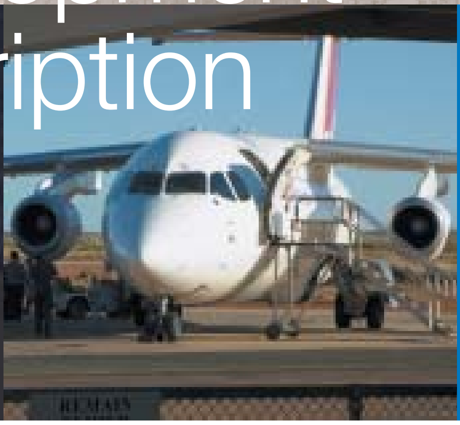
06: Development Description



The Greater Gorgon area contains a number of known and prospective hydrocarbon resources, with the most well-known being the Gorgon gas field, which gives the region its name. Following a rigorous and extensive review (as discussed in Chapter 3), the Gorgon Joint Venturers are proposing to develop the Gorgon gas field resources through a gas processing facility to be built on Barrow Island from where various gas and liquid products will be directed to market.

The proposed Development includes the installation of approximately 25 offshore wells and associated flowlines and manifolds. The offshore facilities initially required to develop the Gorgon resources will be entirely subsea in approximately 200+ m of water. The flow from each well will be controlled from Barrow Island and will be delivered via a 70+ km-long, high pressure pipeline.

The gas processing facility will be located at Town Point on the east coast of Barrow Island and will consist of a Liquefied Natural Gas (LNG) plant, a domestic gas plant, hydrocarbon condensate handling facilities, and associated utilities. The LNG plant will initially comprise two LNG trains capable of producing a nominal capacity of 10 million tonnes per annum, requiring approximately three LNG shipments from Barrow Island per week, which will be loaded from a dedicated jetty. The domestic gas plant will be designed to deliver in the order of 300 Terajoules per day (TJ/day), which will be transported via a pipeline tying into the existing domestic gas transmission pipeline network. Condensate associated with the feed gas will be separated and stored prior to loading into ships for market (approximately one ship per month).

Carbon dioxide (CO_2) will be removed from the feed gas to meet market quality specifications for domestic gas, and to prevent the CO_2 in the feed gas from freezing and causing a blockage in the LNG equipment. It is proposed that it will then be compressed, dried and injected into subsurface formations some 2000 m beneath Barrow Island. Limited venting of the reservoir CO_2 will be required during commissioning, periods of maintenance, injection equipment downtime, or reservoir constraints. Waste water that cannot be recycled or safely discharged to the environment will be injected deep beneath Barrow Island.

Infrastructure will be required to support the construction activities and subsequent operations. This infrastructure will include a construction village with associated amenities and utilities (such as power generation facilities), mainland supply bases in the Pilbara region and Perth, and upgrades to the current airport, roads, and services on Barrow Island.

Construction is expected to occur over a period of approximately 45 months and require a peak island-based workforce of approximately 3300 personnel.

The life of the proposed Development is nominally 60 years, during which time an operational workforce of around 150–200 personnel will be accommodated on Barrow Island, in addition to the existing operations personnel and contractors. The operational workforce is expected to increase by approximately 250–500 people for approximately one to two months in most years for planned maintenance.

In the future, it may be proposed to expand the capacity of the gas processing facility by adding a third and possibly a fourth LNG train, with associated feed gas pipelines, utilities and other infrastructure. A number of activities are included in the scope of the initial development to enable such an expansion with minimal environmental impact. Depending on the nature of the proposed expansion, separate environmental approval may be required, but any such expansion will occur within the 300 ha area designated under the *Barrow Island Act 2003.*

This chapter is a description of the various components of the facility, as well as relevant aspects of their construction and operation, to serve as a basis for the environmental impact assessment outlined in Chapters 10 to 15.

6.1 Introduction

The Greater Gorgon area is located off the west coast of Australia. The area is abundant in hydrocarbon resources, as outlined in Chapter 1. A gas processing facility located on Barrow Island will enable the long-term development of the Greater Gorgon area. Each of the fields in the Greater Gorgon area contains a different gas composition, so the gas processing facility will be designed to handle a range of feed gas compositions.

The Gorgon Joint Venturers are proposing to initially develop these resources as feed gas for a nominal 10 million tonne per annum (MTPA) LNG facility with a 300 TJ/day domestic gas plant on Barrow Island. Approximately 2000 m^3/day (12 000 bbl/day) of hydrocarbon condensate will also be produced from the hydrocarbon liquids associated with the gas fields.

Two additional LNG trains and associated infrastructure may be added in the future. If this expansion occurs, it may happen as a single activity or as several smaller expansions.

This chapter describes the facilities and activities associated with the proposed Development. It also describes the facilities that are proposed to be installed, and activities that are proposed to be undertaken, within the scope of the proposed Development to assist future expansion and minimise the cumulative environmental impact. Any future expansion will be located within the 300 ha area designated for development under the *Barrow Island Act 2003.*

6.1.1 Gas Compositions – Feed and Product

Table 6-1 shows the feed gas composition of the Gorgon field, the Jansz field, a typical specification for LNG, and the current domestic gas specification. These compositions will vary slightly over the production life of the field due to natural variations in the gas composition within each field and in response to the changing pressure in the reservoirs resulting from the extraction of the natural gas. The reservoir gas compositions presented here are the anticipated gas compositions at approximately year 20 of production. This table shows that the reservoir fluids are predominantly methane with a very small proportion of liquid hydrocarbon components (i.e. butane and heavier).

6.2 Major Infrastructure Components

Development of the hydrocarbon reserves in the Greater Gorgon area will require a number of phases, and a variety of infrastructure to extract and transport natural gas to Barrow Island for processing and delivery to market. The Development will initially consist of a subsea development for the production and transport of gas from the fields to Barrow Island; and a gas processing facility located at Town Point on Barrow Island (Figure 6-1). Utilising a subsea development removes the initial need for an offshore processing platform.

In the future, the pressure in the reservoirs will be insufficient to sustain peak production rates. At that time it may be necessary to install compression

Table 6-1:
Feed Gas and Product Gas Compositions

Component*	Gorgon	Jansz**	Typical LNG Specification	Current Domestic Gas Specification
CO_2	14–15 volume%	0.28 volume%	<100 ppm	<3.6 volume %
N_2	2–3 volume%	2.35 volume%	<1 volume%	Total inert gases <6.5 volume %
Hydrocarbons				
– Methane	76.71	91.48	–	–
– Ethane	3.23	3.75	–	–
– Propane	0.89	1.06	–	–
– Butane	0.30	0.41	–	–
– Pentane and heavier	0.13	0.63	–	–
Total	83+ volume%	97.4 volume%	99 volume%	93.5+ volume%

* *The feed gas will also contain traces of Hydrogen Sulphide (H_2S), mercury, and aromatics from the reservoirs.*

** *Composition of Jansz gas included here as the gas processing facility will receive gas from both Gorgon and Jansz fields and as such emissions calculations and modelling have been based on the total incoming gas stream.*

facilities. This may be a platform, but subsea technology is evolving rapidly and so it could be a subsea facility. The compression facility is outside the scope of this Draft EIS/ERMP, and if required will be the subject of a separate approval process. Other fields may also be tied into the gas processing facility through the subsea systems.

LNG and condensate produced at the gas processing facility will be shipped to buyers directly from Barrow Island. Provided it is commercially viable (refer to Chapter 2 for more specific details), treated gas for domestic consumption will be exported by a subsea domestic gas pipeline to tie into the domestic gas transmission network.

It is proposed to remove the reservoir CO_2 from the feed gas and inject it into the Dupuy formation deep beneath Barrow Island, this is discussed in more detail in Chapter 13. Waste water that cannot be recycled or discharged to the environment will also be injected deep beneath Barrow Island. In addition, a range of associated infrastructure will be required on the island and in the adjacent marine area.

The main components of the proposed Development are:

- the Gorgon gas field wells and subsea installation
- a feed gas pipeline from the Gorgon gas field to the gas processing facility on Barrow Island
- an easement along the Gorgon gas field pipeline (onshore and traversing state waters) to accommodate additional feed gas pipelines
- a gas processing facility on Barrow Island (including two LNG trains, domestic gas and condensate facilities)
- port/marine facilities at Barrow Island
- water supply and disposal
- a construction village and associated facilities
- a proposal to dispose of reservoir CO_2 by injection into the Dupuy formation
- monitoring of CO_2 movement in the Dupuy formation
- an optical fibre cable connection to the mainland
- a domestic gas pipeline to the mainland
- utilities to support the hydrocarbon processing facilities including power generation, instrument air and nitrogen
- site works to accommodate selected aspects for future expansion
- a mainland supply base
- other associated infrastructure such as upgrades to the airport, roads, and other utilities.

For the purpose of cumulative impact assessment, this Draft EIS/ERMP addresses the impacts on, and near, Barrow Island associated with the installation of the Jansz feed gas pipeline to process gas from the Jansz field and other potential tieback opportunities associated with the Greater Gorgon area, or other nearby prospects.

The Gorgon Joint Venturers have completed the concept selection phase for the design of the gas processing facilities. As the design of the Development proceeds, a number of components of the facilities will be reviewed and significant additional engineering detail completed. As a result, some of the information presented in the chapter is subject to change. Where a range of options is still open, the range is presented and the subsequent assessment is based on the impacts likely to be associated with that range. Thus, these options are not expected to significantly change predicted environmental impacts. Furthermore, potential and actual impacts will be frequently reviewed and managed to further reduce the environmental impact as the design develops.

6.2.1 Wells and Subsea Facilities

The proposed Development will utilise an all subsea concept for wells and manifolds. Consequently all offshore facilities are proposed to be placed on the seafloor with no initial need for any permanent surface facilities.

Up to 25 subsea wells will be drilled in the Gorgon gas field throughout its production life. These wells will be in water depths ranging from approximately 190–250 m. They will be directionally drilled from a small number of drill centres located across the field. The final number of wells and their locations will be optimised prior to drilling.

Figure 6-1:
Proposed Gorgon Gas Development

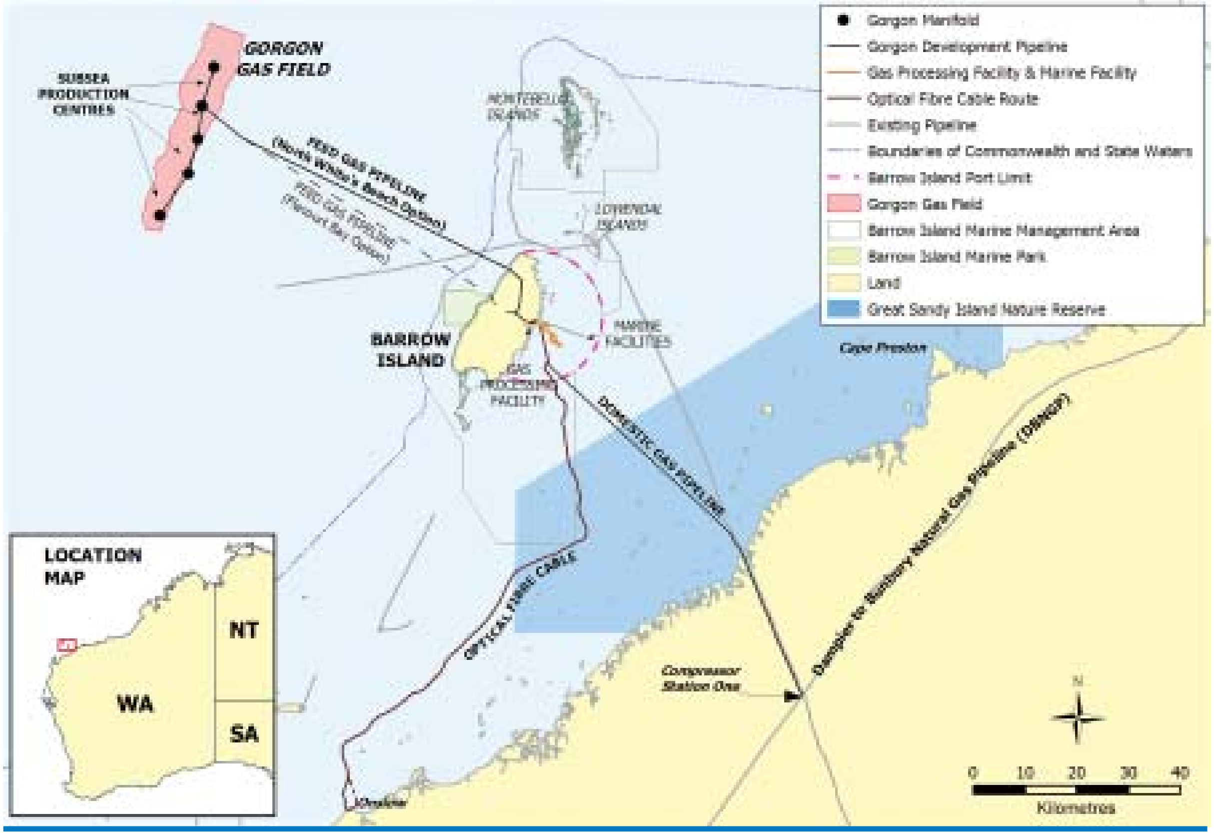


Plate 6-1:
Typical Drilling Rig used in North-West Australia

Wells will be drilled using a vessel similar to that shown in Plate 6-1. Such vessels are commonly used in north-west Australia in similar water depths.

Each well will be fitted with an arrangement of valves, controls and instrumentation referred to as a 'subsea tree' which is located on the seafloor.

A subsurface safety valve will be installed in each well approximately 300 m below the seabed to enable isolation of the gas reservoir. These valves (as well as the valves on the subsea tree) are designed to close automatically in the event of a mechanical failure or loss of system integrity. A 'choke' valve will also be included in the tree to control the fluid flow and pressure from the well to the pipeline.

Each group of wells will use 'well jumpers' to connect them to their 'cluster manifolds'. Each cluster manifold will serve between one and eight wells. From these cluster manifolds, an 'intrafield flowline' will transfer fluids to the export feed gas pipeline(s). The production fluids (gas, water and some condensate, with production chemicals) will then be piped to Barrow Island via the feed gas pipeline(s).

Feed gas pipeline(s) will be corrosion resistant alloy (CRA) clad carbon steel or carbon steel. The well flow rates could range from less than 13 m^3(st)/s to more than 110 m^3(st)/s (40–340 million standard cubic feet per day (MMscfd)), with flow reducing over time as reservoir pressure declines.

To support the operation of the wells and manifolds, as shown in Figure 6-2, they will be connected to the gas processing facility by an umbilical bundle. The umbilical bundle will include:

- electrical power and signal lines
- control line (water-based control fluid)
- chemical injection lines
- spare lines.

Separate (Mono Ethylene Glycol (MEG)) injection lines and utility lines and other essential service lines will also be required.
This chemical is used as a hydrate inhibitor which is discussed in more detail below.

Natural gas hydrates (solid crystalline compounds like ice but consisting of water and natural gas components) have the potential to form in the flowlines if they are subject to elevated pressures and reduced temperatures. These conditions may occur with the decrease of pressure across the choke and as the gas cools along the various flowlines and pipelines and/or as a result of other operating, shut-down and transient conditions. The resulting hydrates can adversely affect the normal operation of equipment and so must be prevented. Monoethylene glycol is the preferred hydrate inhibitor, and it will be stored at, and pumped from, the gas processing facility located at Barrow Island to the field through a dedicated line. It will flow back with the gas stream to shore through the feed gas pipeline. At the gas processing facility, it will be recovered for treatment and re-use.

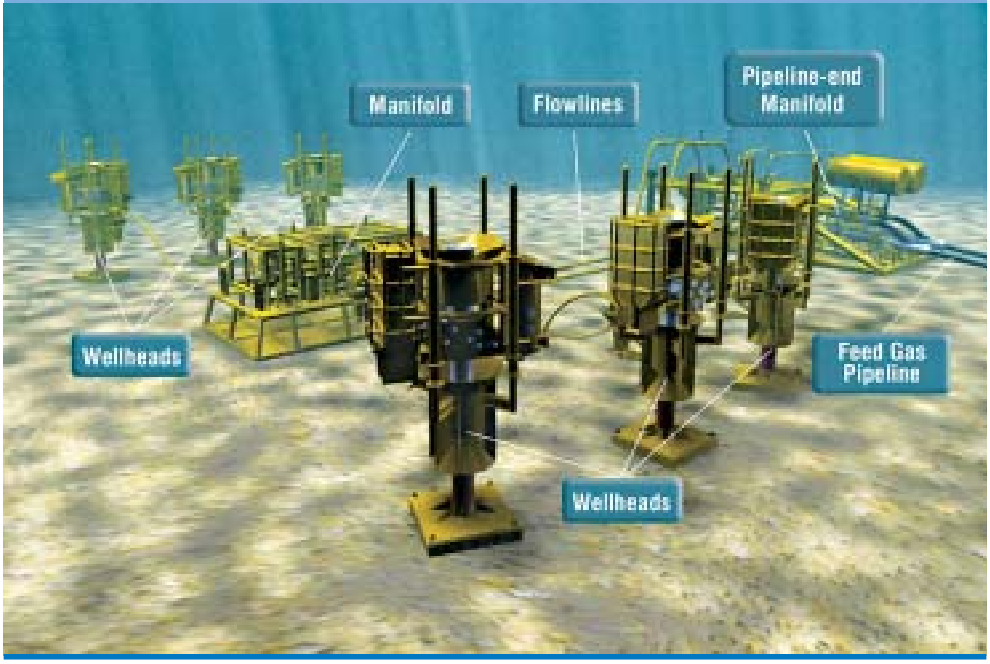
An electrohydraulic control system will be adopted to control the valves on the subsea trees, with control fluid powering valve movements controlled by solenoid valves. The control fluid will be a water-based fluid (with glycol), which has been designed and selected to be suitable for release to the environment. The control fluid is widely used internationally and in the north-west of Australia in similar applications with regulator approval. Small quantities of this water-based control fluid will be released to the ocean during operation of the well and pipeline control valves. Alternative 'closed loop' systems exist but react too slowly for this service. Final selection of the water-based control fluid will ensure environmental impacts are as low as reasonably practicable.

A multipurpose utility line will be used to maintain operational flexibility and to depressurise subsea components connected to the gas processing facility or feed gas pipeline to allow for maintenance.

Corrosion inhibitors and other chemicals may also be injected into the wells and flowlines in the future via the umbilical bundle which will follow the path of the main feed gas pipeline. Other chemicals that may be required in the future include scale prevention chemicals, pH stabiliser, and acids for well maintenance.

An alternative concept was considered for offshore production prior to deciding on the subsea development concept as summarised in Box 6-1.

Figure 6-2:
Schematic of Typical Subsea Trees and Cluster Manifold Layout



Box 6-1:
Alternative Considered – Offshore Processing

During the concept selection process, an offshore platform was considered for pre-processing the gas. The primary purpose of the platform would be to remove and dispose of the produced water to sea or back into the reservoir. This would remove the need for any special corrosion resistant pipelines or corrosion inhibitor injection. However, it would incur the additional cost of a platform with permanent or temporary personnel presence.

The elimination of a platform reduces the safety risks associated with helicopters by avoiding the need for personnel to be permanently based offshore, or periodically required to visit the platform. It also avoids emissions associated with operation of the platform and significantly reduces overall capital costs; which improves the international competitiveness and overall viability of the proposed Development.

6.2.2 Feed Gas Pipelines

As described in Chapter 3, Town Point is the preferred site for the proposed gas processing facility with the feed gas pipelines crossing the shore at North White’s Beach. Flacourt Bay is also being carried into subsequent design phases as an alternative fallback shore crossing location to allow for unforeseen geological conditions at North White’s Beach. The feed gas pipelines will transport the production fluids from the gas fields to the gas processing facility at Town Point. Figure 6-1 shows the overall development.

The feed gas pipelines will be constructed in accordance with appropriate standards which include AS2885 and DNV OS-F101. During subsequent phases of design for the Development, the pipeline design will continue to be reviewed, and the route will be refined as further information and knowledge becomes available. Any changes will result in environmental impacts which are similar to, or less than, those assessed in this Draft EIS/ERMP.

During normal operation, the pipeline flow and pressure will be primarily controlled by the choke valves at the wellheads such that the normal operating pressure in the feed gas pipeline will be significantly less than the maximum allowable operating pressure.

Table 6-2:
Indicative Feed Gas Pipeline Specifications

Parameter	Specification
• Length (offshore)	• ~ 70 km
• Length (onshore, Barrow Island)	• ~ 14 km (~ 42 ha easement)
• Length of state-water easement*	• ~ 5.6 km
Diameter	600 to 900 mm (24–36 inch)
Maximum Design Pressure	~ 26 500 to 36 500 kPa
Material	Carbon Steel with a Corrosion Resistant Alloy (CRA) lining for corrosion resistance or carbon steel with stabilisation chemicals.
Concrete Coating	50 to 100 mm (density 3040 kg/m^3) for stability

* *Potential impacts in the easement in state waters associated with construction and operation of the Jansz (or other) feed gas pipelines are considered for cumulative impact assessment purposes.*

Due to the CO_2 and water content of the gas from the Gorgon field, the production fluids will be corrosive. This will require special design of the pipeline to ensure it meets environmental, safety and operational requirements for the required service life of the Development. Indicative specifications for the pipeline are provided in Table 6-2, while alternatives for the pipeline material are discussed in Box 6-2.

Box 6-2:
Alternative Feed Gas Pipeline Material

An alternative to CRA pipeline material is carbon steel with high corrosion allowance and with continuous injection of corrosion inhibitor chemicals. This option is currently undergoing further technical engineering and laboratory assessment. A decision to utilise carbon steel will only be made if the integrity of the pipeline can be assured, and if the proposal receives the regulatory approval.

Frequent ‘pigging’ of the pipelines for cleaning or inspection is not expected to be required. However, the pipeline will be designed to allow the use of conventional or instrumented ‘intelligent pigs’ for pipeline integrity testing. Such testing is expected to occur in the order of once every five years, and so may occur approximately 5–10 times during the life of the Development for each pipeline.

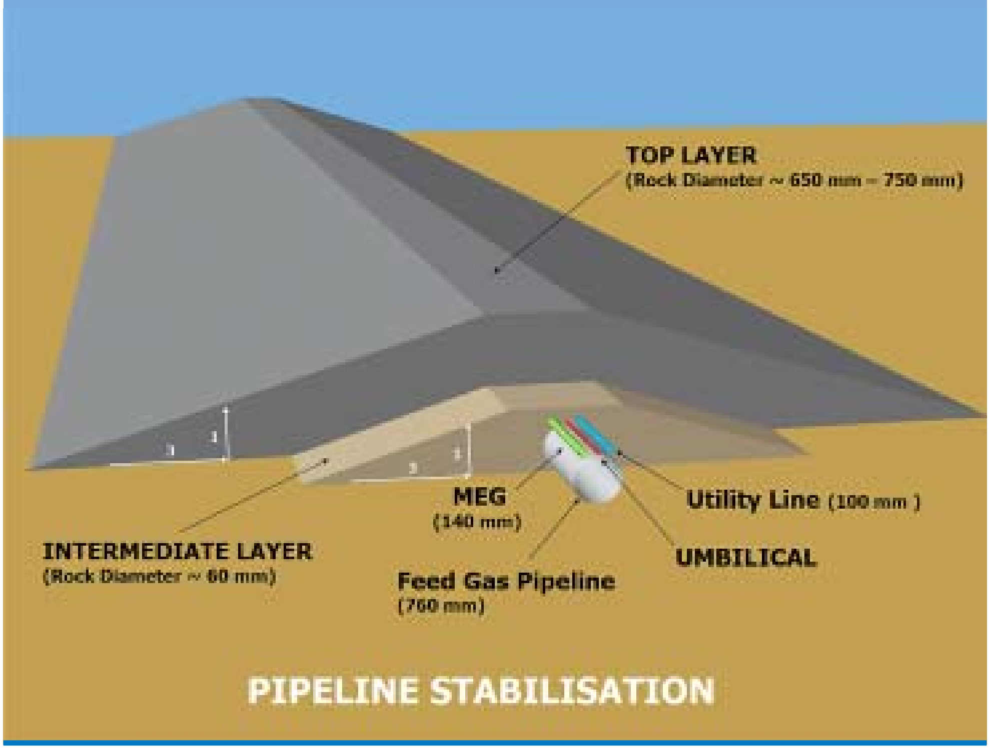
To meet government regulations and safety requirements, corridors centred on the offshore pipelines and all subsea infrastructure will be established in which anchoring by commercial vessels will be prohibited, and access restricted. The corridors, which will extend approximately 500 m on either side of the pipeline and around subsea equipment, will be gazetted and marked on navigation charts.

Offshore Pipeline Stabilisation

The offshore sections of pipelines will be stabilised by a combination of measures to protect against hydrodynamic forces such as waves and currents and, where necessary, to protect from external impacts such as ship anchors. Potential measures include concrete coating, trenching into the seabed, rock bolting, stabilisation mattresses or rock stabilisation. The final decision about which measure, or combination of measures, will be employed will be made as the design develops, but the following provides an explanation of the most likely concept. The environmental implications of each option being considered are similar.

A concrete coating will be used as necessary to stabilise the pipelines from the gas fields to a water depth of approximately 40 m (approximately 15 km from Barrow Island). The coating thickness will vary based on the degree of stabilisation required. Other stabilisation methods such as rock bolting may be considered as alternatives during finalisation of the design details.

Figure 6-3:
Pipeline Rock Stabilisation Detail



Rock stabilisation (e.g. placing rocks on top of the pipeline) will be used where appropriate to protect the feed gas pipelines from the increased hydrodynamic forces as the pipelines approach the shore (Figure 6-3). The pipelines will be initially covered with smaller rocks (approximately 60 mm diameter) and then larger rocks overlaid (approximately 750 mm diameter). This is expected to be required from approximately the 40–50 m water depth contour toward the shoreline (e.g. to the drilled shore crossing breakout point).

Shore Crossings and Near Shore Zone

Conventional shore crossing techniques involve the use of excavation equipment, such as cutter suction dredges or backhoe dredges, to create a pipeline trench. The pipes would then be pulled into the trench from a shore based winch, and the pipes buried under dumped rock for protection. Due to the constant swell and high seabed rock strength identified on the west coast of Barrow Island, the use of rock dredging equipment is not considered technically feasible. Therefore, the range of possible shore crossing techniques was short-listed to horizontal directional drilling (HDD), tunnelling, and laying the pipe on/above the seabed. More detailed assessment (as discussed in Chapter 3) has shown that tunnelling will also require dredging at the offshore breakout point and so has also been ruled out as not being technically feasible due to sea conditions on the west coast.

Laying the pipe on/above the seabed requires the construction of a temporary jetty/groyne out to approximately 5 m water depth (~200 m from the shore line). This is required to provide access for equipment to stabilise the pipeline. This option is not preferred over directional drilling since it will have a higher environmental impact, higher cost, and longer installation schedule.

Exclusion of these techniques leave directional drilling as the preferred technique. This technique would require a directionally drilled hole extending from approximately the 12 m water depth contour (1 km from the shore), continuing under the seabed and beach, to surface on dry land at the rear of the beach. A typical directional drilling setup is shown in Plate 6-2.

Further design work will be undertaken to determine the optimal number and size of holes required during the initial development. Directional drilling would involve holes of up to approximately 1067 mm diameter. Approximately seven holes will be required for two complete feed gas pipeline systems. There is a possibility that additional feed gas pipelines and associated shore crossings will be required in the same area to enable future phases of development. This would require the creation of new directionally drilled holes of similar number and size and these have been allowed for in the design layout but are outside the scope of this approval.

Plate 6-2:
Horizontal Directional Drilling Operation

Onshore Section of Pipelines

The proposed pipeline route across Barrow Island follows existing road easements as much as possible from North White's Beach to the gas processing facility at Town Point. Provision is being made in the proposed Development for the initial installation of two feed gas pipelines (and associated auxiliary lines), and to allow for another two feed gas pipeline bundles in the future to run parallel to the initial lines from the shore crossing. Optimisation of the pipeline route and shore crossing will continue throughout the design phases of the Development.

The onshore section of the pipelines will be supported above ground with sufficient clearance to ensure that fauna can pass freely underneath the pipeline. The pipelines will be buried under roads with appropriate culvert and right-of-way systems to enable installation of future pipelines. Trenching and/or excavation will be restricted to the pipeline supports and road crossings. This option will minimise the overall level of ground disturbance that would take place during construction, as well as the quantity and duration of excavation and blasting required, and therefore will minimise direct impacts associated with construction activities. It will also minimise the amount of land requiring rehabilitation. Seasonal water crossings may be traversed or trenched depending on their size, surrounding terrain, geology and other factors.

If the feed gas pipelines were to be buried for the entire onshore length, blasting and trenching across Barrow Island would be required. Box 6-3 is a summary of a number of alternative designs for the pipeline.

Box 6-3:
Alternative Onshore Pipeline Designs

Three alternative pipeline configurations were considered for the onshore section:

Above Ground Installation – An above ground pipeline would ensure that fauna can pass freely underneath the pipeline and that ground disturbance is minimised during construction. The pipelines would be trenched to pass under roads, with appropriate culvert and right-of-way systems to enable installation of future pipelines. Trenching and/or excavation will be restricted to the pipeline supports and road/water crossings. This option minimises the overall level of ground disturbance that takes place during construction, minimises the quantity and duration of excavation and blasting required, and therefore minimises direct impacts associated with construction activities.

An elevated pipeline may create condensation due to the temperature of the fluids flowing through the pipeline, which will affect flora and fauna by providing additional water and shade. The elevated pipeline would also have a 'permanent' visual impact over the life of the Development. At the end of field life, it would be possible to remove the above ground sections of the pipelines without significant environmental impact, while buried sections would remain *in situ.*

Surface installation – a pipeline laid across the natural ground surface would offer low installation costs, but is not considered technically acceptable to the Joint Venturers due to the potential for unconstrained movement of the pipeline resulting from thermal expansion and/or wind loading.
The large diameter of the pipelines would also create obstructions for fauna and water movement.
A variation of this option would be to lay the pipes on the natural ground surface and provide earthen mounds over them to assist the movement of fauna.

Box 6-3: (continued)
Alternative Onshore Pipeline Designs

This option was ruled-out as it would increase site disturbance and create a barrier to natural water movement.

Trenched installation – this option would lead to increased land disturbance from grading, trenching and soil stockpiles. Burial could also require extensive blasting to achieve the required trench depth. The open trench during construction could prove to be a hazard to fauna, requiring careful management. The increased depth of disturbed or tilled soil over the backfilled pipeline trench could lead to permanently changed vegetation associations along the pipeline route. Bedding material, used to protect the pipe in the trench, would most likely have to be imported to the island, representing a potential quarantine threat. Soil excavated (to accommodate the volume of the pipelines and bedding material) would have to be moved away from the area to avoid significantly changing the topography. Some of this material may be able to be utilised at the gas processing facility. Burial is considered to have a slightly higher installation cost. At the end of field life leaving these pipelines buried would have less impact on the environment than re-excavation and removal, followed by backfilling and reinstatement of vegetation and original land contours.

On balance of these aspects, an above ground pipeline installed on supports is the preferred option, however the final decision will be made during subsequent design phases.

Figure 6-4 shows an indicative pipeline support concept, but final details will not be available until later design phases. The layout of the feed gas pipelines and the accompanying supports will be designed to allow for future expansion with minimal environmental impact.

The distance between the pipeline supports would vary between 5 and 20 m depending on the pipeline diameter. The key aspects which determine this spacing are the strength of the pipe and the terrain.

The current base case for each of the feed gas pipelines is that there will be no valves in the pipeline outside of the gas processing facility area. This will minimise the need for access to the pipeline and reduce the likelihood of leaks outside the gas processing facility boundary. In this case, the main pipeline isolation valve will be located at the front end of the gas processing facility within the plant boundary. This valve is required to enable the contents of the pipeline to be isolated from the gas processing facility in the event of an incident or for maintenance.

There is also the possibility, due to safety (Chapter 14) and operability constraints that this valve station may have to be located outside the plant, such as near the shore crossing. The final decision on valve location will be made during subsequent design phases.

6.2.3 Gas Processing Facility

The gas processing facility will produce three main products for export from Barrow Island:

- Liquefied Natural Gas (LNG) for international export
- domestic gas for use on the Australian mainland if economically feasible
- hydrocarbon condensate (light oil) for domestic or international consumption.

Production from the gas fields will have to be pre-treated prior to processing them into these three products. Pre-treatment involves separating the liquids from the gas, then separating the liquids into water, MEG, and condensate.

Carbon dioxide and hydrogen sulphide (H_2S) will be removed from the gas stream in an Acid Gas Removal Unit. The hydrocarbon gas will then be dehydrated and passed through a mercury removal unit from where it will pass to the main liquefaction portion of the gas processing facility.

A schematic representation of the gas treatment process is shown in Figure 6-5, while a likely layout for the proposed gas processing facility is presented in Figure 6-6.

At the gas processing facility, some of the gas would be treated to meet domestic gas specifications before being compressed and exported through the domestic gas pipeline to the existing domestic gas network.

Figure 6-4:
Indicative Pipeline Support Detail

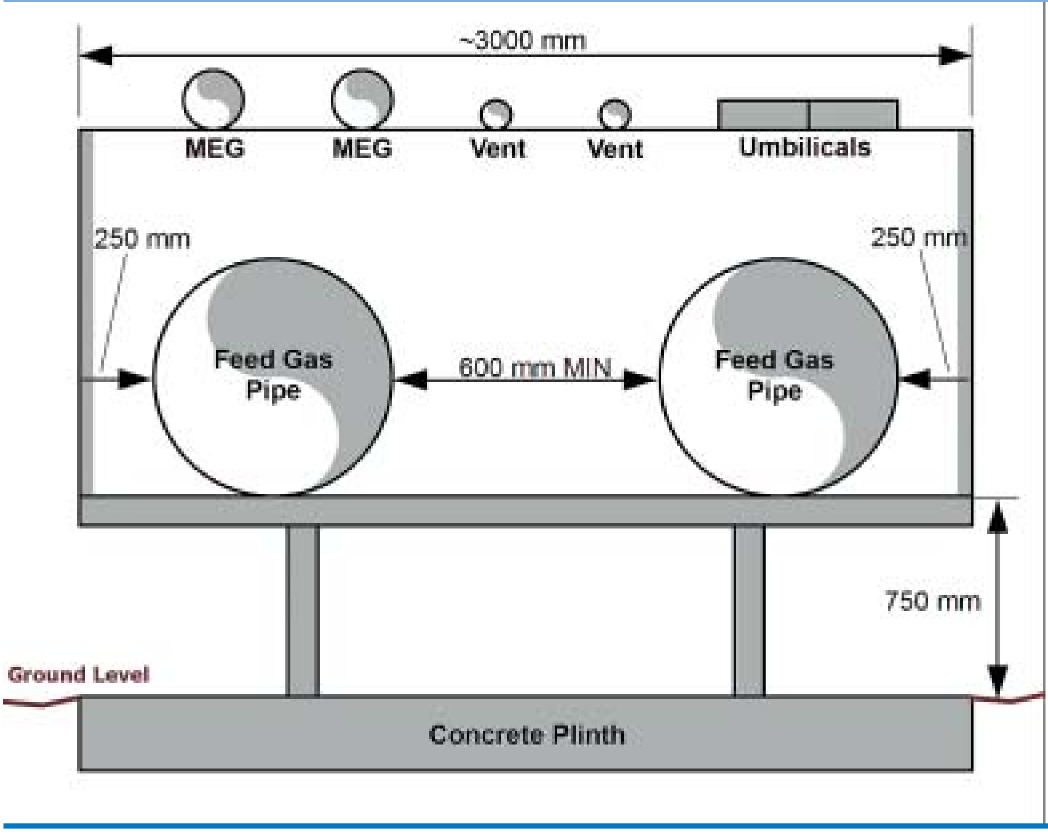


Figure 6-5:
Typical LNG Plant Process

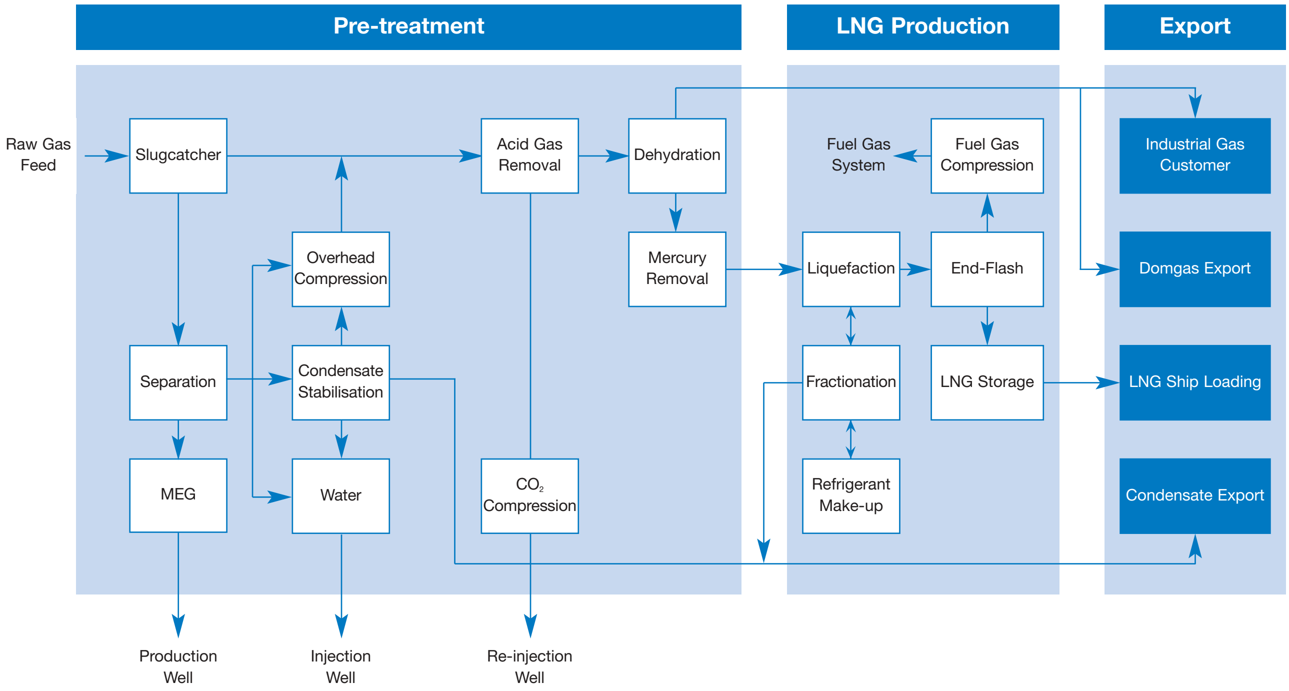
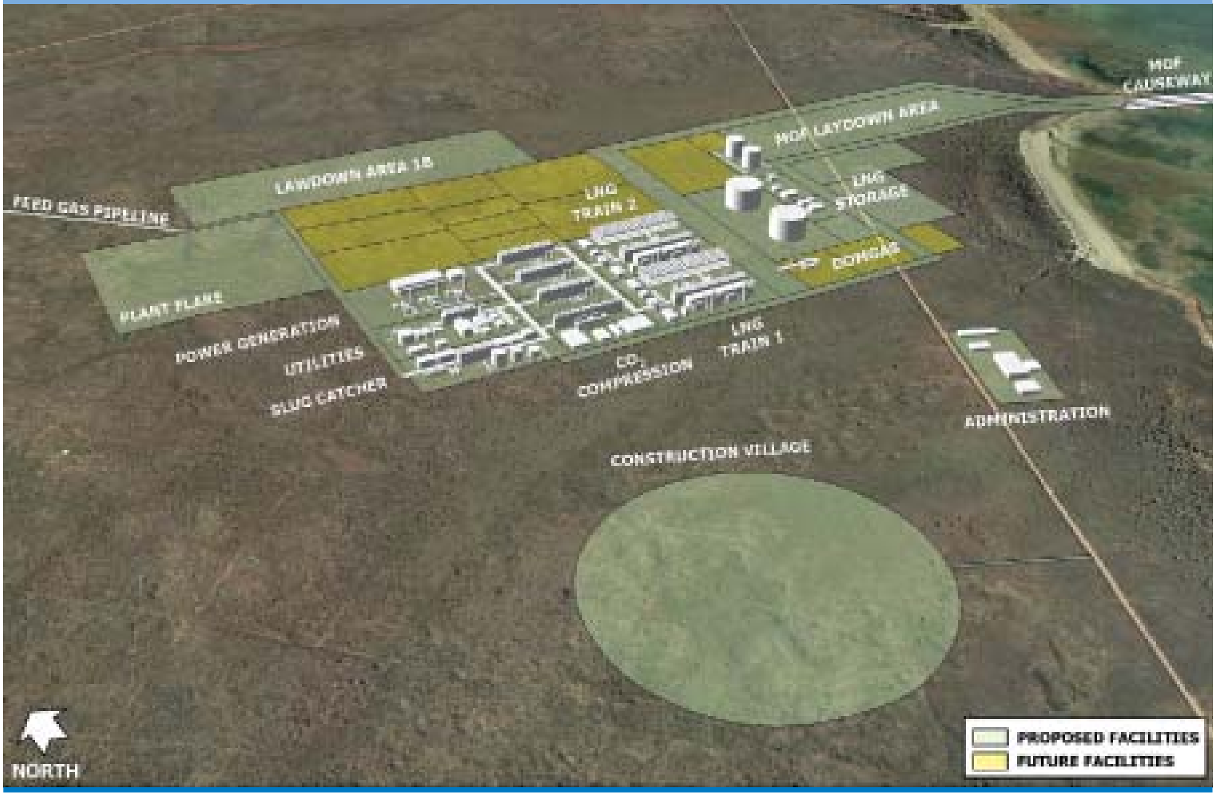


Figure 6-6:
Indicative Gas Processing Facility Layout



Condensate will be stabilised for storage in tanks before being shipped to customers.

The gas processing facilities will be designed to allow some flexibility in the supply of the feed gas. This will ensure the facilities can be utilised for other fields in the Greater Gorgon Area in the future with no, or relatively minor, modifications.

A key design philosophy for the gas processing facility is to recover products from the feed gas wherever practicable, rather than flaring the streams as waste. This typically requires the use of compressors to increase the pressure of 'waste' hydrocarbon gas streams, then directing the stream back into the process, or to the fuel gas system. Specific aspects are discussed where relevant in subsequent parts of this chapter.

The following describes each of the main components of the gas processing facility.

Main Components of the Gas Processing Facility

Slugcatcher

Production fluids from the feed gas pipelines will be fed into a slugcatcher(s) to separate the natural gas from the liquids. The slugcatcher(s) will be either a 'finger-type' or a 'vessel-type'. The advantage of the vessel-type is a significant reduction in required land area compared with the more traditional finger-type slugcatcher, which is based on long runs of straight pipes. However, the size of the liquid slugs expected may require use of the finger-type slugcatcher. The decision on slugcatcher type will be made during subsequent design phases. Current land use estimates assume the greater of the two.

Three-Phase Separator and Overhead Compression

The liquids from the bottom of the slugcatchers will be directed to a three-phase separator. Gas that is liberated in this separator will be compressed in the overhead compression section and returned to the gas stream from the slugcatcher. Hydrocarbon condensate will be separated from the water phase and directed to the condensate stabilisation process. Water (containing MEG, other water-soluble chemicals and salt naturally contained in the reservoir water) will be directed to the MEG recovery system.

Hydrate Inhibitor (MEG) Recovery System

The water and MEG (plus salt and other water-soluble chemicals) from the bottom of the three-phase separator will be directed to the Hydrate Inhibitor Recovery (HIR) package. This package will heat the liquids to vaporise the water, thus concentrating the MEG, so it is suitable for re-use. The MEG will be cooled before storage prior to being pumped back to the wellheads and re-used. Hydrocarbon gases liberated from the MEG regeneration process will be captured and may be utilised as fuel in the plant. Recovered produced formation water containing dissolved salts will be sent to the water treatment facilities for injection. Rich MEG (i.e. MEG with a large amount of water) will be stored in tanks prior to HIR processing. After HIR processing, the lean MEG (i.e. MEG with a smaller amount of water) will be stored in tanks ready for re-use. The size of these tanks will be determined in a subsequent phase of engineering; however, they are likely to be in the order of 3–5000 m^3 and 6–10 000 m^3. The MEG tanks will be contained within impervious bunds designed to meet Australian Standard AS 1940.

The MEG recovery process concentrates salt, which is naturally present in the formation water, into the lean MEG product. A salt reclamation system is an integral part of the HIR package. This package will maintain salt concentration below specified levels by separating salts from the lean MEG via crystallisation and centrifugation or other suitable technology. Salt recovered in this way will be injected with the effluent water along with a small amount of residual MEG into a formation deep beneath Barrow Island. Other options may arise as the design develops such as sale or disposal on the mainland.

Condensate Stabilisation

The hydrocarbon condensate from the three-phase separator will be stabilised by heating the condensate to drive off the volatile components (as gaseous vapours). These gaseous vapours will be compressed with the gas from the three-phase separator in the overhead compression system and returned back to the process feed gas. Stabilised condensate will be fed to the condensate storage tanks to await export. Condensate storage and offloading are discussed later in this chapter.

Acid Gas Removal

The gas from the slugcatcher will be rich in CO_2 with trace levels of H_2S. These two gases are collectively referred to as ‘acid gases’. The acid gases must be removed to meet the LNG product specification and domestic gas specification, and to ensure that the CO_2 does not freeze in the liquefaction process and block the main cryogenic heat exchanger or other equipment. It is likely that a total of three acid gas removal units will operate in parallel for the proposed Development.

The acid gas removal units will utilise accelerated-methyldiethanolamine (accelerated-MDEA or a-MDEA) in water as the solvent for CO_2 and H_2S removal. Alternatives to the a-MDEA process are discussed in Box 6-4.

The a-MDEA/water solution will flow in the opposite direction to the feed gas within a contactor vessel. During this process, the CO_2 and H_2S will be chemically removed from the hydrocarbon gas stream along with a very small amount of hydrocarbons. One of the significant advantages of selecting the a-MDEA process is that it selectively removes CO_2 (and H_2S) whilst absorbing very little hydrocarbon compared to other commonly used amine-based solvents.

The a-MDEA, rich in CO_2 (and H_2S), will then be fed to a ‘flash vessel’. Here the pressure will drop and ‘flash off’ the majority of the hydrocarbons and some of the CO_2. The resulting stream of ‘flash gas’, primarily containing hydrocarbons with a small amount of CO_2, will be compressed, utilised as fuel gas or otherwise directed back to the process. This flash gas will also be treated (such as with a water scrub) to remove carryover of a-MDEA so that it does not impact the fuel system and fuel consumers.

From the flash vessel, the rich a-MDEA will be directed to a regeneration column which operates at close to atmospheric pressure. The rich a-MDEA solution will be heated in the regenerator by hot oil. The heating process and reduced pressure will liberate the CO_2 with minor quantities of H_2S and hydrocarbon gases (including some benzene, toluene, ethylbenzene and xylene (BTEX)). The regenerated a-MDEA will then be cooled and pumped back to the contactor vessel to start the cycle again.

Lean–rich heat exchangers in the acid gas removal system will be provided to improve the overall energy efficiency of the process.

Should storage areas be required for a-MDEA, these will be designed, operated and maintained in accordance with appropriate Australian Standards.

The liberated CO_2 and minor quantities of H_2S and hydrocarbon gases will be piped to the CO_2 compression unit. During normal operations, none of the impurities removed from the feed gas will be emitted to the atmosphere as they will be injected along with the CO_2.

During non-routine conditions (such as when an injection compressor stops) the CO_2 and associated gases will be vented via a gas turbine exhaust (or dedicated vent) to ensure adequate dispersion.

For further details on the injection of CO_2 refer to Chapter 13, and refer to Chapter 7 for a discussion on the dispersion of the reservoir CO_2 vent stream when it is operating.

Box 6-4:

Alternative CO_2 Removal Options Considered

During the concept selection stage of the Development, several CO_2 removal concepts were assessed. These included cryogenic distillation, a chemical solvent (a-MDEA) process, and a combined physical and chemical solvent process.

In the cryogenic process, CO_2 would be liquefied by chilling the gas stream, enabling separation. Although this option was studied in detail, the increased complexity and cost of processing made it an undesirable option.

The chemical solvent process (a-MDEA) and combined physical and chemical solvent process are very similar. From an environmental perspective, the major difference is the quantity of hydrocarbon that is entrained in the solvent in the CO_2 absorption process. Hydrocarbon entrainment is considered undesirable as it is a valuable product and during those times when the CO_2 is vented to the atmosphere (Chapter 13), this entrained hydrocarbon would be emitted. The a-MDEA process was selected as the preferred process due to its proven application, reduced cost, and because it entrains significantly less hydrocarbons than competing solvent technologies. The existing North West Shelf Project LNG plant in Karratha has recently converted to a-MDEA in the acid gas removal system.

CO_2 Compression and Dehydration

The CO_2 stream (containing minor quantities of H_2S, BTEX and other hydrocarbons (refer to Chapter 13 for concentrations of these compounds in the reservoir CO_2 stream) will be fed from the regeneration column to CO_2 injection compressors. The injection compressors will compress the CO_2 stream from approximately atmospheric pressure to the required injection pressure. This is likely to be achieved via multiple compression trains, consisting of 4 x 25% compressors driven by electric motors. Dehydration of the gas stream will be accomplished through the interstage knock-out facilities. The exact compressor configuration and location will be determined during detailed design.

Following compression, the CO_2 will be fed into a pipeline to the injection wells which are described in Section 12.2.4. Chapter 13 describes the expected availability of this system and estimates CO_2 emissions from the proposed Development.

Dehydration

The CO_2-free (and H_2S-free) hydrocarbon gas from the slug catchers will be directed to one of the two proposed LNG trains. The hydrocarbon gas stream from the acid gas removal units must be dehydrated to prevent ice forming in the downstream cryogenic equipment. To achieve this, the treated gas will first be cooled using a combination of air and propane refrigerant to condense the bulk of the water, which will then be removed in a separator vessel and sent to the water treatment facilities for deep well injection. Gas from the dehydration separator will be passed through molecular sieve beds, which will remove any remaining water to below 1 part per million by volume (ppmv).

The molecular sieves will be regenerated using hot gas to drive the moisture out of the beds. The regeneration gas will be heated with waste heat from the gas turbines rather than a separate fired heater/furnace. This hot, water-rich stream will be cooled to condense the water, which will be directed to the waste water treatment facilities and the gas will be returned upstream to ensure complete removal of CO_2. It is common to have multiple vessels (typically three) in this service so that two can be online, while one is undergoing regeneration.

The recovered water will contain small amounts of hydrocarbons and possibly solids which could cause significant process upsets if it were recycled back to the acid gas removal unit. It may be possible to clean this water sufficiently to allow it to be reused within the process and this will be examined as the design progresses.

Mercury Removal

Elemental mercury in the feed gas will occur in ultra trace amounts, but any amount can cause degradation of the aluminium used in the LNG process equipment. To prevent this, gas will be passed through a mercury removal unit downstream of the dehydration unit.

A mercury removal unit is a vessel that typically contains an absorbent such as activated carbon granules treated with elemental sulphur. As the gas passes through the vessel, traces of mercury in the feed gas will react with the sulphur and remain chemically trapped on the carbon granules. The bed material acts as a filter and will need to be removed periodically for disposal. The management and disposal of the bed material impregnated with the resulting mercury sulphide is discussed in Chapter 7.

An alternative design could utilise a special zeolite without sulphur impregnation. Hot and dry natural gas would be used to regenerate the zeolite beds. The regeneration gas can be cooled and elemental mercury collected as a product. Further information will be collected on this alternative prior to a final decision during subsequent design phases of the Development, but selection of this option is highly unlikely.

Scrub Column and Fractionation

Heavier hydrocarbons (i.e. those heavier than methane) known as liquefied petroleum gas (LPG) (primarily ethane and propane) will be recovered from the gas for use as refrigerant in the liquefaction process for the LNG system.

First, the main gas stream will be chilled with propane refrigerant to liquefy the heavier hydrocarbons. These hydrocarbons will be separated from the main gas stream in the scrub column, and the resulting lean gas stream will be directed to the main cryogenic heat exchanger to ultimately become LNG.

The liquids from the scrub column will be directed to a fractionation unit. The fractionation unit will use a combination of heat and pressure to separate the various components. Lighter components (methane, ethane, propane, and butane) in excess of those required for refrigerant makeup will be returned to the LNG process. Remaining stable liquid, stripped of all light components, will be directed to the condensate storage tanks for export.

The ethane and propane storage will be located in a separate refrigerant storage area located outside of the process area. The approximate stored volume of ethane and propane will be 500 m^3 and 1800 m^3 respectively. It will be necessary to import ethane and propane to start the LNG process but after a period of time the system will be self-sufficient in these products.

There will be insufficient quantity of LPG in the Gorgon reservoirs to be commercially produced for export. However, an alternative to returning the excess ethane, propane and butanes (collectively referred to as natural gas liquids) to the main process, on a continuous basis, is to store these liquids for blending into a limited number of LNG cargoes to meet the heating value requirements of specific LNG customers. This alternative requires additional pressurised storage for approximately 6000 m^3 of natural gas liquids. This situation is factored into the public risk assessment included in Chapter 14, to be conservative at this early stage of the design.

Cryogenic Heat Exchanger and Refrigeration Process (Liquefaction)

The main cryogenic heat exchanger and the associated refrigeration process comprise the core of each LNG train. Their combined purpose is to chill the natural gas to create LNG, so this exchanger and the refrigeration process are also referred to as the liquefaction section of the plant. The Joint Venturers will utilise a commercially available and proven liquefaction technology. Approximately 90% of current LNG plants around the world use a variation of the propane pre-cooled liquefaction technology from Air Products and Chemicals, Inc (APCI). This process is based on a mixed refrigerant process that utilises nitrogen, methane, ethane and propane as refrigerants. This technology is used for assessment in this Draft EIS/ERMP, and is the preferred technology.

The overall process uses the same fundamental principles as a household refrigerator. The main cryogenic heat exchanger is similar to the evaporator plate inside a refrigerator or freezer. A compressor compresses the refrigerant and provides the energy for the cooling process. The condenser that is usually found on the back of a refrigerator is replaced in an LNG plant with a large bank of fan-cooled heat exchangers.

The main cryogenic heat exchanger is a large vertical vessel containing internal tubing. This provides an enormous surface area to efficiently transfer heat from the main gas stream to the refrigerant.

Currently the most common configuration for an LNG train, at the size proposed for this Development, includes direct drive gas turbines on the refrigerant compressors and separate gas turbine drivers of a roughly similar size to generate electrical power required for these facilities. For the purposes of this Draft EIS/ERMP, it is assumed that the refrigerant compressors on each LNG train will be driven by two large industrial gas turbines. This aspect is discussed in more detail in Chapters 7 and 13. These turbines will be assisted by electric motor starter/helper drivers that provide mechanical power for starting the turbines, and additional energy for production. Gas turbines will also be used for generation of electrical power.

Gas turbine exhaust waste heat recovery units will provide the heat for the hot oil system and the dehydration regeneration gas.

The LNG leaving the main cryogenic heat exchanger will be at a temperature of approximately minus 150°C, prior to the end flash process section.

End Flash

The final process in the production of LNG will be to drop the pressure of (to flash) the LNG from the main cryogenic heat exchanger to near atmospheric pressure, thus reducing the temperature to -161°C. At this temperature and near to atmospheric pressure, the LNG will be a liquid and can be effectively stored and shipped around the world at a volume approximately 1/600th of the volume of natural gas at normal atmospheric pressure and temperature.

As part of the ‘flashing process’, some of the LNG will be turned back to a vapour. This ‘flash gas’ will be relatively rich in nitrogen (expected to be approximately 25 vol %), allowing the remaining LNG product (mostly methane) to meet the nitrogen sales specification. The nitrogen-rich flash gas will be compressed and used as the main source of fuel gas for the gas processing facilities on Barrow Island.

LNG Storage and Offloading

LNG product from the liquefaction process will be stored in two full containment storage tanks of approximately 135 000 m^3–155 000 m^3 net each.

The tanks are expected to be approximately 35–40 m high and 70–80 m in diameter. LNG tanks come in three different configurations referred to as single containment, double containment, or full containment type. The Development team will use a full containment tank design. A full containment type tank is shown in

Figure 6-7:
Schematic of Full Containment LNG Tank

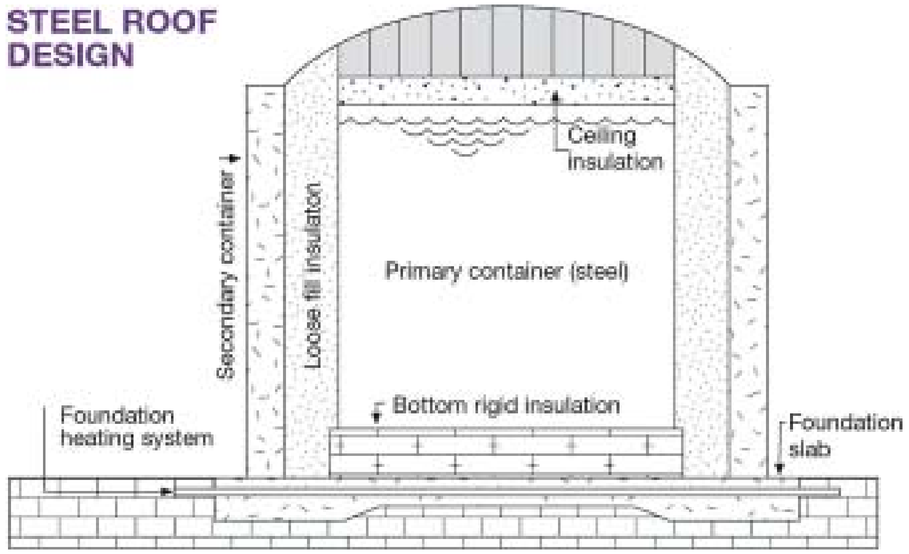


Plate 6-3:
Typical LNG Carrier

Figure 6-7. The final LNG tank size and number will be further optimised as they are dependent on the ultimate market for LNG and the size of ship used, but environmental impacts will not change significantly. The design of LNG tanks is carefully controlled through British Standard EN1473 ‘Installation and Equipment for LNG – Design of Onshore Installations’. Plate 6-3 shows a typical LNG ship which the Barrow Island terminal will be designed to receive.

The LNG will be stored in the tanks at approximately -161°C at slightly above atmospheric pressure. The LNG storage system will include submerged pumps, control/monitoring systems, pressure relief valves, a loading platform and a fire suppression system for the loading platform. Heat leakage through the insulation will produce a small amount of boil-off vapours, which will be recycled through the LNG plant or consumed as fuel in the LNG plant. Vapours displaced from the tanker being loaded will be directed back to the boil off gas recycle compressor in a closed loop under normal operations. All filling and loading operations will be conducted through the top of the tank to minimise the chance of a leak. All nozzle connections will be located on the top of the tank. LNG tanks will not be exposed to internal corrosion risks as all materials will be contained in a methane atmosphere and there will be negligible water in the stored product.

In the unlikely event that a leak occurs, it would be detected by thermal sensors in the leak detection system. In addition to leak detection, other protective systems for the tanks will include pressure relief valves, vacuum relief valves, overfill protection systems, and fire and heat detection systems with water sprays and/or foam dispensers.

In the extremely unlikely event that an LNG tank was close to over-pressurisation and the normal boil-off gas compressors could not handle the vapour load, surplus pressure would be relieved to a dedicated storage and loading flare. A dedicated flare is required because the tanks cannot withstand backpressures associated with the main plant flare. A final level of overpressure protection will vent vapour to atmosphere, but this is extremely unlikely to occur.

The tanks will be designed to withstand cyclonic wind forces and any impact from items caught by cyclonic winds.

The LNG product will be transferred from the storage tanks to the ship loading facility via submerged pumps in the LNG tank and insulated loading lines via loading arms.

Condensate Storage and Offloading

Condensate production will be in the order of 2000 m^3 per day. Condensate will be stored in two conventional floating roof storage tanks located within bunds meeting Australian Standard AS 1940. Condensate tanks, bunds and associated piping will be designed, tested, operated and monitored to prevent leakage into underlying soil.

The tanks are expected to have a capacity of approximately 35 000 m^3 net each. The condensate will most likely be loaded onto ships using the existing Barrow Island oil loading facilities; therefore several tie-ins to the existing systems will be required. The use of vapour recovery from the export tankers while loading condensate is not currently envisaged due to the infrequent offloading requirements and low emissions. Refer to Chapter 7 for further details.

One of the options that may be considered during later phases of engineering design is to run a new condensate load out line along the LNG jetty. The condensate line would run subsea from the LNG jetty to a Single Buoy Mooring. This alternative condensate loading line is carried as an option in the event that the use of the existing subsea load out line proves to be infeasible. Another alternative being considered is to load condensate from the LNG jetty.

Domestic Gas Facilities

Following acid gas removal, the gas destined for the domestic gas market will be dehydrated and the hydrocarbon dew point controlled to meet the domestic gas specification.

Dehydration will be achieved through a Triethylene glycol (TEG) system that is similar to that proposed for the CO_2 injection system. There will be a very low pressure waste stream from the TEG regeneration system containing water vapour and a small amount of hydrocarbons. This low pressure gas stream (typically containing low concentrations of benzene, toluene, xylene components) will be directed to the flare system. The hydrocarbon dew point specification will be met by cooling the dehydrated gas with propane refrigerant followed by simple vapour/liquid separation.

Alternative process technologies for dehydration (molecular sieve), hydrocarbon dew point control (Joule Thompson (JT)) valve expansion, turbo-expander, and both dehydration and dew point control (regenerable adsorbent silica gel, other new technologies), are being considered for domestic gas treatment. Further information will be collected on these alternatives prior to a final decision during later design phases of the Development, but environmental aspects will be similar.

The domestic gas stream will require compression prior to export via the domestic gas pipeline to the existing domestic gas network. The current design concept is to utilise a compressor driven by an electrical motor, negating the need for a dedicated gas turbine. This configuration will be reviewed as part of the energy optimisation process (Box 6-5) as the design is developed, but overall emissions will be comparable between options.

Heating Medium

A number of the processes within the gas processing facility will require heat. For a heating medium system to remain efficient and cost-effective, it is important to keep the heat sources close to the heat users. Process heat will be supplied by a closed loop hot oil circulation system. Alternative heating media (hot water and steam) have been considered and ruled out.

The largest requirement for heat will be the acid gas removal system for the regeneration of the a-MDEA. Other heat demands include the hydrate inhibitor recovery system, condensate stabilisation, the TEG regeneration systems, the LNG scrub column and fractionation distillation columns. The heat for these users will be provided by a waste heat recovery system.

The design of these systems is part of an ongoing energy optimisation process which is discussed in Box 6-5.

Various chemicals are often associated with heating medium systems. These will be stored in accordance with relevant legislation.

Electrical Power Generation System

As mentioned above, electrical power for the gas processing facility will be provided by gas turbines. The main users of electrical power will be motors for the process compressors, gas turbine helper motors, pumps and the air cooler fans. The optimum use of waste heat recovery on these gas turbines will be included in the energy optimisation study.

Box 6-5:
Energy Optimisation

The Joint Venturers are committed to adopting best practices in environmental management, which includes emissions to the atmosphere. As standard practice, Chevron requires all large developments to implement energy optimisation as part of the design process. The process is driven by both the economic value that can be obtained from an efficient plant and the environmental benefits of reduced energy consumption and associated emissions. As part of this process all major heat, motive, and electric users and sources are reviewed for optimisation opportunities.

The proposed gas processing facility on Barrow Island will require energy in the order of approximately 600 MW of direct power (motive and electrical) from the gas turbines and a similar quantity of heat. The base design case assumes that this energy will be provided by:

- 5 x 80 MW industrial gas turbines for electricity production (or equivalent system)
- 4 x 80 MW industrial gas turbines for the refrigerant compressors (two on each train)
- 4 x waste heat recovery units on the compressor gas turbines.

A heating medium system is coupled with this to distribute the heat.

Details on greenhouse gas emissions from the proposed Development can be found in Chapter 13, while details on other atmospheric emissions are discussed in Chapter 7 and Chapter 10.

Plant Lighting

Minimising light spill is an important design criterion for the proposed Development due to potential impacts on turtle hatchlings. To minimise the potential impact, a hierarchical lighting strategy has been prepared. In general, lighting levels will be minimised to those required for safe working and security.

In areas where colour definition is not required for safety or operational purposes, shielded red or monochromatic lights are proposed. This includes areas such as the MOF causeway, jetty, roads within the gas processing facility and general open areas. In areas where minimal colour definition is required, a reduced spectrum yellow/orange type of shielded light, such as sodium vapour, will be used. These lights will form the primary lighting for the facility.

Areas that require inspection during operator rounds and/or regular maintenance (e.g. filter change outs) will utilise fully shielded full spectrum white lights that are normally off. These lights will be switched on only as required. For an emergency situation, additional lights will be required for safety, including perimeter flood lights.

The lighting regime will continue to be reviewed during subsequent phases of design and is subject to confirmation that it is acceptable from a health and safety perspective. For further details on lighting levels refer to Chapter 7, and for further details on light management and mitigation strategies refer to Chapter 11.

Flare System

The proposed Development will have a ‘no routine flaring policy’ incorporated into the design of the gas processing facility. This means that during normal day-to-day operation, the flare will not be used as a waste gas disposal route.

A total of three flares will be required for the safe operation of the gas processing facility (Plate 6-4). The two main flares will be located on a flare tower which is expected to be 150 m high and located to the west of the facility, although a ground flare concept is also being evaluated. These flares would be used during plant emergencies, start-up, shut-down and short-duration upset conditions. Short-term (several hours) flaring can avoid the need for a full plant shut-down which would result in a greater volume of gas being flared.

For safety reasons the flare will require a pilot light (or alternative ignition system) to ensure that the gas from any flaring event is ignited. To avoid an explosion in the flare system, it is also necessary to provide a low level purge of the flare system with fuel gas (or other gas) to ensure that oxygen does not enter the system. The feasibility of using exhaust gas, CO_2 or nitrogen, as the purge medium will be reviewed in subsequent design phases.

The third flare is similar to the other two but will be located near the LNG storage tanks and will be used if the boil off gas compressor, which will be used to recover the vapours from the LNG tanks or LNG carriers, stops. These vapours and gases will be recovered back to the process as much as possible. This flare may also be used if an arriving LNG carrier requires cooling. As the carrier is cooled to receive LNG the inert gases and associated LNG vapours from the vessel would be directed to the flare.

Alternatives to reduce anticipated flaring loads, and possibly the size of the main flare stacks, will be reviewed during subsequent design phases of the Development.

Other Utilities

The proposed Development will also require other utilities such as nitrogen, instrument air, and demineralised water which will be generated onsite.

6.2.4 CO_2 Injection Facilities

After the CO_2 is compressed (estimated at 21.5 MPa discharge) within the gas processing facility, it will be transported via pipeline to the injection wellheads. The pipeline will be above ground and approximately 250–350 mm diameter made from carbon steel, which will be fully pressure-rated to the compressor output and injection reservoir pressure.

The injection wells will be arranged into a small number of drill centres with approximately three to four wells at each centre. Wells will be directionally drilled from each drill centre to the bottom-hole injection location. Careful selection of the bottom-hole locations of the wells will be required to achieve the desired injection rates and distribution. The use of a cluster arrangement with directional or deviated drilling will ensure that land use is minimised. Figure 6-8 shows the proposed CO_2 injection well drill centres and bottom hole locations.

One option that may prove feasible is the use of fewer drill centres but the resultant increased well deviation will increase the likelihood of using non-water based

Plate 6-4:
Typical Flare Tower

muds (such as synthetic based drilling fluids mentioned for the offshore wells) which have their own potential environmental impacts. The injection wells will be constructed from corrosion-resistant materials to ensure well integrity in the sub-surface corrosive environment created by CO_2 injection.

The CO_2 injection pipeline will follow the most direct path practicable to the injection well locations while preferentially using as much previously disturbed land as possible. One key aspect in routing the CO_2 pipeline is to ensure the safety of personnel in the unlikely event of a pipeline release. Measures taken to protect people will also generally protect flora and fauna.

6.2.5 CO_2 Monitoring Activities

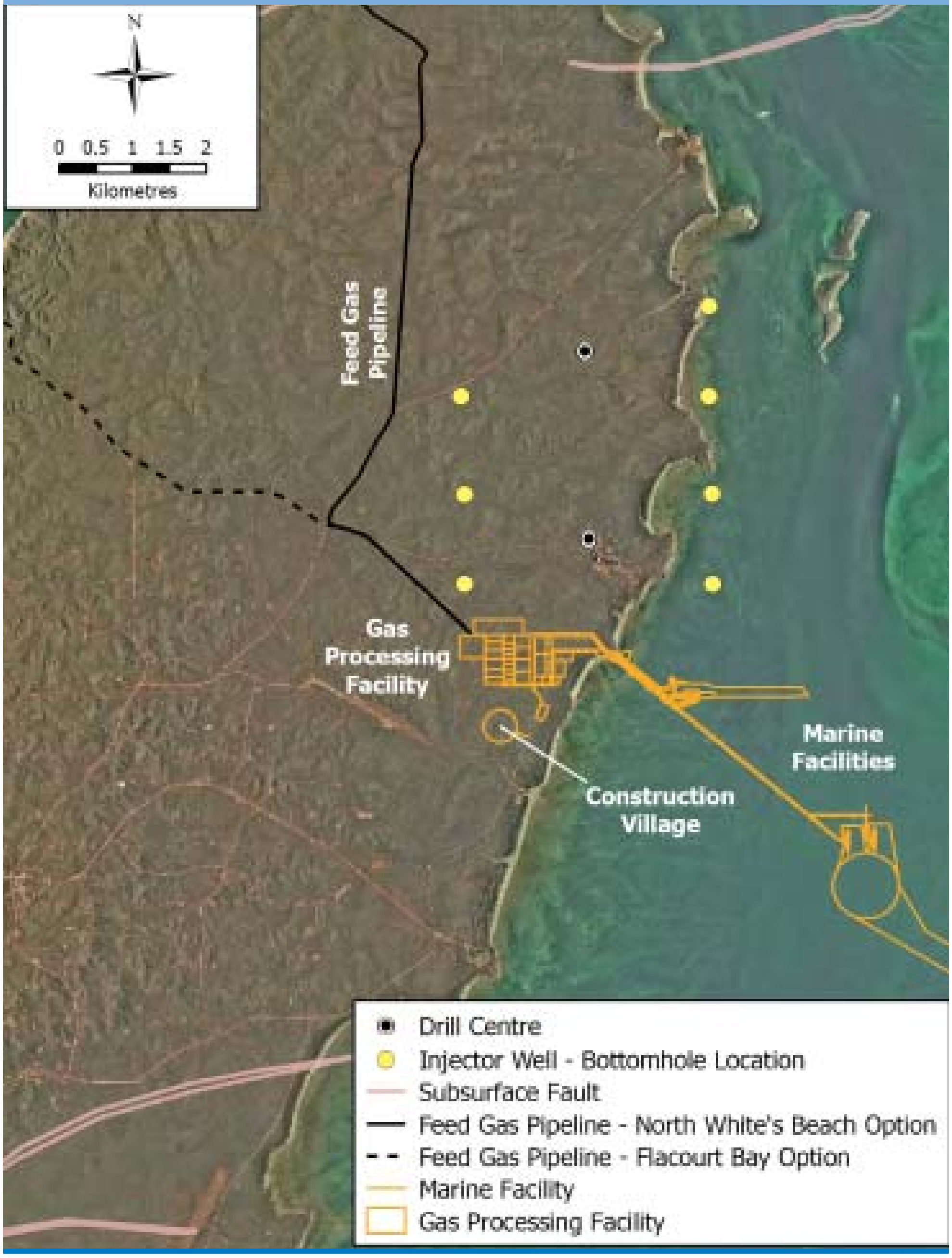
The movement of CO_2 within the Dupuy formation will be monitored to determine if it is behaving as predicted. Refer to Chapter 13 for a discussion of the behaviour of CO_2 in the subsurface once it is injected. The monitoring program has yet to be designed. As such, the following description should be considered as the reference case for the purposes of environmental impact assessment. The final concept and design of the monitoring program will be developed to ensure that the nature and extent of potential environmental impacts are consistent with those described herein.

The reference case monitoring program involves a combination of monitoring wells and seismic data acquisition. An investigation into established and developing CO_2 monitoring methodologies indicates that time lapse seismic (often referred to as ‘4-D’) is the most effective technology for direct detection and mapping of the plume migration. The injection of CO_2 is expected to significantly alter the seismic response, therefore time lapse seismic will reveal the movement of the CO_2. The basic steps in time-lapse analysis for CO_2 monitoring are:

- acquire a ‘baseline’ seismic survey (3-D) prior to any gas injection to establish a dataset unaffected by the presence of CO_2
- acquire repeat seismic surveys
- subtract the baseline data from each of the ‘repeat’ datasets.

Acquiring good quality seismic data suitable for 4-D monitoring on Barrow Island is difficult due to a near-surface cavernous karst limestone layer. Numerous 2-D and 3-D seismic surveys have been acquired on Barrow Island, all of which have provided variable data quality due to problems associated with the karst layer. The most extensive survey was the 1994 3-D, which covered the entire northern half of the island. It was acquired on a grid with source lines 500 m apart and receiver lines 300 m apart; and used an array of four surface vibrators and 12 geophone receiver arrays spread over 25 m. Processing tests have shown the data acquired in the 1994 3-D survey is unsuitable for a 4-D baseline survey.

Figure 6-8:
Proposed CO_2 Injection Well Drill Centre Locations



Future surveys need to improve data quality while using considerably less land. Acquisition modelling and processing tests indicate that suitable data quality can be achieved through improved survey design and advances in technology.

The source and receiver lines in the 1994 3-D grid were cleared, and the survey used approximately 220 ha of land which can now be reduced to below 40 ha with careful planning and new technology. The challenge remaining is to balance the need to acquire seismic data of sufficient quality with the desire to minimise environmental impact.

The survey design options therefore include the following:

- use of pre-existing roads wherever possible
- use of pre-disturbed source lines (from the 1994 3-D survey) wherever feasible, where off-road source lines are necessary
- hand carrying of all surface receiver equipment from existing access roads, tracks and source lines.

The surface seismic program will include both onshore and offshore acquisition methods, even though the majority of the plume will remain under the island. Key technologies and design improvements need to be tested to ensure acquisition of sufficient quality data while minimising environmental impact. It is imperative that all repeat surveys are acquired with the same parameters as the baseline survey (i.e. all source and receiver locations will be revisited for each survey).

Previous surveys were not optimised to create an accurate near surface model, which is a critical factor in improving data quality. The model is used in the data processing stage to correct for variations introduced by the karst layer. An ‘up-hole survey’ will be used to provide input to the required model, which will involve the installation of one to two hundred 30–50 m deep holes. These will be located on the seismic source lines.

Onshore Seismic

The preference for using areas previously disturbed by 3-D seismic survey places the following constraints on the monitoring survey:

- source line spacing will be 500 m
- receiver line spacing will be 150 m (half the 1994 3-D spacing).

The grid layout will be altered to avoid sensitive areas (e.g. source lines can be curved to avoid bettong warrens). The other two main considerations when designing seismic surveys are the type of source and receiver and their spacing, which are described below.

Source

There are three main source types in seismic land acquisition, namely: vibroseis, accelerated weight drops and explosives. Each source type will be tested in order to determine the optimum and are discussed below.

Option 1: Vibroseis – A vibroseis truck is approximately 3.8 m high, 10.8 m long, 3.5 m wide, and is fitted with vibrator pads that are approximately 1.4 m x 2.3 m. The vibrator induces a controlled vibratory force which is transferred through a base plate into the ground to create seismic waves. An electronic control system generates a low amplitude sinusoidal signal that varies in frequency, from 8 to 80 Hz over 6 to 10 seconds. The vehicles can be fitted with rubber tracks or extra wide tyres to minimise both ground pressure and impact on vegetation. The previous acquisitions on Barrow Island used between two and four vibroseis units arranged in a line. New technology may allow the use of a larger single hydraulic vibrator unit, which will reduce the environmental impact by reducing the number of times each ‘shot’ (or vibration) location is revisited by 75%. Multiple smaller vibroseis units may still be required technically; if this is the case, land usage will decrease as the smaller units are approximately 2.5 m wide.

Option 2: Accelerated Weight Drop – Accelerated weight drops use a hydraulic system to raise and lower a weight of just over 1200 kg. The weight is released under pressure, causing it to hit the base plate previously lowered onto the ground creating a short duration impulsive energy source similar to explosives. The pad size is approximately 1.3 m in diameter. The accelerated weight drop is mounted on the back of a manoeuvrable but oversized 4WD, with a width of 2.5–3.0 m and a total weight of approximately 12 000 kg. This flexibility and manoeuvrability allows the source locations, density of source points and source effort, to be tailored to minimise the environmental impact. This is the environmentally preferred source option due to its reduced line width, increased manoeuvrability (over vibroseis) and holes will not need to be drilled.

Option 3: Explosives – Explosives are the preferred technical option as they have been shown to provide the best data quality on Barrow Island, particularly in areas which have a thicker karst limestone cap. Placing explosive charges beneath the air-filled caverns greatly reduces the amount of scattered energy created, and significantly enhances data quality through improving waveform, amplitude and frequency content of the energy reaching the target layer. In order to minimise the use of explosives and the amount of drilling, explosives will only be used if and where absolutely necessary. If testing shows explosives are required, it is likely to only be in areas of higher elevation or with significant karst limestone. Vibroseis or accelerated weight drop will be used for the remaining source locations. This will significantly reduce the number of shot-holes required for the survey (expected to be much less than 1000 holes).

Explosive charges are used commonly in seismic acquisition and, in the majority of cases, the explosives are placed below the water table. Each explosive charge is usually less than 5 kg and is placed in a PVC cased hole 5–10 m below the water table (average depth of hole is 25 m). The shot-holes will not be back-filled and will use a small head of water for detonation. A 2 m wide source line is required for the drilling program which uses small percussion drilling rigs mounted on the back of a 4WD. The percussion drilling will eliminate the need for drilling fluids and all cuttings will be used as fill material at the gas processing facility site. Contrary to common perception, explosive charges used in seismic surveys lead to minimal surface disturbance. Very few detonations result in any visible evidence that a charge has been detonated. The only observable event is a small ‘thud’ equivalent to a fist striking a table.

Receivers

Land receivers (geophones) will be firmly planted into the topsoil (e.g. a 7 cm brass spike pushed into the ground). All receivers will be hand carried from the nearest source line or access track to minimise off-road vehicle traffic. Flexibility in the placement of each receiver element will allow environmentally sensitive areas to be avoided. The receivers will be recovered after each survey is completed.

The 1994 3-D survey used receiver lines separated by 300 m and groups of 12 geophones spread over 25 m along the receiver line, and a geophone every two metres along the receiver line. This type of receiver layout did not adequately attenuate the back scattered energy commonly seen on Barrow Island. Improving the receiver response is critical to the success of any seismic monitoring program.

The main differences between the methods for improving seismic response are largely logistical in nature. For example, if 24-geophone groups are used, then approximately 200 000 individual geophone elements will need to be transported and handled in a manner that meets quarantine requirements, and then planted in the ground. However, if the single three-component geophones are technically acceptable, then less than 10 000 individual geophone elements will be required. The 24-geophone group option requires significantly more people, as well as 24 times the weight and volume of equipment than the three-component option. If the improvements in the receiver response from these changes are significant, the receiver station spacing may be increased from 25 m to 37.5 m or even 50 m, reducing the number of receivers required by approximately 50%. In practice, this may result in groups of 12 geophones spaced every 18.75 m, with two adjacent groups of 12 geophones being combined to form one aerial array of geophones.

From a logistical point of view, minimising the number of surface geophones per group and increasing the receiver group interval are critical items.

Another option is to place special ‘4-C’ receivers at or below sea level. This would require many thousands of boreholes to be drilled to sea-level, involving the creation of a 2 m wide access track for the percussion drilling rig and hence a considerable amount of land usage. The very large number of holes required for this receiver option and the large land use required makes this option impracticable for a full 3-D survey. However, the use of 4-C receivers below sea level may be required for a small portion of a 3-D survey where data quality is particularly poor. It is highly likely that this technique would be required for any 2-D program.

Overall the reference case for impact assessment is estimated to require 81 km of off-road source line length and a total receiver line length of 850 km. Contingency is required to allow for such matters as deviation of source lines from the grid of the 1994 3-D to avoid environmentally sensitive areas or changes in track width.

Marine Seismic

The water depth to the east of Barrow Island is typically shallower than 20 m. Shallow draft vessels are required to allow seismic acquisition in water depths to 1 m. Receiver cables, containing pressure sensitive receivers, will be laid on the sea floor with each cable being up to 4000 m in length. Alternatively, individual receiver pods may be deployed on the sea floor and recovered after each survey is completed. The survey will be carefully designed to ensure receiver locations and cables will avoid any sensitive areas such as corals. In deeper water, no equipment needs to be placed on the sea floor as towed streamer vessels can be used. The source will be a standard marine seismic survey airgun, which generates an acoustic wave in the 10 to 300 Hz frequency range by releasing high pressure compressed air.

The Commonwealth Department for the Environment and Heritage (DEH) guidelines for seismic acquisition will be used. These require that activities be suspended when whales are within 3 km of the seismic vessel. Trained observers will be onboard vessels to scan the ocean surface for the presence of marine mammals, and shut-down operations accordingly. When restarting operations a ‘ramp-up’ procedure will be used. This procedure gradually increases the emitted sound levels by turning on the array’s airguns over a period of time. Surveys will be scheduled to avoid critical cetacean migration and turtle breeding periods. Shot locations will be planned to take maximum advantage of the tides and to avoid any impact on coral. Ideally, the timing will be such that the energy from the offshore sources can be recorded by the onshore receiver grid.

Refer to Chapter 13 for additional details regarding CO_2 monitoring and to Chapters 10 and 11 for a discussion of potential impacts associated with this program and their management.

6.2.6 Domestic Gas Pipeline

Gas for domestic use may, if proven to be commercially viable, be exported by a domestic gas pipeline from Barrow Island to the domestic gas distribution network. For the purposes of this Draft EIS/ERMP, it is assumed that the domestic gas pipeline will tie-in at Compressor Station One (CS1) on the Dampier to Bunbury Natural Gas Pipeline. The proposed pipeline route is shown in Figure 6-9. Alternative concepts are described in Box 6-6.

It is proposed that the pipeline will be routed directly from Town Point, on Barrow Island, to the mainland. The route shown is essentially a straight line but this will be modified to avoid sensitive habitat as the design develops. This pipeline will approach the mainland immediately adjacent to the existing Apache Energy Gas Sales Pipeline to reduce the environmental impact associated with the development of a new shore crossing. The pipeline will be concrete weight-coated for protection and stability; and will be further stabilised by a combination of burial by jetting, rock bolting and other appropriate stabilisation techniques commonly used in the area. Pipeline installation will require the use of construction vessels moored in shallow water at both the Barrow Island and mainland ends. The potential for directional drilling at the mainland shore crossing will be considered as the design progresses.

Box 6-6:
Domestic Gas Pipeline Alternatives

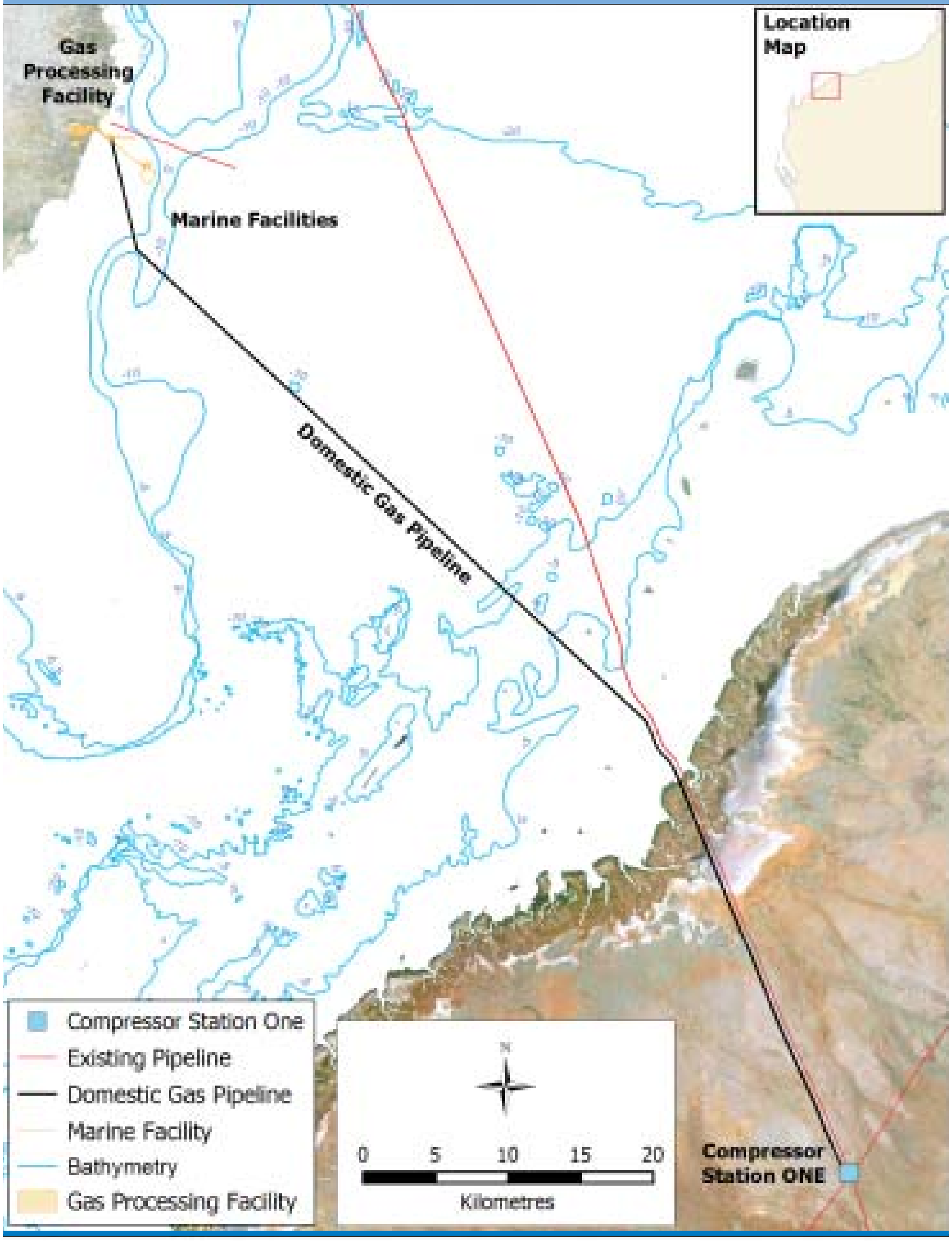
Alternatives to the installation of a new pipeline from Barrow Island directly to Compressor Station 1 (Dampier to Bunbury pipeline), involve tying the domestic gas pipeline into existing domestic gas supply facilities operated by Apache Energy on and around Varanus Island. Alternative concepts include:

- a pipeline from Town Point to the Apache Sales Gas Pipeline, with ‘hot-tap’ subsea connection and installation of subsea isolation/pig receiving facilities
- a pipeline across Barrow Island, and subsequent offshore pipeline to Varanus Island with tie-in at the Apache Onshore Gas Plant
- a pipeline across Barrow Island to Cape Dupuy area, and a subsequent offshore pipeline to the Apache East Spar Pipeline and hot tap subsea connection and installation of subsea isolation/pig receiving facilities.

The latter two have been ruled out.

From the mainland shore crossing point to Compressor Station 1, the pipeline will run parallel to the Apache Energy Gas Sales Pipeline. Except for valves that are required for pipeline maintenance, this pipeline will be buried for the entire route. The easement required for the pipeline will be approximately 30 m wide. Tie-in to the mainland pipeline network may involve hot-tapping, and will necessitate installation of adjacent pipeline isolation and ‘pig-receiving’ facilities to enable future maintenance of the domestic gas pipeline without impacting gas transportation in the main trunkline.

Figure 6-9:
Proposed Domestic Gas Pipeline Route



6.2.7 Water Supplies

Water will first be required during the construction phase and this aspect is addressed in the section on construction in this chapter.

6.2.8 Drainage and Waste Water System

The objective of the waste water system is to maximise the reuse of water, and to protect soils, subterranean fauna, groundwater and the marine environment from contamination. To achieve this, a tiered waste water management approach has been adopted, which comprises the following:

- diverting water, which flows naturally onto clean areas of the site during rainfall events, to natural drainage areas
- allowing water from unpaved areas and paved non-process areas (e.g. roads, and building runoff) at the site, where no contamination is likely to soak naturally into the ground, or directing this water to natural drainage channels

- directing water in areas that could be contaminated, but are usually considered to be relatively clean, to a holding basin for water quality testing before discharge. (Uncontaminated water will be discharged back to natural drainage areas, while contaminated water will be pumped to a treatment system.)
- directing water from areas that are expected to be contaminated (e.g. sumps and areas around pumps, turbines) to an oil recovery system.

The design of this tiered waste water facility will take into account the increased flows associated with severe storm events and potential firewater runoff (which may be contaminated with hydrocarbons, chemicals and salt).

All process water plus hydrocarbon contaminated surface runoff water will be treated in an oil recovery system. Any recovered hydrocarbons will be recycled (most likely by directing them back into the process), requiring them to be returned to the mainland for recycling or other appropriate treatment.

To cater for the infrequent periods when the water disposal system is not operational waste water storage facilities will be provided. This system will be designed to cater for the longest expected duration of such downtime, and the most likely volume of water produced during such a period. As this water will be contaminated, the storage tank will be bunded in line with Australian Standards.

The Code of Practice CP25 – Wastewater Management at Bulk Petroleum Storage Sites (AIP 1994) will be used in the design of the waste water treatment system. Appropriate water quality guidelines, such as the Australian Water Quality Guidelines for Fresh and Marine Waters (Australian and New Zealand Environment and Conservation Council 2001) will be used to design the water treatment facilities, and as a basis for assessment of contamination.

Waste water management is also discussed in more detail in the construction section of this chapter as these facilities will be required during the construction phase.

6.2.9 Port and Marine Facilities

The major components of marine infrastructure required to support the proposed Gorgon Development include: a Materials Offloading Facility (MOF) and causeway, jetty facilities, a shipping channel and turning basin. Each of these is described in the following section.

Materials Offloading Facility and Causeway

A MOF will be needed to receive construction materials including heavy pieces of equipment and prefabricated modules during the construction phase. The facility will also be used to receive maintenance material and provisions during the operational phase. Ocean going vessels, similar to that shown in Plate 6-5, are likely to be used for the delivery of large equipment such as the main cryogenic heat exchangers, absorber columns, and modules. The larger equipment will be unloaded and positioned on-site using multi-wheeled vehicles.

Plate 6-5:
Typical Construction Equipment Delivery Vessel

Access to the MOF will be provided via an 800 m long causeway from Town Point. The MOF will extend a further 325 m from the offshore end of the causeway. This concept will significantly reduce the volume of material to be dredged and associated blasting of the limestone platform that would otherwise be required to provide an access channel to a shore-based facility. Vessels will access the MOF via a dredged channel approximately 1.3 km long, 120 m wide and dredged to 6.5 m relative to chart datum. At this depth the channel will be tidally restricted for the larger vessels required during construction. A deeper pocket will be dredged against the MOF to enable these larger vessels to be unloaded during all tidal conditions.

The MOF will also incorporate mooring facilities for tug boats and other vessels required to support the LNG carriers, and refuelling capabilities for the smaller vessels (such as tugs). The details of the MOF specification will be reviewed with respect to module and equipment sizes determined as the design proceeds, however the basic concept will not change.

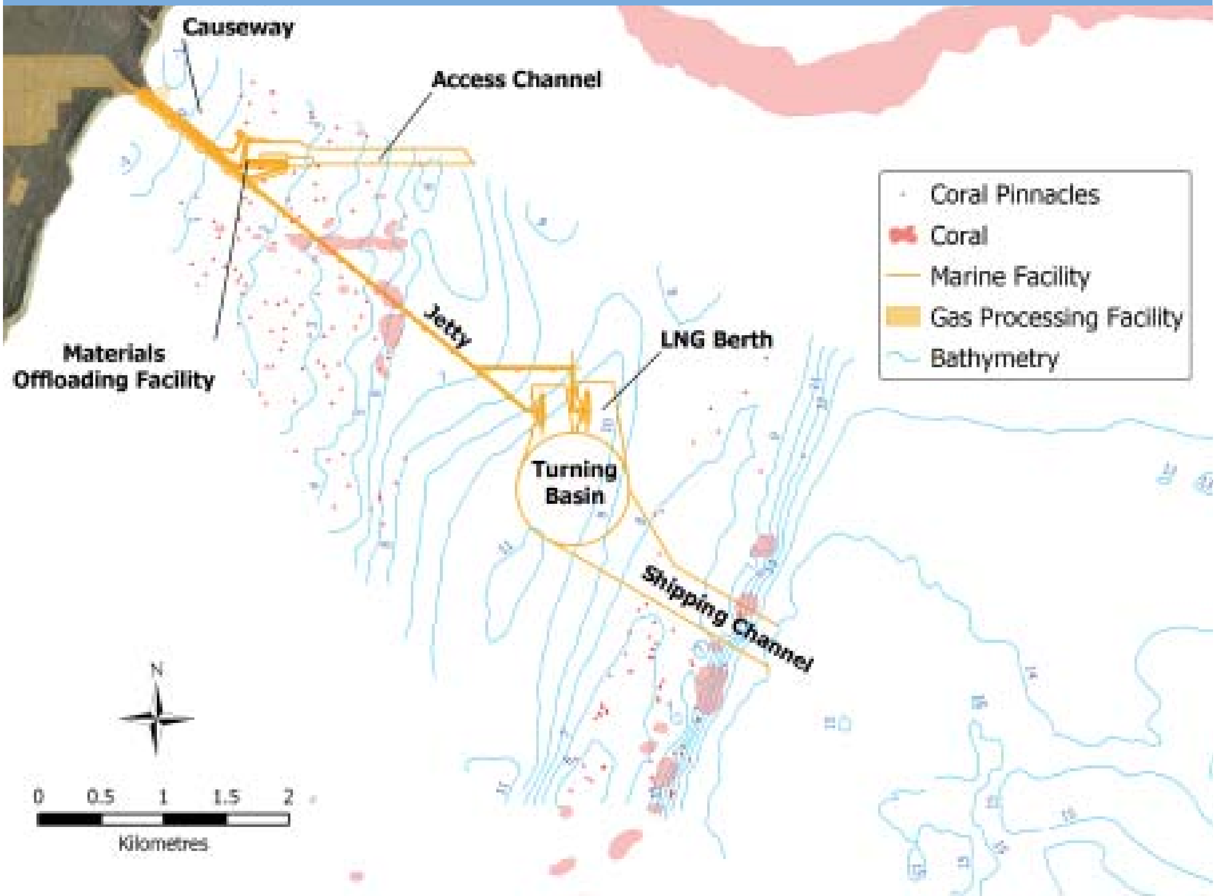
Jetty Facilities

A jetty will be built with mooring facilities to receive LNG carriers. The proposed jetty location and configuration is presented in Figure 6-10. The LNG export facility will include vapour recovery equipment. Emergency shut-down systems will be installed to minimise the risk of product spills.

The proposed facility will be capable of handling various sized LNG carriers between 125 000 m^3 and 215 000 m^3. The regular fleet is expected to be 165 000 m^3 vessels, however smaller and larger vessels may be accommodated to load spot cargoes.

The jetty will be approximately 3.1 km long commencing from the offshore end of the causeway. The final length, orientation and method of construction will be confirmed after further geotechnical and geophysical surveys, berth orientation modelling and simulated navigational studies are completed, but environmental impacts will not be significantly different.

Figure 6-10:
Offshore Facilities East Coast Barrow Island



The export facilities will include a loading platform, breasting and mooring dolphins, a field auxiliary room and substation, navigational aids and other infrastructure. The loading platform will accommodate:

- LNG loading arms for liquid transfer and vapour recovery, equipped with emergency shut-down and release systems and quick connect/disconnect couplers
- nitrogen purging facilities to drain the gas loading arms after use
- loading arm power pack and controls
- gas and fire detection and fire fighting equipment and fire monitors
- gangway tower for ship access
- life-saving equipment
- a drainage system incorporating spill containment
- space for maintenance plant and equipment
- a small boat landing.

The jetty will accommodate an access roadway, pipe racks and electrical cabling. The approach trestle and loading platform will be constructed with a steel open pile design and the height will be sufficient to avoid wave forces on the underside of the deck. The access roadway and loading platform deck will most likely be constructed of pre-cast concrete units fabricated off-site and lifted into position from construction barges. The jetty will also support a diesel powered seawater fire pump which will provide backup firewater to the gas processing facility in case of emergency.

The Joint Venturers have considered alternatives to the base case for the jetty design as described in Box 6-7, but the option of using a cryogenic line has been ruled out.

Shipping Channel and Turning Basin

The LNG carriers will require safe access via a shipping channel. The safety of the approach is determined by aspects such as depth, width, alignment and the presence of other marine traffic. The location of the proposed LNG loading berth has been developed in consultation with the Barrow Island shipping pilots, and is located several kilometres from the existing crude oil loading mooring.

The minimum required depth for the LNG carriers will be 14 m relative to the chart datum to allow access/egress at any tidal condition. The approach route will have an alignment as straight as possible with any bends at least 1000 m radius, if bends cannot be avoided. The approach channel will require a minimum width of approximately 300 m. The channel will be equipped with appropriate navigation aids. An exclusion zone will be established around the LNG jetty and channel in accordance with industry guidelines. The proposed shipping channel and turning basin are shown in Figure 6-10.

During the operations phase the Barrow Island port will be controlled by a Loading Master/ Harbour Master who will control all activities within the port limits. During construction, these duties will be assumed by a Marine Operations Manager, or similar role.

Box 6-7:
Jetty Alternatives

Alternative	Considerations vs. Base Case
A conventional jetty to deeper water.	• Higher capital cost • Longer construction schedule • Less dredging
A simpler trestle structure to deeper water.	• Lower or neutral capital cost • Higher operating cost • Less dredging • No vehicle or personnel access to loading platform • Not as safe
Subsea cryogenic pipeline technology	• Capital cost slightly less or neutral • Higher operating cost • Less dredging • Unproven technology

During severe adverse weather conditions, LNG ships and condensate ships will be either diverted, delayed, or released to avoid being caught in shallow or confined waters. Tugs will also be released to avoid the weather. During severe adverse weather conditions, construction vessels will shelter in the Dampier archipelago, which is common practice in the region.

6.2.10 Supporting Facilities

The key facilities to support the gas processing facility are outlined below.

Administration and Maintenance Facilities

An administration building and maintenance facilities will be constructed either within the gas processing facility site, or in the vicinity. This area will contain offices and workshop facilities for the maintenance of the gas processing facility equipment. Some of these facilities may be shared with the existing oil operations on Barrow Island.

Accommodation

The main operations workforce will be accommodated on Barrow Island. The location of the accommodation for the operations work force is still under consideration and may be within an extension to the existing camp or within a dedicated section of the proposed construction village. Refer to Section 6.3.6 for details on the site selection process, and additional details on the construction village. A portion of the construction village will be retained to support potentially larger maintenance campaigns, such as planned shut-downs, or to support construction of future expansions.

Diesel Supply

A diesel storage facility and distribution system will be required for the operating phase of the proposed Development. Diesel will also be required during the construction phase and this is discussed in the construction section of this chapter. The diesel required by the gas processing facility will supply the back-up firewater pumps and emergency generator and similar equipment, and supply the vehicles and other equipment required to support the operation on Barrow Island.

The diesel will be stored in an above-ground tank, bunded to Australian Standard AS1940. The tank size will be determined during later phases of design, but is likely to be relatively small (currently expected to be in the order of 30 m^3). A bunded area will also be provided for vehicle refuelling and all diesel day-tanks. Pipes from the tank will distribute fuel to the various day-tanks associated with the emergency equipment, but alternatives such as distribution by truck are currently being considered. It is currently envisaged that diesel storage facilities will be above-ground. However, should below-ground tanks or piping be required, they will be designed in accordance with AS1940 and the Code of Practice CP4 – The Design, Installation and Operation of Underground Petroleum Storage Systems (Australian Institute of Petroleum 2002).

Diesel will most likely be supplied by trucks carried on barges which will be unloaded at the MOF, but there is potential for diesel to be bunkered in barges and pumped to shore.

The option to produce a diesel-like fuel on Barrow Island from the local crude oil was explored. This would have avoided the need to handle diesel from the mainland but following further investigation was not considered feasible.

Resupply of fuel to support vessels will be undertaken at the mainland and at the MOF. Dry break couplings will be used on bulk diesel transfer lines.

Roads

The construction of the gas processing facility will require the re-alignment and upgrading of several existing roads on Barrow Island. These upgrades will be between the proposed gas processing facility and the construction village. The upgrades will involve widening, grading and sealing. These upgrades will increase the safety of the road for both personnel and fauna due to increased visibility. Paving the main roads will also reduce dust generation. Strict procedural controls will be placed on drivers to minimise environmental impacts, such as when driving at dusk or dawn. Stormwater runoff management will be a criterion in the design to ensure potential for scour is minimised and pooling on the sides of roads is reduced. These aspects are discussed in more detail in Chapter 10.

Interconnections with Existing Operations

There are likely to be a number of interconnections with existing facilities on Barrow Island, such as:

- condensate loadout
- power supplies
- water injection systems
- water supplies
- communications
- construction fuel gas supply.

Where possible, these facilities will be installed along currently disturbed areas (e.g. power lines along existing roads), or along a common corridor, to reduce environmental impact.

6.2.11 Mainland Supply Base(s)

Logistical support facilities are required to support both offshore and Barrow Island operations. Mainland supply bases (Figure 6-11) will allow for consignment, loading and refuelling of support vessels and subsea construction vessels (if adjacent), storage of construction materials, and offloading of deliveries requiring transport and the return of waste. For these facilities the preferred option is to utilise existing facilities that either meet the construction requirements, or that can be upgraded readily. The exact location and nature of the facilities have yet to be decided; however, it is anticipated that existing infrastructure in the King Bay area near Dampier and at the Australian Marine Complex south of Perth may be utilised with various locations in the Perth metropolitan area. The facilities will incorporate lay-down and storage areas, warehouses, quarantine facilities (such as wash down bay, fumigation facility, inspection pit, etc), administration and wharf facilities (if adjacent), together with appropriate waste management systems and waste water collection and treatment systems. These facilities will also support the Development quarantine management system, and will have security surveillance.

Should a new supply base(s) be required, then these will be the subject of a separate approval.

6.2.12 Estimated Land Use

The *Barrow Island Act 2003* establishes the basis for land available to be cleared for gas processing and associated infrastructure. The Development team is actively managing land requirements on Barrow Island to minimise footprint and vegetation clearing. The land required for the Development will be monitored during later phases as the design progresses. Table 6-3 presents an estimate of land requirements against the allocation stipulated in the Barrow Island Act.

6.3 Construction Activities

6.3.1 Construction of Offshore Wells

The initial development phase for the Gorgon gas field is anticipated to require 5–10 wells to be drilled. Additional wells in the Gorgon gas field will be drilled over the next 30 years, with the final number expected to be in the order of 18–25 wells.

Drilling requires approval by the Western Australian Department of Industry and Resources (DoIR) under the Commonwealth *Petroleum (Submerged Lands) Act 1967* (P(SL)A). Detailed Environment Plans, Oil Spill Contingency Plans and drilling fluid management procedures will be produced as part of this process.

Wells will be drilled in groups to optimise the efficiency of rig operations and to minimise footprint on the seafloor. Most wells will be drilled using directional drilling technology as it will allow the clustering of wells and subsea facilities. Drilling will be undertaken using typical offshore petroleum industry equipment such as semi-submersible rigs (Plate 6-1) or drill-ships (Plate 6-6), which are anchored on location.

The drilling process commences with boring a hole (typically in the order of 1 m diameter) in the seabed to a depth of approximately 150 m. A steel liner (tube or ‘casing’) is then placed inside the hole and cement is pumped through the steel liner and allowed to flow back up the annular section to fill the gap between the hole and the liner.

Figure 6-11:
Proposed Mainland Supply Base Area in Karratha

Table 6-3:
Estimated Land Use

Estimated Land Use (ha)*			
Barrow Island Act 2003 reference	Gas Processing Clause 6(2)	Pipeline Easements Clause 6(3)	Future Development Clause 6(10)
Land Allocation	150	50	100
Development Component			
Gas Processing and Associated Facilities	142**		55
Onshore feed gas pipelines		40	
CO_2 injection pipeline	8		
Total	150	40	55

* *These figures are approximate only and may change during design phase. Any changes will be maintained within the allocated limits.*

** *Includes 35 ha for CO_2 wells and monitoring*

When the cement has set, a smaller diameter hole is then drilled through the bottom of the cemented liner and continues to a depth of approximately 1000 m. At that point another liner (slightly smaller than the new hole) is placed inside the hole and cemented in place in a manner similar to the first. This process of ever decreasing sizes of hole and liner continues until the reservoir section is reached.

During the drilling process, the rock (or ‘drilled cuttings’), which is crushed and ground by the drill bit, must be continuously removed from the hole. This is achieved using a specially formulated drilling fluid. The fluid serves many other purposes such as to cool the drill bit and ensure the reservoir fluids are controlled once this section is penetrated. Equipment is provided on the drilling rig to pump the drilling fluid down through the drill pipe and drilling bit, and then when it returns to the rig other equipment separates the drilling fluid from the cuttings. The fluid is re-used as much as possible and the cuttings discharged overboard.

It is currently proposed that a water based drilling fluid will be used for the majority of drilling activities for the proposed Development. However, a synthetic based fluid may be required for technical reasons in the lower section(s) of some wells. These synthetic fluids are frequently used in the north-west of Australia and around the world. Should a non-water based mud be required, then cuttings driers will be considered in line with current best practice in the region, and details will be provided in the Environment Plan.

Drilling fluids, cuttings and other drilling wastes to be discharged during drilling activities are discussed in more detail in Chapter 7, while the associated environmental impacts and their management are covered in Chapter 11.

Plate 6-6:
Typical Drill Ship (Courtesy: Deepwater)

6.3.2 Construction of Onshore CO_2 Injection Wells

The onshore CO_2 injection wells will be drilled using a similar process to that described above for the offshore production wells, but using a rig similar to that shown in Plate 6-7.

The drilling operation will also require the following:

- access roads for personnel and equipment
- water and other materials required for the drilling fluid
- a level work site on which to place the rig
- excavated and lined pits or tanks in which to store fluids
- facilities to remove cuttings from the drilling fluid
- systems to manage cuttings disposal
- facilities to enable each well to be cleaned up.

The proposed safeguards associated with drilling are proven and environmental management processes well established on Barrow Island. However, the Development team is currently examining alternatives for cuttings disposal to meet current day practices and international best practices. The options being considered include: cuttings re-injection, chemical flocculation, stabilisation with cement (such as for use in earthworks associated with the gas processing facility and associated infrastructure), collection in skips or dedicated bulk bags for disposal on the mainland or for storage until future disposal options are developed.

One of the critical components of the CO_2 injection wells will be the CO_2 resistant cement used to fix the casing in place, and to avoid the release of CO_2 via the wells. CO_2 leakage is discussed in more detail in Chapter 13.

Details of, and the rationale for, the selected alternative will be included in the drilling approval documentation.

6.3.3 Construction and Installation of Subsea Systems

The following section describes the installation of the various components that will collectively comprise the subsea facilities.

Subsea Trees

The subsea trees will form the interface between the well and the seabed facilities and will be installed by the drilling rig as part of the drilling process. Rigorous

Plate 6-7:
Onshore Drilling Rig

safety and functional tests will be carried out at that time to ensure that pressure integrity is achieved and that all safety and control systems are working correctly.

Cluster Manifolds and Pipeline End Manifolds

The manifolds will be designed and built so that they can be installed by a drilling rig or construction vessel with suitable crane and deck space capacity.
The current manifold design is based on a piled foundation concept.

In this case, the drilling rig or other construction vessel will install one or more piles in the seabed. Then the manifold assembly (Figure 6-2) will be lowered to the seabed and latched on to the top of the pile foundation at the seabed. Other options, such as skirt foundations, are also being examined but further geotechnical work is required to enable this decision to be confirmed. Other concepts will have a similar environmental effect.

Plate 6-8:
Remotely Operated Vehicle (Courtesy: COVUS Corporation)

Suitably equipped Remotely Operated Vehicles (ROVs), similar to that shown in Plate 6-8 and other construction equipment will be used to tie-in the connecting flowlines and control umbilical jumpers between each tree and the manifold.

Umbilical Bundle

The control umbilical bundles, which will interconnect and control the subsea facilities, will be loaded onto specially modified construction vessels, similar to those shown in Plate 6-9, and installed progressively from the gas processing facility to the offshore wells. Umbilicals will be reeled off the vessel's deck to the seabed and pulled through pre-installed conduits at the shore crossing. The vessel will then move away from the shore and pay-out the umbilical, laying it on the seabed in a corridor close to the subsea flowlines and pipelines. The length of time that the vessel will operate near the shore is expected to be limited to a few days.

At the gas field, the umbilical will be laid on the seabed close to the Pipeline End Manifold (PLEM), pulled in and connected to the subsea facility using an ROV deployed from the construction vessel. Once connected, the umbilical and the control system it serves will be pressure-tested and function-tested to ensure all safety and production systems are operating correctly.

6.3.4 Construction of the Feed Gas Pipeline

Pipeline fabrication facilities in Australia are not currently able to produce pipe to comply with the Development's requirements. As such, it is anticipated that the pipe will be manufactured overseas. The pipeline will comply with AS 2885 (onshore) and appropriate International codes, such as DNV OS-F101 (offshore).

The pipe will be coated either overseas, in Australia or in Western Australia. If coating is undertaken in Australia, a coating area will be required on the Australian mainland for up to two years. Subsequent approvals will be sought for this area as required, by either the Joint Venturers, or contractors acting on their behalf.

Plate 6-9:
Typical Offshore Installation Equipment (Courtesy: Clough Limited)

Construction of the Shore Crossing

From approximately 150 m inland at North White's Beach to approximately the 12 m water depth contour, the pipelines will be located underground. The installation technique used to achieve this will be HDD (Figure 6-12 and Plate 6-2). This involves establishing a construction site at the entrance point onshore and then boring a hole of approximately 1 km in length to the subsea exit point. The majority of the drill cuttings and drilling fluids will be separated at the onshore end, while the separated drilling fluids will be re-used, and the drill cuttings set aside for disposal.

At completion of the hole-boring operation, the pipelines can be passed into the hole. A key advantage of the North White's Beach site is that it allows pipeline stringing to take place onshore behind the HDD holes, and the pipe can be fed down the hole from onshore to offshore using a pipe thrusting machine. An additional length of approximately 300 m will be fed through and left on the seabed for recovery by the pipeline construction vessel.

At the subsea exit point, a small amount of jetting or rock dumping will be required to create a gentle transition from the exit angle to the natural seabed contour to prevent a large unsupported pipeline span being generated as shown in Figure 6-13 and Figure 6-14.

The shore crossing construction is anticipated to take up to 12 months to complete. The drilling operation is estimated to take between 3–5 months, with the remainder of the time involving site preparation work, pipeline installation and site rehabilitation.

It is currently envisaged that in the offshore area close to Barrow Island, the feed gas pipelines will be separated as shown in Figure 6-14. The spacing is only 5 m apart at the entrance point onshore and the holes fan out to approximately 10 m at the exit point. There are drivers to have the spacing as close as possible such as to facilitate recovery of the pipeline by the lay barge, keep the drilling in similar ground conditions, and minimise land use. However there is a practical limit of how close the lines can be positioned, this is due to the survey equipment used and the potential

Figure 6-12:
Schematic of HDD Procedure

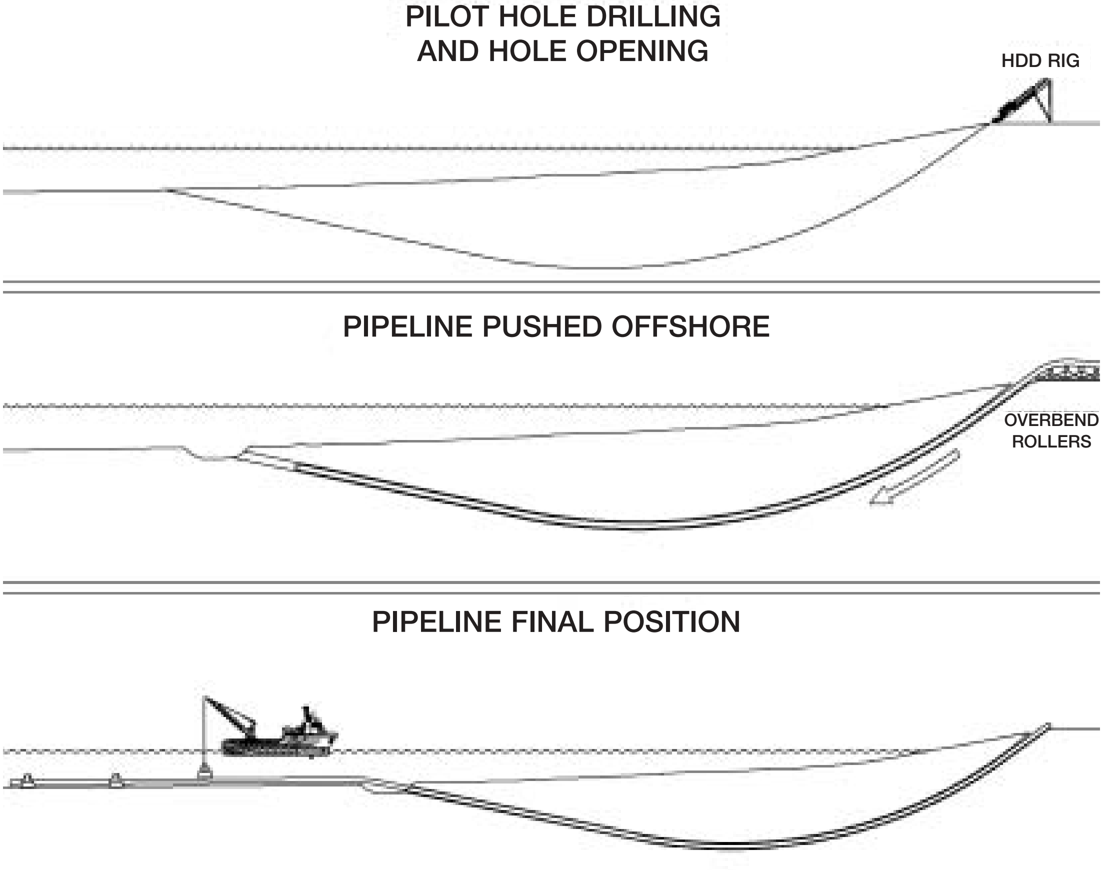
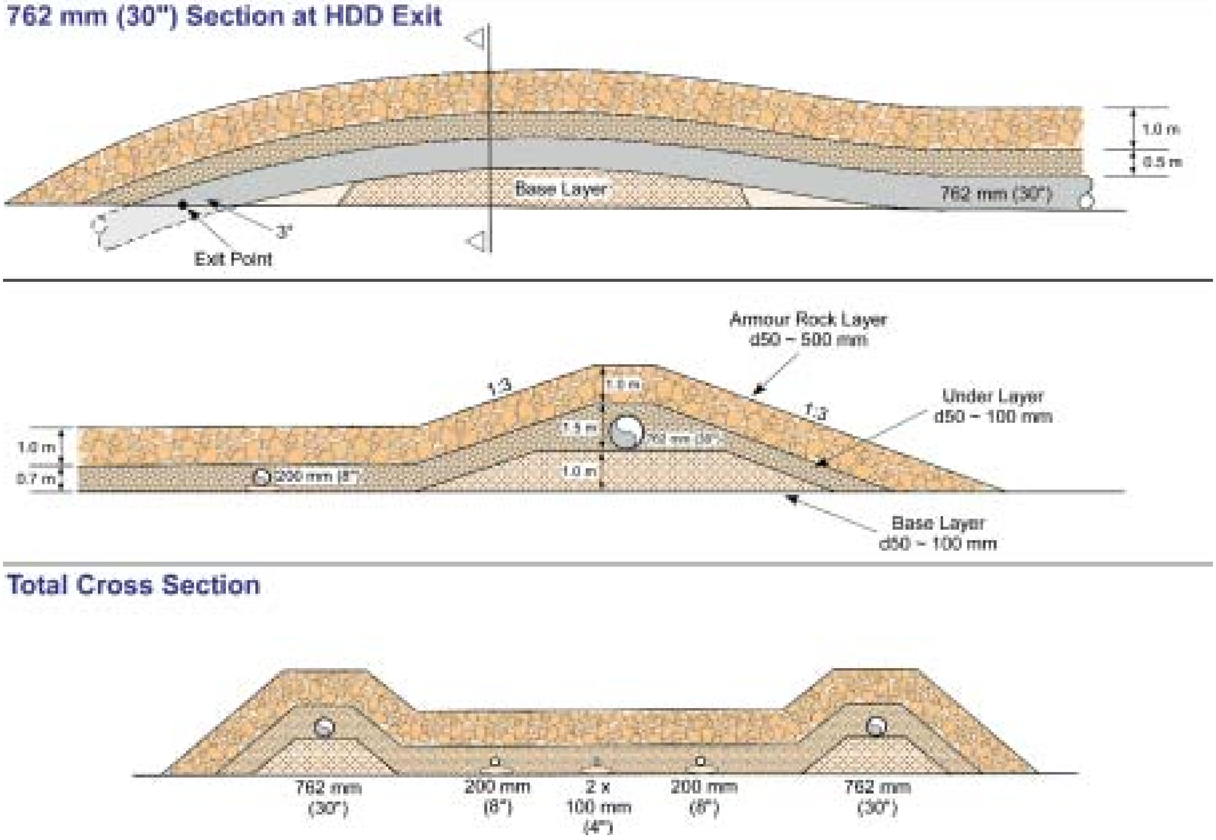


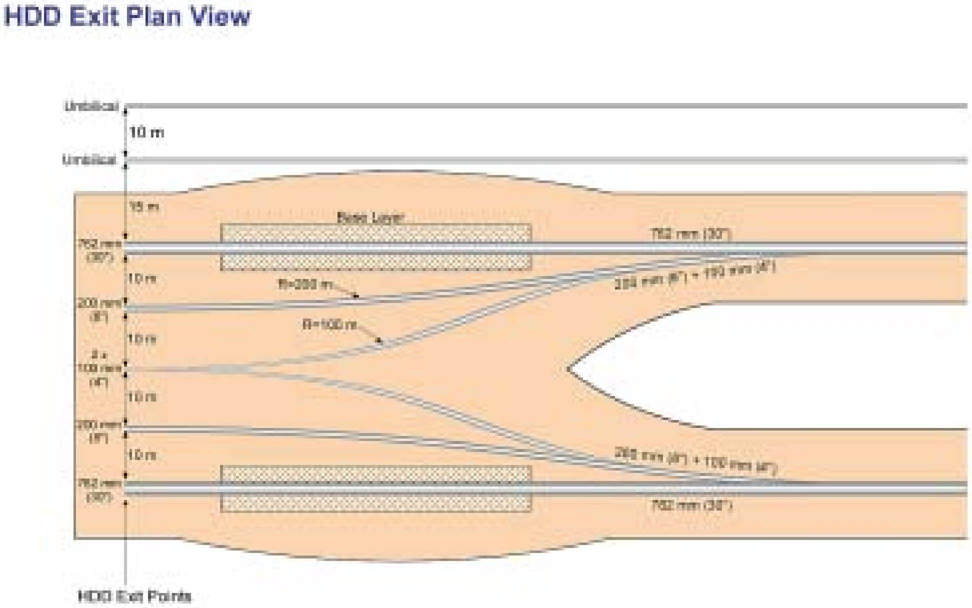
Figure 6-13:
HDD Breakout Point



762 mm (30") Section at HDD Exit

Total Cross Section

Figure 6-14:
HDD Operation in Plan View



HDD Exit Plan View

positioning error. There is also magnetic interference to the survey equipment when drilling along side installed pipelines if the holes are too close together. This spacing offshore is also required to enable the installation vessels to safely return to install future feed gas pipelines while installed feed gas pipelines remain fully operational.

The pipeline lay barge will need to approach within approximately 1 km of the shore in order to recover the pipeline tail (i.e. 300 m section). In this area, at least 6–8 anchors will need to be deployed (3–4 either side) to hold the vessel on location. If the pipeline construction vessel is not dynamically positioned then anchors will need to be routinely reset as the pipeline is installed. In shallow water the anchors will need to be reset more frequently than in deep water.

Away from the immediate shore crossing area, the pipeline will be installed from a pipe-lay barge (Plate 6-10). The pipe-lay barge will be utilised for welding the pipeline lengths together and stringing them across the seabed. The shallower, near shore sections to approximately the 40 m depth contour (approximately 15 km), will most likely be covered with rock to stabilise the exposed pipeline.

Plate 6-10:
Typical Pipe-lay Barge

Shore Crossings

The areas required for construction will be limited to the minimum practicable area necessary for safe operation. Where feasible, activities will be conducted away from shore areas. To facilitate the pipeline installation, and provide area for construction equipment, laydown, and other temporary works, an area of approximately 4 ha may be required close to shore (which includes land use for future expansion).

6.3.5 Construction of the Onshore Feed Gas Pipelines

The installation of the onshore pipelines will be performed in a manner that causes minimum ground disturbance and optimises rehabilitation potential. The feed gas pipelines, auxiliary lines, CO_2 injection pipeline, water lines and domestic gas pipeline will all be installed in a broadly similar manner.

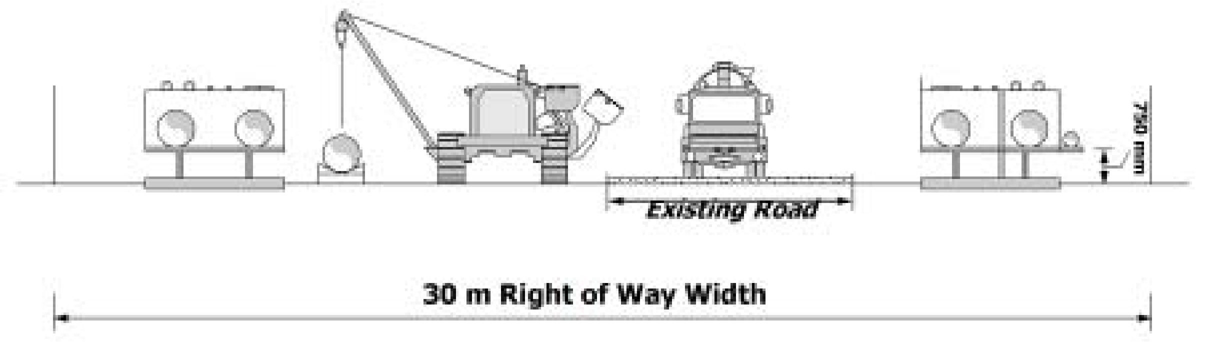
The feed gas pipeline construction activities will be located within a 30 m easement, but as the design develops endeavours will be made to improve on this. This width will provide adequate space for short-term stockpiling of vegetation and topsoil where it exists, as well as safe manoeuvrability for construction machinery and associated traffic. Vegetation along the easement will be slashed to prevent outbreak of fire associated with welding and promote successful regrowth. The easement will be graded, where necessary, to provide a safe and level working area and to minimise the potential for impacts associated with water runoff, such as erosion and sediment transport. Easements for smaller lines will be much smaller.

The onshore feed gas pipelines will be separated by a distance that allows safe installation of future lines while the existing lines remain fully operational. This distance, which will be determined as the design develops, will also provide sufficient access for future maintenance and inspection programs to be carried out.

Once the access has been completed as required, the foundations for the pipeline supports will be installed. To achieve this, holes will either be drilled or excavated for the plinth foundations. The plinths can then be installed ready for the pipeline supports.

Pipe sections will be strung alongside the supports. The pipe ends will be prepared (which involves grinding and heating) and welded together. Welds will be inspected by visual examination and radiography so that any defects can be detected and repaired. The pipe will be lifted into place on the supports by a series of pipe-lifting machines holding the pipe in slings. An alternative is to lift the larger pipe diameters individually onto the pipe supports and weld them in place. The pipeline installation technique is illustrated in Figure 6-15.

Figure 6-15:
Pipeline Installation Technique



6.3.6 Construction of the Gas Processing Facility and Infrastructure

Construction of the gas processing facility will take almost four years. Given the complexity of the facility, the numerous equipment items which will be installed, and the preliminary nature of the construction planning at this stage, it is not currently possible to provide a full description of the construction process. However, the process used will be consistent with the current industry standard for developments of this type, such as most recently used on North West Shelf LNG Train 4 on the Burrup Peninsula. To reduce work and workforce on Barrow Island, it is likely that some equipment will be brought to the island as prefabricated packages. The actual configuration for each section of the gas processing facility will be determined as the design proceeds.

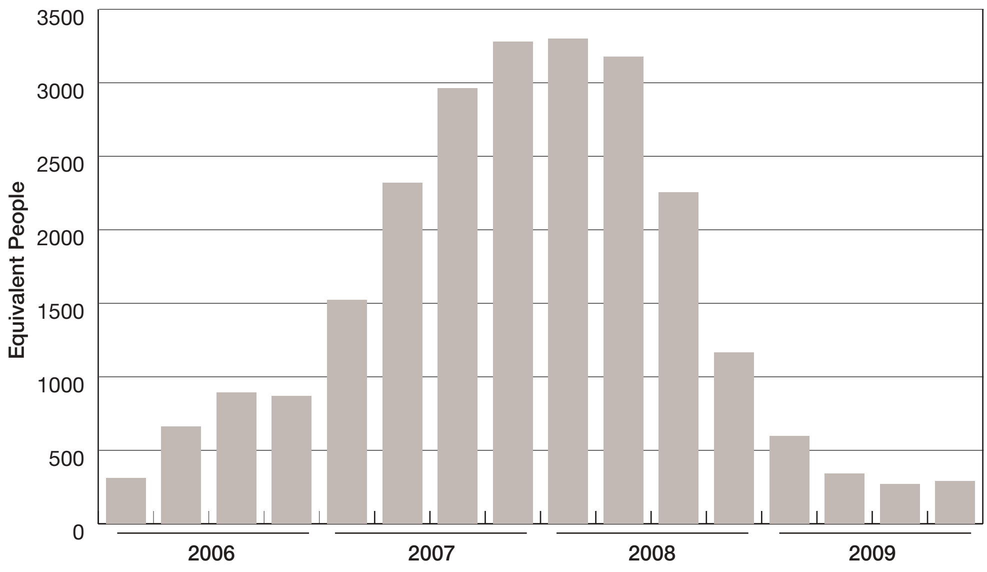
Site establishment works will dominate the early stages of the proposed Development to prepare for the main construction activity on the gas processing facility. This work includes construction of a construction village, site preparation works, the MOF and other infrastructure as described below.

Workforce and Accommodation

Figure 6-16 illustrates the estimate of the expected workforce size over the construction period. It shows a ramp up from 2007, a peak is expected to occur during 2008, then the numbers taper off to the level required for steady operations.

Most of the personnel involved in marine activities such as drilling, pipe-laying, dredging and transportation will be accommodated on their

Figure 6-16:
Estimate of Barrow Island Workforce



respective vessels. These crew will not require routine access to Barrow Island, but if they do require access to the island for any reason they will be subject to the full quarantine requirements discussed in Chapter 12.

Approximately 140 additional crew will also be required at the mainland of which around 95 people will be working at any time during the peak of construction. There will also be approximately 70–90 personnel operating barges and tugs, with 50–60 working at any time during the peak of construction.

Pioneer Camp

The existing oil field operations camp currently has the capacity to support a workforce of approximately 200 personnel. A pioneer camp is required to accommodate an additional workforce of approximately 250 people.

The additional workforce will undertake mobilisation activities, site preparations, installation of the main construction village and associated utilities and other infrastructure required for the proposed Development.

The pioneer camp will require additional amenities such as water treatment, sewage treatment and waste management.

This workforce will also require approximately one additional flight to Barrow Island per week.

The pioneer camp does not form part of the proposal covered by this Draft EIS/ERMP as it will be constructed during the EIS/ERMP assessment period and will be subject to a separate approval process. The camp has been included here for completeness and to allow consideration of cumulative impacts.

Construction Village

The existing camp on Barrow Island including pioneer facilities will be too small to accommodate the expected number of people required to construct the gas processing facility and associated infrastructure or to operate the facilities on a long-term basis. Therefore a construction village will also be required.

A construction village will be established to cater for a peak workforce of approximately 3300 personnel. It is envisaged that approximately 12 additional flights will be required to Barrow Island each week and approximately two bus trips per day from the airport to the village and return during the peak of construction. If a decision is taken to evacuate the site for a cyclone, (an average of six are announced per year but not all require evacuation), it will require approximately 38 additional flights from Barrow Island. A similar number of flights will be required to return the workforce to Barrow Island after the cyclone passes. An option which is currently being investigated is to upgrade the design of facilities so personnel do not have to be removed from the island.

A section of the village will be designed as a permanent installation to support large-scale maintenance campaigns, or as an operational village. Decommissioning of the village will be assessed based on foreseeable work and requirements.

The construction village will require facilities and utilities such as:

- power generation
- water supply
- waste water management
- sewage treatment (with connection to the water injection system)
- recreational facilities
- mess facilities
- laundry
- bus parking facilities
- incinerator
- other waste management facilities
- medical facilities
- fire station
- telecommunications (including internet and phone).

Box 6-8:
Floating Accommodation Concept

Floating accommodation in the form of a ‘floatel’ or converted cruise ship was considered as an option for the construction workforce. However this option was discarded for several reasons, including logistics, quarantine aspects, industrial relations, and safety issues. The problems include moving personnel from the accommodation to shore, as the vessel will be located some distance offshore due to the vessel draft requirements. During a cyclone, all personnel would require evacuation from the vessel. Further, the vessel may need to be moved to a safe harbour or out to sea to avoid being in the path of the cyclone.

Where technically and economically feasible, the utilities and infrastructure installed for the construction village will be designed to meet the requirements of the gas processing facility.

An alternative considered for accommodating construction personnel is discussed in Box 6-8.

A detailed study was undertaken to identify alternative locations for siting of the construction village to support approximately 3300 people. The study involved:

- determining site evaluation criteria and assigning a level of significance
- analysing the relative values of each site in accordance with the evaluation criteria and short listing priorities
- undertaking ecological surveys of the priority sites and assigning values
- ranking each site
- reviewing the process, criteria and findings with stakeholder groups.

The factors used in the construction village site selection process included:

- topography (geotechnical issues, geology, earthworks, drainage requirements, effects on existing drainage)
- buffer distance to the gas processing facility (risk and noise, travel time, air quality, visual amenity, aircraft noise)
- proximity to associated sites (LNG plant construction site, airport, new roads, old airstrip and laydown areas)
- supply of infrastructure (electricity, water, sewage treatment, telecommunications)
- environmental aspects (potential for road kills, light spill, existing vegetation cover, rare and endangered flora and fauna, cultural heritage sites)
- exposure to weather (prevailing weather conditions, cyclone exposure and height above sea level)
- effects on existing infrastructure (old air strip, lay down area, gas/oil lines and facilities, water pipelines, power cables/overhead lines).

A total of seven sites were identified (Figure 6-17) to be of potential interest, and these were:

- LNG (basecase)
- CVX Camp Site 2
- Old Airstrip
- CVX camp Site 1
- Dove Point
- Airport
- Howard’s Landing.

The airport site and Howard’s Landing were eliminated due primarily to their remoteness from the proposed LNG construction site and the resultant economic implications for supply of infrastructure.

Dove Point was eliminated due to its remoteness, requirement to establish new roads, potential to fall within noise limit boundaries and its significant potential for light spill onto beaches which could adversely impact turtles. Dove Point scored lowest on the latter aspect.

Four priority sites remained to undergo a detailed ecological survey. Preliminary findings showed that the majority of flora and fauna species identified are representative of the composition and diversity across Barrow Island.

The combined assessment included safety and environmental considerations and ranked all sites similarly overall, however not all sites are equal in all respects. Sites closer to the existing Chevron campsite offer reductions in site works and opportunities for synergies with that camp, but present increased service routes and travel distance to the gas processing facility. The Old Airstrip campsite is closer to the LNG site, but also close to oilfield production facilities and as it is low lying it is susceptible to inundation.

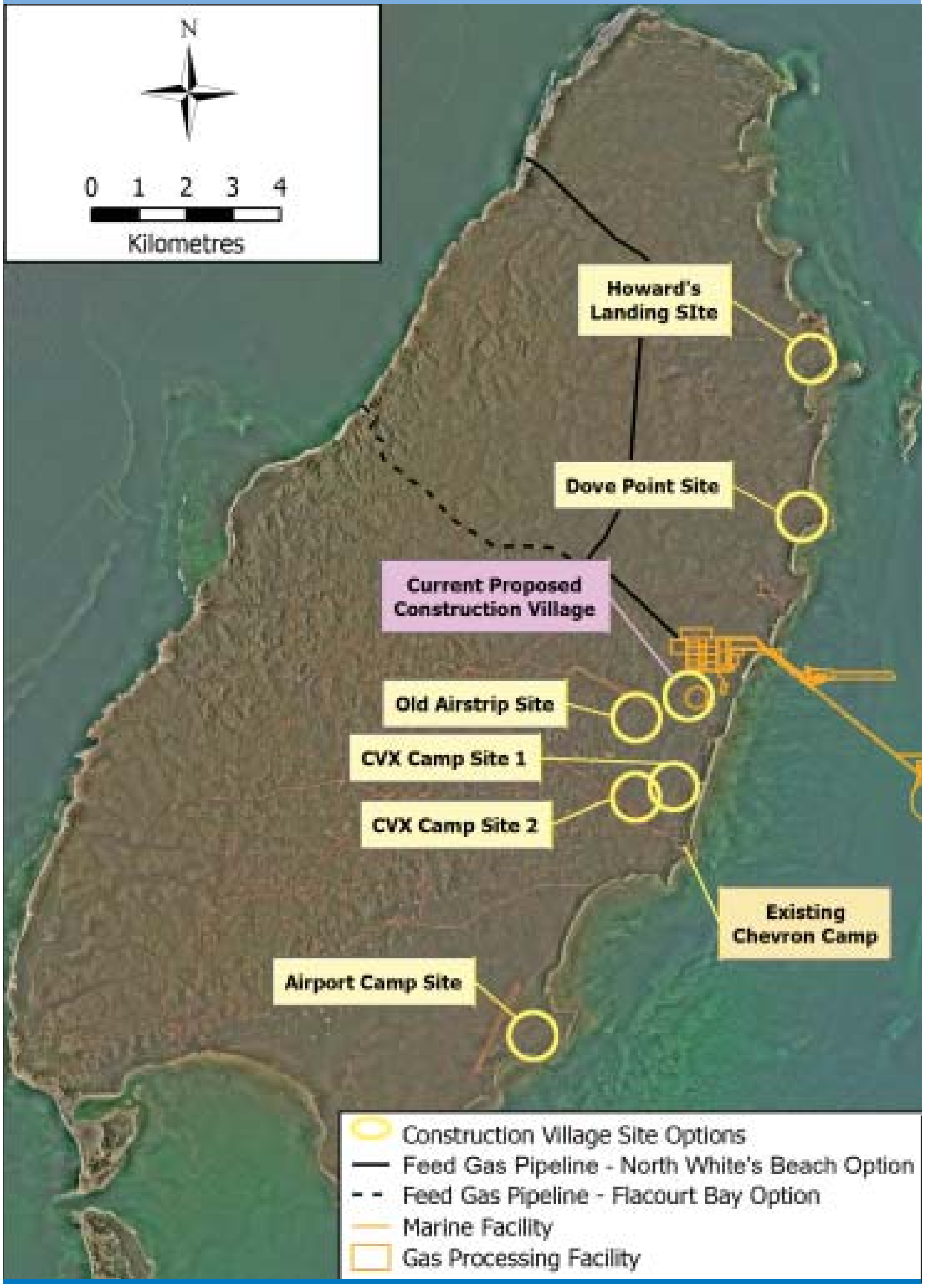
Further work will be undertaken in later phases of Development to narrow this selection to one site on the basis of equal or reduced environmental impact, social and economic factors.

Further details on the utility requirements are provided later in this chapter.

Site Establishment Works

Site preparation will commence with clearing by dozers, together with drilling and blasting of rock. This rock will be used as fill within the site area, as road base material and for the MOF. The approximate volume of material to be excavated and filled is 1.5 million m^3. Sand and aggregates required for concreting, service trench bedding and other needs will be met either by material from the facility site or imported from third-party operated quarries on the mainland. No new quarries or borrow pits will be created for the Development on Barrow Island.

Figure 6-17:
Potential Construction Village Sites



Earthworks around the airport may also be required for potential extensions to, and realignment of, the runway and any expansion of the terminal.

Plant Construction

The equipment required for the gas processing facility will be sourced locally, nationally and internationally, depending on the nature of the equipment and local availability. The larger processing vessels and equipment items, such as the main cryogenic heat exchanger and gas turbines, will be prefabricated prior to delivery to site. Preference will be given to sourcing materials and equipment locally where economically and technically practicable.

Following completion of the bulk earthworks, construction will commence on utility trenching and foundation installation.

Construction will require the use of lay-down areas for staging of equipment delivered by barges at the MOF facility. Construction will require the use of several large cranes and a concrete batching plant. Activities during the main construction phase will include steel and pipe erection, equipment setting, welding, electrical and instrument installation, along with insulation and application of coating materials.

During construction, various workshops and other temporary buildings such as offices, and warehouses will be required.

To ensure future expansion options are not technically compromised, the initial Development will include various works, such as:

- piping corridors – the location, layout and design of piping corridors will allow for installation of additional feed and product pipes alongside operational pipelines
- plant layout – the plant layout will account for the construction of the additional facilities next to an operational facility
- LNG tank pads – if blasting is required for the foundations associated with the additional LNG tanks required for a potential plant expansion, the necessary blasting will be undertaken during the initial phase of development.

No additional condensate tanks are envisaged for potential future expansion options as any increase in production could be accommodated by an increase in the frequency of off-take tanker movements.

Construction Utilities

A single utilities area comprising power generation, fresh and potable water plant and waste water treatment facilities and fuel storage will be established to accommodate the construction utilities plant. The utilities area will be established at an early stage to support early construction activities and provide services to the construction village.

The preferred location for the utilities area is either near the construction village or near the gas processing facility site. A utilities corridor will be established between the utilities area, the construction village and the gas processing facility to house the various services.

Utilisation of the existing infrastructure on Barrow Island will be considered to realise potential synergy opportunities where the existing operation can provide such utilities and services.

Water Storage

Two of the existing crude storage tanks on Barrow Island are redundant and are currently out of service. It is proposed to refit these tanks and utilise them to store treated construction water and potable water for commissioning activities. This will include installation of impervious liners within the tanks.

Tanks will also be provided within the utilities area and within the construction village to store potable water.

Sanitary Waste

Sanitary waste water systems are required to support all phases of the works from site preparation and infrastructure development through construction to the operating phases of the Barrow Island gas processing facility. The facility installed during the pre-construction phase will be modified, as necessary, to support the permanent operations. Investigations are currently examining alternatives for split stream processing, whereby the black (toilet) and grey (all other) water systems are dealt with separately to enable re-use of the treated grey-water for construction purposes.

Treated effluent will be disposed of via one or a combination of the following systems/methods:

- re-use for construction, hydrotesting and/or land farming
- utilisation of the existing produced water disposal system
- injection to drilled deep wells.

The treated process water and the effluent from the demineralisation plant will be combined with the treated water from the sewerage plant and injected into subsurface formations below Barrow Island.

It is anticipated that sludge will be removed from Barrow Island and disposed of on the mainland.

Power Generation and Distribution

Power generation and distribution to support the construction workforce accommodation facilities, construction works and utilities will be required to be installed early in the construction schedule. Planning is underway to install a connection to the existing Barrow Island central power station. This connection would provide initial power and allow electricity transfer from the Gorgon Development facilities in the future. It is presently considered this approach would be able to service a construction workforce until numbers reached approximately 600 personnel by which time the Gorgon Development power station would be commissioned.

The power station will provide power to the two major load centres; namely the gas processing facility construction site and the construction village. The power station will be located in the common utilities area. Current indications put the power station peak demand at approximately 15 MW which will be generated in a multi-unit configuration. The final configuration is yet to be finalised, but emissions will be similar regardless of configuration.

The power generator drivers will be dual fuel (i.e. gas/diesel) machines; both gas engines and gas turbines will be considered as the design proceeds. Construction fuel gas supply will be sourced from the existing facilities. Diesel fuel will be used as an alternative fuel in the event that fuel gas is not available at any time.

A power distribution network will be established to distribute power from the power station to the construction village, to provide construction power to the gas processing facility and to provide a link to the existing power system. The distribution network will be run over pre-disturbed land as much as possible. The distribution system will be an overhead power distribution system, 'ABC' conductors (insulated conductors) strung on power steel and/or concrete power poles. The use of insulated conductors will alleviate the necessity of regular maintenance intervals that would normally be required using bare conductors.

Telecommunications

A communications network will be installed at Barrow Island to support the gas processing plant and the construction activities. The network will provide for radio, telephone and data links between most facilities on the island as well as providing a reliable link to the mainland by way of an optical fibre cable.

Two mainland landfalls locations are currently under consideration for the optical fibre cable. These include Onslow and Peedamulla, (which provides a shorter subsea route but a significantly longer terrestrial route).

The submarine section of the optical fibre route in each case will traverse relatively shallow and highly trafficked marine areas; a risk mitigation study may require that the cable be provided with some form of protection either locally or along the entire cable route. The principal method of protection will be trenching; however, in close coastal areas, other methods may be utilised. To protect the terrestrial section the cable will be buried over its entire length.

Landfall at Barrow Island will utilise areas that have been previously disturbed and/or within utilities corridors. The preferred cable landing point on Barrow Island is the Marine Offloading Facility but other previously disturbed areas may be considered.

Refer to Figure 6-18 for a proposed optical fibre route from Barrow Island to the mainland.

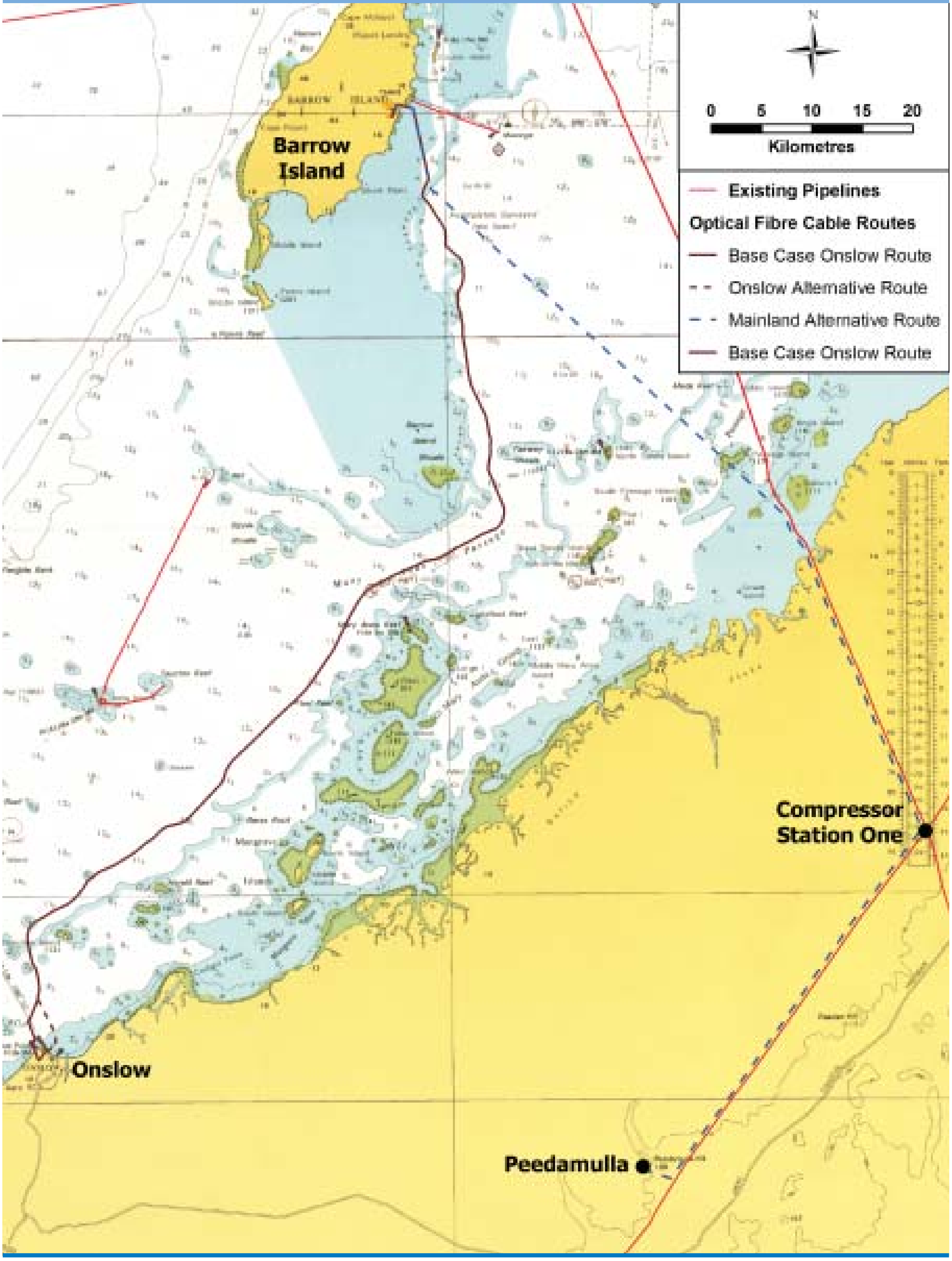
Diesel Supply

Diesel consumption during the construction phase has been preliminarily estimated at approximately 9 million litres. This figure excludes consumption that may be required for the new power station which is pending confirmation of gas supplies.

Diesel will be delivered to Barrow Island from the mainland via barges, which in the first instance will land at the existing barge landing. Later, as the MOF and associated facilities are commissioned, it will be used for fuel offloading as this will decrease the travel distance from the existing Barrow Island landing point to the major area of consumption.

For bulk storage, relocatable, self-bunded storage tanks designed, operated and maintained in accordance with AS1940 'The Storage and Handling of Combustible Liquids' and AS1692 'Tanks for Flammable and Combustible Liquids' will be used for storage volumes up to approximately 60 000 litres and

Figure 6-18:
Possible Routes for Optical Fibre Communications Link



may be used for as much as 100 000 litres. Alternative schemes for bulk storage will be considered in circumstances where the self-bunded tanks are either uneconomical or where permanent storage is required to support the operating phase of the Development.

Potable Water Supply

Potable water will be provided by a reverse osmosis plant or similar water making technology. A production capacity of 1000 m^3/day will be required with peak production capacity of approximately 1500 m^3/day fresh water output. The system will be designed to support all phases of the Development.

The most significant single requirement for water will be associated with hydrotesting the feed gas pipelines and the LNG tanks. This is discussed in the relevant sections for these activities.

Horizontal directional drilling will be used for the pipeline shore crossings, and this technique will also require a significant quantity of water (approximately 20 000 m^3) which would most likely be salt water, but may need to be fresh water depending upon the selection of drilling mud.

Three options are currently being considered for the supply of water to the water making facilities as discussed in Box 6-9.

Brine Waste Water Disposal

The water making process will produce approximately 3000 m^3/day of waste brine during peak fresh water demand. The waste water from the water making plant will be disposed of via one of two alternatives presented in Box 6-10. Options are currently being assessed.

Waste Staging Area

Various wastes will be generated through all stages of the Development as described in Chapter 7. The principles of 'avoid, reduce, re-use, and dispose in an environmentally responsible manner' will be followed. The principal focus will be on avoiding waste at the source by working with the suppliers in the tendering and contracting processes. Appropriate waste segregation and storage facilities will be provided, such as for food wastes (e.g. covered where possible to keep out fauna), scrap steel (i.e. for recycling), hazardous wastes (e.g. bunding for liquid wastes in line with relevant Australian Standards), and other similar appropriate facilities. These facilities will be designed in accordance with Australian Standards and incorporate best practice principles.

Box 6-9:
Water Supply Alternatives

Alternatives for the water supply that are currently being considered are:

- groundwater
- seawater
- the Dupuy formation.

One option is to provide source water from a new saline water bore field located close to the Development site. The design, location and number of the water extraction wells has not been finalised but it is anticipated that saline water will be drawn from Tertiary limestone aquifers at 150–250 m below the surface. The extraction rates and design of the well(s) will ensure that the halocline (freshwater/salt water interface) remains stable, and the associated draw down will be minimised, so that any impact to the freshwater lens is avoided or minimal. The water from this location is expected to have salinity similar to seawater.

Direct supply from the ocean will require dedicated infrastructure for the intake, consisting of a pipeline secured to the sea floor via rock anchors, burying or concrete mattresses, as the LNG jetty or MOF will not be completed when the water is first required for construction. The intake line will require chemical treatment, such as chlorine, to prevent fouling by marine organisms. A dedicated seawater intake (and offshore disposal of water maker effluent) is still being evaluated as an option. If this option is selected, the intake pipeline will be designed in accordance with good engineering practice and it is currently anticipated that the flow rates will be accommodated by a 300 mm line. The intake will be located away from areas of marine vessel activity in an area that remains submerged during low tides. It is possible, due to suction head requirements, that the intake will not be operable during some tidal conditions.

The third option is to drill wells deep into the sands of the Dupuy formation, potentially using the CO_2 injection monitoring wells. This option will provide a lower salinity water source than seawater or alternative groundwater which minimises the energy requirement of the reverse osmosis plant and avoids the need for the use of extensive corrosion resistant materials. The cost of drilling wells over 2 km deep, the temperature of the extracted water, the energy to pump from this depth and the risk of hydrocarbon contamination in the Dupuy formation is likely to

Box 6-9: (continued)
Water Supply Alternatives

result in this option being discarded. A data well into the Dupuy formation is being undertaken for CO_2 injection testing and the well will be completed to enable testing the Dupuy formation as a water supply option.

However, selection of this method of saline water extraction is dependent upon hydrogeological investigations, which are scheduled for the third quarter of 2005. The investigations will be focussed on:

- potential impacts to subterranean fauna habitat
- well design for extraction and re-injection
- definition of the fresh/brackish water lens, the halocline and the seawater interface
- sustainable yield of the Tertiary limestone aquifers for both the construction period, and ongoing operations
- aquifer parameters including permeability and porosity
- aquifer recharge
- groundwater extraction impacts including water quality and water table levels
- groundwater management procedures
- bore field design to maximise yield and reduce water level impact.

These investigatory water wells do not form part of the proposal covered by this Draft EIS/ERMP as they will be constructed during the EIS/ERMP assessment period and will be subject to a separate approval process. Information is provided here only to provide background to the reader.

6.3.7 Construction of Onshore Water Supply/ Re-Injection Wells

Onshore water supply and injection wells (if required) will be drilled using conventional water well drilling methodology, i.e. mud rotary drilling. Drilling mud, consisting of a suspension of bentonitic clay in water, is the most common drilling fluid used. This drilling mud coats the wall of the hole which provides stability of the hole and prevents the loss of drilling fluid to permeable formations. If the drilling mud cannot prevent the caving in of the walls, a well casing will be placed as the drilling proceeds. The wells will be drilled to approximately 350 mm diameter to install 200 mm diameter casing.

To support the drilling operations a pad of approximately 20 m x 40 m will be required and the following will also be required:

- access tracks for personnel and equipment
- water and other materials required for the drilling muds
- a level work site on which to place the rig
- excavated lined pits or tanks in which to store drilling muds and measure well yields
- facilities to remove cuttings from the drilling fluid
- systems to manage cuttings disposal
- facilities to enable each well to be cleaned up.

Box 6-10:
Alternative Brine Waste Water Disposal Options

The options for disposal of waste brine from the water making facilities essentially fall into two categories: injection and offshore disposal.

The injection option involves disposal of the effluent water into a formation approximately 200 m beneath Barrow Island.

The option for disposing brine from the water making system (i.e. reverse osmosis unit or similar) directly to the ocean is currently being investigated. This water will essentially be concentrated seawater and so will pose negligible environmental risk. The benefit of this option is that it avoids using up capacity of the injection system. The offshore disposal option would occur via an ocean outfall as is common practice and is currently being employed for the disposal of brine from the 500 m^3/day Rottenest Island potable water production facility. This method of disposal will be subject to further investigation to assess the requirements for pre-treatment additives (if any) and their impact. If this option is selected, a mechanism of diffusion will be employed to ensure suitable dispersion in the proximity of the discharge.

The alternative method of disposal of the brine is via re-injection wells drilled in a location close to, but sufficiently remote from, the saline source wells to avoid cross contamination of the groundwater. This option is being assessed as part of the groundwater assessment discussed above.

Refer to Chapters 7, 10 and 11 for additional details on these options.

6.3.8 Construction of Marine Facilities

A MOF will be required as early as possible in the construction cycle to move equipment and materials to Barrow Island. The initial equipment will be landed at the existing barge landing (Plate 6-11) until a landing can be developed at the MOF site.

The initial concept was to dredge a channel into a land-backed MOF wharf at Town Point using a cutter suction dredge and hopper barges, then disposing dredge spoil at nominated sites shown in Chapter 7.

However, investigations indicated that the material near the shore will need to be drilled and blasted prior to dredging. To reduce this impact, an alternative concept was developed to construct a causeway out into deeper water. While there is still a requirement to dredge, the material appears softer and the quantities have been significantly reduced from that expected in the original concept. Should any isolated pockets of hard material be encountered, it may be necessary to undertake limited drilling and blasting. However the existence of such material is not indicated in any of the geotechnical or geophysical investigations. It is currently expected that the MOF channel will require dredging of approximately 800 000 m^3.

The causeway and MOF head will be constructed from a core material, faced with armour protection. The core material will comprise a combination of cut material from preparation of the plant site and as much dredge spoil from the MOF channel as practical. This will alleviate the need to import core material from the mainland and reduce the amount of dredge spoil at the disposal site. Armour protection will comprise rock imported from the mainland and precast concrete units.

The construction will commence by utilising rock material from the site preparation to construct a containment bund around the perimeter of the MOF and causeway. The bund will be lined with a geotextile to prevent sediments dispersing through the bund. A cutter suction dredge will excavate material which will be piped directly into the bund area. Fine suspended particles will pass through the geotextile and overtop the bund as the infill material is dewatered by the construction process. This method alleviates overflow and propeller wash from hopper barges which would be required if offshore disposal was adopted.

Any remaining dredge spoil not accommodated within the bunded area will be transferred by hopper barges and deposited at the nominated dredge disposal sites shown in Chapter 7. However, the final design will be based on balancing the MOF size and dredge quantities.

Utilisation of dredge spoil onshore for general fill material is a practical engineering solution for the disposal of the material. However, this was discounted due to the salt content of the spoil potentially impacting the surrounding vegetation and/or the existing groundwater regime.

Figure 6-10 shows the proposed MOF and associated channel layout.

Plate 6-11:
Existing Barge Landing

Shipping Channel and Turning Basin

Dredging will be necessary to create a shipping channel and turning basin that is approximately 14 m deep (Figure 6-10). The current estimate of the volume of dredge material produced is approximately 9 million m^3. It is proposed that the channel will be dredged by removing unconsolidated material by trailer suction hopper dredge, then using a cutter suction dredge to break the hard material and load into hopper barges moored alongside the vessel. In order to further reduce the impact of surface turbidity, an alternative dredging method is being assessed which makes greater use of the trailer suction hopper dredge. This alternative method has the potential to minimise the abrasion caused by handling of the dredged material through pumps and pipelines. This method would also minimise aeration. The selection of the alternative will be based upon demonstrable reduction in predicted environmental impacts based on modelling, technical feasibility and equipment availability.

Should any isolated pockets of hard material be encountered, it may be necessary to undertake limited drilling and blasting. However the existence of such material is not indicated in any of the geotechnical or geophysical investigations. Further investigation drilling will be undertaken. For further details on management of dredging operations refer to Chapter 11.

Dredging from the LNG berth and turning basin areas is expected to result in 2–4 million m^3 of fist sized rock fragments and coarse sand. This material will be used elsewhere in the Development if feasible.

Jetty Construction

The LNG jetty will be installed with equipment similar to that shown in Plate 6-12. This typically requires a combination of drilling and driving jetty piles. Small plumes of drilling fluid and cuttings will be associated with these activities, but these are very low volumes.

To ensure potential future expansion options are not technically compromised, the proposed Development will include the following:

- Jetty location – the location of the jetty was selected such that the additional LNG ships associated with any potential future expansion can use the same approach channel.
- Jetty design – the location and design of the jetty will be such that an additional berth can be added to accommodate the additional LNG carriers associated with a potential plant expansion.

Maintenance Dredging

Modelling of three significant tropical cyclones indicated a maximum of 50 mm of sediment could be deposited in the dredged area as a result of the cyclonic conditions. This indicates a need for only infrequent maintenance dredging to remove these silts and maintain the required water depth. Dredged material will be disposed to the same location as the spoil removed during the original dredging operation.

Plate 6-12:
LNG Jetty Construction Equipment

6.3.9 Construction of the Domestic Gas Pipeline

The domestic gas pipeline will be constructed from the gas processing facility to Town Point extending along the MOF causeway and the jetty. From the jetty, the pipeline will be located on the seabed. One option which is currently being examined is the opportunity to install a conduit in the MOF structure through which the domestic gas pipeline could be installed.

As the pipeline approaches the mainland it will again be trenched, backfilled and stabilised for the shore crossing. Near shore, the pipeline will be laid using a shallow water lay-barge which minimises dredging requirements. Surface materials at the mainland shore approach are unconsolidated marine sediments. The current base case is to use the existing Apache Energy Gas Sales Pipeline approach to shore and the existing shore crossing on the mainland. Tidal variation will be used to maximise the shore crossing construction from the onshore side.

The onshore pipeline section to Compressor Station One on the Dampier to Bunbury Natural Gas Pipeline will be buried to a depth to allow for approximately 750 mm of cover except where valving stations are required. This section of pipeline will require an easement width of approximately 30 m and will be aligned parallel and adjacent to the existing pipeline through pastoral grazing land. The construction of the pipeline will be confined to the easement and will involve:

- clearing the easement, including retention of topsoil
- trenching, using either backhoe or wheeled ditching machine
- bending, aligning, welding coating (joints)
- non-destructive testing of the weld joints
- placing the pipeline in the trench
- backfilling the pipe trench, and restoring topsoil as far as practicable and installing surface breakers and water control structures as required
- hydrostatic testing of the installed pipeline
- remediating and revegetating the easement.

6.3.10 Installation of the Optical Fibre Cable

The main portion of the optical fibre cable will be installed using offshore vessels and shore crossing equipment which is broadly similar to that already discussed. Under the *Telecommunications Act 1997* all of the methods to be used are deemed ‘low impact’. The offshore component is expected to take less than two weeks to install. A preliminary desktop study has identified a preferred alignment based on computerised modelling of bathymetric and environmental considerations. A detailed submarine route survey is yet to be undertaken to determine the optimal alignment of the marine section of the route.

The mainland onshore section is expected to be buried below the natural surface of the ground using conventional earthmoving equipment.

6.3.11 Construction of Other Pipelines

The following pipelines will be installed in a manner that is largely consistent with that described for the fee gas pipeline:

- CO_2 pipeline
- onshore water supply/disposal pipeline(s)
- offshore water supply/disposal pipeline(s)
- new condensate loadout line
- common interconnections.

6.3.12 Pipeline Hydrotesting

Prior to operation, the feed gas pipelines, domestic gas pipeline, CO_2 pipelines, and auxiliary pipelines will be filled with treated water, leak-tested and pressurised to confirm their integrity in accordance with AS 2885 and other applicable codes. This will require approximately 35 000 m^3 of water for the feed gas pipeline. Fresh water will most likely be required to test the feed gas pipeline because corrosion resistant alloy pipe cannot withstand the high chloride content of seawater. Where fresh water is required, it will be sourced from the water-making facilities installed at the gas processing facility. Hydrotesting will also require approximately 5500 m^3 water for the domestic gas pipeline and additional water for the auxiliary pipelines. The water will be re-used between services where practicable.

Hydrostatic test (hydrotest) liquids will remain in the pipeline sections until they are discharged at the commencement of the pre-commissioning works (e.g. dewatering, swabbing, and drying if required). If the hydrotest liquids must be discharged to the sea, this will occur at a location and flow rate that will minimise environmental impacts. It is proposed that the feed gas pipelines and auxiliary lines will be dewatered from the Barrow Island end toward the offshore facilities to utilise the seabed profile and minimise the environmental impact.

Unlike the feed gas pipelines, the domestic gas pipeline is land-locked at both ends. Water will most likely be provided from Barrow Island because sourcing water from the mainland would create another quarantine pathway. The base case concept is that the domestic gas pipeline will be dewatered from the mainland towards Barrow Island, so that the maximum possible re-use of water can be made prior to being injected into the deep water disposal wells. Other potential options for disposing of the water from the domestic gas pipeline include to:

- pump the water to the mainland and store in a constructed bund, allow natural evaporation to occur and then reclaim the contaminants for disposal
- pump to the mainland and use road tankers to transport the water to a designated disposal site (which will require around 800 tanker loads)
- dispose of the water off the east coast of Barrow Island such as off the jetty at a rate which presents acceptable level of environmental risk.

Based on current technology, typical treatment chemicals which will be used as part of the hydrotest program include oxygen scavenger, biocide, corrosion inhibitor and a dye to detect any leaks. Chemicals used during the hydrotesting process will be pre-approved by regulatory authorities in compliance with the pipeline permit application and will be consistent with current industry practice. Minimum volumes of chemicals will be used and the toxicity of chemicals and potential disposal techniques will be considered during the selection process to avoid potentially adverse environmental consequences of testing and commissioning activities. All aspects associated with managing the hydrotest operation, and alternatives considered, will be included in hydrotest water management procedures.

An alternative which may prove feasible (subject to safety considerations) for the subsea pipelines is the use of pneumatic testing (i.e. using a gas such as nitrogen or hydrocarbon gas) instead of hydrotesting (i.e. water). This will be examined in more detail as the design progresses.

6.3.13 Onshore Equipment Hydrotesting

As the LNG tanks, MEG tanks and condensate tanks will be built on Barrow Island, they must be hydrotested *in situ*. They will also require a significant volume of water which, in the case of the LNG tanks, is expected to be fresh water.

The hydrotest water used for pressure testing the pipes, vessels and tanks will be re-used several times through the various gas processing facility components wherever reasonably practicable. The hydrotest water will be similar in composition to the pipeline hydrotest water. Once the hydrotest water is no longer required, the current base case is that it will be disposed of through the waste water injection system. However, offshore disposal (such as via the feed gas pipeline) may be an option depending on the required timing of activities and technical requirements regarding hydrotest water quality.

A number of options may prove feasible for disposal of the hydrotest water from the LNG tanks. An option that will be available if no chemicals are used (or are minimal) is disposal into natural water courses, or use as a dust suppressant. However, these uses may require short-term (days) storage to enable the water to be re-oxygenated. If this is not possible, then offshore disposal may be feasible. As a last resort, test water will be injected with other waste water streams. Pneumatic testing may also prove to be feasible for some equipment, subject to safety considerations.

6.4 Pre-Commissioning, Commissioning, and Start-Up

Once installed the facilities must be commissioned. This involves checking that all equipment works, expelling air from hydrocarbon systems, introducing hydrocarbons into the systems and starting equipment for the first time. The following section examines the main aspects requiring commissioning and briefly describes the commissioning process.

6.4.1 Commissioning of the Gas Processing Facility

Commissioning the gas processing facility comprises a number of steps. However, as the design of the plant and specific equipment components is only conceptual at this early stage, detailed commissioning requirements have not been developed. Environmental management procedures will be developed to cover this phase once further definition is available.

The major steps in the commissioning process will be:

- cleaning of some systems (e.g. an acid wash, such as using citric acid to clean the pipework and vessels of scale; steam and air blowing, flushing of the compressor lube oil systems to remove debris; and a 'caustic' wash to remove grease and oil from the a-MDEA system)
- commissioning of rotating equipment (turbines and pumps)
- pressure testing of the various vessels, piping systems and tanks
- bulk loading of the various solvents and chemicals required in the process (e.g. a-MDEA, TEG and MEG)
- bulk loading of the various adsorbents required in the process, such as molecular sieve for dehydration, and activated carbon for the mercury removal unit
- first fill of refrigerants
- introducing gas into the facility and the cooling and stabilisation of the process
- testing the various systems.

Once equipment has been installed, it will be necessary to confirm that the system has no leaks. This will be accomplished by leak testing systems at their operating pressure using air or some other safe fluid. The initial introduction of gas into the process equipment will be undertaken very carefully. First gas will be introduced to slightly pressurise the equipment. Potential leak sources, such as flanged connections, will be checked to confirm their integrity and rectified if necessary. As the system is further pressurised, potential leak sources will be rechecked. This process will continue in stages until the system is up to operating pressure and has no leaks.

Any water present in equipment will be removed as it could freeze in the cold conditions associated with LNG production and impact the process. Moisture in the air cannot be tolerated, so a dry source of feed gas will be heated, passed through the process equipment systematically and (normally) directed to the flare, as it will not meet product specifications.

Once the system has been confirmed to have no leaks and has been defrosted, it will be ready to commence cooling the equipment to normal operating temperatures. As the system will initially be too warm to create LNG, the gas will be directed to the flare in line with normal practice. However as the process continues, and systems cool down toward their normal operating conditions, LNG will begin to be produced. The system throughput can then be slowly increased until steady operation is achieved for the first time.

Recycling gas back to the plant inlet is one option that may prove feasible in reducing flaring associated with these operations. This option will be examined in the later design phases.

6.5 Operation of the Gorgon Development

6.5.1 Operation of the Offshore Facilities

The offshore production wells will be controlled from the control room located at Barrow Island. Remotely Operated Vehicles (ROV), offshore work vessels and drilling rigs will be used for inspection and maintenance of the wells and subsea facilities. The flowlines, manifolds, and PLEMs will be periodically inspected by an ROV to monitor the exterior surface and surroundings and to detect any problems with seafloor conditions.

There may be a periodic requirement to maintain wells using a drilling rig similar to that already described or inspect the subsea infrastructure using an ROV. There will be very little other operational activity in the field.

6.5.2 Operation of the Gas Processing Facility

The initial start-up of an LNG plant typically takes several weeks. However, there is a strong economic incentive to stabilise operations as soon as possible to produce LNG product for export. Previous experience on similar facilities shows that during the first year, and in particular the first few months, the gas process typically has a lower availability than in subsequent years. This can result in unplanned equipment outages and thus some flaring of gas during the outage and subsequent restart.

The gas processing facility on Barrow Island will have a stable process, using well-proven technologies designed for continuous operation. As a result, it is expected that the facility will operate for more than 90% of the year. LNG loading will occur approximately one day in three when an LNG carrier is berthed at the jetty. During the remaining time, no ships will be present and all of the LNG will be directed to the storage tanks. The gas processing facility is expected to continue operating during cyclones, as currently occurs in the region, although shipping movements will be curtailed.

The gas processing facility will be controlled and its integrity monitored by a computer based Integrated Control System that includes a Process Control System, a Safety Instrumented System, a Subsea Control System and a Fire and Gas System.

The gas processing facility will have a comprehensive computerised maintenance database of all equipment items. This system will ensure that all inspection requirements are fulfilled, appropriate preventative maintenance of equipment items is conducted, and planned and unplanned downtime is monitored. Major shutdowns will be conducted on a regular basis (every few years) and will involve significant planning. Appropriate maintenance of facilities will ensure the integrity of facilities.

The number of unplanned shut-downs of the facilities is difficult to predict. However, based on operational experience on similar facilities, it can be expected that approximately 10 shut-downs will occur per annum. These shut-downs could be initiated by the operators for maintenance, or if the gas processing facility is at risk of operating outside of its design limits. The automatic safety instrumented shut-down system could also initiate a shut-down. Depending on the cause of the shut-down, the gas processing facility could be either shut-in with no depressurisation to the flare, or undergo partial or complete depressurisation.

6.5.3 Operational Workforce

The operational workforce on Barrow Island is anticipated to be 150–200 people, with approximately the same number on rotation off the island. One option is to accommodate the operational workforce in the existing oil field operations camp. This will require an expansion of the existing facilities and upgrade of some of the supporting infrastructure. The expansion will occur within existing disturbed areas. Various support personnel will also be required in Perth.

6.5.4 Transportation during Operations

The gas processing facility will require relatively few raw materials beyond the production fluids from the wells. However various production chemicals, such as antifoam, corrosion inhibitor, a-MDEA, MEG, TEG, lube oil for rotating equipment and similar materials, will be required on first fill and subsequent routine basis. It will be necessary to bring ethane and propane onto the island for the first fill of the cooling circuits to enable the system to operate, until such a point that it is self-sufficient in these essential materials for the refrigeration system.

The current Barrow Island oilfield operation is supported by 1–2 barges and five planes per week (although aircraft currently service supports a range of other operators in the area). Gorgon Development (at steady state conditions) is expected to require two additional barges per week and two additional planes per week.

6.6 Decommissioning

The gas processing facility and equipment will be decommissioned when operations are no longer economically viable. Specific equipment may be decommissioned when no further use can be found for that equipment. Prior to any decommissioning, re-use and recycling alternatives will be considered where feasible. These may include: removal from Barrow Island for use by another operator; removal from Barrow Island for sale to a third party; transport of hydrocarbons for a future development; and/or access to the plant and equipment for additional field(s).

If none of the above options are feasible, the facilities (or parts of) and associated infrastructure will be decommissioned. The aim is to leave the areas utilised by the Development in an appropriate condition which allows them to be transferred back to state or federal agencies. This generally means that whatever remains after decommissioning, it should pose negligible risk to safety and the environment.

The decommissioning of all offshore facilities is covered under International Maritime Organisation (IMO) resolutions, the Commonwealth *Environment Protection (Sea Dumping) Act 1981* (which implements the IMO's London Convention 1972) and *Petroleum (Submerged Lands) Act 1967.* Relevant pipelines will also be covered by the Western Australian *Petroleum (Submerged Lands) Act 1982* and the *Petroleum Pipelines Act 1969.* The requirements of all these legislative instruments have been included in the possible decommissioning options outlined below. The main considerations of the above regulations are: that safety of navigation will be ensured; that marine pollution will be prevented or controlled; and that the marine and terrestrial environment will continue to be protected.

As the life of the proposed Development is expected to be in the order of 60 years, it is reasonable to assume that there will be changes to decommissioning procedures and regulatory requirements that incorporate advances in technology and information. Rather than making definite commitments to exact procedures now, the Joint Venturers will adopt best practices in environmental management at the time of decommissioning. However, the basic principle is that all surface equipment will be removed and the site rehabilitated.

The strategies outlined below indicate current industry practice in decommissioning. The general principle will be to flush and purge any equipment of hydrocarbons, ensuring that there is no, or minimal, adverse release to the environment and that a maximum amount of hydrocarbon product will be safely recovered.

The equipment will then be recovered for its existing use, recovered for scrap, or if the impact of removing the facility is greater than leaving it in place, abandoned *in situ.* For larger equipment items, it may be necessary to undertake a lifecycle analysis, which includes consideration of the energy, safety and resource requirements involved in recovery and the recycling of the equipment if recovered, together with other environmental impacts associated with the recovery process. This is of particular relevance to the offshore facilities that will be at a water depth greater than 200 m.

6.6.1 Decommissioning of Production Wells, Subsea Facilities and Flowlines

An assessment of decommissioning options will be undertaken approaching the end of the Development life. Current industry practice is to plug production wells and recover some elements such as manifolds, well flowlines and well heads. Larger elements such as the intrafield flowlines will be treated in the same manner as pipelines. The assessment will give due consideration to all regulatory requirements and industry standards.

6.6.2 Decommissioning of Pipelines

The current industry methodology for decommissioning offshore pipelines is:

- flush the pipeline of hydrocarbon liquids and vapour
- flood the pipeline with seawater
- seal the pipeline openings with mechanical plugs
- abandon all subsea sections of pipeline in place (including rock dumping) to minimise disturbance
- remove other ‘above-seabed’ facilities including the tie-in spool, subsea isolation valve assembly and the control umbilical
- update navigation charts for offshore areas to show what remains.

The current industry methodology for decommissioning onshore pipelines is:

- flush the pipeline of hydrocarbon liquids and vapour
- flood the pipeline with water
- seal the pipeline openings with mechanical plugs
- leave *in situ* all onshore sections that are buried
- remove above ground facilities including piping, equipment, controls, instrumentation and fencing and valve stations (including backfilling any valve pits)
- fill all major road/water crossings
- remove all warning signs along the onshore pipeline route
- rehabilitate disturbed land.

6.6.3 Decommissioning of the Gas Processing Facility

The decommissioning of the gas processing facility will be completed to standards that reflect community expectations and industry best practice at that time. Current expectations are that equipment which can be salvaged will be re-used/resold off Barrow Island. Where feasible, material which can not be used for its original purpose will be recycled/scrapped. The aim will be to minimise the amount of waste requiring disposal during decommissioning.

Prior to the removal of any equipment, it will be depressurised, purged and flushed of hydrocarbons to ensure that the removal process does not result in significant or adverse hydrocarbon releases. Advances in the management of the decommissioning processes will be utilised.

The hydrocarbon product to be processed will be predominantly gaseous, therefore soil contamination is not expected to be an issue, as precautionary measures will be adopted in the design process to minimise the potential for soil contamination. However, a soil contamination survey will be conducted to determine if there has been any inadvertent contamination. If any significant contamination is discovered, a comprehensive soil remediation program will be instigated, consistent with best practice environmental management as it stands at the time of decommissioning. The aim will be to obtain certification from the relevant government authority that the site has been left to agreed standards.

Once gas processing facility equipment has been removed from the site, the land will be rehabilitated to a condition which is consistent with the surrounding environment. This will involve re-establishment of representative indigenous flora species, and contouring to match the surrounding landscape. Appropriate funds will be made available for rehabilitation and maintenance.

6.6.4 Decommissioning of the Marine Facilities

The jetty facilities associated with the ship loading operations will be flushed and removed in a similar fashion to the gas processing facility components.

As the removal of the jetty facilities has the potential to cause significant local turbidity effects, and therefore adverse environmental impacts, a comprehensive decommissioning plan will be developed beforehand. This plan will take into consideration any advances in technology that will reduce the impact of removal. It should also incorporate lifecycle considerations to ensure that removal is the best option. It may be found that removal of all hydrocarbon contamination and transfer of ownership to the relevant government authority is the preferred option. As the jetty will have been in operation for approximately 60 years, the local seabed area will have adapted to its existence. Thus, removal may actually cause more disturbance to the local benthic and aquatic flora and fauna than leaving it in place. The current assumption is that the jetty piles will be cut off at the mud line, removed and disposed of to the mainland.

The dredged shipping channel will not be refilled as the resulting environmental damage would be greater than leaving the channel to reach a natural equilibrium.

The MOF causeway will be left *in situ,* because disturbing it is likely to result in a greater level of environmental impact than allowing it to remain.

The new condensate line (if provided) and water supply/effluent lines (if provided) will be recovered because they are in shallow water.

6.6.5 Decommissioning of the Optical Fibre Cable

An environmental assessment will be conducted at the time of decommissioning to determine whether the optical fibre cable should be recovered or allowed to remain in place. After some 60 years of service, it is likely that its recovery cannot be justified due to the resultant impacts. However, if the cable were to be removed it is likely to require equipment similar to that used for installation.

6.6.6 Decommissioning of the CO_2 Injection Facilities

Decommissioning of the CO_2 compression facilities will be undertaken in a similar way to that described for the gas processing facility mentioned in Section 6.6.3. The CO_2 pipeline will be decommissioned in a similar way to that described in Section 6.6.2. The CO_2 wells will be decommissioned in line with the principles used for other wells as described in Section 6.6.1 and as further detailed in Chapter 13.

6.6.7 Decommissioning of the Water Supply/Injection Facilities

Decommissioning of the water supply/injection facilities will be undertaken in a similar way to that described for the gas processing facility mentioned in Section 6.6.3. The water supply/injection pipelines will be decommissioned in a similar way to that described in Section 6.6.2. The water supply/injection wells will be decommissioned in line with the principles used for other wells as described in Section 6.6.1.

6.6.8 Decommissioning of the Dredge Spoil Disposal Site

No specific decommissioning actions are proposed for the dredge spoil disposal site.