OMV Australia

SOLE DEVELOPMENT

(Patricia Baleen Extension)

Retention Lease VIC/RL3

SD-01-RE-0012

PROPOSED DEVELOPMENT PLAN

TABLE OF CONTENTS

Figures

Tables

1 SUMMARY

1.1 Background

Basin Oil Pty Ltd (a wholly owned subsidiary of OMV) proposes to develop the offshore Sole gas field, extend the onshore production facilities at the existing Patricia Baleen Gas Plant and provide a new connecting pipeline and umbilical control line between the wells and the plant.

This *proposed development plan* (PDP) is submitted as the final contribution in stage two of a two-stage process to obtain Regulatory Approval from the Victorian Government for a production licence for the Sole Gas Field ("Field"), located offshore Victoria, Australia.

The PDP plan includes a summary of the status of commercial arrangements, an evaluation of geology, reserves, description of the planned development facilities and schedule for the project. The PDP also addresses the comments made by the Designated Authority in the Joint Technical Paper response to the *proposed development concept* (PDC) submitted by Basin Oil. Further technical comments under the Joint Technical Paper were addressed by OMV in technical discussions with Geoscience Australia (GA) in November 2003.

Sole has an expected ultimate recovery of 227 Bscf. The production life is expected to be around 8 years depending on the final gas contracts. Underpinning the work to support these conclusions has been geological modelling of the static reservoir description and simulation of the dynamic flow performance. A full uncertainty analysis of the key subsurface and surface variables based on numerical simulation has been carried out.

1.2 Development

The submission of this Field Development Plan is made to support the application to the Joint Authority for the granting of a Production licence over graticular blocks 1789, 1860 and 1861 located in the Victorian Adjacent Area within the Victorian Retention Lease No. 3 (VIC/RL3). Plans for the development of the Sole gas field are presented in this Proposed Development Plan.

The proposed action by Basin Oil was referred under the EPBC Act on 28 January 2003 (EPBC 2003/937).

The Commonwealth Environment Minister decided on 25th February 2003 that the action proposed by Basin Oil Pty Ltd to develop the offshore Sole gas field, onshore production facilities at the existing Patricia Baleen Gas Plant and new connecting pipeline and umbilical control line was not a controlled action. Hence, no further environmental impact assessment is required under the EPBC Act.

On 4th April 2003 the Victorian Minister for Planning determined that the Sole project would undergo a Supplementary EES under the Victorian *Environment Effects Act* as part of the approvals process with jointly exhibited Planning Permit(s), Pipeline Permit and Works Approval applications. The EES was written as a supplement to the Patricia Baleen EES and has been through the public exhibition and Panel process. The Minister for Planning's assessment report under the Environment Effects Act 1978 granted on January 22nd approval of the Sole planning permits and a recommendation to the Victorian Minister of Energy, Minister of Environment and the EPA that the granting of associated licences and permits be approved subject to some minor conditions.

The Sole Gas Field will be developed to supply gas into the Eastern Gas Pipeline (EGP) via an expanded Patricia Baleen (PB) onshore gas processing and export facility that is owned and operated by the PB Joint Venture Partners. A new 14" 65km pipeline to shore will be laid. A Sole field production rate up to 110 MMscf/d is planned from two subsea wells. The PB gas plant will be expanded and have an H_2S removal facility added to produce sales quality gas. The planned capacity of the combined PB and Sole plant will be up to 120 TJ/d of sales gas (net of fuel gas).

Offshore facilities will be completely controlled from the onshore plant. The treated gas will meet the quality specification and entry pressure requirements for the Eastern Gas Pipeline.

A competitive tender process has been carried out for the Engineering, Procurement, Installation and Construction (EPIC) of the offshore scope of work which includes the pipeline, umbilical and well tie-ins.

Pre qualification for the Engineering, Procurement and Construction Management (EPCM) contract for the onshore plant expansion work is complete and a tender process will be entered into on completion of commercialisation of the project.

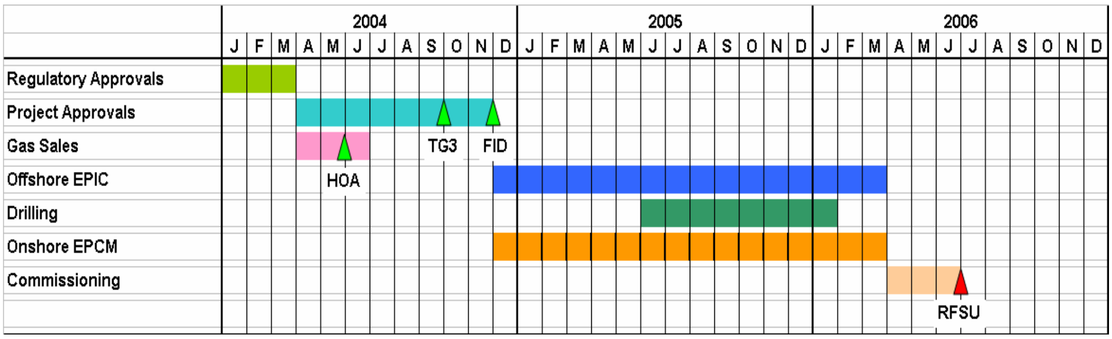
The final well locations will be selected as part of the development optimisation in light of gas contractual arrangements, plant capacity and availability requirements.

1.3 Schedule

Some key milestones are shown in the projected project schedule below in figure 1:

- First Gas is targeted for mid 2006
- Joint Venture Parties Final Investment Decision (FID) is 4th quarter 2004
- A gas sales Heads of Agreement by mid 2004

Figure 1 Sole Project Schedule



2 COMMERCIAL ARRANGEMENTS

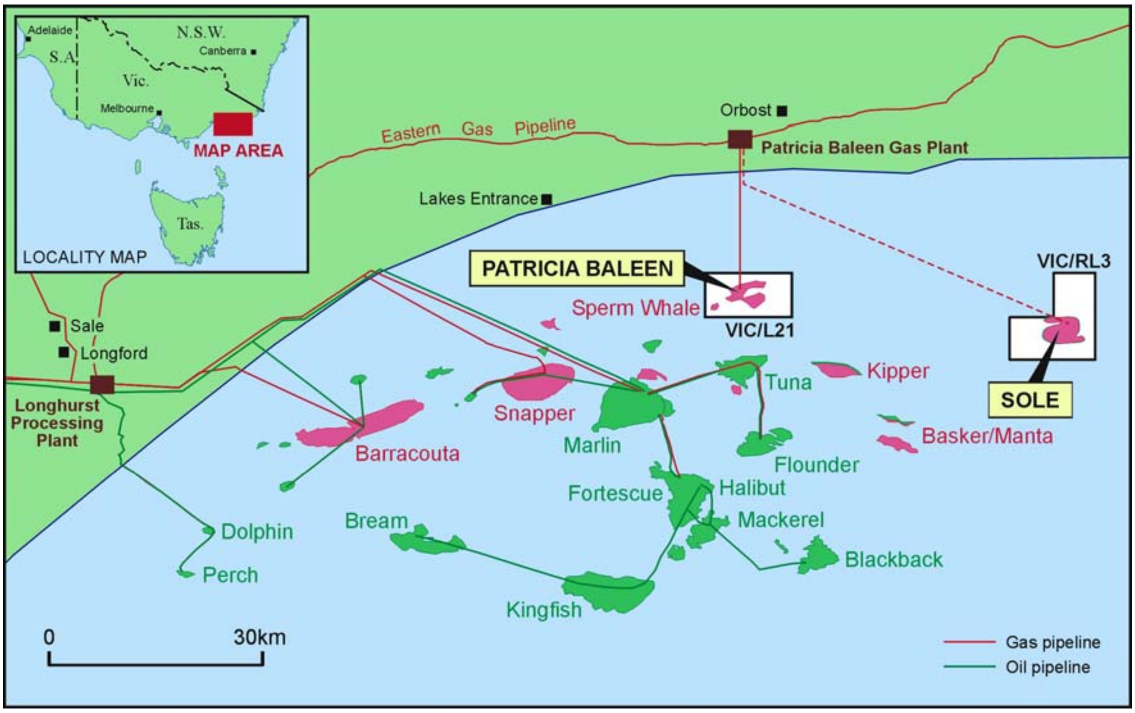
2.1 Introduction

This section covers the commercial background for the project describing the permit history and equity arrangements of the Sole Joint Venture. An overview of the Sales Gas Marketing strategy and current status are also provided. The commercial contracting strategy is covered separately (see section 7.3).

2.2 Title

The Sole Gas Field is located in the offshore Gippsland Basin in Retention Lease VIC/RL3. The lease is held and operated by Basin Oil Pty Ltd (ABN 36 000 628 017) (35%), a wholly owned subsidiary of OMV Australia Pty Ltd ("OMV"), together with joint venture partners Santos Limited (ABN 80 007 550 923) (35%) and Trinity Gas Resources (ABN 29 098 099 908) (30%), a company owned 75% by Mitsubishi Corporation and 25% by Tokyo Gas Co Ltd.

Figure 2 Sole Field Location



2.2.1 Permit History

The Sole Gas Field is located in Retention Lease VIC/RL3 in the Gippsland Basin, offshore Victoria, Australia, (Figure 2). VIC/RL3 consists of three (3) graticular blocks of the Melbourne Map Sheet, being blocks 1789, 1860 and 1861, and covers an area of approximately 203 sq km.

VIC/RL3 was originally awarded on 23 December 1993 for a five (5) year term to The Shell Company of Australia Limited, Ampolex Limited and Santos Limited. The lease conditions included the monitoring of Australian and international gas markets and offshore technology, including gas production and processing, for any significant developments that would enhance prospects of the early development of the Sole discovery.

The Retention Lease was renewed for a five (5) year term, to The Shell Company of Australia Limited, Mobil Australia Resources Company Pty Ltd and Santos Limited, from 14 April 2000. The lease interests at the beginning of the renewal term were The Shell Company of Australia Limited 45%, Mobil Australia Resources Company Pty Ltd 30% and Santos Limited 25%. The lease conditions for the renewal term state that the lessees will undertake studies at an indicative cost of $250,000 during the term of the lease. The studies would be aimed at better understanding the major areas of project development uncertainty and would target technical, market and infrastructure developments that have the potential to improve the commercial viability of the project.

During 2001, OMV Australia Pty Ltd submitted an offer to purchase the Shell Development (Australia) Pty Ltd 45% interest in VIC/RL3. Santos Limited exercised its pre-emptive rights and gained a 70% share in the Retention Lease.

OMV Australia Pty Ltd subsequently offered to purchase the 30% interest from Mobil Australia Resources Company Pty Ltd. A Sale and Purchase Agreement between Mobil Australia Resources Company Pty Ltd and Basin Oil Pty Ltd was dated 27 September 2002.

On 29 November 2002, Santos Limited and Basin Oil Pty Ltd signed a Sale and Purchase Agreement to transfer a 35% interest to Basin Oil Pty Ltd.

On 16 December 2002, Trinity Gas Resources Pty Ltd and Basin Oil Pty Ltd signed a Sale and Purchase Agreement to transfer a 30% interest to Trinity Gas Resources Pty Ltd.

On 23 December 2002, Santos Limited submitted its resignation as operator of the JV, to be replaced by Basin Oil Pty Ltd.

The current Joint Venture participants are: -

Participant	Equity (%)
Basin Oil Pty Ltd (Operator)	35
Santos Limited	35
Trinity Gas Resources Pty Ltd	30

Three (3) wells have been drilled in the VIC/RL3 area, being Sole-1 and Dart-1 exploration wells in 1973 and the Sole-2 appraisal well in 2002. OMV acted as Agent of the Operator (Santos) in the drilling of the Sole-2 well.

2.3 Gas Sales Planning & Status

Gas produced from the Sole and Patricia Baleen gas fields would be expected to compete for existing load or growth in both the Victorian and New South Wales gas markets as well as for uncommitted potential load in Tasmania.

Whilst the physical flow of gas from the Sole field will be northwards along the EGP (given the volume of gas flowing from Longford to NSW), the commercial arrangements for the sale of Sole gas may be such that the gas could be marketed into NSW or into Victoria or Tasmania via a backhaul arrangement along the EGP.

Sole gas is anticipated to provide either a direct supply opportunity to an existing or potential retailer or major gas user in one of these various State markets. If Sole gas is contracted with an existing retailer, a key outcome is that it is likely to provide supply diversity as part of that party's total gas portfolio.

Discussions are ongoing with potential purchasers. It is a requirement of the Joint Venture to have a Gas Sales Agreement in place in advance of the Final Investment Decision (Figure 1). A Gas Marketing Group within the Joint Venture is currently marketing the gas with the intent of having a gas sales agreement in place by mid 2004. The commercialisation of a significant quantity of Sole gas is required to underpin the project financial approvals.

3 SUBSURFACE EVALUATION

3.1 Background

The Sole Gas Field is located 55km offshore in over 124m of water in the eastern part of the Gippsland Basin (Figure 2). The Sole-1 exploration well is located on the Northern Platform of the basin and was drilled by Shell Development Australia Pty Ltd (SDA) in 1973.

The Sole-2 appraisal well, was drilled and production tested by OMV at the crest of the field in 2002. The well intersected a 70m+ gas column in high quality sandstone at the top of the Latrobe Group.

A 212km, 1km x 1km appraisal grid of 2D seismic data was recorded over the Sole Field in 1991 to define the extent of the trap. In 2003, 223km of 2D seismic lines were acquired to improve the confidence in the gross rock volume range.

The Gas in Place ("GIP") and Reserves were estimated with results reported below. The detail of the GIP and Reserves, the petrophysics, the Gross Rock Volume ("GRV") and mapping, the geology and reservoir engineering are reported in Parts A to D respectively.

3.2 GIP and Reserves Results

On a P50 basis the estimate of GIP and reserves in the Sole field are 346 Bscf and 227 Bscf respectively (Table 1 and Figure 3). The P90 estimate of GIP and reserves are 300 Bscf and 191 Bscf respectively.

The P90 to the P10 probability (i.e. 80% confidence range) for the GIP and reserves estimates is covered by 98 Bscf and 80 Bscf respectively.

Table 1 Overview of 2003 GIP and Reserves

Sole Field	**OMV-2003**			
	Mean	P90	P50	P10
GIIP (Bscf)	**346**	300	346	398
Reserves (Bscf)	**230**	191	227	271

Figure 3 Sole Field GIP & Reserves Distribution

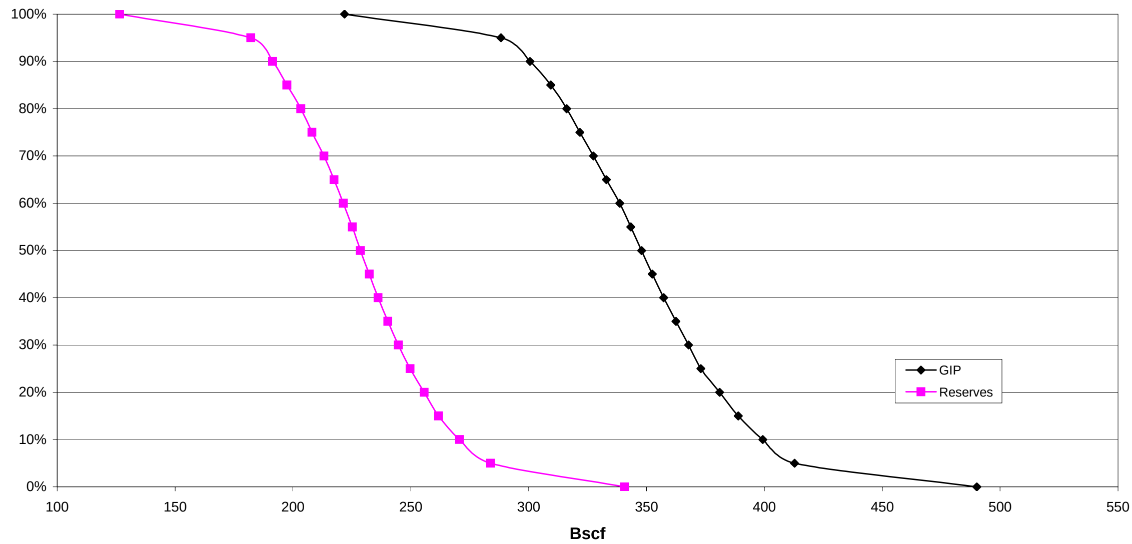
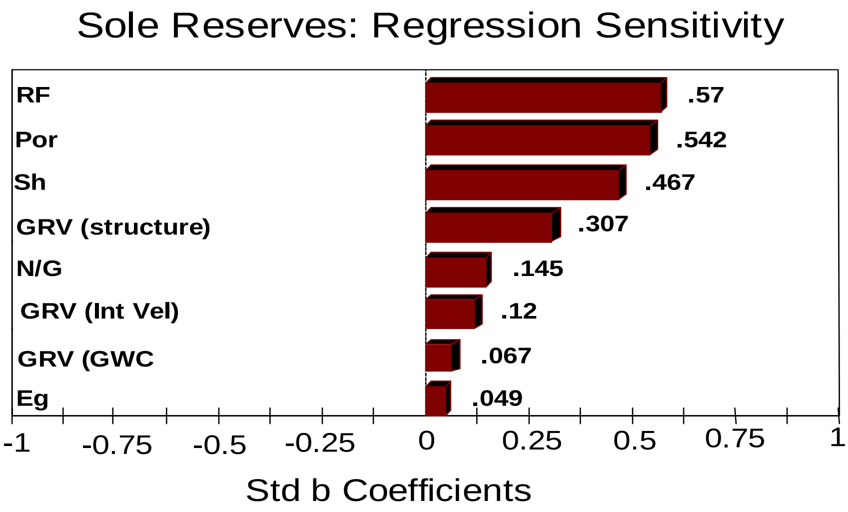


Figure 4 Sole Reserves: Regression Sensitivity[1]



The uncertainty of the Recovery factor ("RF") is identified as the most significant parameter on the reserves uncertainty (Figure 4) followed by Porosity, Sh and the mapped GRV range etc., the uncertainty on the RF is primarily a function of the uncertainty in the residual gas saturation.

There is limited scope for reserves uncertainty reduction through further engineering studies. Moreover it is considered that there is no scope for reserves uncertainty reduction by way of further data acquisition on a value of information to cost basis in advance of a potential field development. However further simulation modelling will help in the optimisation of well placement for field development.

3.3 Reservoir Management

The selected development concept (i.e. subsea) and the subsequent well and facilities design will be based on a non-well intervention philosophy.

The development plan will evolve over the life of the project as reservoir data is collected primarily through production history and surveillance activities. During production life, data will be collected at regular intervals and be used as input to a history-matched dynamic simulation model. Updating of the model in this way will ensure that the prevailing description can be tested against field information to highlight any production impairment or to define and exploit reserves upside

The prime areas of production impairment risk are sand and water production. To minimise the risk to the facilities and plant early detection of these and other potential problems will be carried out at the wellhead. Wellhead pressures, temperature and flowrates will be measured on each well. The installation of sand probes at the wellhead is being investigated. Permanent downhole gauges are not required.

[1] The stb b coefficient values correspond to the fraction change in the standard deviation of the output parameter (Reserves) from a 1 standard deviation change in the input parameter. This sensitivity analysis identifies the "driving variables" that merit additional scrutiny and, by contrast helps reduce effort wasted on worrying about the wrong things. Unlike the traditional tornado chart or spider diagrams obtained by tracking the changes in an output caused by allowing exactly one model input to vary while holding the others fixed, this sensitivity analysis from Monte Carlo simulation is far more versatile because it permits functional or correlation-type relationships among the inputs.

Based on the selected development type, a more expansive reservoir management plan will be part of the final field development plan submission.

3.4 Exploration and Appraisal Wells

The Sole-1 exploration well is abandoned.

The Sole-2 well was suspended as a gas producer after testing the Latrobe Coarse Clastics reservoirs. The technical integrity of the well is not considered suitable for Sole H_2S gas production.

The two (2) planned development wells will be subsea wells and most likely vertical wells.

3.5 Upside Potential

The upside reserves potential within VIC/RL3 is limited to the Sole Field with P10 reserves identified at 271Bcsf. There are no other exploration prospects within the VIC/RL3 area.

The field development will take account of third party gas opportunities.

4 DEVELOPMENT FACILITIES

The Sole Gas Field will be developed to supply gas into the Eastern Gas Pipeline (EGP) via the existing Patricia Baleen (PB) export facilities that are owned and operated by the PB Joint Venture Partners. A new pipeline to shore will be laid. A Sole field production rate up to 110 MMscf/d is planned. Sharing of facilities between PB and Sole will be maximised to the greatest extent possible but expansion of compression, dehydration and utilities will be necessary. An H_2S removal facility will be added to process Sole gas.

The relatively dry gas, the low liquids ratio and the pressure of the Sole well stream fluids permit their transmission to shore without any offshore processing. Control of hydrates during well start-up and during certain operational conditions, requires the injection of hydrate inhibitors at the wellhead. In addition, potential sweet and sour gas corrosion of the transmission pipeline will be mitigated by corrosion inhibitor injection to protect the pipeline system.

The development configuration will comprise the following major components:

- Two (2) subsea wells.
- An umbilical to provide safe and effective well control from shore and to transport hydrate and corrosion inhibitors to the wellheads.
- A pipeline to transport the well stream fluids to the expanded onshore plant, with a shore crossing adjacent to the PB pipeline shore crossing.
- Additions and upgrades to the PB onshore plant facilities to permit processing and export of Sole gas to current sales gas and EGP transmission specifications.

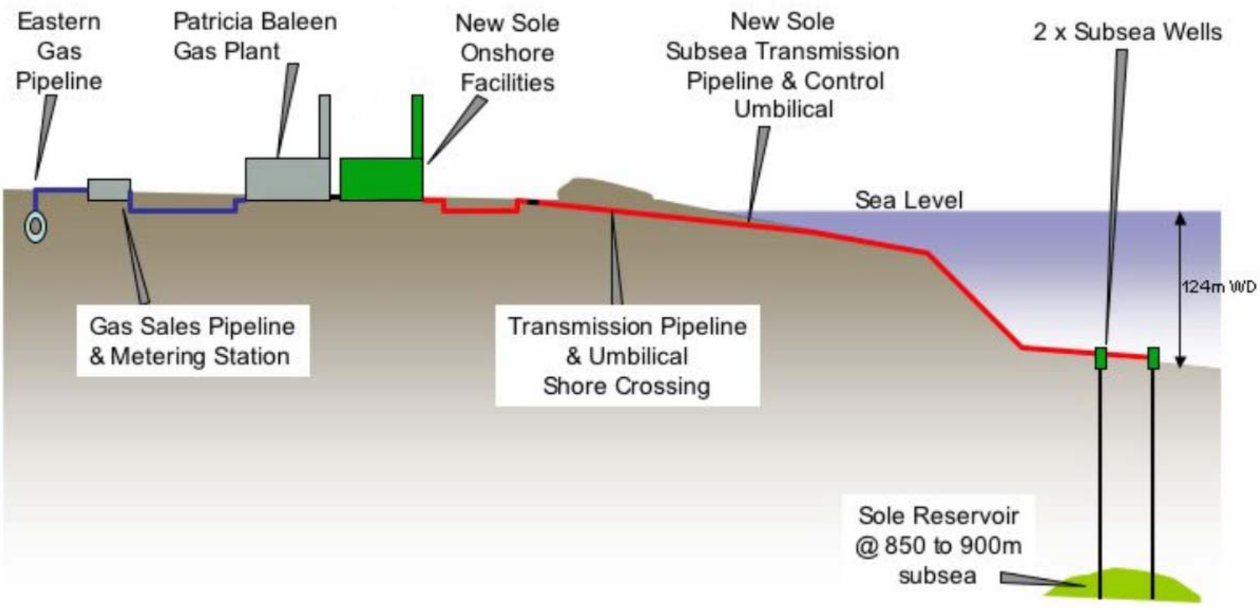
Provision will be made in the Sole offshore facilities to allow the tie-in of an additional well or for the transportation of gas from potential future nearby developments. The facilities will have a design life of 15 years.

The development will comply with applicable Commonwealth and State legislation and regulations and the requisite regulatory approvals will be sought in accordance with the approach used during the recent PB development.

A number of alternative development concepts for the offshore facilities were evaluated. These alternatives included a base case option similar to the all-subsea system development for PB, through to a floating platform (buoy), and to a fixed platform and service facilities.

The base case (Figure 5) was selected as the most attractive option for the Sole offshore facilities.

Figure 5 Schematic of Sole Base Case



4.1 Offshore Facilities

4.1.1 Base Case - Subsea Production System

An all-subsea development configuration, similar to that used on PB forms the basis of the offshore development. It comprises two (2) subsea wells tied into the subsea transmission pipeline to permit free flowing of the well stream fluids to shore.

A multiplexed electro-hydraulic well control system is planned. The control system will provide for up to 3 wells, 2 initial and 1 future.

The main components of the system include:-

- Two (2) Subsea Christmas Trees.
- Wellhead controls and hydraulic systems for opening and closing wellhead valves and sub surface safety valves.
- Chokes (remotely controlled from onshore with position indication).
- Rigid spools connecting each well to the export pipeline.
- Cathodic protection for trees, flow lines and guide bases, as appropriate.
- Provision for future intelligent pigging of the pipeline.
- Corrosion and hydrate inhibitor injection into each well stream. Instrumentation and data gathering for collecting process data and status indication.
- Umbilical connections from the onshore plant to the wellheads. The umbilical shall contain duplicated hydraulic control system cores, power and signal cables.
- An hydraulic power unit at the onshore plant or upgrade / expansion of PB facilities.
- An electric power unit at the onshore plant.
- Chemical injection skid for hydrate and corrosion inhibitors including storage, pumps and metering facilities at the onshore plant.

- A man/machine interface (VDU) type control interface in the onshore plant control room.

The offshore production facilities will have a number of features that include corrosion monitoring facilities for the pipeline. These will consist of corrosion probes, located on the well rigid spools, with data transmission to shore via the umbilical.

Continuous hydrate inhibitor injection is not planned. A chemical injection point shall be provided upstream of the choke for use on those occasions when production fluid compositions or ambient seabed conditions dictate the need for hydrate inhibitor injection. These requirements can be related to well start up, water production, produced fluid and seawater temperatures, flow rates and flow compositions.

Diverless methods for maintenance and repair will be adopted unless these are shown to be less cost effective compared with diver intensive techniques. Where possible, systems will be designed for maintenance free operation during the life of the field.

All flow line and manifold piping will be designed in accordance with AS 2885.

Marine growth will be considered, from mudline to Chart Datum (+) 2.0 m.

The subsea Xmas trees will be supported on wellheads and a permanent guide base in the conventional manner, and will be drill-through type. The trees will house the valves required to isolate and regulate flow, being master, wing and choke valves. Annulus and cross-over valves will also be installed.

A multiplex electro-hydraulic control system is proposed, requiring a sub-sea umbilical cable between the onshore plant and the offshore wells, crossing the coastline through a horizontally drilled dedicated steel casing. The umbilical will be buried where required to provide protection from external impact from fishing activities.

The control system configuration will be similar to that used for the Patricia Baleen project. A subsea control module (SCM) will be fitted to each Xmas Tree and connected to the main electro-hydraulic umbilical via flying leads to a termination assembly. The choke value, SCM and jumper connections will be suitable for intervention by remotely operated vehicle (ROV). Xmas Tree valves will also be suitable for operation by ROV.

The umbilical will contain an hydraulic power supply back-up core.

The control system will be designed to provide full redundancy so that there is no loss of control or production following the failure of any single component within the control system, including the hydraulic power unit.

The control system shall be configured so that in event of loss of signal all production is stopped within 30 minutes.

Sand monitoring probes will be provided downstream of each choke valve, with data transmission to shore via the umbilical.

The Sole subsea production facilities have been configured to allow the tie-in of an additional well at either the tee of the two Sole development wells or at the end of the pipeline.

In addition a full bore (14") tie-in of another field/accumulation can be carried out at the end of the pipeline. The viability will be dependent primarily on issues associated with gas composition, co-mingling and onshore plant processing requirements.

The provisions are made with a valve and blind flange at each tie-in point.

The control system has the capacity to control three wells simultaneously (i.e. a well in addition to Sole-3 and Sole-4).

4.1.2 Offshore Pipeline

The pipeline will be run from the furthest offshore well, past the second well and then northwest to shore and run parallel to the PB pipeline for the last 7 kilometres to the shore crossing. This route has been the subject of a detailed route survey and has been shown to be free of major obstructions.

Having reached the Patricia Baleen corridor, the line will run to the coast at an offset of approximately 20 metres from the PB offshore pipeline. It will pass through a horizontally drilled shore crossing to a point just east of the existing onshore plant where a new inlet separator and manifold pipework will be installed.

The main specifications of the transmission pipeline are:

- 14" nominal diameter
- wall thickness 12.7mm minimum
- approximately 65km in length
- pipe steel grade X52 or higher
- design pressure to ANSI Class 600
- water depth range 0 to 130 metres
- corrosion coating of asphalt enamel or fusion bonded epoxy
- weight coating of high density concrete or extra wall thickness
- external cathodic protection by anodes
- total corrosion allowance of 7mm
- operating temperature range from 0 to 40 deg. C
- design life of 15 years
- design storm of 50-year return period.

Critical pipeline design and operating parameters and means of control will be as follows:

Internal corrosion. The pipeline will be designed with an allowance for internal corrosion of 4mm. Corrosion inhibitor, required due to small amounts of H_2S and carbon dioxide in the gas stream, will be injected at the Xmas trees. A corrosion monitor will be installed in the flowline between each well and the pipeline as part of the corrosion management system. The product stream received at the onshore gas plant will be also analysed at intervals as a further check on the effectiveness of the corrosion inhibitor.

On-bottom stability. The pipeline will be designed to maintain on-bottom stability throughout its design life. It is anticipated that stability can be achieved over most of the pipeline length by an external coating of high-density concrete or by added wall thickness. At water depths less than 30 metres (i.e. to a distance of approximately 3.2km from the beach), stability may be enhanced by partial burial of the pipeline depending on the weight coating system adopted.

Free spanning. Spans will be measured and evaluated according to DNV – 1981 – Rules for Submarine Pipeline Systems. Post-installation spans will be corrected prior to start-up. Surveys will be carried out after severe storms to check for any required remedial work.

External loadings. Apart from hydrodynamic forces, possible accidental loadings on the pipeline may be caused by anchor dragging, trawl gear, dropped objects, mines or unexploded depth charges in the vicinity. It is not possible to protect pipelines from dragging of large anchors, however the vessel activity in the area should be limited to relatively small fishing vessels, which would not be expected to anchor near the pipeline. Drilling or construction vessels for the project will operate under procedures that will minimize the risk of dropped objects on the pipeline.

Well and pipeline control. The pipeline design pressure will be higher than the maximum well shut in pressure, making the system fail-safe, should system control or shut-down functions for the Xmas tree valves not operate as intended.

The pipeline will be designed to include the provision for future intelligent pigging.

4.2 Development Options Considered

A total of six (6) offshore development options were considered.

All subsea development, similar to PB

Subsea development with disc type, well control buoy

Subsea development with spar type, well control buoy

Subsea development with control platform

Subsea development with umbilical shore crossing at Bemm river

Wellhead platform development

These options were initially studied independently and then narrowed down to three (3) key options as summarised below.

The control platform was significantly more costly than the wellhead platform option due to the cost of the subsea trees and control system in lieu of dry xmas trees and a simplified on-platform wellhead control system. The control platform option with subsea trees was not considered as a viable option in the final evaluation.

The Bemm river option was considered as a way of reducing costs by reducing the length of the offshore umbilical. The complexities of establishing a new site, remote from the PB plant, requiring a new location for environmental evaluation for the shore crossing and umbilical termination support facilities ruled this option out.

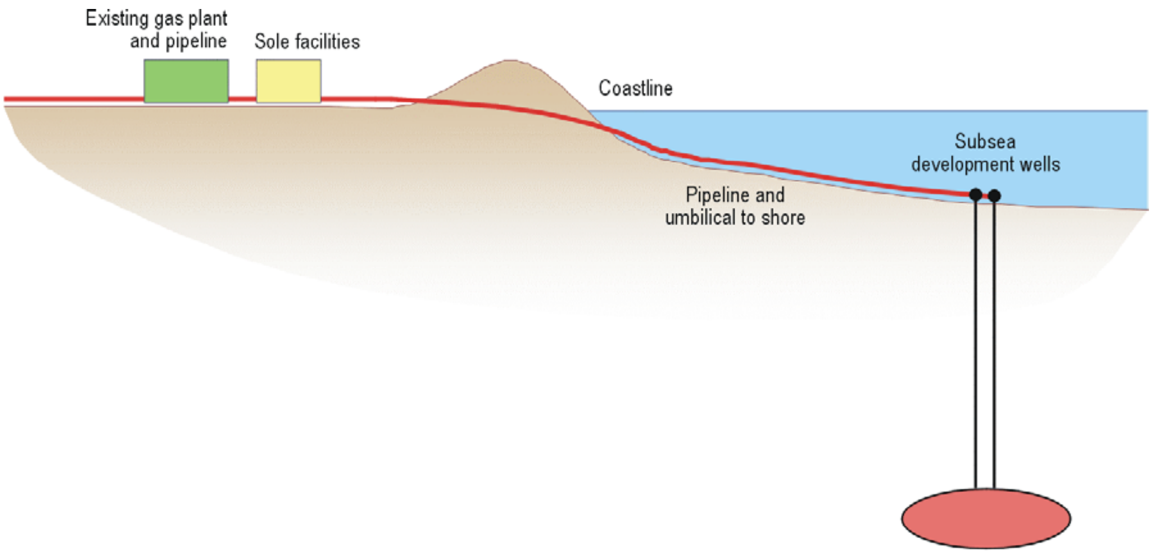
The disc buoy and spar buoy were grouped and summarised below as one (1) key option due to the overall concept similarity, except for the type of buoy.

The three (3) key options are summarised below.

4.2.1 Option 1 - Reference Case

The Sole Field will be developed through two (2) subsea wells in a Patricia Baleen style 'daisy chain' design with a 14" diameter, 65 km pipeline, linked to the PB onshore plant through a HDD shore crossing (Figure 5).

Figure 6 Option 1 – Reference Case



The subsea wells will be controlled from the PB plant site, using a new ~65km long umbilical, run parallel with the pipeline. The umbilical will be buried along its length and brought ashore through a horizontally directionally drilled (HDD) shore crossing next to the existing PB shore crossing. The pipeline will only be buried to the extent necessary to achieve stabilization.

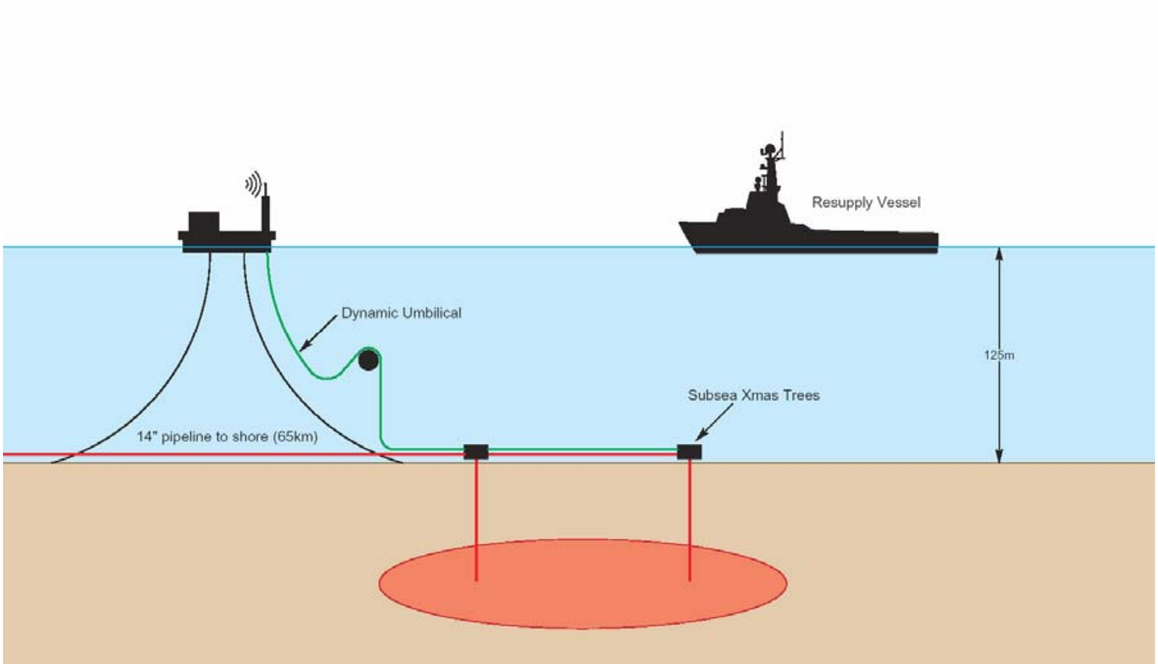
The Sole pipeline and umbilical will run parallel to PB in the shore approach. This has the effect of avoiding sensitive subsea terrain features and limiting the areal impact on the fishing industry.

4.2.2 Option 2 – Well Control Buoy (Disc or Spar type)

The Sole Field would be developed through two (2) subsea wells in a Patricia Baleen style 'daisy chain' design with a 14" diameter, 65km pipeline linked to the PB onshore plant through a HDD shore crossing.

The well control buoy would be either a disc buoy or a spar type buoy anchored to the seabed adjacent to the subsea wells at Sole (Figure 7).

Figure 7 Option 2 – Well Control Buoy



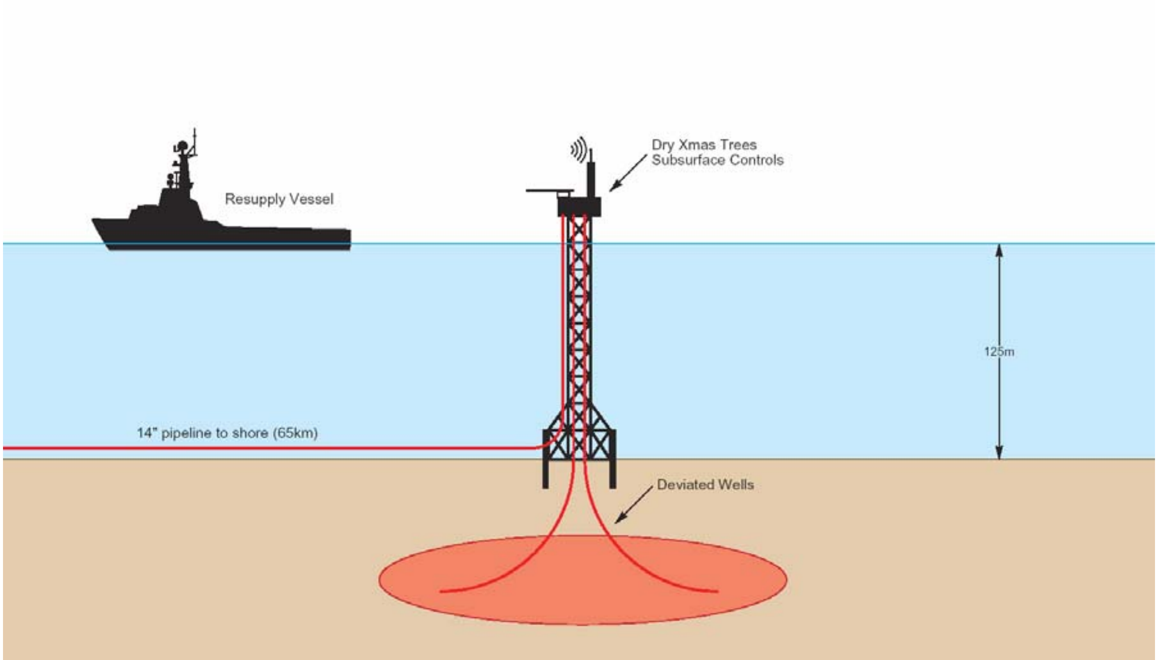
The subsea wells would be 'daisy-chain' linked via a static / dynamic subsea umbilical to the well control system on the buoy. It would have the same functionality as the onshore-based well control system in Option 1 (i.e. the Reference Case). Communication between the well control buoy and the well control unit at the PB plant would be via a telemetry link via the Mount Cann Telstra Tower.

4.2.3 Option 3 – Wellhead Platform

The Sole Field would be developed through two (2) directionally drilled wells, drilled through a subsea template, and subsequently tied back to dry xmas trees at deck level on the wellhead platform. A 14" diameter, 65km pipeline, connected via a riser from the platform would transport the well stream fluids to the PB onshore plant through a HDD shore crossing.

The wells, with dry xmas trees, would be controlled from a relatively simple wellhead control panel on the platform (Figure 8). There is no requirement for an umbilical in this option.

Figure 8 Option 3 – Wellhead Platform



This option assumes that a semi-submersible drilling rig would drill the two (2) deviated wells through a template near the existing Sole-2 wellhead. The new wells would be completed to mudline, with connectors to allow future completion at platform deck level using a platform based hydraulic workover rig.

4.3 Discussion of Key Development Options

The main pros and cons, along with the major risks and uncertainties for the 3 key options are set out below. A summary of the findings related to the key issues raised follows each table.

4.3.1 Option 1 – Base Case – All Subsea Development

Pros – Cons

Weight	Issue
+	Proven technology with very recent experience and cost basis
+	Robust cost estimates with high degree of completeness and accuracy
+	Reduced likelihood (wrt other options) of cost/schedule escalations
-	Umbilical route to be trenched – potential fishing industry issue minimised
+	Opportunities exist for installation cost optimisation.
+	Known installation methodology able to provide high level of confidence with identified vessel types and standard installation methods/equipment
+	Specialized vessels used for specialized tasks minimize the technical risk

Negotiations with the fishing industry in regards to Patricia Baleen reached an agreed commercial outcome. OMV will carry out extensive discussions with the broader fishing industry to reduce or eliminate the fishing related risks to the Sole umbilical and pipeline and provide a mechanism for dispute resolution. The EES process and ongoing community consultation will provide some insight to any concerns that the fishing industry may have and these will be addressed if and when they arise. To minimise risk to the umbilical the umbilical is planned to be buried along its length to approximately 750 mm below seabed.

Major Risks and Uncertainties

1.	Ability to trench umbilical to depth over entire distance to depth

The recent soil sampling work, analysis of samples, side-scan sonar and burial study work etc, indicate that umbilical burial can generally be achieved to the required depth along the entire route.

The key issue is to ensure that the right burial tool is selected for the harder soil materials identified in some short intervals at the shore end of the umbilical route.

The burial could be achieved using a jetting, or standard plough type tool for the sandy/silty areas, and mechanical cutters, either wheel or saw type tools, would be required in the limited regions of harder materials.

Further soil sampling is being considered to identify the specific locations of the harder materials and to enable the proper selection of mechanical trenching tools for these locations.

4.3.2 Option 2 – Well Control Buoy Option

Pros / Cons compared to Option 1 (Reference Case)

+	No requirement to bury an umbilical
-	Short dynamic umbilical required
-	Signal Communication Attenuation Issues
-	Requires regular offshore re-supply and intervention with high Opex
-	1- off development with no success history
-	Dynamic umbilical more complex than static umbilical
-	As there is no direct line of sight between the PB plant site and the Sole buoy, a radio transmitter station would have to be installed at an elevated onshore location.
-	Potentially more difficult construction contracts

The capital costs associated with the disc buoy are similar to Option 1. The added operating costs include covering the onshore support infrastructure. Regular servicing and re-supply are higher in this Option than Option 1. In addition, the recent experience gained from design and successful installation of Patricia Baleen increases the confidence in the costing and execution of Option 1.

The alternate to a disc buoy was a spar type buoy, which was shown to improve the reliability of the communications, but was more costly to fabricate and install than the disc buoy. It also resulted in a more compact facility, with multiple levels and confined spaces, which increased the difficulty of accessing the facility for servicing and repair/re-supply activities. A helideck would be included to enable all weather access for maintenance.

Major Risks and Uncertainties

1	Ability to achieve acceptable buoy motion characteristics to allow for continuous operations (equipment) and regular personnel access for servicing in suitable sea-state windows.
2	Brand new design for environmentally rugged application – ability to compile all issues in design basis and detail design
3	Risk of cost blow-out due to design and fabrication issues (issues requiring changes, omissions, errors)
4	Ability to maintain design, fabrication, installation and commissioning schedule

The spar type buoy was considered as a means to reduce the motions associated with the disc buoy that were considered to be unacceptable for regular access and servicing of onboard equipment.

The spar type buoy also improves the reliability of the communications link. However, the spar buoy is more complex and more costly than the disc buoy and has greater potential to incur design, fabrication and installation challenges leading to cost blow-outs.

The disc control buoy option, being a prototype, is potentially more costly. It has a greater design and installation risk profile than the subsea development with an umbilical (i.e. Option 1).

A risk and safety review also concluded that the control buoy presented a greater risk to life and could not be supported on safety grounds relative to Option 1. The control buoy options were dropped from further consideration.

4.3.3 Option 3 – Wellhead Platform Option

Pros / Cons compared to Option 1 (Reference Case)

+	Cheaper simpler dry Xmas trees and control system
+	The pipeline can be pigged at low cost which may help with corrosion monitoring / protection
+	Other developments in the area can be tied-in to the platform without the need to run a long pipeline to shore or perform a subsea tie-in.
+	No need for umbilical to control the wells. A simple well control panel can replace the subsea control system.
-	Requires regular offshore visits resulting in very high opex. A helideck would be provided to facilitate access. A high level of automation, redundancy and reliability would be necessary to minimise personnel visits.
-	Environmental approval may be longer and more complicated than for the subsea option, however there are a large number of platforms in the area.
-	As there is no direct line of sight between the PB plant site and the platform, a radio transmitter station would have to be installed at an elevated onshore location.
-	Further front end engineering effort required, which might cause schedule delays and additional capex requirements.
-	Additional offshore sour gas operational site. (This applies only to leaks as all gas used on the platform would be treated with H_2S scavengers)
-	Higher Total Capex and Opex

The capital costs for the wellhead platform (or control platform option) together with the operating costs covering the onshore support infrastructure, marine support services and helicopter services etc, would be significantly higher than the costs for Option 1.

Major Risks and Uncertainties

1	Length of design and environmental approval processes
2	Synergies with the pipeline installation vessel or the drilling rig may reduce the platform installation costs and / or the umbilical and pipeline tie-in costs.
3	De-commissioning costs for the control or wellhead platforms would be greater than those for the umbilical in the base case.
4	Soil conditions for foundations would require extensive investigation adding to front end costs and potentially very high foundation costs to secure the platform using piles.

The statutory approval processes for a Sole field development concept utilising surface facilities would increase the duration and brings greater uncertainty to the timing of the project relative to Option 1 (the reference case).

In addition to the approvals, a fixed platform would require an onsite geotechnical investigation programme followed by laboratory analysis and testing etc, to enable the foundation design concept to be selected, developed and costed. The foundation conditions in Bass Strait are known to present considerable challenges and require complex /costly solutions.

These risks and uncertainties, resulted in a more costly capital development, higher operating costs, and an overall higher risk profile of this option. The wellhead platform (and control platform) options were dropped as possible development options for Sole.

4.3.4 Recommendation / Conclusion

OMV has recently successfully completed the Patricia Baleen development in Bass Strait utilising subsea wells, a subsea pipeline and a buried control umbilical. Analysis of the offshore development options confirms that the development of the Sole field should utilise an essentially identical concept capitalising on the available experience.

The Sole Project will be developed utilising an all subsea development similar to Patricia Baleen.

4.4 Onshore Facilities

4.4.1 General

The purpose of the Onshore facilities is to receive the Sole Field produced fluids from the offshore pipeline, process and compress the Sole gas to sales gas specification for delivery into the EGP pipeline. In addition, the facilities shall store and dispose of waste products from the Sole wellstream in accordance with approved management plans.

4.4.2 Patricia Baleen Onshore Gas Plant

The Patricia Baleen onshore facilities located southwest of Orbost are currently sized to process a maximum of 60 TJ/day of sales gas (i.e. net of fuel gas requirements). Capacity is limited by installation compression power (60 TJ/day) with the balance of plant sized for 75 TJ/day and the sales gas pipeline sized for 200 TJ/d. The plant comprises the following main elements:

- Facilities for installation of temporary pig receivers
- Separation
- Compression
- Dehydration
- Odorisation
- Export Metering & Sales Gas quality control
- Produced water handling and disposal
- Horizontal Flare system
- Utilities
- Power Generation
- Fire and Gas detection facilities
- Offshore well control for the two PB wells
- Chemical Injection for PB well operation and pipeline corrosion
- Central control room for operation of both offshore and onshore facilities

All PB onshore facilities including piping, structures and equipment has external coating suitable for an exposed coastal, salt laden environment.

4.4.3 Additions to PB Facilities for Sole Gas Processing / Export

All new facilities for the processing of Sole gas will be constructed in a new plot located adjacent and to the east of the existing PB plant on land to be acquired by the Sole Joint Venture. This will minimise potential safety and sensitive industrial relations issues during the construction period. Facilities will be added to increase the capacity of the combined PB and Sole plants to 120 TJ/d of sales gas (net of fuel gas). The new facilities to be installed for Sole will have a design life of 15 years.

Onshore Pipelines

The Sole offshore transmission pipeline will come ashore via a horizontally drilled shore crossing, adjacent to the existing Patricia Baleen shore crossing. At the point at which it crosses beneath the low water mark the pipeline becomes regulated under the Victorian Pipelines Act and approximately 400m of pipeline is regarded as ‘onshore’. To minimise pressure drop, the onshore feed line from the offshore transmission line to the PB Plant will be 14” NB. It will be built to the same specification as the offshore pipeline but electrically isolated for corrosion purposes. Process fluids will flow through this feed line to the inlet separator.

Pig Receiver

The offshore transmission pipeline will terminate at the plant with facilities suitable for housing temporary pig receivers. The receiver will be designed for receiving intelligent pigs from the pipeline. The internal diameter of the inlet of the pig receiver shall be identical with the pipeline internal diameter.

Separation

The produced fluids from the pipeline will enter a new two-phase inlet separator / slug catcher. The separator shall be sized for a maximum gas flow of 129,700 Sm3/h (110 MMscfd) and up to 2000 bpd of total water production (water of condensation plus formation water). Water from the separator will be discharged to the new sour produced water handling and disposal system. The existing Patricia-Baleen facilities (designed for 400 bwpd) have sufficient capacity to handle the Sole water production until significant volumes of formation water are produced. The onset of formation water production cannot be accurately estimated at this stage therefore the existing produced water plant will not be upgraded until better production forecasting can be developed after the Sole field start-up. The existing produced water system shall be provided with connections to allow for expansion. The inlet separator will be designed with a liquid slug handling capacity of 20 m3. Gas from the inlet separator will be fed to the H_2S removal system.

H_2S Removal

The H_2S level in the Sole gas stream will be reduced to the sales gas specification in a H_2S removal plant. The H_2S will be removed using the Shell-Paques process that utilises thiobaccilli bacteria to convert the H2S into elemental sulphur in a single step. The produced sulphur cake (65% sulphur and 35% water) will be stored on site and either disposed as trade waste or sold as a by-product. Sweet gas from the H_2S removal system will be directed to the compression system. The H_2S removal and sulphur recovery plants will be sized to process a maximum of 129,700 Sm3/h (110 MMscfd) of gas with up to 1500 ppm of H_2S. Bleed water from the Shell-Paques process will be disposed to the East Gippsland Sewage Treatment Plant or stored in new evaporation ponds. The Shell-Paques process at the plant design flowrates will produce approximately 7 tonnes per day of sulphur cake and 4 m3/hr of bleed water.

Compression

Sole gas will be compressed by a combination of new gas engine driven reciprocating compressors and the Patricia Baleen compressors. The total plant compression capacity will be 120 TJ/d sales gas equivalent.

Dehydration

A 50 MMscfd TEG dehydration system will be added to the Sole facilities to supplement the existing Patricia Baleen facilities.

Sales Gas Metering

Sales gas metering will utilise the existing Patricia Baleen metering. Additional in-plant metering will be installed for allocation of Patricia Baleen and Sole gas and produced water.

Produced Water Disposal

Produced water from the Sole inlet separator is routed to a new sour water treatment system for separation of dissolved gases and treatment to neutralise H_2S.

Water from the sour water treatment system will be discharged into a sour water pit for further treatment before it is discharged to the ponds or to the East Gippsland Sewage Treatment plant located nearby. An additional evaporation pond may be built north of the Patricia Baleen plant if required.

Shutdown Relief and Vent System

Pressure vessels, compressors and other equipment containing hydrocarbon gases under pressure will be provided with pressure safety valves (PSVs). A blowdown system will be provided to depressurise pressure vessels, compressors, coolers and so forth.

Automatically operated isolation valves will be provided at the battery limits of the onshore plant on both the feed and delivery gas pipelines to limit the inventory of gas in an emergency conditions. Additional automatic isolation valves will be installed to isolate individual areas within the process plant and further limit the inventory of gas, especially gas containing H_2S .The plant will be provided with an emergency relief and vent system for discharge of PSVs and blowdown valves. The system shall comprise collection headers, knock out drums and elevated flare tips.

Manual emergency shutdown will be provided from pushbuttons located in the control room, at the main plant gate and locally within both the Sole and Patricia Baleen facilities. All manual emergency pushbuttons will initiate a shutdown of the entire gas Plant. Depressurisation can also be initiated manually from the control room.

Utilities

Plant utilities provided for Patricia Baleen will be expanded as required.

An additional fuel gas system and additional power generation will be provided.

Fuel gas usage has been estimated as less than 3% of the Sole gas production.

A vertical flare will be required to ensure GLC's (ground level concentrations) are met. Hydrocarbon gas losses due to flaring will be minimum as no operational flaring is planned other than provision of a small flow of purge gas. Flaring shall only occur during plant start-up conditions, major process upsets, lifting of pressure safety valves and emergency blowdown. The existing horizontal flare will be decommissioned.

Control, Instrumentation and Communications System

The Patricia Baleen system will be expanded as required. A new Motor Control Centre and Electrical and Instrumentation room will be provided to house the Sole plant electrical equipment.

Fire and Gas Protection

Fire and gas detection shall be provided at suitable locations throughout the plant. The plant shall shutdown automatically on confirmed fire detection including closure of battery limit valves to isolate the plant from the gas inventories in the feed and delivery pipelines. Blowdown will be initiated automatically on confirmed fire detection.

Confirmed hydrocarbon gas detection will cause plant shutdown and confirmed H_2S detection will automatically isolate all plant areas containing H_2S.

Fire fighting will be provided by fire extinguishers (hand held and trolley or trailer mounted). The Patricia Baleen fire ringmain system will be extended to cover the Sole plant. Water and suitable hydrant hose connections shall be provided for use by the local fire fighting authority.

Additional water storage, water pumps and hoses will be provided from the process water make-up system to be used during maintenance of equipment that may contain Iron Sulphide.

Additional gas detection for H_2S as well as personnel protection equipment such as breathing apparatus and portable H_2S sensors will be provided as required.

Environmental Protection

The plant shall be designed to minimise environmental impact. Venting of hydrocarbons shall be minimised. Equipment selection shall take fuel and power consumption into consideration.

Paved and / or bunded areas will be provided under equipment which may have liquid discharges due to operation or maintenance activities, e.g. lube oils, chemicals, hydraulic fluids, diesel fuel systems.

Liquids collected in equipment bunds will be directed to the Patricia Baleen API Separator.

Systems will be provided to minimise the release of H_2S contaminating gas streams and to minimise any sources of odour.

All emissions will comply with the Victorian Environment Protection Act. Works will be undertaken in accordance with an EPA Works approval.

4.4.4 Alternatives Considered

H_2S Removal Technology Selection

A Sole onshore plant H_2S removal technology selection study was carried out by Worley Ltd. as part of the Front End Engineering Design (FEED) for the Sole gas Development. An H_2S removal expert was contracted and H_2S Removal / Sulphur Recovery technologies were identified and vendor enquiries issued to 13 companies covering all identified technologies. The vendor responses were received, clarifications were obtained and contact with operating companies was made to determine actual design and operating experience.

An evaluation table and criteria were developed by Worley and approved by OMV. The Worley FEED team, the H_2S expert consultant and OMV carried out an evaluation of the various technologies and concluded that whilst the amine + claus technology appeared to be the most suitable for the development on the basis of being a well proven technology for sour gas processing, the evaluation results for two other proprietary technologies (Shell-Paques and Crystasulf) were close enough to warrant further consideration in light of the advantages they offered with regards to capital and operating costs, higher sulphur recovery, lower plant emissions and less equipment required.

Further review of the Crystasulf process indicated that it was not yet sufficiently developed to be worth any further consideration and was eliminated.

The amine system uses a solvent to remove H_2S from the gas stream. The solvent is regenerated using heat releasing the H_2S to the Claus unit where a catalyst and additional heat is used to convert the H_2S to elemental sulphur.

The Shell-Paques uses a solvent to remove H_2S from the gas stream. The solvent is regenerated using air in a bio-reactor (i.e. use of bacteria as a catalyst). Elemental sulphur is produced in the bio-reactor.

The Shell-Paques process licensor was contacted and a preliminary design for an amine + claus plant was commissioned from a reputable vendor to obtain further information. The FEED work has continued on the basis of utilizing the amine + claus process for the Sole plant and the information contained in this document has been based on this process.

The response received from the Shell-Paques process licensors indicated that some of the perceived risks with this technology could be mitigated with further investigation. The licensor was commissioned to carry out a preliminary design of the Shell-Paques process for the Sole gas plant to provide the information required to complete the selection process. In addition to this, a site visit of the Shell-Paques plant in Bantry, Canada was carried out in early July 2003.

The H_2S removal and Sulphur recovery technology selection was completed in August 2003. The evaluation used the Kepner-Tregoe method to evaluate the processes. The various categories selected for evaluation were assigned a weight value depending on the perceived value assigned by the project to the particular category. The sum of all the category weights is 100.

Additional evaluation sub-categories were included for each category and each of them were also assigned a percentage of the total value for the category. The weight for each sub-category was calculated by multiplying the category weight by the sub-category percentage. Each sub-category was then assigned a score between 0 and 100 for each of the processes evaluated. A total score was derived for each process by multiplying the sub-category score by the sub-category weight and adding all the values for each process evaluated. The results of the updated technical evaluation are listed in the table below and indicate that the Shell-Paques process has scored higher than the Amine+Claus process.

				Amine + Claus		Shell-Paques	
Category			Sub-category weight	Grade	Weighted Score	Grade	Weighted Score
Description	weight	%					
Economics	30						
Evaluated Cost (Capex + 5 years Opex)		60	18	90	16.2	100	18
Capital Cost		20	6	100	6	100	6
Availability (lost production)		20	6	80	4.8	100	6
sub total for category			30		27		30
Commercial Issues	20						
Proven Operating Experience		40	8	100	8	60	4.8
Availability of chemicals (sole source, etc)		10	2	100	2	80	1.6
Warranties		25	5	100	5	100	5
Technical Support		25	5	100	5	90	4.5
sub total for category			20		20		15.9
Operability and Maintainability	25						
Manning requirements incl. Spec. skills		30	7.5	80	6	100	7.5
Turndown		30	7.5	100	7.5	100	7.5
Need for lab and other special req'ts.		10	2.5	90	2.25	100	2.5
Ease of operation / maintenance		30	7.5	60	4.5	100	7.5
sub total for category			25		20.25		25
Construction	5						
Constructability		100	5	80	4	100	5
sub total for category			5		4		5
Environmental & Safety	20						
Hazardous raw materials / products (Incl. exposure)		25	5	90	4.5	100	5
H2S inventory & concentration		25	5	65	3.25	100	5
Waste Stream disposal & undesirable emissions		25	5	60	3	100	5
visual impact		25	5	70	3.5	100	5
sub total for category			20		14.25		20
Total Weighted Score					**85.5**		**95.9**

Table 5.1 Technical Evaluation Summary Table

The main reasons for the assigned scores are listed below:

Economics

- Evaluated cost from the A&C process was scored lower than S-P due to the potential for operating cost savings in the S-P process waste disposal.
- Capital costs were scored the same as the difference in the estimated costs is well within the cost estimate accuracy.
- Availability of the A&C process is considered to be lower due to the need to reduce feed gas flow when Claus plant is shutdown to allow it to cool down ahead of the annual maintenance shutdown. It may also extend the shutdown time to allow the plant to heat up.
- The availability score for the A&C process was also lowered due to the potential for longer annual shutdown required to maintain / inspect more equipment. The additional maintenance costs for the A&C process are included in the operating cost.

Commercial Issues

- Proven operating experience for S-P is scored lower as there is in only one plant in operation. The score takes into consideration that the Bantry plant is operating without problems and that the high pressure caustic absorption and Paques technologies have a long track record.
- Nutrients and biomass for the S-P process can only be purchased from Paques therefore there is a higher risk.
- Warranties for both processes are equivalent.
- Technical support for the S-P process was scored slightly lower than for A&C as at the moment it is based in USA or Europe however it is likely that support from SGS in Kuala Lumpur would become available in the future.

Operability and Maintainability

- Manning requirements and special skills to handle molten sulphur are likely to be greater than to handle the wet sulphur cake.
- Turndown of both plants meet the project requirements.
- Need for laboratory and other special requirements. A&C was scored slightly lower due to the need for greater monitoring on the make-up water purity
- A&C process is more complex to operate than S-P, the main areas of concern are the requirements to keep the sulphur product hot to avoid blocking of pipes and vessels, requirement for heating medium systems and burner management systems for Claus reactor and thermal oxidiser, fluctuations in the acid gas composition may affect the Claus system performance.
- Maintenance of the A&C system is more complicated due to the high temperatures (need to wait until systems cool down, removal and reinstatement of insulation, etc) and greater numbers of equipment.

Construction

- A&C plant is more complex than S-P, requires extensive use of insulation on piping and vessels / tanks, access to molten sulphur lines for cleaning limits options for piping layout.

Environmental and Safety

- A&C was scored lower due to the need to handle molten sulphur.
- The H2S inventory and concentration is high in the Amine regeneration process and Claus process which poses a personnel risk.
- Storage, loading and transport of molten sulphur is more complex and has a higher risk (heat, H2S release and H2S ignition and fire in sulphur pits, etc) to personnel and public safety than for the S-P sulphur cake.
- Air emissions from the A&C process are significantly greater than for the S-P process due to the lower conversion efficiency of the Claus process which requires disposal of the tail gas.
- The A&C plant is larger and includes a tall thermal oxidiser stack that has a negative effect on the plant visual impact.

- The conclusion from the technical evaluation is that the Shell-Paques process is better suited to the Sole plant than the Amine + Claus process. The main advantages of the Shell-Paques process are in the areas of environmental emissions (higher sulphur recovery leads to lower SO2 emissions), plant safety (there are no gas streams with high H2S concentration), operability / maintainability and plant availability (less equipment and no process heating required) and lower capital costs.

Gas Plant Location Alternatives

The Sole gas plant is an extension of the existing Patricia Baleen gas plant and needs to be installed adjacent to the existing plant to make use of common infrastructure. Plant sites north and south of the existing plant were discounted due to the interference with Corringle Creek and Ewing's Marsh. The alternatives for the plant site location were limited to the following:

Sole plant located to the east of the Patricia Baleen plant site.

Sole plant located to the west of the Patricia Baleen for the plant site.

Sole plant located within the existing Patricia Baleen plant site.

The areas east and west of the plant are covered in trees therefore they are equivalent with respect to the clearing of trees and vegetation required. However, the land to the west has a lower elevation (located within the Land Subject to Inundation Overlay), which will require importation of fill to locate the plant above the flood level. It is closer to Corringle Creek therefore there is a risk that the effects of construction could affect Corringle Creek. Location of the plant to the west of the existing plant was therefore discounted from any further evaluation.

A detailed assessment was carried out for the other two alternatives.

The preferred location for the Sole plant is east of the existing gas plant. The main reasons for selecting this alternative are:

- the distance from the local residences will allow the EPA buffer distance for odorisation to be met;
- better site access is provided during construction without affecting the existing plant operation;
- construction activities generating dust, noise, etc will have less effect on the Patricia Baleen operators;
- the amount of equipment required to be installed for the Sole gas plant cannot easily be accommodated in the space available within the existing plant plot. Even with major modifications to the flare and evaporation ponds at the existing plant, the new plant layout would have resulted in short separation distances between the various items of equipment. This is not in accordance with best industry practices and increases the risk of escalation in case of a fire or explosion.

Blowdown and Pressure Relief Alternatives

Three alternatives were evaluated to determine the most appropriate method to combust the gas released from pressure safety valves or blowdown valves. A cold vent was not considered due to the damaging effect of methane release to the atmosphere. The following flare options were considered:

- Expansion of the existing Patricia Baleen low level flare to handle the combined plant flaring capacity,

- Provision of a separate low level Flare for the new Sole equipment,
- Provision of a separate elevated Flare for the new Sole equipment,
- Provision of a new elevated flare to handle the combined plant flaring capacity.

Initial gas dispersion calculations indicated that the EPA Victoria guidelines on allowable ground level concentration for H_2S and SO2 could not be met with a low level flare therefore alternatives A and B were discounted from further evaluation.

Alternatives C and D are both feasible provided the elevated flare height is approximately 35m to ensure the ground level concentration can be met for SO2 and H_2S. Alternative D was selected as it results in a flare location that is remote from the control room area at the Patricia Baleen plant and it provides a single exclusion zone for heat radiation freeing up areas of the existing Patricia Baleen plant for future use.

5 DRILLING AND COMPLETION

5.1 Introduction

The proposed field development is to drill and complete two vertical sub-sea wells. Details of the drilling and completions programs are provided below.

5.2 Drilling History

Two vertical exploration wells and one appraisal well have been drilled in VIC/RL3. A summary of well information is given in Table 2.

Table 2 Summary of Sole well Information

Well	Summary Information		Results / Status
Dart-1	Spud Date: TD: Spud to TD: Total Duration:	16 Nov 1973 1219 mMD 4 days 7 days	Plugged & abandoned No hydrocarbon shows No cores No drill stem tests 2 suites wireline logs
Sole-1	Spud Date: TD: Spud to TD: Total Duration:	28 Jan 1973 1129 mMD 8 days 12 days	Plugged & abandoned 2 suites wireline logs 18m-gross/15.3m net gas pay in top Latrobe. No Cores No drill stem tests 2 x FIT samples
Sole-2	Spud Date: TD: Spud to TD: Total Duration:	11 Jul 2002 1005 mMD 6 days 16 days	1 suite wireline logs 4 cores cut DST Latrobe 20.6 MMscfd gas 1000+ ppm H_2S Well suspended as gas producer

No significant drilling problems were experienced apart from the H_2S content of the gas produced on test from Sole-2. Shallow gas was not encountered in any of the wells.

5.3 Drilling / Completion Program

5.3.1 Drilling Program

The drilling and completion plan is based on information gained from the wells drilled to date.

The Sole-2 well (2002) will not be used as part of the development because the development well design requires the installation of high specification CRA materials and expandable sand screens. This design would require the existing wellbore to be sidetracked. With these changes the cost of a new well is almost on par with a re-entry, sidetrack and completion of Sole 2, but with reduced operational risk. Consequently the decision has been taken to drill a new well. Sole 2 will be left in its current condition and will be abandoned at the end of field life along with the development wells.

The base plan is to drill two vertical wells into the main field both at near crestal positions but 1.6 kms apart. All well construction materials used in the well casing(s) and production tubing string and all other completion materials as well as the sub sea production trees will be made of selected CRA materials and have been designed to last for the life of the field without the need for intervention.

A summary of well hole sizes with depth is given in Table 3.

Table 3 Well Hole Sizes with Depth

Hole Size	Purpose	Formations	Depth mMD
36" x 26"	Conductor	Gippsland Limestone	185
17 ½"	Intermediate Casing	Gippsland Limestone, Lakes Entrance	650
12 ¼"	Production Casing	Lakes Entrance	771
8 ½"	Production Hole	Latrobe Group	~790

Holes sizes will be optimised having regard to production rates and pipeline size and gas sales requirements.

5.3.2 Casing Program

A summary of the borehole sections and casing program for the development wells is shown Table 4.

Table 4 Borehole Sections and Casing Program

Description	Casing Size	Approx. Setting Depth (mMD)
Conductor	30" (762 mm) x 20" (508 mm)	185
Intermediate Casing	13-3/8" 339mm	650
Production Casing	9-5/8" (245 mm)	770
Production Liner	7"(178 mm) or sand screen/gravel pack	~790

Special corrosion resistant alloy steel is planned for all flow wetted casing and tubing strings to cater for the H_2S and CO_2 content of the gas.

A 30" (762mm) conductor string, swaged down to a 20" (508mm) shoe, will be utilised. The conductor string will be cemented back to the seabed.

The intermediate casing string will consist of 13 3/8" (340mm) casing set at approximately 660m to give sufficient kick tolerance for the next hole section to enter the reservoir. The casing will have buttress connections and be cemented in place.

The production casing will consist of 9-5/8" (245 mm) casing set at the top of the planned production interval. The casing will have premium connections and be cemented in place.

5.3.3 Drilling Fluid Program

An optimum drilling fluid program is of primary importance to ensure that the development wells are drilled successfully and on gauge with a minimum amount of risk. The drilling fluid program will be very similar to that used in the Patricia Baleen development wells. No significant problems were encountered on these wells.

Seawater, supplemented with high viscosity sweeps for hole cleaning will be used to drill the surface and intermediate hole sections.

A low solids, inhibitive potassium chloride/polymer drilling fluid will be used to drill the 12 1/4" hole section to provide inhibition for the Lakes Entrance formation that overlies the reservoir.

A drill-in fluid has yet to be selected for the reservoir section, but it is likely to be a low solids, inhibitive potassium chloride/polymer fluid very similar to that selected for the Patricia/Baleen development wells.

5.3.4 Completion Program

A 5 1/2" expandable sand screen (ESS) will be installed across the reservoir and a 7" CRA completion string, complete with permanent packer and tubing retrievable sub surface safety valve, will be stung into the hanger of the ESS.

The presence of H_2S and CO_2 in the very dry gas stream requires corrosion resistant alloy steel to be utilised.

Following individual well completion, each well will be cleaned up using the drilling rig.

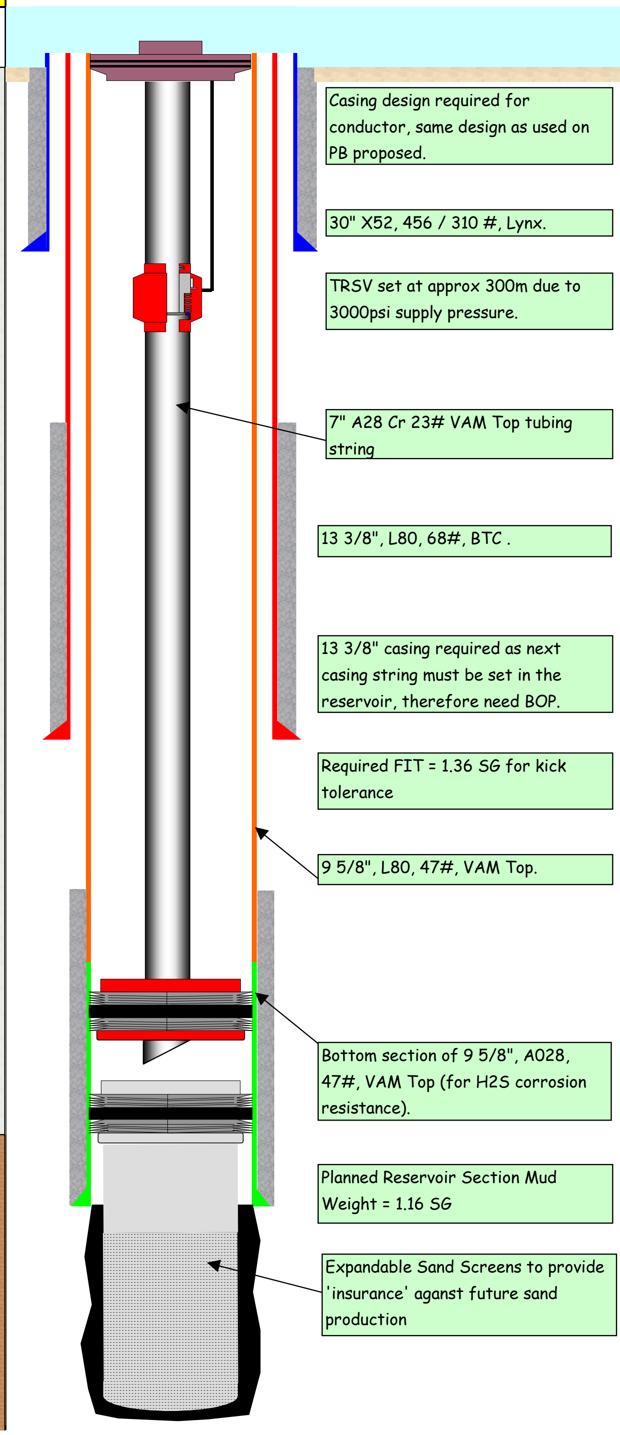
The proposed well/completion schematic is included as Figure 9.

Figure 9 Well Schematic

Sole 3 / 4 Well Design

Description	Measured Depth	True Vertical	Lithology
All depths ref. RT! (Assume 25m air gap)			
Sealevel (LAT)	25 m		
Seabed	148 m	148 m	
30 / 20" Shoe	184 m	184 m	Calcareous, bioclastic
TRSV	300m	300m	
TOC in 17 1/2" Annulus	310 m	310 m	
13 3/8" Casing Shoe	660 m	660 m	Very calcareous claystone (Marl), soft and plastic, may be sticky. CAC03 content >50%
TOC in 12 1/4" Annulus	310 m	310 m	
Production Packer			Becoming more argillaceous in nature, gamma ray values increasing, evidence of silt
Screen Hanger			
Top of Reservoir	769 m	769 m	
9 5/8" Casing Shoe	771 m	771 m	Sandstone, loose to friable, poorly sorted, highly porous
TD	784 m	784 m	

Comments



5.3.5 Workovers and Well Intervention

Routine well intervention is not planned through the production life of the field. The well design philosophy is to engineer out potential failure modes where possible.

Any well intervention will require either a drilling rig or other suitable vessel and will be dependent on the availability of such a vessel in the region.

5.3.6 Drilling and Completion Schedule

The drilling, completion and cleanup of Sole-3 and 4 is estimated to take 15 to 20 days per well.

The timing of the drilling and completion programme will be driven by both rig availability and the requirement to complete the wells prior to tie-in to the pipeline and umbilical control systems.

6 ENVIRONMENTAL, SAFETY AND SECURITY

6.1 Introduction

OMV AG adopts an integrated approach to the management of health, safety and environment. OMV AG has established a number of corporate Guiding Principles, setting out an ideal against which OMV Australia can measure ourselves, and against which we as a company would like to be measured. One of the Guiding Principles states that: "we are guided in our work by the responsibility for man, the environment, and technical advance".

OMV AG has also established HSE Guidelines to be used for the establishment of HSE management systems in OMV operated ventures. These Guidelines are designed to document OMV principles in health, safety and environment.

OMV Australia has established its own HSE Policy to implement the corporate HSE Guidelines and in line with local Safety and Environmental legislation. The HSE Policy is in Appendix I. To implement the HSE Policy, OMV Australia has developed a Health, Safety, Environmental and Quality Management System (HSEQMS). The HSEQMS is designed to ensure that the likelihood of people or the environment being adversely affected as a result of OMV Australia's activities is reduced to as low as reasonably practicable.

The various components of the system have been documented in the HSEQ Management System Manual (HSEQ-AU-00- 02-00) to facilitate their understanding and implementation.

6.2 HSE Management on the Sole Project

6.2.1 HSE Philosophy

The Sole project team is committed to the identification and assessment of HSE hazards relating to the construction, commissioning, operation and decommissioning of the onshore and offshore facilities associated with the Sole field development. The HSE risks will be managed to ALARP. OMV’s strategy is either to eliminate or mitigate HSE risks during design wherever possible and to deal with the residual risk during construction and/or operation.

OMV will ensure that:

- All potential environmental and safety hazards associated with the facilities are identified and assessed.
- Controls are put in place to ensure delivery of the project that will not cause unnecessary harm to the environment.
- Construction and commissioning work is undertaken in a safe and environmentally acceptable manner.
- A system of incident and emergency procedures and contingency plans are initiated for each stage of the project.

OMV will also ensure that all contractors to OMV are aware of applicable regulations as well as the conditions agreed with regulatory authorities in approving the commencement of construction and operational activities. Contractors will be audited to ensure that their operations are acceptable and that in carrying out their activities they fulfil the requirements of the project Health and Safety and Environmental Management Plans.

6.2.2 Environmental Management

OMV is committed to delivering the Sole project to meet the highest environmental standards expected by government and the community.

An Environmental Strategy Plan has been produced for the development phase of the Sole project and is a component of the Project Execution Plan (PEP). It references other documents and procedures produced under the PEP umbrella and is focused on establishing clear and concise actions, roles and responsibilities for the environmental scope of work for the Sole project. The plan builds upon the successful program implemented over the last three years for the Patricia Baleen Gas Development.

The principal objectives of the environmental strategy plan for the Sole project are to:

- Identify and obtain the necessary government approvals required
- Prepare and manage the schedule for the environmental work
- Identify internal and external resources requirements
- Identify scheduling, operational and information links with other work packages to enable optimal development and transfer of necessary information
- Prepare and manage a budget for the environmental execution of the Sole project
- Develop environmental objectives for the project and ensure that they are met throughout the design, construction, commissioning, operations and decommissioning phases of the project
- Identify management tools that will assist in the delivery of environmental objectives
- Define the strategy and methodology and technical competence to successfully complete the environmental work
- Define how the requirements of the OMV Company Standards will be implemented for the project

6.2.3 Safety Management

The main philosophy underlying safety planning for the Sole project is the adoption of "inherent safety in design" principles involving the identification and elimination of hazards at the earliest possible stage. In line with this philosophy, OMV has defined a set of Safety Goals and Safety Acceptance Criteria. The Safety Goals define the objectives, with respect to hazard minimisation and risk reduction, that the performance of an operating facility is measured against. Risk Acceptance Criteria define the level of risk to which an individual or group of individuals may be exposed to, which is either intolerable, broadly acceptable (negligible risk) or tolerable if reduced to as low as reasonably practicable.

Goals are designed to focus efforts during design, construction or operation in order to determine whether an installation is inherently safe. Safety goals also assist in the development of safety procedures and action plans. The five Safety Goals set by OMV are:

1 To Eliminate or Minimise the Hazards

2 To Prevent Realisation of the Hazard

3 To Prevent Escalation of an Accident Event

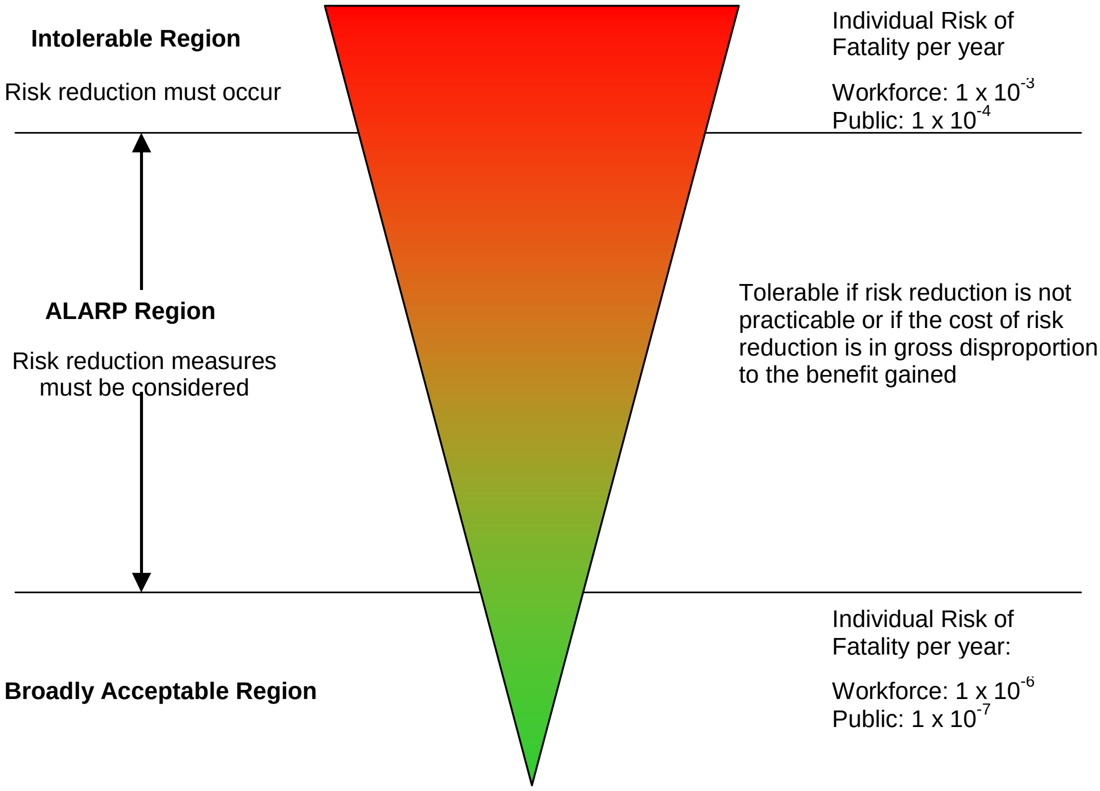
4 To Minimise Exposure of Personnel to Hazards

5 To Provide Effective Emergency Response

The Risk Acceptance Criteria for the project are:

1 Risk levels to workers may be presented in terms of Individual Risk Per Annum (IRPA). Figure 7.3.1 illustrates the OMV individual risk acceptance criteria for workers. Individual risk levels above 1 x 10^{-3} per year are deemed intolerable and must be reduced, irrespective of cost. Individual risk levels below 10^{-5} per year are broadly acceptable without further study. Risks that lie between 1 x 10^{-3} and 1 x 10^{-5} per year must be reduced to ALARP through modifications to the facilities and/or incorporation of safeguards into procedures.

Figure 10 Individual Risk Per Annum Acceptance Criteria



2. Risk criteria for public safety are in accordance with guidelines provided by the Victorian WorkCover Authority. The applicable criteria for the Sole project are those for new installations and are as follows:

The target individual risk of fatality is 10^{-5} per year at the plant boundary;

Individual risk of fatality must be below 10^{-7} per year in residential areas.

3. To demonstrate ALARP, additional risk reduction measures, above those already in place, must be identified and their "practicability" assessed.

During the pre-project phase of the development OMV Australia will undertake a number of safety studies to ensure that the chosen development option meets the stated safety goals. Previous studies completed for the Patricia Baleen development will be considered to determine the impact of the Sole project on the existing facility. These studies include:

- Comparative Risk Ranking of offshore development options;
- Comparative Risk Ranking of H_2S removal options;
- Preliminary Hazard Identification Workshops;
- Onshore Gas Plant Coarse Risk Assessment.

6.3 Regulatory Approvals

On the basis of experience gained in the development and approvals of the Patricia Baleen project, OMV has established a comprehensive work programme that complies with relevant legislation and is designed to deliver the required approvals for Sole in a timely manner for expeditious project development.

The final environmental approvals required and the processes under which they are obtained depend primarily upon governments' perception of the environmental significance of the project and project area.

The project as described was referred to the Commonwealth for a decision under the EPBC Act and was determined on February 25th 2003 not to be a controlled action. Therefore the Commonwealth Environment Minister is not required to approve the actions taken in relation to the development unless there is a departure from the proposed development concept.

On 4th April 2003 the Victorian Minister for Planning determined that the Sole project would undergo a Supplementary EES under the Victorian *Environment Effects Act* as part of the approvals process with jointly exhibited Planning Permit(s), Pipeline Permit and Works Approval applications. The EES was written as a supplement to the Patricia Baleen EES and was on public display for a period of four weeks. Fifteen submissions were received in relation to the project and were heard by an Independent Panel appointed by the Minister for Planning. The Panel will make a recommendation to the Minister who will then decide whether or not to approve the Planning applications and to advise the other decision Minister and the EPA whether or not to approve their applications.

Work is progressing towards production of other anticipated documentation requirements in relation to the Planning Permit, the Pipeline Permit, EPA works approvals and PB Pipeline Licence Variation. Native title consents have already been achieved for the project.

The principal regulatory requirements for the Sole development are associated with the requirements of the:

Petroleum (Submerged Lands) Act (Cth 1967 and Vic 1982)

Environment Effects Act (Vic)

Environment Protection Act (Vic)

Pipelines Act (Vic)

Planning and Environment Act (Vic)

Approvals under the PSLA and Pipelines Act will be administered by the Victorian Department of Primary Industries. Approvals under the Environment Protection Act will be administered by the Environment Protection Authority. Planning approvals will be given by the Minister for Planning under the 'call-in' provisions of the Act.

6.3.1 Safety Case

The existing Operations Safety Case (PB-HSE-GEN-PL04) created for the Patricia Baleen facility demonstrates that all hazards associated with the facility and with the potential for causing significant harm to people, the environment and assets have been identified, assessed and controlled. This Safety Case will be modified to incorporate the new offshore and onshore facilities associated with the Sole development. The objective will be to maintain a single Safety Case covering both the existing facility and any new development / additions to ensure that Safety Case principles are applied uniformly across the project and to provide a single reference document for use by the facilities' operator, whilst still satisfying the various legislative requirements.

Adequate time will be allowed for review and approval of the Safety Case and it will be developed with full and open consultation with all relevant parties. The updated Operational Safety Case and supporting documentation will be submitted to the Regulatory Authority - principally the DPI for the offshore and plant works and the Office of Gas Safety for the export pipeline matters.

Submission to the Regulatory Authority will effectively be achieved in three stages. The first stage will comprise this section of the submission and the available details for the onshore and offshore facilities descriptions. The stage 2 submission will correspond with the Pipeline Management Plan submissions to the DPI as required by legislation and will include:

- A more detailed facilities description including the critical operating parameters;
- Aspects of OMV Australia's and the contractors' Safety Management Systems controlling design, construction and installation activity; and
- A formal safety assessment to demonstrate that hazards are known and that the risks associated with them are understood and being effectively managed, such that the risks are As Low As Reasonably Practicable (ALARP).

It is anticipated that documents will be submitted to DPI as and when they become available and that issues arising will be discussed and resolved on an ongoing basis. Not withstanding this it is proposed that the formal Stage 2 documentation will be submitted to DPI approximately 1 month prior to the beginning of offshore construction.

The third stage of the process will be the compilation and submission of the updated "Operations Safety Case" for the facility. The Operations Safety Case will be submitted to the DPI and OGS and will comprise:

- Safety Case Overview;
- Facilities Description - providing a complete overview of the main systems, processes and equipment present at the facilities;
- HSE Management System - covering the way health, safety and the environment issues are managed at the facility;
- Formal Safety Assessment - incorporating comments from the DPI and OGS; and

- Remedial Action Plan – identifying further actions required and a schedule for implementation.

It is proposed that the formal Stage 3 documentation will be submitted to Regulatory Authority approximately 1 month prior to the beginning of production operations.

Offshore drilling activities will be conducted under a separate drilling rig Safety Case and bridging document.

7 PROJECT EXECUTION

7.1 Project Management

The project management approach for the engineering and construction phase of the Sole Gas development is founded on the maintenance of key members of the Patricia Baleen project team and structure. This is supported by other in-house groups (technical, commercial, legal, accounting, etc). Specialists on a part-time basis as required will supplement the team.

The team will be led by the Sole Project Manager, who is responsible for achievement of the overall project objective, which is to achieve start-up within the specified time frame and budget, to the required standards of operational efficiency, quality, safety and environmental care. Senior engineers, each typically having more than 20 years experience, will support the Sole Project Manager and take responsibility for sub-sections of the project such as development drilling, petroleum engineering, engineering and construction of surface facilities, project controls, and development of the Safety Case.

The primary role of the project management team is to:

- Consider alternative development schemes, nominate the most appropriate and upon approval, prepare and implement a plan that satisfies the project objectives.
- Coordinate the requirements of all contributing parties, including the Company, contractors, government agencies and the community.
- Identify and manage risks, and foresee and manage events that may threaten the project objectives.
- Provide sufficient flexibility to cater for changes in parameters, but implement change control on the development concept and design bases in accordance with agreed authorities.
- Ensure that information is available when required to those who require it to make timely decisions, give approvals and/or produce critical documentation.
- Avoid duplication of effort in reaching project objectives, but apply sufficient supervision to ensure that contractors meet quality and schedule objectives.
- Monitor and report on costs and progress.
- Ensure that those responsible for operation of the facilities are provided with sufficient information and access to ensure a smooth start-up and safe and efficient continuing operations.

A Project Execution Plan will provide a detailed explanation of project milestones and constraints, work breakdown structure, contracting strategy, risk management, regulatory requirements, project controls, quality management, industrial relations and preparation for operations. For information, the latest planning on these matters is given below.

7.2 Summary Schedule and Constraints

The target for "First Gas" is at the end of the 2nd quarter of 2006 (Figure 1). The key assumptions and constraints to achieve this date are:

- Final Investment Decision (FID) by all JV partners available 4th quarter 2004
- Onshore EPCM and Offshore EPIC contracts awarded immediately after FID
- Drilling campaign completed before offshore construction campaign commences in Q4/2005 or Q1 2006
- Commencement of commissioning 2nd Quarter 2006

Early (pre-FID) capital commitments are required to make fully tested Xmas trees and tree control systems available as early as possible for the start of the drilling campaign.

With the exception of the shore crossings for pipeline and umbilical, one offshore EPIC contractor will perform all of the offshore scope of the project. Upon mobilization, most likely from the North Sea, this contractor may be able to deliver the umbilical on the pipelay vessel for maximum synergy. This vessel will first lay the umbilical and subsequently install and pre-commission the offshore pipeline. Following the pipelay, trees, pipeline and umbilical will be tied-in for the pre-commissioning of the offshore control systems.

The engineering, procurement and construction schedule for the new onshore production facilities and the additions to the Patricia Baleen (PB) facilities is as demanding as the offshore program. The construction of the various new facilities and especially the tie-ins to the existing facilities need to be carefully scheduled into the planned PB shutdown and maintenance program.

7.3 Contracting Strategy

It is likely that the Project will be broken down into 3 main contracting areas (Figure 11) as follows:

Development wells

The scope of work is made up of engineering and procurement of the well tubulars and Xmas trees, the construction of two production wells and the installation of the trees.

OMV Australia will manage all aspects of the well construction programme including tendering and contract award. The drilling rig will also be used for installation of the Xmas Trees.

Offshore Facilities

The offshore facilities scope of work is made up of engineering, procurement and installation of the sub-sea umbilical and the offshore pipeline along with the associated tie-ins for both the umbilical and flowlines. This combined scope will most likely be completed with one EPIC contractor.

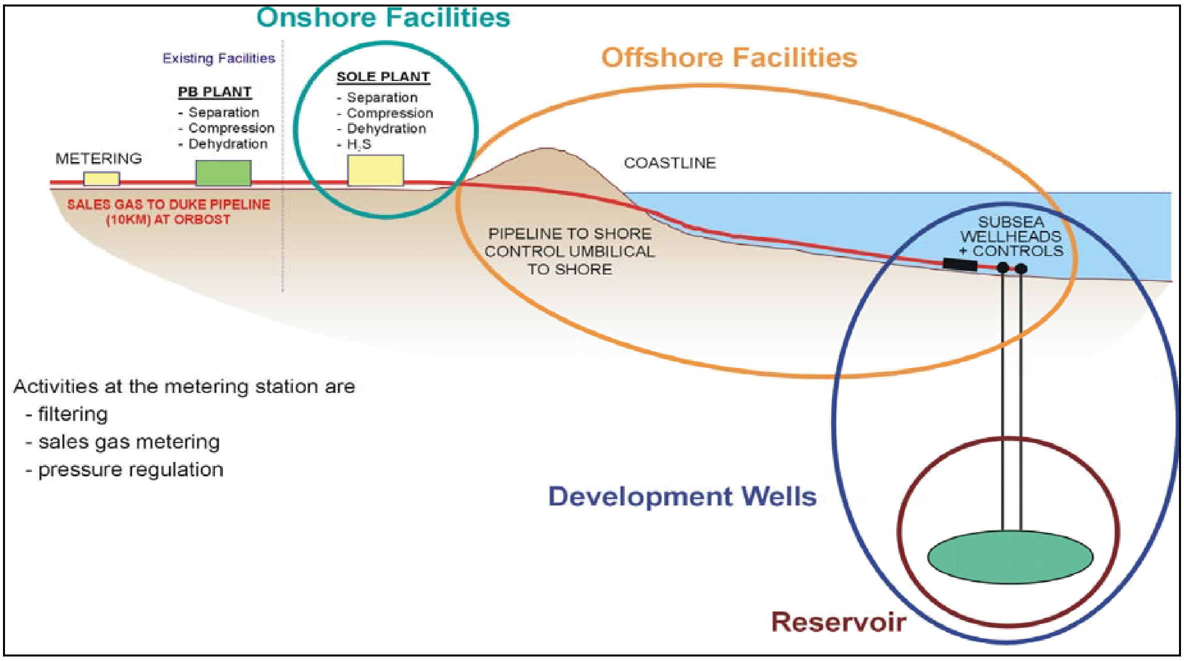
The design and construction of the shore crossing for the pipeline and umbilical will be managed as a separate contract within the offshore scope of work.

Onshore Facilities

The onshore scope is made up of the engineering, procurement and installation of an H_2S removal and recovery plant, additional compressors, produced water system, dehydration system and modifications/tie-ins to the existing Patricia Baleen plant.

The above contracting areas will be managed by the OMV Project Team.

Figure 11 Contracting Strategy



<u>Governing Principles</u>

The key philosophies governing the contracting strategy are risk minimisation, cost effectiveness and schedule optimisation. They include the following considerations:

- Use of only relevantly experienced, pre-qualified specialist Contractors
- Programming of the work to maximise the use of specialised Contractors already mobilised in the area
- Packaging of the work to minimise interfaces

A competitive tender process will be carried out for the pipeline and umbilical installation spreads, covering both main options for pipelay, i.e., the conventional stovepipe method of pipelay using a 3rd generation derrick/pipelay spread, or a dynamically positioned reel lay vessel.

Detail design of the pipeline, and construction engineering for the installation method, will be carried out by the selected contractor.

For the new onshore facilities, an EPCM contractor will be used to provide the Engineering, Procurement and Construction Management for the onshore plant expansion work to achieve a pre-commissioned facility warranted to satisfy specified performance requirements.

All development and installation work will be competitively tendered to appropriately qualified organisations locally, nationally and internationally. Full and fair opportunity will be given to local industry to participate where the local company can demonstrate satisfactory financial robustness, quality, environmental and safety management systems and the capability to meet the schedule requirements of the project.

The existing PB operations and maintenance contractor will carry out commissioning of the facilities.

7.4 Quality Management

The Sole Project Quality Plan (PQP) will conform to the requirements of ISO 9000, without necessarily seeking formal certification. The plan must cover Project Management, Engineering, Procurement, Construction, Commissioning and address the following aspects of each;

- Organisation, roles & responsibilities, delegation of authority.
- Standards & Specifications
- Control Procedures
- Inspection & Testing requirements
- Certification plan and procedures.
- Documentation Control
- Audit & Review

Project Health & Safety Management Plan (HS Plan) and a project Environment Management Plan (EMP) will define the method on which the HSE management systems will be applied to the project and how they are integrated with the PQP. The Sole Project H&S and Environment Management Plans will cover all safety and environmental issues in Project Management, Design, Procurement, Construction and Commissioning and will include in general:

- Organisation, roles & responsibilities
- Summary of Hazards
- Legal Requirements, standards & specifications
- Identification of critical activities
- H&S and E&C management plan & performance targets
- Project Safety Reviews
- Objectives, scope & timing of audit & reviews.

In particular, the HSE plans will address;

- Hazard Identification and analysis (Hazid/Hazan)
- Hazard & Risk Management strategies, including elimination, mitigation & control
- Consequence analysis
- Risk Assessment
- Contingency Planning
- Reviews of Hazops, Fire Plans
- Layouts & technical safety reviews
- Interface with contractor and supplier H&S and E&C management systems.

7.5 Industrial Relations

OMV will develop an over-arching IR strategy. The strategy will build on agreements established during the Patricia Baleen project phase and set the framework for OMVs direct interaction with unions.

All construction contractors will develop an Employee Relations Management Plan and name an IR advisor or industry body, both of which will be approved and audited by OMV.

In all construction contracts, the contractor will take responsibility for employee relations within its own workforce. To avoid disruption to the project the Company will apply the following guidelines:

- Contractors' track record in industrial relations will be considered as part of the evaluation of bids.
- Major contractors will be encouraged to maintain membership of one of the recognised industry associations. Rates of pay and other working conditions should follow existing precedents wherever possible.
- The workforces of different contractors will be separated as far as practicable, to avoid disputes arising from differences in working conditions, and to avoid contractors being able to attribute their own problems to other contractors and thus to the Company.
- Contractors will be required to maintain effective safety policies and procedures so that safety disputes do not arise.

7.6 Cost Control and Forecasting

A cost control system will be established to develop a realistic project estimate as a basis for approval of the project budget and Authorisations for Expenditure (AFEs).

- Track commitments against budget elements to provide an ongoing forecast of completion costs.
- Accommodate, record and manage any project scope changes.
- Forecast cash flows for administration of cash calls to enable timely payments.
- Enable allocation of costs against assets.
- Provide audit ability of records and cost data.
- Control of variation claims.

7.7 Planning and Scheduling

The objectives of the planning and scheduling system are to:

- Provide a realistic project schedule for setting timely performance goals.
- Define and schedule major project approvals that can constrain the first gas date.
- Identify and report physical progress (overall 'S' curve and critical path).
- Identify suitable weather windows for the project.
- Control contractors' claims for extensions of time and variations
- Provide flexibility in accommodating project scope changes.

8 OPERATIONS AND MAINTENANCE (O & M)

The plan for operating and maintaining the facilities is integral to a successful development. The O&M approach has a large influence upon the design of the facilities requirements and yearly operating costs. For the Sole development, the O & M approach will be extended from and integrated with the existing PB approach.

8.1 Operations and Maintenance Approach

The intent is to extend the PB operations and maintenance (O&M) programme that is designed to ensure safe, reliable, cost effective operations and environmentally responsible operations. The PB operations and maintenance (O&M) programme will be modified to incorporate operating and maintenance requirements for the hydrogen sulphide (H_2S) in the Sole feed gas.

The O&M contractor will provide sufficient resources and staff within its organization to perform most of the normal day-to-day needs of the operation initially. The contractor will be committed to recruiting and training local personnel for ongoing operations and maintenance of the facilities. For peak requirements, such as campaign maintenance programs, these resources can be supplemented from the O&M contractor's national resource pool on an as needed basis. For highly specialized and/or labor intensive procedures such as plant shutdown and inspection, pigging, drilling and well intervention activities, specialist contactors will be utilized as required.

The maintenance of the Sole production facilities will be by a specialist contractor under a service contract for the supply of operating and maintenance services. The specialist contractor will be required to have a track record in the operations and maintenance of both onshore and offshore hydrocarbon facilities. The incumbent Patricia Baleen plant operator will also operate and maintain the Sole production facilities.

The O&M contractor shall manage the day-to-day operations and maintenance activities of the onshore gas processing, the onshore pipelines and the offshore pipeline and wells. The contractor shall be responsible for the operations of the subsea production facilities with the exception of activities requiring well intervention or drilling.

All offshore maintenance associated with the subsea facilities will be managed by OMV Australia. The gas metering facility will be operated and maintained by OMV Australia or Duke Energy International (under contract to OMV).

OMV Australia will maintain ongoing engineering and production support for the offshore facilities, reservoir and geology in the most cost effective manner.

Maintenance will be carried out on a campaign basis, at planned intervals, using experienced contract O&M personnel. Inspection of pressure vessels and recertification of safety valves will be included in the planned maintenance activities. The sales gas compressors are anticipated to require the most maintenance effort. These will be serviced in accordance with the manufacturers recommendations.

Inspection, testing and monitoring programs will be implemented to monitor the efficiency of protection systems and plant integrity. Corrosion and erosion monitoring will be provided by a combination of methods, including corrosion probes, corrosion coupons, ultrasonic thickness testing and regular fluid sampling. A risk based inspection approach, which considers the consequences and probability of failure, will be adopted to focus inspection resources and provide an increased level of inspection for higher risk plant and equipment items. Inspection, testing and monitoring will be managed by OMV Australia and performed by the O&M contractor and/or specialist inspection contractors. OMV Australia will optimise protection systems (eg. corrosion inhibitor injection) and the inspection, testing and monitoring based on the results of the programs implemented.

Equipment sparing and redundancy will be provided to meet a high level of plant availability.

Online H_2S, moisture and sales gas composition analysers will be provided to monitor sales gas quality and shut-in production if sales gas specifications are not met.

Hydrate formation in the offshore pipeline will be prevented by operating outside normal hydrate formation conditions and injecting hydrate inhibitor during brief periods of low seabed temperature.

8.2 Onshore plant

The predominant activities are centred on the day-to-day operations and maintenance of the facilities. The following functions are envisaged:

- Onshore plant operation and maintenance
- Pipeline operation / maintenance and pigging as required
- Pipeline repair response
- Gas sales metering
- Co-ordination of all offshore activities (when they occur)
- Facilities routine and predictive maintenance
- Facilities repair
- Co-ordination of vendors to support warranty maintenance as required
- Data gathering
- Sales gas quality monitoring
- Safety and environmental management.
- Sulphur by-product and waste disposal.

Onshore operations will be responsible for logistics management including co-ordination of maintenance activities, control of operational and maintenance spares, warehousing, procurement and so forth.

The onshore contract operator shall be committed to supporting a sound health, safety and environmental approach to work and providing ongoing training for all operational activities. Continuous monitoring of quality, safety and environmental performance shall be a key performance indicator in the ongoing management of the facilities.

The manning requirements for the onshore facilities will be determined and agreed in consultation with the O&M contractor. After the Sole facilities are installed and operational it is anticipated that three operators will man the combined plant 24 hours a day, seven days a week on a 12 hour back to back shift basis, with a plant supervisor present during day shift, at least five days a week. Additional maintenance resources can be called up as required. After the first few years of initial operation the strategy may be reviewed to determine if it is possible to reduce manning levels.

8.3 Offshore Facilities

8.3.1 Offshore Control System

A VDU, located in the PB onshore control room next to the onshore display panel, will allow convenient operation of the Sole offshore facilities by the onshore operators. It is unlikely that additional resources will be required routinely to operate and maintain the offshore subsea pipeline and facilities. The predominant day-to-day activities will be centred around:

- Control of the offshore wells via an umbilical containing the power, hydraulic and signal cables
- Adjustment of the choke valves via position indicators
- Corrosion inhibitor injection either into each well stream or into the pipeline inlet
- Injection of hydrate inhibitor
- Maintenance of the chemical injection skid and the hydraulic and electric power unit located within the PB onshore gas plant
- Pipeline operation
- Pipeline maintenance and pigging as required
- Pipeline repair response
- Data gathering

8.3.2 Well Intervention

Whilst Sole well intervention is unplanned, any operation or maintenance activity, including workovers and drilling will be managed by OMV.

The head office, based in Perth, will coordinate, manage and execute all well intervention activities through its full time Drilling Manager and team of specialised staff. Where required external resources will be contracted in to assist in design, construction or job execution programmes as required.