# Australia Pacific LNG Project

## Volume 2: Gas Fields

## Chapter 3: Project Description

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# 3. Project description

## 3.1 Overview

Australia Pacific LNG proposes to develop a world class coal seam gas (CSG) to liquefied natural gas (LNG) project in Queensland. This includes the development of the Walloons gas fields, the construction of a high pressure gas transmission pipeline from the gas fields to Curtis Island near Gladstone and a LNG facility on Curtis Island. The Project being assessed by this environmental impact statement (EIS) will be spread over 30 years and has been addressed under the following three main components:

- Gas fields
- Gas pipeline
- LNG facility.

This chapter describes the construction, operational and decommissioning phases involved in developing the gas fields element of the Australia Pacific LNG Project (the Project).

To supply the required quantity of CSG to support the LNG facility at Gladstone, a series of gas fields will need to be developed, along with the associated gas processing facilities. While this infrastructure is not technically complex, it will be spread across a large region.

Infrastructure associated with the development of the gas fields includes gas compression and processing, power generation and water treatment facilities, low pressure gas and water pipelines as well as high pressure gas pipelines. Other infrastructure required will consist of road and access tracks, communications infrastructure, warehousing, temporary and permanent accommodation facilities, communications and logistics-related infrastructure.

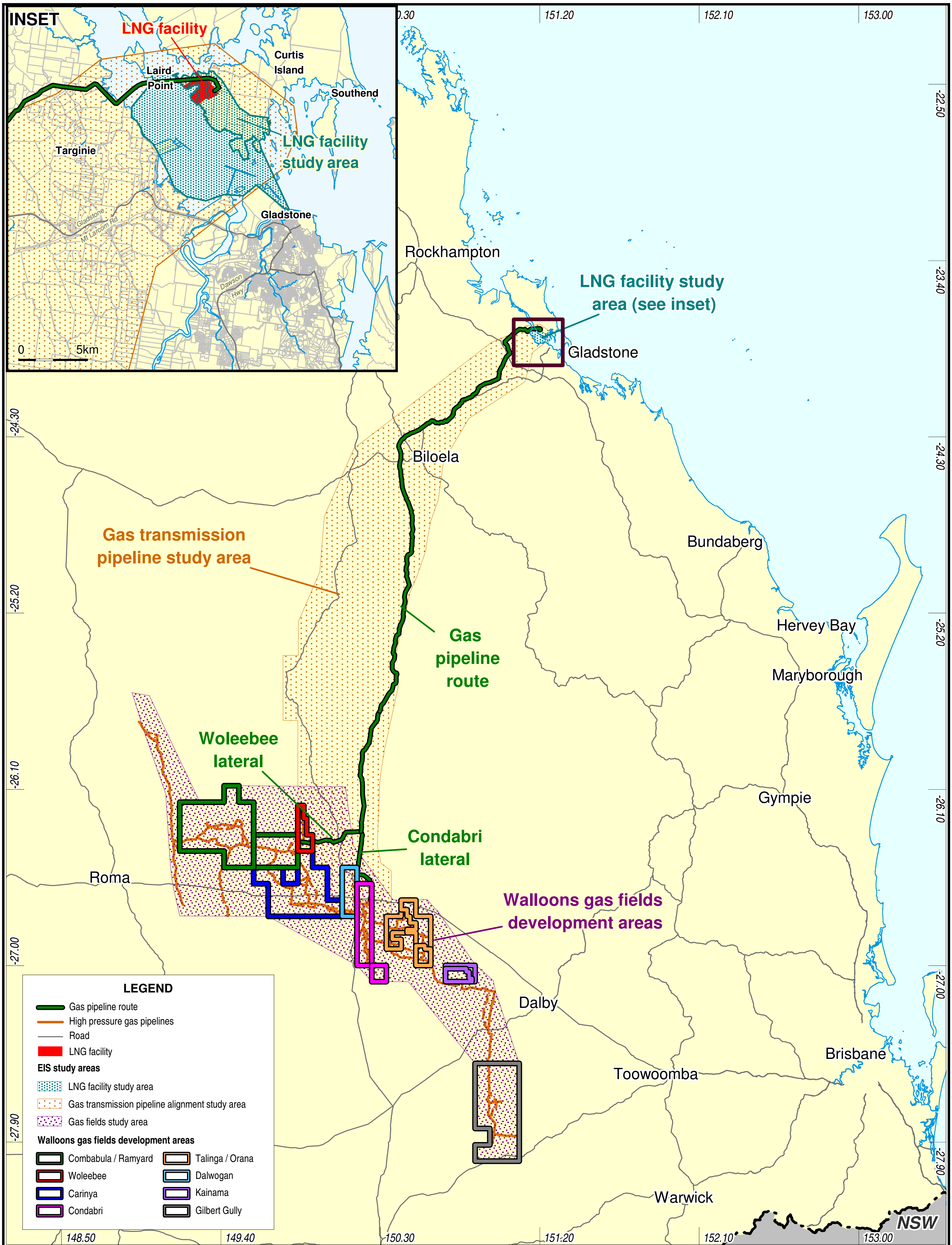
The development timing for the infrastructure associated with the Project will be staged to coincide with drilling program progress. Facility sizes will vary from location to location, based on the predicted production rates from each gas field.

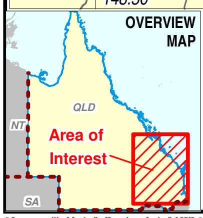
Based on a conservative 9km drainage circle radius, the gas fields' development could have a maximum of 23 gas processing facilities (GPFs) across the entire development area, over the 30-year life of the Project. The final design will aim to minimise the number of installed facilities. Each facility would handle 75, 150 or 225 terajoules per day (TJ/d) of gas production, and would be based on 75TJ/d modules, but could also include smaller booster compressor stations in some areas.

The Project is underpinned by sustainability principles and a risk management approach that applies to all stages of the Project life. Australia Pacific LNG will continue to openly engage with the community to ensure that their interests are identified and incorporated into project planning, design, construction, operations, decommissioning and rehabilitation stages to the greatest degree possible.

### 3.1.1 Location

The Walloons gas fields are located in Queensland's Surat Basin on the Western Downs. They cover an area of approximately 570,000 hectares (ha). The gas fields are located in the three regional council areas of Maranoa, Toowoomba and Western Downs. The nearest townships are Roma, Wallumbilla, Wandoan, Miles, Condamine, Chinchilla, Kogan and Millmerran. An overview of the Project's location is provided in Figure 3.1. Figure 3.2 to Figure 3.8 show each gas field development area.




SOURCE INFORMATION

Roads
Department of Main Roads 2009

Towns
Department of Main Roads 2009

Digital cadastral database
Department of Natural Resources and Water 2009

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Latitude/Longitude
Geocentric Datum of Australia 1994

**AUSTRALIA PACIFIC LNG PROJECT**

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**Figure 3.1 Regional Context**

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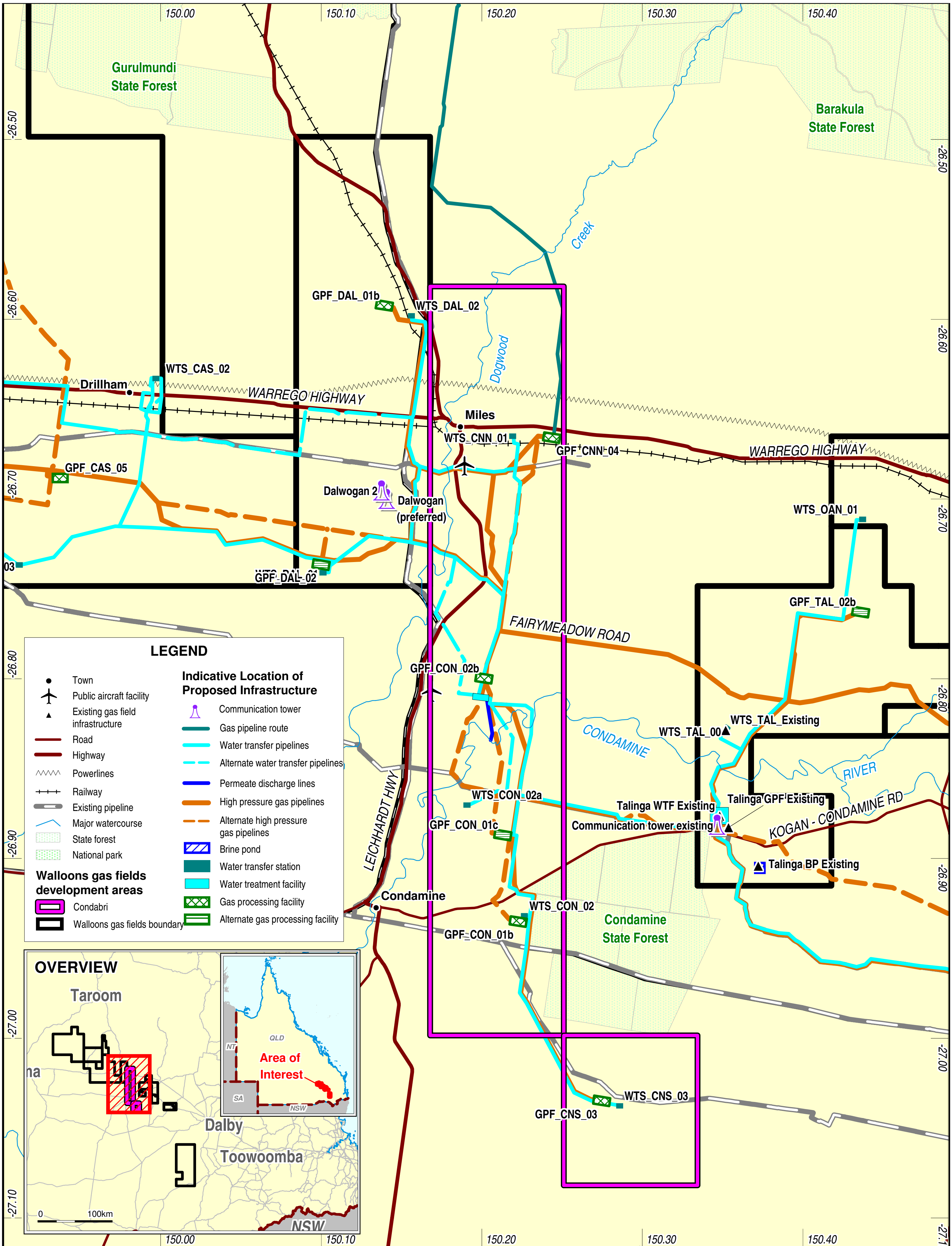


**SOURCE INFORMATION**

Protected Areas Of Queensland (estate) and Wetlands Directory of Important
Department of Environment and Resource Management (DERM) 2009
Aircraft Facility Point and Powerlines (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009

Watercourse (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009
Pipelines
Commonwealth of Australia (Geoscience Australia) 2009
Department of Mines and Energy, MERLIN
Mining Tenures system and Database (MTDB) 2009
Roads
Department of Main Roads 2009

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**Figure 3.2 Condabri Development Area (2013 to 2023)**

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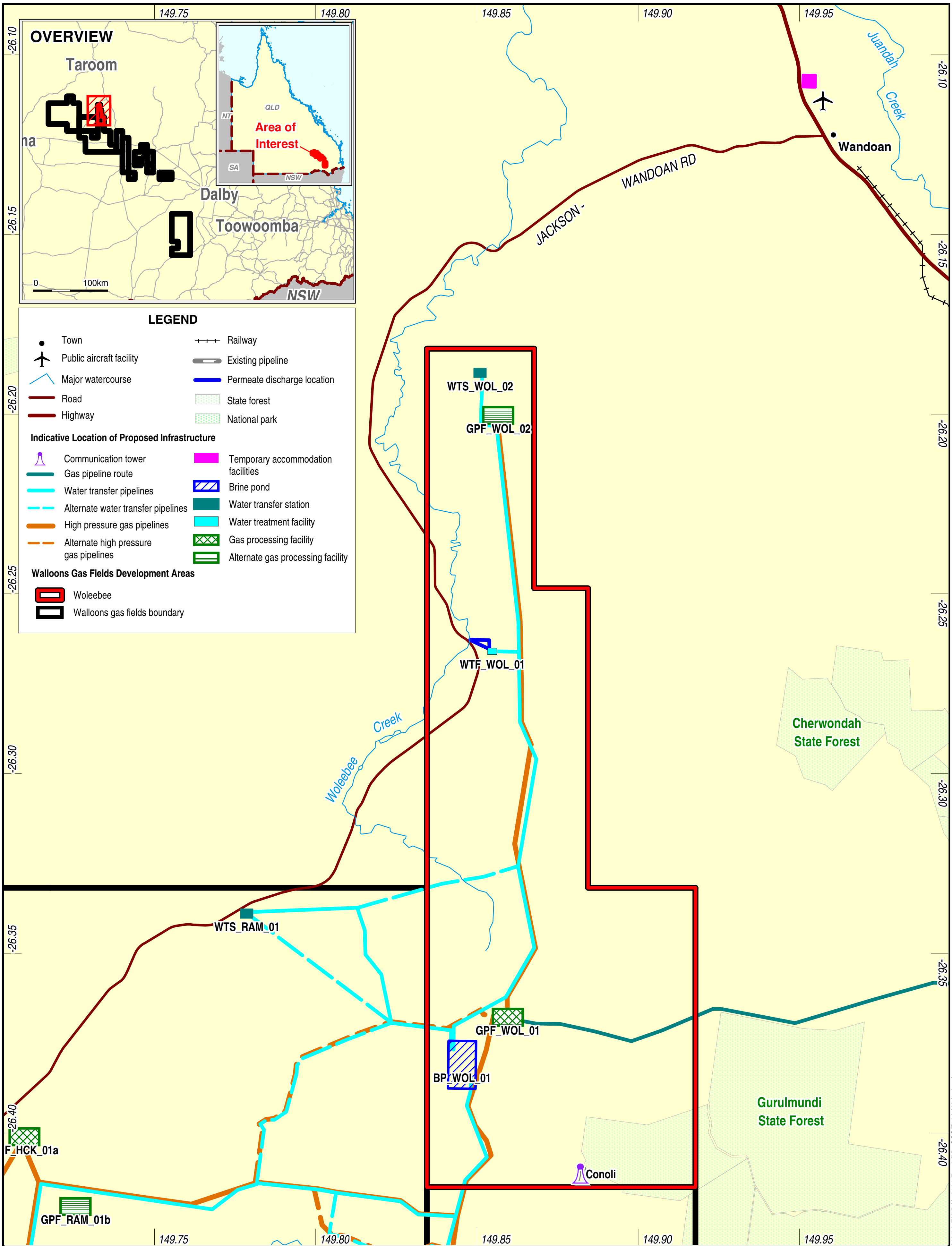


**SOURCE INFORMATION**

Protected Areas Of Queensland (estate) and Wetlands Directory of Important
Department of Environment and Resource Management (DERM) 2009

Aircraft Facility Point and Powerlines (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009

Watercourse (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009

Pipelines
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Department of Mines and Energy, MERLIN
Mining Tenures system and Database (MTDB) 2009

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AUSTRALIA PACIFIC LNG PROJECT

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**Figure 3.3 Woleebee Development Area (2016 to 2029)**

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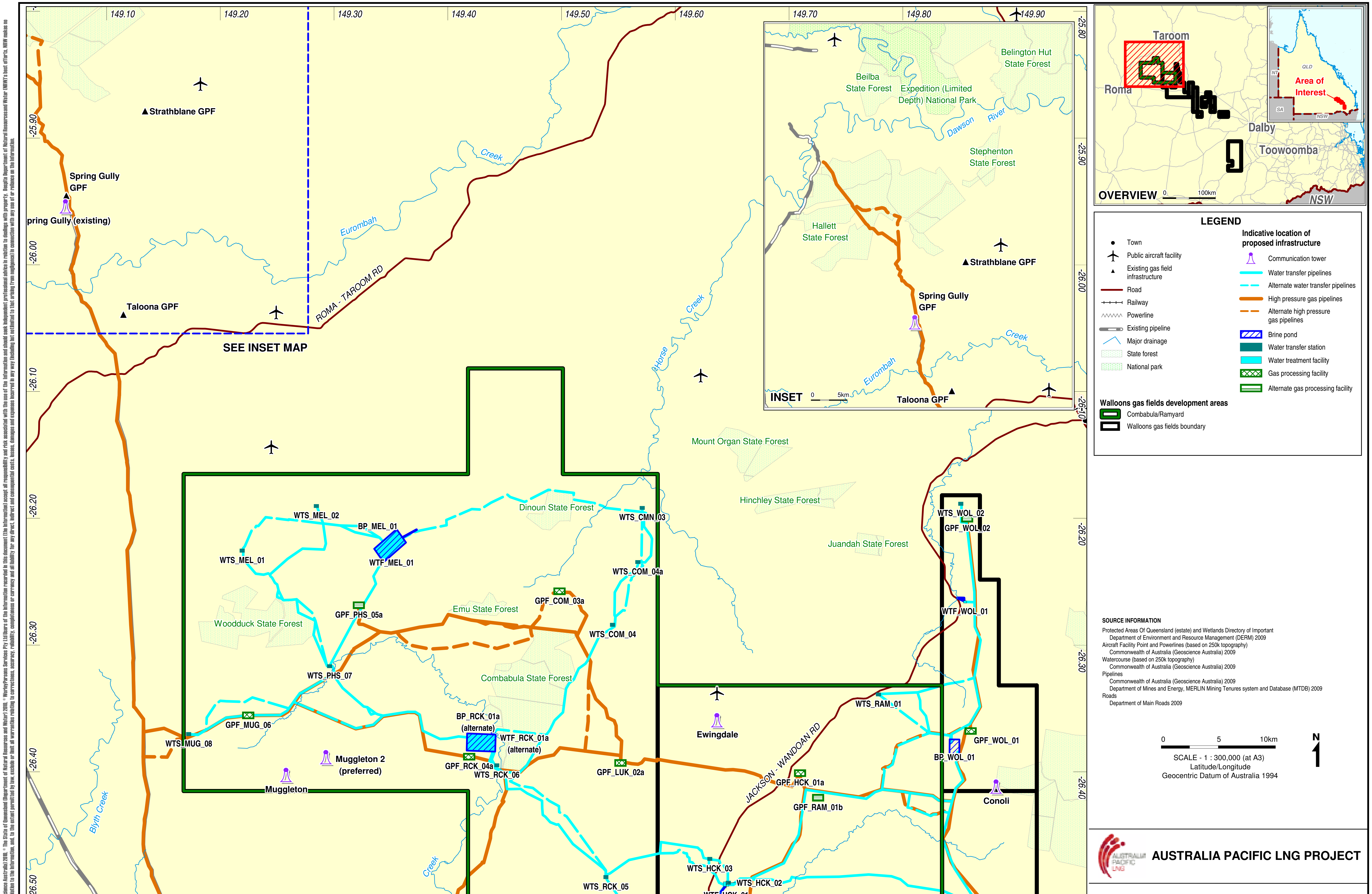


Volume 2 Chapter 3
Figure 3.4 Combabula / Ramyard Development Area (2012 to 2031)

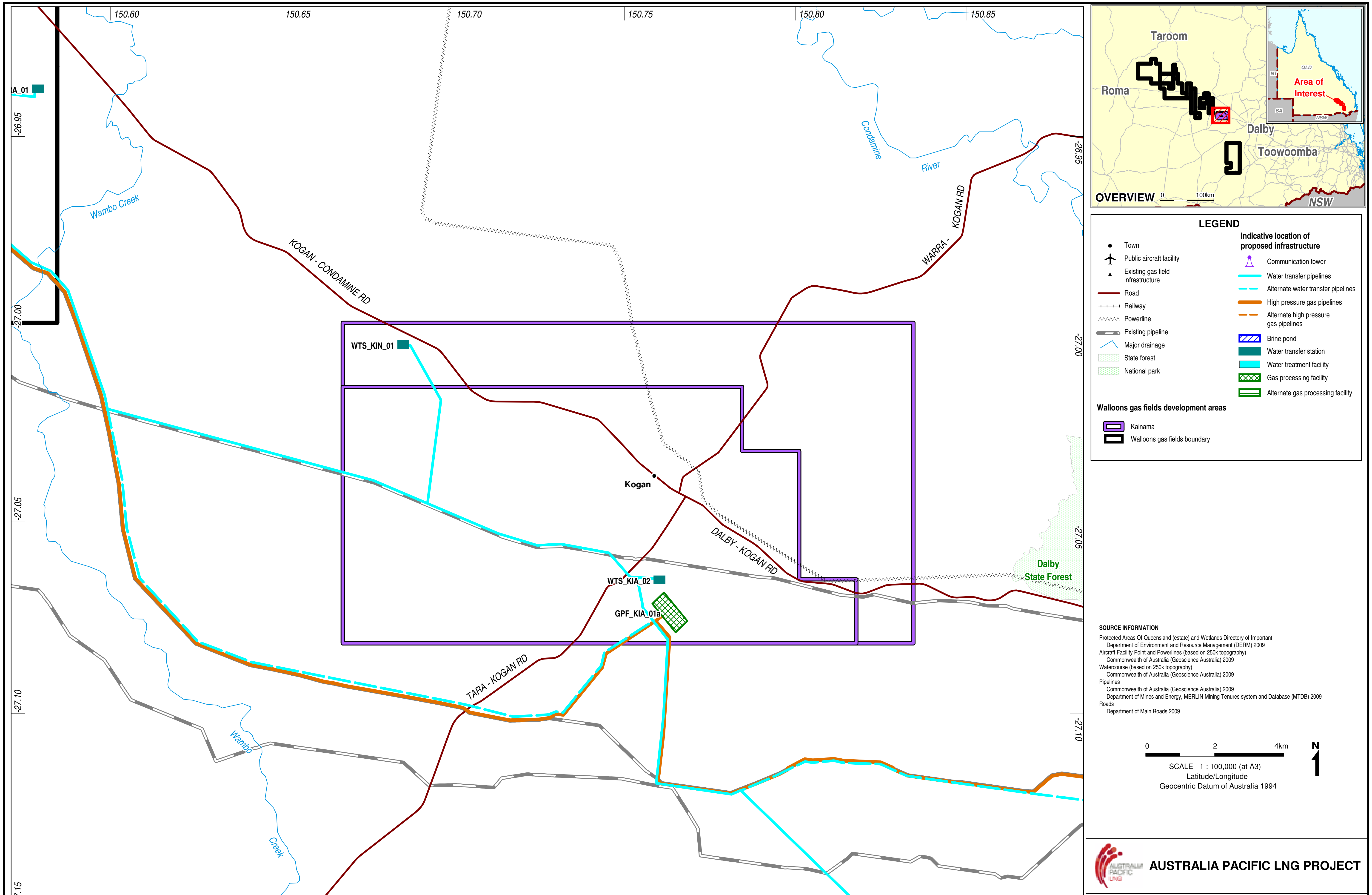


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**Figure 3.5 Kainama Development Area (2015 to 2028)**

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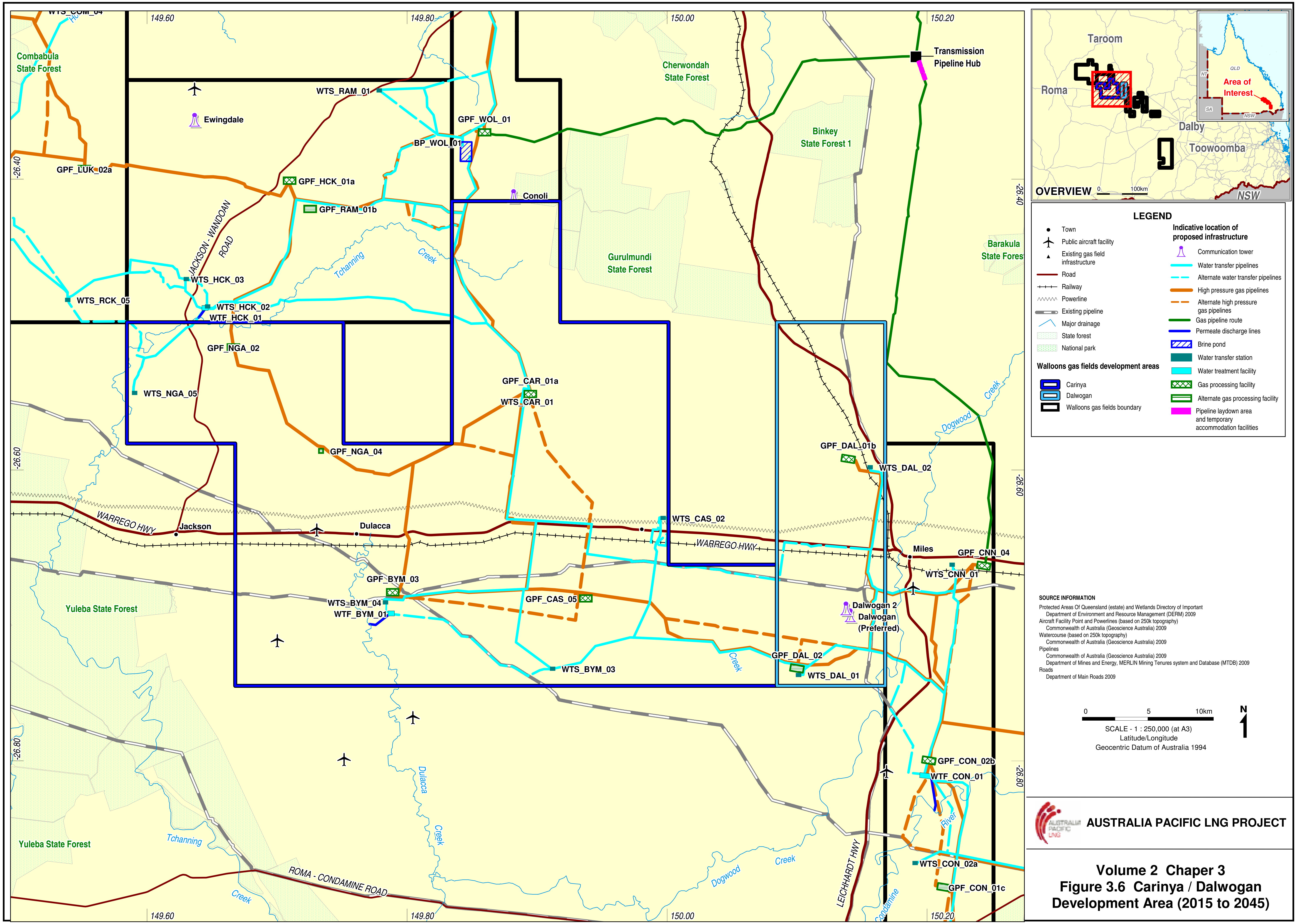


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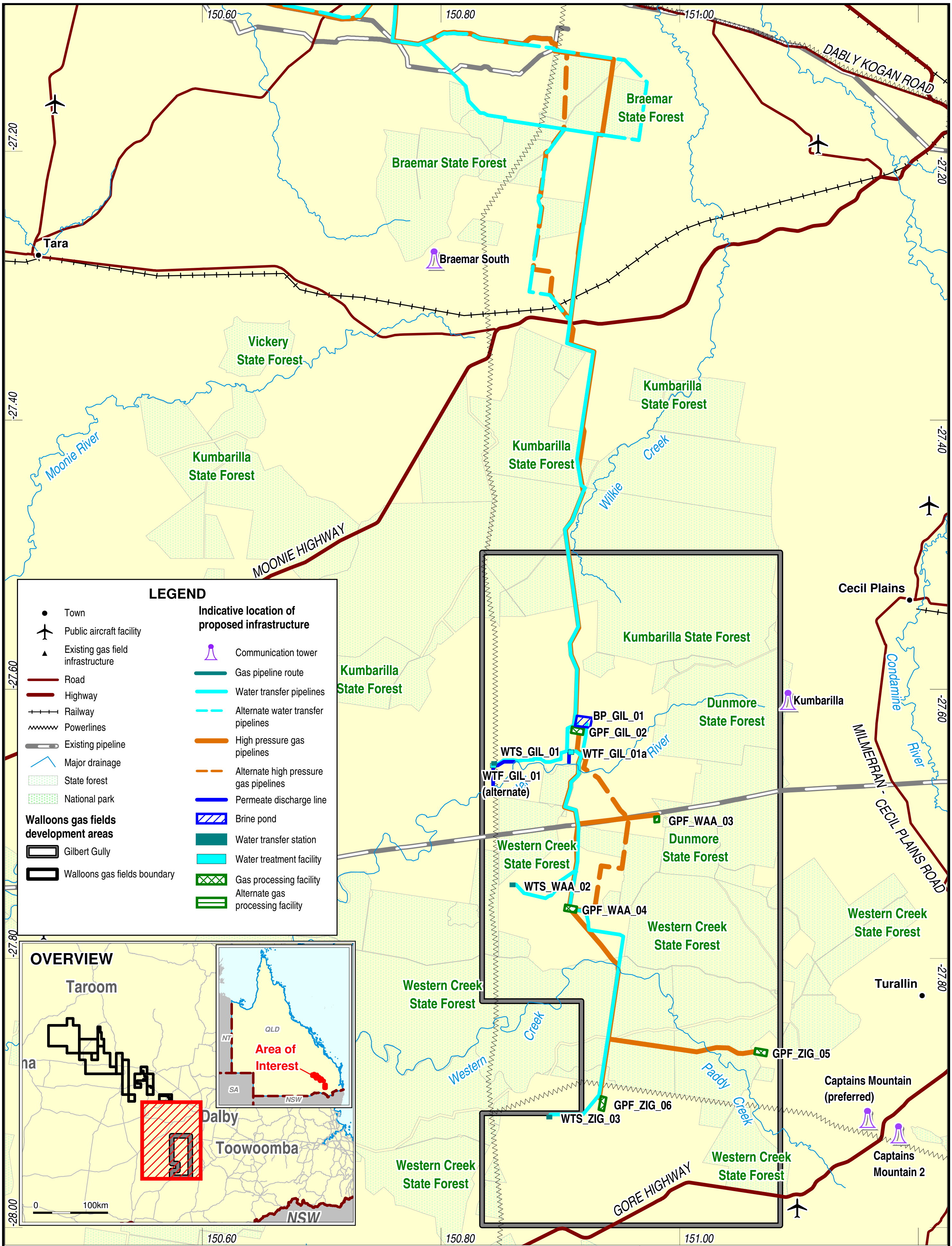
Figure 3.6 Carinya / Dalwogan Development Area (2015 to 2045)

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Commonwealth of Australia (Geoscience Australia) 2009

Watercourse (based on 250k topography)
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Pipelines
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**Figure 3.7 Gilbert Gully Development Area (2016 to 2034)**

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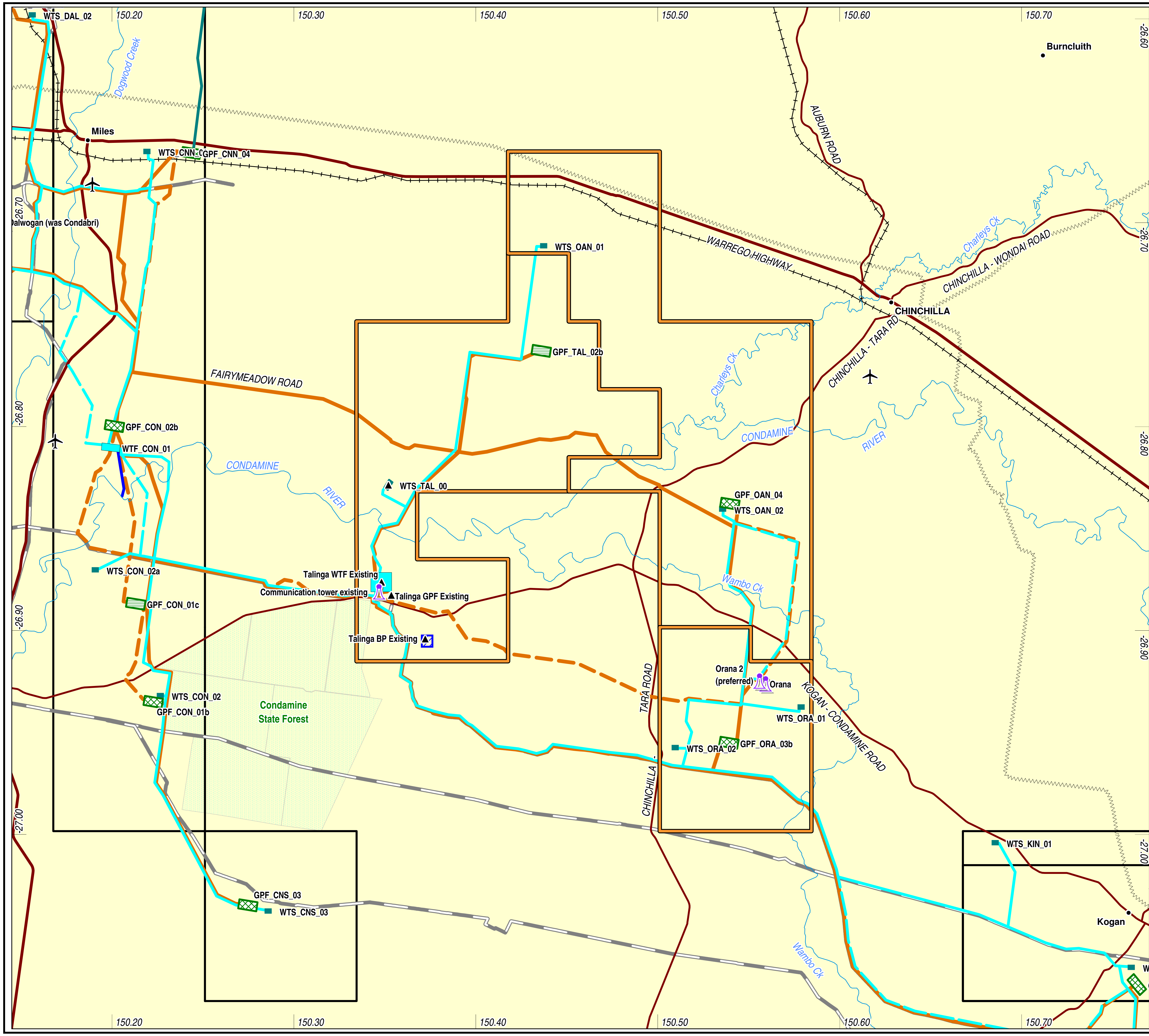


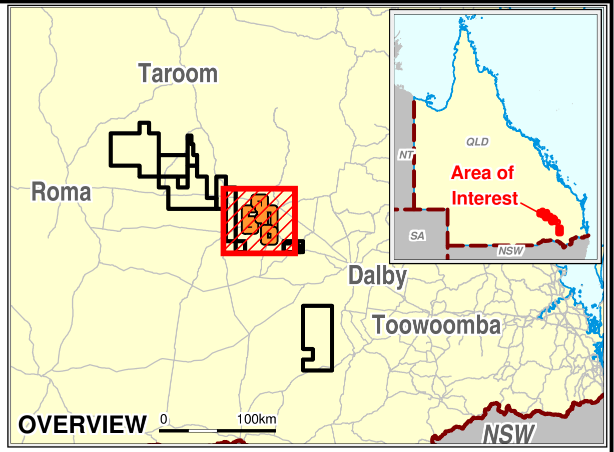


**LEGEND**

- Town
- Public aircraft facility
- Existing gas field infrastructure
- Road
- Railway
- Powerline
- Existing pipeline
- Major drainage
- State forest
- National park

**Walloons gas fields development areas**

- Talinga/Orana
- Walloons gas fields boundary

**Indicative location of proposed infrastructure**

- Communication tower
- Water transfer pipelines
- Alternate water transfer pipelines
- High pressure gas pipelines
- Alternate high pressure gas pipelines
- Gas pipeline route
- Permeate discharge lines
- Brine pond
- Water transfer station
- Water treatment facility
- Gas processing facility
- Alternate gas processing facility

**SOURCE INFORMATION**

Protected Areas Of Queensland (estate) and Wetlands Directory of Important
Department of Environment and Resource Management (DERM) 2009
Aircraft Facility Point and Powerlines (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009
Watercourse (based on 250k topography)
Commonwealth of Australia (Geoscience Australia) 2009
Pipelines
Commonwealth of Australia (Geoscience Australia) 2009
Department of Mines and Energy, MERLIN Mining Tenures system and Database (MTDB) 2009
Roads
Department of Main Roads 2009

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**Figure 3.8 Talinga / Orana Development Area (2011 to 2023)**

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### 3.1.2 What is coal seam gas

The Project involves the collection of CSG from a number of approved petroleum authorities within the gas fields' development area. CSG is trapped by molecular bonding (adsorption) on the internal surfaces of micro pores (cleats) within the coal. The gas is generated in-situ by microbial activity and/or thermogenic (heating) processes.

The 'adsorption capacity' of coal is a function of coal type, rank (maturity) and mineral (ash) content. For a given coal, this capacity increases with pressure and decreases with temperature. Coals are referred to as 'under saturated' when their measured gas content is less than their adsorption capacity at reservoir temperature and pressure.

Permeability of coal seams is a measure of the ability of the gas to move through the coal and is primarily a function of cleat development (Figure 3.9), along with fracture, density and orientation. Permeability usually reduces with depth of burial because of compaction and calcite cementation, but can be preserved or enhanced if extensional stress conditions prevail.

**Figure 3.9 Example of a coal cleat**

Gas production is usually preceded by water production, which is a necessary precursor to lower reservoir pressure and enable desorption of adsorbed gas. The water present within the coal seams is generally referred to as 'associated water' in the petroleum industry as it is normally extracted with the gas stream and is therefore an associated product of the gas collection process. Figure 3.10 represents this gas-water association for a typical CSG well over its production life.

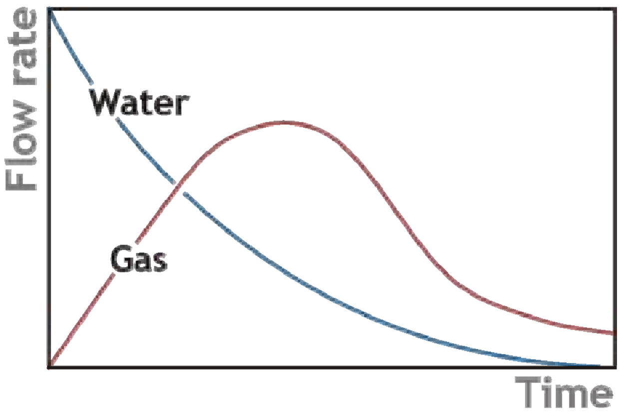



**Figure 3.10 A typical CSG well production curve**

### *Differences between coal seam gas and conventional gas*

Natural gas in Australia has traditionally been extracted from conventional gas fields. In a conventional gas field, the gas has been generated over geologic time from organic material trapped in a source rock which has then migrated into a trapping reservoir which typically has high porosity and permeability. Compared to CSG, conventional gas reservoirs are generally at greater depth, the gas flows to surface at higher pressure and there is very little water associated with the gas production. Conventional gas reservoirs are generally discrete structures compared to the regionally extensive coal seams and typically fewer wells are required to develop a conventional gas resource.

### 3.1.3 Innovation and environmental design

For the purposes of the environmental impact statement, equipment which is both current industry standard and used by Australia Pacific LNG in its existing CSG facilities, has been selected as the development base case. However, to help minimise the Project's environmental impact, a number of initiatives have been included or are under further investigation in the design of the gas fields' development. These initiatives include:

- Using alternative drilling rigs with the capability of drilling on reduced lease sizes. Australia Pacific LNG has recently contracted four drilling and work-over rigs which are built for purpose to deliver the safest, most efficient and cost effective wells. The rigs have improved safety levels and environmental impact compared to existing rigs, and they also have dedicated CSG capability and hybrid rig technology
- Co-locating infrastructure (e.g. GPFs and WTFs) and pipelines and utility infrastructure to reduce disturbance
- Initial injection studies have shown that aquifer injection is technically possible, and has possible advantages over other water management options. Australia Pacific LNG will undertake further studies and trials into hydraulic properties and chemical compatibility of the potential injection aquifers
- Actively reviewing options to reduce the overall noise generated by drilling rigs
- Selecting micro-turbines (or grid supplied electricity) as the primary power source at the wellheads, as they have significantly lower emissions than gas engine driven units. In particular, nitrogen oxide ($NO_x$) emissions are lower for micro-turbines
- Ensuring all compressor and power generator drives in the gas processing and water treatment facilities use 'lean-burn' technology which significantly reduce $NO_x$ emissions
- Improving the design of vents releasing CSG from GPFs for emergencies (relief valves) or equipment depressurisation (for safety or maintenance), so they are directed to flaring
- Automated wellhead controls, as discussed in Section 3.6.1, to allow a rapid response to changes in CSG demand, and therefore reduce flaring and greenhouse gas emissions
- Explore the use of compressor coolers with electric motors to drive fans in the GPFs.

Alternative technologies and methods to reduce potential impacts will continue to be investigated and considered. Some of these key alternatives are discussed in Section 3.8.

## 3.2 Key components of gas fields development

The Project's gas fields will be developed in a similar way to Australia Pacific LNG's existing Spring Gully, Peat and Talinga gas fields. The process of CSG resource development in the Surat and Bowen Basins in Queensland has been refined over a decade of operation.

This section describes the key components of developing a CSG field; from initial exploration and drilling of the wells through to the point where the gas is transported from the gas fields' gathering and processing pipeline system to the main gas transmission pipeline for delivery to the Project's LNG facility on Curtis Island and ultimately final decommissioning and rehabilitation at the end of the Project life.

### 3.2.1 Overview

CSG development differs significantly from developing conventional natural gas. To produce gas from a coal seam, normally the water associated with the gas in the reservoir must first be withdrawn using artificial lift (pump) installed in the well at the depth of the coal seam being targeted. This reduces the pressure within the coal seam and liberates the adsorbed gas from the coal.

Figure 3.11 shows the extraction of gas and associated water from the coal seams. This includes the well bore to the depth of the coal seams, a well head with a pump to draw down the water and a separator to remove the associated water from the gas.

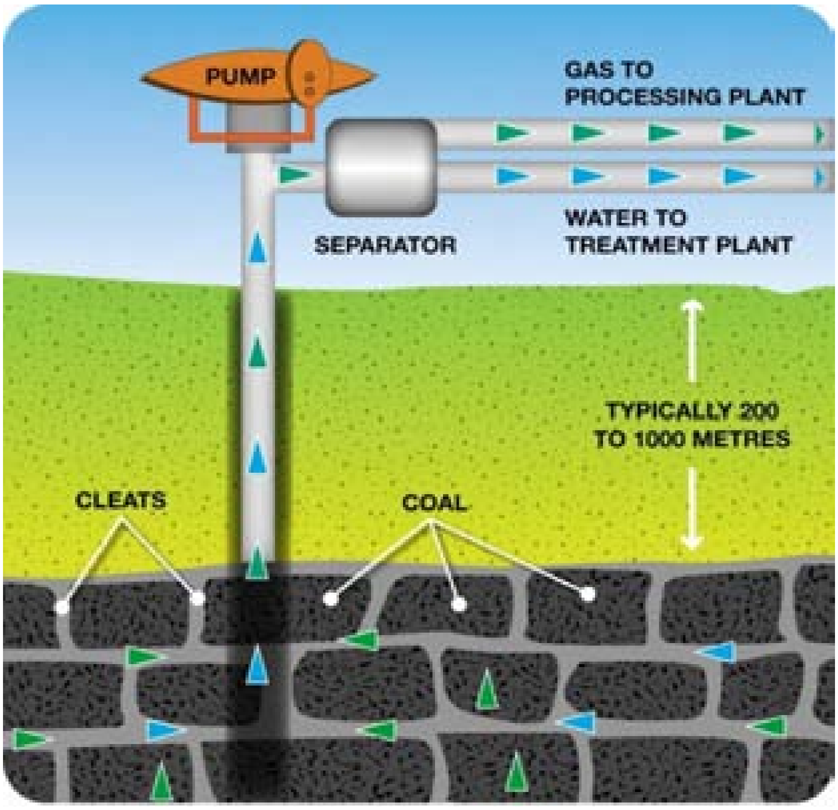



**Figure 3.11 Extraction of gas and associated water from coal seams**

An individual CSG well generally produces less gas than conventional natural gas wells, irrespective of the extent of dewatering. More wells must be drilled per unit area to make a project viable, compared to an equivalent conventional gas development. Wells may be located as close as 500m apart once an area is fully developed. The Australia Pacific LNG Project's development is based on a

typical 750m well spacing, while actual well spacing may be greater or lesser depending on reservoir characteristics and/or location constraints.

Associated water production declines during the life of the well as gas production increases, as shown in Figure 3.10. Once sufficient water has been removed, or the well has been 'dewatered', the gas will begin to release from the coal seams. Over time, as the amount of water being pumped declines, the gas flow increases until it reaches a maximum or 'peak' flow. It then tapers off to a long period of almost constant low flow or 'post-peak' flow.

Water continues to be produced throughout the life of the well, but in reducing quantities. This, combined with new wells brought online to maintain gas production, necessitates a requirement for water management infrastructure throughout the life of the Project.

The period between initial dewatering, peak gas production and minimum constant flow from a well, varies across the different CSG fields, as well as between individual wells in the same gas field. A single well could 'peak' at any time, from under one year to almost three years.

### *Petroleum approvals*

Prior to petroleum activities being undertaken in a designated gas field, the proponent must have an approved tenement over the site (generally an authority to prospect for exploration activities or a petroleum lease for production activities) and an associated environmental authority in accordance with the *Environmental Protection Act 1994.*

The Project will incorporate the exploration and development of the following petroleum leases (PL), petroleum lease applications (PLA) and authority to prospects (ATP) are currently held or have been lodged by Australia Pacific LNG:

- ATP 606P – Combabula
- ATP 972P – Ramyard
- ATP 973P – Carinya
- PL 209 – Woleebee
- PLA 216 – Dalwogan
- PLA 267 – Condabri North
- PLA 266 – Condabri South
- PL 215 – Orana
- PLA 225 – Kainama
- ATP 663P – Gilbert Gully
- PLA 289 – Kainama North
- PLA 272 – Orana North
- ATP 692P – Kainama North
- PLA 265 – Condabri Central
- PL 226 – Talinga (excluding the approved 90TJ/d).

Volume 1 Chapter 2 provides further details on the legislative requirements associated with petroleum activities and outlines the project approvals required for the Project.

## 3.2.2 Exploration and appraisal

Exploration is generally carried out within areas covered by an ATP. It begins with seismic or other geophysical surveys, to determine the geological setting of the area. This is followed by drilling wells to gain a better understanding of the characteristics of the coal, including coal thickness, gas content and quality.

Production pilots are then used to determine the production potential of the coal seams. This involves drilling, completing and putting into operation a group of approximately five wells. The production data

obtained, along with the geological parameters, are then assessed to identify if the area is suitable for development and production.

Exploration and appraisal activities are currently being undertaken and will continue within all the Walloons gas fields permit areas under the existing exploration tenures. Exploration and appraisal activities undertaken during 2009 included the drilling of 55 exploration and appraisal wells (including pilot test wells) and completion of two seismic surveys (Quinn Gully 2D and Pathfinder 2D seismic surveys) and are continuing outside the scope of approvals being sought for the Project.

Future exploration activities will include:

- Seismic surveys, which involve vehicles operating on the surface to image subsurface geological structures
- Single well core holes, from which cores are taken to determine coal thickness, gas content and coal quality
- Delineation wells, which are specific locations drilled to determine reservoir quality and thickness
- Production pilots, which usually include a small number of wells, gathering lines, a central pond and a flare. The number of production pilots per exploration tenure will depend on the characteristics and uncertainties of the reservoir.

Single well core holes, delineation wells and seismic surveys will be required in various locations across the Project's acreage. This will depend on whether additional geological and geophysical data is required. Exploration activities will continue during the life of the gas fields.

### 3.2.3 Field planning

The field development is planned from the information obtained during the exploration and pilot studies. The actual location of wells, gas and water gathering system and access tracks is designed using constraints mapping giving consideration to topography, vegetation, cultural heritage and impact on landowners. Where possible, previously disturbed areas are utilised for petroleum infrastructure, whilst gathering network and access tracks are co-located. To minimise potential disturbance, access tracks will utilise existing roads and farm tracks, rather than develop new access infrastructure, where practicable. New sealed major roads will be designed to follow natural terrain contours to minimise earthworks, and achieve better visual integration outcomes.

Selected locations are refined during front end engineering design (FEED) studies, and site inspections in consultation with landholders and other associated stakeholders.

### 3.2.4 Drilling

The drill rig used for drilling CSG wells is typically comprised of:

- Diesel motor/s that drives the rig’s operation
- A derrick, which is essentially a vertical tower used to manage the long pieces of drill pipe for the drilling process
- A mud pump which pumps drilling mud through the drill pipe and brings the cuttings to the surface then circulates the mud into tanks or ground sumps, where the drill cuttings settle out and the mud is reused
- An iron roughneck, which tightens the pieces of drill stem together as the hole is drilled deeper

- A generator to maintain power to equipment
- Associated ancillary buildings.

Figure 3.12 provides an example of the type of drill rig Australia Pacific LNG will use during the drilling program for the Project.

**Figure 3.12 A typical drilling rig used by Australia Pacific LNG**

Drilling of wells is undertaken in a number of stages including:

- Well site selection and drilling program planning
- Well pad preparation, including access routes
- Drilling of the well
- Well completion
- Well stimulation.

These stages are described in more detail below.

### *Well site selection and drilling program planning*

The well site is initially selected to optimise the development of the gas fields. The actual location is refined by desktop constraints analysis followed by onsite field scouting. Following field verification of site constraints, the final well site location is selected and pegged. In environmentally sensitive locations, the option for drilling multiple wells from a single pad or other innovative technology may be considered if technically feasible.

### *Well pad preparation*

Before the drilling rig is mobilised, the drilling site or 'well lease' and access tracks are prepared to accommodate the physical characteristics and operational requirements of the drill site. This includes three main steps.

Firstly, vegetation is cleared within the lease site and for access tracks. Where larger vegetation is felled, a self-propelled mulcher may be used and the mulch stored at the edge of the lease for later rehabilitation use. Hollow timber, larger rocks and other features will be stored for later microhabitat rehabilitation.

Next, topsoil is removed using earthmoving equipment. This is stockpiled to one side of the lease site for later rehabilitation. Finally, earthmoving equipment is used to cut and fill the lease site where necessary to accommodate the operational area required for the drilling operations as shown in Figure 3.13.

The latest generation of drilling rigs planned to be used for the Project will significantly reduce the amount of lease preparation in already cleared areas and reduce the lease size required in vegetated areas (as discussed in Section 3.1.3).

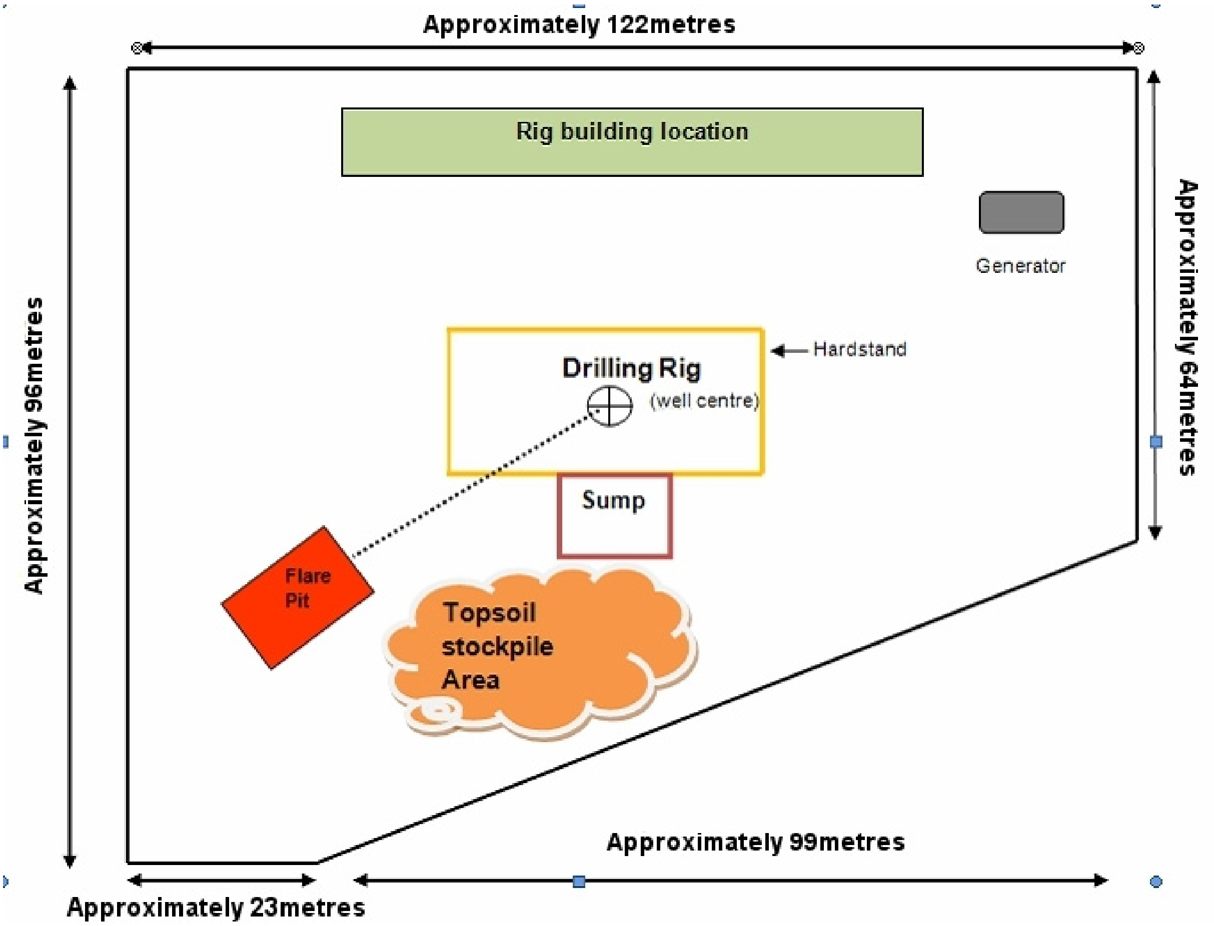



**Figure 3.13 Layout of a typical drilling lease**

## *Drilling of the well*

When the site is prepared, a drilling rig moves in to drill and installs a large diameter conductor pipe. The drilling rig first drills the surface section of the hole which takes around one day. A casing is then cemented in place by pumping cement into the wellbore and circulating back through the casing/well ring. This cement isolates any shallow surface aquifers and prevents cross contamination.

The second stage is to drill the production section of the hole, which is cased with perforated casing across the coal seams to allow CSG and associated water to flow into the well. Above the coal seams the casing is cemented back to surface to prevent any contamination of aquifer sands. It will usually

take around two to three days to drill the wells to a depth of 600m to 1,000m. The drilling rig is then packed up and moved to the next well. Figure 3.14 provides a schematic of Australia Pacific LNG's CSG production well construction.

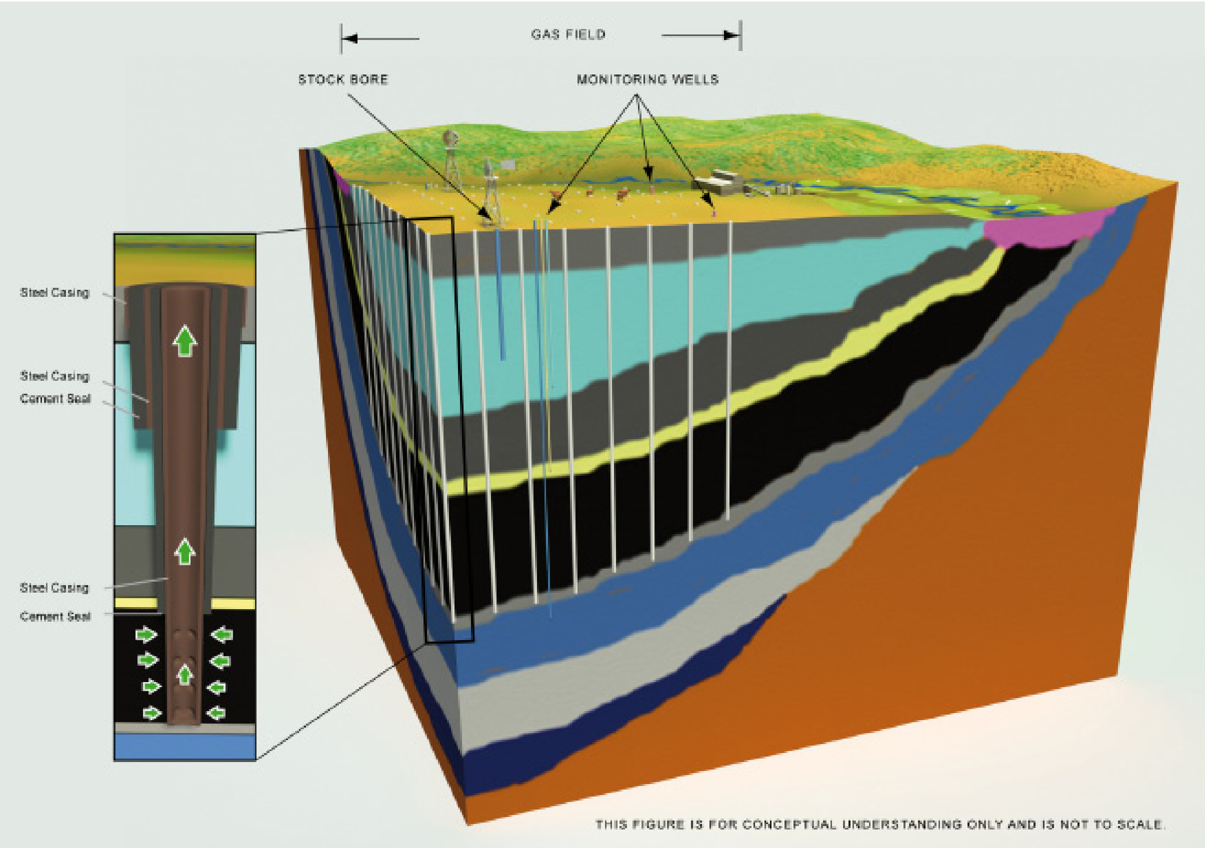



**Figure 3.14 Schematic of a typical gas well in relation to the Walloons Coal Measures**

### *Completions*

Following the drilling program, a completions rig is mobilised to site, assembled and the rig then drills through the cement barriers left by the drilling and installs the equipment required to operate the gas well.

During the life of a well, a similar rig may need to be mobilised to the well lease to work-over the well to replace the down-hole pump or remediate a down-hole problem.

Figure 3.15 shows a typical completions rig constructing a CSG well.

**Figure 3.15 Typical completions rig constructing a coal seam gas well**

### *Stimulation*

Some wells will require stimulation to enable successful gas production as part of the completion of the well. This will primarily be by hydraulic fracture stimulation or 'fraccing', and occasionally by cavitation.

Fraccing involves pumping treated fluid (usually water) containing sand grains into coal cleats at a high rate and pressure to form and extend a fracture in the coal reservoir. This creates a high conductivity pathway to the well bore and increases the production capability of the well. Fraccing requires high pressure pumping equipment at surface which is usually on site for two days to perform 3-4 fracs per well. Most of this time is spent rigging up and down the equipment with approximately one hour spent pumping each coal seam.

Only the coals are fracced and therefore shallow aquifers are not exposed to the frac fluids. The frac fluids are also inert and do not pose any significant environmental hazard.

Cavitation is an alternative technology for well completion that may be utilised for some wells in the study area when other well completion methodologies are not suitable. Cavitation uses air pumped at high pressure to penetrate the coal cleats and occurs underground within the formation. The pressure

is held on the well bore for a given amount of time. It is then released suddenly, causing the coal to fail and slump into the well bore. The failed coal is flowed to the surface, leaving a cavity in the coal reservoir sections and a zone of increased permeability around the cavity within the coal formation. The cavitation process requires a work-over rig on site and typically takes 10 to 14 days per well.

In a well designated for cavitation, the production casing is set above the coal seam which ensures that only the coal seams are subjected to the cavitation process. The cavity created is relatively small and has no impact on the surface topography.

### *Typical chemicals used in drilling, completions and stimulation operations*

Drilling of a well will utilise approximately 200$m^3$ of drilling mud comprised mainly of water and inert bentonite. Water from the drilling mud will be separated from the drill cuttings and disposed to the brine ponds. The rill cuttings brought to the surface will be rehabilitated in-situ.

Well completion, involving fracturing of the coal seam, will utilise about 1,600$m^3$ of fluid, predominately water, containing inert proppant solids (typically glass beads, sand and/or silica in composition). This fluid remains in-situ to assist in maintaining the flow of CSG. The well completion fluids used for fracturing the coal seam will be pumped from the well during development, returned to the surface, and treated through the water treatment plant.

Minor quantities of additional chemical additives are blended into the drilling and completion fluids to assist the drilling process. Most of the chemicals, including biocides and corrosion inhibitors, utilised in well drilling and completions are not dangerous goods, as defined by the *Dangerous Goods Safety Management Act 2001*. Biocides are used to limit the growth and spread of bacteria that may cause fouling. Corrosion inhibitors limit potential for corrosion and failure of well completions, thus maintaining the integrity of the wells.

The drilling process also utilises limited quantities of chemicals that are classed as dangerous goods including corrosive liquids (Class 8) such as acetic acid and caustic soda solution, as well as some flammable surfactants (Class 3) used during the completion of the wells.

In support of drilling operations, fuels such as diesel (combustible liquid) are used to fuel power generation supplies and other drilling related required equipment.

All chemicals will be stored and handled in accordance with the relevant legislative requirements and Australian Standards including the provisions of:

- AS 3780:2008 – The storage and handling of corrosive substances
- AS 1940:2004 – The storage and handling of flammable and combustible liquids.

All chemicals used during the drilling operation are considered to have minimal impact on the environment based on the following mitigation measures being implemented:

- Adherence to relevant legislative and Australian Standard storage and handling requirements
- Use of inert and/or non dangerous goods for the majority of the drilling operations
- Limited used of chemicals and fuels classed as dangerous goods for fraccing operations
- Treatment of drilling and fraccing fluids removed from the well through the Project's water treatment facilities (WTFs).

In addition, Australia Pacific LNG will continue to investigate additives that are safer to handle, which may have lower toxicity constituents yet still meet operational standards.

### *Well production*

Wellhead and separation equipment is installed to separate the well flow into two streams – gas and associated water. The lease sites are rehabilitated to a small production lease. The access track will also be modified to an appropriate standard to support long term operations. Wells are typically operational for up to 30 years or longer.

The typical surface facilities associated with a CSG well are:

- A wellhead through which the gas and associated water is brought to the surface
- A pump that lifts the associated water to the surface
- A micro-turbine or other power supply to drive the pump
- A wellhead separator with associated control devices (Figure 3.16).

All of these facilities will be appropriately fenced. As discussed in Section 3.1.3, Australia Pacific LNG proposes to primarily use gas fired micro-turbines for power generation. These are totally enclosed highly reliable systems that run on CSG. However, in flood prone areas, alternative gas-fired power supply packages may be used.

In the early stage of gas field development, prior to CSG being available, liquefied petroleum gas (LPG) may be used as a temporary fuel source for power generation.

As the well pressure declines, a small compressor may be required at the wellhead to ensure that maximum recovery of available gas is achieved. At that time, a pump may also be required to maintain water transfer. Alternatively, 'nodal' compressors, which are small compressors used in the field to support naturally declining well and pipeline operating pressure, may be installed. Each nodal compressor would serve a number of wells.

**Figure 3.16  Typical wellhead separator**

Figure 3.17 shows typical configuration of flows of gas and water from the coal seam wells.

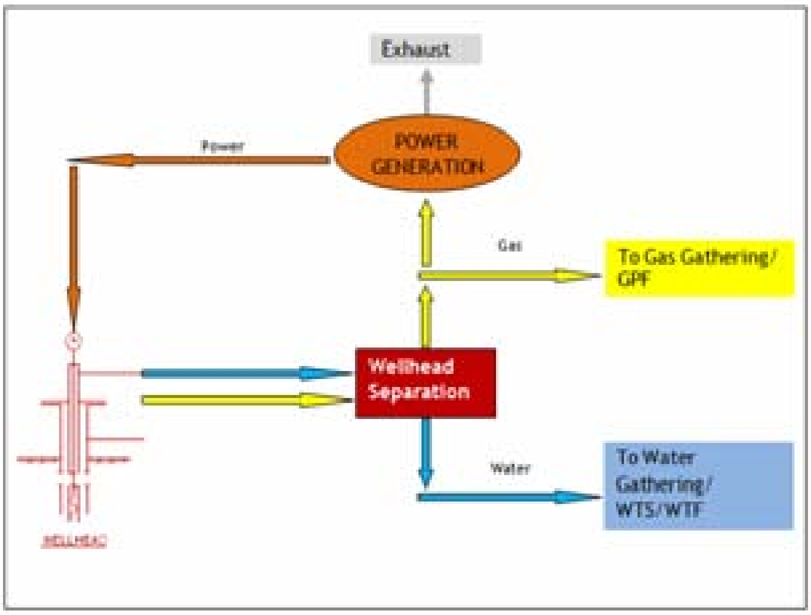



**Figure 3.17 Typical input/output streams for a gas well**

### 3.2.5 Gas and water gathering system

Flow from the well is separated into water and gas in a small vessel called a wellhead separator. Some gas will be entrained in the water and some water will be present with the gas. After separation occurs at the wellhead, the low pressure CSG from each of the wellhead separators flows into a system of low pressure buried pipelines.

These interconnect all wells operating in a specific area to form the gas gathering system. The entire gas gathering system up to the GPF may operate at pressures of up to 830 kilopascal gauge (kPag), and will be constructed from high density polyethylene pipe.

The gas flows through several subsystems which direct the gas to the central GPF. Each GPF is typically served by wells in an area within an approximate 9km radius or 'drainage circle'. However, optimum design of the gas gathering system in some areas may allow a larger drainage circle and thereby minimise the number of GPFs required.

After separation at the wellhead, the associated water flows into a similarly buried high density polyethylene pipeline system. This forms the water gathering network which channels the water to the nearest WTF. The system up to the WTF operates at pressures between 210 and 1,230kPag, depending on the terrain.

### 3.2.6 Water transfer stations and water transfer pipelines

Associated water will be collected at water transfer stations at locations of low elevations along the water gathering network. From there, a transfer station pump will pump the water to higher elevations along the route to the water treatment facilities. The transfer stations are typically comprised of a lined and fenced holding (transfer) pond and pumping station, constructed on a concrete pad (200 x 300m).

### 3.2.7 Gas processing facility

CSG enters a GPF via the gas gathering system. Here, the CSG is compressed and dehydrated to remove any remaining water which may have been transferred with the gas through the gas gathering system. The compressed CSG is then sent to the high pressure gas pipeline system for transmission to the main gas transmission pipeline (the gas pipeline) or another regional transmission pipeline.

The existing Spring Gully GPF is shown in Figure 3.18. The gas processing and compression area is in the background, behind the offices and workshop area. The facilities for the Australia Pacific LNG Project will generally be larger than the Spring Gully facility, and would use a different compression configuration, but the facility layout would be similar. Construction of each GPF will require the clearing of an area of approximately 50ha.

**Figure 3.18 Spring Gully gas processing facility**

Based on a conservative nine kilometre drainage circle radius, the Project could have a maximum of 23 GPFs across the entire development area over the 30-year life of the Project (refer to Figure 3.2 to Figure 3.8). The final design will aim to minimise the number of installed facilities.

Capacities of the various GPFs mainly depend on production capabilities of the associated wells. Depending on actual field performance, some GPFs may be increased in capacity to accept additional gas flows over time. In some cases, the GPF could decrease in production output, so installed equipment may be re-deployed to other gas processing locations.

Each will be a self-contained entity including stormwater diversion drainage systems, runoff treatment via oily-water capture and processing for skid-mounted equipment and first-flush sediment ponds. The alternative technologies and enhancements discussed in Section 3.8 are also being considered and may be incorporated.

#### *Process description*

The gas travels through the gathering system to arrive at the GPF. When the wells are at their pre-peak condition (generally at the start of the gas field's life), the arrival pressure is expected to be

around 140kPag. Later, when most wells are operating at post-peak production, the arrival pressure could be lower.

The gas is then collected and transported to a number of compression units operating in parallel to raise the gas pressure to approximately 13,500kPag. The development base case for this environmental impact statement assumes that the compression units would be a combination of rotary screw compressors for the initial pressure boost, followed by reciprocating units to meet the required noise guidelines. The optimal selection of technologies will depend on the availability of electrical power, the gas field productivity characteristics and site-specific noise constraints.

Both types of compressors are likely to be driven by internal combustion engines which use CSG as fuel.

As the CSG is compressed it becomes heated. It then passes through a cooler, separating the residual water from the gas. The cooled compressed gas flows to a dehydration unit. This removes most of the water in the gas so it meets specification requirements for transport in gas pipeline.

This dehydration process is carried out via circulating tri-ethylene glycol liquid to absorb water vapour from the gas stream in the dehydration unit. The tri-ethylene glycol is then regenerated for reuse by heating it to approximately 200ºC to boil off the absorbed water. Tri-ethylene glycol dehydration is a low cost, well-proven technology used for most CSG and conventional natural gas processing.

For application in CSG, this is an energy efficient process that produces relatively few gaseous or liquid emissions. While there are alternative technologies available, these generally over-dehydrate and are therefore energy inefficient and not appropriate for this application.

Once dehydrated, the dried gas is metered and directed to the high pressure gas network or gas pipeline. The development base case adopted for the EIS is based on using discrete compression 'building blocks' handling 75, 150 and 225TJ/d of CSG.

The 75TJ/d compression block usually includes:

- Seven screw compressors driven by internal combustion engines, with compressed gas cooling carried out using air coolers with engine-driven fans
- Four reciprocating compressors, with internal combustion engine drives with engine-driven cooling fans.

The 150TJ/d compressor block usually includes:

- Thirteen screw compressors driven by internal combustion engines, with compressed gas cooling carried out using air coolers with engine-driven fans
- Seven reciprocating compressors, with internal combustion engine drives with engine-driven cooling fans.

The 225TJ/d compressor block usually includes:

- Twenty screw compressors driven by internal combustion engines, with compressed gas cooling carried out using air coolers with engine-driven fans
- Ten reciprocating compressors, with internal combustion engine drives with engine-driven cooling fans.

Other ancillary systems required within a GPF to support its operation, include:

- Power generation facilities fuelled by CSG including switch gear and cabling

- Instrument air systems, instrumentation and control equipment
- Flare facilities for safe combustion of CSG during short-term periods of compression outage, process upsets of component plant or unscheduled stoppage of the entire GPF. Flare systems are key parts of any GPF and allow the facility to be operated safely under a range of process and ambient conditions
- Administration, maintenance, warehousing and accommodation facilities.

Figure 3.19 shows typical configuration of flows of gas through a gas processing facility.

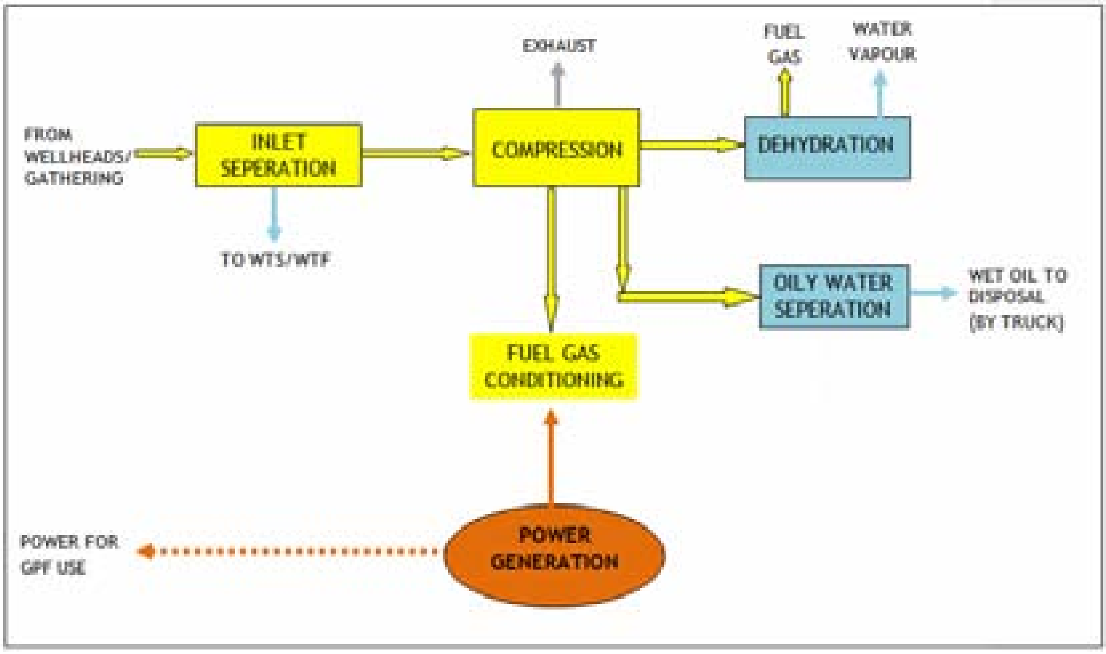



**Figure 3.19 Typical input/output streams for a gas processing facility**

### *Typical chemicals used in gas processing facilities*

GPFs use a range of chemical additives and petroleum products such as oils both in the CSG compression and dehydration process and in the GPF equipment.

Most of the chemicals, including biocides and corrosion inhibitors, used in the GPFs are not dangerous goods, as defined by the *Dangerous Goods Safety Management Act 2001*. Limited quantities of dangerous goods, including corrosive liquids (Class 8) such as sodium hypochlorite, are used during gas processing activities.

In support of the gas processing operation, fuels and oils such as hydraulic oils are used in the GPF and associated facility equipment. All chemicals will be stored and handled in accordance with the relevant legislative requirements and Australian Standards including the provisions of:

- AS 3780:2008 – The storage and handling of corrosive substances
- AS 1940:2004 – The storage and handling of flammable and combustible liquids.

Chemicals commonly used in the GPFs are included in Table 3.1.

**Table 3.1 Chemicals used in gas processing facilities**

| Chemical | Packaging type | Packaging size ($m^3$) | Estimated for 75 TJ/D 'building block' ($m^3$) | Notes (DG = dangerous goods) |
|---|---|---|---|---|
| Anti-scalant | Bulk | 1 | 3 | Non-DG |
| Biocides | Drum | 0.02 | 0.2 | Process chemical to prevent sulphur reducing bacteria in wells and process. Non-DG |
| Flocculants | Bulk | 1 | 4 | Non-DG |
| Hydraulic Drive Oil | Bulk | 25 | 2 x 25 | Non-DG, combustible liquids |
| Sodium Hypochlorite | Drum | 0.02 | 0.2 | Class 8 DG, Hypochlorite solution, bunded pallet |
| Tri-ethylene glycol | Bulk | 1 | 3 | Process chemical – gas dehydration |
| Oils | Drum | 0.02, 0.205 and 1 | 4 | Non-DG , combustible liquids including hydraulic oils |
| Crankcase Lube Oil | Bulk | 25 | 2 x 25 | Non-DG, combustible liquid |
| Cylinder Lube Oil | Bulk | 25 | 2 x 25 | Non-DG, combustible liquid |
| Diesel | Bulk | 12.4 | 2 x 13 | Non-DG, combustible liquid |

1. Range of other chemicals and products including reverse demulsifier, aerosol cans, oxy-acetylene bottles, gases and minor chemical storage at accommodation facilities.

All chemicals used during the gas processing operation are considered to have minimal impact on the environment based on the following mitigation measures being implemented:

- Adherence to relevant legislative and Australian Standard storage and handling requirements
- Use of inert and/or non dangerous goods for the majority of the gas processing operations
- Limited used of chemicals and fuels classed as dangerous goods.

In addition, Australia Pacific LNG will continue to investigate additives that are safer to handle, which may have lower toxicity constituents, yet still meet operational standards. More detailed information regarding the handling and storage of dangerous goods is provided in Chapter 22, Hazard and Risk.

### *Design criteria*

The typical composition of CSG exported from the GPF is made up of methane (97.3%), ethane (0.1%), nitrogen (2.3%) and carbon dioxide (0.3%). Gas entering the GPF is essentially the same composition except that it contains approximately 1.6% water vapour.

Each facility would handle 75, 150 or 225TJ/d of gas production, and would be based on 75TJ/d modules but could also include smaller booster compressor stations in some areas.

Gas flow rates will also vary depending on the productivity of each gas field. Inlet pressure will typically be 140kPag at 10 to 30ºC, possibly reducing later in field life. The GPF will discharge the gas at pressures between 10,000 and 13,500kPag at approximately 55ºC.

GPFs are designed to achieve high reliability and low scheduled maintenance requirements. The high reliability design is expected to minimise the number of operations staff, reduce exposure levels to routine and non routine tasks and contribute to an improved safety performance.

The compression technology evaluation and design will consider occupational health, safety and environment (HSE) impacts, such as footprint, noise and air emissions. The design will conform to Australian Standards and/or equivalent international standards. It will also comply with Australia Pacific LNG's HSE management system requirements to meet environmental performance and process safety objectives.

The GPFs will incorporate an integrated information and communication system which will be designed to improve operator response time and serviceability.

### 3.2.8 Water treatment facility

Associated water from the low pressure gathering system is delivered to the WTF's feed pond. At this location, the associated water is treated using a variety of processes. The water treatment facilities will vary in size depending on the volume of associated water produced. The main treatment technology being considered is desalination via reverse osmosis technology.

Reverse osmosis is a specialised filtration process often used for water treatment, where pressure forces a solution through a membrane that traps most of the dissolved components. The result is a 'permeate' stream, while the dissolved salts are kept aside as a concentrated saline solution (brine stream).

A range of management options, focussing on beneficial re-use, are currently being developed for both the permeate and brine streams, in accordance with regulatory policy. Proposed management options will require associated infrastructure, such as pipelines for permeate and lined storage ponds for brine.

The treated water could be suitable for a number of uses. This might include commercial use, such as:

- Water for mining, power stations or feedlots
- Irrigation for local agriculture
- Supplementing community water supplies and environmental flows
- Recharging aquifers within the Great Artesian Basin
- CSG industry aggregation of associated water for beneficial reuse.

Associated water typically contains a range of salts which include sodium chloride or 'common salt', sodium carbonate and sodium bi-carbonate. Australia Pacific LNG has an existing WTF that uses reverse osmosis technology operating successfully at the Spring Gully field (Figure 3.20).

Up to 85% of the associated water can be recovered at the Spring Gully facility using reverse osmosis as treated water with a salt content of less than 0.15 grams per litre. Post-treatment may be required to ensure compatibility, depending on the final use of the treated water. Options to achieve treated water recoveries above 95% are being considered for inclusion in the design of new water treatment facilities.

**Figure 3.20 Spring Gully water treatment facility**

### *Surface facilities and infrastructure*

The typical facilities associated with a WTF are lined water feed ponds, reverse osmosis feed pumps, reverse osmosis facilities, lined storage ponds for high salinity brine water and power generation. The estimated total footprint (cleared area) of a WTF, irrespective of its capacity, is approximately 4ha. A typical feed pond requires 20ha and a typical brine storage pond requires between 100 and 220ha.

Strategically the associated water treatment facilities have been located centrally to several gas fields' developments. The centrally located sites have been determined through a multi-criteria analysis and are shown on Figure 3.2 to Figure 3.8. This selection process ensures that environmental, hazard and risk, social and cultural heritage values are considered as part of the decision making process.

The facilities are modular and responsive to actual development sequence and produced water flow rates. For the scale of development being considered, a modular 20ML/d facility has been demonstrated to be the most efficient. Each WTF would be expected to have a capacity of between 20 and 80 ML/d of associated water, depending on water production at the time.

The development timing for these facilities will be staged to coincide with the progression of the drilling program. Associated water is produced from the wells in relatively large volumes before significant gas production, so all associated water handling infrastructure must be in place before the wells in an area commence production. The plant sizes will vary from location to location, based on forecasts for collective well performance in each gas field.

Eight possible locations for WTFs have been identified across the entire development area. These WTFs would only be provided as and when the respective gas fields were developed. Only six locations are likely to be required to support the entire CSG fields' development, so two of these are considered to be 'alternative locations'.

Further details on construction of associated WTFs are provided in Section 3.5.5.

### Process description

Associated water from gathering systems flows into the feed pond at the WTF. The pond is mainly an inlet collection system for the facilities and provides buffer storage capacity, some cooling, and separation of coarse suspended solids. The water is pumped from here to the reverse osmosis unit, where it is pre-treated using very fine filtration. It then passes through to the primary and secondary stages of the reverse osmosis system process. Figure 3.21 shows the basic flow-through of a typical WTF.

The treated water or 'permeate' leaves the reverse osmosis unit and may need to be further treated before being utilised for beneficial reuse or disposed of in an approved manner. Meanwhile, the brine stream from the reverse osmosis unit is directed to the lined storage pond, where evaporation will cause further concentration. Final salt disposal options, which are still under investigation, include:

- Producing potentially saleable salt products
- Implementing salt crystallisation and burying salts in approved waste management facilities
- Injecting high concentration brines into deep, hydraulically isolated geological reservoirs.

Apart from brine, waste from the WTF primarily consists of filtered solids and other chemical cleaning solutions. This waste would be biodegraded and recycled via feed ponds where technically practicable. Any remaining streams would be combined into the brine waste stream.

Filtration solids collected prior to reverse osmosis treatment will be dewatered and appropriately managed. Beneficial use of this material is subject to the sludge composition which may form part of the brine re-use options reviewed in Volume 2 Chapter 12, and will be subject to Department of the Environment and Resource Management (DERM) approvals.

It is expected that each WTF will have oily wastewater in very small volumes. This will be directed to the nearest GPF oily water treatment system and appropriately managed as discussed in the EM Plan (refer Volume 2 Chapter 24). Grey and black water will be managed on a site-by-site basis, according to current regulations.

Stormwater will be managed by firstly diverting it around the facility. Stormwater collected on the facility site will be captured through a conventional stormwater system. This usually includes a trench network, valves, sumps and sedimentation ponds. Stormwater is tested in the sedimentation ponds and released when discharge criteria is achieved. Chapter 11: Surface Water, provides more detailed information regarding the Project’s stormwater management systems.

All associated water, plant wash-down water and other wastes will be segregated from stormwater systems. All process area wash-down wastes will be captured and returned to facility feed ponds for reprocessing.

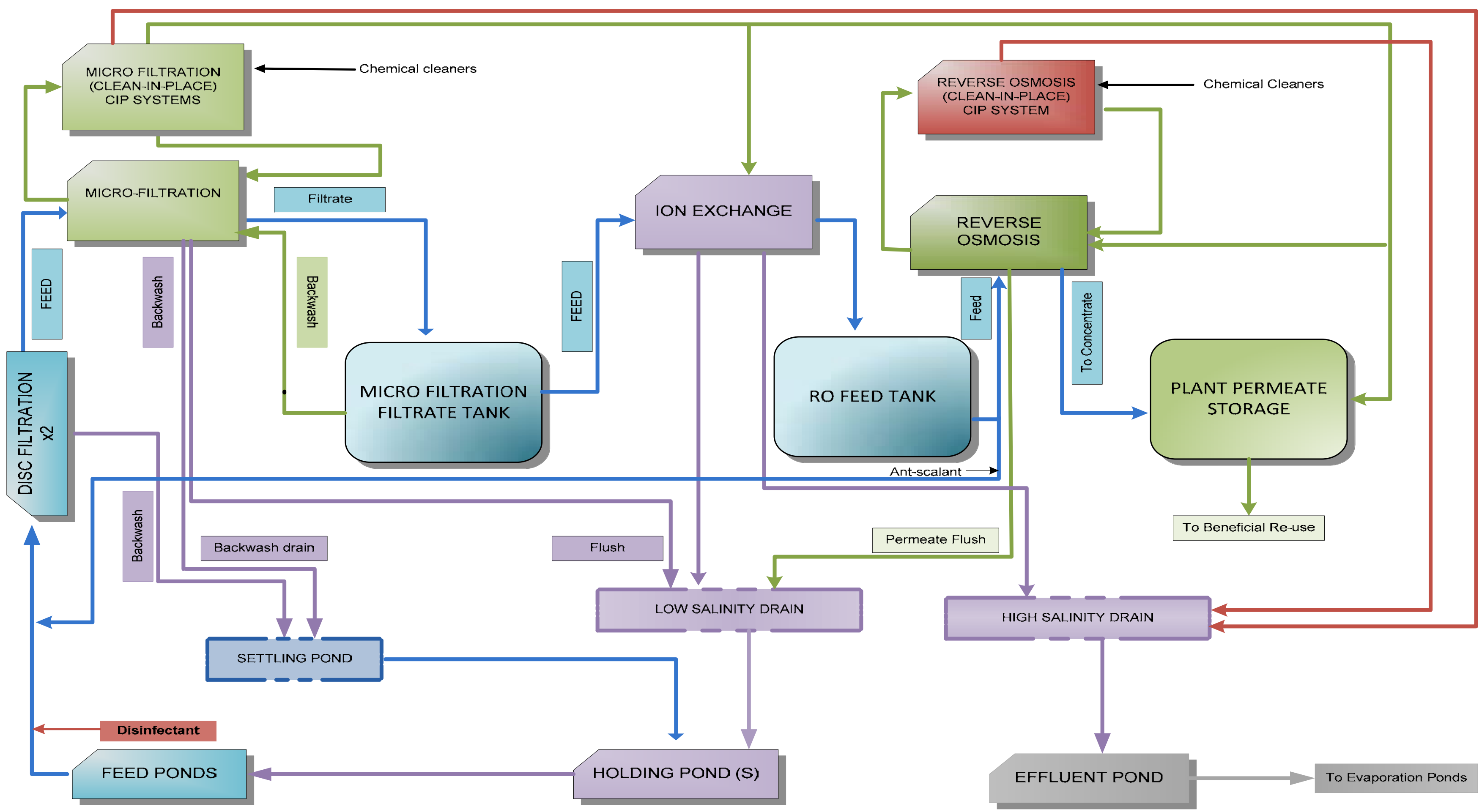



**Figure 3.21 Water treatment facility – process diagram**

### *Typical chemicals used in water treatment facilities*

The water treatment process incorporates various chemicals during the different phases of treatment. The majority of these chemicals are classed as dangerous goods as defined by the *Dangerous Goods Safety Management Act 2001*.

In support of the WTFs, fuels and oils (e.g. diesel) are used in the facility and associated equipment.

All chemicals will be stored and handled in accordance with the relevant legislative requirements and Australian Standards including the provisions of:

- AS 3780:2008 - The storage and handling of corrosive substances
- AS 1940:2004 - The storage and handling of flammable and combustible liquids.

The chemicals commonly used in the WTFs are included in Table 3.2.

**Table 3.2 Chemicals used in water treatment facilities**

| Chemical | Packaging type | Estimated storage for max. 80ML/d facility ($m^3$) | Notes (DG = dangerous goods) |
|---|---|---|---|
| Anti-scalant | Bulk | 48 | Non-DG |
| Biocides | Bulk | 8 | Class 6 DG, packaging group III |
| Citric acid | Bulk | 33 | Non-DG |
| Diesel | Bulk | 6 | Emergency generator, Non-DG, combustible liquid |
| Hydrochloric acid | Bulk | 150 | Class 8 DG, packaging group II (33%) if ion exchange is part of design |
| Anhydrous ammonia | Bulk | 2 | Class 2.3 Toxic Gas |
| Chlorine | Bulk | 5 | Class 2.3 Toxic Gas |
| Lubrication oil | Bulk | 7 | Non-DG, combustible liquid, self-bunded tanks |
| Sodium bisulphate | Bulk | 70 | Class 8 DG, packaging group III |
| Sodium hydroxide | Bulk | 58 | Class 8 DG, packaging group II |
| Sodium hypochlorite solution | Bulk | 45 | Class 8 DG, packaging group III |

Note: Around 30 miscellaneous chemicals and blends of chemicals (reagents) in small quantities will also be used.

### 3.2.9 Brine ponds

The salts removed from the associated water during reverse osmosis treatment are concentrated into a low volume reject or 'brine' stream. This has a salt content of around 60 grams of salts per litre. This brine will be stored in fully engineered, purpose-built, lined ponds to further concentrate the stream by evaporation. Prior to transport to the ponds, small amounts of brine may be blended for reprocessing through the reverse osmosis plant. The majority of the effluent stream will be piped to the identified pond locations.

At this stage it is anticipated that only one of the potential six WTFs would include brine ponds as part of the WTF itself. Remote brine ponds would be provided for the remaining five facilities with consolidation to minimise the development footprint. In the first five years of the Project’s maximum development case, from 2012 through 2016, it is estimated that the total footprint of brine ponds could reach as much as 670 ha. During the initial five year development period (maximum development case) an annual average increase of salt loading in the brine ponds of 116,000$m^3$ (dry weight) is estimated.

### 3.2.10 High pressure gas pipelines

To enable delivery of the CSG to the LNG facility at Gladstone, a network of in-field high pressure pipelines will be developed which will collect gas from a number of GPFs in the gas fields and deliver it to the gas pipeline. The high pressure gas pipeline network is shown on Figure 3.2 to Figure 3.8. The connection of the high pressure pipelines (connecting laterals) to the commencement of the gas pipeline is also indicated.

The in-field high pressure gas pipeline network consists of the following:

- Fairview to Spring Gully pipeline
- Spring Gully to Wallumbilla loop
- Combabula lateral, including the:
  - Pine Hills spur line
  - Reedy Creek spur line
  - Combabula 2 spur line
  - Combabula 1 spur line
  - Ramyard spur line
- Condabri South lateral, including the:
  - Condabri South nodal spur line
  - Condabri South spur line
  - Condabri Central spur line
- DDPS Pipeline related supply, including:
  - DDPS Condabri link
  - Talinga spur line (existing)
  - Orana spur line

  - Kainama spur line.
- Associated pig launchers and receivers (scraper stations):
  - Connections for future GPFs
  - Mainline valve facilities.

Where practicable, it is planned that the high pressure gas pipeline network will be co-located with other infrastructure such as the low pressure system, roads, tracks and fibre optic cable.

The high pressure gas pipeline network operates in free flow mode, as the GPFs include adequate discharge compression capacity. Additional booster compression at the Talinga metering station may be required to flow gas from the spur lines feeding the eastern section of the existing Darling Downs Power Station pipeline into the western section of the existing Darling Downs Power Station pipeline before delivery to the Darling Downs Power Station Condabri link.

The design, construction, operation and rehabilitation of all pipelines will be in accordance with Australian Standard 2885.

### 3.2.11 Rehabilitation and decommissioning

Once infrastructure is no longer in use, it is removed and reused, recycled or disposed of. The disturbed area is then rehabilitated to the original land use.

DERM requires a financial assurance to be lodged as part of the application for an environmental authority, which is a necessary approval for the field development. This financial assurance is updated throughout the life of the environment authority in accordance with the approval conditions of the Project.

Decommissioning and rehabilitating the GPFs, WTFs, well sites and connecting pipelines will involve:

- Stakeholder consultation
- Environmental assessment
- Preparatory works
- Cessation of production
- Pipeline decommissioning
- Peripheral equipment decommissioning
- Process equipment decommissioning
- Electrical and control systems decommissioning
- Buildings decommissioning
- Tanks and ponds decommissioning
- Material and equipment removal and disposal
- Hazardous material treatment
- Site clearance, such as removal of roads, drains, fences and other project-related infrastructure and/or components
- Site rehabilitation.

While these activities are listed in their typical order of occurrence, they would not always occur in this sequence. The decommissioning and rehabilitation process is discussed in more detail in Section 3.7.

## 3.3 Field development schedule

Australia Pacific LNG plans to explore and develop the following petroleum leases and authority to prospects:

- ATP 606P - Combabula
- ATP 972P - Ramyard
- ATP 973P - Carinya
- PL 209 - Woleebee
- PLA 216 - Dalwogan
- PLA 267 – Condabri North
- PLA 266 – Condabri South
- PL 215 - Orana
- PLA 225 - Kainama
- ATP 663P – Gilbert Gully
- PLA 289 – Kainama North
- PLA 272 – Orana North
- ATP 692P - Kainama North
- PLA 265 – Condabri Central
- PL 226 – Talinga (excluding the approved 90TJ/d).

The development of the above petroleum leases and authority to prospects will involve up to 10,000 wells with a maximum of 600 wells drilled per year. Well spacing for field development depends on a number of variables including surface and land use constraints, environmental constraints, hazard and risk reviews, cultural heritage constraints and the productivity of an area. It is envisaged that the well spacing will be between 500m and 1500m. However, an average well spacing of 750m has been used for development planning and impact assessment purposes.

Approximately 5,000 wells will be drilled in the period from 2011 to 2021 to meet the demand of a two-train or 9Mtpa LNG facility. An additional 5,000 wells will be drilled over the remaining years of the Project to supply the LNG facility when it is upgraded to four LNG production trains. This may include infill of existing developed areas. Gas may also be sourced from the existing Queensland gas pipeline network under commercial arrangements.

The development will include GPFs, WTFs, water transfer stations, and brine ponds. It also includes a local separator/metering facility at well sites and a system of low pressure gathering lines linking individual wells. The pipeline network will include high pressure pipelines and the water transfer pipelines.

Other facilities will also be required to support the gas fields' development. This includes access roads, pipe and equipment stores and stockpile areas, temporary and permanent workforce accommodation facilities, power and communication systems.

### 3.3.1 Plan overview

A field development plan will be developed to support the development of the gas fields and provide efficiency in the allocation of resources for specific construction activities. The field development plan will include details for the:

- Preparation of well sites, followed by drilling and completion of wells
- Development of the low pressure gas system and water gathering network

- Construction of a water pipeline from an existing operating WTF to the gas field, for construction purposes, if practicable. Water bores or supply from another source will be required when treated associated water is not available
- Establishment of temporary accommodation facilities for the construction workforce and permanent accommodation facilities for the operational workforce along with related infrastructure. Treated water from the WTF will be utilised where possible for these facilities
- Development of water treatment facilities
- Development of GPFs
- Commissioning of WTF installations, GPFs and permanent operations infrastructure
- Progressive rehabilitation of well sites and pipeline corridors
- Demobilisation and relocation of the construction workforce and temporary accommodation facilities to the next field development area.

An overview of the order of field development and timing of major infrastructure is summarised in Table 3.4. An indicative schedule of the number of wells drilled for each year, the location of gas fields and key infrastructure is also included.

The project infrastructure, including capacity requirements, planned for each field is outlined in Table 3.3. The actual field development plan will be refined during the front-end engineering design (FEED) process which will be undertaken prior to a final investment decision being made for the Project. Following this decision, the field development plan will then be progressively updated to account for each gas field's production performance and to incorporate the results of the ongoing exploration and pilot testing programs.

**Table 3.3 Indicative project infrastructure by field (to be used as a guide only)**

| Development area | GPF/WTF | Capacity |
|---|---|---|
| Condabri | GPF_CNN_04 | 75TJ/d |
| | GPF_CON_02b | 150TJ/d |
| | GPF_CON_01b | 150TJ/d |
| | GPF_CNS_03 | 150TJ/d |
| | WTF_CON_01 | 80ML/d |
| Woleebee | GPF_WOL_01 | 75TJ/d |
| | WTF_WOL_01 | 40ML/d |
| Combabula/Ramyard | GPF_COM_03a | 225TJ/d |
| | GPF_RCK_04a | 150TJ/d |
| | GPF_MUG_06 | 150TJ/d |
| | GPF_LUK_02a | 150TJ/d |
| | GPF_HCK_01a | 75TJ/d |
| | WTF_MEL_01 or WTF-RCK_01a | 80ML/d |

| Development area | GPF/WTF | Capacity |
|---|---|---|
| | WTF_HCK_01a | 20ML/d |
| Kainama | GPF_KIA_01a | 75TJ/d |
| Carinya/Dalwogan | GPF_NGA_02 | 75TJ/d |
| | GPF_BYM_03 | 75TJ/d |
| | GPF_CAS_05 | 75TJ/d |
| | GPF_CAR_01a | 75TJ/d |
| | GPF_DAL_01b | 75TJ/d |
| | WTF_BYM_03 | 40ML/d |
| Gilbert Gully | GPF_ZIG_06 | 75TJ/d |
| | GPF_GIL_02 | 150TJ/d |
| | GPF_WAA_04 | 75TJ/d |
| | GPF_ZIG_05 | 75TJ/d |
| | GPF_WAA_03 | 75TJ/d |
| | WTF_GIL_01a or WTF_GIL_01 | 80ML/d |
| Talinga /Orana | GPF_OAN_04 | 75TJ/d |
| | GPF_ORA_03b | 150TJ/d |
| | Talinga_GPF | 90TJ/d (existing) |
| | Talinga_WTF | 40ML/d (existing) |

### Table 3.4 Indicative field development program (to be used as a guide only)

| FIELD | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028-2045 (last year of drilling) | Project Water Treament Capacity (ML/day) | Project Gas Production Capacity (TJ/day) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Talinga | | | | | | | | | | | | | | | | | | | 80** | 90* |
| Combabula | | | | | | | | | | | | | | | | | | | | 225 |
| Condabri South | | | | | | | | | | | | | | | | | | | 80 | 450 |
| Pine Hills | | | | | | | | | | | | | | | | | | | 80 | 150 |
| Reedy Creek | | | | | | | | | | | | | | | | | | | | 300 |
| Condabri Central | | | | | | | | | | | | | | | | | | | | 75 |
| Orana | | | | | | | | | | | | | | | | | | | | 150 |
| Orana North | | | | | | | | | | | | | | | | | | 2028 | | 75 |
| Kainama | | | | | | | | | | | | | | | | | | 2028 | | 75 |
| Dalwogan | | | | | | | | | | | | | | | | | | | | 75 |
| Gilbert Gully | | | | | | | | | | | | | | | | | | 2034 | 80 | 450 |
| Woleebee | | | | | | | | | | | | | | | | | | 2029 | 40 | 75 |
| Ramyard | | | | | | | | | | | | | | | | | | 2031 | 20 | 75 |
| Carinya | | | | | | | | | | | | | | | | | | 2045 | 40 | 300 |
| Wells Drilled per Year | 300 | 300 | 345 | 450 | 555 | 540 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 565 | 520 | 235 | *150-50/yr* | | up to 10,000 wells drilled |
| | | | | | | | | | | | | | | | | | | | **Up to 420ML to be built** (not all identified locations will be built to maximum capacity) | **Up to 1,800 TJ to be built** (not all proposed locations will be developed) |

Duration of drilling, construction and operation activities within the tenure

Gas Processing Facility Upgrade (75TJ/d) except Talinga (90TJ/d)

Water Processing Facility Upgrade

* Total Talinga gas processing capacity will be 180 TJ/d given existing approved capacity is already 90TJ/d

Gas Processing Facility (75TJ/d) except for Talinga expansion

Gas Processing Facility (150TJ/d)

Water treatment facility (20 ML/d) including associated feed + brine ponds

** Total Talinga water treatment capacity will be 80ML/d given existing capacity is already 40ML/d.

### 3.3.2 Additional gas sources

Australia Pacific LNG will also access gas for the Project from additional sources. These include Australia Pacific LNG tenures outside of the Walloons gas fields, such as Spring Gully, and gas may eventually be sourced from Australia Pacific LNG's exploration areas in other gas fields in the Bowen Basin and the Galilee Basin. Australia Pacific LNG also holds significant equity in a number of tenures operated by other gas producers, from which additional gas will be sourced. Supply of gas from areas other than the Walloons gas fields is outside the scope of the approvals being sought for the Project.

Throughout the life of the Project, Australia Pacific LNG will continue to evaluate commercial opportunities. This may include acquisition of additional permits, purchasing gas from third parties or acquiring additional equity in producing areas.

Existing pipeline connections to the Spring Gully and Fairview gas processing facilities have been assessed under existing approvals. However, upgraded pipelines and the connections to the Wallumbilla hub and Darling Downs Power Station pipeline have been assessed in this EIS.

Staged investment in the gas fields will be based on an overall integration of the schedule with the gas pipeline and LNG facility schedules.

### 3.3.3 Ramp-up gas

The Darling Downs Power Station is an Origin owned gas-fired power station in the Darling Downs region near Braemar, 40km west of Dalby. It is anticipated to reach full commercial operation in the first half of 2010. Ramp-up gas, which is gas produced prior to the commissioning and operation of the LNG facility, will be directed to the Darling Downs Power Station and the Wallumbilla gas hub for use in the domestic market.

High pressure gas pipelines will be built from the Walloons gas fields and connect to the existing Wallumbilla to Darling Downs Power Station pipeline. The Darling Downs Power Station pipeline and power station are approved and operating under existing environmental authorities and are therefore excluded from this EIS.

### 3.3.4 Supporting infrastructure

#### *Water*

Significant construction infrastructure will need to be in place in these reasonably remote areas. This will drive early investment in the gas fields' area, to deliver supplies of both potable water and water for constructing facilities. This will be achieved by implementing a field development plan that efficiently uses associated water supplies to reduce the need for local water sources during construction.

Over the life of the Project, the primary source of water will be associated water, treated to a regulatory standard level appropriate for the intended use. In the latter stages of construction and during operation, the Project intends to have a largely self-sufficient water supply.

The estimated water usage for the Project is detailed in Table 3.5, including both low quality (averaging 2,000mg/L total dissolved solids) and high quality (potable) water use. The table also details predicted water demand by infrastructure type required for the Project.

Initially, potable water will be trucked and stored in designated tanks. Water for the ongoing operation of completed facilities will be sourced from the WTFs and will form only a small fraction of the project

construction volumes. Water efficiency measures will be implemented for the Project during construction and operation activities.

**Table 3.5 Water use over the 30-year life of the Project**

| Category | Description | Low quality (total ML) | High quality (total ML) | Total units | Total (ML) |
|---|---|---|---|---|---|
| Well | Per well for drilling, completion, rehabilitation and workforce | 0.264 | 0.070 | 10,000 | 3,340 |
| Gas and water gathering | Per well, gathering, tie-in, rehabilitation and workforce | 0.381 | 0.24 | 10,000 | 6,210 |
| Gas processing facility | Per facility, construction, dust control, commissioning and workforce | 500 | 32 | 23 | 12,236 |
| Water treatment facility | Per facility, construction, dust control, commissioning and workforce | 942 | 19.5 | 6 | 5,769 |
| High pressure gas pipeline network | High pressure gas pipeline network, construction, dust control, commissioning and workforce | 44 | 26.6 | - | 70.6 |
| Roads | Road construction, dust control and workforce for 160km of road | 184 | 1.6 | - | 185.6 |
| Vehicle wash-down | For development per day | 1 | | (20yr) 7,300 | 7,300 |
| Total | | | | | 35,111.2 |

### ***Telecommunications***

Telecommunication equipment will be installed early in the construction phase. Telecommunications is essential during construction and to ensure the health and safety of personnel.

Data and voice communications will be used on construction sites via the proposed microwave network infrastructure which will interface with the telecommunication carriers' service positioned at designated centres. These include two towers in the Combabula/Ramyard gas fields, one each in the Woleebee and Dalwogan gas fields, two in the Talinga/Orana gas fields, one between the Kainama and Gilbert Gully gas fields and two to the east of the Gilbert Gully gas fields. The preferred sites for the nine 50m telecommunication towers are shown on Figure 3.2 to Figure 3.8.

The disturbance area should not exceed 70m by 70m, with the tower as a central point. This area will be a fenced compound to maintain security and safety requirements, as it includes the anchor points used to stabilise the tower. An example of a telecommunication tower is shown in Figure 3.22.

**Figure 3.22 Telecommunication towers**

During the post construction phase, the microwave infrastructure will remain. Telecommunications towers will also be used for wireless communication applications such as two-way radio and wireless data.

For operations, fibre optic cable will also be used for communication between control centres (administration buildings) and the respective facilities. Where possible, the fibre optic cable will be co-located in a trench with gas or associated water pipelines.

The overall telecommunications infrastructure including fibre optic cable, microwave towers, radio repeater stations and wireless are required to support:

- Business data and voice network services, for access to all corporate data applications and telecommunications services, Australia Pacific LNG's internet protocol telephony based system, and all communications outlets at each in-field facility. Wireless local area network access to network services may be provided in future.
- Radio services for mobile two-way radio devices, and coverage for all in-field operational areas including well sites and along the high pressure gas pipelines
- Control network services, for network connectivity for control and telemetry equipment at all sites and pipeline valve stations. All control/telemetry traffic is to be segregated from business systems traffic using physically separate network equipment and cabling
- Security systems, as use of the telecommunication infrastructure for network communications between closed-circuit television equipment and other security equipment may be required in the future.

### *Transport*

The transportation of workers and materials for construction and operations for the Project will utilise a number of methods including road, rail, air and shipping. The transportation of construction and operations materials includes a combination of the following:

- Shipping from overseas to Australia
- Truck and rail movements from the Port of Brisbane and the Port of Gladstone (or other entry ports) to the operational areas
- Air transport from overseas and domestic locations
- Rail from centralised locations to regional areas to be transferred to heavy vehicles
- Heavy vehicles for transfer of goods and materials to regional locations.

The supply chain for the gas fields will generally extend from Brisbane to regional logistics hubs to be established at Miles and Roma via the Warrego Highway. From these central locations construction materials, equipment, products and supplies will be distributed to the gas fields.

Workers and external contractors and suppliers will also transverse to and from the gas fields using the various forms of transportation available, and on a daily basis will travel from their homes, or temporary and permanent accommodation facility (50 to 800 workers per facility) using buses and small capacity working vehicles (e.g. welding and drilling trucks).

Upgrades to road networks are anticipated to be required in the gas fields for the Project's activities. Each of the intersections and road networks which have been identified as potentially requiring upgrades are detailed in Volume 2 Chapter 17. Australia Pacific LNG is currently in discussions with Queensland Rail regarding Project related rail movements and to identify if upgrades would be required to the rail network.

The air transportation network has also been identified as potentially requiring upgrades to meet the demands of the gas fields' development, specifically the Miles Aerodrome. Australia Pacific LNG also supports Maranoa Regional Council’s efforts to obtain federal funds to upgrade Roma airport. Airport upgrades will be further assessed once movement of non resident workers to and from the gas fields has been more fully defined.

The Gladstone and Brisbane ports are not expected to require additional expansion resulting from the Project's activities. Australia Pacific LNG will work with the responsible authorities for the movement of materials required for the Project through the ports.

Heavy trucks will be utilised to move earth moving equipment, drilling rigs, modular gas plant and WTF components. These loads will be delivered where practicable between 6:30am and 6:30pm to laydown areas, construction sites and well sites.

Peak traffic volumes will occur during the construction phase of the Project. It is anticipated that peak daily traffic for all activities across the gas fields may be over 500 vehicle movements per day. These activities should be localised and short term, as the construction and development is completed and these workforces are relocated.

It is anticipated that during the operational phase of the project traffic movements will plateau to an average daily volume of 450 to 500 vehicle movements across the entire gas fields' area.

Full details about transporting plant and equipment, construction material, water and personnel, most of which will be done by road, are available in Volume 2 Chapter 17 and in Volume 5 Attachment 35.

## 3.4 Project planning

The Project is one of the largest, geographically diverse and complex projects proposed in Australia to date. Key planning steps as part of the project development process include:

- Preliminary siting of key project infrastructure, such as gas process facilities and water treatment facilities
- Stakeholder and community engagement and review of existing land use
- Multi-criteria analysis to objectively evaluate technical, environmental, social and cultural heritage constraints using existing information, and to identify further assessment requirements (including optimising the location of the project footprint, as discussed in Section 3.4.1)
- Using the principles of a strength, weaknesses, opportunity and threats analysis (SWOT) process for selection of major technology and key practices, verification of available information by assessing recent aerial photography, site inspections and revised mapping to ensure there were no additional constraints to sites selected through multi-criteria analysis
- Refinement of major infrastructure locations and technologies based on further information and impact assessment processes
- Identification of mitigation measures and monitoring requirements, based on a risk assessment process that considers legislative requirements and impacts on the natural environment, the community and cultural heritage. The risk assessment framework is discussed in Volume 1 Chapter 4.

Planning for a 30-year CSG project requires more flexibility than the traditional gas industry field development approach, given the potentially wide variations in quantities of gas and associated water produced in any one area. CSG projects evolve significantly over time due to the nature of gas fields. As such, the infrastructure requirements detailed in the EIS are expected to cover the maximum development case. Depending on actual reservoir conditions, some infrastructure identified may not ultimately be required.

Beyond the EIS process, the Project will continue to evolve through an adaptive planning approach as gas reserves are proven and developed. Selection of sites to be developed will be guided by gas and

associated water profiles, which are only available approximately six months after pilot studies begin in each region. For this reason, the first five years of the Project are more defined as preliminary data is available for these areas. The Project beyond the first five years will be refined on a continual basis to reflect production experience and monitoring results from the pilot exploratory stages of the development.

The availability of new technologies will also be a component of the adaptive approach to planning. This EIS seeks approval for the maximum development scenario. However, adaptive management is expected to result in further reductions in impact.

Detailed planning and refinement of individual gas fields' are part of a field development plan, which is usually completed at least 12 to 24 months before access to the area may be required. The field development plan locates facilities, giving careful consideration to known constraints such as landowner requirements, the environment and cultural heritage aspects. The proposed location of wells, gathering network and access tracks then requires further investigation and site inspections, to confirm constraints at a local level and consult with individual landholders.

When major Project infrastructure is planned in an area, Australia Pacific LNG will either:

- Site major facilities such as central GPFs, water treatment facilities, and accommodation on properties owned by Australia Pacific LNG, or
- Consider long-term leasing arrangements, where the siting of facilities complements the landowners existing business (e.g. the CSG facilities installed on the privately owned Taloona property adjacent to the Australia Pacific LNG-owned Spring Gully)

Australia Pacific LNG will consider these two options throughout the life of the Project to enable appropriate siting for the construction of Project infrastructure.

### 3.4.1 Multi-criteria analysis

The multi-criteria analysis is designed to confirm key site constraints. This is achieved by developing a scoring spreadsheet to assess potential infrastructure siting locations. It also enables key constraints to be identified, including technical constraints such as topography and constructability, and environmental and social factors such as threatened ecological communities, regional ecosystems and proximity to townships.

The multi-criteria analysis identified data gaps and requirements for further studies, particularly the field validation and assessment through the EIS process.

#### *Assessment criteria*

An initial assessment of the original and alternative plant and facility locations was undertaken based on the criteria in Table 3.6. The criteria were assigned a numerical value between 1 and 5, with 1 being a failure to meet a specific criteria and 5 being fully satisfying the criteria. The output of the initial assessment was workshopped and the criteria further refined to provide specifics for each infrastructure type – GPFs, WTFs, water transfer stations and brine ponds.

**Table 3.6 Assessment criteria for plant and facility locations**

| | |
|---|---|
| **Technical criteria** | |
| Utilisation of plant | Proximity to optimum position for wellhead group |
| | Proximity to existing gas pipelines or proposed major trunk line |
| Hydrology and flood risk | Flood risk |
| | Runoff and erosion |
| Geotechnical constraints | Foundations |
| Infrastructure access | Rail |
| | Road |
| | Airport |
| | Township |
| Constructability | Site topography and bulk earthworks requirements |
| | Ease of excavation |
| | Access |
| **Environmental criteria** | |
| Land use | Impact on agricultural land |
| | Nature conservation (ecological significance and proximity to environmentally sensitive areas). |
| | Disturbance footprint (based on plant layout) |
| **Social criteria** | |
| Noise | Proximity to sensitive receptors (residences) |
| | Mitigating terrain |
| | Cost of mitigation |
| Social and public amenity impact | Built visual pollution |
| | Proximity to regional centre |
| | Flare visibility |
| Cultural heritage | Indigenous sites |
| | Non-indigenous sites |
| | Native title |

### 3.4.2 Strengths, weaknesses, opportunities and threats analysis

A SWOT analysis is a common strategic planning tool. It ensures that clear objectives are defined for the selection process and that all factors related both positive and negative, are identified and addressed. The process of the SWOT analysis involves four areas of consideration:

- Strengths: attributes that are considered to be important to the ultimate success of the Project
- Weaknesses: attributes that prevent the achievement of a successful result to the Project
- Opportunities: potential elements that will prove helpful in achieving the goals set for the Project
- Threats: potential factors that could threaten the success of the Project.

Australia Pacific LNG has used SWOT analysis to assist the decision process for the Project. SWOT analysis has also been used for the pre-FEED design, adaptive associated water management plan and this EIS.

In general, SWOT analysis has assisted in defining alternative options to achieve the objective of managing issues in the most socially, financially and environmentally beneficial manner. The analysis provided direction and clarification of the options under consideration. It also provided a holistic oversight distinguishing likely opportunities given the project parameters, requirements and ultimate project objective.

### 3.4.3 Logistics plan

An integrated logistics plan will be developed and implemented, and is planned to be supported by logistics centres in Brisbane, as well as regional centres such as Roma and Miles. The plan will be developed to ensure the effective flow of goods and services to the field locations.

This infrastructure will be established early in the project life, and will remain in place to service the ongoing requirements of the operational phase.

### 3.4.4 Health, safety and environment

Origin will develop and operate the Walloons gas fields and the gas pipeline on behalf of Australia Pacific LNG. The gas fields will operate under the Origin Energy HSE management system, as summarised below.

The HSE management system was developed in accordance with the principles of the Australian/New Zealand Standard ISO 14001 Environmental Management Systems.

Australia Pacific LNG's existing Spring Gully and Talinga developments are comparable but at a smaller scale compared with the Walloons gas fields' project, with similar environmental, cultural heritage and social impacts. These impacts are managed under the existing and evolving Origin HSE management system with particular emphasis on:

- Continual improvement of the management system, petroleum activities and operations, and assessment of new technologies
- Personnel training in issues related to health, safety, environment and cultural heritage relevant to their roles and responsibilities
- Key potential impacts monitoring; ecology, surface and ground water, weeds, erosion and rehabilitation success, with follow up action when necessary

- Internal and external reporting, including to relevant authorities and the community through an annual report
- Rehabilitation of disturbed areas following construction and operation, to return an area to a land use consistent with the surrounding environment
- Internal and external environmental auditing, including internal auditing of risk, HSE management, compliance with environmental approvals, and other key HSE aspects. External audits include HSE management system audits, and DERM audits of activities.

Examples of Origin's effective implementation of these HSE management system components include:

- Public reporting on greenhouse gas emissions, consumed water, produced water, nitrogen oxides and sulphur oxides in the 2008 Sustainability Report[1]
- Reducing the standard drilling footprint through a new drilling contract and changes to procedures and practices. Research is also ongoing to help reduce the footprint of other project activities, such as pipeline easements
- Conducting rehabilitation trials to identify the best ways to rehabilitate and establish biodiversity offsets in the Spring Gully area
- Establishing a plantation of Pongamia trees to beneficially reuse treated associated water from CSG production. Pongamia trees produce oil which can be converted to biodiesel for cleaner energy production
- Working with government agencies and other CSG producers to develop long term strategies for associated water use and other aspects of CSG production
- Engaging with landowners before conducting activities on their property to address concerns where practicable
- Researching injection of associated water to minimise impacts on groundwater users.

A requirement of Origin's HSE management system is to prepare a HSE plan or plans prior to construction and for all parts and phases of operations. These will include the EM Plan as outlined in Figure 3.23. This figure also lists the HSE management system standards and identifies the drivers for change and scheduled HSE management system activities. The Project's HSE plan is incorporated as a component of the field development plan.

The Project's activities will be measured against the EM Plan and HSE plan(s) to report on implementation of the management strategies.

[1] <http://www.originenergy.com.au/800/Sustainability-reports>

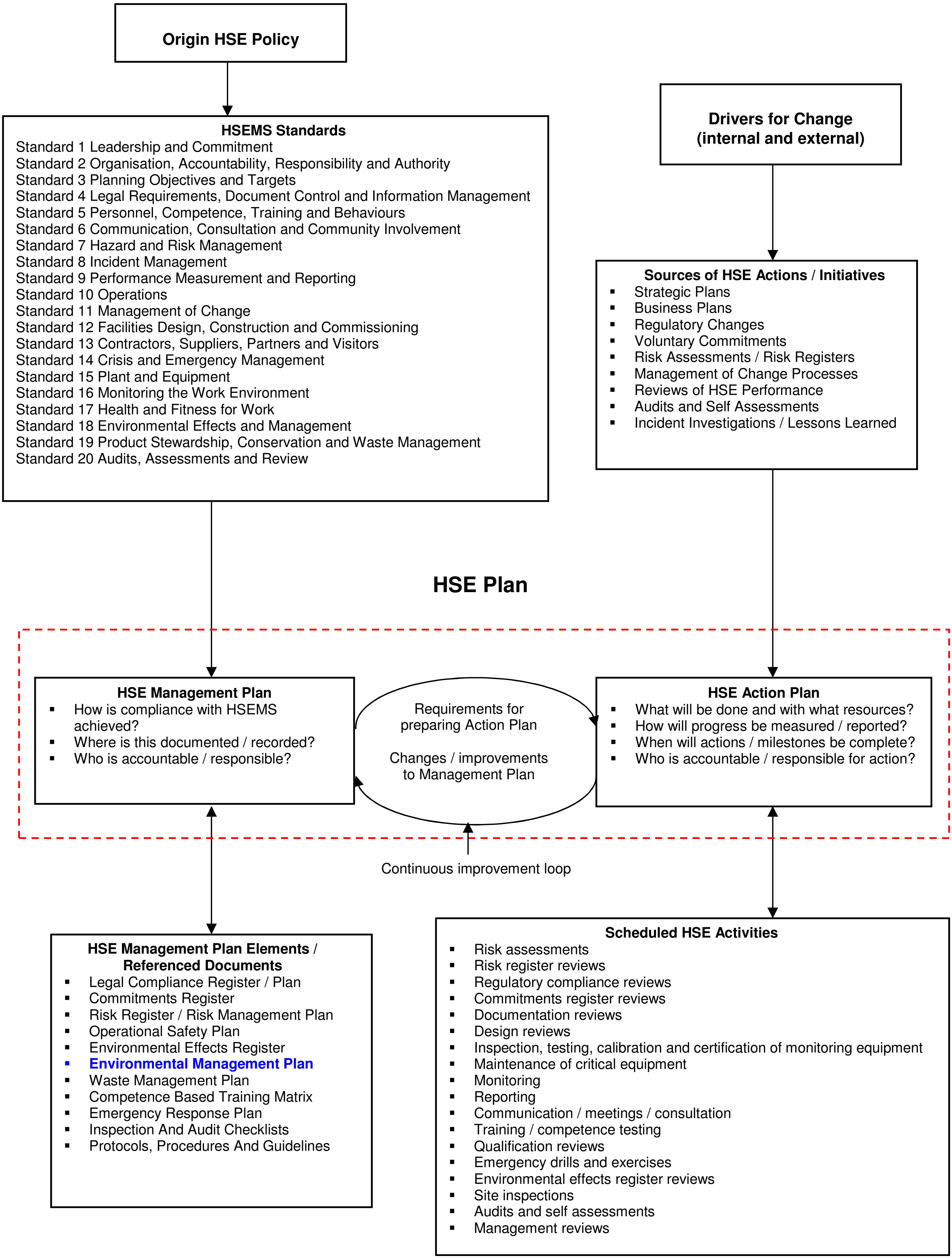



**Figure 3.23 Origin's Health, Safety and Environment Management System (HSEMS)**

## 3.5 Construction

The development of the gas fields will occur incrementally over the 30-year life of the Project. During construction, it is estimated that up to approximately 6,000ha of remnant vegetation will be cleared for the Project. A detailed assessment of the impacts and mitigation measures is provided in Volume 2 Chapter 8 and Volume 5 Attachment 14. In particular, an overview of environmentally sensitive areas and creek crossings is provided Volume 2 Chapter 9, and Volume 2 Chapter 8.

It is important to note that the footprint of the Project's activity decreases once the construction phase is completed and the operational phase begins. This is due to the progressive rehabilitation of disturbed areas, as discussed in Section 3.7.

Due to the flexible nature of CSG developments, relocating existing infrastructure such as roads, powerlines and utilities, is not anticipated.

### 3.5.1 Wells

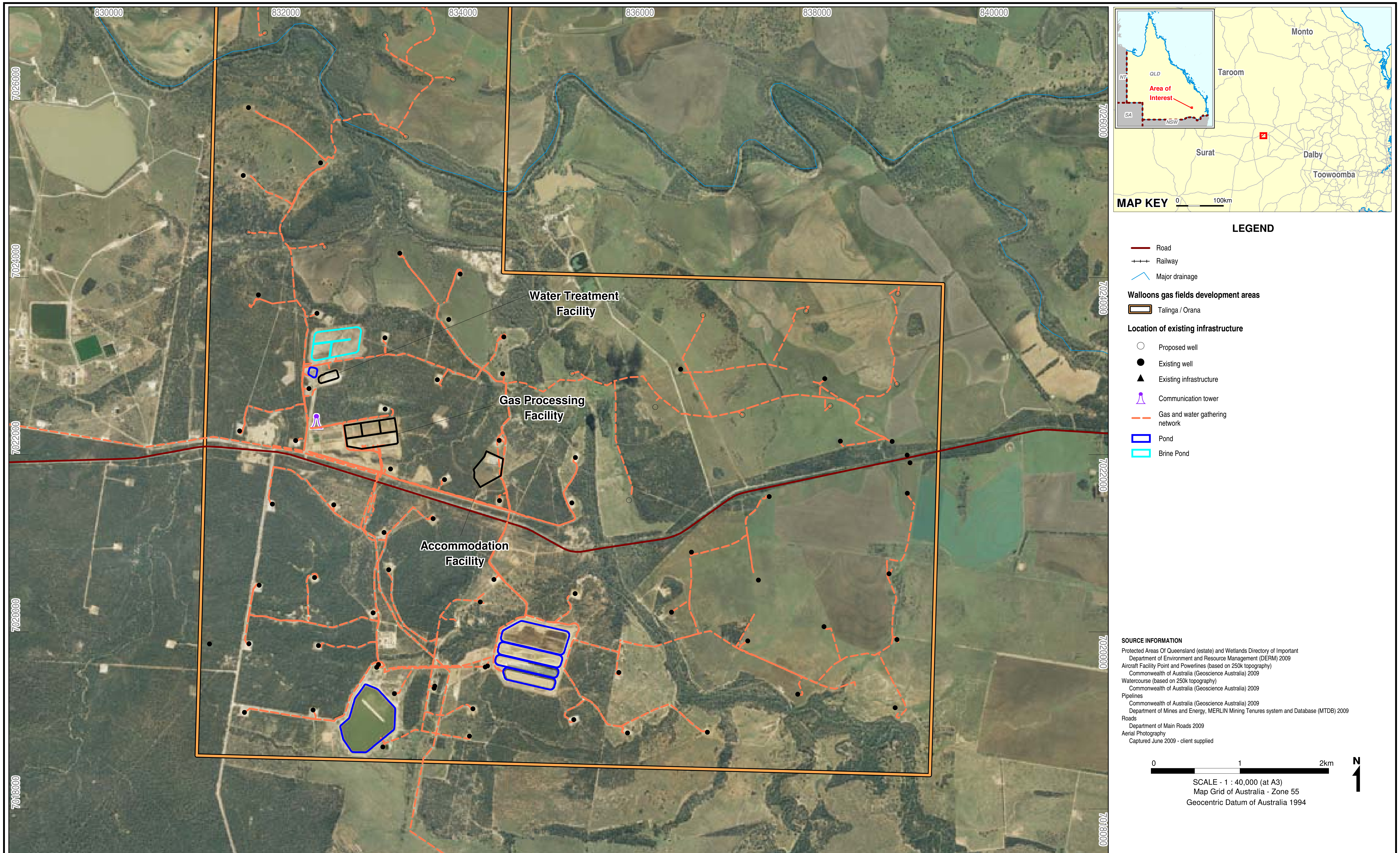
Australia Pacific LNG is proposing to drill up to 10,000 wells over the life of the Project. During the period from 2011 through to the end of 2021, 5,000 wells are expected to be drilled. This will occur in the regional area centred on Miles and on a southeast-northwest trend extending from west of Millmerran in the southeast to north of Wallumbilla in the northwest.

The drilling of the wells will be undertaken by up to nine drilling rigs, with up to nine more rigs required for well completion and well work-overs during the life of the Project. It is likely to take an average of two to three days to drill each well to the required depth (refer to Section 3.2.4). Australia Pacific LNG has committed to an extensive engagement process with landholders and other stakeholders to ensure that the size of this project is adequately described and that potential issues have been cooperatively discussed and effectively considered.

Australia Pacific LNG also recognises that, during the first five years of the Project, there will be a need to investigate continued improvement in gas field development. Investigations will include minimal lease disturbance techniques and the potential for the application of alternative drilling techniques. The targeted outcomes include further mitigation of social, environmental and land use impacts and a reduction in greenhouse gas emissions.

Details on the sources and estimated sources and quantities of construction inputs, materials and methods of transport are discussed in Volume 2 Chapter 17. While there will be a strong preference for local and regional sourcing, it has been assumed that much of the construction material such as machinery, general materials and temporary accommodation will be sourced from Brisbane, including imported materials and transported primarily by road. Other materials and consumables will be generally supplied from the regional distribution centres proposed in Miles and Roma.

The Project's well development programme assumes a typical well spacing of 750m, with all wells conventionally drilled vertically from the surface locations. CSG wells are considered shallow (averaging 600m to 1,000m) and are primarily of low operating pressure (30 to180psi). The well spacing may vary in response to a range of site constraints. The existing Talinga development layout including wells and gathering network are shown in Figure 3.24. The current maximum lease size for drilling a CSG well is about 1ha. A typical lease site has an irregular shape to minimise the footprint and maintain safety on the site. The process of developing the wells, from lease site preparation, including vegetation clearing, and on to well completion was discussed in Section 3.2.4.




AUSTRALIA PACIFIC LNG PROJECT

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Figure 3.24 Talinga Existing Development

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### 3.5.2 Gas and water gathering systems

The gas and water gathering system network will be comprised of underground high density polyethylene piping constructed using trenching techniques as described in Section 3.2.5. The gas and water gathering systems will be designed and constructed considering topography to optimise gravitational pressure and retain a low pressure gathering system to reduce energy requirements.

The gathering network will also be installed where possible next to existing infrastructure, access roads and tracks along with known property and fence boundaries to minimise overall disturbance. When selecting a preferred route, existing easements and buffer zones will be taken into consideration.

The low pressure gas and water gathering networks will be installed as follows:

- Networks will be located in areas where environmental, cultural heritage, landholder and engineering constraints have been addressed.
- Vegetation will be cleared from the right of way (maximum 18m), stockpiled and possibly mulched by a self-propelled mulcher. The mulch will be reused during rehabilitation where it will provide protection from erosion and root stock for vegetation regeneration. Features such as hollow timber or larger rocks will be retained for later use in rehabilitation to provide microhabitat.
- Surface water drainage and erosion will be managed appropriately to reduce scour and suspension of sediments in overland runoff. Measures such as contour drains and sediment traps will be implemented as part of the environmental management plan to be developed prior to construction.
- Topsoil will be removed and stockpiled to one side using earthmoving equipment. The topsoil will be respread over the right of way as part of rehabilitation.
- Trenching will be completed using a self-propelled trencher or a tracked excavator. The depth of the trench for low pressure lines will comply with installation standards and risk assessment outcomes. Open trenches are kept to a minimum to reduce the risk of animal's falling into the trench, injury to third parties or trench slumping.
- The pipeline will be strung out adjacent to the trench along the gathering network right of way. Pipe-end caps are kept in place to prevent fauna from entering the pipe. The strung pipe will be welded together using special polyethylene pipe welders.
- The pipe will be lowered into the trench using side boom mounted tractors.
- The trench will be backfilled and re-profiled consistent with the surrounding area. Once re-profiling is completed, the rehabilitation process of the right of way can commence and will include:
  - Ripping of soil may be required to relieve compaction before distributing topsoil
  - Mulch and cleared vegetation will be spread over the disturbed area to promote vegetation re-growth
  - Access by others may be restricted to allow rehabilitation of the area
  - Erosion and sediment control measures will be installed as necessary
  - The area will be rehabilitated to be consistent with the surrounding area

- The success of the rehabilitation will be checked, and additional works will be carried out if necessary.

The exact quantity of low pressure pipe required for the development will be established as part of the detailed design phase. Staging facilities will be developed to effectively support the gathering network construction.

Each staging facility will only carry the nominal amount of pipe expected to be used over a given period of time as well as pipe fittings, valving and miscellaneous equipment during the construction phase of the Project.

### 3.5.3 High pressure pipelines

The high pressure pipelines network will be constructed with up to 800km of steel pipe ranging in size between 50 to 600mm depending on the volume of gas to be transferred. The high pressure gas network interconnects the GPFs, and also transports the gas to the gas pipeline and other regional transmission pipelines (refer to Figure 3.2 to Figure 3.8).

The high pressure pipeline will be constructed in the same manner as the gas pipeline, which is discussed in Volume 3 Chapter 3. The basic high pressure pipeline construction activities will include:

- Identifying and/or constructing access tracks
- Roads, pipeline route clearing and grading
- Construction of temporary fencing
- Trenching
- Possible rock blasting
- String and bending
- Bedding and padding
- Welding
- Field joint coating
- Non-destructive testing
- Lowering and backfilling.

### 3.5.4 Pipeline specifications - High and low pressure network

Pipeline specifications for both gas and associated water gathering lines are provided in Table 3.7. Preferred materials for the low pressure pipelines will be high density polyethylene while high pressure pipeline will be steel. Fibreglass may also be considered for use in specific applications.

**Table 3.7 Pipeline specifications**

| Pipe material | Gas and water gathering system<br>Polyethylene | | Fibreglass[1] | | High pressure gas pipeline<br>Steel | |
|---|---|---|---|---|---|---|
| | **Minimum** | **Maximum** | **Minimum** | **Maximum** | **Minimum** | **Maximum** |
| Pipe diameter | 63mm | 630mm | 50mm | 600mm | 50mm | 600mm |
| Pipe wall thickness (to be confirmed during detailed design) | 3mm | 60mm | 1.5mm | 20mm | 3mm | 10mm |
| Normal operating flow rate | Minimum 0.3TJ/d, maximum 30TJ/d (through a single branch) | | | | | |
| Maximum allowable operating pressure | 0kPag | 1560kPag[2] | 0kPag | 1600kPag | 0kPag | 15,168kPag[3] |
| Normal operating pressure | Minimum 34kPag, maximum 1374kPag for gas and water gathering system | | | | | |
| Maximum allowable operating temperature | -20°C[4] | 60°C[4] | -12°C | 65°C | -29°C | 60°C |
| Normal operating temperature | Approximately 35°C to 45°C | | | | | |

1. These values are based on information from the supplier
2. This value is based on water at a temperature of 45°C
3. This value is based on 1.25 times the design pressure (200psi) as accepted by AS2885
4. This value is based on the minimum and maximum temperatures as accepted by AS4130.

### 3.5.5 Major infrastructure

Australia Pacific LNG anticipates the following construction activities will take place for facilities such as the GPFs, WTFs and water treatment storages and power generation:

- Geotechnical investigations to determine physical and chemical soil properties, including adjacent soils and/or rock nature, volume, storage, handling and disposal of solid and liquid wastes.
- Vegetation will be mulched and topsoil stripped accordingly, and stockpiled for use in future rehabilitation.
- Materials and modular components for construction and installation will be delivered principally from the regional distribution centres in Miles and Roma or from Brisbane.

- Infrastructure will be constructed, tested and commissioned.
- Disturbed areas not required for operations will be rehabilitated.

As discussed in Section 3.4.1, preliminary site selection has been undertaken using a high level multi-criteria analysis, to address environmental, technical, social and cultural heritage aspects. Site selection will be finalised during the detailed design phase following further environmental and social investigations, and geotechnical and ground-truthing exercises.

Once the detailed design is finalised and work commences, general construction techniques will include:

- Cut and fill will be used to minimise the requirements for cartage of additional fill material. Local material will be sourced for hardstand areas when required and where possible.
- The facilities will be located on a flat pad prepared by scraper units, bulldozers and graders. Contouring will be completed to ensure any existing runoff is diverted around the construction site. Runoff within the facilities will be captured in first flush onsite sediment ponds and treated onsite.
- Concrete foundations will be constructed to provide support to facility infrastructure as required. Foundation design will vary from site to site depending on the geotechnical nature of the soils. However, the concrete foundations will typically consist of a series of bored concrete piers supporting a thick reinforced concrete slab. Most concrete foundations will include a concrete bunded area to contain any wash-down or stormwater.
- Bucket excavators and augers will be used to prepare foundations, followed by fabrication of timber framework and placement of steel reinforcing prior to the concrete pours. Concrete is typically provided from a mobile batch plant located on or near the construction site
- Mechanical installation will involve placing the main processing modules, and constructing aboveground steel piping connections between each module.
- Around 15,000m of piping will be installed for each GPF. Most of this will be assembled in a pipe fabricator workshop. This will minimise the number of site welds required.
- Electrical and instrument cabling will be installed for each processing module, connecting back to a main control room. This is usually installed in above-ground cable trays alongside the main piping runs.

Treated and untreated associated water will be used where possible for construction activities in accordance with applicable regulatory requirements.

### 3.5.6 Storage ponds

Associated water feed and brine ponds will be constructed using typical earthmoving equipment such as bulldozers, scrapers, tracked excavators, dump trucks, water trucks and graders. All untreated associated water ponds and brine storage ponds will be lined with impermeable membranes.

These ponds will also be constructed to comply with DERM guidelines. Treated water storages will be designed and constructed according to regulatory and engineering requirements, and considering both the low hazard nature of the water and specific site conditions as detailed in Chapter 11; Surface water.

### 3.5.7 Equipment, ancillary facilities and materials

For all major infrastructure, Australia Pacific LNG will seek to use equipment and components that can be easily transported. This will minimise lead times and onsite construction requirements, and will enable relocation and reuse of plant infrastructure.

Typical equipment used during the construction of gas and water gathering systems, high pressure pipelines and major infrastructure includes, but is not limited to:

- Four- and two-wheel drive vehicles
- Passenger buses
- Tilt tray truck
- Tipper trucks
- Dolly trailer
- Fuel truck
- Vacuum truck
- Concrete truck
- Trailers
- Water trucks
- Prime movers
- Tankers
- Flatbed trucks
- Bobcat, with bucket, forks and or chain trencher
- Grader and backhoe loader
- Excavators
- Toilets
- Site offices
- Welding machines
- Generators
- Compressors
- Compactors
- Pressure testing equipment
- Pumps
- Rollers
- Winches
- Sideboom (low pressure gas and water gathering system)
- Dozers
- Frontend loaders
- Blade tractor
- Tow tractor
- Franna cranes
- Mulchers
- Trenchers
- Temporary accommodation.

A number of support facilities and services will be provided during the construction phase including site offices, lunch rooms and ablution blocks will typically be modular transportable buildings, powered by diesel generators, unless reticulated power is available.

Potable water will be stored on site and will be either trucked in, pumped from existing water bores or sourced from WTFs.

Storage of flammable and combustible goods, such as diesel, will comply with AS1940 specifications. Waste disposal skips and bins will be provided for each construction site, along with regular pickup and disposal by an approved waste collection contractor.

Until permanent sewage treatment systems are installed, waste from ablution blocks will be stored and periodically transported to an approved disposal site via an approved regulated waste transporter. Sewage from temporary accommodation facilities will be treated and discharged to subsurface soil via a leach field and absorption ponds, and sludge from the treatment process will be transported and managed offsite at licensed facilities.

### 3.5.8 Construction workforce and accommodation

During construction activities the workforce, including contractors, is expected to live in temporary accommodation facilities. These facilities are required to house between 50 and 800 personnel, and be constructed near the proposed project infrastructure locations.

Peak construction workforce numbers for the entire gas fields are likely to be up to 2,100 people. These temporary accommodation facilities will move as new areas are developed. There will be a requirement for facilities to house construction workers over the life of the Project, but the peak need will be during the first five years.

Temporary accommodation facilities will require relevant statutory approval for their construction and will be operated in a manner that does not adversely affect the nearby community. The facilities will include individual units, mess halls, recreational facilities, utilities, car parking, sewage treatment plants, administration facilities and waste management areas (Figure 3.25).

Sewage from small temporary accommodation facilities (e.g. for drilling rigs) will be disposed of onsite in an appropriate manner.

**Figure 3.25 Indicative layout of a temporary accommodation facility**

### *Workforce plan*

The Project's size and complexity requires a large workforce and significant supporting infrastructure. The construction workforce will have an initial peak period of five to six years with an ongoing construction and operational workforce required for the life of the Project.

During the construction activities various skill sets will be required between construction sites at specific stages of the Project. Given the area covered by the Project, it is preferable to provide temporary accommodation facilities close to construction sites to effectively utilise skilled personnel as required.

The workforce will be rostered according to their activity and work schedule. For example, drill rig crews will work 12-hour shifts around the clock and be rostered in line with drilling industry standards. Construction workers engaged in facility and pipeline construction will only work daylight hours in up to 12-hour shifts. The projected workforce trend required for the maximum construction case is provided in Figure 3.26.

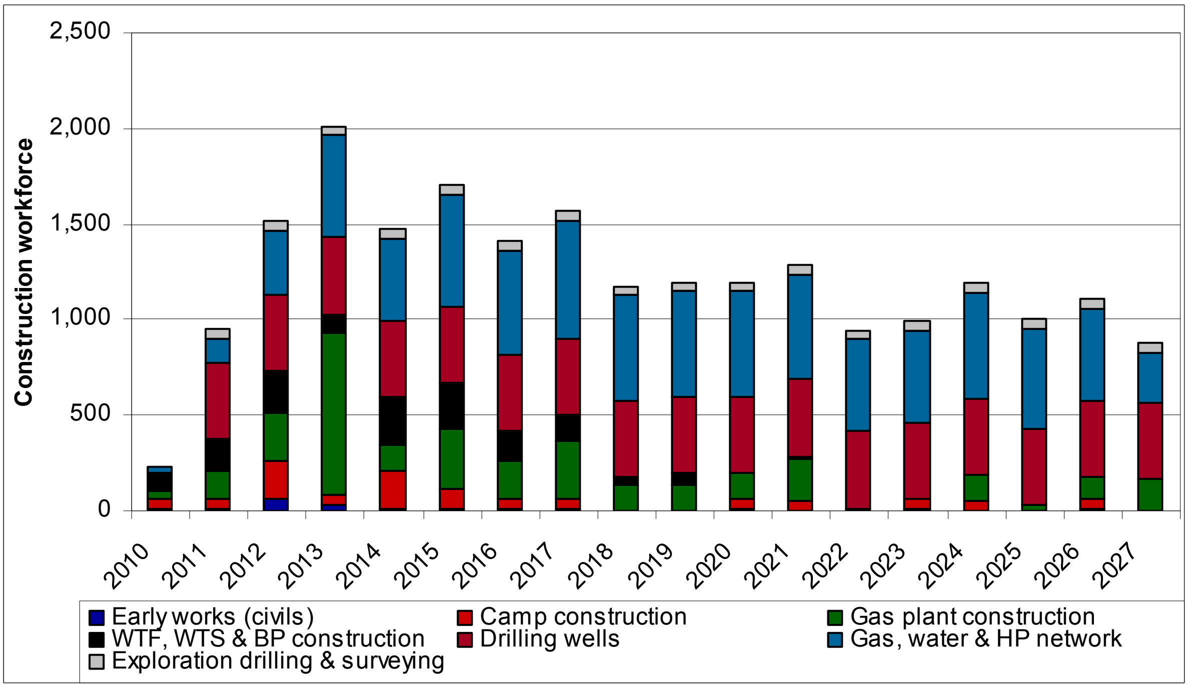


**Figure 3.26 Construction workforce trend**

An integrated workforce and logistics strategy is being developed to address the following key elements:

- A local business procurement policy and targets
- Detailed environmental health and safety planning
- Social impacts and mitigation strategies
- Integration with government's local infrastructure planning
- Self-sufficiency, if practicable, for each temporary accommodation facility's water supply based on use of treated associated water.

These strategies and commitments for further investigations are discussed in Volume 2 Chapter 20 – Social Assessment. Risk assessment and HSE requirements will determine the appropriate transport methods and vehicle use for each location. The main aim will be to restrict vehicle movements to help minimise impacts arising from vehicular accidents, noise, dust and traffic congestion. Traffic and transport is discussed in more detail in Volume 2 Chapter 17.

## 3.6 Operations

On completion of the construction and commissioning phases of the gas fields, a handover between the construction team and operational teams is undertaken. This transfer between teams is conducted in accordance with the requirements of the project handover process and the HSE management system.

This section describes operational fundamentals, from the wells where the gas is brought to the surface, to the point where the gas is delivered to the gas pipeline. In addition, the section describes the necessary supporting infrastructure to sustain these facilities.

For each gas field, CSG production generally involves operating and maintaining the wells, gas and water gathering system, water transfer stations and pipelines, WTF, GPF and high pressure gas pipeline system. The gas pipeline to Gladstone is discussed in Volume 3 Chapter 3.

### 3.6.1 Wellhead

It is planned that the operations at the CSG wells would be monitored remotely through an integrated control system. Process conditions such as separator pressure, gas and associated water flow rates are monitored and transmitted to a central location via a radio telemetry system. In addition, operating changes such as reducing gas production or shutting in selected wells could also be managed via telemetry. This will enhance the safe operation of all facilities associated with the gas fields.

The Project's operators will also visit wells as required for scheduled maintenance and to ensure their integrity and safe and efficient operation. The well facilities are designed to operate unmanned and to remain in a safe condition, so these visits are not expected to be frequent.

Typical operations activities include inspection of all wellhead equipment, checks of monitoring equipment, regular inspections and servicing of power generation equipment and inspection of safety devices to ensure system integrity. Occasionally, the subsurface pumps will need replacing. This requires a significant well intervention/repair exercise called a 'work-over'.

Well operating conditions including flow, pressure and temperature vary in each well, depending on location and overall field maturity. Operating pressures in the well separator are generally around 300kPag at moderate temperatures between 35ºC and 45ºC.

#### *Wellhead control*

As wellhead control is relatively simple most of the control on the wellhead will be remote. This allows for remote monitoring and adjustment of a large number of wells, reducing travel time for field operators.

Remote control refers to the ability to manipulate control from a centralised location, at any distance from the wellhead. The actual control is performed locally using an electronic device called a remote telemetry unit. Manipulation requires a radio signal to be transmitted from the centralised location to the remote telemetry unit. Local control relies on devices installed as part of the wellhead.

Once the CSG wells are operational, a change in production such as a well shut-in may cause the well to return to its pre-dewatered state. In this case, gas production may take a period of time to return to pre-shut-in production levels. It is likely that production can only be restarted by either recommencing dewatering or undertaking a well work-over. The ability of the well to return to pre-shut-in performance will vary from well to well.

### 3.6.2 Gas and water gathering systems

The gas and water gathering systems are simple systems that operate without the need for any major process equipment. The gas gathering system is provided with low point water drains at various locations, depending on terrain, to remove water condensed from the gas stream. This prevents the water from accumulating and being carried through to the GPFs, where it could interrupt production. These drains are manually operated on a regular basis. The water from these drains will undergo a risk based analysis in each production area to determine whether it is collected and returned to the WTF for processing or released.

A very small quantity of gas is dissolved in the water when it leaves the wellhead separator. As the gas passes along the gathering system it loses pressure and some of this gas is liberated. The water gathering system is provided with automatic high point vents to allow accumulated gas to be removed to prevent 'vapour locking' that would interrupt flow. This very small quantity of gas is vented to the atmosphere in a safe manner. The automatic vents are monitored and maintained regularly to ensure that gas is vented to maintain water flow.

Buried pipelines have a design life far in excess of the production life of the gas wells they service; so limited inspections are anticipated, apart from frequent patrols of the surface along the pipeline route. The location of buried lines is clearly marked at surface level.

### 3.6.3 High pressure gas pipelines and water transfer pipelines

The operation and maintenance of the high pressure pipeline network will be in accordance with Australian Standard (AS) 2885 Part 3. The pipeline licensing requirements are as prescribed by the Department of Employment, Economic Development and Innovation.

Commissioning will be undertaken in accordance with industry standards and the pipeline will be established with appropriate safety signage at all intersections with roads and access tracks as well as kilometre signs to aid identification during aerial patrols.

The pipeline will be operating continuously. The buried steel pipeline and associated stations will be monitored through a supervisory control and data acquisition (SCADA) system. Selected equipment will be remotely controlled via the SCADA system.

A pipeline safety and operating plan and a pipeline integrity management system will be developed during the project design stages to address ongoing environmental management commitments and requirements.

Scheduled inspection and maintenance activities are expected to include regular pipeline surveillance, regular inspections at pipeline stations, cathodic protection audits, and cleaning and internal inspection using pipeline inspection gauges (known as pigging).

Unscheduled outages are not generally expected. Emergency line pipe, repair equipment and sufficient spares will be available in the event urgent repairs are required. Any repairs will be managed by a range of technical and risk assessments and repair procedures.

A safety and operations plan, including an emergency response plan will be developed and managed in accordance with AS2885.3.

Custody transfer flow metering will be installed at the gas process facility outlet. Metering may also be installed at the inlet of the gas pipeline. The metering data will be transmitted back to the control room and be accessible through the SCADA system. Critical instrumentation will be maintained by quality checks at regular intervals.

Maintenance of the pipeline will entail inspection surveys by vehicle along the pipeline, occasional visual inspections from the air, pigging at regular intervals and occasionally 'dig ups' of sections of the pipeline for visual inspection of any areas of concern detected by inspection.

### 3.6.4 Gas processing facilities

Each GPF will operate on a continuous basis, be fully automated, and will usually be staffed during the day. A paging system will be used to alert operators to any critical alarms after normal operating hours. The location of operator accommodation facilities close to GPFs will minimise response time.

Control of a GPF is significantly more complex than for a wellhead, but facilities such as those planned for the Project are common in the gas processing industry and are already operated by Australia Pacific LNG. As a result, plant control is well understood and previous learnings will be incorporated into the design.

Control of the GPFs will be designed for minimum operator intervention and the majority of controls would be remote control. The philosophy of control is to ensure that the facility processes and exports the gas from the fields as reliably as possible. This is achieved by automatically reacting to changes in system parameters (primarily pressure) and taking action to avoid either inefficient operation of plant and equipment or flaring of gas.

The operation of the GPFs will also be integrated with operation of the wellheads. This will allow the control system to detect any loss of processing capability, such as an unscheduled compressor shutdown. Well production is then automatically reduced to prevent loss of gas to flare.

As is normal in the gas processing industry, GPFs would also have a separate high integrity safety shutdown system in addition to the 'normal' control system. This system operates independently of the control system. It monitors deviations in processing parameters that could escalate into a serious safety threat if not acted upon. The system takes immediate action to safely shutdown, isolate and where necessary reduce the facility operating pressure to a safe level. This can involve taking action on single sections of the facility, such as a compressor, or on the entire facility..

### 3.6.5 Water treatment facilities

All associated water for the Project is planned to be processed in WTFs, as discussed in Section 3.2.8. WTFs generally operate continuously, with one or two operators present during daylight hours and on-call after hours.

While the water treatment process is technically complex, Australia Pacific LNG has extensive experience operating a similar facility at Spring Gully. Operators must have a wide range of skills such as power plant operation, chemical handling and analytical skills. Operators have access to specialised in-house technical support resources for performance troubleshooting and environmental monitoring.

External service and equipment providers are used for specialised work, such as laboratory work or specialised maintenance of process and analytical equipment. General mechanical maintenance is

usually not intensive and is handled by plant operators in conjunction with in-house maintenance services. Mechanical maintenance demands are greatest for power generation rotating machinery.

### 3.6.6 Operation workforce and accommodation

The operation of the gas fields will be a major development in the region, requiring an operational workforce of around 520 people in 2016. This will increase to over 700 people around 2027, as shown in Figure 3.27. It is expected that initially most of the operational workers will be housed in permanent accommodation facilities that will be set up by Australia Pacific LNG in the vicinity of key infrastructure within the fields. In addition, approximately 150 workers will be employed at logistics hubs, and are anticipated to be housed in Roma (50 people in 2016), Miles (50 people in 2016) and Brisbane (50 people in 2016).

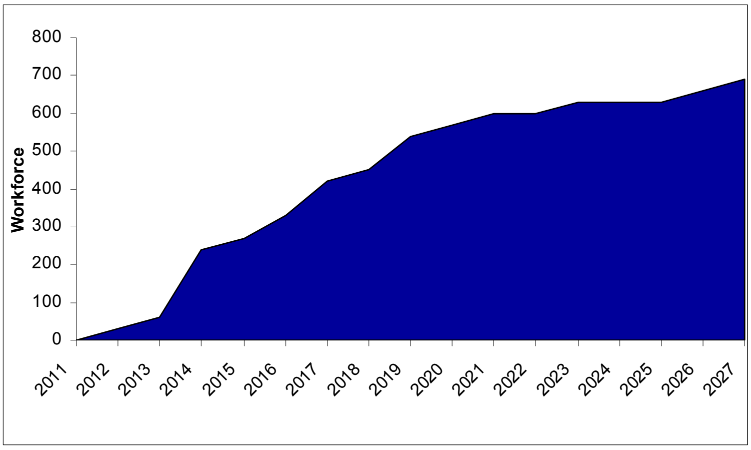


**Figure 3.27 Operations workforce trend (excludes employment at logistics hubs)**

Australia Pacific LNG intends, where possible, to recruit locally for its operational workforce but expects a large proportion of staff will work on a fly-in/fly-out and drive-in/drive-out basis. This is discussed in more detail in Volume 2 Chapter 17. An integrated workforce and logistics strategy is being developed as discussed in Section 3.5.8.

### 3.6.7 Health and wellbeing for construction and operation

Australia Pacific LNG cares about the health and wellbeing of its employees, and will ensure field staff and contractors have access to:

- Medical care for severe life-threatening trauma and medical emergencies
- Clinical care for routine or minor traumas and medical emergencies during working hours
- Emergency response through the Incident Command Post, which will coordinate with external response providers to provide the most appropriate and rapid course of action, and assist with transfers to those external providers
- Assistance in facilitating and coordinating aero-medical retrieval as required.

For injury or illness, the Project will provide the following services:

- Follow up service for illness or injuries in collaboration with a designated return to work coordinator
- Monitoring of illness and injury reports and ensuring these are documented

- Education at toolbox talks on a range of health topics such as dehydration, heat illness, envenomation and first aid management in the field
- Occupational health and safety and First Aid training for the construction and operations workforce
- Assistance with local emergency medical response plan development and standard operating procedures that integrate with Australia Pacific LNG's existing emergency response plans participation in planning and conducting emergency response exercises.

### 3.6.8 Security

Australia Pacific LNG will develop a security plan and associated procedures. A risk based approach will be used to determine security requirements. This approach will consider aspects detailed in the National Code of Practice for the Control of Major Hazard Facilities [NOHSC: 2016 (1996)], including the nature and size of the hazard, the likelihood of mischief or sabotage, and the remoteness of a facility.

A risk-based approach is consistent with this National Code of Practice, and with Australian Standard AS 2885 (Pipelines – Gas and liquid petroleum) and AS 4360 (Risk management).

#### *Wellheads*

Wells will have warning signs installed and have a cattle-panel type of fence. Valves on equipment at the wellhead that are safety critical may be locked to prevent inadvertent operation.

For future development, wellheads may be placed relatively close to major roads or townships where there is an increased likelihood of mischief or sabotage. If so, security fencing with locked gates will be considered based on risk assessment

#### *Gas gathering system*

The pipeline route will have standard markers within sight of each other. These indicate the buried pipeline and provide a contact number for emergency response. Gathering pipelines have marker tape installed at a depth that will not be affected by normal agricultural practices such as ploughing activities. General security is provided through routine pipeline inspections.

#### *Major infrastructure*

The GPFs and most other major infrastructure will have a security fence around the perimeter of the facility.

A risk-based approach of all major facilities will identify the need for work hours and after-hour's security. Safe and secure storage of chemicals will be managed by compliance with the relevant Australian Standards.

Any personnel entering the site must register their name in a visitors book and undertake an induction. Personnel leaving the facility need to sign out. Inductions include security awareness, especially of unrecognised personnel and unusual activities or objects.

Because of their isolated location, GPFs usually have a defined workforce. Security risk from third party damage is low, as the workforce would usually be aware of strangers entering the site.

Security personnel and on call personnel will be equipped with VHF radios tied into the facility alarm system. This will alert them to any unusual occurrences, including those due to third party intervention.

## 3.7 Decommissioning and rehabilitation

Australia Pacific LNG will engage with stakeholders during all phases of the Project including the decommissioning and rehabilitation phase. This engagement will inform stakeholders of the:

- Process of decommissioning
- Activities that will take place
- Potential impacts on stakeholders in the affected area.

The proposed methodology for decommissioning and rehabilitating at the end of field life is firstly to plug and abandon all remaining wells at the cessation of production in a manner approved by regulatory agencies. This process will also occur progressively during the life of a field as wells are depleted.

Following cessation of production, the connecting pipelines and process equipment are purged, vented and flushed with water. Equipment and materials are then made safe for removal from each gas processing facility and WTF site. The permanent accommodation facilities, utilities and other related infrastructure would only be removed once all facilities have been decommissioned.

The land, on which the assets were constructed, would be remediated and rehabilitated to a condition consistent with the surrounding area as far as practicable. It is anticipated that the assets would be decommissioned in phases as the gas field declines over the course of its life cycle.

### 3.7.1 Preparatory works

Preparatory works involve gathering necessary data for the detailed decommissioning and rehabilitation plan to be produced. These works may include, but are not limited to, the following:

- Preparing a detailed inventory of all materials and equipment contained within the GPFs, right of way and wellhead sites
- Carrying out environmental site assessment studies, which may include soil and groundwater analysis, to identify the presence of any potentially hazardous materials from either the original installation or from hydrocarbon production activities
- Undertake a formal decommissioning hazard identification process to finalise decommissioning and rehabilitation planning
- Preparing a final rehabilitation report (including a contaminated land assessment, landowner commitments/agreements and rehabilitation status) and a decommissioning plan, and submitting these to the appropriate authorities for approval.

### 3.7.2 Well sites

Wells will be plugged with cement to isolate any porous formations and prevent further production. When this is completed, surface equipment will be decommissioned and removed. Earthworks will then be carried out to re-contour the lease to a condition consistent with the surrounding area as far as practicable.

### 3.7.3 Gas and water gathering systems

Decommissioning of the gas and water gathering systems would generally be undertaken before or in parallel with the GPF decommissioning. At cessation of production, the gathering system will be isolated at both the wellhead and GPF connections.

The gathering system pipelines are made safe, isolated, drained, purged and vented. The pipelines can then be flushed typically using water. Water generated from the gathering system pipeline flushing will be channelled to the WTF. The cleaned gathering system pipelines would then be capped at the ends and left in-situ.

### 3.7.4 High pressure gas pipelines and water transfer pipelines

In the event that a high pressure pipeline within the network is no longer required, it will be decommissioned through:

- Moth-balling, which involves depressurising the pipeline then capping and filling with an inert gas such as nitrogen or water with corrosion inhibiting chemicals. The cathodic protection would be maintained to prevent the pipe corroding.
- Abandonment, which could involve purging the pipe of natural gas, disconnecting it from the manifolds and removing all aboveground facilities. The pipe would be cut at intervals to prevent inadvertent transfer of groundwater from one area to another. The pipe would then be left to corrode in-situ. All of the above will have the potential for small scale temporary environmental impacts that will need to be carefully managed.

Removing the pipe from the ground is unlikely to be a commercially viable option and would result in significant and unnecessary environmental impacts. A detailed rehabilitation and monitoring program would be developed and implemented in consultation with landholders and the administering authority at the time of abandonment. The abandoned pipeline easement would be returned to its pre-pipeline vegetation or as negotiated with the landholder.

### 3.7.5 Equipment

#### *Gas processing facility equipment*

GPF equipment mainly consists of a raw gas inlet and separation system, a gas compression system, a gas dehydration system, and ancillary equipment.

Each of these components will be isolated following internal procedures, drained of all accumulated liquids, then purged and vented to remove any traces of gas or other potentially hazardous materials. All interconnecting pipe work would be removed and dismantled into transportable lengths. The units would then be transported off-site in the largest practicable packages, depending on the availability of locally based cranes and transport vehicles.

The compressor and after-cooler packages and other process equipment will be disassembled and removed.

#### *Ancillary equipment*

Ancillary equipment installed at the GPFs includes power generation and distribution equipment, the plant air system, flare system, various tanks, and other utility systems. These systems will be individually isolated and secured before being disassembled and removed.

### Electrical and control systems

The power supply to the gas processing equipment can be isolated ahead of gas generator decommissioning. This would first involve isolating the power distribution system to the process equipment, which would allow the cabling and trays to be removed safely.

Once the generators are no longer needed, the power input to the switchgear is isolated and both the generators and switchgears can be removed. The remaining earthing grid and any other buried cables would be removed during the site clearance operations.

### Buildings

The buildings on the site commonly include the administration building, control room, workshop and warehouse, electrical control room and compressors enclosure. The buildings are constructed of steel frame with metal sheet cladding and concrete footings. Demounting and deconstructing these structures would be relatively straightforward if beneficial post-project uses are not identified, such as use as agricultural buildings.

### Water treatment facilities

The majority of the equipment contained within the water treatment facilities is modular and can be removed as individual units. All equipment will be purged, vented and drained, including the bulk chemical aboveground storage tanks before removal from site.

### Storage ponds

The decommissioning of storage ponds can only be undertaken when all the water used to flush the processing equipment and pipelines has been collected and treated by the WTF.

Salts can be disposed of in a purpose built facility which, if required, would be designed, located and constructed according to regulatory requirements. This may be provided by a third party specialising in these facilities. This site would be a registered waste disposal facility and be managed accordingly. Alternatively, any remaining salts will be collected and reinjected into a hydraulically isolated aquifer, as discussed in Section 3.8.4.

Any aboveground concrete structures, such as pipe and pump footings, will then be broken up at ground level and removed. Site investigations would be completed to determine the requirements for soil treatment or removal, in consultation with the administering authority. This process will be conducted in accordance with the relevant legislative requirements in Queensland and the approved management measures identified based on site conditions. Finally, the ponds would be graded to be consistent with the surrounding landform contours, seeded and revegetated.

### Permanent accommodation facilities

The permanent accommodation facilities and utility buildings will be constructed in modular and prefabricated modules. These modules can be removed from site as single units, and may be reused or sold. Other installations which cannot be reused or dismantled will be demolished and the waste material removed from site.

Services associated with permanent accommodation facilities such as roads, drainage, fences and underground utilities will be excavated and removed as required. The sewage system will be pumped out by approved regulated waste transporters. Excavated materials will be reused onsite where possible or removed offsite for disposal.

### 3.7.6 Site rehabilitation, finishing earthworks and revegetation

When all the process equipment, buildings, structures and imported material have been removed, it will then be necessary to return the site to a condition consistent with the surrounding area as far as practicable, unless otherwise approved under the environmental authority. This would entail remediating and rehabilitating any contaminated areas, then grading and revegetating the site to minimise wind and water erosion.

All internal roads including perimeter fencing would be removed. The main access road would be left in place if required by the landholder.

All excavations and pits resulting from the decommissioning process would be backfilled and graded to the original contours. The area, including gravel tracks, would then be spread with mulch and seeded with native vegetation.

### 3.7.7 Material and equipment removal and disposal

The decommissioning and rehabilitation methods applied will adhere to the internationally accepted good industry practice hierarchy for disposal of materials. Reuse is the preferred option, followed by recycling and, if unavoidable, then disposed to landfill or alternatively suitable regulated waste disposal facilities.

The material and equipment likely to be suitable for reuse includes process and chemical pumps, aboveground storage tanks, compressors and process equipment, gas and diesel engine power generators, and demountable and modular buildings.

The material and equipment likely to be suitable for recycling includes building steel frames and cladding, electrical switchgear, control systems equipment, pipelines and manifolds, separators, deconstructed aboveground storage tanks, fencing and miscellaneous steelwork including recovered rebar, crushed concrete and electrical cabling.

The material and equipment likely to be unsuitable for reuse or recycling includes plastic and glass fibre reinforced plastic pipework and tanks, and sludge from pipelines and equipment. These would need to be properly disposed of to appropriate facilities.

### 3.7.8 Hazardous material treatment

Based on a review of the gas fields and associated plant processes, hazardous substances present onsite are likely to be limited to process chemicals such as anti-corrosives and lubricating oils. The likelihood of other hazardous materials, such as mercury, is low. However, the Project will conduct detailed studies and analyses as part of the pre-cessation of production surveys to determine the presence or absence of such materials at targeted locations.

### 3.7.9 Alternative uses of decommissioned assets

There may be some alternative uses for the decommissioned assets. However, the feasibility and suitability of the options presented will depend on actual field conditions, and would require additional studies.

As the neighbouring activities to the assets generally include pasture land for livestock and agriculture, it is possible that this could be returned to pasture and agriculture uses once all surface impediments have been removed. Detailed studies will address human and grazing animal health concerns by identifying any soil and groundwater contamination.

These studies would establish guidelines relating, but not limited, to the types of vegetation suitable for growth at the site, the safety of food products derived from the grazing animals, and using groundwater for livestock watering and irrigation.

### 3.7.10 Issues identification and risk management

Desktop studies, carried out as part of the preparatory work discussed above, would identify most of the potential issues and risks associated with closure and decommissioning. Potential issues and risks will be analysed to help develop management and/or mitigation strategies.

Contingency planning will also be carried out. Where issues and risks involve stakeholders, such as environmental pollution, appropriate rehabilitation plans will be developed in consultation with the affected parties.

## 3.8 Technical alternatives

Initiatives to investigate alternative technologies and methodologies are being investigated and considered, to reduce the potential impacts of the Project. Key alternatives are discussed in this section.

### 3.8.1 Air coolers

The development base case assumes that the compressed gas is cooled using air coolers at the GPFs. Like a car radiator, the shaft of the gas engine drives the fans of these air coolers. Air coolers that use fans driven by electric motors are also being considered.

Engine driven units have been used as a base case, primarily to assess the noise impact due to their low frequency. However, electrically driven fans may reduce the noise impact, as high fan speeds have a higher frequency. There are also potential process and efficiency benefits in their use. This option is undergoing further analysis.

### 3.8.2 Electrically-driven compression

While the EIS assumes a base case of gas engine drivers and contains all the details associated with this technology, analysis continues to assess possible and more efficient compression options. This includes the type of compression equipment, the type of drivers used to drive the compressors, and the energy source for compression.

Considerations include compressor type, driver type, electrically-driven equipment with local or central power station and/or grid connection, and centralised control facilities. Synergies with co-located water treatment (reverse osmosis) facilities or Australia Pacific LNG compression are also being considered, along with stakeholder impacts for all options.

The final decision on the drive option will occur following further studies of the electrical distribution system. In particular, the existence of any specific line route issues that may negate selection of electrical motor drives is being investigated.

This section sets out the rationale for the potential use of electric motor driven compression and installation of generator capacity in terms of:

- The rationale for selecting electricity as the method of powering the gas compression
- The predicted need for electricity generation to meet compressor loads and subsequently support grid operational reliability

- The strategy behind the possible staged introduction of power generation, which may be carried out by constructing a dedicated generation unit with a supporting 132kV power distribution network. Longer term, these dedicated power networks would likely be connected to the National Electricity Market via Powerlink's 275kV network
- A review of major alternatives investigated.

### Compressor drive options

An analysis has been conducted to assess the possible compression options, including the type of compression equipment, the type of drivers utilised to drive the compressors and the energy source for compression. The analysis compared different compression options based on the whole of life cycle cost, using the following generic inputs which applied to all options:

- Compression plant capacities
- Pre-peak operating conditions
- Post-peak operating scenario
- Gas/LNG price, price of carbon emission permits and electricity price
- Preliminary availability and reliability
- Standard noise attenuation measures to meet 85dB(A) at 1m.

Different compression technology options were considered, including:

- Screw and reciprocating – gas engine driven
- Screw and centrifugal – electric motor driven from grid
- Screw and reciprocating – electric motor driven from grid
- Screw and reciprocating – electric motor driven from a centrally-located power plant
- Screw and reciprocating – electric motor driven from local open cycle gas turbine power plant operated at each plant
- Screw and centrifugal – electric motor driven from a centrally located power plant
- Centrifugal only – electric motor driven or gas turbine driven.

### Electric drive compression

When compared to equivalent alternatives, the electric motor driven compression potentially offers significant benefits to the Project from an environmental and strategic perspective. This is mainly because electricity transmission infrastructure exists, or is expected to be built close to the proposed gas fields.

As part of the option to use electric motor drives, a transmission line is required from a terminal point on Powerlink's existing and planned transmission network through selected regions within the project area. Powerlink is the transmission network service provider for all of Queensland[2].

These selected regions include Combabula (northern), Condabri/Talinga North (central), Kogan/Western Downs (southern), and Gilbert Gully (south-eastern).These would become 'load

[2] <http://www.powerlink.com.au>

centres' which will reduce the voltage from 275kV to 132kV for distribution to the various GPFs. These load centres may also require small power generation stations, which are capable of supplying the compression load until the main transmission line is connected. The advantages and impediments are shown in Table 3.8 and Table 3.9.

**Table 3.8 Advantages of electrically-driven compressors**

| Parameter | Comments |
|---|---|
| **Environmental benefits** | |
| Local air emissions | Air emissions associated with engine drives are eliminated within the gas processing facility premises. |
| Efficiency | Less wells required per unit of LNG exported. |
| Noise | Very low - can be moderate, if driving a reciprocating compressor. |
| Vibrations | Very low - can be moderate, if driving a reciprocating compressor. |
| Waste disposal | Little or no waste disposal required, unlike engine drives. |
| Size | Smaller footprint. |
| **Strategic/commercial benefits** | |
| Diversity of power source | Use of electric drives, when powered from the grid, facilitates the use of diverse energy sources.<br>If not connected to the grid, regional power generation is still expected to be more efficient than using individual engines to power the compressors. |
| Capital cost | Industry estimates indicate that electrically-driven compression facilities cost the same or approximately 10% less, and the driver-only cost is substantially lower than engine drives. |
| Maintenance costs | Maintenance costs for electrically-driven options are substantially lower than engine drives. |
| Manning | Compression plant, when electrically-driven, requires very little maintenance. |
| Equipment reliability | High. |
| Construction time | Shorter time required for the construction of GPFs. Commissioning time is also significantly shorter. Time may be required to complete the electrical works and transmission line routing, but this can be reduced through early planning. |
| Easy Dispatch | Push-button start-up instead of lengthy start-up procedures. |
| Process Control | Significantly superior load matching and capacity control using variable speed drives. Besides precise control, this is also energy efficient. |
| **Project benefits** | |
| Synergies with LNG facility | Potential advantages arise in relation to shared turbine type with the LNG production trains. This has maintenance, training and spares advantages. |

**Table 3.9 Impediments to electrically-driven compressors**

| Parameter | Comments |
|---|---|
| Power supply reliability | Engine drivers use onsite energy, so each compressor station is independent. Can be mitigated through proper design, and study of existing infrastructure. |
| Third party reliance | Ability of third party to deliver transmission network within required timeframe including approvals and environmental assessments. |
| Environmental and social impacts | Impacts associated with overhead high voltage transmission lines. |
| Electrical system transmission costs | This cost is not required for engine drives, as gas is supplied from the low pressure pipeline that supplies the feed gas into the gas processing facility. |
| Possible schedule constraints | Exact schedule constraints are unknown at this time, but perceived to be significant. However, collaboration between CSG industry and government can mitigate this risk significantly. |
| Energy price | Exposure to electricity pricing structure and economics. This can be mitigated by strategic business decisions, diversified interests and contractual mechanisms. |
| Industry bias | Gas industry has had limited exposure to the electricity generation industry. |

### *Compressor load requirements and schedule*

The plant load requirements consists of compressor loads associated with the extraction activities of CSG, water treatment facilities and other minor plant loads. The CSG supply will expand over the lifecycle of the Project, with gas plants being commissioned in a staged manner to match the gas supply requirements and the life of each coal seam.

The current projection for electrical demand in 2015 will be approximately 200MW to 300MW. This will gradually increase to 400MW to 500MW. The expected energy consumption will plateau between 2016 and 2017 when the load shifts as gas fields decline and new fields are commissioned.

### *Electric motor-driven compression option*

The electric option includes the construction and operation of high voltage overhead transmission lines, to supply between 400MW and 500MW of electrical power to operate the electric driven gas compressors.

Onsite generation would be installed at the load centres if required, before the connection to the transmission network is available. Following connection of the transmission network, these generators may then be used to provide peaking power and to act as backup support.

A number of power generation sites would be located adjacent to compressor facilities in the north and south. These load centres include Combabula/Reedy Creek (northern), Condabri/Talinga North (central), Kogan/Western Downs (southern), and Gilbert Gully (south-eastern).

In summary, using electric motor-driven compressors and installing the preliminary power generation capacity (if required) has the potential to:

- Increase Queensland installed electricity generation capacity

- Use fuel and technology that maximises energy efficiency and minimises greenhouse gas emissions
- Use technology that provides the flexibility to operate efficiently and economically under a broad range of operating duties, both now and in the future
- Have the flexibility to meet future demand growth, while reducing commercial risk through a staged construction approach
- Have access to a secure, long-term power option through direct connection to the National Electricity Market, via the government-owned Powerlink transmission network
- Be located on a site that allows direct connection to both the load centres and the high-voltage electricity transmission network
- Better utilise the gas resource.

### *Load centre selection process*

To minimise the Project's footprint and minimise design, operational and engineering constraints, power generation would be located in the same facility footprint as the load centre sites.

The key phases in the selection process for the load centre sites include:

- Assessing strategic alternatives and selecting the study area – a progressive and iterative assessment of the options for gas supply and electrical connection that meet Australia Pacific LNG's commercial and strategic objectives.
- Assessing the study area, selecting and carrying out preliminary ranking of potential sites – further detailed desktop and field studies undertaken to select a number of potential sites within the study area.

### *Electrical network*

Powerlink has approval from the Australian Energy Regulator and has publicly announced that its Southern Queensland reinforcement (to include the Western Downs substation) and network augmentation is scheduled to be completed and fully operational in the fourth quarter of 2012.

Connection studies have shown that Powerlink's proposed Western Downs 500kV/275kV/132kV substation near Braemar would be an appropriate connection point for the transmission and distribution network with a proposed connection voltage at 275kV.

To supply the compressor sites, potentially four main load centres have been proposed. These would be supplied from the Western Downs substation via a new double circuit 275kV transmission line.

Each load centre would be integral to Australia Pacific LNG's infrastructure planning and would include the following connection and generation assets:

- Electrical compressor stations
- Power stations, if required for early compression duties
- 132kV switchyard
- Reverse osmosis plant; and associated plant, equipment and control buildings.

Each load centre would be connected to the 275kV network via a spur connection to the main 275kV line. These load centre substations would then connect the various compressor sites, either via a

132kV ring network or double circuit network constructed to the standard Ergon Energy design. Construction would be undertaken by a third party or Australia Pacific LNG.

Powerlink would be the owner of the 275kV transmission line and associated substations. Powerlink would follow its government-approved development, design and approval process to provide the Project with the required transmission services.

#### Structure types

The typical infrastructure for the electrification of the gas fields will include:

- A 132kV ring or double circuit line
- Poles – 26-32m high, of various materials
- Aluminium conductors
- Insulators
- Earthwire.

#### The 132kV substations

A high voltage substation consists of a number of structures, equipment items and support services, including:

- Electrical equipment such as circuit breakers, isolators, power transformers and instrument transformers, each mounted on individual support structures - circuit breakers will utilise conventional switchgear pressure sealed and gas insulated
- Gantry structures which support conductors transporting power between items of equipment
- Busbars which transport power from one equipment bay to the next
- Capacitor banks
- Buildings which house control, protection and communications equipment.

#### Onsite generation

If required in advance of network connection, generation capacity would be installed across the selected load centres, allowing islanded supply to the CSG compressor loads connected to these load centres. Fuel gas for this electric drive option would be sourced from the high pressure export pipeline.

It would also be necessary to install small approximately 1MW, engine-driven generators as a source of power for emergency use and to start the gas turbines. Fuel for these backup generators would be either natural gas from the export pipeline or diesel.

Should the transmission line be completed, any site generation can be used as backup for transmission system failure. It can also be used during periods of high demand on the network.

#### Indicative machine type

For the purposes of illustration, one of the potential machine selections is a General Electric, model LM2500 + GE4 (Figure 3.28). While there are subtle differences between manufacturers and models, all exhibit similar visual, emission and acoustic properties for similarly-sized units.

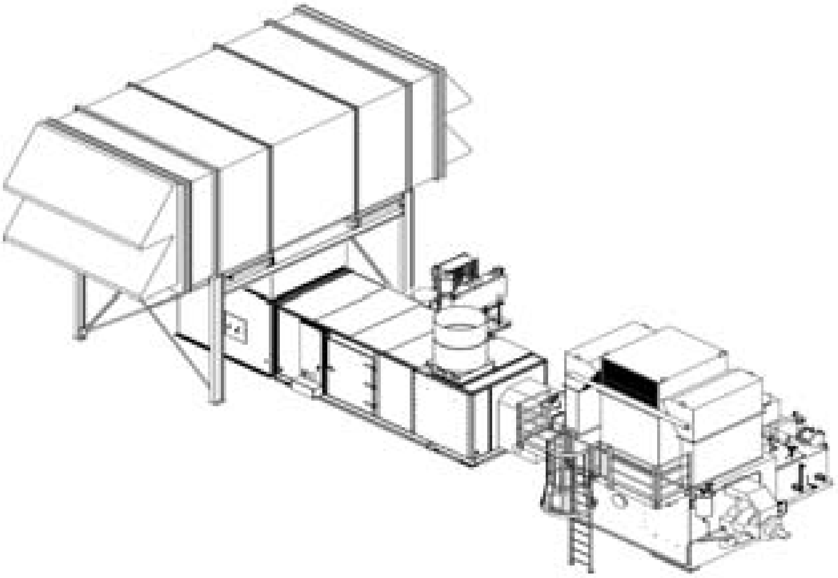

**Figure 3.28 Example of a gas turbine power plant configuration (LM2500 shown)**

### *Water requirements and supply*

The proposed gas turbine plant configuration requires water for operation of the inlet air evaporative cooling systems. Water would be sourced from the WTF situated at the load centres. Onsite storage is likely to be required to manage daily use of water.

### *Construction activities*

Construction of the proposed onsite generators would involve:

- A detailed site survey to allow structure design - geotechnical survey will need to be performed, depending on the site survey and deep piling and foundations may be required
- Filling and benching sites for drainage and flood attenuation
- Earthworks including levelling, filling, compaction, piling and reinforcement for all foundations and access roads
- Installation of concrete foundations to provide a stable platform for equipment and buildings
- Installation of the gas turbine mechanical and electrical equipment
- Installation of earthing system for the equipment onsite
- Installation of site drainage system
- Trenching of conduits and cable system
- Erection of conductors and earthwires
- Erection of structures and buildings
- Erection of bunding and pits
- Installation of walkways and stairways
- Installation of fencing.

### 3.8.3 Power reticulation to gas wells

Should grid power become available it would be possible to consider alternative power to the wellheads, rather than using local power generation.

This would involve the installation of 132 kV /22 kV transformers and switchgear at each GPF. A 22 kV overhead distribution network would reticulate power via trunk lines throughout the fields. These would be in a ring main configuration, where possible, as this offers higher reliability over radial configuration. Final connections to the individual wells would be by buried cable, co-located with the gathering lines.

Power reticulation to gas wells has a number of benefits. It significantly reduces air emissions from the local wellhead power generation units and creates considerably less noise than local power generation options. It also reduces manpower requirements for inspection and maintenance, which in turn reduces the frequency of travel and environmental impact by vehicles, while increasing safety. Liquid waste, such as generator oil, is also eliminated. Further review and possible implementation of this alternative will depend on a decision on the electric driven compression option, as discussed in Section 3.8.2.

### 3.8.4 Aquifer injection

While Australia Pacific LNG has not yet trialled it in Australia, aquifer injection has been used as a way of managing associated water in international CSG developments. From a review of economic, environmental and social benefits of various associated water management options, aquifer injection has emerged as a favourable option for associated water and brine management.

If proven feasible, this option could provide a solution which allows CSG production to proceed with reduced operational risks. Australia Pacific LNG's initial studies have shown that aquifer injection is technically possible, and has possible advantages over other options. Australia Pacific LNG is planning to undertake further studies and trials into hydraulic properties and chemical compatibility of the potential injection aquifers.

The details of the studies are addressed in the Project's adaptive associated water management plan in Volume 5 Attachment 24.