

Section 4

Project Description



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4. Project Description

4.1 Project Overview

This section describes the proposed Blacktip Project during the following phases:

- design
- construction and installation
- commissioning
- operation
- decommissioning

At the time of preparation and submission of the Draft EIS to Government, the Blacktip Project was in the Front End Engineering Design Phase (FEED) and as such, certain project details have been well established, while others are currently under consideration. The project design will be refined in the future when design enters the ‘detailed design’ phase during which engineering details and decisions are confirmed. To ensure a fully transparent and robust environmental and social assessment, where details are currently unconfirmed, a range of possible options have been provided for assessment in the Draft EIS.

In order to recover gas from the Blacktip gas reservoirs, various facilities and supporting infrastructure will be required. The Blacktip Project will comprise an unmanned wellhead platform connected to an export pipeline, which will carry the reservoir fluids to an onshore gas plant. No processing will be undertaken offshore.

Once onshore, the gas will be separated from the other reservoir fluids: namely, PW and condensate. The gas will then be compressed and transported to available markets. Following treatment of PW to remove free oil and contaminants, a saline effluent will remain which will be discharged to sea through a PW pipeline. The condensate will be stabilised onshore and exported through a condensate pipeline to a condensate export mooring located a few kilometres offshore, where it will be loaded onto tankers approximately four times per annum.

The key characteristics of the onshore and offshore components of the project are summarised in **Table 4-1** and **Table 4-2**, respectively. The components are categorised as either offshore or onshore related. There are a number of facilities located in the marine nearshore environment (such as the PW and condensate pipelines) but because they originate from the onshore gas plant they are summarised in the onshore table.

■ **Table 4-1 Key Blacktip Project Characteristics for Offshore Components**

Project Component	Purpose	Characteristics	Draft EIS Section
Production Wells & associated facilities	Recovery of reservoir fluids Control of well flow and pressure Transport of reservoir fluids from wells to wellhead platform	Two initial wells drilled to a total depth of approx 3,100 m. Potentially up to a total of six wells may be drilled Wellheads Risers	4.5.2
Wellhead Platform	Control of well flow and pressure	Unmanned, remotely operated High Integrity Pressure Protection System (HIPPS) Emergency Riser Shutdown Valve (ERSDV) Communications Equipment Access via helipad and/or boat	4.5.2
Gas Export Pipeline	Transport of reservoir fluids from wellhead platform to onshore facilities	3-phase, subsea trenched pipeline ¹ Carbon steel, concrete coated 18" diameter Approx 107.5 km from wellhead platform to low water mark	4.5.3 4.5.4
Laybarge and support/supply vessels	Accommodation	Accommodate up to 250 personnel offshore mostly on laybarge	4.5.13

Note 1: The degree of trenching along the route will not be confirmed until a seabed investigation has been completed at the end of 2004.

■ **Table 4-2 Key Blacktip Project Characteristics for Onshore-Related Components**

Project Component	Purpose	Characteristics	Draft EIS Section
Condensate Stabilisation Facilities	To stabilise the condensate and make it suitable for tanker loading.	Medium pressure separator, condensate heater, low pressure separator	4.7.3
Condensate Storage and Export	Onshore condensate stabilisation and storage facilities Export of condensate via tanker	Approx 7 km (including 2.5 km onshore) of 14" diameter condensate export pipeline from onshore storage facilities to nearshore condensate export mooring Condensate export mooring located in 14 to 16 m water with condensate loading facilities onto tankers	4.7.3
PW Treatment and Export	Treatment of PW to remove condensate and contaminants Disposal of PW	Produced Water Flash Drum and Gas Flotation Unit. A 4–6" diameter 4.5 km (including 2.5 km onshore) export pipeline 100–7800 bpd of PW discharged	4.7.4
Onshore Gas Export Pipeline	Transport of reservoir fluids to onshore gas plant Relates to shore crossing and onshore component of pipeline Beach storage area for pipeline sections during installation	Approx 2.5 km from low water mark to onshore gas plant Approx 100 m x 100 m (1 ha) pipe laydown area on the beach above the high water mark for pipeline construction materials and facilities	4.5.3 4.5.7 4.7.1

Project Component	Purpose	Characteristics	Draft EIS Section
Onshore Gas Plant	Processing, compression and metering of gas Onshore storage area for construction materials and vehicles	Approx 350 m x 440 m (15.4 ha), within 800 x 800 m (64 ha) onshore gas plant footprint including a firebreak Slug catcher and primary liquids separation. Water and hydrocarbon dew-pointing Compressor including turbines to compress gas to 150 bar Laydown area within onshore gas plant footprint for materials, vehicles, construction camp, onshore facilities	4.5.8 4.7.2
Concrete Batch Plant	To provide concrete for footings and paving	Approximately 100 m x 100 m (1 ha) within the 64 ha gas plant footprint, positioned adjacent to access route	4.5.11.2
Construction Waste Facilities	To provide an area for the safe storage and classification of construction waste	Approximately 100 m x 100 m (1 ha) for scrap metal, timber and other waste construction materials	4.5.11.3
Utilities	Support facilities for onshore processes	Includes: Power generation, flare, instrument air, liquid and gaseous fuel systems, drains, effluent treatment and firewater systems	4.8
Access and Haul Routes	Several options are being considered to transport provisions, equipment and personnel to and from the site	Road from Darwin, Wadeye airstrip or barge landing. 50 m corridor required for construction of new road, laydown areas and drainage channels from Wadeye to gas plant. Permanent access road 4 m wide. Ditch run-outs also required.	4.5.10 4.7.5
Groundwater bores	To provide freshwater for human consumption, dust suppression and possibly hydrotesting of onshore storage tanks and pipework	Within gas plant footprint, exact location unknown	4.8.4
Accommodation	A single accommodation camp will be used	Pioneer camp (0.5 ha) will be established whilst main camp is under construction Main camp - Approx 180 m x 230 m (4.1 ha), within 64 ha onshore gas plant footprint for materials, vehicles, construction camp, facilities Up to 130 (peak) personnel during construction. The camp will be downsized following peak construction period to accommodate approx 10 personnel during operations phase Up to two operational personnel, with additional personnel as required for maintenance (40 peak)	4.5.13 4.7.7

4.2 Project Location

The Blacktip reservoir is located in approximately 52 m of water and extends approximately 4 km north to south and 6 km east to west. The seabed is generally flat and is characterised by soft sediment. The closest petroleum production facility is the Buffalo development, located in the Timor Sea, over 300 km north-west of the Blacktip reservoir.

sediment. The closest petroleum production facility is the Buffalo development, located in the Timor Sea, over 300 km north-west of the Blacktip reservoir.

The gas export pipeline will extend approximately 107.5 km from the Blacktip gas field in a south-easterly direction to landfall near Wadeye. Almost 2 km of the subsea pipeline route is likely to be installed in less than 10 m of water. The shore crossing and onshore components of the export pipeline are detailed in **Sections 4.5.6** and **4.5.7** of this report.

The pipeline landfall has been identified at the northern end of Yelcher (Yelthirr) Beach situated between two prominent rocky headlands. The beach is approximately 700 m in length. A further 2.5 km pipeline will connect the landfall to the onshore gas plant.

The plant will be located on the proposed pipeline alignment and an existing track, approximately 10 km west-south-west of Wadeye.

Coordinates of the major project components are shown in **Table 4-3**. The locations of the offshore and nearshore/onshore components of the project are shown in **Figure 1-1** and **Figure 4-1**, respectively.

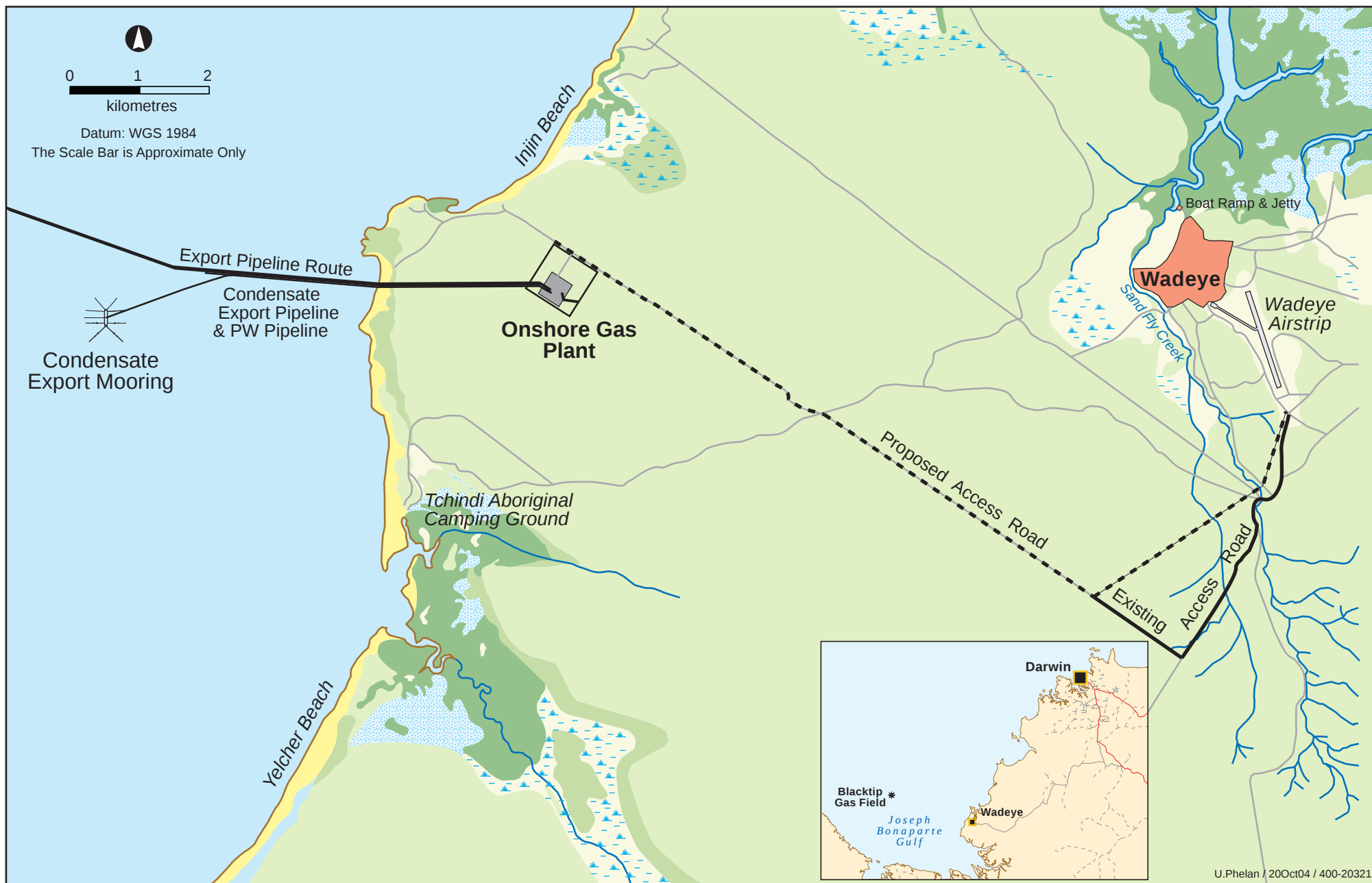
■ **Table 4-3 Project Coordinates**

Project Component	Coordinates
Unmanned Wellhead Platform	444,259 mE 8,464,840 mN
Export Pipeline Landfall	544,493 mE 8,425,505 mN
Onshore Gas Plant	129°25'52.09"E 14°14'33.60"N 129°26'05.87"E 14°14'13.22"N 129°26'26.77"E 14°14'26.66"N 129°26'12.99"E 14°14'47.04"N
Produced Water Pipeline	Exact location to be determined during detailed design
Condensate Export Anchoring Location	539,875 mE, 8,424,800 mN

4.3 Preliminary Project Schedule

The preliminary project schedule is summarised in **Table 4-4**. It is anticipated that site preparation and clearing for the proposed gas plant will commence in the 2nd quarter 2005, followed by construction of the onshore gas plant and associated facilities in the following year. Commencement of production well drilling is scheduled for 3^d quarter 2007. Each well will require approximately thirty days of drilling to completion. Construction of the offshore pipeline and installation of the wellhead platform will begin in the 2nd quarter of 2007. Following installation and commissioning of facilities, production of first gas is scheduled for 4th quarter, 2007. The project's lifespan is expected to be 30 years.

The project construction schedule is likely to be impacted by seasonal variations in climatic conditions. For example, installation of the onshore pipeline and construction of the gas plant will be limited to the dry season, when road vehicle access is available.



Blacktip Project

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ONSHORE AND NEARSHORE COMPONENTS OF THE BLACKTIP PROJECT

Figure 4.1

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■ **Table 4-4 Project Schedule**

Project Phase	Start Date	Finish Date
Construction		
Site preparation and access road construction	Quarter 2, 2005	Quarter 3, 2005
Onshore gas plant construction	Quarter 2, 2006	Quarter 4, 2007
Install and backfill onshore pipeline to plant	Quarter 3, 2007	Quarter 3, 2007
Beach trench excavation	Quarter 2, 2007	Quarter 3, 2007
Shore pipeline pull	Quarter 2, 2007	Quarter 3, 2007
Wellhead platform installation	Quarter 2, 2007	Quarter 2, 2007
Subsea export pipeline construction	Quarter 2, 2007	Quarter 3, 2007
Drilling of production wells	Quarter 3, 2007	Quarter 4, 2007
Condensate / PW pipeline construction	Quarter 2, 2007	Quarter 2, 2007
Install condensate export mooring facility	Quarter 3, 2007	Quarter 3, 2007
Commissioning		
Wellhead platform and pipeline commissioning	Quarter 3, 2007	Quarter 3, 2007
Export pipeline dewatering	Quarter 3/4, 2007	Quarter 3/4, 2007
Condensate/ PW pipeline	Quarter 4, 2007	Quarter 4, 2007
Onshore gas plant commissioning/hydrotesting	Quarter 4, 2007	Quarter 4, 2007
Operation		
First gas	Quarter 4, 2007	2037

Note: No significant construction is expected to take place onshore during the wet season months.

4.4 Well Construction and Completion

4.4.1 Well Drilling

In order to recover gas from the Blacktip reservoirs, two production wells will initially be drilled in a single drilling campaign. It is possible that additional wells (up to six in total) may be drilled at a later stage in the project. It is anticipated that wells will be drilled using a conventional Jack-up Mobile Offshore Drilling Unit (Jack-up) (MODU) similar to that shown in **Figure 4-2**. Jack-ups are commonly used in shallow waters by Woodside and throughout Australian waters.

The Jack-up will be towed to site where the legs will be lowered into place and the rig secured. During drill well engineering operations, the Jack-up will be self-sufficient with facilities to accommodate up to 200 personnel, if required. It is expected that up to two or three supply vessels will support the Jack-up during well construction and completion operations and will be on site for two to three months.

Prior to commencement of drilling, the well design and locations will be finalised and the technical integrity assessed in consultation with the relevant regulatory authority.

4.4.2 Well Construction

The Blacktip field is comprised of nine stacked reservoirs containing lean gas condensate, at depths ranging from 1,000 to 3,100 m TVDSS (True Vertical Depth Sub Sea). Development will initially be focused on production from four Keyling Formation reservoirs (approximately 2,000 to 2,800 m

TVDSS) and the deepest Treachery Formation reservoir (approximately 3,100m TVDSS). Two wells will be drilled initially, a primary well and a backup well. The conceptual designs for these wells are shown in **Figure 4-3**. The primary well will be drilled vertically downward, and the back-up well by means of deviated drilling.

The two wells have distinct roles. The primary well will be the major gas supplier, however it will not penetrate as deeply into the formations as the backup well. The backup well will provide an additional supply of gas to ‘top up’ that obtained from the primary well. The exact direction and end of hole location of any further wells is still under consideration; however, any additional wells will be represented by one of the existing conceptual designs.

Production wells are typically drilled by progressively decreasing the pipe diameter through the rock formation using a drill string (made up of a bottom hole assembly and drill pipe) and a rotary drill bit. It is likely that drilling will be undertaken in the following order:

- 1) Initially a 30” hole will be drilled with the aid of seawater and occasional flushing with pre-hydrated bentonite (PHG) to remove drill cuttings from the hole. The result will be a mound of cuttings and muds, consisting mainly of coarse cutting particles, discharged to the seabed directly around the wells and gradually becoming thinner, with finer particles being distributed further from the wells.
- 2) The 24” (Blacktip Backup Well) and 17½” sections will follow mostly the same procedure as the initial 30” hole. However, the 17½” section for Blacktip Primary Well will use an open circulation system (the mud is discharged directly to the seafloor along with drill cuttings) but the same section for Blacktip Backup Well will use a closed circulation system as described below.
- 3) The 12¼” and 8½” sections of the borehole will be drilled entirely with either water based muds (WBMs) for example KCL/PHPA/polyglycol AQUADRILL or a non-water based mud (NWBMs) with casing or liner strings run and set as appropriate. The drill cuttings and drilling mud will be circulated back to the Jack-up for processing, where the drilling mud will be separated from the cuttings by vibrating screens and then re-circulated as much as possible. A suitable casing will then be slotted in and set with cement.



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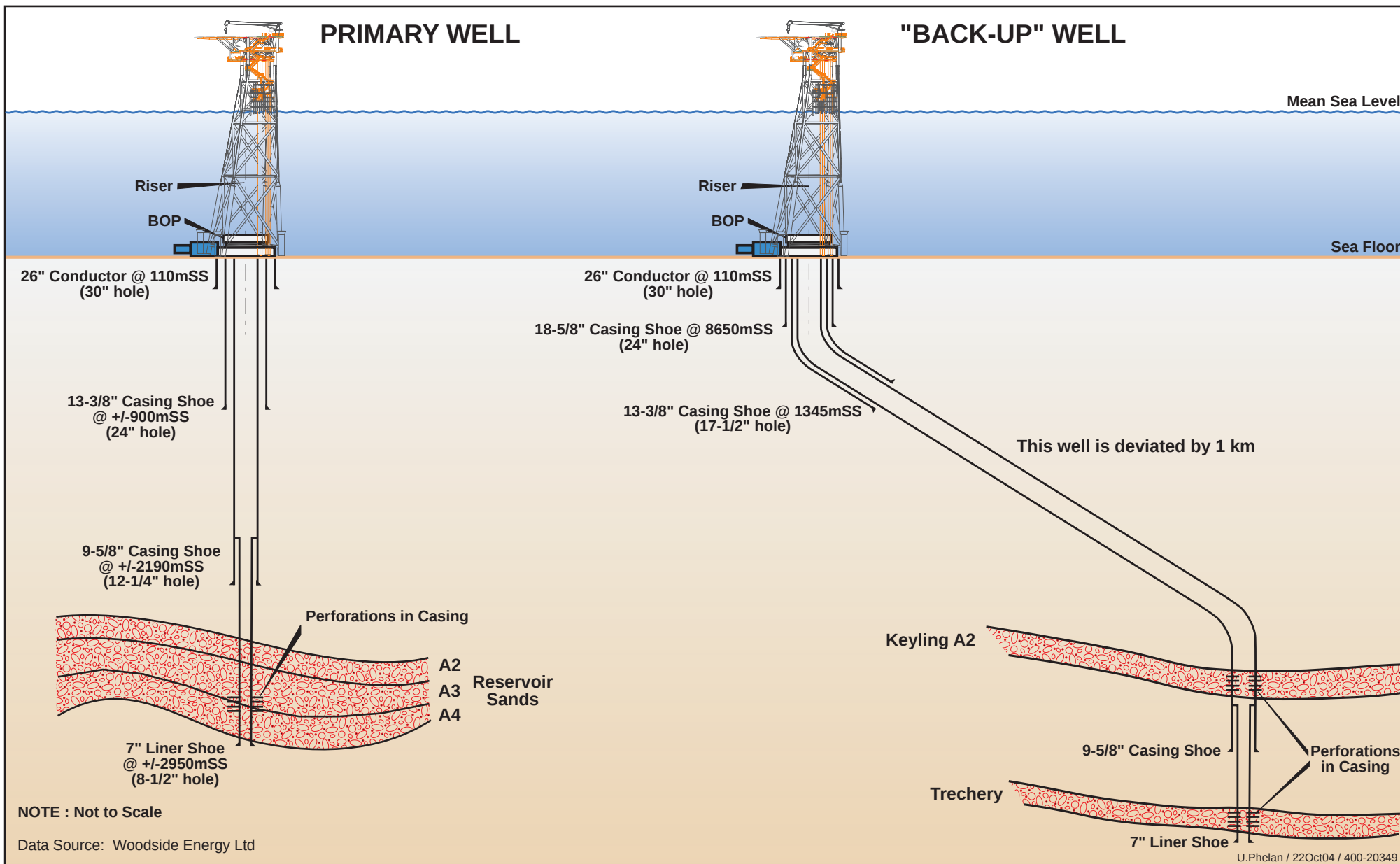
Blacktip Project

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JACK-UP DRILLING UNIT

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CONCEPTUAL WELL DESIGN

Figure 4.3

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Estimated quantities of drill cuttings and drilling muds are shown in **Table 4-5**. It may be necessary to use NWBMs in the lower sections of the wells to assist in borehole stability, this will be confirmed as detailed design progresses.

■ **Table 4-5 Estimated Drill Cuttings and Muds' Volumes**

Hole Size (")	Circulation System	Mud Type	Start Section (m)	End Section (m)	Hole Length (m)	Cuttings Volume (m ³)	Mud Volume (m ³)
Blacktip Primary Well							
30	Open	Seawater and PHG	Seabed	60	60	27	400
17½	Open	Seawater and PHG	60	850	790	122	1570
12¼	Closed	NWBM or WBM	850	2010	1160	88	375
8½	Closed	NWBM or WBM	2010	2810	700	26	287
TOTAL						263	2632
Blacktip Backup Well							
30	Open	Seawater and PHG	Seabed	60	60	27	400
24	Open	Seawater and PHG	60	750	690	201	1622
17½	Closed	NWBM or WBM	750	1130	380	59	310
12¼	Closed	NWBM or WBM	1130	2770	1640	125	490
8½	Closed	NWBM or WBM	2770	3160	390	14	310
TOTAL						426	3132

Notes: Information for these wells is based on preliminary design and may change as detailed design progresses
WBM - Water-based Mud; NWBM - Non-Water-based Mud; PHG – Pre-hydrated Bentonite

4.4.3 Drilling Fluids

Drilling fluids, commonly referred to as 'muds', consist of a mixture of base fluid, liquid and solid additives, and weighting materials. Drilling muds fall into two broad categories; water-based muds (WBMs) and non-water-based muds (NWBMs).

Drilling Mud Use: The drilling mud is essential to many aspects of the drilling process, including protection of equipment, stabilisation of the well bore and removal of drill cuttings. The most important function of the drilling mud is to maintain primary well control. The hydrostatic pressure of the mud is maintained at a level estimated to exceed the reservoir pressure along the open hole and therefore prevents uncontrolled flow and reservoir fluid and/or collapse of the well bore. The drilling mud is designed to assist with removal of cuttings and debris from the well bore, in addition to lubricating and cooling the drill bit.

The mud is mixed, stored and maintained in tanks on the drilling rig. During drilling, it is pumped down the drill string to the rotary drill bit, and is then forced up the annulus between the drill string and well bore or casing (**Figure 4-4**). In an open circulation system, the mud is discharged directly to the seafloor along with drill cuttings. This is generally the case during the preliminary stages of drilling, where the bore is not deep enough to insert drill casing. When casing has been inserted and cemented into place, the circulation system can be closed, which allows the drilling mud to be circulated to the surface facilities, along with the drill cuttings, for processing.

Processing equipment enables the mud to be recycled by recovering as much mud as is practical and removing a large proportion of the drill cuttings with vibrating screens (shale shakers).

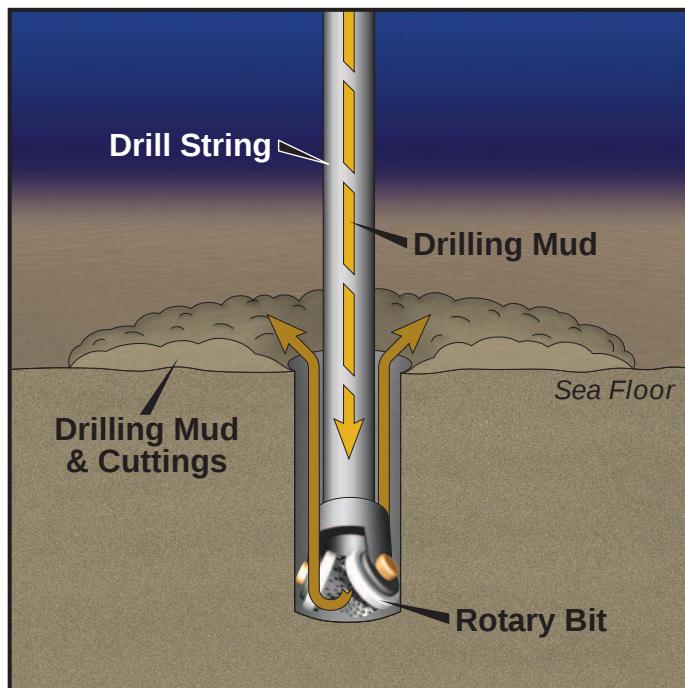
Excess WBMs will be flushed with seawater and discharged to the ocean through a direct overboard drain. Where WBMs are used, the whole drilling muds will be routinely discharged to the ocean at the end of drilling, or when mud property requirements change. The result will be a thin layer of cuttings and muds widely distributed over the seabed, as well as a plume of turbid water created by the finer particles which remain suspended in the water column for some time before they sink to the seabed.

Where NWBMs are used, excess muds will be recirculated to the drill rig, retained and transported to the shore for disposal or reconditioning. Under no circumstances will NWBMs be discharged into the marine environment should they be used. Drill fluids handling and disposal procedures will be designed in accordance with a Drilling Environment Plan.

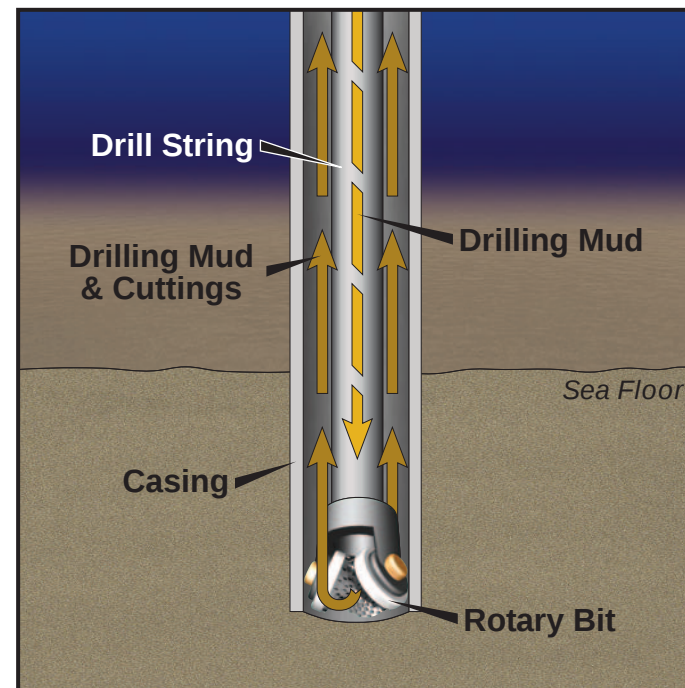
Water-Based Muds: WBMs are the least toxic of the available drilling fluids. WBMs are regularly used for drilling operations in the Timor Sea and considered an acceptable technology to employ in environmentally sensitive locations. WBMs use fresh or sea water as the continuous phase, with additives including bentonite, potassium chloride (KCl), polymers and partially hydrolysed polyacrylamide (PHPA) added to condition the mud. WBMs deliver acceptable performance for drilling non-challenging wells, such as vertical wells with inert rock formations.

Non Water-Based Muds: The well design for the Blacktip Project is currently in preliminary stages therefore specific drilling mud systems have not been confirmed. However, it is expected that WBMs will be used for the upper sections and NWBMs such as 'SYNTEQ' may be used for the lower hole sections. The NWBM is expected to be synthetic-based; the impacts of which are discussed in **Section 11**. Design details will be investigated further during the detailed well design phase. Oil-based muds (OBMs) will not be used to drill the wells.

Drilling Mud Additives: Other additives may be required in small amounts to assist in the control of bacteria and corrosion controls; and to produce specific fluid characteristics. Likely additives include biocides, weighting agents, alkaline chemicals, inorganic salts, defoamers, corrosion control agents, scale inhibitors, drilling lubricants, lost circulation materials and pipe release agents. Pipe dope, a lubricant used when connecting threads on pipe strings, becomes mixed with the mud as it is forced along the pipe string. Any excess dope is lost down hole during drilling and ultimately lost to sea with the drill cuttings and muds.



Open Circulation System



Closed Circulation System

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4.4.4 Drill Cuttings

Drill cuttings comprise small formation rock fragments (usually less than 10 mm in diameter) and related mineral residues which are removed from the well bore during drilling. The geological composition of drill cuttings is site-specific and can be predicted using lithological data from other wells drilled in the area. Based on data gathered from the Blacktip-1 exploration well, cuttings are likely to consist of very fine sands, silt and clay. Samples collected at the Blacktip drilling location show that sediments are predominantly composed of fine to very fine particles with 50 to 70% by weight below 63µm, and 30 to 40 % between 63 to 125µm in size (BBG 2000). Drill cuttings generally contain up to 10% by weight of adhered drilling muds.

Drill cuttings will be discharged to the marine environment in two ways:

- Open circulation system: When the upper section of the well is drilled without any drill casing in place, cuttings are directly discharged onto the seabed along with any drilling mud.
- Closed circulation system: Cuttings are circulated from the well to surface facilities and separated from the drilling mud using shale shakers. Once separated, the drill cuttings are disposed overboard via a drain or chute. Inevitably, some drilling mud will remain adhered to the cuttings and are also discharged to sea. Where WBMs are used, the amount of WBM discharged to the marine environment varies depending on the viscosity, mud weight and the water repellent nature of the drilling mud. Discharge of drill muds to the marine environment will be limited to a maximum amount of 10% by dry weight of base fluid on drilled cuttings, in line with regulatory requirements.

4.4.5 Well Completion and Clean-Up

Following successful drilling and casing of the reservoir, well completion is undertaken to connect the reservoir subsea production facilities. Commonly at the top of the well casing string, subsea facilities including internal tubing string, high-pressure wellhead housing and a blow-out preventer (BOP) are installed to prevent fluid escape from the well and to maintain well pressure. After running and cementing the liner, the drilling mud in the tubing and casing annulus is displaced by completion brine (typically potassium chloride solution). This provides a solid-free medium for the completion string that will generate minimal chemical interaction when in contact with reservoir formation fluids and maintain a positive overbalance to reservoir pressure. After running the completion, the tubing is displaced with diesel to provide an under-balanced condition in the tubing to assist in flowing hydrocarbons to the surface after perforation. Diesel being a hydrocarbon product would generate minimal formation damage if it should come in contact with the reservoir.

4.5 Installation and Construction Activities

4.5.1 Introduction

The weather will be a major constraint in both the shore crossing and gas plant construction as the vast majority of construction activities will have to be confined to the dry season when access is available via road and site working conditions are much improved.

4.5.2 Field Layout

No processing facilities will be located offshore; however, an unmanned wellhead platform will be used to control the flow of reservoir fluids from the wells through the export pipeline to shore. The wellhead platform will be fabricated offsite, transported by barge to the gas field and installed. The wellhead platform will comprise a fixed steel platform located in water depth of approximately 52 m (**Figure 4-5**). The various components of the wellhead platform will be transported to the site by barge, where it will be installed by either the Jack-up or a derrick/laybarge (the same barge used for pipeline laying) (**Section 4.5.3**). A removable pig launcher will also be installed on the wellhead platform for pipeline maintenance and inspection purposes. The substructure of the wellhead platform will comprise a four leg jacket secured to the seabed by deep or shallow foundations. The topsides of the wellhead platform will be safely supported above water by its substructure and will be designed to withstand extreme environmental conditions, including cyclones.

The two initial production wells will each be capable of producing approximately 180 Tera joules per day (TJ/d) of reservoir fluids. The current Maximum Daily Quantity (MDQ) is expected to be 191.2 TJ/d or 187 MMscf/d of raw gas offtake. The wellheads are located on the wellhead platform topsides. Flow from each well will be collected in a choke manifold and will then flow down the export riser and into the export pipeline.

It will be necessary to deploy divers and Remotely Operated Vehicles (ROVs) from support vessels or barges to undertake the installation and tie-in activities.

4.5.3 Gas Export Pipeline Specifications & Corridor Requirements

Export Pipeline Specifications: Design and construction of the export pipeline will be in accordance with the requirements of AS2885.4 for the offshore section of the pipeline; and AS2885.1 for the onshore section, as well as relevant legislation and licence conditions. The use of a 3-phase pipeline will allow reservoir fluids to flow simultaneously in the gas, condensate and water phases. The export pipeline specifications are described in **Table 4-6**.

Pipeline Corridor Requirements: Construction corridors of varying widths will be required. Offshore the export pipeline will require a 1 –1.4 km wide construction corridor, which will reduce down to 60 m between High Water Mark (HWM) and Low Water Mark (LWM). The onshore pipeline will require a construction corridor 40 m wide from the high water mark to the gas plant. In the vicinity of the shore crossing two laydown areas will be required to store pipe and equipment. Pipeline corridor requirements are shown in **Figure 4-6a & b**. In the event that the barge landing option is used (**Section 4.5.10.3**), a temporary corridor parallel to the shore approach of approximately 50 m wide will be required to facilitate barge landings. This will be a temporary requirement.

■ **Table 4-6 Export Pipeline Specifications**

Characteristic	Specification
Diameter	18"
Length	107.5 km offshore 2.5 km from shore crossing to onshore gas plant
Construction Material	Carbon steel, concrete coated
Operating Pressure	Approximately 100 barg
Design Pressure	110 barg
Pipe Wall Thickness	Approx 11.6–15.3 mm
External Concrete Coating Thickness	40 to 100 mm
External Anti-corrosion Coating	Fusion bonded epoxy or asphalt enamel
Internal Corrosion Protection	Continuous corrosion inhibitor
Cathodic Protection Offshore	Sacrificial anodes
Cathodic Protection Onshore	Sacrificial anodes
MDQ Flowrate	191.2 TJ/d or 187 MMscf/d
Expected Design Life	30 years

4.5.4 Subsea Export Pipeline

The 107.5 km offshore section of the gas export pipeline is expected to be trenched for its entire length between the wellhead platform and landfall unless seabed conditions dictate otherwise. Seabed conditions will be determined and the pipeline stabilisation method confirmed at the end of 2004 when all geotechnical and geophysical data for the route will become available.

Internal Corrosion Protection: Corrosion inhibitor will be injected into the export pipeline at the wellhead platform to reduce internal corrosion to such a level that pipeline integrity will be maintained for the pipeline's required life. No continuous hydrate inhibitor will be required for the pipeline due to the operating pressure of the pipeline and seawater temperatures.

External Corrosion Protection: The subsea section of the export pipeline will be protected against external corrosion by sacrificial anodes. The sacrificial anode is made of metal that is more reactive than the steel pipeline. The anode, when applied to the pipeline and immersed in water, corrodes rather than the pipe, thereby protecting the pipeline. The anode system will be inspected as part of an agreed maintenance and inspection schedule to ensure it is functioning properly. External concrete coating will provide additional stability and negative buoyancy to the pipeline. An anti-corrosion coating of fusion-bonded epoxy or asphalt enamel will be applied to the pipeline underneath the concrete, which will be the primary corrosion inhibitor.

Offshore Pipeline Installation: The pipeline lengths (typically 12 m) will be transported by barge or bulk pipe carrier from the pipeline coating yard to the site. If bulk carrier transport is selected the pipe lengths may be transferred from the bulk carrier to barges or pipe feeder vessels for final delivery to the offshore laybarge. The laybarge may carry a supply of pipeline lengths, or joints, sufficient for one or two days of pipelaying. The stocks will continually be replenished from the bulk pipe carrier or barge.

The subsea pipeline installation process will begin with the welding of the pipeline lengths. Following completion of each weld, a Non-Destructive Examination (NDE) technique will be employed to inspect the weld, and weld repairs will be performed if required. An anti-corrosion heat shrink sleeve or cold tape will then be applied to the weld area, and the void between adjacent concrete coatings may then be filled with a suitable infill. Upon completion of this process, the pipe is laid over a pipe support ramp (stinger) on the stern of the laybarge.

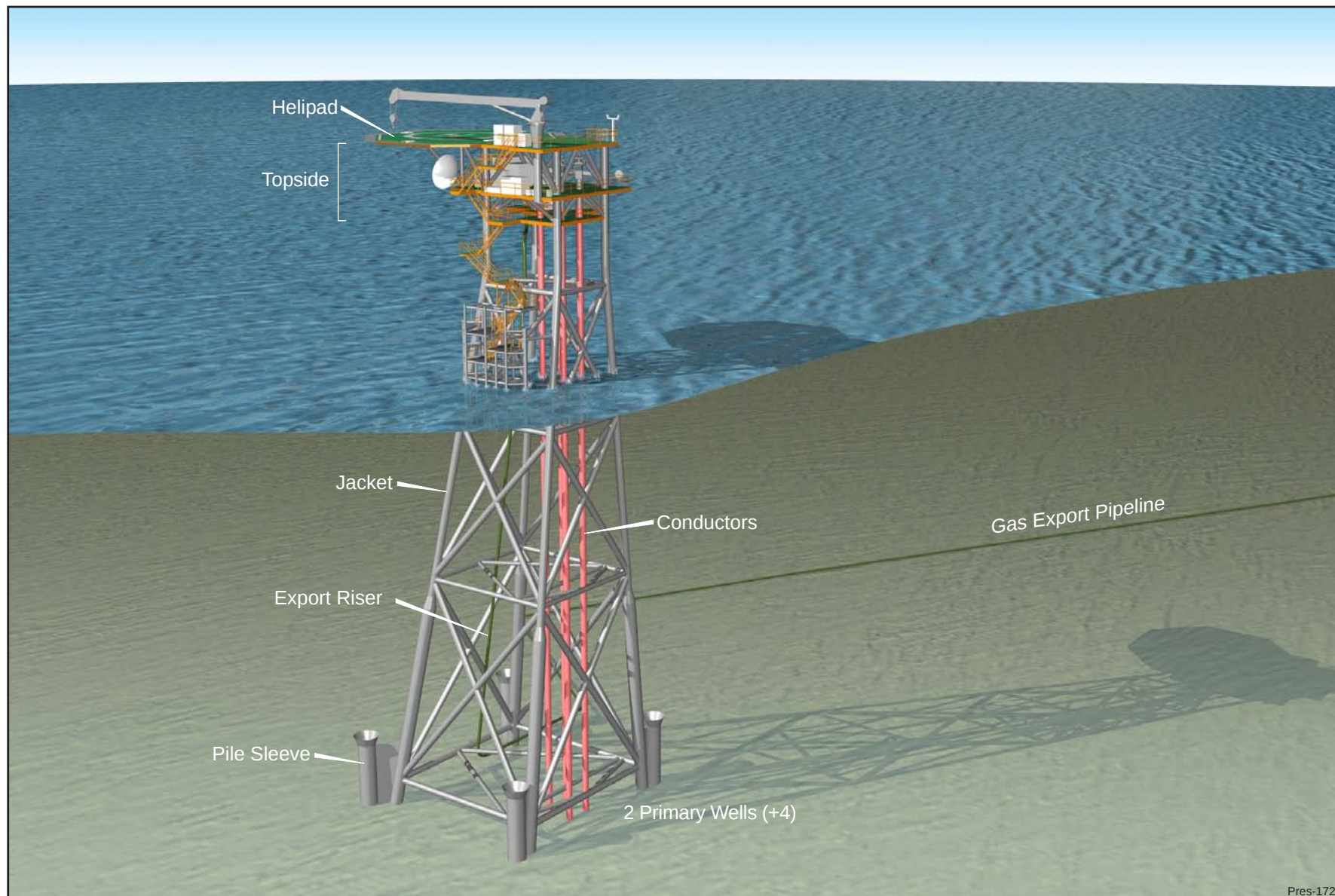
The laybarge will position the pipeline directly onto the seabed by lowering it over the stinger as the laybarge pulls forward on its anchors. The laybarge will be shifted along the pipeline route by its anchors (eight to twelve, depending on the barge type selected). The barge will move by pulling on anchor winches that are connected to the anchors via wire rope. Support vessels continually reposition the anchors, moving them forward in sequence. **Figure 4-7** identifies a typical laybarge laying pipeline. It will be necessary for the laybarge to anchor in several different locations in the nearshore area. As illustrated on **Figure 4-8**, this will require anchoring within the boundary of a site known as *Walpinhthi* Reef identified as being culturally sensitive (**Section 9 & 13**). This submerged reef is located approximately 1.5 km west of Yulow Point approximately 500 m south of the export pipeline.

Where the seabed conditions permit post-lay trenching will occur for the entire length of the offshore pipeline, except for the area designated as the shore crossing which will be trenched before pipelay (**Section 4.5.6**). A couple of options are being considered for post-lay trenching.

Option 1: Involves the use of a plough, which is towed along the pipeline by a vessel and digs a trench under the pipe as it is laid in place (**Figure 4-7**). It is estimated that at least 200,000 m³ of seabed material will be displaced during trenching; an exact figure is difficult to determine at this stage in design.

Option 2: Use of a jetting sled, which is mounted with high-pressure water jets and pulled along the seafloor either behind the laybarge or some other support vessel. The sled straddles the pipe and jets beneath it to dig a trench. The pipe finally touches down on the trench bottom some way behind the jet sled. Such an apparatus can trench pipe at an average of 1.6 km/day. Jetting disperses sediments over the otherwise undisturbed water bottom that flanks the jetted trench. The area covered by settled sediment and the thickness of the settled sediment depends upon variations in bottom topography, sediment density and currents.

The survey system will determine the precise end position of the pipeline and a lay down head will be welded to the end of the pipeline to complete the pipeline laying process.



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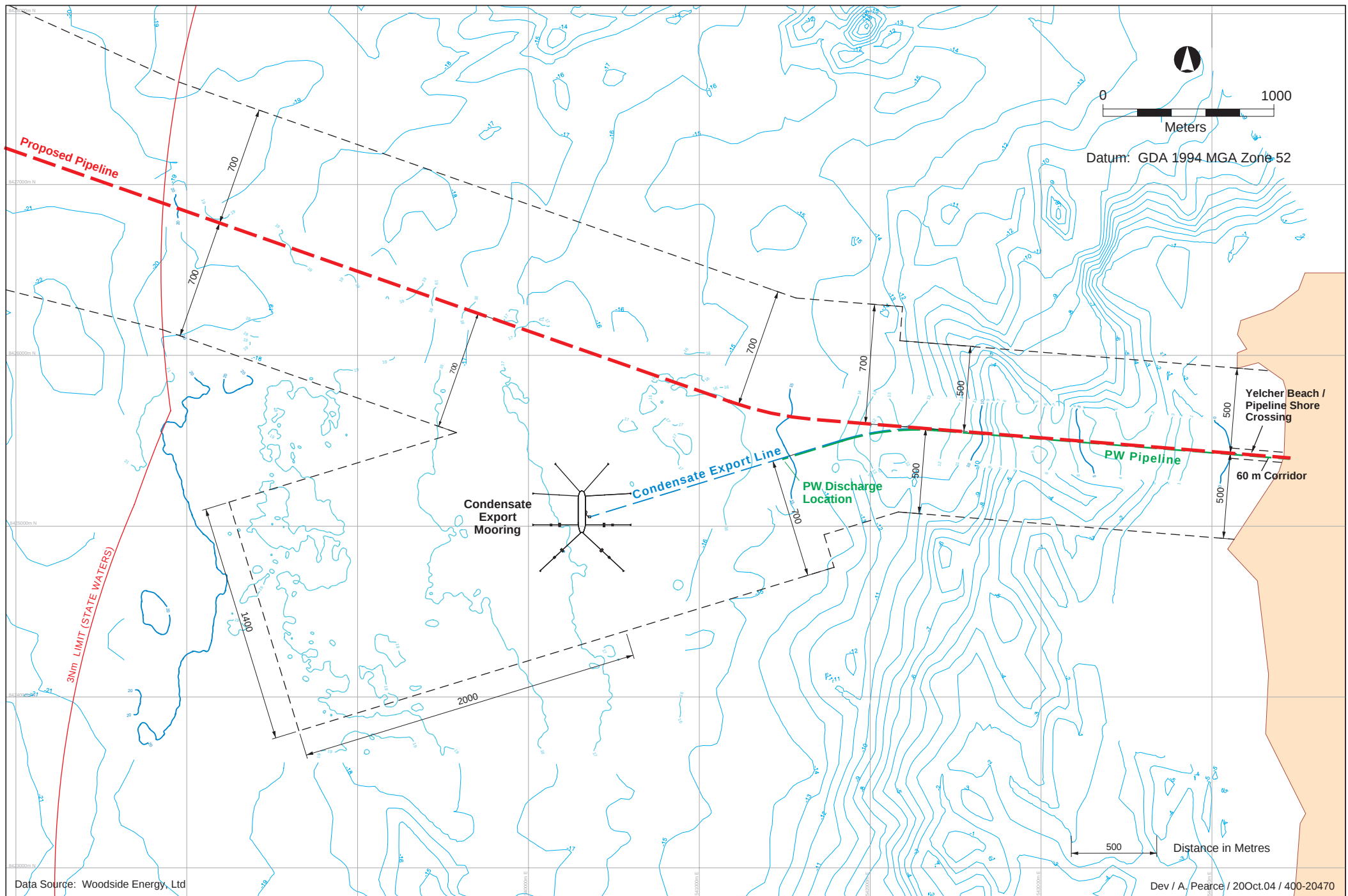
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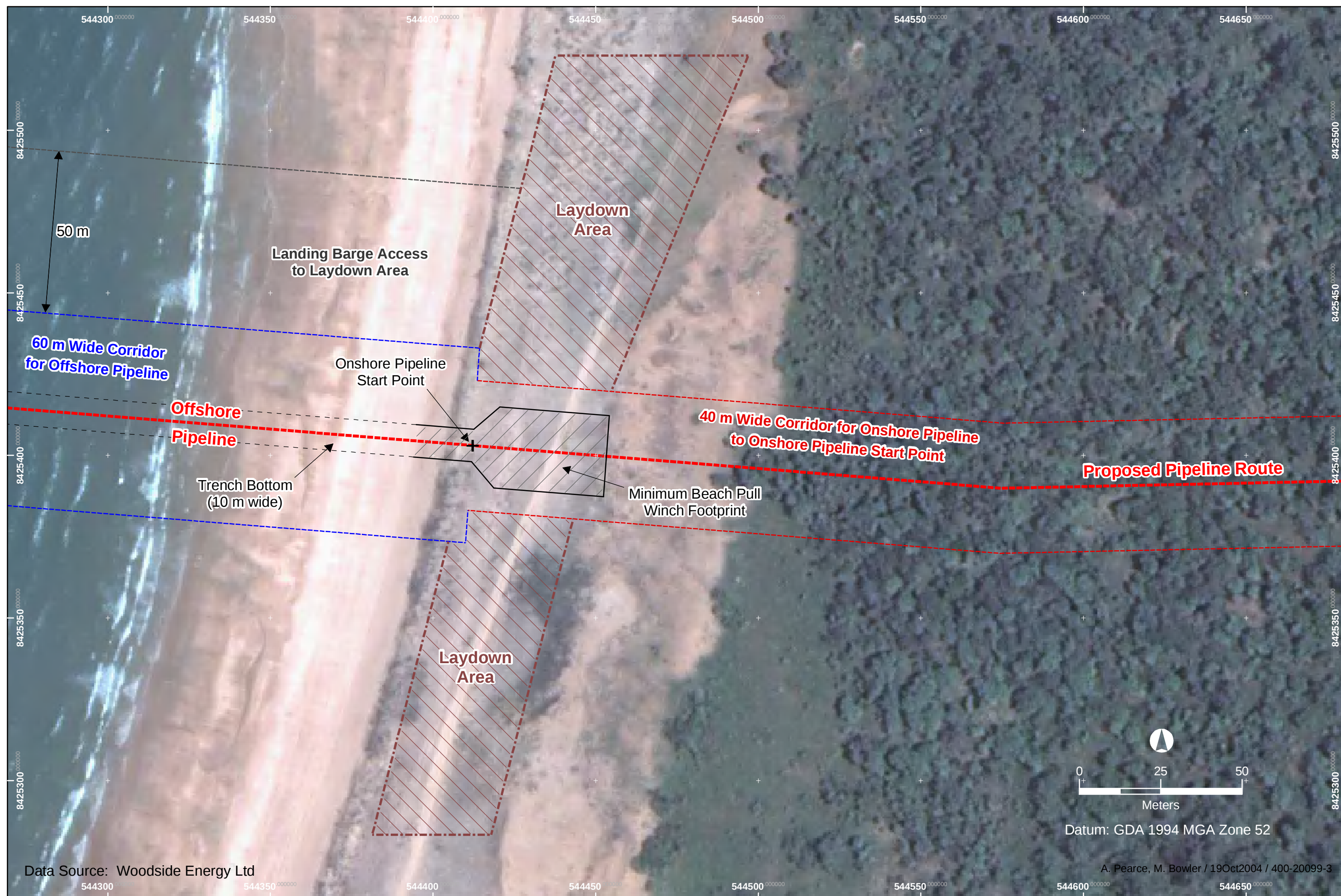
BLACKTIP UNMANNED WELLHEAD PLATFORM

Figure 4.5

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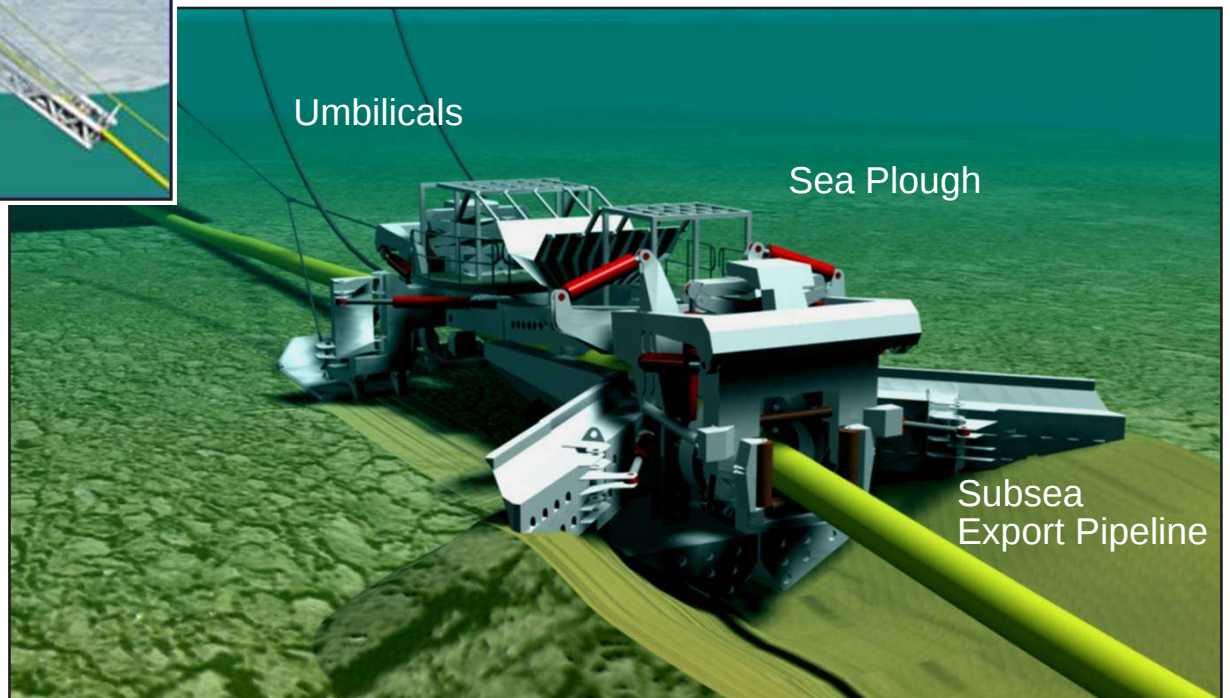
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Support
Vessel

Support vessel

Stringer



Umbilicals

Sea Plough

Subsea
Export Pipeline

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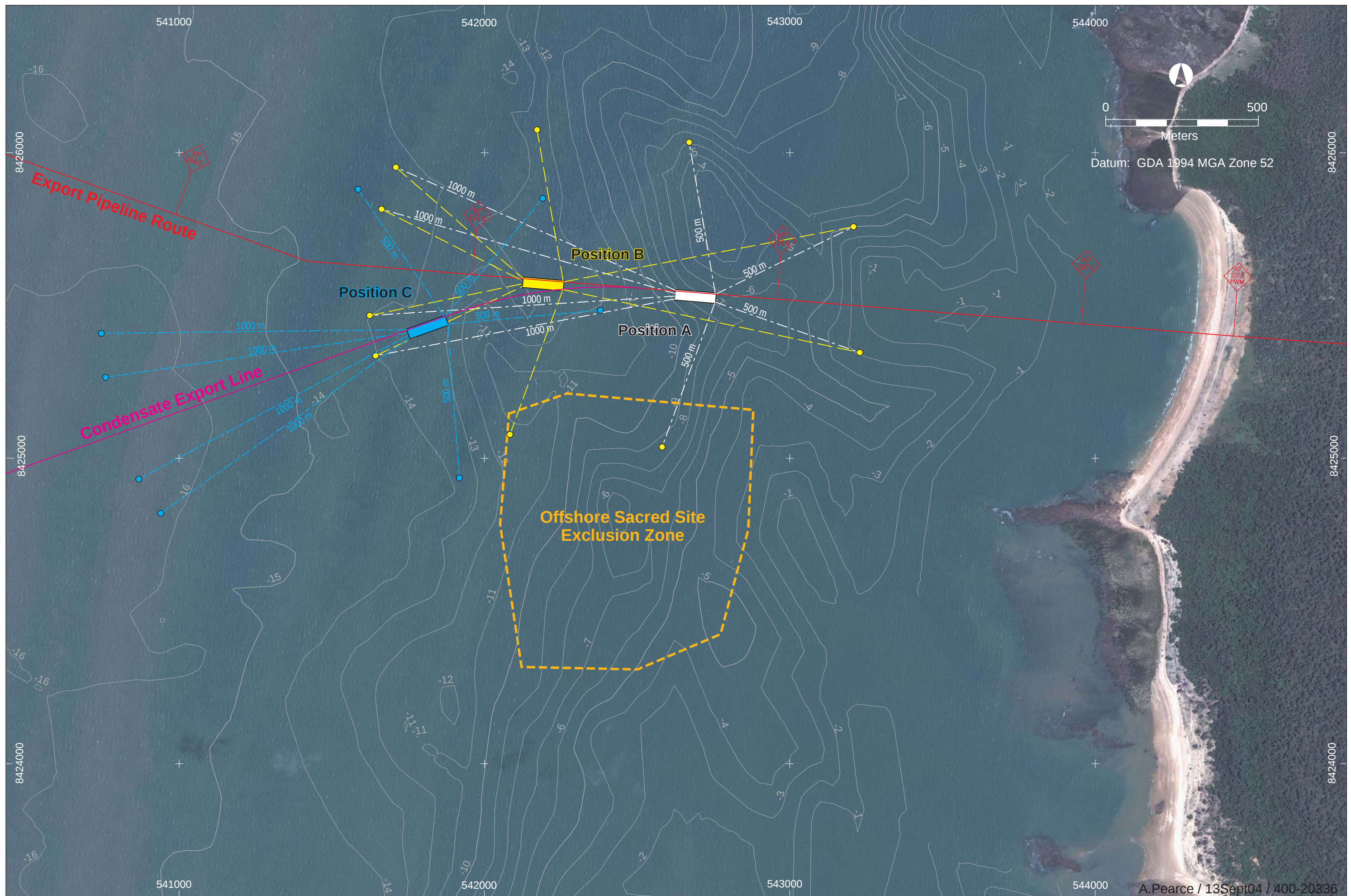
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LAYBARGE AND PIPELINE TRENCHING SYSTEM

Figure 4.7

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Following pipeline installation, an underwater Remotely Operated Vehicle (ROV) will be deployed to undertake an ‘as laid’ survey through video surveillance. The survey will be undertaken to identify spanning beneath the pipeline and to confirm that the pipe is undamaged and laid within the specified tolerance limits.

4.5.5 Condensate and Produced Water Pipelines

The condensate export pipeline and end manifold, condensate export mooring and PW pipeline diffuser, will be manufactured offsite and transported to the project area for assembly and installation. The characteristics of the condensate and PW pipelines are shown in **Table 4-7**.

■ **Table 4-7 Characteristics of the Condensate and PW Pipelines**

Characteristic	Condensate Export Pipeline	PW Pipeline
Diameter	Approx 14"	Approx 4–6"
Length	Approximately 4.5 km offshore 2.5 km from onshore gas plant to shore crossing	Approximately 3 km offshore 2.5 km from onshore gas plant to shore crossing
Construction Material	Carbon steel, concrete coated	High Density Poly Ethylene (HDPE)
Pipe Wall Thickness	Approx 12 mm	To be confirmed during detailed design
External Concrete Coating Thickness	100 mm (maximum)	None
Internal Corrosion Protection	Corrosion allowance	None
Cathodic Protection Offshore & Onshore	Sacrificial anodes	None
External Anti-corrosion Coating	Asphalt enamel	None
MDQ Flowrate	60,000 bbl/d	7000 bbl/d
Operating Pressure	To be confirmed during detailed design	To be confirmed during detailed design
Design Pressure	15 barg	To be confirmed during detailed design
Expected Design Life	30 years	30 years

Note: MDQ – Maximum Daily Quantity

The 14" carbon steel condensate export pipeline will transport condensate offshore for loading onto tankers. The pipeline has been sized on the basis of loading 50,000–60,000 bbl of condensate onto a tanker over 12 hours with a fluid velocity of 2.5 m/s. The pipeline configuration will be confirmed during the detailed design phase. The pipeline will terminate at a condensate export mooring, consisting of six conventional drag anchors connected to chain mooring lines and secured in approximately 14 to 16 m water depth. These will be lowered into place by an installation vessel, and marked with buoys. A valve will be installed at the end of the condensate export pipeline, and a float will be provided to mark its location.

The 4–6" PW pipeline will be ‘piggybacked’ onto the condensate export pipeline or the gas export pipeline using a spacer and clamp on the laybarge.

The condensate and PW pipelines will be laid in the same trench as the subsea export pipeline for approximately 1.7 km from the HWM. At this point the condensate and PW pipelines will deviate from the main export line. The condensate export pipeline will continue for approximately 2.5 km to the condensate export mooring, while the PW pipeline will continue for up to an additional 1.3 km to a discharge point.

The condensate export pipeline will terminate with an attachment to a condensate loading hose. This will provide a flexible link between the condensate export pipeline end manifold and a moored tanker. The submarine hose will be manufactured from reinforced rubber material with the outer cover resistant to aging, abrasion, weathering, sunlight, oil and seawater penetration.

Prior to loading, one end of the hose will be picked up using the tanker's crane and connected to the tanker manifold for loading. Once loading is completed, the line end will be isolated, disconnected and set down on the seabed where it will remain on the seabed until the next loading operation.

The PW pipeline will have a diffuser attached to disperse the PW and will be located below low tide level.

4.5.6 Shore Crossing

The gas export pipeline landfall will be located on a beach approximately 12 km to the south-west of Wadeye. Coordinates of the shore crossing are provided in **Table 4-3**. The gas pipeline specifications at the crossing are the same as those shown in **Table 4-6**.

The export pipeline will require a construction corridor 60 m wide up to the HWM (approximately). Landward of the HWM the corridor will be reduced to 40 m.

Figure 4-6b presents an outline of land requirements at the shore crossing.

Shore Crossing Corrosion Protection: Significant consideration will be given to anti-corrosion coating design. Cathodic protection against external corrosion will be achieved through a combination of sacrificial anodes.

Laydown Area: It is expected that two temporary laydown areas, approximately 100 m by 50 m in size, will be needed near the shore crossing construction site located at the shore pull start area and winch location (**Figure 4-6b**). The laydown area will store materials, vehicles and machinery, pipe lengths and other pipeline components during site preparation and construction phases. The exact location of this laydown area is not yet confirmed.

Landfall Construction Methods: Over the shore crossing length (defined as between the HWM and LWM approximately) the construction corridor will be 60 m wide, and the pipeline trench 5–10 m wide at the bottom of the trench.

The landfall construction methods are summarised in **Table 4-8**. Landfall construction will take approximately 20 weeks and will be carried out using an ‘open cut’ technique which involves five main stages undertaken in the following order:

- 1) nearshore trench dredging
- 2) beach/dune trench excavation
- 3) pipeline installation
- 4) backfilling
- 5) rehabilitation and pipeline marking

Nearshore Trench Dredging: With pre-lay trenching a marine-based excavator dredge will be used to dig a trench from a point seaward of HWM (depending on the draft of the marine based excavator) to the 5–8 m water contour, approximately 1.7 km offshore. However, if conditions are favourable post-lay trenching may be employed before reaching the 8 m contour mark, with the marine excavator continuing offshore to complete post-lay trenching for the remainder of the pipeline route.

The spoil will either be cast to the side of the excavation in the immediate vicinity of the trench or stockpiled prior to backfilling. Tidal action may cause the spoil to migrate further than 30 m from the pipeline route ie outside of the 60 m working corridor. During construction some dredging may be required in the trench so that it is maintained prior to pipelay.

Beach/Dune Trench Excavation: Land-based excavators will be used to excavate the trench between the HWM to the end of the nearshore trench (described above). The excavators may construct a temporary groyne so that work can be undertaken safely in the area around LAT and slightly beyond.

The spoil disposal methods assume that no acid sulfate soils (ASS) will be found in the construction corridor. An ASS sampling and analysis programme was undertaken in the shore crossing area to confirm the potential for ASS. Results of the survey will not be available until the end of 2004 and if they show evidence of ASS, then these disposal methods will be reassessed in accordance with an Acid Sulfate Management Plan (**Section 12.2.1**). However, preliminary indications are that ASS will not be an issue at the site.

Pipeline Installation: The export pipeline will be pulled ashore separately to the condensate pipeline; the PW pipeline will be ‘piggybacked’ to either the condensate or gas pipeline. All three pipelines will be pulled ashore from a laybarge using an anchor and winch set up 1 m above HWM (**Figure 4-9**). The winch will be located in the 40 m working corridor.

It may also be necessary to install shore-based anchors at two discrete sites outside of the designated corridor between the dune and the water line so that the laybarge can hold its position during the shore pull. The ground will be disturbed in these two areas and cleared of vegetation. Land-based plant will also need access to areas along the beach to install these anchors. Access will typically be through the dune cutting and along the beach. An archaeological site known as a

shell midden (**Section 9**) is located along the dune system through which a working width of approximately 40 m will be required. During construction the remainder of this site will be fenced off in accordance with the requirements of the Cultural Heritage Management Plan (**Section 15**).

Backfilling: The requirement for backfilling will be confirmed during the detailed design phase. However, it is expected that indigenous sediments and/or imported backfill material stockpiled adjacent to the trench will be used to backfill the pipeline trench in the nearshore trench. The material will be replaced in the reverse order to which it was excavated. Similarly, in the dune/beach area the material excavated will also be returned to the trench.

Rehabilitation and Pipeline Marking: Immediately following backfill, the beach/dune area will be revegetated in accordance with a Rehabilitation Management Plan (**Section 15**) to prevent the occurrence of erosion and soil degradation. Signs will be erected at the landfall HWM, which will be legible from a distance of at least 100 m from the waterside of the landfall.

4.5.7 Onshore Pipelines

The onshore section of the export pipeline will extend for approximately 2.5 km from the HWM to the gas plant (**Figure 4-10**). No watercourses will be crossed by the pipeline. Installation of the onshore section will be undertaken in consultation with local community, and as required by AS2885.1, relevant legislation and licence requirements.

The condensate and PW pipelines will be placed in the same trench as the gas pipeline.

Onshore Corrosion Protection: To prevent corrosion cathodic protection will be by means of sacrificial anodes.

Onshore Construction Methods: Construction of a pipeline is typically undertaken in a ‘spread’ which refers to the equipment and crew required to construct a pipeline. This operates like a production line: preparing the work area; fabricating and installing the pipeline; backfilling and then rehabilitating the work area upon completion. The Right of Way (ROW) will be 40 m wide (**Figure 4-11a & b**). Where possible this ROW will be reduced to minimise potential impacts on areas of environmental sensitivity.

■ **Table 4-8 Landfall Construction Methods**

Construction Phase	Machinery	Description	Location of Activity
Nearshore Trench Dredging (seaward of HWM)	Pontoon-mounted hydraulic excavator supported by hopper barge	Soft sediments and fractured rocks will be dredged from the trench and stockpiled on the barge or dumped in a spoil heap to the side of the trench. The sediment may be returned to site once pipeline installation is complete. Controlled drilling and blasting will be performed if necessary, although geotechnical investigations indicate this is unlikely.	Approximately 1.7 km offshore, ie from a point seaward of HWM to the 5–8m water depth contour.
Beach/ Dune Trench Excavation (HWM to end point of nearshore trench)	Large tracked hydraulic excavator	The onshore section of the landfall will be excavated. If rock is present on the beach then excavation will be performed prior to laying the pipe. Material excavated from the trench will be stored on the opposite side of the working width and returned once pipeline installation is complete.	Trench down to a position seaward of HWM.
Pipeline Installation	Winch set up	Pipeline will be pulled ashore from a laybarge using anchor and winch set up above HWM.	Dune area, at least 1 m above HWM.
	Laybarge	The pipeline will be installed on the seabed in a continuous operation from the laybarge.	Can operate in a minimum of 5 m of water, which is up to 1.7 km from LWM.
Backfilling	Hydraulic excavator	Indigenous sediments (1–1.5 m cover on top of pipe) and/or imported backfill material will be used to backfill the pipeline trench in the nearshore trench, seaward of HWM. To be confirmed during the detailed design phase. The beach/dune trench will be backfilled using material stockpiled adjacent to the trench. The material will be replaced in the reverse order to which it was excavated. Tramping or rolling will be used to consolidate the backfill material.	Approximately 1.7 km offshore from HWM to the 5–8 m water depth contour. To be confirmed during the detailed design phase. Trench down to a position seaward of HWM.
Rehabilitation and Pipeline Marking	Graders, contour ripping equipment, scrapers	Immediately following backfill, the area will be revegetated to prevent the occurrence of erosion and soil degradation. Signs will be erected at the landfall HWM, which shall be legible from a distance of at least 100 m from the waterside of the landfall.	Trench above HWM on the beach/dune area. Signs at the landfall HWM of the submerged pipeline.

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PIPELINE SHORE PULL WINCH SYSTEM

Figure 4.9

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All environmental approvals and permits will be obtained by Woodside prior to commencement of construction activities. The construction of the onshore pipeline will be undertaken by the gas plant contractors. Construction activities along the pipeline spread will include:

- pre-construction survey
- ROW preparation
- topsoil stripping and grading
- trenching
- stringing
- welding
- field coating
- pipeline lowering
- tie-in and testing
- dewatering
- backfilling
- rehabilitation and pipeline marking

The plant and equipment typically associated with these activities are summarised in **Table 4-9**.

▪ **Table 4-9 Vehicles & Equipment Required for Onshore Gas Pipeline Construction**

Construction Phase	Typical Plant and Equipment
Clear and grade	Graders Backhoes
Trenching	Bucket wheel trencher Rock ditcher Hydraulic excavators
Stringing	Trucks
Welding & joint coating	Side boom tractors
Padding	Padding machine
Pipeline lowering	Side boom tractors with lifting cradles
Tie-ins & road crossings	Side boom tractors
Shading & backfilling	Padding machine Graders Earthmoving equipment

Pre-construction Survey: Detailed terrain surveys will be conducted to profile the pipeline route. These surveys will be completed as part of the detailed design. Survey pegs will be placed in the ground to facilitate the layout and clearing of the construction ROW.

Preparation of ROW: The ROW will be cleared of heavy vegetation to a maximum width of 40 m. Suitable vegetation will be stockpiled for respreading during rehabilitation. Any measures agreed to in relation to working width, as part of the landowner agreements, will be implemented prior to arrival of the pipe joints on site.

The pipeline centre line will be set out using pegs to establish the exact pipeline route. Based on the pipeline centre line the extent of the working width will be clearly marked using pegs or other temporary measures. All construction activities will be carried out within the designated working width, which may increase or be reduced over short lengths in certain areas, as required. The working width (40 m) will not be fenced, except at points of public access or deep excavations.

Drainage will be installed where necessary, especially in wet areas of land with poor drainage or a high water table where the natural water table would intrude into the trench. Drains will enable the contractors to temporarily lower the water table and keep the trench relatively dry during installation and tie-in operations.

Topsoil Stripping and Grading: The topsoil and associated seed bank will be stripped from the working width and set to one side, separate from other stockpiled soil (**Figure 4-11a & b**). Disturbance will be minimised to reduce the risk of soil deterioration. Graders and backhoes will be used to level the area to the required gradient.

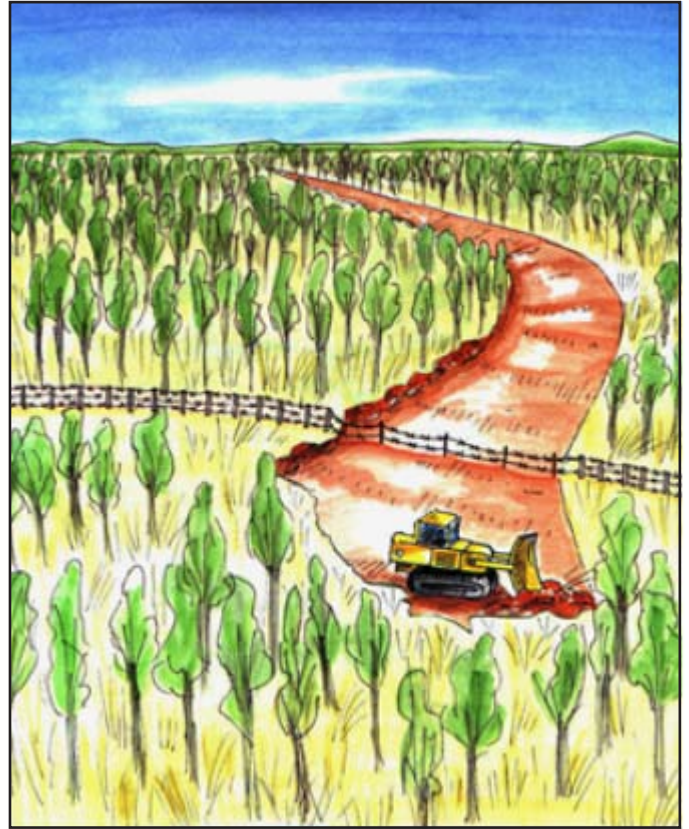
Trenching: Machinery such as excavators, trenching machines and rock saws will be used to prepare a trench 5–10 m wide to accommodate installation of all three pipeline (gas, condensate, PW). Depending on the nature of the ground, it may also be necessary to drill and blast some sections but this can not be confirmed until the onshore geotechnical surveys are completed at the end of 2004. Blasting will be carried out in accordance with AS2187.2.

Generally a trench will be dug to 1.5 m, which will give the pipe a soil cover of at least 750 mm when backfilled. Typically the machinery will straddle the trench or move along the side placing the excavated soil to one side of the trench separate from the stockpiled topsoil. Sloping ramps away from the trench will be installed to enable fauna to escape at appropriate intervals. Where the public can easily access the trench, it will be clearly marked by bunting, hazard lighting and will be fenced off.

Stringing and Bending: Stringing involves the distribution of pipe joints along the pipeline route. The contractor will collect pipe joints from the pipeline laydown area. Trucks will transport the pipe to the spread, where it will be laid out adjacent to the alignment of the trench, bent as required and placed on skids to protect the pipe coating from damage.



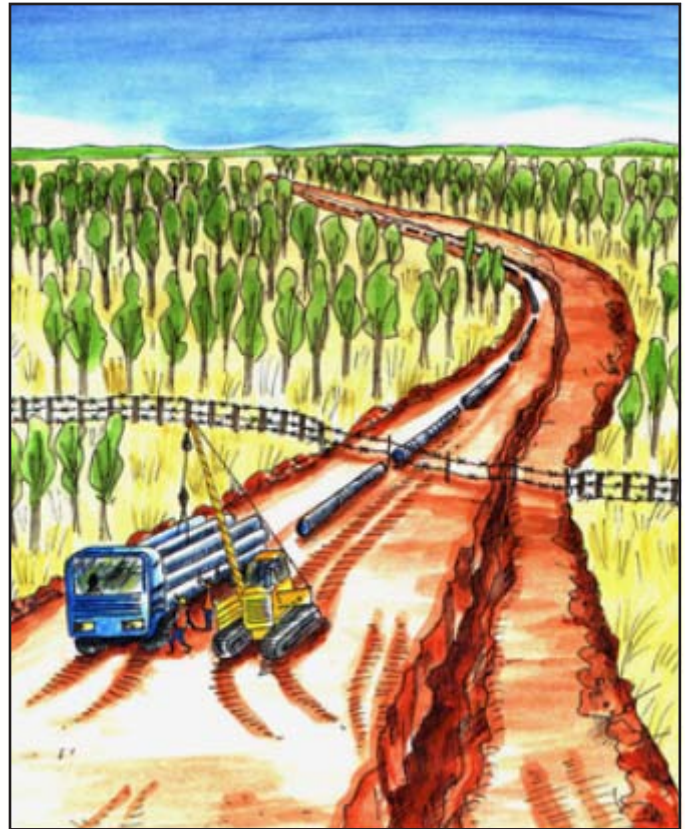
Pre-construction



Clear and Grade

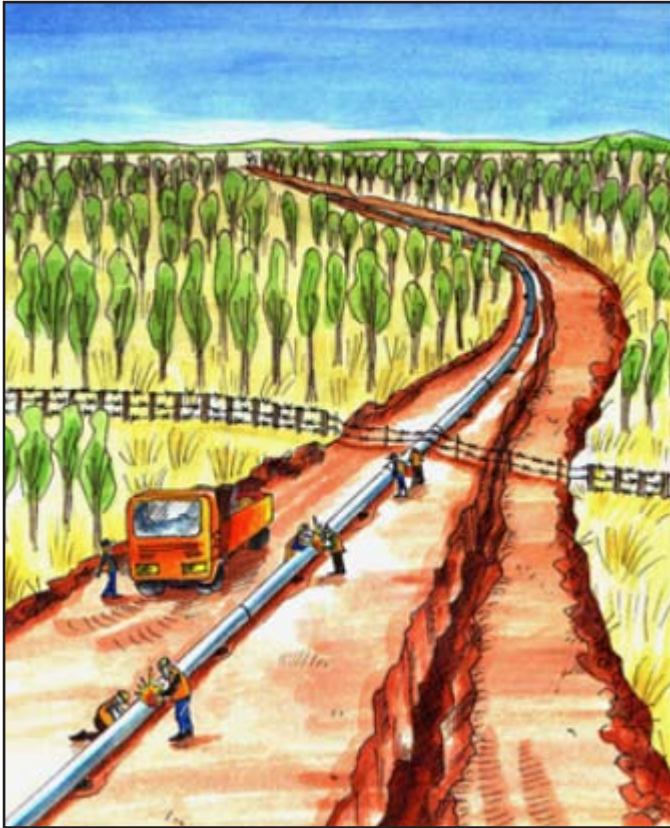


Trenching

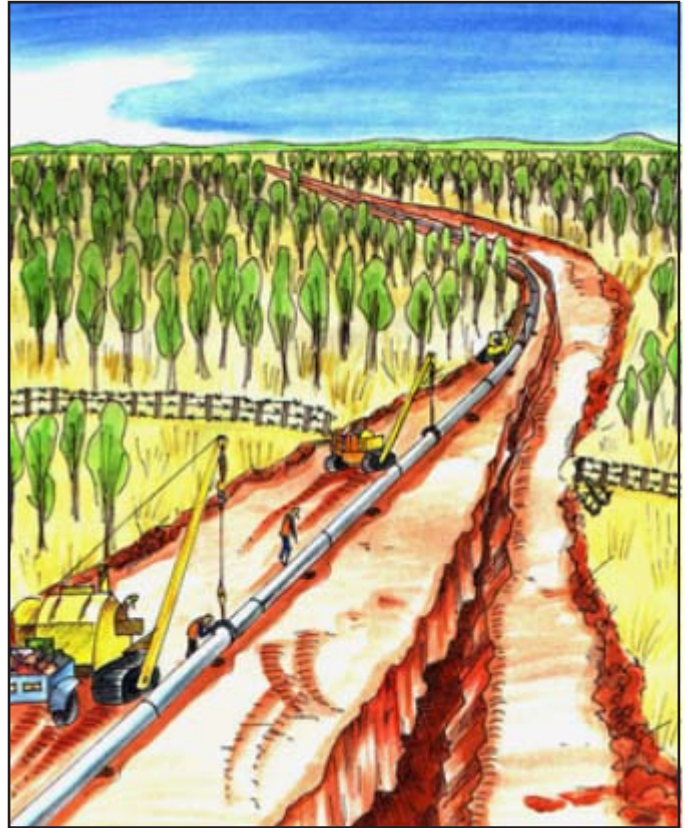


Pipe Stringing

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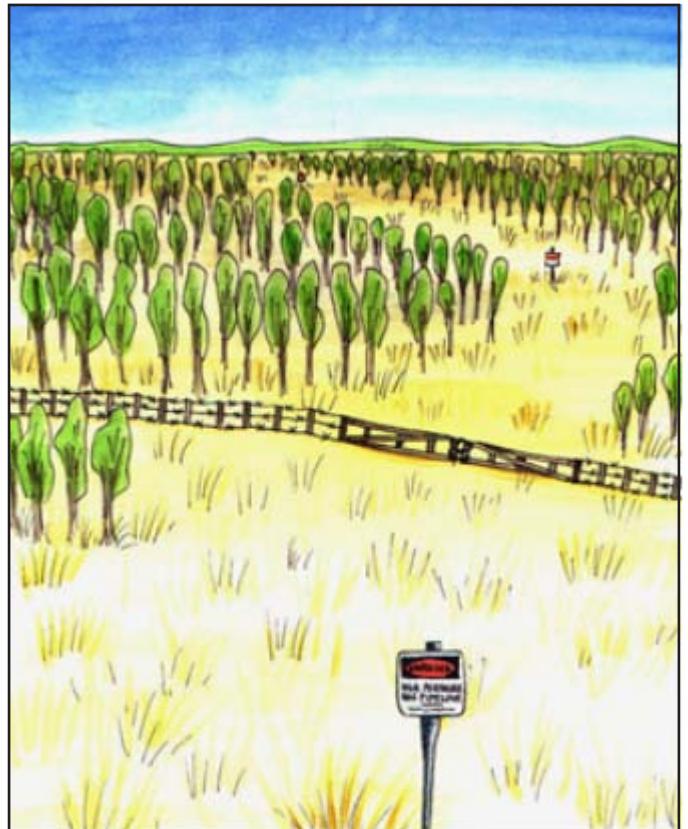
Pipe Welding



Lowering in



Back Filling



Post Rehabilitation

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Welding: Once strung, joints will be welded together on site prior to placement in the trench. A line up crew will position the pipe using side boom tractors and line up clamps. The pipes will then be welded together by suitably qualified welders. Weld quality will be a primary concern, and each weld will be subject to a radiograph or ultrasonic inspection to ensure compliance to specifications. Strict acceptance criteria will be applied in accordance with requirements of AS2885. If a weld is deemed unsatisfactory, it will be either repaired or remade.

Coating and Corrosion Protection: Following welding, field coatings will be applied to the welded joints to protect the pipeline from corrosion. The coating quality will be checked against strict acceptance criteria and in accordance with AS2885 and related Australian Standards.

Pipeline Lowering: When a section of trench has been dug and pipe sections welded, graded material will be placed at the bottom of the trench and the pipe will be lowered in using a series of sideboom tractors. The side booms will raise a section of pipe and lower it into the centre of the trench. Careful handling will be essential during this operation to ensure that the external coatings are not damaged during the process. This operation will be carried out as soon as possible following the opening of the trench.

Testing: Integrity testing will comply with the requirements of AS2885. Pipeline testing will be undertaken to verify the integrity of the pipe.

Backfilling: Once tested, the pipe is covered with the stockpiled trench spoil and is backfilled in layers and compacted using rollers. Once the pipeline is in place, the backfilling process will commence. The trench will be backfilled in the reverse order to which it was excavated using the stockpiled soil adjacent to the trench, or where necessary imported material. The trench will be backfilled in layers, and compacted using rollers.

Rehabilitation and Pipeline Markers: The pipeline ROW and construction access routes will be cleaned up and rehabilitated in consultation with the relevant landowner requirements, and in accordance with Australian Standards, legislation and licence requirements. After backfilling the trench, the site will be contoured, and stockpiled topsoil and vegetation will be respread. The disturbed area will also be reseeded in consultation with landowners to ensure correct procedures are adopted and that no exotic species are introduced. It is anticipated that land users will be able to resume their previous activities over the pipeline provided it does not involve excavation activities or deep rooting vegetation.

During the reinstatement of boundaries, signs and aerial markers will be installed at regular intervals along the pipeline route. This is so that the pipeline can be easily recognisable from the air, ground or both. Signs will be placed at each change of direction.

Crossings: No major sealed roads will be crossed during construction of the short section of onshore pipeline. Unsealed minor roads and tracks will be crossed using the open-cut technique as per the majority of the pipeline. All road and track crossings will have a minimum depth of cover of 1000 mm. There will be no watercourse crossings.

4.5.8 Onshore Gas Plant

Construction Activities: All onshore facilities, including the onshore gas plant and ancillary systems, will be prefabricated as much as practicable offsite, transported to site and then assembled within the plant laydown area. Other materials and supplies will also need to be transported to site, these are detailed in **Section 4.5.10**.

Onshore plant construction activities will include:

- establishment of the site, for example construction of access roads, pioneer construction camp, main accommodation camp and utilities;
- clearing of vegetation within the plant site and laydown areas;
- preparation of the construction site;
- laying foundations and erecting facilities;
- installing equipment, piping and ancillary systems, for example communications, instruments and electrical;
- testing and pre-commissioning of systems and equipment;
- clean up and removal of all construction related equipment and facilities.

A pig receiver will also be installed within the boundary of the onshore gas plant footprint for pipeline maintenance and inspection purposes.

Various machinery and equipment will be brought onto the site to undertake the construction and installation activities, including compacters, welding machines, cranes and concrete trucks.

Laydown Area: A permanent laydown area will be required for the onshore facilities during the life of the project. The laydown area will be located within the gas plant site boundary. During construction, this area will be used for storage of materials, vehicles, waste and equipment and it will also house the construction camp. As detailed in **Section 4.7.5**, during operation an accommodation camp for operations/maintenance personnel will also be located within the same laydown area.

Onshore Gas Plant Testing: Part of the onshore gas plant construction activities will be the hydrotesting of the storage tanks and the plant piping. It is envisaged that one of the tanks will be utilised as a hydrotest water storage tank, so that the hydrotest water can be transferred to the other tanks when required. The stored water may also be used for the plant piping hydrotesting programme. A total of 6,000 m³ of hydrotest water will be required which will most likely be sourced from bore water, although seawater will be considered. If borewater is used it is likely that no chemicals will be added to the hydrotest water. Discharge of the hydrotest water will take place to sea through the condensate export pipeline or the PW pipeline.

4.5.9 Export Pipeline Testing

Testing of a pipeline and ancillary components is an integral part of pipeline construction. Testing will generally take the following forms:

- testing materials prior to construction;
- testing of welds;
- hydrostatic testing.

Testing Materials Prior to Construction: The manufacturers of materials and equipment will carry out quality assurance tests of all items prior to transport to site. Any materials that fail the quality test will be marked and quarantined so as to ensure they are not used.

Testing of the Welds: All welds will be checked in accordance with strict industry standards. Pipe lengths will be welded together on site prior to placement in the trench. Strict acceptance criteria will be applied in accordance with AS2885 (Parts 2 and 4). Each weld will be subject to an X-ray or ultrasonic inspection to ensure compliance to specifications. Any unsatisfactory welds will be repaired or cut out.

Hydrostatic Testing: Hydrostatic testing of both the subsea and onshore sections of the export pipeline will be undertaken as per AS2885, which requires proof of pipeline strength and leak tightness, and pressure testing to confirm the maximum allowable operation pressure (MAOP). As the two sections will have slightly different characteristics, they may require different test pressures and may therefore be tested as separate units.

Testing of the pipeline system from pig launcher on wellhead platform to pig receiver in the gas plant will involve the injection of filtered seawater comprising small quantities of chemical additives. A volume of hydrotest water, slightly greater than the capacity of the export pipeline and risers, is injected into the structures to ensure that the entire lengths of the export pipeline and risers are treated with hydrotest water. Typically, the flooding water will consist of:

- filtered seawater to flood the line;
- fluorescein dye to aid in detection of any leaks;
- oxygen scavenger and a biocide.

Fluorescein dye will be injected at the offshore end of the pipeline to detect leaks at flanges adjacent to the wellhead platform. If necessary, a corrosion inhibitor may be added to the hydrotest water, this will be confirmed during the detailed design stage. An estimated 16,000 m³ of treated seawater will be required for testing, and this will be sourced from the Joseph Bonaparte Gulf near the wellhead platform. The combination of additives and optimum dosage is dependent on factors such as water quality, pipeline material, temperature and exposure time.

Pressure testing will be performed for the pipeline during which the pipeline will be flooded with the hydrotest water to a pressure above MAOP. The export pipeline may initially be tested in sections depending on the contractors pigging battery limits, although this is considered unlikely.

If tested in two sections, the onshore section would require the higher test pressure. Joints or welds between the pipeline sections will be subject to non-destructive testing (NDT) to confirm the join quality.

Following completion of testing, 'dewatering' of the pipeline is undertaken whereby the hydrotest water is discharged to make way for production fluids. This is discussed in **Section 4.6.3**.

4.5.10 Construction Access Routes

Several modes of transport are currently under consideration to access the project area and are presented in **Figure 4-10** and **Figure 4-12**, and summarised in **Table 4-10**.

The need for a high-grade access road is a major safety requirement of the project. The existing Injin Beach access track from Wadeye is of insufficient quality to be used by large construction vehicles and requires extensive upgrading along its entire length to the plant site. The existing road would pose a significant safety issue and would require restrictions on local traffic during the construction period. The new all weather construction road will be 13 km long, 4 m wide and will require a construction corridor 50 m wide to accommodate lay down areas at various intervals along the corridor. The new road (**Figure 4-10**) will accommodate both construction traffic and local traffic during the busy construction period, which will fall in the dry season.

Not all of the 50 m corridor will be cleared of vegetation. The amount of clearing required for the construction of the access road will be determined by the need for laydown areas and their locations, all of which will be located inside the 50 m corridor.

Drainage channels will also be constructed parallel to and adjacent to either side of the road within the 50 m corridor and will be 4–9 m wide (**Figure 4-10**). After construction the combined width of the parallel drainage channels/ditches and permanent road surface will be approximately 26 m for its entire length.

Connected to the parallel drainage channels/ditches will be drainage ditch run-outs which will increase in width as they fan out from the road. These will also vary in width and length; the largest is anticipated to be 1.8 km long and will fan out from 9 m near the road to 40 m wide at the furthest point. These ditches are required to lower road drainage velocities thereby preventing soil erosion. The construction of these runout ditches will involve initial clearing of the vegetation and grading of the soil to the correct profile. Vegetation will be allowed to re-establish in these runout ditches provided it does not impede the flow of water draining from the road surface.

Prior to construction proceeding the proposed access road and associated drainage channels and ditch run-outs will undergo detailed environmental surveys to a level similar to those already undertaken for the Draft EIS and in consultation with traditional landowners.

4.5.10.1 Access & Haul Roads

Road access is the preferred option for general construction requirements. Gaining access by road from Darwin requires over 350 km of travel. The pavement width in some areas from Darwin to

4.5.10.1 Access & Haul Roads

Road access is the preferred option for general construction requirements. Gaining access by road from Darwin requires over 350 km of travel. The pavement width in some areas from Darwin to Wadeye is minimal, although this is not considered a problem. A one-lane bridge at Burrell Creek presents a limitation, in that while wide and heavy loads could negotiate the bridge, this would require the removal and subsequent replacement of roadside furniture. Loads traversing this bridge would be limited to axle loads that are within the bridge design load and width limits.

The major constraint in regards to landfall and gas plant site access is the climate, with access during the wet season limited to either barge or plane; the construction schedule will be organised around this.

■ **Table 4-10 Construction Access Options under Consideration**

Transport Type	Purpose	Requirement
Barge or other supply vessels	Transport of materials and provisions to boat ramp at Sandfly Creek, near Wadeye	All year access
Beach Landing or Flat Top Barge	Transport of heavy loads to pipeline landfall	May be required for some loads; however, use of barges is not confirmed. Haul road between beach and gas plant would need to be constructed within the pipeline ROW to a standard suitable to transport pipe lengths and shore pull machinery and equipment.
Heavy Transport Vehicles	Transport of materials and provisions by road to plant site	Dry season access only May include vehicles such as road trains, excavators, graders and trucks
4WD Light Vehicles	Transport of personnel to plant site	Dry season access only Would be parked within the 64 ha plant site whilst in the area
Helicopter or Light Aircraft	Transport of personnel to plant site	All year access Will make use of existing Darwin and Wadeye airports

Beyond Daly River the route to Wadeye is unsealed and there are a number of floodways to be crossed which are impassable in the wet season. A load limit of eight tonnes is imposed on unsealed roads west of Daly River during the wet season, and the unsealed road surface becomes saturated and prone to high axle loads breaking through the gravel surface. Despite these limitations, the road formation is generally elevated and well drained as far as Wadeye.

The onshore facilities will require the construction of an access road between Wadeye Airstrip (where the main road from Daly River to Wadeye ends) and the proposed gas plant. This will provide access between the plant and Wadeye during the wet season. Part of this road will be newly constructed and the remainder will be upgraded to a standard suitable for haul trucks as shown in **Figure 4-12**. Continual grading, watering and rolling maintenance will be required to ensure good road condition on unsealed surfaces if heavy traffic volumes use the road.

Any significant transport between the gas plant and shore crossing would also require the construction of a dry weather haul road. This road could be incorporated into the ROW for the onshore section of the export pipeline to a standard suitable to transport pipe lengths and shore pull machinery and equipment.

4.5.10.2 Existing Wadeye Ramp

The existing boat ramp in Sandfly Creek is used by *Perkins Shipping* to supply provisions from Darwin to the Wadeye community. The landing barge operates on a fortnightly basis and is essential during the wet season as the access road to the Stuart Highway can be impassable for up to five months. Access to the ramp is tidal, and the size of vessels is limited, therefore the ramp will not be able to fully support construction. However, the existing ramp is an option in terms of importing some materials during construction and provisions such as spare parts and lubricants during operation, subject to satisfactory arrangements being made with the Wadeye community.

4.5.10.3 Beach Barge Landing

Depending on the selected method of construction, there may be a requirement to bring in large loads. Due to restrictive road access as described above, the preferred option for large loads would be transport to the pipeline shore crossing location via flat top or landing barge.

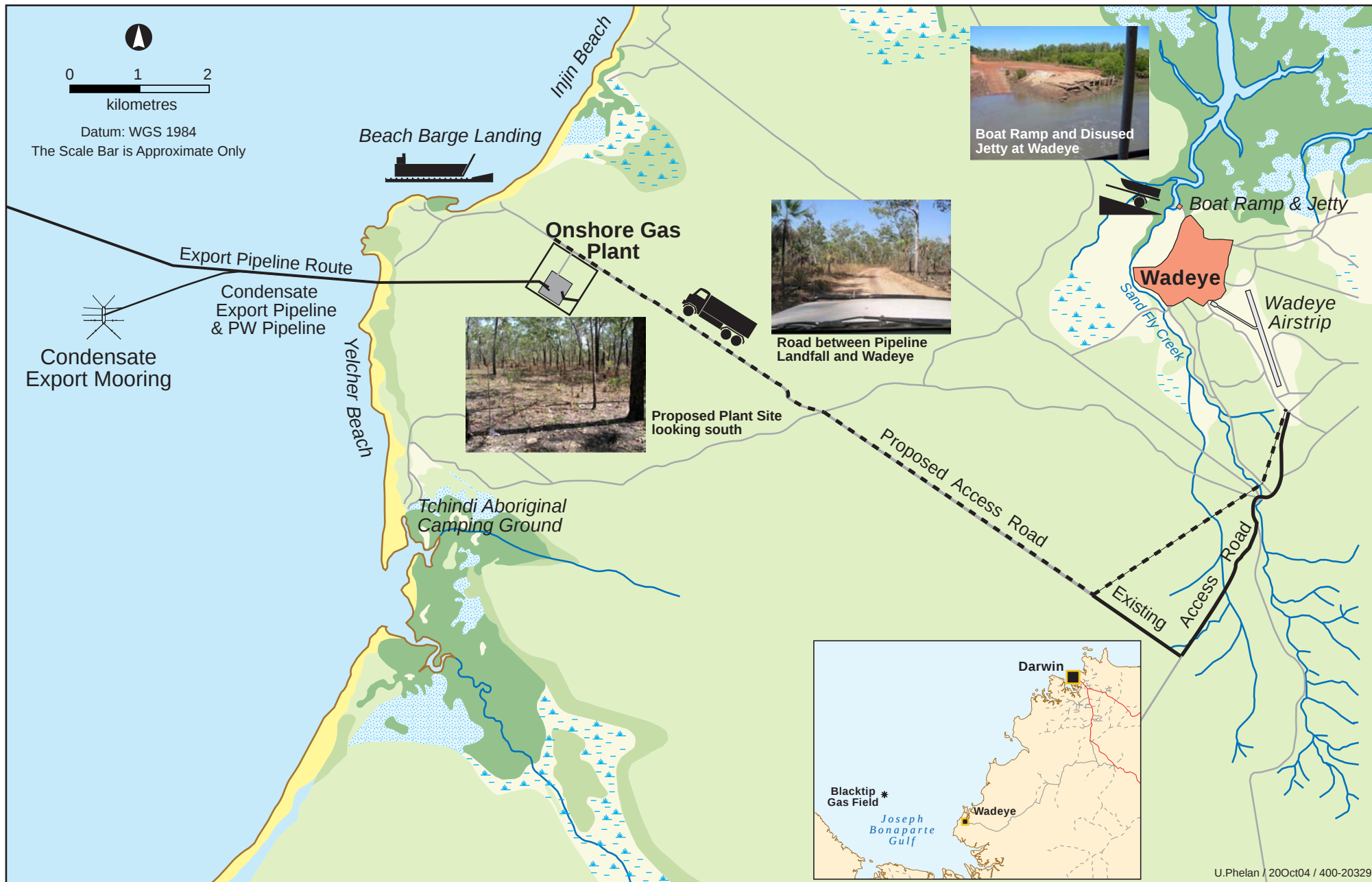
A landing barge could land on the beach during high tide and the load towed off; whereas, a flat top barge would need a ramp or temporary abutment pushed up so the barge could be beached and the load rolled off. In both cases it is expected that some earthworks or ground improvements would be required to support the trailer wheel loads.

In the event that the barge landing option is used a temporary corridor parallel to the shore approach of approximately 50 m wide will be required to facilitate landings (**Figure 4-6**).

4.5.10.4 Wadeye Airstrip

A sealed, all weather airstrip is located on the perimeter of Wadeye, and provides access via fixed wing aircraft. The runway length is 1410 m and the strip is 18 m wide. The airstrip is equipped with lights for night landings.

Current road access from the airstrip to the pipeline landfall is narrow and in relatively poor condition. This road will be upgraded and culverts installed (**Figure 4-12**), access between the onshore Blacktip Project facilities and the Wadeye airstrip could be maintained in all weather conditions, presenting an option for fly in/out crews during construction.



Blacktip Project

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PROJECT ACCESS OPTIONS

Figure 4.12

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4.5.10.5 Summary

The preferred access option is to transport materials to the site by road from Darwin to Wadeye during the dry season. Use of the Wadeye airstrip would be effective as access for personnel and should it be required, the existing boat ramp may be beneficial, particularly in the wet season. The beach barge landing is not a preferred option, as various existing access methods should be adequate. However, consideration will be given to its use, particularly during the wet season, when other transport methods will be unavailable.

4.5.11 Construction Materials and Infrastructure

In order to provide the required construction materials to the Blacktip Project, a variety of infrastructure and facilities will need to be sourced or developed. These include sources of rock fill and aggregates, facilities for quarantining of materials sourced overseas, and facilities for the production of construction materials, specifically concrete and cement.

4.5.11.1 Quarantine and Staging Areas

To comply with the requirements of Australian Quarantine and Inspection Service (AQIS) all equipment and material arriving from overseas will be required to be quarantined, and inspected upon arrival to the country.

To facilitate this process and reduce on-site storage a staging facility may be constructed at the Port of Darwin. This facility may include a covered warehouse and a security-fenced, on site storage area. If Darwin is not deemed an appropriate site, and/or other locations are also required to site staging facilities these will be accessed as required.

Offshore construction vessels will not travel to the staging facility at Darwin but will travel directly to site, where customs officers will meet the vessel to inspect materials.

4.5.11.2 Concrete Batch Plant

A concrete batch plant will be required at the gas plant site or another suitable location, requiring 1 ha of land. This plant will produce concrete to be used on specific components of the plant.

4.5.11.3 Construction Waste Materials

Many items of mechanical equipment will arrive on site in timber packing cases, with timbers treated as required by AQIS to prevent pest infestation. The timber packaging and other waste materials will be segregated to allow the recycling of materials where possible. This will occur within a 100 m by 100 m waste storage area contained within the plant footprint. The waste area will also contain a compactor, so that non-recyclable waste materials are compacted prior to disposal at the local Wadeye Council landfill facility, subject to capacity and approval.

4.5.11.4 Aggregate Sources

Potential sources of aggregate include igneous rock present in the vicinity of the Moyle River crossing. These rock sources are confirmed on the local geographic maps; however, the feasibility

of quarrying these aggregate sources has not yet been confirmed. Other potential sources for aggregate include existing quarries near Darwin or left over spoil from the Alice to Darwin railway.

4.5.12 Construction Working Hours

Offshore: Working hours offshore will typically comprise 12 hour shifts for a 24 hour operation. A typical roster may consist of 28 days on and 14 days off for construction crews (for example those working on the offshore facilities); and five weeks on and five weeks off for marine crew (for example those operating support vessels etc). The specifics of the construction roster will be confirmed closer to the commencement of construction.

Landfall/Shore Pull: Construction will be on a 24 hour basis during the shore pull operation; with 12 hour working days during setup and dismantling.

Onshore Gas Plant: It is expected that plant construction activities will be carried out on a ten hour a day, seven days a week, rostered system. An example of such a system would be a rotation of four weeks on, one week off (ie 28 working days and 7 days leave); however, the specific rosters will be confirmed closer to the commencement of construction.

Onshore Export Pipeline: It is expected that pipeline construction activities could be carried out on a ten hour a day; four weeks on, one week off roster (ie 28 working days and 7 days leave).

4.5.13 Construction Workforce and Accommodation

Offshore: During field installations and construction of the export pipeline and wellhead platform the workforce is estimated to peak at approximately 250 personnel, all of whom will be accommodated on the laybarge and support vessels. The laybarge will be fully contained and provide accommodation facilities for up to 250 personnel.

Onshore Gas Plant: The onshore gas plant will be constructed over three years, predominantly during the dry seasons. Based on preliminary estimates, during the first year of construction approximately 40 personnel will be required, followed by approximately 80 personnel during the second year and a peak workforce of 130 personnel during the third year.

A construction camp will be required to accommodate up to 130 personnel. The accommodation will be provided within the Blacktip gas plant construction camp. The majority of the camp will be removed once construction is complete, although minimal facilities will remain on site for the life of the project to accommodate operations and maintenance personnel. During the initial site preparation work a temporary pioneer camp (0.5 ha in size) will need to be established to accommodate personnel whilst the main construction camp is under construction.

Landfall: Construction at the landfall will require a separate construction team of approximately 24 personnel (12 per shift). The landfall crew will be accommodated at the Blacktip gas plant construction camp. Most workers will be sourced from the onshore gas plant contractor, with the remainder sourced from the offshore contractor.

Onshore Export Pipeline: The onshore section of the pipeline will be installed by the onshore gas plant contractor. The construction workforce of approximately 30 personnel will be accommodated at the Blacktip gas plant construction camp.

4.6 Commissioning Activities

4.6.1 Offshore Facilities

Wellhead Platform: Virtually all fabrication and commissioning of the wellhead platform will be undertaken in construction yards prior to its transport to site. However, once assembled and installed on site, the following wellhead platform systems will require commissioning:

- wellhead controls and services;
- safety systems;
- control systems and communications systems;
- power and utility systems;
- chemicals (for example corrosion inhibitor) storage facilities;
- pumping systems.

Commissioning of the above infrastructure involves testing the systems and undertaking any adjustments to ensure normal operating performance. The topsides of the wellhead platform will be commissioned in the fabrication yard; however, other components will be commissioned on site. Site wellhead platform commissioning will take place over three to four weeks. Leak testing and commissioning of wellhead platform process systems will also be undertaken. No flaring will take place on the wellhead platform.

Production Wells: Upon well completion, the wells will be sealed to maintain well pressure. Immediately prior to commissioning, the seals will be perforated and flushed with commissioning fluids, comprising of brine and diesel, to clean the wells. Commissioning fluids will be recirculated to the Jack-up, along with any reservoir fluids, where the brine is separated out and the remaining commissioning fluids (diesel) will be burnt off through flaring. Commissioning of the production wells then involves bringing the wells on-line for first production.

4.6.2 Onshore Facilities

Commissioning is required for all components. Commissioning of onshore facilities will include testing and adjustment of equipment, introduction of reservoir fluids and start-up of production.

Onshore Gas Plant: The onshore gas plant will consist of various systems to separate the reservoir fluids and produce dry gas suitable for export. Once systems have been installed and deemed 'mechanically complete', commissioning will be undertaken for the following:

- slug catcher and primary liquids separation;
- water and hydrocarbon dew-pointing;
- export gas compression and metering;

- utility systems.

Condensate: The condensate stabilisation system will be commissioned, as well as the condensate storage tanks and pumps for the offsite export facilities. Condensate export facilities will be tested for leaks and prepared for introduction of stabilised condensate. Commissioning of the condensate export mooring will include testing of condensate loading facilities with water prior to receipt of first condensate.

Ancillary Facilities: Other onshore systems associated with the onshore gas plant that will require commissioning include:

- power generation systems;
- firewater systems;
- instrument/service air;
- water and drainage systems;
- flare and relief systems;
- safety, control and communications equipment;
- utility liquid and gaseous fuel systems;
- chemical storage and distribution systems.

4.6.3 Export Pipeline

Following completion of testing (**Section 4.5.9**), ‘dewatering’ of the pipeline is necessary whereby the hydrotest water is discharged to make way for production fluids. The pipeline is dewatered by propelling pigs through the pipeline with reservoir fluid introduced into the export pipeline at the wellhead platform. Bulk dewatering is complete when successive pigs fail to sweep appreciable quantities of water from the pipeline. The pipeline will then be ready to operate.

With a number of liquid lines to consider, a number of different options are being assessed for the disposal of hydrotest water. These options are summarised in **Table 4-11**.

■ **Table 4-11 Preliminary Hydrotest Discharge Locations**

Source of Hydrotest Water	End Point Discharge	Components Hydrotested	Volume m ³	Comments
Saline Water	Condensate export mooring	Condensate pipeline	500	PW pipeline hydrotested separately
Saline Water	Condensate export mooring	Export pipeline (onshore and subsea)	16,500	Export pipeline dewatered with product from wellhead platform with a cross over spool located at the plant to connect the export pipeline to the condensate pipeline
Saline Water	PW pipeline discharge point	PW pipeline	100	Condensate pipeline (500 m ³) hydrotested separately

The point of discharge into the marine environment will be selected with the aim of achieving effective dispersion and will consider:

- depth of discharge;
- environmental impact;
- tidal and ambient current factors;
- value of a diffuser;
- discharge rate.

In any case, specific hydrotest and dewatering procedures will be drawn up which will stipulate management measures to deal with any predicted environmental impacts. The plan will provide details on the exact chemicals and quantities to be used and will be reviewed and approved by the regulatory authorities before construction and operation can begin. All proposed hydrotest chemicals will be agreed with regulatory authorities prior to use.

4.6.4 Start-up Activities

Prior to start-up, detailed procedures will be in place to ensure comprehensive information is available to personnel regarding operations, inspections and maintenance of all facilities. Emergency and reporting procedures will also be in place.

Once each of the plant systems has been commissioned, the plant is then deemed ‘Ready For Start-Up’ (RFSU). At this stage hydrocarbons can then be introduced into the gas plant.

Although offshore facilities will be unmanned and remotely operated during production, initial start-up will be undertaken by personnel accessing the wellhead platform by helicopter or boat.

4.6.5 Access during Commissioning

Transfer of commissioning personnel to and from the site will be similar to construction.

4.6.6 Commissioning Workforce & Accommodation

Offshore: Commissioning of offshore facilities is expected to require 10–20 personnel.

Onshore Gas Plant: Onshore facilities will be fully manned for initial start-up until the plant has achieved steady state. Once steady state has been achieved, operations personnel will be reduced to two personnel.

4.7 Production, Operation & Maintenance

All production processes will comply with relevant Northern Territory, Western Australian and Commonwealth legislation. Australian and industry standards will be used throughout the design and operation of the pipeline and facilities, as will Woodside’s comprehensive health, safety and environmental policies and guidelines.

The production process is illustrated in **Figure 4-13**, and the plant layout shown in **Figure 4-14**.

4.7.1 Offshore Production and Onshore Pipeline Operation

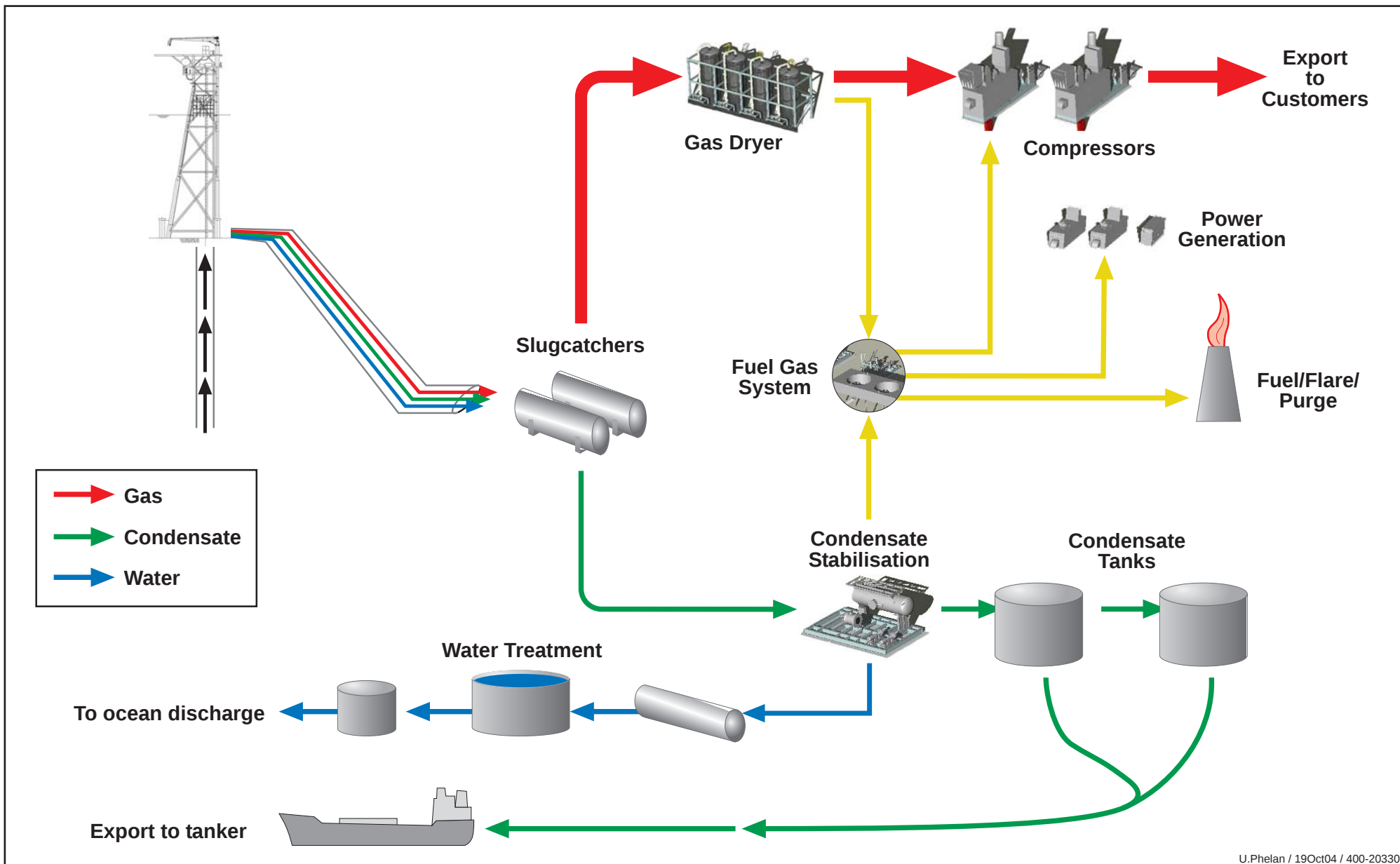
The offshore component of the proposed development will not include any gas processing. Rather, reservoir fluids will free flow directly from two production wells, through the 107.5 km subsea export pipeline to the onshore gas plant. The export pipeline will operate at approximately 100 barg with well flow and pressure being remotely controlled through the unmanned wellhead platform.

Communications, control and safety equipment will be installed on the platform, including:

- marine radio communications and satellite communications;
- power supply and distribution system;
- control panel;
- hydraulic power unit;
- High Integrity Pressure Protection System (HIPPS) to protect the pipeline against overpressure;
- Riser Emergency Shut Down Valve (RESDV);
- cold vent;
- drains system;
- fire and gas detection.

Remote operation of the control panel and associated equipment will be undertaken by using Supervisory Control and Data Acquisition (SCADA) technology, overseen from the onshore gas plant. SCADA systems are commonly used in the oil and gas industry to monitor and manage operations, gather real-time data and perform any necessary analysis of information. The data is transferred to a control centre where data is logged. At this stage, it is envisaged that the control centre will be based in the onshore gas plant. The technology also includes an alert system to warn personnel of any abnormal operating conditions or malfunctions within the reservoir fluid recovery process, and may trigger implementation of the RESDV.

A gazetted safety exclusion zone restricting the access of vessels will be sought under the PSLA from the regulatory authority, to protect Blacktip Project offshore facilities. The safety exclusion zone will extend for 500 m from the outer edge of the unmanned wellhead platform and wellheads. Under the PSLA, all vessels will be prohibited from entering the safety exclusion zone, unless they have the consent of the regulatory authority. Where required, navigation, fog and illumination lighting, acoustic and other devices and equipment necessary for the safety of the petroleum operation will be provided.



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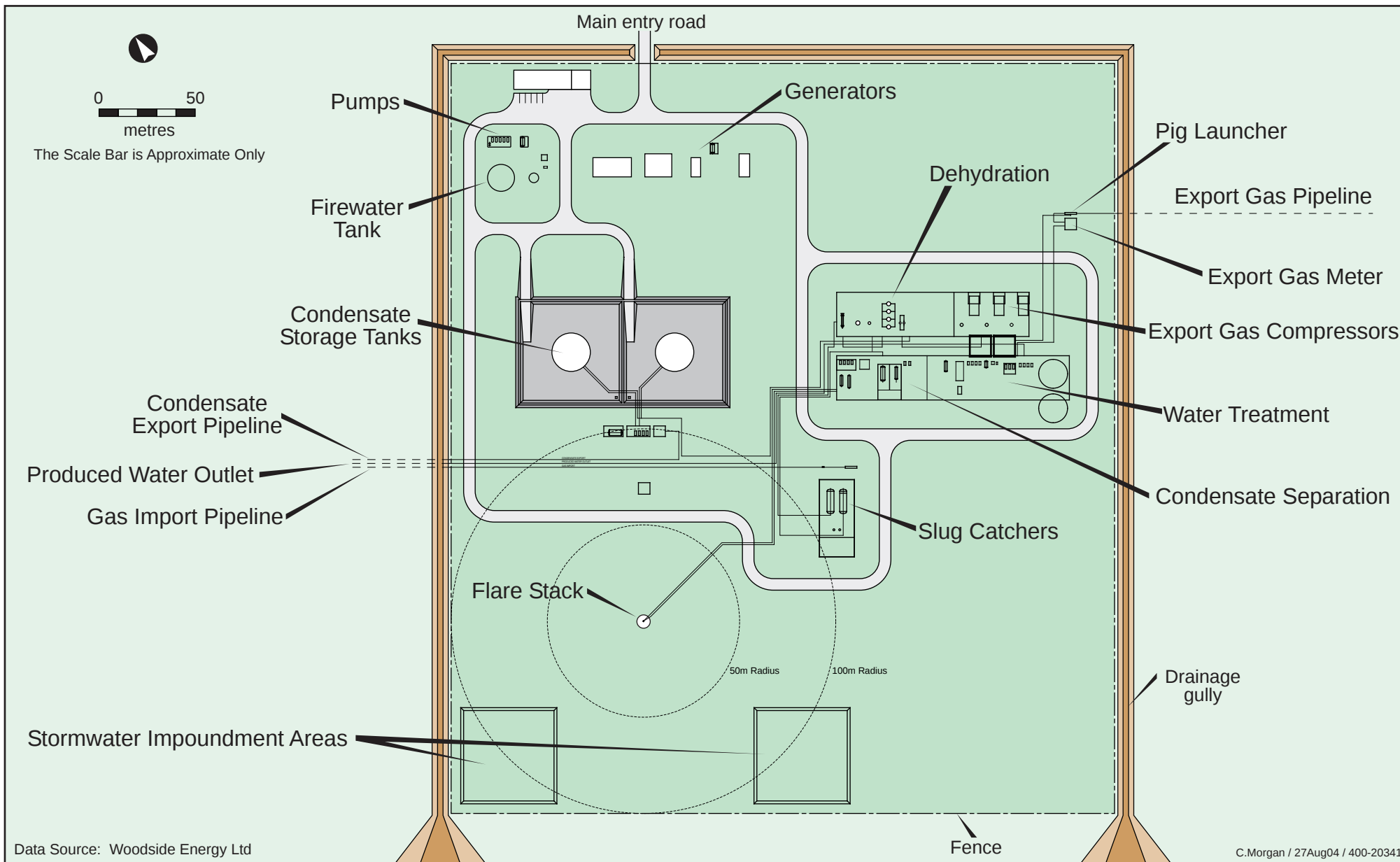
Blacktip Project

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PRODUCTION PROCESS

Figure 4.13

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GAS PLANT LAYOUT

Figure 4.14

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Unmanned Wellhead Platform: Maintenance for the wellhead platform will be minimal, with an estimated ten trips per year required. Personnel undertaking inspection and maintenance operations will access the platform by helicopter or by service vessel for longer operations. The service vessels will house personnel for the extent of the maintenance operations where required. Inspections will be undertaken at regular intervals, as approved by relevant authorities, and will involve checking and testing equipment such as:

- wellhead controls, flow meters and valves;
- power utilities;
- HIPPS;
- RESDV;
- communications equipment.

Approximately every three years, a shutdown programme will be initiated for inspection and maintenance of the offshore facilities.

Production Wells: Generally, minimal well maintenance is required in oil and gas projects. Routine maintenance usually involves flushing of the wells to remove any contaminants or scale, and testing of valves.

Offshore Export Pipeline: Once installed, gas pipelines require little direct access for maintenance. A corrosion mitigation and monitoring programme, and corrosion protection system, will ensure that the steel pipe is kept in good condition, and the majority of the equipment requiring maintenance is located in the above-ground facilities associated with the pipeline.

Several factors will be controlled and monitored during operation of the export pipeline, including:

- inlet pressure, temperature and dewpoint;
- flow rate (liquid and gas).

The offshore pipeline will be inspected at pre-determined and approved intervals during operation using side scan sonar and cathodic protection potential measurement surveys. The external condition of the subsea pipeline will be monitored at intervals by ROV, where possible, to ensure the design requirements remain fulfilled and the pipeline has not sustained any damage. Several factors will be considered during external inspections, including:

- burial status and evidence of free spanning;
- condition of pipeline, concrete coating, anodes and connections;
- evidence of leakage or buckling.

Internal inspection will focus on detection of corrosion, and will be carried out by an inspection pig capable of inspecting the full internal circumference and length of the pipeline's critical sections. It is anticipated that maintenance, if and when required, will be external and will primarily focus on remediation of excessive free spans.

Onshore Export Pipeline: In addition to the pipeline itself, equipment ancillary to the pipeline will be regularly maintained and inspected. Visual surveillance of valves will focus on identifying any corrosion or leaks. Valves will also be tested at regular intervals to confirm functionality.

Once installed, inspection and maintenance programmes at predetermined and approved intervals will be established to monitor the pipeline's integrity and ensure that the public is adequately protected during operation. The inspection and maintenance programme will be carried out by approved and appropriately trained personnel and will include the pipeline and the cathodic protection system. The pipeline licence, incorporating the Northern Territory statutory requirements, will define the frequency of inspections along the pipeline ROW, as well as the frequency of pigging.

Internal inspection of the pipeline will focus on detection of corrosion, and will be carried out by an intelligent pig capable of inspecting the full internal circumference and length of the pipeline's critical sections.

During internal inspection and maintenance, sections of the pipeline will be depressurised or 'blown down' through the gas plant flaring system. Blow down events involving a single section of the pipeline may occur during five yearly inspections, at most, if at all, and would result in significant noise and air emissions.

Pig launchers and receivers will be depressurised up to twice a year and will result in insignificant emissions. Blow down events will be planned and controlled in accordance with various management plans.

A one-off coating survey will be carried out within 12 months of construction completion. This survey will be conducted by a technician walking the entire pipeline route, on top or near the trench, holding probes that are pushed into the ground and which measure electrical current. If a current is registered, this implies that the pipeline cathodic protection system is generating a current, as a result of a coating defect. The size of the defect is estimated according to the signal received. Depending on the estimated size, the line may be dug up and the coating repaired.

After the initial pre-commissioning coating survey, the cathodic protection system will be checked at regular intervals to ensure that the protection voltages are within limits and to monitor any likely areas of corrosion. Testing points are generally located every two kilometres along a pipeline. These testing points will allow for the measurement of structure-to-electrolyte potentials, using a high input impedance voltmeter and half-cell. Adjustments will be made to the cathodic protection current output to ensure that the protective potential is maintained at a sufficiently negative level. Testing will occur every twelve months unless approved otherwise.

Inspections will be carried out along the pipeline ROW at scheduled intervals throughout the life of the pipeline. Inspections will focus on ensuring the pipeline is free from any identifiable leaks, and to identify any new or changed threats to the pipeline.

Inspections may also be carried out after significant events that may render the pipeline exposed or damaged. More frequent monitoring may be scheduled for sections with a known risk of erosion or flooding. The surveillance criteria will include, but not be limited to the following:

- variations to surface conditions (for example corrosion or earth movement);
- indication of leaks such as dead vegetation;
- excess vegetation or weed infestation;
- evidence of pipeline exposure;
- construction activity or evidence of impending construction activity on or near the pipeline route;
- impediments to the access of the route;
- deterioration of the pipeline markers;
- security of the site and evidence of unauthorised entry.

Low-level maintenance for erosion, subsidence and weeds is likely to be necessary, at infrequent intervals, after the initial 12 month defects liability period.

4.7.2 Onshore Gas Plant

4.7.2.1 Gas Processing

The gas plant will use a Joule-Thomson cooling system and low temperature separator, and silica gel-based hydrocarbon processing technology to produce approximately 180 TJ/d of dry gas for export.

The production process will involve the following main steps:

- inlet separation;
- Joule-Thompson cooling system and separation;
- gas dehydration and dewpoint conditioning;
- gas export compression;
- condensate stabilisation (**Section 4.7.3**);
- PW treatment (**Section 4.7.4**).

Inlet Separation: Separation of reservoir fluids will take place as the fluids flow directly from the export pipeline into slugcatchers. Liquid storage capacity of up to 40 m³ will be provided which is considered more than adequate to accommodate any liquid surges. Gas will be separated from the other reservoir fluids in the slugcatchers by gravity. The wet gas from the slugcatchers will then be routed to the gas processing system (high pressure (HP) separator) whilst the remaining fluid is transported to the condensate stabilisation system for further treatment (**Section 4.7.3**).

Gas Dehydration and Dewpoint Conditioning: Gas from the slugcatchers will be cooled in the gas exchanger prior to being letdown through the Joule-Thomson valve. This cools the gas, and the

condensed liquids are then removed in the HP separator and sent to the Medium Pressure (MP) separator. Any liquids transferred over with the wet gas will be removed in the HP separator and the gas will flow to the silica gel adsorption beds. Further processing will take place to ensure that water and heavy hydrocarbons (C8⁺) are adsorbed by the silica gel. The silica gel is contained in four beds. At any one time two are adsorbing, one is being heated and the other cooled. The gas leaving the silica gel beds will meet both water and hydrocarbon dewpoint specifications, and will be passed through a filter to remove any remaining contaminants such as silica gel or other solid particles.

Gas Export Compression: After filtration, the gas will be compressed to a pressure of 150 barg ready for export. The compressor will be situated after the gas processing equipment, and will comprise turbines, scrubbers, air coolers and waste heat recovery.

Downstream of compression there will be an export gas metering skid and a pig launcher. The pig launcher will be provided to allow for pipeline inspections and maintenance. Metering of the gas volumes will be undertaken to quantify gas volumes for customer sales.

Maintenance Operations: Full-scale maintenance operations will be undertaken approximately every three years during which operations will be shut down. The planned shutdown period will last for approximately three to five days, during which time various maintenance activities will be undertaken, including testing of equipment and replacement of the silica used for gas processing (**Section 4.7.2**).

Two options are being explored for silica replacement:

- 1) All the used material will be removed from the site for appropriate disposal/recycling by the vendor, and the system will be replenished with new silica.
- 2) The used silica will be sieved to remove waste material, and the system will be topped up with new silica. The waste material will be taken offsite for disposal/recycling by the vendor.

There will not be any silica disposed on site.

4.7.2.2 Excess Gas and Flare

An emergency flare system will be provided in line with normal design practice. The flare system will be designed to provide a safe means of rapidly disposing of pressurised gas. The flare system will fulfil two major functions:

- depressurisation of process equipment in the event of an emergency (for example fire or gas detection within the plant);
- depressurisation of process equipment prior to maintenance.

The detailed design of the flare has not been undertaken. This will be undertaken at a later stage of the project and will need to take into consideration:

- safety requirements;

- the need for technical integrity and reliability;
- the need to limit noise levels to appropriate standards;
- the need to minimise non emergency flaring to ALARP.

In the event of an emergency such as fire, gas leak or overpressure of equipment the flare is designed to remove the hydrocarbon gas from the processing plant and ensure that it is burnt safely. When a fire is detected in the plant the emergency shutdown system will isolate the plant where this fire has been detected, and the gas contained in this section will be released to the flare and burnt.

In the case of an emergency the plant will need to be depressurised within a short period of time (15–30 minutes) which will result in the highest gas flows, the largest flame lengths and the greatest noise emissions. These noise emissions will not exceed the Woodside standards of 115 dB(A). The level of noise is dependent on the volume of gas flared.

As the system is a safety system it will operate continuously in the form of a small pilot, ensuring that gas can be directed to the flare system and ignited as required, depressurisation can therefore occur at any time of the day or night. However, these events will be very infrequent and of short duration.

There may be occasions particularly during commissioning and initial start-up when the emergency flare will be triggered due to process upsets. This is a normal occurrence and results in flaring of a short duration. On completion of commissioning the frequency will reduce significantly as the plant reaches steady state production and as the operational crew become more familiar with the plant. The exact frequency of this type of flaring is difficult to forecast and is very much dependant on the ability to achieve optimum operating performance as soon as possible.

During maintenance activities flaring of gas is sometimes required to make equipment safe so that it can be inspected. As these maintenance activities will be planned events the rate and time of day at which gas is flared can be controlled, including the potential for forward notice to be given to the local community of the timing and duration of these planned events.

After commissioning and initial start up emergency depressurisation may occur due to spurious gas or fire detection. These events will be minimised through good design, maintenance and operating procedures. However, given that the flare system will be designed to protect the plant and personnel, putting barriers in place to prevent the flare from operating would compromise safety. The flare stack and surrounding exclusion zone are designed to prevent damage to people and equipment in the immediate area.

The expected flaring regime is summarised in **Table 4-12**, although this may be modified as design proceeds.

■ **Table 4-12 Flaring Regime**

Flare Scenario	Maximum Flame Size	Duration	Frequency
Pilot	Very Small	Continuous	Daily
Maintenance	Medium 1–20 m	1–24 hours	Quarterly/Annually
Emergency	Large 20–60 m	15–20 minutes	Quarterly/every 5 years

The flare will be designed so that the radiated heat from the flare flame in the worst case does not injure personnel or damage the plant. The emergency blowdown rate will determine the size of the flare. This rate will be calculated during subsequent design phases of the project. It is anticipated the stack height will not exceed 60 m. Above the stack, the emergency flaring regime is expected to range in height from 20–60 m (**Figure 4-15**).

4.7.3 Condensate Treatment

Condensate Stabilisation: As detailed in **Section 4.7.2**, the condensate and PW are separated from the gas in the slugcatchers and the HP separator, and then removed for further treatment. These fluids then flow through the Medium Pressure (MP) separator, which is a 3-phase separator operating at 15 bara to remove bulk water. The remaining condensate is then heated at an interstage heater to around 120°C before entering the Low Pressure (LP) separator. The LP separator operates at a pressure of approximately 4 bara to further stabilise the condensate before it is pumped to the storage tank.

The maximum production rate of stabilised condensate will be around 500 bpd. It is envisaged that two storage tanks will be required to store the condensate and these will be located within the onshore gas plant. The tanks will have ‘floating’ roofs and will be constructed and banded as per legislative requirements.

Condensate Export: The stabilised condensate will be pumped offsite via the condensate pipeline to a condensate export mooring. The maximum cargo from Blacktip will be 50,000–60,000 bbl which will take 12 hours to load. Smaller cargoes may be loaded depending on tanker availability; however, the minimum size cargo is unlikely to be less than 5,000 m³. In addition to the six anchors of the condensate export mooring, the vessels own forward anchor system will be used (usually two anchors) to secure the tanker. This system is commonly used on the North West Shelf of Australia (**Figure 4-16**). The tankers have a maximum cargo capacity of 100,000 m³.

The mooring will be sized to accommodate an Aframax tanker (approximate dead weight of 105,000 t). One tanker and two support vessels will arrive at the condensate loading location up to four times per year. The tankers will pull alongside the condensate export mooring and will use flexible loading hoses to transfer the condensate.

The system will be designed to operate in conditions below a Beaufort six seastate (ie 39–50 km/h winds). The condensate export mooring components will be designed in accordance with ‘API requirements for the Design and Analysis of Station Keeping Systems for Floating Structures’.

4.7.4 Produced Water Treatment

Following separation from the condensate, the PW will be treated onshore in water treatment facilities to remove free oil, dissolved oil (primarily BTEX) and chemical contaminants such as corrosion inhibitor to an acceptable level before discharge of the treated water to sea. Treatment will meet all relevant environmental requirements (principally the PSLA and associated regulations), and Woodside's standards in that contaminants should be reduced to ALARP levels. In order to cope with PW production rate fluctuations over the life of the Blacktip Project, a Produced Water Flash Drum (PWFD) system with a downstream Gas Flotation Unit (GFU) has been selected as the most suitable treatment facility (**Figure 4-17**).

Entrained hydrocarbon vapour and oil will initially be removed in the PWFD, which also acts as a surge vessel to maintain a steady flow rate to the downstream facilities. The hydrocarbon vapour from this vessel is directed to the LP flare, and the oil is sent to the recovered oil system.

The GFU will remove free hydrocarbons, suspended solids and some volatile dissolved hydrocarbons. LP fuel gas will be used and the spent gas will be directed to the LP flare. The GFU has the capacity to achieve very low oil in water concentrations (<30 mg/L free oil), while being robust to variations in flowrates. The water will be reoxygenated prior to discharge.

PW quality will be regularly monitored and the discharge directed to a break tank or holding tank / pond and recycled to the PWFD if discharge specifications are not met. The treated PW will be pumped offshore through the PW pipeline for disposal to sea, 3 km offshore.

A dispersion study was undertaken (IRC 2004) which determined the preferred offshore discharge location to be 3 to 5 km offshore. The results of this study indicated that the PW discharge would undergo at least 700 dilutions before it reaches the ocean surface and over 20,000 dilutions before the plume would make contact with the coast, even under maximum discharge rate conditions during the wet season when onshore winds dominate.

The discharge rates of PW will vary from 100 bpd to around 7800 bpd over the life of the field, with the rates close to 7800 bpd due mainly to start-up of the pipeline.

4.7.5 Operational Access Routes

Offshore: The unmanned wellhead platform will be accessible via helipad or boat. Extended operations (for example maintenance) will be undertaken with marine vessels. Vessels from an onshore supply base such as Darwin or Wyndham will service the wellhead platform and provide consumables such as diesel and spare parts.

Onshore Gas Plant: Access to the gas plant and associated infrastructure during the operational phase of the project will be by:

- existing airstrip at Wadeye and road to facility;
- highway from Darwin and road to facility;
- existing barge landing at Wadeye and road to facility.

The airstrip at Wadeye is anticipated to be the primary access route for the Blacktip Project. Transfer of operations and maintenance personnel to and from the site will most likely be by plane, utilising the Wadeye airstrip. Access routes to the site are described in **Section 4.5.10** and will generally be the same for operation; although the volume of traffic and loads will be significantly reduced. It is envisaged that supplies and equipment will be transported to the site by road from Darwin during the dry season, and by barge during the wet season.

4.7.6 Operating Hours

The gas plant will be operational for 24 hours a day, seven days a week. The personnel required to operate the plant will be accommodated on site and will operate on a shift basis.

4.7.7 Operation Workforce and Accommodation

Offshore: The platform is being designed to be an unmanned facility. Various maintenance personnel will visit the gas field location as required. There will be no accommodation facilities on board the wellhead platform; accommodation will be supplied on the maintenance vessels.

Onshore Gas Plant: The majority of the construction camp will be removed once construction is complete; however, minimal facilities will remain for the life of the project to accommodate operations personnel. During operation two staff will man the gas plant.

Maintenance will require 20 to 40 personnel every three years. Accommodation facilities will be provided for the additional personnel in the gas plant. The personnel will travel to the onshore facilities by established access routes as discussed in **Section 4.7.2**.

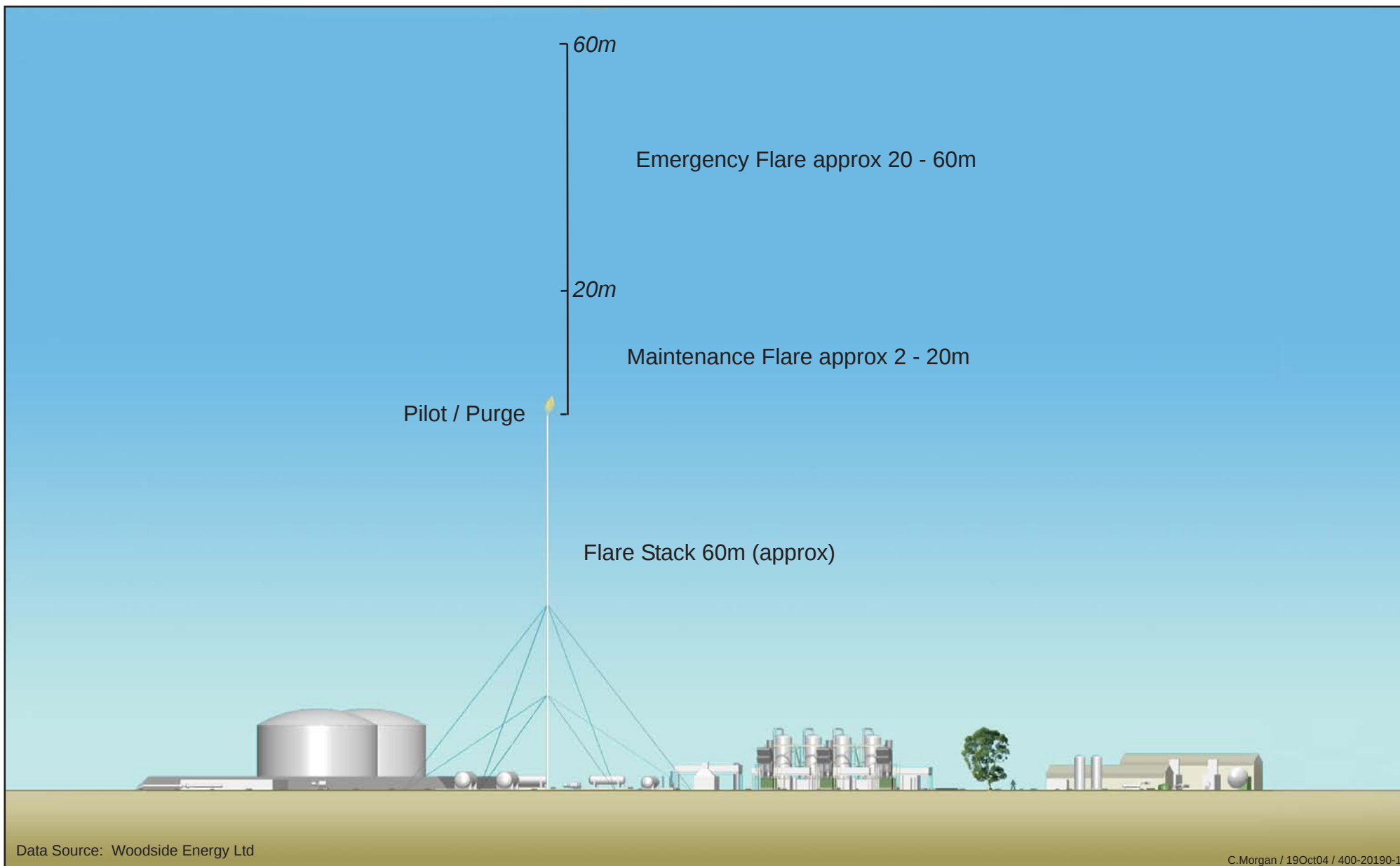
4.8 Ancillary Systems, Facilities and Support

A variety of ancillary systems and facilities will be required throughout the production and operation phases of the development to support the onshore gas plant and personnel and maintain a safe working environment.

4.8.1 Electrical Power

Offshore: Diesel generators will be used to power the Jack-up, laybarge and other support vessels. The wellhead platform will be operated by two small gas-driven Closed Circuit Vapour Turbines (CCVT), approximately 4.5 kW, working at full capacity. Fuel gas will be derived from the wellstream.

Onshore: A gas-driven turbo generator will be used to generate power to run the gas plant. A diesel generator will also be on site as a back-up system for emergencies. The total output will be approximately 12 MW electrical power. Gas from Blacktip will be the main source of fuel for plant power generation.



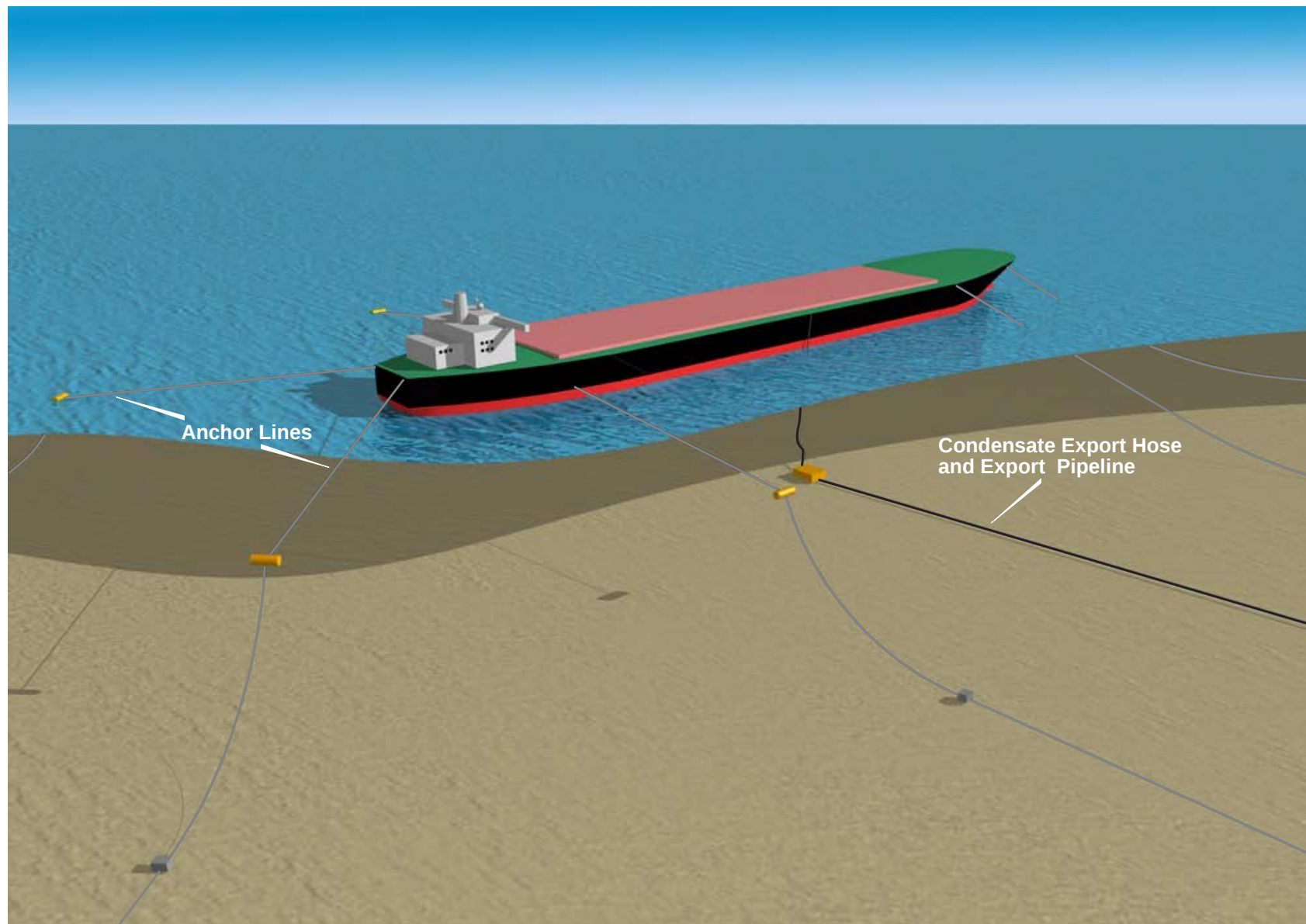
Blacktip Project

DRIMS-#1572636

GAS PLANT FLARE

Figure 4.15

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Data Source: Woodside Energy Ltd

C.Morgan / 19Oct04 / 400-20331

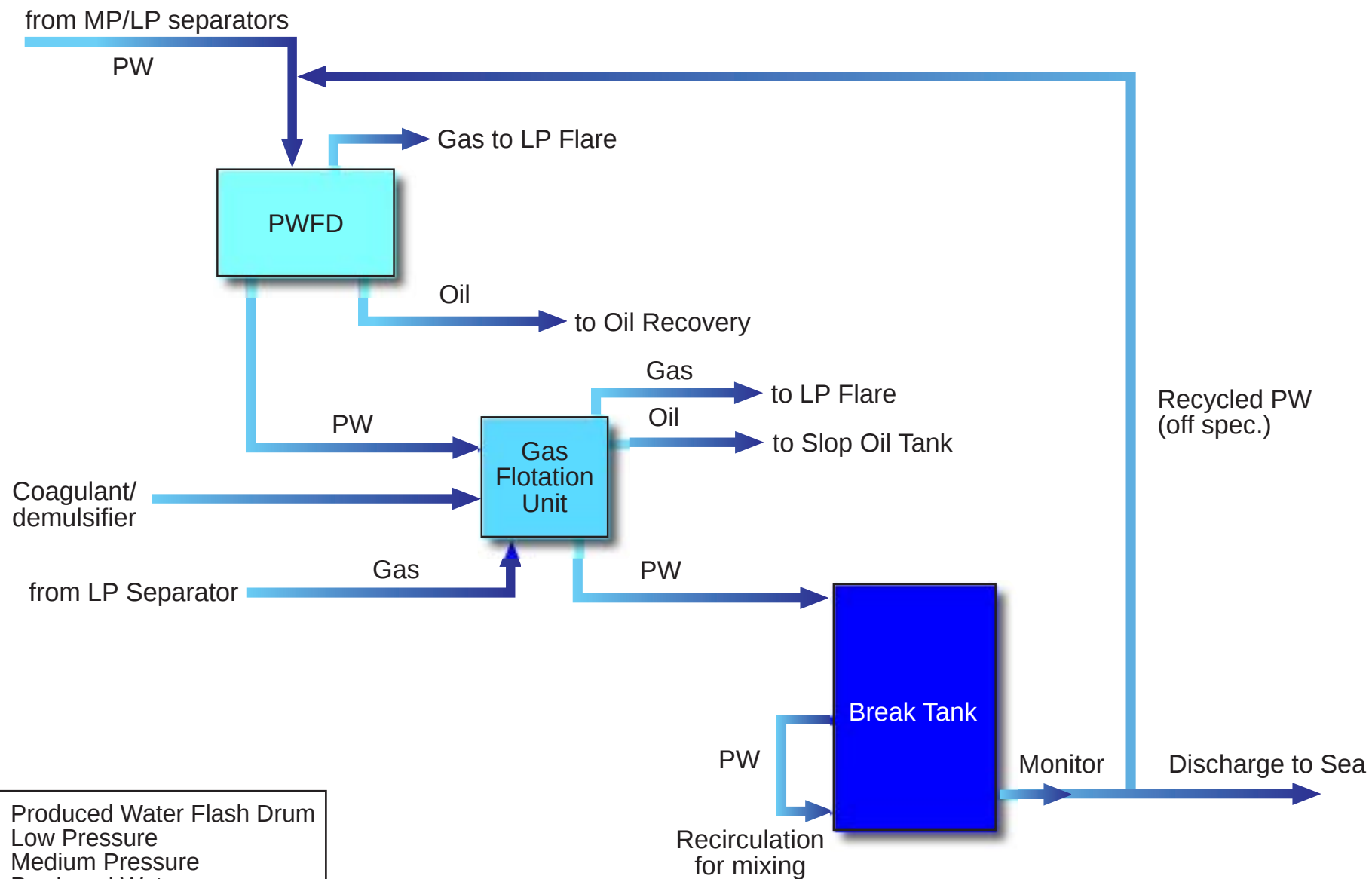
Blacktip Project

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CONDENSATE EXPORT MOORING CONCEPT

Figure 4.16

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PWFD	Produced Water Flash Drum
LP	Low Pressure
MP	Medium Pressure
PW	Produced Water

U.Phelan / 18Oct04 / 400-20332

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4.8.2 Diesel and Chemical Storage

Offshore Storage: Vessels will have standard marine storage systems on board for chemicals. The storage systems on board the wellhead platform will be similar to that of other unmanned wellhead platforms, and may include main storage tanks, clean-up equipment, distribution pumps, smaller storage tanks on equipment and piping for distribution. Other chemicals requiring storage on the wellhead platform will include corrosion inhibitor.

Onshore Storage: Diesel is required during construction to power equipment such as pumps, generators, compressors and machinery. Diesel storage during construction will most likely be in drums.

Diesel will also be used on an ongoing basis to power fire pumps and to back-start the gas generator during gas plant operation. Diesel storage facilities during the operational phase of the project will be located onshore, within the gas plant laydown area, and will consist of tanks or drums with appropriate bunding.

Other chemicals that may be stored on site could include:

- acids and solvents;
- glycol;
- surface active agents and detergents;
- defoamers;
- lubricating fluids and greases;
- hydraulic oils/fluids;
- paints;
- inhibitor chemicals (for example corrosion and scale inhibitors);
- specialised cleaning fluids;
- demulsifier/coagulant.

As the onshore gas plant will be minimally manned, most chemicals will only be stored on site for the duration of maintenance operations, with the exception being those required during normal operations such as demulsifier/coagulant to be used in the flotation unit of the PW treatment process.

4.8.3 Cooling and Heating Systems

Offshore: No cooling or heating systems are required.

Onshore: A number of onshore processing systems will require heating or cooling systems. All onshore cooling will be carried out using direct air coolers. Air cooling systems will be used for condensate rundown, silica gel regeneration gas, and export compressor discharge cooling.

The condensate heater will be electric, and the silica gel regeneration heat will be derived from a compressor waste heat recovery unit.

4.8.4 Water Sources

Offshore: The Jack-up and support vessels will have their own systems to make potable water or will have sufficient reserves in bunkers. The wellhead platform will have water storage facilities for equipment washdown.

Onshore: The onshore gas plant will require water for personnel support, maintenance and firewater. Bore water is likely to be used, and it is expected that a bore will be installed at a suitable location within the gas plant footprint although the location is unknown at this stage. Depending on the water quality, treatment in the form of a resin filter or other standard treatment system may be required, particularly if water is required for equipment washdown.

4.8.5 Safety Systems

Offshore: Safety, control and communications equipment will be installed on the platform, including HIPPS and an RESDV to protect the pipeline against overpressure. The safety system will include fire and pressure detection systems to alert the remote control centre. Fire extinguishers may be kept on board the wellhead platform. The unmanned wellhead will also have a 500 m exclusion zone around it.

Onshore: Various detection systems will be installed in the onshore gas plant: including, gas; flame; high pressure; and low pressure alarms. If triggered, these will alert the remote control centre by transmitting alarms signals. A Closed Circuit Television (CCTV) system will also be installed, which will enable personnel in the Central Control Room (CCR) to visually confirm the presence of fire or other safety issues. A firewater system will be installed throughout the plant and supporting infrastructure that may include water storage, a pumping facility and an underground water distribution system. A primary safety system onshore will be the flare system. This is discussed further in **Section 4.7.2.2**.

A shutdown procedure will be in place for the pipeline, based on measurements of pressure and rates of change of pressure at each end of the pipeline, and may be implemented in the event of an emergency.

There will be a firebreak (50 m wide) located on both sides of the gas plant fence. There will also be a safety buffer zone between the gas plant and the firebreak.

4.8.6 Navigation and Communications Systems

Offshore: Standard marine navigation and communications systems will be in place for the wellhead platform, including offshore navigation beacons.

Onshore: Communications throughout the project life will be via satellite. The onshore gas plant site will be signposted in accordance with Northern Territory regulations.

4.8.7 Lighting

Offshore: Industrial lighting will be required during installation and construction of the wellhead platform to comply with regulatory safety requirements. Artificial light will therefore be generated from the Jack Up, laybarge and various other support vessels. During operation lighting on the wellhead platform will be kept to minimum safety and navigational requirements.

Onshore: Lighting will be required for safe illumination of the plant and accommodation areas during all phases of the development. Lighting will be provided for a safe day and night operations. There will also be security lighting and road lights within the gas plant boundary. The lighting system will take into account any environmental requirements. Otherwise, lighting levels will be in accordance with industry standards.

4.8.8 Drainage Systems

Offshore: The Jack-up, laybarge, support vessels and wellhead platform will have deck drainage systems. Deck drainage will consist mainly of clean rainwater, which will generally be directed overboard.

On board the laybarge and all other vessels the discharge of oily water, such as from bilges, will be via an oil/water separator unit. The unit will be designed in accordance with IMO administration and will be capable of detecting oil content at 15 ppm. Drainage water from machinery space, with hydrocarbon concentration <15 ppm, will be discharged to sea as per MARPOL regulations; however, this may not be allowed within relevant port limits. The vessel contractor will consult with the relevant Port Authority for clarity on allowable discharges (if any) within port limits. Discharge to sea in accordance with MARPOL regulations will not occur during any diving-related activities. Drainage water with hydrocarbon concentration >15 ppm will be collected and transported to shore for treatment. The holding tank contents will be disposed of ashore by a certified waste oil disposal contractor.

Onshore: Drainage facilities will be provided within the gas plant footprint for stormwater and wastewater. The drainage system will collect and convey all plant drainage streams to an appropriate disposal location. This will be done in such a way to protect personnel, plant equipment, and to avoid environmental pollution. The system design philosophy will be based on maximum segregation of sources to minimise contamination and subsequent clean-up problems. The drainage system will comprise of:

- open drain systems
- closed drain systems

Open Drain System: Open drains will be used to collect stormwater, washdown water, fire test water and any accidental spills from equipment. Where necessary, potentially contaminated water will be treated before being mixed with the uncontaminated water and allowed drain off site. Other drainage systems will be provided on site to capture rainwater and treated water from the site. The system will comprise of:

- Open drains to capture uncontaminated water including rainwater and clean water run-off. This water will not be treated, but will be allowed to drain offsite.
- Open drains to capture run-off that may emanate from hydrocarbon liquids equipment. Any run-off from these areas and also from the first flush will be passed through the PW treatment system to remove hydrocarbon contaminants prior to discharge offsite via the PW pipeline.
- Bunded areas with the potential to contain water with chemical contamination, not suitable for treatment by the PW treatment system. This water will be stored separately and removed for treatment offsite. Volumes of this sort of water will be minimal due to high standards of operational procedures on site and minimal use of chemicals.

Closed Drain System: Bunded drains will be provided for equipment that could leak lube oil, diesel or other substances. Any oil collected will be transferred to a recovered oil storage tank for storage prior to recycling back into the process.

Drainage systems will also be aimed at preventing mosquito breeding on site. Equipment and debris, capable of holding water, will be disposed of or removed from site as soon as practicable.

Studies of flooding and drainage at the proposed plant site will be undertaken, and drainage facilities will be designed to incorporate findings from the studies. Clean stormwater will be directed away from the onshore facilities to prevent flooding of the area.

4.8.9 Sewage and Putrescible Waste

Offshore: Sewage and greywater facilities will be provided on board all support and maintenance vessels.

The laybarge (which will accommodate the vast majority of offshore workers) sewerage system will be capable of servicing the full complement of crew on board the vessel. Holding tanks will be sized to contain all generated waste including sewage and grey water. The septic system will comply with Marpol regulations.

The discharge of sewage and grey water from all construction vessels beyond port limits will be in accordance with MARPOL regulations; however, this may be overridden in sensitive coastal areas (within 3–5 nm limits) in accordance with local regulations (*NT Marine Pollution Act*) and port authority requirements.

It is expected that a chemical toilet will be located on the wellhead platform.

Onshore: During the first 3–5 months of the construction phase, before the permanent treatment system is built on site, a portable sewage system will be used. It is likely that this portable system will have the capacity to treat sewage so that it can be irrigated; there will be no sludge residue with this system.

The permanent sewage treatment facilities, for use during the main construction phase and operation, will be provided in the form of an above ground proprietary package membrane reactor,

suitable for a workforce of approximately 130. These units will work by aerobic treatment methods and will consist of a series of chambers combined with an irrigation or drain disposal system. The first chamber is similar to a conventional septic tank. The wastewater enters the chamber and the solids settle to the bottom. Bacteria break the solids down to a sludge, which will be tankered from site as required, and subject to approval, will be disposed at Wadeye landfill facility. The liquid component of the partially clarified water then flows onto a second chamber where it is mixed with air to assist in bacterial break down of the finer organic material. A third chamber allows for additional settling of suspended solids, which are returned to the first chamber. Disinfectant, usually chlorine, is added to the third chamber to reduce the number of bacteria in the effluent.

Subject to approval and the required capacity, the existing sewage treatment works at Wadeye will be used as a back up should either system fail.

All sewage systems will be approved by the Northern Territory Health Department prior to construction, and will comply with all relevant standards and legislation.

4.8.10 Security

The wellhead platform will have secure access through the boat landing.

The gas plant footprint will have a perimeter fence to secure the gas plant and prevent trespassing. A security gate will be provided to maintain access to the area, and it will either be locked or manned by security guards. Internal fencing incorporating firebreaks will be erected around the gas plant and ancillary facilities.

4.8.11 Support Vessels

The types of vessels required for the Blacktip Project are described in **Section 4.5.10** and **11.2**. Vessel movement in the project area is expected to peak during drilling, construction and installation phases. The Jack-up and pipelaying vessels will leave the area following commissioning of the facilities. During operational life, infrequent site visits will be undertaken by supply/maintenance vessels and trading tankers. All vessels will comply with relevant legislation and regulations for daily operations including waste management, safety, communications and Australian ballast water requirements.

4.8.12 Helicopters and Light Aircraft

A helideck and associated equipment will be provided on the wellhead platform, Jack-up and laybarge. During the operation phase of the project, helicopter access on the wellhead platform will be required to meet standard offshore facility requirements for the transfer of personnel undertaking wellhead platform maintenance and supplies. Helicopter fuel will not be stored on the wellhead platform. Helicopter refuelling facilities will be required on the laybarge.

Helicopters and light aircraft may also make use of the existing Wadeye Airstrip to transport personnel during operation and maintenance phases of the project.

4.9 Decommissioning

The objective of decommissioning will be to close down operations and abandon the development area, leaving the environment as near as practicable to its original condition. Decommissioning requirements are generally project-specific, being considered on a case-by-case basis at the expiration of the permit, licence or lease by the relevant regulatory authority, with due regard to the protection of the area's natural resources (APPEA 1996a).

Decommissioning of the proposed Blacktip Project is expected to occur approximately 30 years after start-up and will most likely include:

- shutting down of production processes;
- leaving pipelines in place;
- flushing of pipelines and sub-sea facilities;
- plugging and abandonment of wells;
- decommissioning of wellhead platform;
- removal of onshore facilities;
- rehabilitation of plant site.

4.9.1 Decommissioning Approvals Process

The Blacktip Project will be decommissioned in accordance with the legislation and guidelines prevailing at the end of the project life and in consultation with relevant stakeholders and regulatory authorities. Decommissioning Plans will be drawn up for both offshore and onshore related project components well in advance of decommissioning to ensure appropriate environmental implications have been adequately addressed. The plans will address: drivers; costing; and timing as well as monitoring and rehabilitation requirements for 'permanently' disturbed areas.

4.9.2 Offshore Approvals Framework

The Offshore Decommissioning Plan will incorporate the guidelines of the Commonwealth, Resources Division (2002) which focus on the decommissioning of offshore petroleum facilities.

As summarised in Commonwealth Resources Division (2002) for decommissioning of offshore facilities, under current legislation, approval for decommissioning is required under Commonwealth PSLA legislation and associated regulations administered by the relevant designated authorities. This includes the following steps:

- Application for a permit under the *Environmental Protection Sea Dumping Act 1981*, if the platform is to be disposed of in situ or in other 'Australian waters'.
- Referral of the proposal to the Commonwealth Minister for the Environment and Heritage, under the EPBC Act if the proposed activity is likely to affect any areas of National Environmental Significance.

- Submission of detailed decommissioning documentation under the PSLA for approval by the regulatory authority.

The regulatory authority has the prime responsibility for the coordination, consideration and approval of decommissioning activities under PSLA. Under PSLA the following documentation will be prepared:

- decommissioning Environmental Management Plan;
- decommissioning Safety Case.

Decommissioning documentation may also include modifications to the following:

- pipeline management plan;
- field development plan;
- well operations management plan.

The decommissioning approval process is summarised in **Figure 4-18**.

On completion of decommissioning activities a monitoring programme will be established and approved by the regulatory authority to monitor any remains of the facility at suitable intervals.

4.9.3 Wells

Wells will be decommissioned in accordance with regulatory requirements, relevant guidelines and standard industry practice in place at the time. Specific regulations currently in place are:

- Section 107 of the PSLA;
- PSLA Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production.

Decommissioning of wells will be planned to isolate formation fluids from each other and from the surface, as per APPEA 'Guidelines for Well Suspension and Decommissioning Offshore' (1999).

4.9.4 Wellhead Platform

The extent to which offshore petroleum facilities must be removed is determined by the responsible regulatory authority on a case by case basis. Although the responsibility for decommissioning lies with the operators, government departments have a role in ensuring the acceptability of any removal programme. Under the guidelines developed by the International Maritime Organisation (IMO) there are specific requirements depending on the water depth, weight of structure and date of construction.

Various options are recognised for the removal and disposal process. Those relevant to the Blacktip Project include:

- cutting of the jacket at the seabed and towing it to deep water for disposal as an artificial reef;

- removing of the top bays of the jacket, leaving the remainder on site.

The most suitable option will be decided upon closer to project decommissioning.

4.9.5 Export Pipeline

At present the PSLA and AS2885.4 (including DNV OS F-101) do not stipulate procedures with regard to abandonment of subsea pipelines. The 'APPEA Code of Environmental Practice' (APPEA 1996b) does however provide some environmental guidance on the abandonment of subsea pipelines.

At this stage no decision has been made on decommissioning of the subsea pipeline; however, potential options include:

- leaving the pipeline in place
- partial removal

AS2885.3 and the Draft 'APIA Code of Environmental Practice Part C Onshore Pipeline Decommissioning' (Ecos Draft 2003) contains some guidance on pipeline decommissioning and remediation works for onshore pipelines.

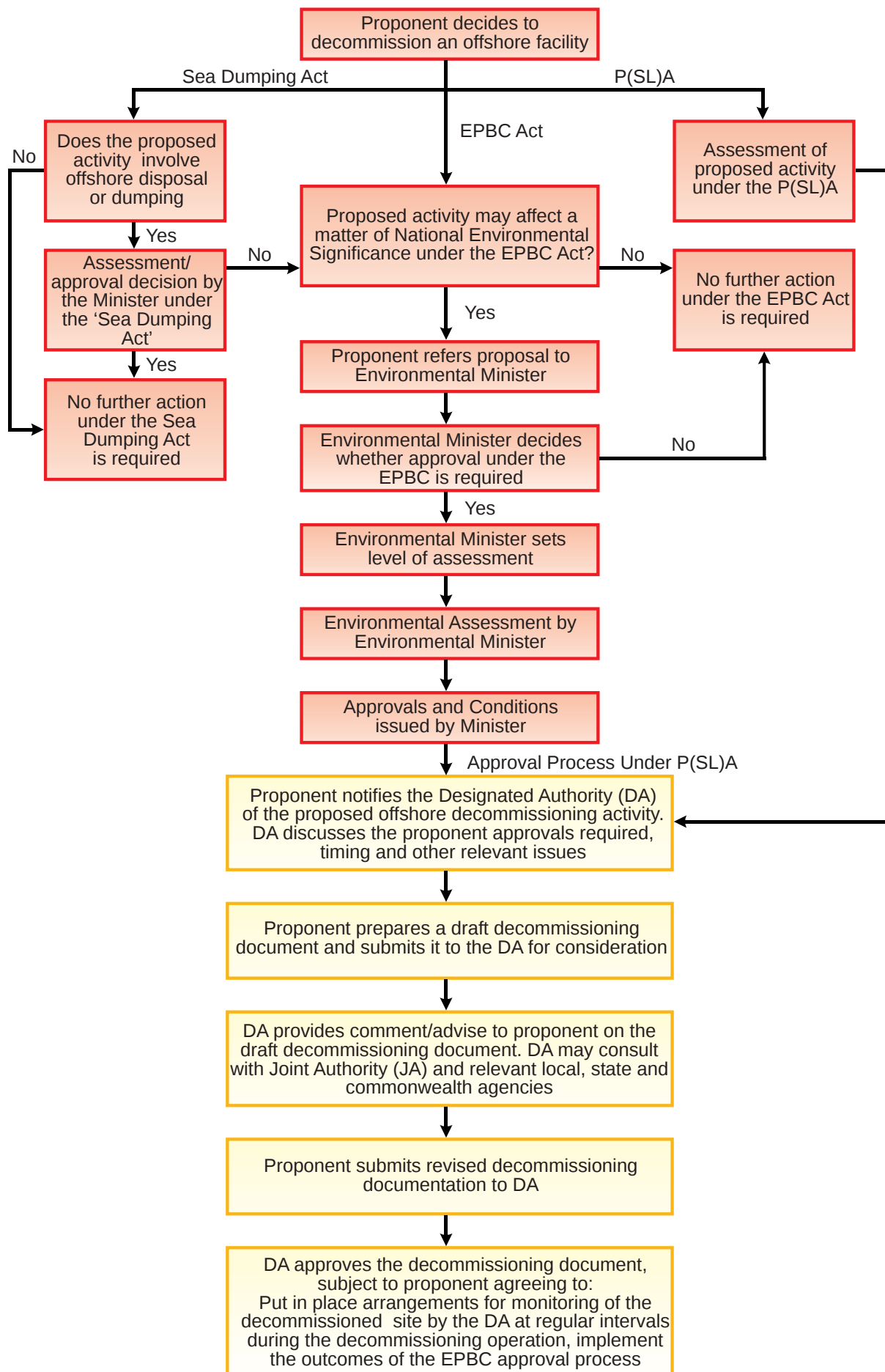
Abandonment in place or suspension are the typical options considered for onshore pipelines. Abandonment of buried pipelines in-situ is considered environmentally preferable to the disturbance associated with the removal of the pipeline which will involve excavation (Ecos Draft 2003). Rehabilitation of the onshore pipeline route will be undertaken once the pipeline has been installed, prior to operations, therefore it is highly likely that removal of the pipe at the end of project life will result in disturbance of rehabilitated land.

At this stage it is considered most likely that the offshore and onshore components of the pipeline will be flushed of hydrocarbons and remain in place.

Decommissioning of the pipeline will comply with legislative requirements, relevant Australian Standards and industry practice in force at the time of abandonment, and will involve consultation with the local community.

4.9.6 Onshore Gas Plant

Decommissioning of onshore facilities will involve the removal of the onshore gas plant, condensate and PW treatment systems, and all associated utilities and infrastructure. A Rehabilitation and Decommissioning Plan will be designed and implemented in consultation with relevant authorities and stakeholders to ensure that the area is suitably rehabilitated.



U.Phelan / 9Sep04 / 400-20364

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