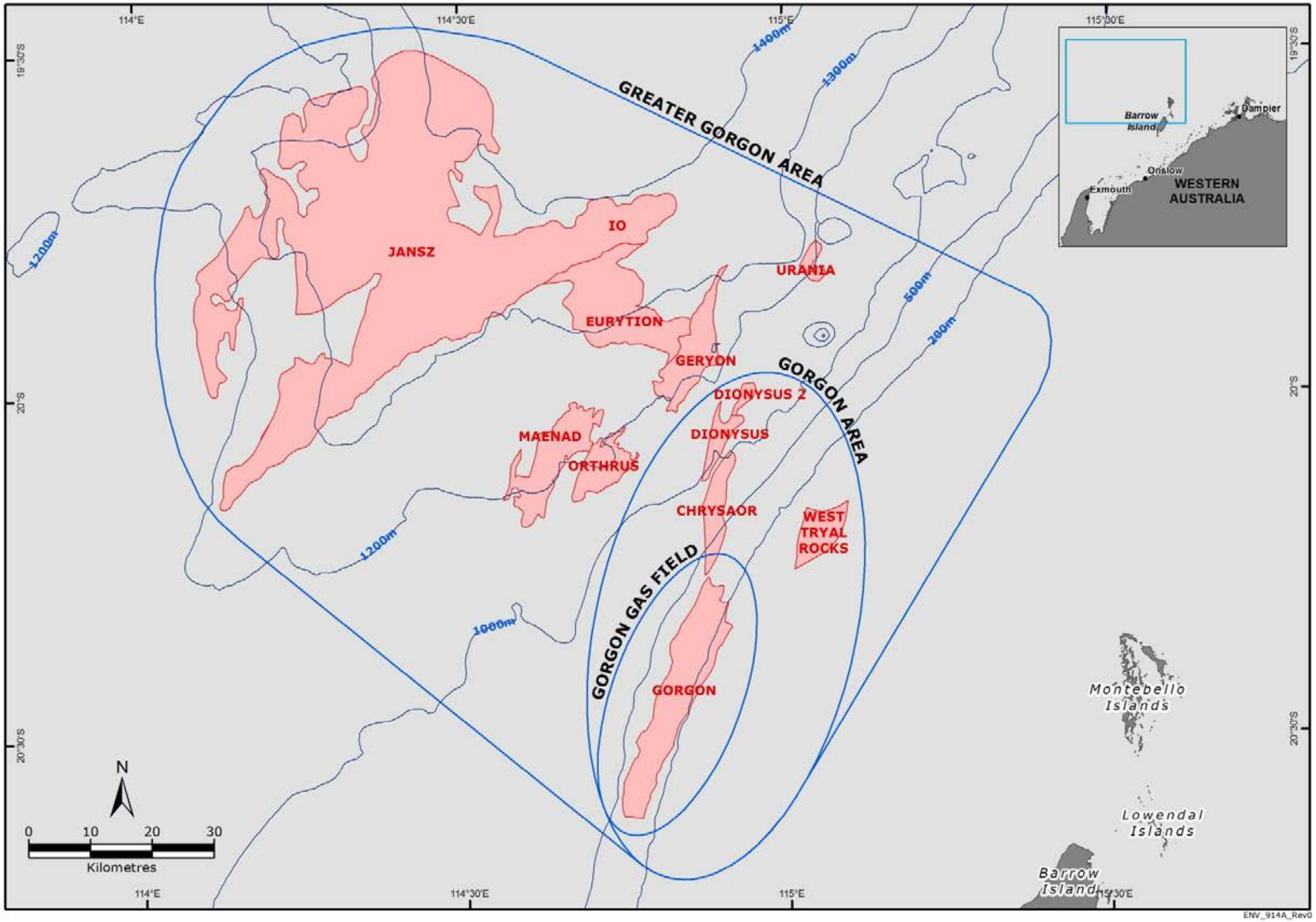

Figure 1-1 Location of the Greater Gorgon Area

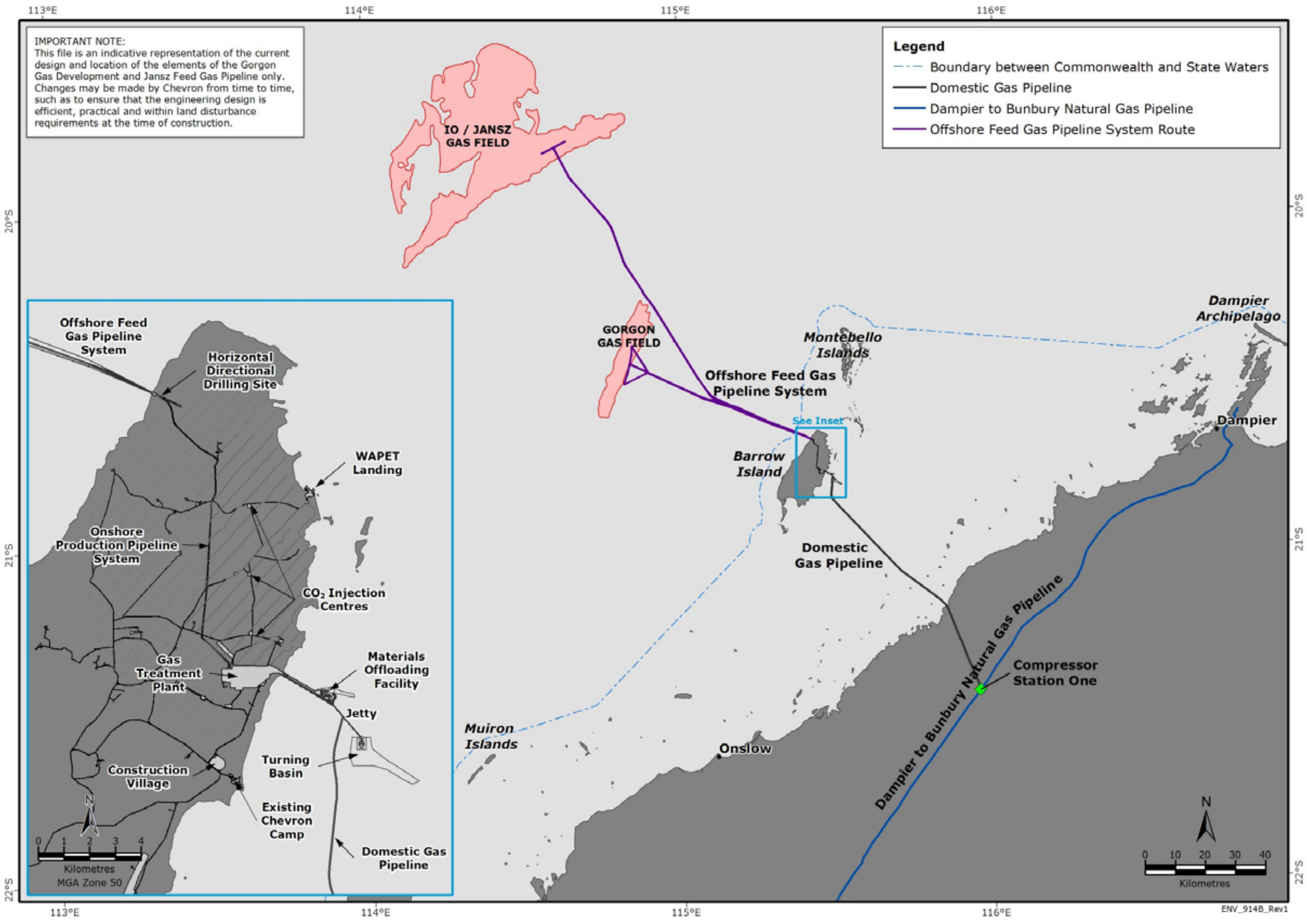

Figure 1-2 Location of the Gorgon Gas Development and Jansz Feed Gas Pipeline

1.4 Approvals

The initial Gorgon Gas Development was assessed through an Environmental Impact Statement/Environmental Review and Management Programme (EIS/ERMP) assessment process (Chevron Australia 2005; Chevron Australia 2006).

The initial Gorgon Gas Development was approved by the Western Australian State Minister for the Environment on 6 September 2007 by way of Ministerial Statement No. 748 (Statement No. 748) and the Commonwealth Minister for the Environment and Water Resources on 3 October 2007 (EPBC Reference: 2003/1294).

In May 2008, under section 45C of the Western Australian *Environmental Protection Act 1986* (EP Act), the Environmental Protection Authority (EPA) approved some minor changes to the Gorgon Gas Development that it considered 'not to result in a significant, detrimental, environmental effect in addition to, or different from, the effect of the original proposal' (EPA 2008). The approved changes are:

- excavation of a berthing pocket at the Barge (WAPET) Landing facility
- installation of additional communications facilities (microwave communications towers)
- relocation of the seawater intake
- modification to the seismic monitoring program.

In September 2008, Chevron Australia sought both State and Commonwealth approval through a Public Environment Review (PER) assessment process (Chevron Australia 2008) for the Revised and Expanded Gorgon Gas Development to make some changes to 'Key Proposal Characteristics' of the initial Gorgon Gas Development, as outlined below:

- addition of a five MTPA LNG train, increasing the number of LNG trains from two to three
- expansion of the CO_2 Injection System, increasing the number of injection wells and surface drill locations
- extension of the causeway and the Materials Offloading Facility (MOF) into deeper water.

The Revised and Expanded Gorgon Gas Development was approved by the Western Australian State Minister for the Environment on 10 August 2009 by way of Ministerial Statement No. 800 (Statement No. 800). Statement No. 800 also superseded Statement No. 748 as the approval for the initial Gorgon Gas Development. Statement No. 800 therefore provides approval for both the initial Gorgon Gas Development and the Revised and Expanded Gorgon Gas Development, which together are known as the Gorgon Gas Development. Amendments to Statement No. 800 Conditions 18, 20, and 21 under section 46 of the EP Act were approved by the Western Australian State Minister for the Environment on 7 June 2011 by way of Ministerial Statement No. 865 (Statement No. 865). Implementation of the Gorgon Gas Development will therefore continue to be in accordance with Statement No. 800, as amended by Statement No. 865.

On 26 August 2009, the then Commonwealth Minister for the Environment, Heritage and the Arts issued approval for the Revised and Expanded Gorgon Gas Development (EPBC Reference: 2008/4178) and varied the conditions for the initial Gorgon Gas Development (EPBC Reference: 2003/1294).

Since the Revised and Expanded Gorgon Gas Development was approved, further minor changes have also been made and/or approved to the Gorgon Gas Development and are now also part of the Development. Further changes may also be made/approved in the future. This Program relates to any such changes, and, where necessary, this document will be revised to address the specific impacts of those changes.

Use of an additional 32 ha of uncleared land for the Gorgon Gas Development Additional Construction, Laydown, and Operations Support Area (Additional Support Area) was approved by the Western Australian State Minister for Environment on 2 April 2014 by way of Ministerial

Statement No. 965 and by Variation issued by the Commonwealth Minister for the Environment. Statement No. 965 applies the conditions of Statement No. 800 to the Additional Support Area and requires all implementation, management, monitoring, compliance assessment and reporting, environmental performance reporting, protocol setting, and record keeping requirements applicable to the Additional Support Area under Statement No. 800 to be carried out jointly with the Gorgon Gas Development.

The Jansz Feed Gas Pipeline was assessed via Environmental Impact Statement/Assessment on Referral Information (ARI) and EPBC Referral assessment processes (Mobil Australia 2005, 2006).

The Jansz Feed Gas Pipeline was approved by the Western Australian State Minister for the Environment on 28 May 2008 by way of Ministerial Statement No. 769 (Statement No. 769) and the then Commonwealth Minister for the Environment and Water Resources on 22 March 2006 (EPBC Reference: 2005/2184).

This Program covers the Gorgon Gas Development as approved under Statement No. 800 and as approved by EPBC Reference: 2003/1294 and EPBC Reference: 2008/4178, and including the Additional Support Area as approved by Statement No. 965 and as varied by the Commonwealth Minister for the Environment.

In respect of the Carbon Dioxide Seismic Baseline Survey Works Program, which comprises the only works approved under Statement No. 748 before it was superseded, and under EPBC Reference: 2003/1294 before the Minister approved a variation to it on 26 August 2009, note that under Condition 1A.1 of Ministerial Statement No. 800 and Condition 1.4 of EPBC Reference: 2003/1294 and 2008/4178 this Program is authorised to continue for six months subject to the existing approved plans, reports, programs, and systems for the Program, and the works under that Program are not the subject of this Program.

1.5 Purpose of this Program

1.5.1 Legislative Requirements

1.5.1.1 State Ministerial Conditions

This Program is required under Condition 27.1 of Statement No. 800, which states :

> *'Prior to the commencement of construction of the Gas Treatment Plant, the Proponent shall prepare and submit to the Minister a Greenhouse Gas Abatement Program (the Program) that meets the objectives set in Condition 27.2 as determined by the Minister.'*

1.5.2 Objectives

The objectives of this Program, as stated in Condition 27.2 of Statement No. 800, are to:

- demonstrate that currently applied best practice in terms of greenhouse gas emissions have been adopted in the design and operation of the Gas Treatment Plant. The greenhouse gas emissions per tonne of LNG produced should be normalised to the standard conditions and benchmarked against publicly available data for other national and overseas LNG processing facilities
- periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing greenhouse gas emissions per tonne of LNG produced.

1.5.3 Requirements

The requirements of this Program, as stated in Condition 27 of Statement No. 800, are listed in Table 1-1. Any matter specified in this Program is relevant to the Gorgon Gas Development only if that matter relates to the specific activities or facilities associated with that particular development.

Table 1-1 Requirements of this Program

Ministerial Document	Condition No.	Requirement	Section Reference in this Program
Statement No. 800	27.2(i)	Demonstrate that currently applied best practice in terms of greenhouse gas emissions have been adopted in the design and operation of the Gas Treatment Plant.	Section 5.0
Statement No. 800	27.2(i)	The greenhouse gas emissions per tonne of LNG produced should be normalised to the standard conditions and benchmarked against publicly available data for other national and overseas LNG processing facilities.	Section 4.0
Statement No. 800	27.2(ii)	Periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing greenhouse gas emissions per tonne of LNG produced.	Section 7.3
Statement No. 800	27.3	The Proponent shall implement the Program.	Section 6.0

1.5.4 Scope

In line with the requirements of Condition 27 of Statement No. 800, the facilities scope of the Program includes the GHG emission sources arising from the commissioning, start-up, and operation of the Gas Treatment Plant on Barrow Island, as defined in Schedule 1, ‘Summary of Key Proposal Characteristics’ of Statement No. 800.

The facilities in scope for the Program include:

- LNG Trains: 3 × 5.2 MTPA (nominal)
- LNG Tanks: 2 × 180 000 m^3 (nominal)
- Condensate Tanks: 4 × 35 000 m^3 (nominal)
- Gas Processing Drivers: 6 × 80 MW (nominal) Frame 7 Process Gas Turbines (GTs) fitted with dry low NO_x (DLN) burners
- Power Generation: 5 × 116 MW (nominal) Frame 9 Gas Turbine Generators (GTGs) fitted with DLN burners
- Flare Systems: Wet and Dry Ground Flares for the main Gas Treatment Plant; Boil-off Gas (BOG) Flares in LNG storage and loading area.

The following Gorgon Gas Development activities will be included in this Program, as per the intent of Condition 27 of Statement No. 800:

- design of the Gas Treatment Plant as pertaining to the objectives of the Program
- commissioning and start-up of the Gas Treatment Plant, including the progressive commissioning and start-up of LNG Trains 1 to 3
- operation of the Gas Treatment Plant.

Greenhouse gases (GHGs) in the scope of this Program include the six commonly reported GHGs under the Commonwealth *National Greenhouse and Energy Reporting Act 2007* (NGER Act) - methane (CH_4), carbon dioxide (CO_2), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Emissions of atmospheric pollutants and air toxics, such as nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), particulate matter (PM), non-methane volatile organic compounds (NMVOC), hydrogen sulfide (H_2S), and benzene, toluene, ethyl-benzene and xylene (BTEX), respectively are outside the scope of this Program and are dealt with in the Air Quality Management Plan required under Condition 29 of Statement No. 800 (Chevron Australia 2009).

This Program also lists Gorgon Gas Development-specific best practice measures to reduce GHG emissions from the Gas Treatment Plant.

1.5.5 Hierarchy of Documentation

This Program will be implemented for the Gorgon Gas Development via the Chevron Australasia Business Unit (ABU) Operational Excellence Management System (OEMS). The OEMS is the standardised approach that applies across the ABU to continuously improve the management of safety, health, environment, reliability, and efficiency to achieve world-class performance. Implementation of the OEMS enables the Chevron ABU to integrate its Operational Excellence (OE) objectives, processes, procedures, values, and behaviours into the daily operations of Chevron Australia personnel and contractors working under Chevron Australia's supervision. The OEMS is designed to be consistent with and, in some respects, go beyond ISO 14001-2004 (Environmental Management Systems – Requirements with Guidance for Use) (Standards Australia/Standards New Zealand 2004).

Figure 1-3 provides an overview of the overall hierarchy of environmental management documentation within which this Program exists. Further details on environmental documentation for the Gorgon Gas Development are provided in Section 6.1 of this Program.

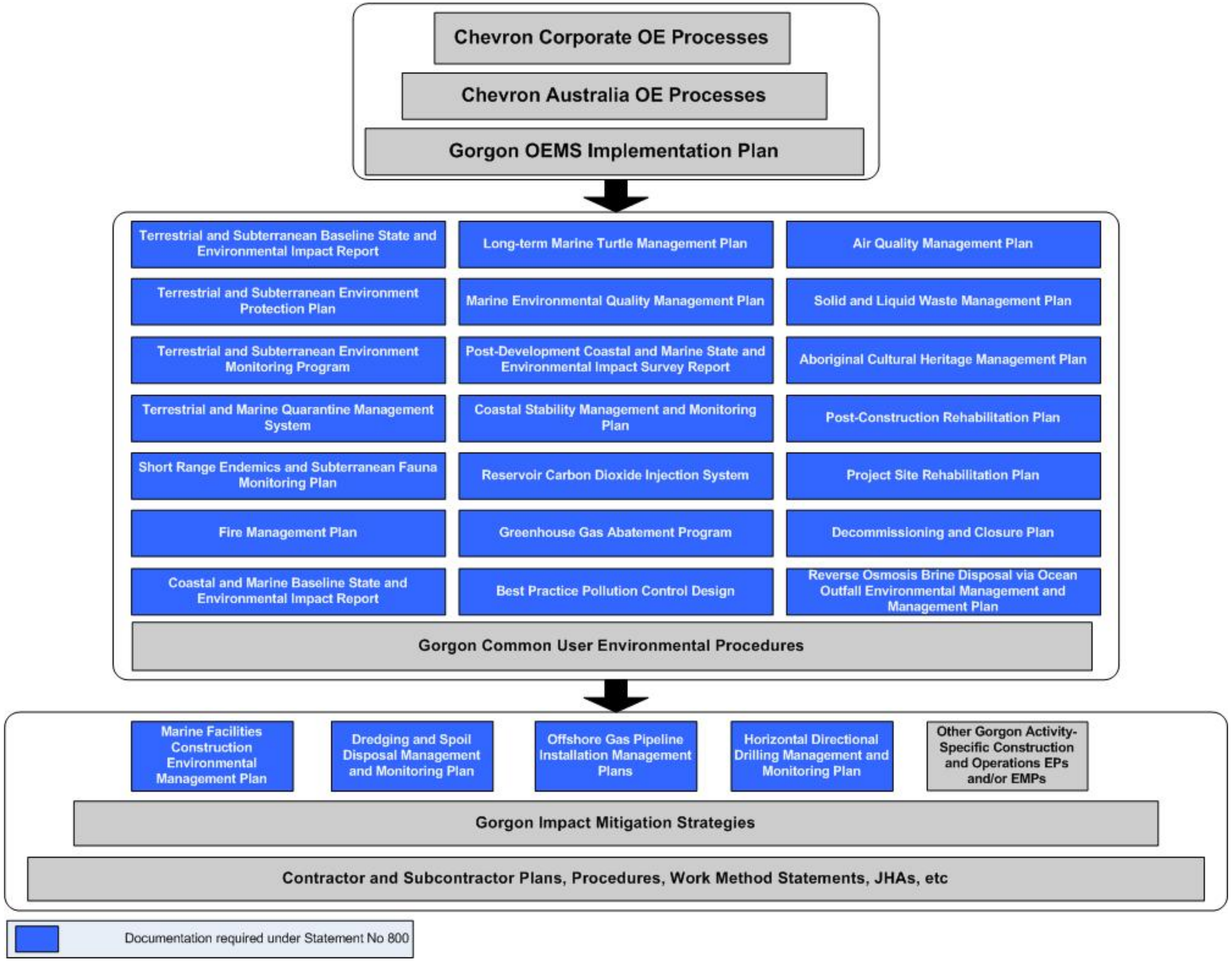

Figure 1-3 Hierarchy of Gorgon Gas Development Environmental Documentation

1.5.6 Stakeholder Consultation

Regular consultation with stakeholders has been undertaken by Chevron Australia throughout the development of the environmental impact assessment management documentation for the Gorgon Gas Development and Jansz Feed Gas Pipeline. This stakeholder consultation has included engagement with the community, government departments, industry operators, and contractors to Chevron Australia via planning workshops, risk assessments, meetings, teleconferences, and the PER and EIS/ERMP formal approval processes.

This Program has been prepared with input from the Western Australian Department of Environment Regulation (DER; formerly the Western Australia Department of Environment and Conservation [DEC]). DER reviewed draft revisions of this Program and their comments have been incorporated or otherwise resolved.

Figure 1-4 shows the development, review, and approval process for this Program.

1.5.7 Public Availability

This Program will be made public as and when determined by the Minister, under Condition 35 of Statement No. 800.

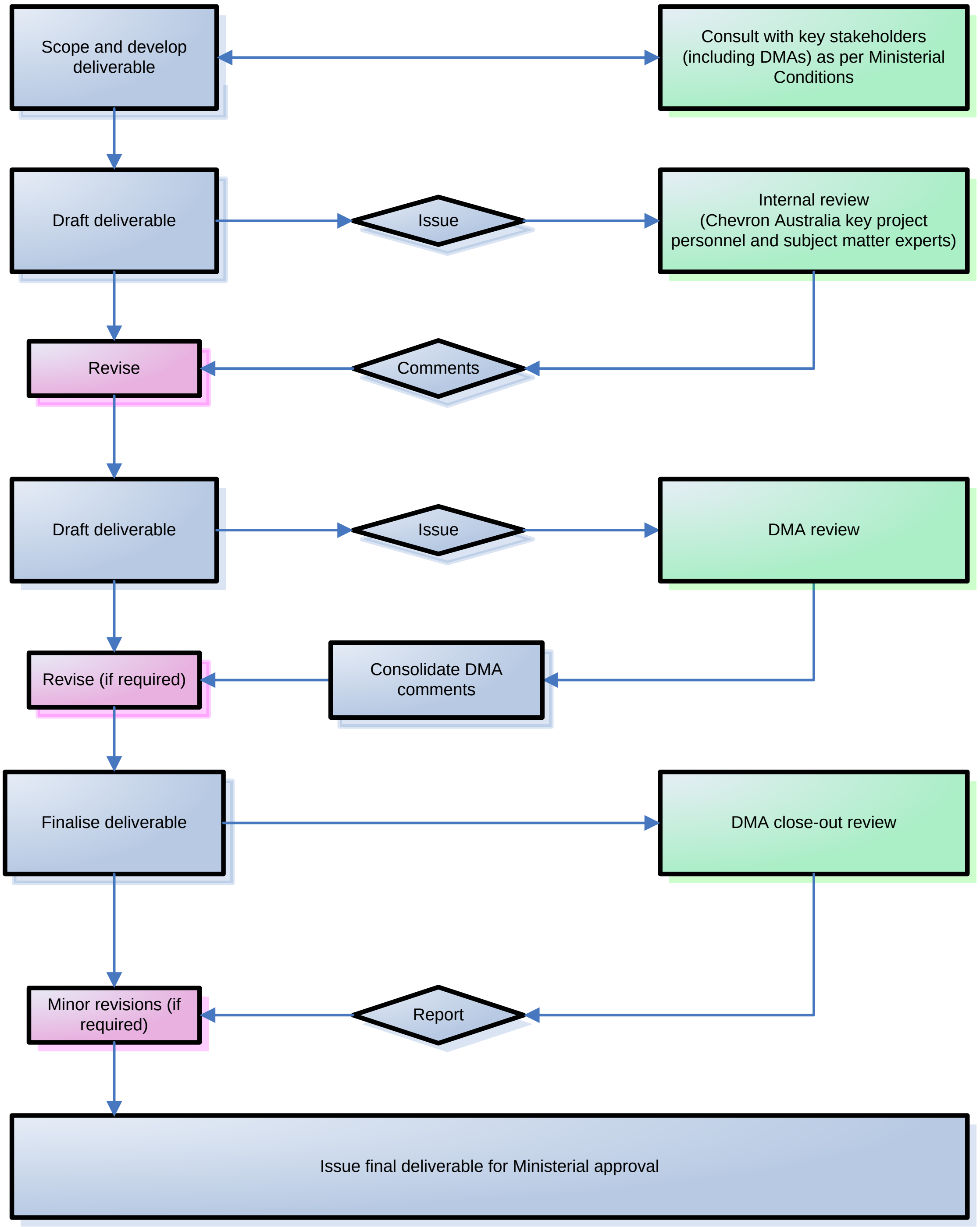

Figure 1-4 Deliverable Development, Review, and Approval Flow Chart

2.0 Government Policy and Regulation

The following sections outline current (as at March 2015) government policies and programs that impact the management of GHG emissions and energy efficiency.

In common with most major energy companies, Chevron Australia applies a price to future GHG emissions in its business plan and to aid capital project decision making. This internal forecast is designed to reflect the cost of GHG emissions regulation over the anticipated operating life of a project.

2.1 Commonwealth Legislation and Policy

Commonwealth Government policy regarding reducing global GHG emissions has changed significantly over the last few years. At the time of publication (March 2015), Commonwealth Government regulation was implemented through the following national legislation:

- *Energy Efficiency Opportunities Act 2006* (Cth) (EEO Act)
- *National Greenhouse and Energy Reporting Act 2007* (Cth) (NGER Act)
- C*lean Energy Act 2012* (Cth) (Clean Energy Act) and associated schemes (e.g. Carbon Pricing Scheme).

With the election of the Liberal/National Party Coalition Government in 2013, it is anticipated that the carbon pricing scheme will be replaced with the Coalition's Direct Action Plan's Emissions Reduction Fund (ERF).

On 15 May 2014, the Commonwealth Government introduced legislation into the Australian Parliament to repeal the EEO Act. On 4 September 2014, the repeal bills were passed by the House of Representatives and Senate, and subsequently passed to the Governor-General for assent (currently pending).

The NGER Act is expected to remain as Australia's national scheme for the reporting of GHG emissions, energy use, and energy production, and is anticipated to underpin several key elements of the ERF.

2.1.1 Carbon Pricing Scheme

The Clean Energy Act established a price on GHG emissions. Most GHG emissions from the Gorgon Gas Development would be directly covered by the Clean Energy Act.

On 14 July 2014, the Commonwealth Government introduced legislation into the Australian Parliament to repeal the Clean Energy Act. On 17 July 2014, the repeal bills were passed by the House of Representatives and Senate, and subsequently passed to the Governor-General for assent (currently pending).

2.1.2 Direct Action Plan and the ERF

The Commonwealth Government has proposed a Direct Action Plan as an alternative to the Clean Energy Act as the principal policy to meet a 5% emissions reduction target by 2020. Of relevance to the management of GHG emissions is the proposed establishment of the ERF, which will comprise three fundamental elements:

- build upon the existing Carbon Farming Initiative, a process for crediting emissions reductions
- a process for the Government to purchase emissions reductions
- a mechanism to 'safeguard the value of funds expended under the ERF and provide businesses with a stable and predictable policy landscape in which to make new investments'.

The reporting arrangements under the NGER Act are proposed to underpin key elements of the ERF.

The Commonwealth Government has indicated its intent to have the crediting and purchasing components of the ERF operational in 2015.

2.1.3 National Greenhouse and Energy Reporting Act 2007

In 2007, the Commonwealth Government introduced the NGER Act, which mandates the national reporting of GHG emissions, energy production, and energy use. Greenhouse gas emissions, energy production, and energy use from the Gorgon Gas Development are currently being reported in accordance with Chevron Australia's obligations under the NGER Act.

2.1.4 Regulation of GHG Emissions under the EPBC Act

Although GHG emissions are not listed as a matter of National Environmental Significance under the Commonwealth *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act), historically the Commonwealth Minister for the Environment has imposed conditions regulating GHG emissions on a number of proposals that have planned emissions in the Commonwealth Marine Area.

In October 2012, the Commonwealth Minister for the Environment wrote to the Proponents of several projects indicating that, with their consent, he would remove these conditions as the projects would now be operating under the Clean Energy Act. Chevron Australia accepted a revocation of conditions relating to the requirement for a Greenhouse Gas Management and Abatement Strategy for the Wheatstone Project (EPBC Reference: 2008/4469).

2.2 Western Australian Legislation and Policy

In October 2012, the State Government released its climate change strategy 'Adapting to our Changing Climate', which establishes that regulation of GHG emissions is viewed by the State Government as a matter for the Commonwealth Government:

> *'The Western Australian Government's view is that decisions on the design, implementation and timing of the regulation of GHG emissions, and support for new low emissions technology, are primarily matters for the Australian Government and Federal Parliament'*

This reaffirms previous statements by the Western Australian Premier and Minister for the Environment and marks a shift from State regulation to national regulation. The policy strategy identifies adaptation planning as the primary role for the State Government and proposes 'complementary action' to assist the national mitigation effort.

2.2.1 Environmental Protection Act

Before the release of the 'Adapting to our Changing Climate' policy statement, the State Government regulated GHG emissions by imposing conditions on the approval of large projects under the EP Act. The form of these conditions has evolved over time and generally required the development of a GHG management or abatement program, and in certain cases, an investment in GHG offsets.

The recommendations of the EPA on minimising GHG emissions played an important role in determining the nature of these conditions. At the time of publication, the EPA's position on the regulation of GHG emissions was under review.

Since the release of the 'Adapting to our Changing Climate' policy statement, several major projects have either been approved or had their approval conditions varied to give effect to the State Government's policy. For example, the approval of the variation to conditions imposed on the Wheatstone Project (Ministerial Statement No. 922) now only imposes conditions related to the reporting of GHG emissions.

3.0 Gas Treatment Plant Overview

3.1 Gas Treatment Plant Processing Facilities

As approved under Statement No. 800, the Gas Treatment Plant comprises the main processing units described in the following sections and depicted in Figure 3-1.

3.1.1 Inlet Processing, MEG Regeneration, and Condensate Stabilisation

The Gorgon and Jansz feed gas arrives at dedicated Gorgon and Jansz inlet processing facilities (slug catchers), designed to segregate the incoming fluids into three separate phases (gas, condensate and aqueous phase) and provide steady flow rates to the downstream units. The reduced pressure gas phase is combined and sent to the Acid Gas Removal Units (AGRUs). A side stream of gas downstream of the Jansz slug catcher is sent to the Domestic Gas (DomGas) Plant for processing and export.

The aqueous phase is sent to the Mono-ethylene Glycol (MEG) Regeneration unit, designed to regenerate the rich (water-saturated) MEG (MEG is used to inhibit hydrate formation in the pipelines) by removing water and salts from a slipstream of the reconcentrated MEG to meet lean MEG specifications. Recovered lean MEG is sent back to the Gorgon and Jansz production wellheads via dedicated MEG utility pipelines.

The condensate stream is sent to Condensate Stabilisation, where further stripping of the light hydrocarbon components is undertaken to produce a stabilised condensate stream, which is combined with the condensate from the LNG Train Fractionation Unit prior to storage and export.

3.1.2 Acid Gas Removal and Carbon Dioxide Compression

The commingled Gorgon and Jansz gas phase streams from the slug catchers and the condensate stabilisation unit are routed to the AGRU for carbon dioxide (CO_2) and hydrogen sulfide (H_2S) (collectively termed 'acid gas') removal from the natural gas using a proprietary activated Methyl Di-ethanol Amine (a-MDEA) technology. Acid gas must be removed from the natural gas to prevent it from freezing out at low temperatures in the cryogenic sections of the Gas Treatment Plant and to meet the LNG product CO_2 and sulfur specifications.

Each AGRU is designed to process 33% of the combined Gorgon and Jansz gas stream. The AGRUs comprise these subsystems:

- an Absorber System, designed to remove CO_2 and H_2S from the natural gas by absorption in an a-MDEA solvent
- a Regenerator System, designed to regenerate the a-MDEA solvent for re-use by separating it from the acid gas components, removed from the natural gas in the Absorption System
- a Mercury Removal Unit (MRU) to ensure that mercury is removed from the acid gas stream prior to injection via the CO_2 Injection System or venting to atmosphere (see Figure 3-2).

The removed acid gas, containing 99.7 mole % of CO_2 and minor residual amounts of volatile organic compounds (VOCs) and H_2S, is compressed in the CO_2 Injection System and injected into the subsurface Dupuy Formation, or vented if the compression or injection system is off line.

The CO_2 Injection System consists of 2 × 50% CO_2 Injection units (A and B) dedicated to each AGRU (see Figure 3-2). Failure of any critical equipment inside each injection unit is likely to result in the immediate shutdown of that unit and local acid gas venting. The second CO_2 injection unit is expected to be able to operate normally during this time. Maintenance on the critical equipment in the shutdown unit is not expected to adversely affect the operation of the second unit, i.e. it is intended that equipment failure in one unit will result in acid gas venting from that unit only, allowing 50% of the acid gas stream processed through the affected AGRU train to continue to be injected.

The CO_2 injection facilities, downstream of the CO_2 injection units, are not part of the Gas Treatment Plant, but are described here for information.

The compressed acid gas is injected via nine CO_2 injection wells, drilled directionally from three CO_2 drill centres. An above-ground CO_2 pipeline runs from the CO_2 compressors on the north side of the Gas Treatment Plant to these drill centres.

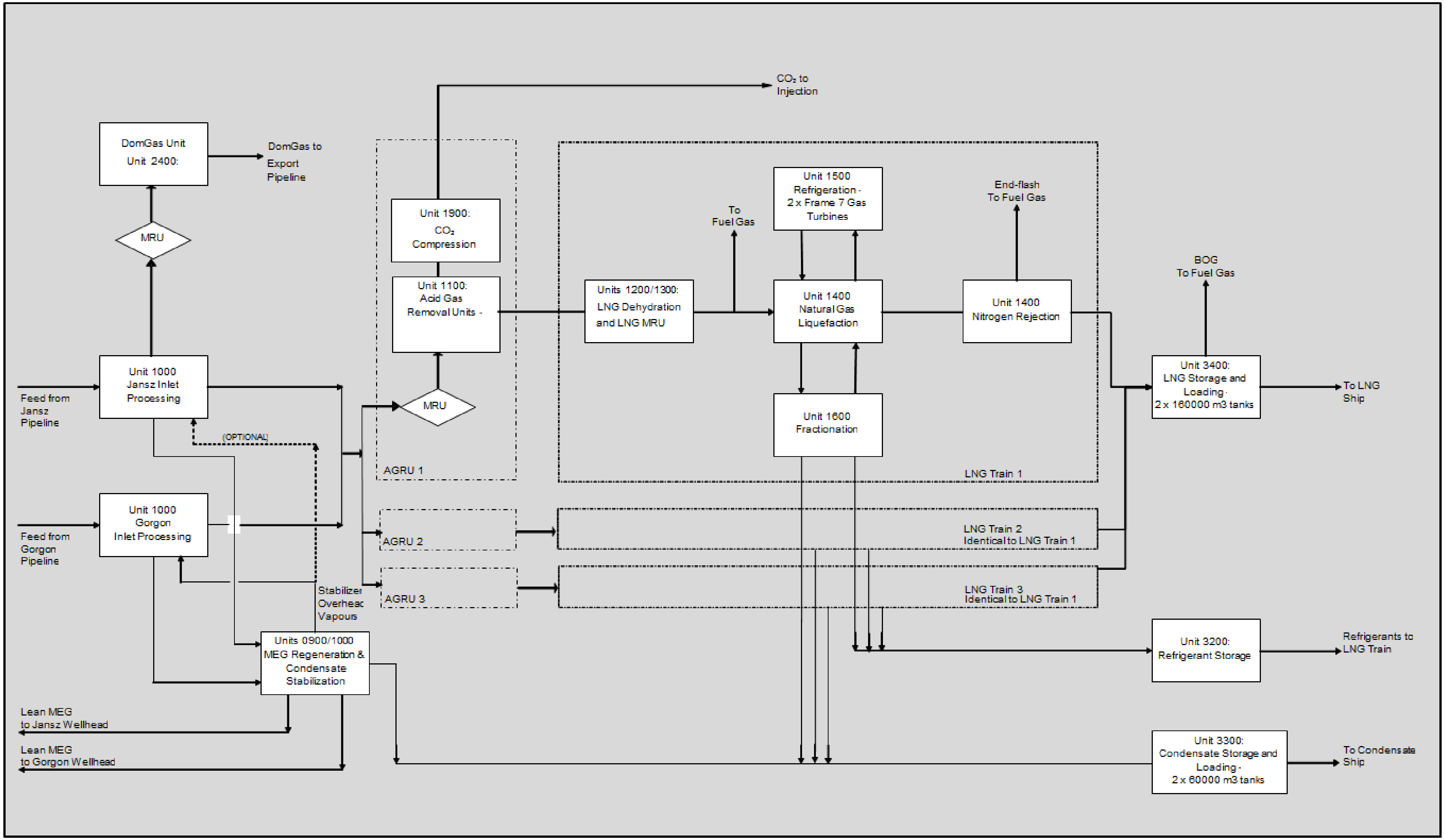

Figure 3-1 Gorgon Gas Treatment Plant Block Flow Diagram

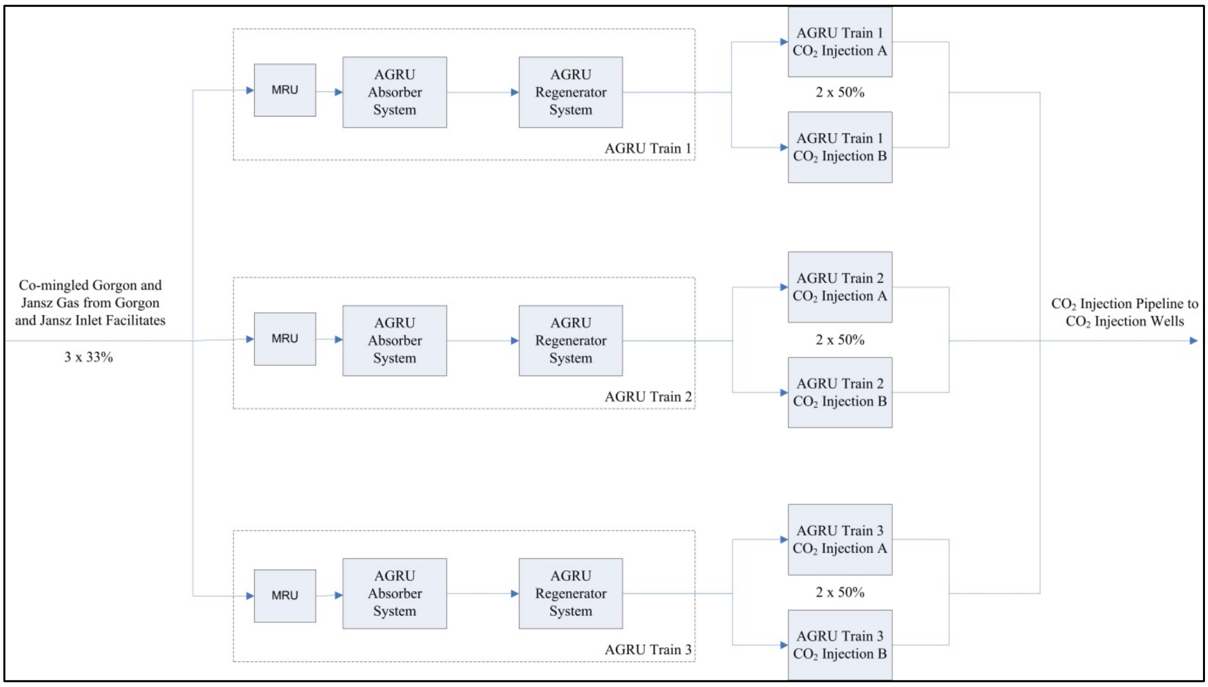

Figure 3-2 Acid Gas Removal and CO_2 Injection System Block Flow Diagram

3.1.3 Dehydration and Mercury Removal in LNG Trains 1 to 3

The Dehydration Unit in each LNG Train removes water from the treated hydrocarbon gas leaving the AGRUs. The treated gas is then dried in a molecular sieve to remove the final traces of water and to prevent hydrate formation in the Liquefaction Unit which could cause blockages of lines and equipment.

The MRU in each LNG Train removes trace quantities of mercury present in the feed gas to the Liquefaction Unit to prevent corrosion of the heat exchanger tubes in the Main Cryogenic Heat Exchanger (MCHE). Mercury adsorbers with non-regenerable packed beds and adsorber after filters will be provided to ensure adequate removal of trace quantities of mercury.

3.1.4 Liquefaction, Fractionation, and Refrigerant Make Up in LNG Trains 1 to 3

Before the dry treated gas from the MRUs can be liquefied, heavy hydrocarbons, which can otherwise freeze out in the liquefied natural gas, need to be removed. For this purpose, the dry treated gas is pre-cooled and fed to the Scrub Column which removes heavy hydrocarbons and aromatics to comply with LNG product specifications and to prevent freezing at cryogenic temperatures in the MCHE; and recovers ethane and propane from the natural gas allowing sufficient refrigerant make up to be produced in the Fractionation Unit. The cooling medium is ambient air.

Liquefaction is the main component of the LNG train; it chills the natural gas to a temperature at which LNG can be produced using large gas turbines and a series of cryogenic heat exchangers. The liquefaction process is the Air Products and Chemicals Incorporated (APCI) Split–MR™ Propane Pre-Cooled Mixed Refrigerant (MR) Process (see Figure 3-3). Each LNG train has refrigeration compressors driven by Frame 7 GTs. The APCI 5.2 MTPA Refrigeration Cycle is illustrated in Figure 3-3.

3.1.5 Nitrogen Removal and End Flash Gas Compression in LNG Trains 1 to 3

Liquefied natural gas is further cooled in the Nitrogen Column Reboiler and subsequently flashed off in the top of the Nitrogen Rejection Column. The LNG product separates in the Nitrogen Rejection Column bottom and is pumped to the LNG Storage Tanks. End flash gas is routed to a multistage End Flash Gas Compressor, which compresses it to the pressure required for the high-pressure fuel gas system.

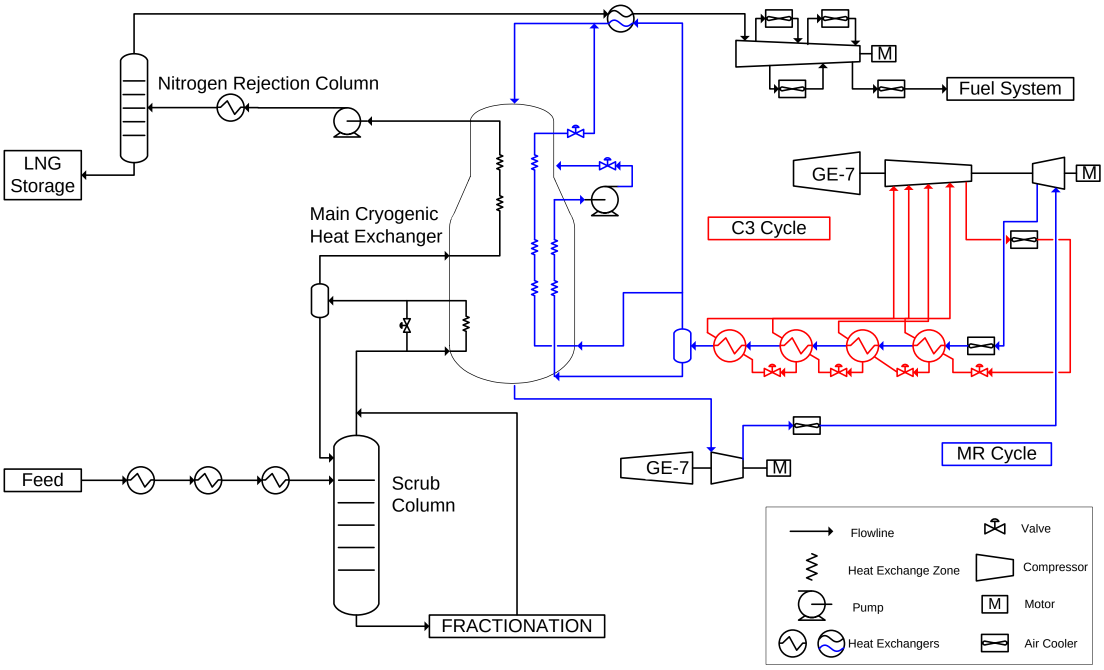

Figure 3-3 APCI 5.2 MTPA Refrigeration Cycle

Legend:

GE-7	*Frame 7 GTs, driving the Refrigeration Compressors*
C3 Cycle	*Propane Refrigerant Cycle*
MR Cycle	*Mixed Refrigerant Cycle*
M	*Refrigerant Compressor Helper Motor*

3.1.6 LNG and Condensate Storage and Loading

The purpose of the LNG Storage and Loading unit is to provide adequate storage and loading facilities to allow continuous production of LNG at the designed production rates and to enable intermittent exports by LNG carriers. The two LNG Storage tanks are full containment tanks with a net capacity of 180 000 m^3 each. Boil off gas (BOG) from the LNG storage tanks is collected, compressed and returned to the high-pressure fuel gas system inside the LNG trains.

The LNG Jetty, located approximately 4 km offshore from the Gas Treatment Plant at Town Point, has two LNG Carrier Berths, each equipped with four loading arms, i.e. two liquid loading arms, one hybrid (liquid and vapour), and one vapour return arm. The BOG generated during LNG loading of LNG carriers is routed back down the jetty via the vapour return arm and the vapour return line and compressed and recycled as feed gas to the Dehydration and MRUs inside the LNG trains. BOG (marine) flares safely dispose of BOG in the event of BOG compressor failure and warm LNG carrier de-inerting.

The purpose of the Condensate Storage and Loading Unit is to provide adequate storage and loading facilities to allow continuous production of condensate at the design capacity of the Gas Treatment Plant and to enable intermittent exports by condensate tankers. The four condensate storage tanks will be emptied by periodic loading of condensate tankers through a load out line that runs along the jetty and terminates at the loading platform at two 50% condensate loading arms.

3.1.7 Domestic Gas (DomGas Unit)

The DomGas Unit will be designed for 300 terajoules of sales gas per day (TJ/d), derived from Jansz feed gas. The unit uses MEG/Joule-Thomson (JT) processing to meet pipeline moisture and hydrocarbon dewpoint specifications. Domestic gas will be exported via a dedicated pipeline to the mainland where it will tie in to the Dampier to Bunbury Natural Gas Pipeline.

Mercury is predicted to be in the feed gas that is diverted to the DomGas Unit after passing through the Inlet Systems. This gas will be passed through an MRU to remove the mercury, thus ensuring that the DomGas produced meets the specification for gas to be received by the Dampier to Bunbury Natural Gas Pipeline.

3.2 Ancillary Systems and Facilities

The main ancillary systems and facilities associated with the Gas Treatment Plant are listed in the following subsections.

3.2.1 Fuel Gas and Recycle Gas Systems

The purpose of the Fuel Gas and Recycle Gas systems is to reliably provide fuel gas to users throughout the Gas Treatment Plant, and to return low-pressure gas, unsuitable for use as fuel, to the process for treating. The unit consists of multiple systems:

- high-pressure fuel gas system in each LNG train to supply the refrigerant GTs
- high-pressure fuel gas system in the Utilities area to supply the GTGs for power generation; an MRU is included on the start-up/backup fuel gas from the Inlet System to ensure the GTGs operate free of mercury contamination
- high-pressure fuel gas is let down to separate low-pressure fuel gas headers to supply the heating medium heaters and the pilots and purge gas for the flare systems
- a Recycle Gas system compresses flash gas from the AGRUs back to the process units for further treatment.

3.2.2 Power Generation

The power generation system will generate power for electrical consumers in the Gas Treatment Plant and other electrical consumers (e.g. Permanent Operations Facility, Butler Park). The estimated total electrical power load for all electrical consumers is 416 MW (with contingency).

Electrical power is provided by five Frame 9 GTGs (N+1 operating philosophy), running continuously and sharing the load, between 80 and 100 MW each, under normal operating conditions. The maximum power output of the power generation plant under average feed composition/average ambient temperature (AFAT) operating conditions is 550 MW (fouled condition) with all five GTGs running.

3.2.3 Heating Medium System

The Heating Medium System is a pressurised, closed-loop hot demineralised water recirculating system. Heat is recovered from the available waste heat from GT exhausts in the Waste Heat Recovery Units (WHRUs) and sent to various heat consumers around the Gas Treatment Plant, including inlet gas heating, AGRU reboilers, MEG regeneration package, etc.

3.2.4 Pressure Relief/Liquids Disposal, Flare, and Vent Systems

The design of the flare system is based on segregation of wet (containing water or water vapour), heavy hydrocarbons and light, dry (water-free), potentially cold hydrocarbons so that hydrate formation, freezing or condensation will not restrict the operation of any system. Three separate systems are provided for this purpose: wet flare, dry flare and the BOG flare.

The design basis for the Gas Treatment Plant specifies no routine flaring during normal operations other than flare pilots and purge gas (Chevron Australia 2008a).

The wet and dry gas flare systems are each comprised of a collection header system for vapours and a collection header system for liquids, a knock out drum and a staged ground flare. No liquid burners are installed. The BOG flare system consists of two 100% low-pressure flares (one operational, one spare) located in the vicinity of the LNG Storage Tanks.

The design basis for the Gas Treatment Plant specifies no routine hydrocarbon venting and there are no routine vents provided on hydrocarbon process streams (Chevron Australia 2008a). Acid gas (CO_2) venting will occur in the event of failure of the carbon dioxide compression or injection system. The availability of the carbon dioxide compression and injection system, which is capable of disposing by underground injection 100% of the volume of reservoir carbon dioxide to be removed during routine processing operations, is expected to be greater than 80%, expressed as a five-year rolling average.

4.0 Greenhouse Gas Emissions and Intensity

4.1 GHG Emissions Forecasting Methodology

The Gorgon Gas Development's GHG emissions forecast has been calculated using a methodology consistent with the technical guidance provided under the National Greenhouse and Energy Reporting Regulations 2008 (NGER Regulations), specifically the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines (Department of Climate Change [DCC] 2009) and the National Greenhouse Accounts (NGA) Factors (DCC 2008).

The methodology used to compile the preliminary GHG emissions forecasts was Method 2, which includes using fuel composition and relevant fuel qualities (e.g. heating value), estimated as part of engineering and design, to calculate fuel-specific emission factors using the methods prescribed in the existing Generator Efficiency Standards (Commonwealth Department of the Environment, Water, Heritage and the Arts [DEWHA] 2006).

During commissioning, start-up, and the operations phase of the Gas Treatment Plant, some sources of GHG emissions are to be calculated using Method 3 where appropriate (based on direct measurement of fuel composition and energy values).

4.2 Gorgon Gas Development GHG Emissions Forecasts

4.2.1 Commissioning and Start-up GHG Emissions Forecasts

The GHG emissions forecasts for the commissioning and start-up of the Gas Treatment Plant are estimated from the commissioning and start-up sequence and schedule documents. Several key commissioning and start-up decisions are still pending resolution and could significantly influence the duration of hydrocarbon gas venting and flaring and acid gas venting activities, which are expected to dominate the total GHG emissions for the duration of this phase. Reasonably practicable measures are expected to be used to reduce GHG emissions from commissioning and start-up activities to as low as reasonably practicable (ALARP).

Gas Treatment Plant commissioning and start-up flaring forecasts are to be provided to DER within a series of Commissioning Plans, required under the Works Approval process under Part V of the EP Act. These Commissioning Plans will be developed and submitted as works progress on the Gorgon Gas Development.

4.2.2 Operations Phase GHG Emissions Forecasts

The preliminary GHG emissions forecasts for the operations phase represent an approximation of the expected actual annual GHG emissions inventory during steady-state operations of the 3 × 5.2 MTPA Gas Treatment Plant (see Table 4-1).The following assumptions underpin these preliminary forecasts:

- LNG production availability is 8170 hours (340.4 stream days) per calendar year (Chevron Australia 2008b), corresponding to an annual average LNG production of 15.59 MTPA Freight on Board (FOB).
- All Frame 9 GTGs are operated at 75.4% part load (corresponding to 416 MW total Gas Treatment Plant power demand without contingency) in an N+1 operating mode, whereby one GTG provides a spinning reserve.
- Gas Treatment Plant utilities, including flares, heaters, power generation plant and diesel consuming safety equipment on stand-by, are required to be available 365 days per calendar year. This has been reflected in the preliminary GHG emissions estimates for these emission sources.
- LNG production is sourced 65% from the Gorgon field and 35% from the Jansz field.
- Domestic gas production is sourced exclusively from the Jansz field during normal operations.

- Twenty per cent of removed reservoir CO_2 is assumed to be vented due to the periodic unavailability of the CO_2 injection system.
- One of the two Heating Medium Heaters is maintained on cold stand-by (pilot flame only) during normal operations; the other is offline.

No perfluorocarbons (PFCs) are planned to be used in the Gas Treatment Plant. Hydrofluorocarbons (HFCs) will be used in the heating ventilation and air conditioning (HVAC) systems and sulfur hexafluoride (SF_6) will be used in some electrical switch gear. However, these uses are for closed systems, so emissions of these substances could potentially occur only under non-routine or emergency conditions. Operating and maintenance procedures for HVAC systems will aim to prevent loss of HFCs during refrigerant change out.

Submission to the DER of preliminary GHG emissions forecasts for the operations phase will be via the application for an operating licence for the Gas Treatment Plant under Part V of the EP Act. A summary is outlined in Table 4-1.

Table 4-1 Preliminary Operations Phase GHG Emissions Forecasts

GHG Emissions Source	Fuel / Emission Type	Total CO_2e by Source
Gas Turbines	Fuel Gas	5 100 000
Heating Medium Heaters	Fuel Gas	10 000
Acid Gas Venting	Acid Gas	850 000
Flaring	Wet/Dry/BOG Hydrocarbon Gas	100 000
Fugitives	Hydrocarbon Gas	20 000
Diesel / Other	Diesel	20 000
Total	**--**	**6 100 000**

Note: Fugitive emissions of CO_2 from the AGRU and CO_2 injection systems within the Gas Treatment Plant are included in the Acid Gas Venting estimate.

4.2.3 Discussion of Major GHG Emissions Sources

The gas turbines (Frame 7 GTs and Frame 9 GTGs), acid gas venting, and flaring collectively contribute approximately 99% of the total GHG emissions associated with the Gas Treatment Plant operations. These major contributors are discussed in the following sections.

4.2.3.1 Gas Turbines

Gas Turbines (GTs) are used for LNG liquefaction and power generation. The GTs account for approximately 85% of the overall GHG emissions associated with the Gas Treatment Plant operations.

4.2.3.1.1 Frame 7 GTs.

The Frame 7 GTs drive the refrigeration compressors at the core of the LNG process. LNG processing train design, incorporating direct drive GTs with an LNG throughput of approximately 5.2 MTPA, represents established best practice in LNG plant design, offering optimum balance between capital cost, GHG emissions intensity, and operability risk profile.

The Frame 7 GTs in the LNG processing trains are fitted with WHRUs to recover additional energy from the latent heat in the exhaust combustion gases from the GTs. This recovered energy stream will be used within the Gas Treatment Plant to provide processing heat required for the regeneration of the CO_2 removal solvent (a-MDEA), regeneration of the hydrate inhibitor (MEG) and feed gas pre-heating and fractionation. In addition to providing approximately 450 MW of mechanical energy, 640 MW of process heat will be provided from the WHRUs fitted to the exhausts of the gas processing drivers. Each Frame 7 GT is fitted with DLN emissions control technology.

4.2.3.1.2 Frame 9 GTGs

The Frame 9 GTGs are used to generate electrical power for the Gas Treatment Plant and its support infrastructure.

Extensive studies were undertaken to identify and evaluate options for alternative power generation (Chevron Australia 2009a). These studies considered a range of open cycle and combined cycle options, as well as options for inlet cooling and water and steam injection. Given the remoteness of the Gas Treatment Plant on Barrow Island and lack of access to the State's electricity grid, the Gorgon Gas Development's power generation configuration must be highly reliable to avoid unplanned outages of the LNG processing trains. The LNG processing trains operate most efficiently when running at full capacity over long time periods. An unreliable electrical power supply would result in the LNG processing trains operating at lower than peak efficiency, or in the worst case, having to be shut down. LNG trips or full train shutdowns would result in a large increase in GHG emissions as part of or the entire gas inventory within the Gas Treatment Plant would have to be flared.

Total power demand for operations comprises 384 MW for LNG processing trains and inlet facilities, 12 MW for domestic gas processing, and 20 MW for Gorgon and Jansz Feed Gas Pipeline infrastructure electricity consumption.

Power generation studies concluded that the most appropriate configuration for the required generation of approximately 416 MW of electrical demand is to employ five open-cycle industrial GTGs each with approximately 117.5 MW (gross) and 110.5 MW (site rated) capacity operated at partial load. Having each turbine operating at partial load enables the operating turbines to quickly take up the load if one turbine should go offline, thereby maintaining a stable electrical supply to the LNG processing trains and avoiding LNG process upsets that might result in increased and potentially long duration flaring events.

Each of the GTGs is fitted with DLN emissions control technology.

4.2.3.2 Acid Gas Venting

Under routine gas processing operations, all reservoir CO_2 removed from the incoming gas stream is intended to be injected into the Dupuy Formation. The injection of reservoir CO_2 and associated impurities (collectively known as acid gas) will reduce GHG emissions attributable to the Gorgon Gas Development by approximately 3.4 million CO_2e tonnes per annum. However, venting of the reservoir CO_2 will be required during non-routine operations; e.g. initial start-up, Jansz-only operations, and periods of facility or injection system maintenance, unplanned downtime, and in the event of unforeseen reservoir or injection well constraints.

Design features aimed at increasing the reliability of the CO_2 injection system include the provision of:

- 2 × 50% CO_2 injection compressors per CO_2 injection train - to allow continued injection of 50% of the acid gas stream and venting of the residual 50% of the acid gas stream if one 50% CO_2 compressor is offline
- pig launching and receiving facilities - to allow intelligent and maintenance pigging of the CO_2 injection pipeline
- three CO_2 drill centres and nine directionally drilled CO_2 injection wells - to allow different regions of the Dupuy reservoir to be accessed
- pressure management facilities for the Dupuy reservoir and production of Dupuy Formation water to the surface - to avoid Dupuy Formation pressure build up and facilitate the CO_2 injection process.

Based on these design features, it is anticipated that the amount of reservoir CO_2 vented in any particular 12-month period will be less than 200 000 tonnes CO_2e; however, there is the potential for a higher level of venting, particularly in the event of unexpected injection well failure or an unexpected subsurface outcome. As a consequence, the reference case for the preliminary GHG emissions used in this Program assumes approximately 850 000 tonnes (or 20% of the reservoir CO_2 available for injection) will be vented annually once the Gorgon gas field is online. This represents a worst-case operational outcome which is anticipated to be improved upon with the development of operational experience.

The anticipated volumes of reservoir CO_2 that will be vented and the volumes anticipated to be injected are identified in Table 4-2. Volumes vented are expected to decline over time as the facility and CO_2 injection operations are optimised.

Table 4-2 Estimated Volumes of Acid Gas Anticipated to be Vented and Injected following Start-up of the Gorgon Gas Field

Percentage of Acid Gas (Reservoir CO_2)	Operations Year 1	Operations Years 2–5	Operations Year 6+	Long-term Performance Target
Percentage of Acid Gas injected into the Dupuy Formation	60–90% p.a. (2.52–3.78 MTPA)	70–95% p.a. (2.94–3.99 MTPA)	80–95% p.a. (3.36–3.99 MTPA)	95% p.a. (3.99 MTPA)
Acid Gas vented due to scheduled maintenance and unplanned facilities downtime	5–15% p.a. (0.21–0.63 MTPA)	5–10% p.a. (0.21–0.42 MTPA)	3–5% p.a. (0.13–0.21 MTPA)	3% p.a. (0.13 MTPA)
Acid Gas vented due to unforeseen reservoir constraints (including well injectivity failure)	0–25% p.a. (0–1.05 MTPA)	0–20% p.a. (0–0.84 MTPA)	0–15% p.a. (0–0.63 MTPA)	2% p.a. (0.08 MTPA)

Note:

- *As the concentration of CO_2 varies in different parts of the Gorgon gas field, these figures represent the anticipated maximum annual CO_2 production rate of 4.2 MTPA (Chevron Australia 2008c).*
- *The availability of the CO_2 compression and injection system, which is capable of disposing by underground injection 100% of the volume of reservoir CO_2 to be removed during routine processing operations, is expected to be more than 80% expressed as a five-year rolling average (despite not being able to inject CO_2 during initial start-up and Jansz-only operations).*
- *The concentration of H_2S within the acid gas stream is approximately 200 ppmv maximum.*

4.2.3.3 Flaring

Total facility flaring includes all routine and non-routine flaring from the wet and dry gas flares. A conservative estimate for flaring during normal operations was calculated based on:

- unplanned LNG Train trips
- one annual LNG Train planned maintenance shutdown and restart per year
- flare pilots and purge gas.

4.2.3.4 Further GHG Emissions Reduction Options

The discussion of the Gorgon Gas Development's major GHG emissions contributors indicates that only acid gas venting realistically offers a potential for considerable future GHG emissions reductions during operations.

4.3 GHG Intensity Benchmarking

4.3.1 Gas Treatment Plant GHG Intensity

The GHG intensity (GI) of the Gas Treatment Plant can be expressed as the mass of GHG (tonne CO_2e) emitted per tonne of LNG produced. Therefore, identification of GHG emissions associated with LNG production only is required. This approach is consistent with the standard industry method for calculating and benchmarking GI for LNG production facilities, as these facilities are often supplied with gas produced by offshore gas production and processing platforms, which also produce other liquid hydrocarbon products, including oil and condensate, propane, and butane, etc.

GHG emissions associated with production of other liquid hydrocarbon products, or the compression and transport of natural gas from the offshore (or onshore) facility to the onshore LNG facilities should be excluded from the LNG facilities GI calculation. GHG emissions from these sources can significantly skew results and make the benchmarking process difficult due to the large variety of processes and emissions involved.

Therefore, based on the preliminary GHG emission forecasts presented in Table 4-1, the contribution of LNG production is presented in Table 4-3. A comparison against DomGas production and infrastructure electricity consumption is also presented.

Table 4-3 Allocation of the Preliminary GHG Emissions Forecast between LNG Production, DomGas Production, and Project Infrastructure Electricity Consumption

Emissions Source	LNG Production [CO_2e Tonnes p.a.]	DomGas Production [CO_2e Tonnes p.a.]	Project Infrastructure Electricity Consumption [CO_2e Tonnes p.a.]
Gas Turbines	4 710 000	140 000	250 000
Heating Medium Heaters	10 000	Minor	Nil
Acid Gas Venting	850 000	Minor	Nil
Flaring	100 000	Minor	Nil
Fugitives	20 000	Minor	Nil
Total	**5 690 000**	**140 000**	**250 000**

Therefore, the Gorgon LNG production facilities GI is calculated for 5 690 000 tonnes of CO_2e produced and an annual average LNG production of approximately 15.59 MTPA FOB LNG based on 340.4 stream days per year (Chevron Australia 2008b):

$$\text{GI} = \frac{M_{GHG}}{M_{LNGproduced}} \text{ (tonnes } CO_2\text{e/tonne LNG produced)}$$

$$\text{GI} = \frac{5{,}690{,}000}{15{,}590{,}000} = 0.36 \text{ (tonnes } CO_2\text{e/tonne LNG produced).}$$

4.3.2 Improvements in GHG Intensity

Early design concepts for the Gorgon Gas Development incorporated a gas processing platform located offshore in the vicinity of the Gorgon gas field, with the LNG processing facility on the Burrup Peninsula. This design concept formed the basis of the 1998 Greenhouse Challenge Cooperative Agreement between the Gorgon Joint Venture Participants (JVPs) and the Australian Greenhouse Office (West Australian Petroleum [WAPET] 1998). The GI, as stated in the 1998 Cooperative Agreement, was 0.89 tonnes of CO_2e emitted per tonne of LNG produced (based on an annual average LNG production of approximately 15 MTPA FOB LNG).

The GI improvements identified below compare the current design to that used as the basis of the 1998 Cooperative Agreement. Specific engineering decisions that have resulted in significant improvements in GI compared to the 1998 design case include:

- replacement of the offshore gas processing platform with subsea development
- advances in LNG process technology
- provision of WHRUs on the Frame 7 GTs resulting in significant reduction in the use of supplementary heaters and removal of boilers to provide heating for process needs
- significant reduction in GHG emissions by injecting removed reservoir carbon dioxide into the Dupuy Formation.

4.3.2.1 Site Selection

The selection of Barrow Island as the preferred site for the Gas Treatment Plant enabled the use of subsea technology rather than platform-based offshore gas processing. The offshore gas production platform in the 1998 design accounted for approximately 600 000 tonnes of CO_2e emissions per year. By eliminating the offshore gas production platform and using a subsea gas production system, the GI of the Gorgon Gas Development has been improved by 0.04 tonnes of CO_2e per tonne of LNG produced.

4.3.2.2 Advances in LNG Process Technology

LNG process technology has evolved significantly, from the use of larger, more efficient plants to the changes in technology used to remove CO_2 from the natural gas stream. A range of incremental improvements in GI have resulted from the inclusion of technology improvements in the design, such as:

- increasing the size of the LNG process trains to the maximum practicable for the selected LNG technology
- using a-MDEA as the CO_2 removal medium in the AGRUs
- using dry compressor and hydrocarbon pump seals
- recovering flash gas from the nitrogen removal column and re-using it as fuel gas.

These technology improvements have resulted in a GI improvement of 0.23 tonnes of CO_2e per tonne of LNG produced, compared to the 1998 LNG process technology.

4.3.2.3 Provision of WHRUs

The design concept, upon which the 1998 Cooperative Agreement was based, included the use of direct fired heaters/boilers. These boilers accounted for approximately 520 000 tonnes of CO_2e emissions per year. The application of WHRUs to capture waste heat from the Frame 7 GTs resulted in restricted use of the Heating Medium Heaters. This has resulted in a GI improvement of 0.05 tonnes of CO_2e per tonne of LNG produced compared to the 1998 Gas Treatment Plant design.

4.3.2.4 Acid Gas Injection

The Gorgon JVPs conducted various studies to further reduce GHG emissions beyond those available through improved plant design. GHG offsets such as forestry or land rehabilitation planting or purchasing GHG credits were also considered. As a result of these studies, the Gorgon JVPs elected to make a significant reduction in GHG emissions by injecting the acid gas removed during gas processing into the Dupuy Formation. For the 15 MTPA Gas Treatment Plant, it was estimated that a minimum of 3.4 MTPA of reservoir carbon dioxide would be injected into the Dupuy Formation, which resulted in a further GI improvement of 0.22 tonnes of CO_2e per tonne LNG produced versus the 1998 development concept.

4.3.2.5 Other Abatement Options Considered

Table 4-4 summarises several technology options considered during the preliminary design phase of the Gorgon Gas Development that had the potential to further reduce GHG emissions but which were not adopted. As was the case for all GHG emissions abatement options considered, these options were assessed on a combination of cost effectiveness, operability, technology, health, safety and environmental risks. The primary reason for not adopting many of the options was the high cost of implementation for a relatively low reduction in GHG emissions. By way of illustration, while the capital costs associated with the injection of separated reservoir carbon dioxide is high, the volume of acid gas disposed of is also very large. This relationship can be expressed as a capital cost per annual mass of CO_2e abated. For the CO_2 injection approach, this metric results in a figure of AU$250/tonne of CO_2e abated. Many options that were rejected had a capital cost of annual CO_2e abated of around AU$1500/tonne. This highlights that these options are not competitive GHG emissions mitigation options when compared to the subsurface injection of separated reservoir carbon dioxide.

Table 4-4 List of other GHG Emissions Abatement Options Considered

Design Option	Offset in GHG Emissions [tonnes CO_2e p.a.]	Evaluation Comments
Use of alternative LNG technology rather than APCI	100 000	Emissions improvement was only a claim as the alternative technology remained unproven at the time. Significant operability, asset, and health, environment, and safety (HES) risk with being the first application of this new technology at the time.
Electric drive LNG compressors rather than direct drive compressors	300 000	Use of electric drive LNG compressors was relatively untested and carried higher technology risks and increased plot space requirements.
Combined cycle electrical power generation	900 000	Combined cycle power generation would increase operating cost, complexity and required plot space and potentially reduce plant reliability. Lack of readily available water supply on Barrow Island.
Aero-derivative gas turbines for electrical power generation	280 000	Increased operating costs and larger plot space requirements.
Power recovery turbines on liquid stream pressure let downs	Small	Rejected due to cost and operational complexity.
Air insulation on high voltage equipment	Small	Rejected due to increase in plot space required over gas-insulated switch gear.

4.3.3 Industry Benchmarking

Benchmark GI data available for other LNG projects is limited due to the proprietary nature of the data. However, the data that are publicly available (i.e. from published EIS/ERMP or PER documentation) has enabled comparison with the GI of the Gorgon Gas Development. These data are restricted to the intensity of LNG production, which is consistent with the standard industry method for calculating and benchmarking GI for LNG production facilities. However, this metric is not a direct reflection of the thermal efficiency of an LNG production facility as it is influenced by:

- the composition of the incoming gas stream, particularly the concentration of reservoir carbon dioxide and nitrogen, as well as the level of non-methane hydrocarbons (e.g. ethane, propane, butanes and pentanes)
- the ambient temperature in which the Gas Treatment Plant operates
- the energy used to inject reservoir carbon dioxide, if it is to be injected
- the degree to which GHG emissions from associated terrestrial infrastructure have been included in the calculations.

Figure 4-1 shows the GI associated with LNG production for several comparable LNG projects currently in production or under construction (as at March 2015). Operating LNG projects are shown as dark grey bars; light grey bars represent the GI for LNG projects currently under construction.

Where data on the emissions intensity of the associated gas production operations are available, these are presented as an additional white bar. Projects where publicly available data on gas production emissions are not available are indicated with a blue arrow. The Gorgon Gas Development, Snohvit, and Prelude Projects all use subsea production systems that do not result in any emissions related to gas production, but which may result in a slight increase in the emissions intensity for that project compared to a scenario where gas production from that facility would have been undertaken at an offshore platform.

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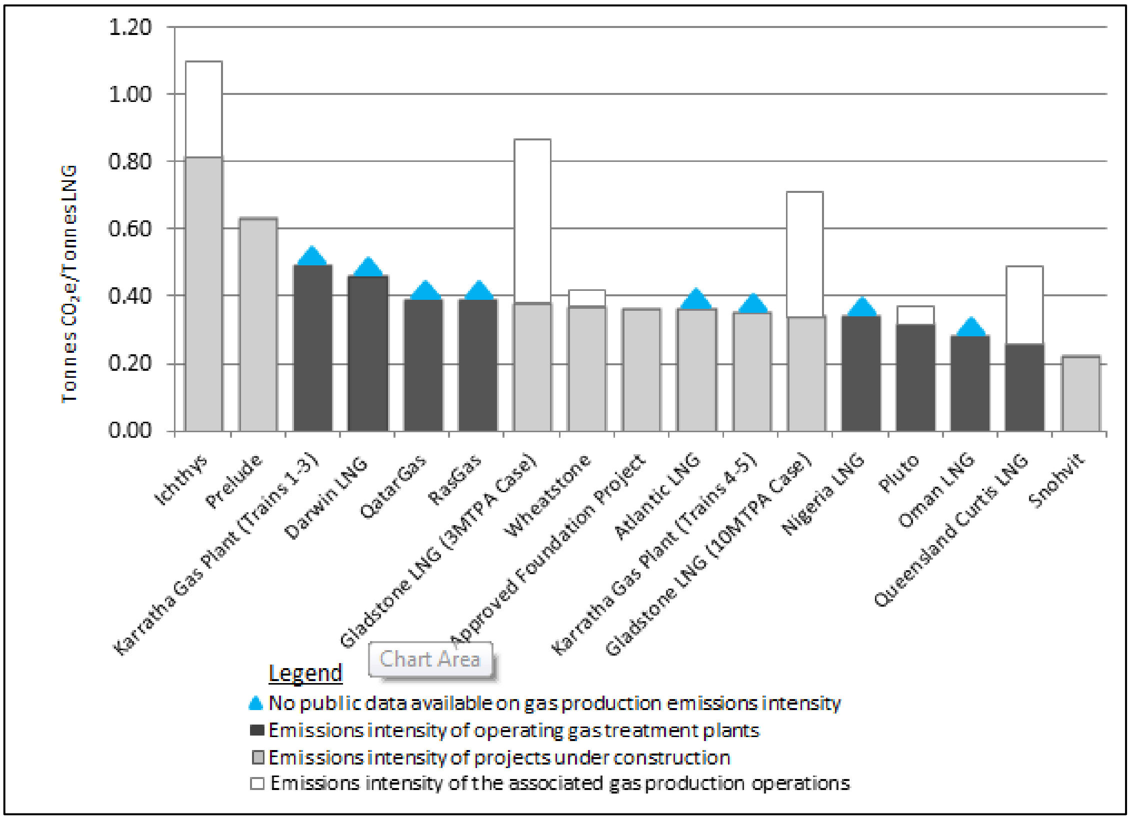

Source: Chevron Australia 2010e

Figure 4-1 Gorgon Benchmarked Greenhouse Gas Intensity

4.3.3.1 Gas Treatment Plant GI Normalisation to Standard Conditions

To illustrate the influence of the reservoir carbon dioxide content in the feed gas and ambient temperature on the Gas Treatment Plant GI and in response to the Statement No. 800 Condition 27.2(i) requirement, the GHG emissions from the Gas Treatment Plant have been normalised and benchmarked against the Oman and Snohvit LNG production GI data.

In comparison to Oman LNG, the Gorgon Gas Development Gas Treatment Plant must remove a greater proportion of reservoir CO_2 from the incoming feed gas. The electrical power required to operate the larger Gorgon Gas Development Gas Treatment Plant AGRUs is estimated at 15 MW. The increased heat load associated with the larger AGRUs has not been considered in this comparison as it is supplied by the WHRU. The 15.59 MTPA Gas Treatment Plant preliminary GHG emissions forecast includes approximately 850 000 CO_2e tonnes per year of reservoir CO_2 that is assumed to be vented and an allocation of 485 000 tonnes of CO_2e per year from the power generation plant GHG emissions, required to meet an 85 MW power demand to operate the CO_2 injection system. If the Gorgon feed gas had the same gas composition as the feed gas for Oman LNG, the benchmarked GI for Gorgon would reduce to 0.27 tonnes CO_2e per tonne LNG. A calculation enabling the Gas Treatment Plant GI to be benchmarked to the GI of the Oman LNG Plant is provided in Table 4-5.

Table 4-5 Normalised Benchmark Comparison to Oman LNG

	Tonnes CO_2e per tonne LNG
Gorgon Gas Development Gas Treatment Plant GI, equivalent to 14.2 mole % of CO_2 in Gorgon feed gas	0.36
Less power to AGRUs	0.006
Less reservoir CO_2 vented	0.054
Less power to run CO_2 compressors	0.031
Resultant Gorgon Gas Development Gas Treatment Plant GI, equivalent to 1.0 mole % of CO_2 in Gorgon feed gas	0.27
Oman LNG Facility GI	0.28

Notes:

1 *Above calculations do not include the reduction in process heat associated with CO_2 removal from the gas stream. Process heat required for CO_2 removal in the AGRUs is provided from the WHRUs. If the savings in GHG emissions, equivalent to the lesser process heat requirements to extract CO_2 from the feed gas in the Gas Treatment Plant AGRUs are considered, then the Gorgon Gas Development Gas Treatment Plant GI is expected to be reduced even further.*

2 *The Oman LNG Plant GI includes GHG emissions equivalent to venting of the 1% (mole) CO_2 content in feed gas, hence if the Oman LNG Plant GI is further normalised to exclude those emissions, its GI will move closer to the normalised Gorgon Gas Treatment Plant GI.*

The Snohvit LNG Plant operates at less than a third (4.1 MTPA LNG) of the gas processing capacity of the Gorgon Gas Development Gas Treatment Plant but shares a similar approach to the management of GHG emissions. Both developments are based around a subsea gas production system and a GHG reduction philosophy of subsurface injection of reservoir CO_2.

Since the GI of the Snohvit LNG Plant assumes that all reservoir CO_2 will be injected, a similar assumption has been made for the Gorgon Gas Development Gas Treatment Plant reservoir CO_2 removed in the AGRUs, thus reducing the Gas Treatment Plant's overall GHG emissions inventory by approximately 850 000 CO_2e tonnes.

The climate in which Snohvit operates is very different from that of the Gorgon Gas Development, as it is located above the Arctic Circle. Average temperatures in the area are approximately 0 °C compared to the design case for the Gorgon Gas Development Gas Treatment Plant of 26 °C. The colder ambient temperatures result in both the Frame 7 GTs and the LNG process working more efficiently. For every one degree reduction in ambient operating temperature, LNG process capacity increases by approximately 0.6%. Assuming the same Gas Treatment Plant configuration, if the Gorgon Gas Development was operating in a similar climate to Snohvit, annual LNG production would lift from 15.59 MTPA to 18.02 MTPA. This alone would improve the benchmarked GI by 0.04 tonne CO_2e per tonne LNG.

A calculation enabling the Gas Treatment Plant GI to be benchmarked to that of Snohvit is provided in Table 4-6.

Table 4-6 Normalised Benchmark Comparison to Snohvit LNG

	Tonnes CO_2e per tonne LNG
Gorgon Gas Development Gas Treatment Plant GI	0.36
Less efficiency improvement due to lower ambient operating temperature	0.04
Less reservoir CO_2 vented	0.054
Resultant Gorgon Gas Development Gas Treatment Plant GI,	0.27

	Tonnes CO_2e per tonne LNG
with no acid gas venting and operations in cold ambient conditions	
Snohvit LNG Facility GI	0.22

4.3.4 Conclusions

The above GI benchmark data shows a wide disparity between the anticipated LNG production emissions intensities of the studied projects, which is further compounded when the limited data on overall project emissions intensity are considered. It is reasonable to assume that the LNG projects currently under construction in Australia are all being designed to be energy efficient, highlighting how the project parameters identified above can influence the GI of a particular project.

However, the GI for the Gorgon Gas Development is comparable to other international and Australian LNG projects, and this reflects the achievement of an appropriate balance between GHG considerations, capital cost, the HES and operability risk profile, and indicates that the design of the Gas Treatment Plant has successfully managed to integrate a number of best practices (as listed and discussed in Section 5.0).

5.0 Best Practices in GHG Emissions Management

5.1 Integrating GHG Considerations in Design and Operations

The Gorgon JVPs recognised GHG emissions as a key environmental aspect and have fully integrated GHG considerations in the design and planning for the commissioning, start-up, and operations phases of the Gas Treatment Plant through these management measures:

- The Environmental Basis of Design (Chevron Australia 2008a) sets a number of environmental design and performance requirements on the design and operation of GHG emissions-generating activities and equipment, including flaring, venting, fugitive emissions, etc.
- The Environmental Basis of Design requires ALARP to be demonstrated and cost-benefit assessments to be conducted over a range of possible costs per tonne of CO_2e emitted when selecting equipment (e.g. when selecting the configuration of the Gas Treatment Plant power generation plant).
- Procurement strategies include requirements for major equipment vendors to provide environmental performance information for their equipment, including GHG emissions, which becomes a consideration in the vendor and/or equipment selection process.
- The ABU Hazardous Materials Management Process (Chevron Australia 2006a) requires assessment of the hazardous properties of chemicals, including their Global Warming Potential (GWP) and selection and approval for purchase and use of those chemicals that are least hazardous to the environment.
- The Management of Change Process (Chevron Australia 2008e) requires identification of environmental aspects associated with the change and assessment of environmental impacts using a risk-based approach. This also includes GHG emissions considerations.

Sections 5.2 and 5.3 list specific best practice measures for GHG emissions minimisation in design, and measures planned to be implemented in the Gas Treatment Plant commissioning, start-up, and operations phases. These measures are aimed at reducing the total net GHG emissions and GHG emissions per unit of LNG produced from the Gorgon Gas Development.

5.2 Best Practice in Gas Treatment Plant Design

Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include:

- Injecting reservoir carbon dioxide recovered from the AGRUs into a confined subsurface reservoir (Dupuy Formation) below Barrow Island. Reservoir CO_2 is intended to be vented only in the event of injection system maintenance or unplanned downtime, or in the event of an unforeseen reservoir performance or injection well constraint.
- No routine flaring of hydrocarbons. Routine flaring is defined as the continuous flaring of process hydrocarbon gas beyond that required for the safe operation of the flare system (i.e. flare pilots and purge gas) and plant (e.g. small flows from equipment purges which are not practicable to collect during normal production operations).
- No routine venting of hydrocarbons. Minor quantities of hydrocarbons may be vented only under non-routine operating conditions such as prior to maintenance activities, process or equipment trips, etc.
- Using the end flash gas from the nitrogen rejection unit as fuel gas. Prior to use as fuel, the low temperatures in this gas (-160 °C) are used to cool mixed refrigerant and reinjection liquefied petroleum gas (LPG) components, thus recovering ‘cold energy’ from this stream. This reduces the amount of power required to produce a unit of LNG, thereby reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for a given amount of LNG production.

- Using tandem dry gas seals for process compressors in the plant, and on smaller compressors in minor service, where appropriate.
- Using a subsea development approach for the Gorgon and Jansz gas fields, thus eliminating the need for an offshore production and compression platform.
- Using a waste heat recovery system on the refrigeration compressor GTs to recover thermal energy from the GT exhaust gases, significantly reducing the need to use heaters/boilers to meet process heat demand during routine production operations.
- Using activated MDEA (a-MDEA) as the preferred amine for acid gas removal from the feed gas. Activated MDEA uses significantly less energy for CO_2 removal than competing amines such as Mono-ethanol Amine (MEA) or Di-ethanol Amine (DEA). The use of a-MDEA means that electrical energy is saved from a smaller circulation rate, as well as thermal energy from a lower heat of desorption and less circulation.
- Choosing Split Mixed Refrigerant (MR) technology developed by APCI (see Section 3.1.4) to produce LNG. This best-in-class process, first employed at the RasGas LNG Plant in 2003, uses all available power from two primary drivers by splitting the MR compression duty onto the two drivers. This provides the optimal refrigeration split, and achieves a best-in-class process efficiency and decreased GHG intensity.
- Using LNG and MR expanders to produce an isentropic pressure drop for the LNG and refrigerant fluids, reducing the amount of lost work in the process relative to using an expansion valve. This reduces the amount of power required to produce a unit of LNG thereby reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for the same amount of LNG production.
- Using a recycle compressor to recover flash gas from the nitrogen rejection system and recycle it to the feed gas (see Section 3.1.5). Most plants recover this flash vapour to the low-pressure fuel system. Since the flash gas is CO_2-rich, fuel gas consumers using this fuel gas source emit more CO_2 than those using normal plant fuel gas. Therefore, the Gorgon Gas Development use of the flash gas recycle compressor and plant configuration provides a significant reduction in GHG emissions.
- Using a stabiliser overhead compressor to compress hydrocarbon-containing vapour from the stabiliser into the feed gas, preventing the flaring of this gas.
- Recovering vapours from MEG flash and distillation processes via compression and/or condensing them. The MEG flash vapour compressor will send vapours (largely CO_2) to the suction of the CO_2 injection compressors, where they will be injected into the Dupuy Formation. Other vapours will be sent to the produced water injection wells after condensing.
- Requiring a high-efficiency motor design, by implementing low and medium voltage motor specifications for use on the Gas Treatment Plant.
- Recovering and re-using LNG BOG generated during ship loading operations by compressing it to the front end of the Gas Treatment Plant via a BOG recycle compressor.
- Recovering BOG from the LNG storage tanks during normal LNG holding mode by using redundant BOG compressors. This gas will be sent to fuel, where it displaces an equivalent amount of fuel that would otherwise be sourced from the feed gas. The BOG recycle compressor provides sparing for the BOG compressor when not engaged in LNG loading operations (i.e. in LNG holding mode only). This reduces the potential for flaring in the event that the BOG compressor fails during normal LNG holding mode.
- Under normal operations, maintaining the LNG loading lines in a cold state between LNG carrier loadings. While this strategy increases the overall heat leak into the LNG lines, it decreases the amount of vapour generated during loading operations, which would otherwise require flaring

during peak cool-down operations or a slow and inefficient loading operation. Either of these options would result in an increase in GHG emissions.

- Sending any vapour generated in the refrigerant storage vessels to a LNG storage tank rather than directing it to flare.
- Fitting adjustable speed drives to selected motors as appropriate. This will allow plant operators to match the motor duty to the process requirements without wasting energy.
- Using a High Integrity Pressure Protection System (HIPPS) to prevent plant equipment trips and increased flaring due to high flow/high pressure in the feed gas system.
- Specifying control valves as low fugitive emission type, with a maximum allowable process fluid leakage. Since control valve leaks are responsible for the majority of fugitive process fluid emissions in the plant, and the Gas Treatment Plant process emissions are largely methane, this is expected to provide a significant reduction in GHG emissions in the order of several thousand tonnes of methane annually.
- Developing a flaring and venting procedure to manage the shutdown or depressurisation of selected equipment during events where safety of personnel and/or asset protection is required.
- Considering, including reserving plot space, the potential future installation of WHRUs, which could be used for further cogeneration and/or combined cycle power generation, if practicable.
- Specifying lighting reductions in the Gas Treatment Plant both to conserve energy and to reduce environmental impact of light on Barrow Island fauna. These changes will include reduced lighting intensity, switched or timed lighting in most areas, changing from area lighting to task-specific lighting where practicable, and other modifications.
- Installing a pressure-controlled line from the MCHE shell side to the End Flash Gas Compressor suction, so that tube leaks in the MCHE will first be routed to fuel gas usage instead of being flared. However, if the pressure continues to increase, the gas is routed to the flare.

5.3 Best Practice in Gas Treatment Plant Commissioning, Start-up, and Operations

A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up, and operations phases. These actions include, but are not limited to:

- developing commissioning, start-up, and operating procedures that aim to reduce the duration and frequency of hydrocarbon flaring and venting and/or acid gas venting
- developing operational, start-up, shutdown, and maintenance procedures with the objective of reducing GHG emissions during normal operations and planned maintenance shutdowns
- developing marine operational procedures to reduce flaring associated with 'warm' LNG carrier de-inerting operations
- once the Gorgon Gas Treatment Plant is operational, undertaking energy optimisation studies in line with requirements in Chevron Australia's OEMS.
- continuing to periodically review and, where practicable, adopt advances in technology and operational processes aimed at reducing GHG emissions per tonne of LNG produced.

6.0 Implementation

6.1 Environmental Management Documentation

6.1.1 Overview

Figure 1-3 in Section 1.5.5 of this Program shows the hierarchy of environmental management documentation within which this Program exists. The following sections describe each level of documentation in greater detail.

6.1.2 Chevron ABU OE Documentation

As part of the Chevron ABU the Gorgon Gas Development is governed by the requirements of the ABU OEMS, within which a number of OE Processes exist. The Gorgon Gas Development will implement internally those OE Processes (and supporting OE Procedures) that apply to the Gorgon Gas Development activities where those Processes are appropriate and reasonably practicable.

The key ABU OE Processes taken into account during the development of this Program, with a description of the intent of the Process, are:

- **Environmental, Social and Health Impact Assessment Process** (Chevron Australia 2009b): Process for addressing potentially significant environmental, social and health impacts of projects under consideration.
- **HES Risk Management Process** (Chevron Australia 2012): Process for identifying, assessing and managing HES, operability, efficiency, and reliability risks related to the Gorgon Gas Development.
- **Environmental Stewardship Process** (Chevron Corporation 2007): Applies during the Operations Phase of the Gorgon Gas Development. Process for ensuring all environmental aspects are identified, regulatory compliance is achieved, environmental management programs are maintained, continuous improvement in performance is achieved, and alignment with ISO 14001:2004 (Standards Australia/Standards New Zealand 2004) is achieved.
- **Hazardous Communication Process** (Chevron Australia 2006a): Process for managing and communicating chemical and physical hazards to the workforce.
- **Management of Change Process** (Chevron Australia 2008e): Process for assessing and managing risks stemming from permanent or temporary changes to prevent incidents.
- **Contractor Health, Environment and Safety Management Process** (Chevron Australia 2010a): Process for defining the critical roles, responsibilities, and requirements to effectively manage contractors involved with the Gorgon Gas Development.
- **Competency Development Process** (Chevron Australia 2010b): Process for ensuring that the workforce has the skills and knowledge to perform their jobs in an incident-free manner, and in compliance with applicable laws and regulations.
- **Incident Investigation and Reporting Process** (Chevron Australia 2010c): Process for reporting and investigating incidents (including near misses) to reduce or eliminate root causes and prevent future incidents.
- **Emergency Management Process** (Chevron Australia 2010d): Process for providing organisational structures, management processes and tools necessary to respond to emergencies and to prevent or mitigate emergency and/or crisis situations.
- **Compliance Assurance Process** (Chevron Australia 2009c): Process for ensuring that all HES- and OE-related legal and policy requirements are recognised, implemented, and periodically audited for compliance.

6.1.3 Gorgon Gas Development Documentation

6.1.3.1 Ministerial Plans and Reports

In addition to this Program, a number of other plans and reports have been (or will be) developed for the Gorgon Gas Development that are required under State and/or Commonwealth Ministerial Conditions (see Figure 1-3). These documents address the requirements of specific conditions and provide standards for environmental performance for the Gorgon Gas Development.

6.2 Training and Inductions

All personnel (including contractors and subcontractors) are required to attend environmental inductions and training relevant to their role on the Gorgon Gas Development. Training and induction programs facilitate the understanding personnel have of their environmental responsibilities, and increase their awareness of the management and protection measures required to reduce potential impacts on the environment.

Chevron Australia has prepared the ABU Competency Development Process (Chevron Australia 2010b) to deal with the identification and assessment of required competencies for environmental roles, which it internally requires its employees, contractors, etc. to comply with.

Environmental training and competency requirements for personnel, including contractors and subcontractors, are maintained in a Gorgon Gas Development HES training matrix or the Competency Management System for operations personnel.

7.0 Auditing, Reporting, and Review

7.1 Auditing

7.1.1 Internal Auditing

Chevron Australia has prepared the internal ABU Compliance Assurance Process (Chevron Australia 2009c) to manage compliance, and which it internally requires its employees, contractors, etc. to comply with. This Process will also be applied to assess compliance of the Gorgon Gas Development against the requirements of Statement No. 800 where this is appropriate and reasonably practicable.

An internal Audit Schedule has been developed and will be maintained for the Gorgon Gas Development (with input from the Engineering, Procurement and Construction Management [EPCM] Contractors) that includes audits of the Development's environmental performance and compliance with the Ministerial Conditions. A record of all internal audits and the audit outcomes is maintained. Actions arising from internal audits are tracked until their close-out.

Any document that is required to be implemented under this Program will be made available to the relevant DER auditor.

7.1.2 External Auditing

Audits and/or inspections undertaken by external regulators will be facilitated via the Gorgon Gas Development Regulatory Approvals and Compliance Team. The findings of external regulatory audits will be recorded and actions and/or recommendations will be addressed and tracked. Chevron Australia may also undertake independent external auditing during the Gorgon Gas Development.

7.2 Reporting

7.2.1 Compliance Reporting

Condition 4 of Statement No. 800 requires Chevron Australia to submit a Compliance Assessment Report annually to address the previous 12-month period. A compliance reporting table is provided in Appendix 1 to assist with auditing for compliance with this Program for Statement No. 800.

7.2.2 Environmental Performance Reporting

Environmental performance reporting obligations for the Program arise from the requirements of Condition 5 of Statement No. 800, which call for an annual Environmental Performance Report to be submitted to the Minister covering the following topics of relevance to the Program, quoting:

- data on GHG emissions intensity (defined as GHG emissions per tonne of LNG produced) averaged over one year and describe the methodology used
- trend of annually averaged greenhouse gas emissions intensity and explain the reasons for any change
- the actual energy efficiency of GTs in the Gas Treatment Plant.

Further, Condition 5 of Statement No. 800 requires that every five years from the date of the first annual Environmental Performance Report, Chevron Australia submits an Environmental Performance Report for the preceding five-year period, which covers in addition to the annual GHG Program reporting requirements listed above, recent advances in technology and/or operational processes for LNG processing facilities and justification for the adoption or otherwise of these recent advances in technology and/ or operational processes (Items 10iii and 10iv in Schedule 3 of Statement No. 800 respectively).

7.2.3 Routine Internal Reporting

The Gorgon Gas Development will use a number of routine internal reporting formats to effectively implement the requirements of this Program. Routine reporting is likely to include daily, weekly, and/or monthly HES reports for specific scopes of work on the Development. These reports include information on a number of relevant environmental aspects, such as details of environmental incidents (if any), environmental statistics and records, records of environmental audits and inspections undertaken, status of environmental monitoring programs, tracking of environmental performance against performance indicators, targets and criteria, etc.

7.3 Review of this Program

Chevron Australia is committed to conducting activities in an environmentally responsible manner and aims to implement best practice environmental management as part of a program of continuous improvement. This commitment to continuous improvement means that Chevron Australia will review this Program periodically.

These reviews will examine advances in technology and/or operational processes aimed at reducing the GI of the Gas Treatment Plant, and consider adoption of those technologies that offer a practicable way of reducing GHG emissions per tonne of LNG produced as per the requirement of Condition 27.2(ii) of Statement No. 800.

Reviews will also address matters such as the overall design and effectiveness of the Program, progress in environmental performance, changes in business conditions, and any relevant emerging environmental issues.

If the Program no longer meets the aims, objectives or requirements of the Program, if works are not appropriately covered by the Program, or measures are identified to improve the Program, Chevron Australia may submit an amendment or addendum to the Program to the State Minister for Environment for approval under Condition 36.2 of Statement No. 800. The State Minister for Environment may also direct Chevron Australia to revise the Program under Condition 36.2 of Statement No. 800.

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Appendix 1 Compliance Reporting Table

Section No.	Key Action	Timing
4.2.2	Submission of preliminary GHG emissions forecasts for the operations phase to DER will be via the application for an operating licence for the Gas Treatment Plant under Part V of the EP Act.	Early Operations
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Injecting reservoir carbon dioxide recovered from the Acid Gas Removal Units into a confined subsurface reservoir (Dupuy Formation) below Barrow Island. Reservoir CO_2 is intended to be vented only in the event of injection system maintenance or unplanned downtime, or in the event of an unforeseen reservoir performance or injection well constraint.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • No routine flaring of hydrocarbons. Routine flaring is defined as the continuous flaring of process hydrocarbon gas beyond that required for the safe operation of the flare system (i.e. flare pilots and purge gas) and plant (e.g. small flows from equipment purges which are not practicable to collect during normal production operations).	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • No routine venting of hydrocarbons. Minor quantities of hydrocarbons may be vented only under non-routine operating conditions such as prior to maintenance activities, process or equipment trips, etc.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using the end flash gas from the nitrogen rejection unit as fuel gas. Prior to use as fuel, the low temperatures in this gas (-160 °C) are used to cool mixed refrigerant and reinjection liquefied petroleum gas (LPG) components, thus recovering 'cold energy' from this stream. This reduces the amount of power required to produce a unit of LNG, thereby reducing overall GHG emissions from the mechanical drive turbines by an equivalent amount for a given amount of LNG production.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using tandem dry gas seals for process compressors in the plant, and on smaller compressors in minor service, where appropriate.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using a subsea development approach for the Gorgon and Jansz gas fields, thus eliminating the need for an offshore production and compression platform.	Design

Section No.	Key Action	Timing
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using a waste heat recovery system on the refrigeration compressor GTs to recover thermal energy from the GT exhaust gases, significantly reducing the need to use heaters/boilers to meet process heat demand during routine production operations.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using activated MDEA (a-MDEA) as the preferred amine for acid gas removal from the feed gas.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Choosing Split Mixed Refrigerant (MR) technology developed by APCI to produce LNG.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using LNG and MR expanders to produce an isentropic pressure drop for the LNG and refrigerant fluids, reducing the amount of lost work in the process relative to using an expansion valve.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using a recycle compressor to recover flash gas from the nitrogen rejection system and recycle it to the feed gas.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using a stabiliser overhead compressor to compress hydrocarbon-containing vapour from the stabiliser into the feed gas, preventing the flaring of this gas.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Recovering vapours from MEG flash and distillation processes via compression and/or condensing them. The MEG flash vapour compressor will send vapours (largely CO_2) to the suction of the CO_2 injection compressors, where they will be injected into the Dupuy Formation. Other vapours will be sent to the produced water injection wells after condensing.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Requiring a high-efficiency motor design, by implementing low and medium voltage motor specifications for use on the Gas Treatment Plant.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Recovering and re-using LNG BOG generated during ship loading operations by compressing it to the front end of the Gas Treatment Plant via a BOG recycle compressor.	Design

Section No.	Key Action	Timing
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Recovering BOG from the LNG storage tanks during normal LNG holding mode by using redundant BOG compressors. This gas will be sent to fuel, where it displaces an equivalent amount of fuel that would otherwise be sourced from the feed gas. The BOG recycle compressor provides sparing for the BOG compressor when not engaged in LNG loading operations (i.e. in LNG holding mode only). This reduces the potential for flaring in the event that the BOG compressor fails during normal LNG holding mode.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Under normal operations, maintaining the LNG loading lines in a cold state between LNG carrier loadings. While this strategy increases the overall heat leak into the LNG lines, it decreases the amount of vapour generated during loading operations, which would otherwise require flaring during peak cool-down operations or a slow and inefficient loading operation. Either of these options would result in an increase in GHG emissions.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Sending any vapour generated in the refrigerant storage vessels to a LNG storage tank rather than directing it to flare.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Fitting adjustable speed drives to selected motors as appropriate. This will allow plant operators to match the motor duty to the process requirements without wasting energy.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Using a High Integrity Pressure Protection System (HIPPS) to prevent plant equipment trips and increased flaring due to high flow/high pressure in the feed gas system.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Specifying control valves as low fugitive emission type, with a maximum allowable process fluid leakage.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Development of a flaring and venting procedure to manage the shutdown or depressurisation of selected equipment during events where safety of personnel and/or asset protection is required.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Considering, including reserving plot space, the potential future installation of WHRUs, which could be used for further cogeneration and/or combined cycle power generation, if practicable.	Design

Section No.	Key Action	Timing
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Specifying lighting reductions in the Gas Treatment Plant both to conserve energy and to reduce environmental impact of light on Barrow Island fauna. These changes will include reduced lighting intensity, switched or timed lighting in most areas, changing from area lighting to task-specific lighting where practicable, and other modifications.	Design
5.2	Chevron Australia has adopted a suite of best practice measures in GHG management for implementation in the design. These include: • Installing a pressure-controlled line from the Main Cryogenic Heat Exchanger shell side to the End Flash Gas Compressor suction, so that tube leaks in the Main Cryogenic Heat Exchanger will first be routed to fuel gas usage instead of being flared. However, if the pressure continues to increase, the gas is routed to the flare.	Design
5.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up, and operations phases. These actions include, but are not limited to: • developing commissioning, start-up, and operating procedures that aim to reduce the duration and frequency of hydrocarbon flaring and venting and/or acid gas venting.	Prior to Commissioning and Start-up of relevant Gas Treatment Plant Systems
5.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up and operations phases. These actions include, but are not limited to: • developing operational, start-up, shutdown and maintenance procedures with the objective of reducing GHG emissions during normal operations and planned maintenance shutdowns.	Prior to Commissioning and Start-up of relevant Gas Treatment Plant Systems
5.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up, and operations phases. These actions include, but are not limited to: • developing marine operational procedures to reduce flaring associated with 'warm' LNG carrier de-inerting operations.	Prior to Commissioning and Start-up of relevant Gas Treatment Plant Systems
5.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up, and operations phases. These actions include, but are not limited to: • once the Gorgon Gas Treatment Plant is operational, undertaking Energy Optimisation Studies in line with requirements in Chevron Australia's OEMS.	Operations
5.3	A number of actions are planned with the objective of reducing the Gorgon Gas Development's GHG emissions during the Gas Treatment Plant commissioning, start-up, and operations phases. These actions include, but are not limited to: • continuing to periodically review and where practicable, adopt advances in technology and operational processes aimed at reducing GHG emissions per tonne of LNG produced.	Operations
7.1.1	Any document that is required to be implemented under this Program will be made available to the relevant DER auditor.	All Phases

Section No.	Key Action	Timing
7.1.2	The findings of external regulatory audits will be recorded and actions and/or recommendations will be addressed and tracked.	All Phases