PATRICIA 2

DRILLING PROGRAM

&

COMPLETION AND TESTING PROGRAM

OMV Australia Pty Ltd

OMV Timor Sea Pty Ltd
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915144 002

OPS02-046

Petroleum Regulation Unit
Correspondence No: 1415
Audit Reference: —
Incident: Reference: —
Recfind No: PE/17/0503/1
Initials: K. Siu 7/5/02

2 May 2002

Mr Robert King
Department of Natural Resources and Environment
240 Victoria Parade
EAST MELBOURNE VIC 3002
Fax: 03 9412 4803

Dear Mr King

Application to Drill Patricia 2

Please find enclosed the following documentation to support the Application to Drill for the Patricia 2 Well in VIC/L21:

- Patricia 2 Drilling Program

The other documents in support of this application, namely;

- VIC/L21 Emergency Response Plan
- VIC/L21 Oilspill Contingency Plan
- VIC/L21 Safety Case Bridging Document
- Environment Plan for the Drilling of Baleen 3 & Patricia 2 in VIC/L21

Have been previously submitted with the application to drill Baleen 3 dated 11th April 2002. Following discussion with NRE personnel, updates to the Environment plan were submitted on 26th April 2002.

In compliance with the Application to Drill outlined in Clause 501 of the Petroleum (Submerged Lands) Acts Schedule – Specific Requirements as to Offshore Petroleum Exploration and Production, the required information has been provided or referenced below.

a)	Well Name:	Patricia 2
b)	Location: Water Depth:	38° 01' 39.97"S 148° 26' 57.83"E Easting 627 209 Northing 5 790 098 UTM Zone 51 Spheroid ANS Datum: AGD66 51 m MSL
c)	Programmed Depth	1,397 mMDRT / 710 TVDRT
d)	Estimated Spud Date	6th June 2002
e)	Estimated Drilling Time	22 days
f)	Attendant Craft	Pacific Sentinel Pacific Conqueror
g)	Drilling Contractor	Diamond Offshore General Company Level 9, 225 St George's Terrace Perth, WA 6000
h)	Drilling Unit	"Ocean Bounty" Semi-submersible (Enhanced Victory Class Crucifix Form Column Stabilised Semi) rated to 7,620 m with 5" drill pipe, maximum water depth 456 m. BOP equipment detailed in the Patricia 2 Drilling Program.
i)	Service Contractors	Detailed in the VIC/L21 Emergency Response Plan
j)	Well Design and Construction Details	Included in the Patricia 2 Drilling and Program
k)	OMV Contact	The person responsible for communications with the VIC/DRNE will be: Graham Dwyer Operations Manager Ph: (08) 9223 5013 Fax: (08) 9223 5004 Email: graham.dwyer@omv.com.au
l)	Proposed Well Path	Patricia 2 will be a horizontal well as Detailed in the Patricia 2 Drilling Programme
m)	Drilling Procedures	Drilling Procedures are outlined in the Patricia 2 Drilling Program. The Ocean General Operating Manual and the Ocean General Safety Case cover detailed work procedures for drilling operations.
n)	Geological Prognosis and Objectives	Detailed in the Patricia 2 Drilling and Geological Program
o)	Pollution Control Measures	Detailed in the VIC/L21 Oil Spill Contingency Plan.

In anticipation of your approval.

Yours sincerely

Graham Dwyer
Operations Manager
For and on behalf of OMV Timor Sea Pty Ltd
ABN 70 064 126 138

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OMV Australia

Basin Oil Ltd
(ACN 36 000 628 017)
A wholly owned subsidiary of OMV Australia Pty Ltd
Level 29, 44 St Georges Terrace
Perth WA 6000

AUSTRALIA
GIPPSLAND SUB-BASIN
VIC/L21

PATRICIA - 2

Drilling Program

April 2002

Prepared: ____________________
Steve Crocker – Drilling Engineer

Prepared: ____________________
Mark Adamson – Operations Geologist

Prepared: ____________________
Andy Ion – Senior Reservoir Engineer

Reviewed: ____________________
Ron King – Drilling Superintendent

Approved: ____________________
Colin Allport – Drilling Manager

Approved: ____________________
Graham Dwyer – Operations Manager

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Document Title: **Patricia - 2 Drilling Program**

Copy No:

Signed: ______________________ Date: ______________

Print Name: ______________________ Organisation: ______________

Please return this acknowledgement to:

Colin Allport
Drilling Manager
OMV Australia Pty Ltd
Fax: +61 8 9223 5009

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1.0 GENERAL

1.1 Summary Data

Well:	Patricia - 2	
Permit:	VIC/ L21	
Block Equity Percentage:	Trinity Gas Resources	40%
	Basin Oil Pty Ltd	35% (Operator)
	Santos Ltd	20%
	OMV Timor Sea P/L	5%
Target formation:	Gurnard Formation sandstones	
Type of Well:	Horizontal Field Development	
Seismic Line:	Surface/Rig:	Inline 403, Xline 3688
	Heel target :	Inline 409, Xline 3634
	Toe target:	Inline 417, Xline 3552
	(Baleen 3D 2000)	
Location:	Toe Target:	Heel Target:
	Easting: 626 529	Easting: 626 935
UTM: Zone 55S	Northing: 5 789 558	Northing: 5 789 880
Spheroid: ANS	Surface/Rig:	
Datum: AGD66	38° 01' 39.97"S	
	148° 26' 57.83"E	
	Easting: 627 209 E	
	Northing: 5 790 098 N	
Rig Location Tolerance:	5m radius of surface location	
Target Location Tolerance:	Within 5m vertical and 50m horizontal target box	
Proposed Total Depth/ Target Depth:	1397m MDRT/ 710m TVDRT	
Water Depth:	~51m	
Estimated Time to Drill:	22 days	
Anticipated Spud Date:	May 2002	
Drilling Contractor:	Diamond Offshore General Co	
Drilling Unit:	Ocean Bounty	
RT above sea level:	25m	
Planned Rig Heading:	257°	
Operator Personnel on Site:	Drilling Supervisor / Night Supervisor /Geologist	
Summary	The Patricia - 2 horizontal development well is located crestally within the Patricia gas accumulation. The planned 500m production interval has been designed to optimally drain gas during the field production life.	

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1.2 Purpose and Objectives

The purpose of the Patricia - 2 well is to:

- Optimally drain gas from the Patricia gas reservoir.

The objectives of the Patricia - 2 well are to:

- Confirm the reservoir structure and internal architecture as modelled
- Provide wellbore access to the Patricia gas reservoir with both formation damage and risk of sand production minimized.
- Obtain complete open hole log information throughout reservoir interval
- Estimate initial reservoir pressure prior to commencement of production
- Determine well deliverability/inflow performance from multi-rate testing
- Determine rate-dependent wellbore skin factor from multi-rate testing
- Acquire flowing/static pressure data to optimise wellbore hydraulic model
- Obtain representative reservoir gas samples

1.3 Location and Transport

Patricia - 2 is located in VIC/ L21 approximately 140NM from Port Welshpool and 285NM from Geelong with one way sailing times of 12 and 25 hours respectively. Crew changes will take place out of Essendon by helicopter via Sale to the rig.

1.4 Elevation, Datum and Water Depth

Datum for all vertical measurements will be Lowest Astronomical Tide (LAT). The water depth at location will be confirmed when the 36" BHA is set on the seabed prior to spud. The Ocean Bounty has a rotary table elevation above sea level of ~25m and all depths will be reported in metres below the rotary table (mRT) corrected for tide and referenced to LAT. (MSL ~0.6m above LAT)

1.5 Rig Sequence and Operational Procedures

The Ocean Bounty will be towed from the previous location to the Patricia - 2 location in VIC/ L21.

Well construction design and operational procedures will be conducted in accordance with the following documents:

Application to Drill Patricia - 2

Patricia - 2 Drilling Program

Patricia - 2 Completion Program

OMV Offshore Drilling Operations Guidelines

Diamond Offshore Drilling Operations Manual

Diamond Offshore Well Control Procedures

Diamond Offshore Ocean Bounty Vessel Safety Case

OMV HSE Management System Guidelines

OMV Emergency Response Management manual

OMV Location Specific Oil Spill Contingency Plan

1.6 Regulations

Drilling operations will be conducted under the following:

Petroleum (Submerged Lands) Act 1967

Petroleum (Submerged Lands) Regulations 1985

Petroleum (Submerged Lands) (Management of Safety On Offshore Facilities) Regulations 1996

Petroleum (Submerged Lands) (Management of Environment) Regulations 1999

Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production (1995) (November 1999 Electronic Consolidation).

In addition to the legislation above, environmental aspects of the well will comply with:

Environmental Protection and Biodiversity Conservation Act 1999

Environmental Protection and Biodiversity Conservation Regulations 2000

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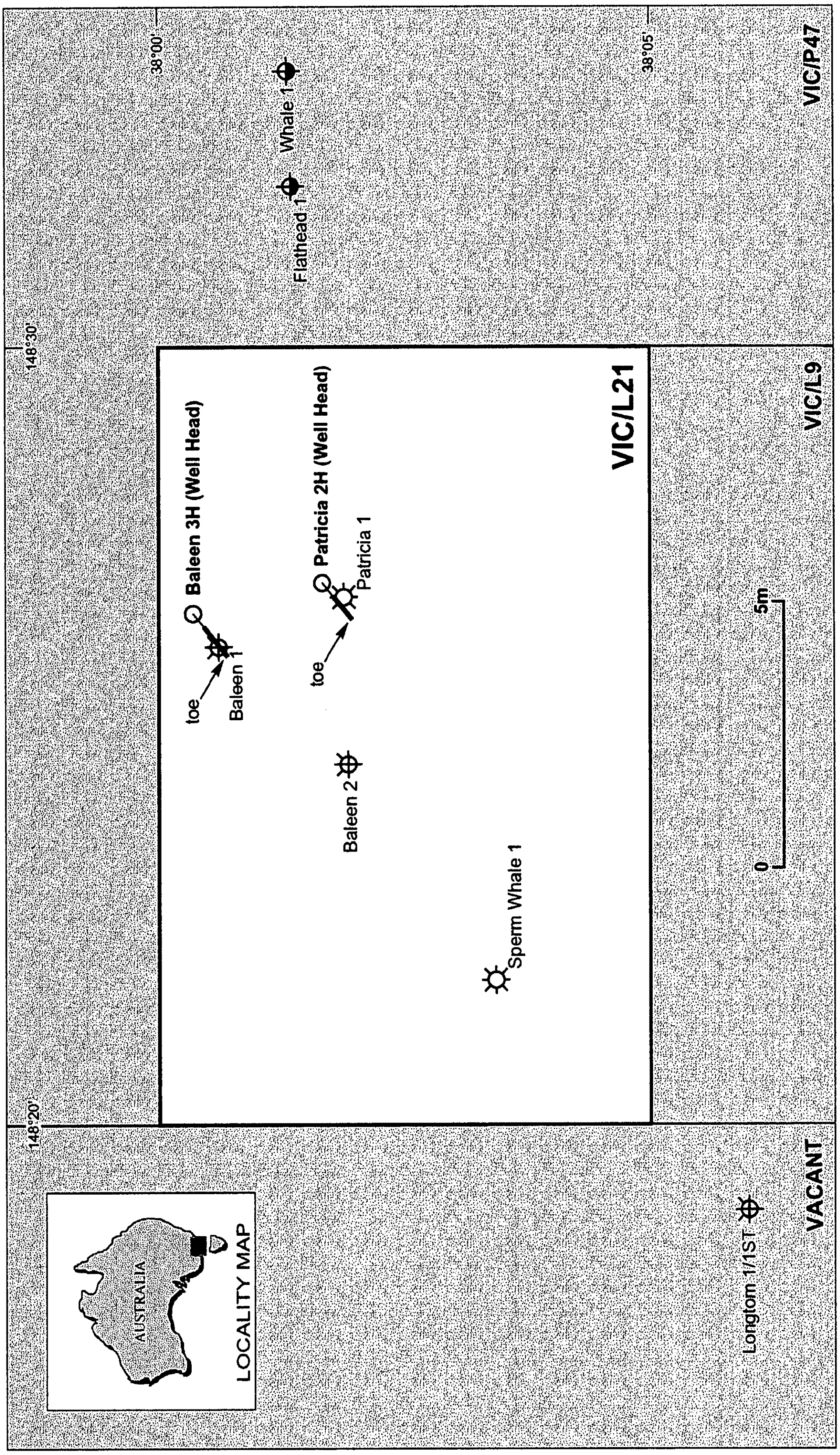
2.0 FIGURES

2.1 Location Map



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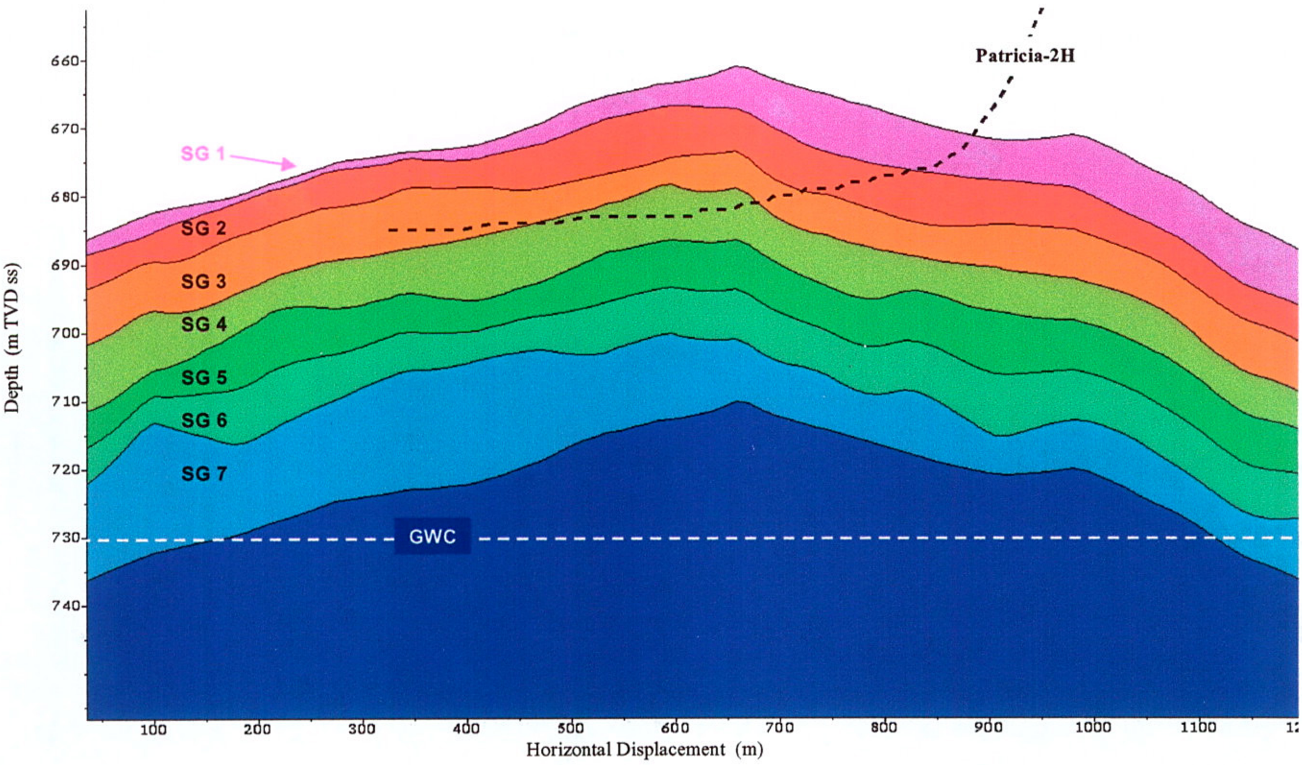
2.2 Cross section through Target Location



Stratigraphic Horizon	*Depth (m TVD MSL)*	*Depth (m MD RT)*
Top Lakes Entrance	611.0	682.2
Top Gurnard	671.7	834.9
Top Subgrid 2 (Top Porosity)	676.5	890.0
Top Subgrid 3	679.5	990.0
Top Subgrid 4 (down)	681.0	1040.0
Top Subgrid 5	N/I	N/I
Top Subgrid 6	N/I	N/I
Top Subgrid 7	N/I	N/I
Top Subgrid 6	N/I	N/I
Top Subgrid 5	N/I	N/I
Top Subgrid 4 (up)	683.7	1240.0
Top Subgrid 3	N/I	N/I
Top Subgrid 2	N/I	N/I
Top Gurnard	N/I	N/I
Total Depth	685.0	1396.5

Note: N/I = not intersected

2.3 Seismic and Inversion Lines through Target Location

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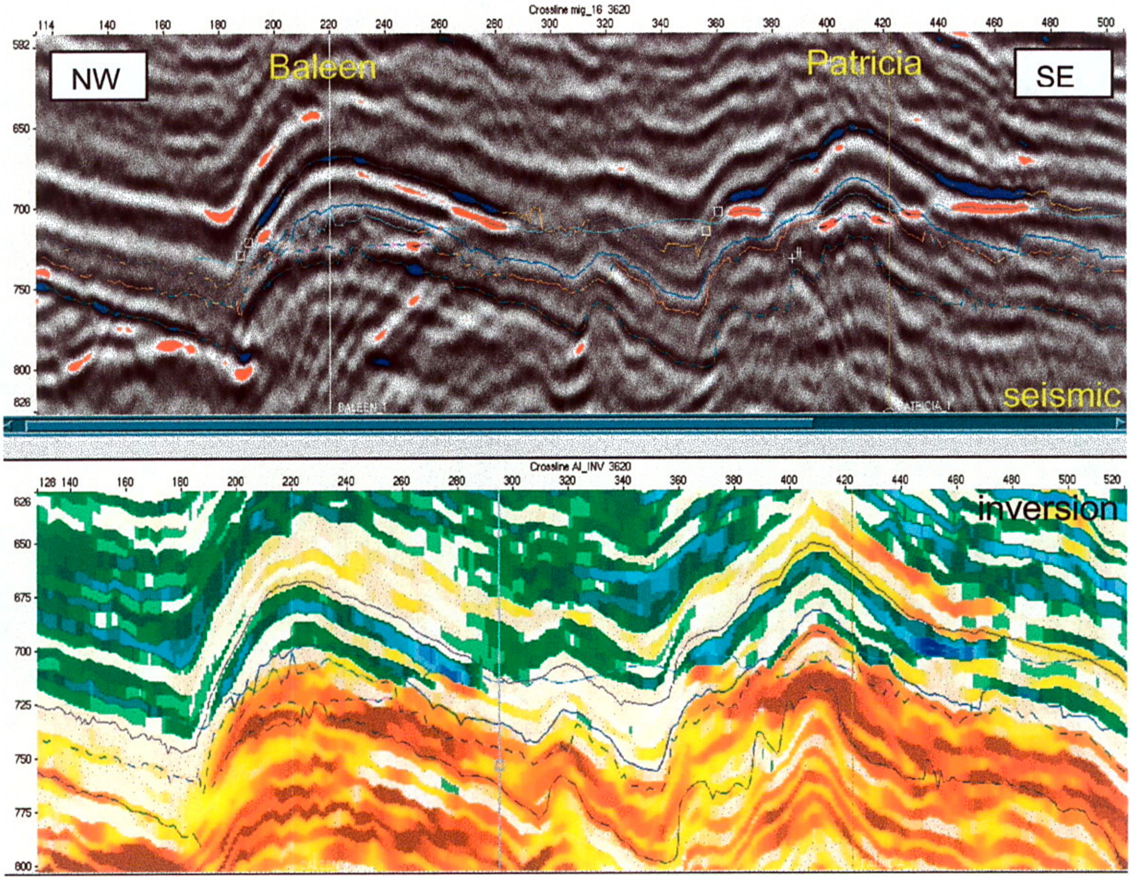

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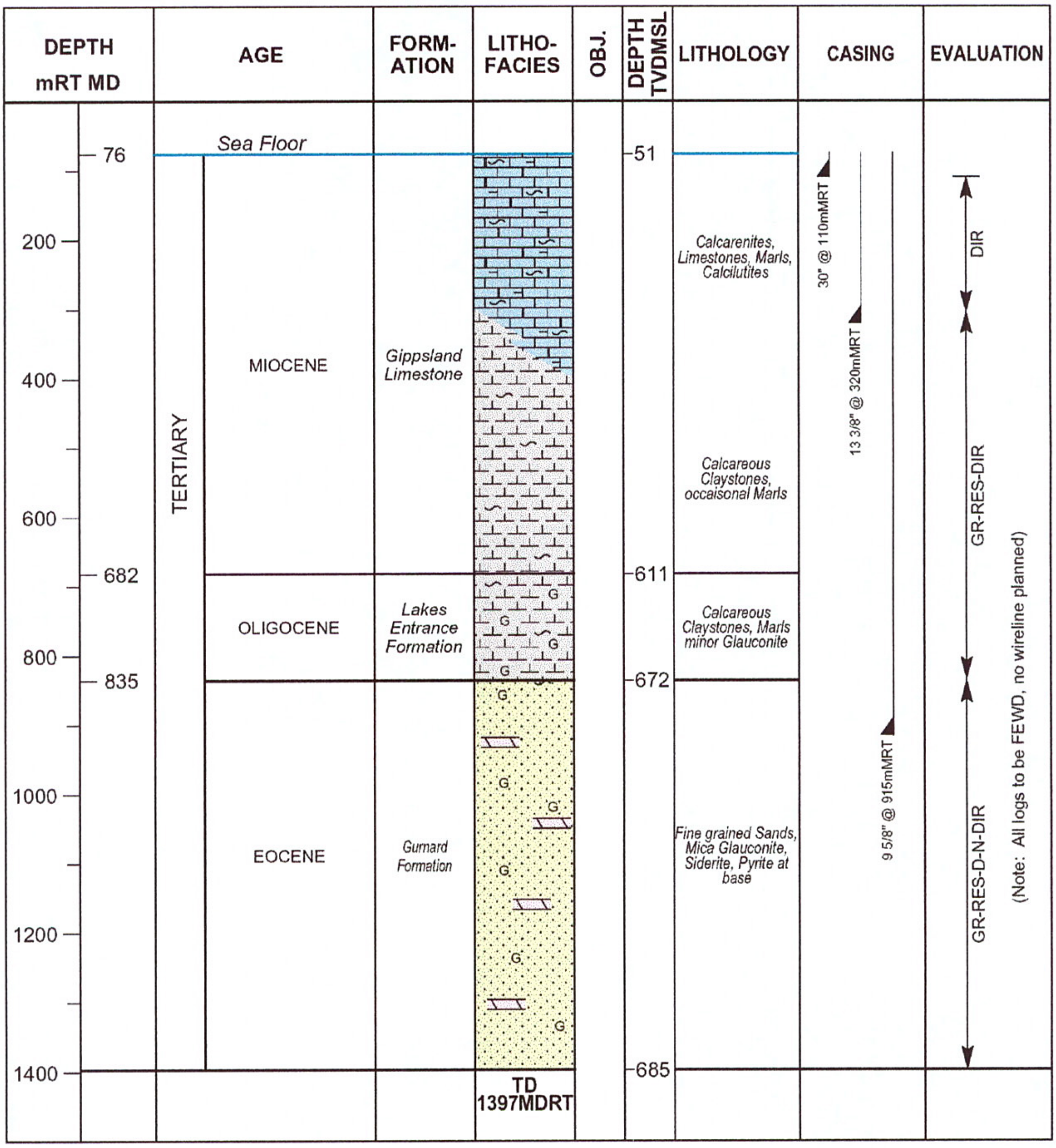
2.4 Summary: Geological Section and Evaluation



2.5 Top Gurnard Fm Depth Structure Map

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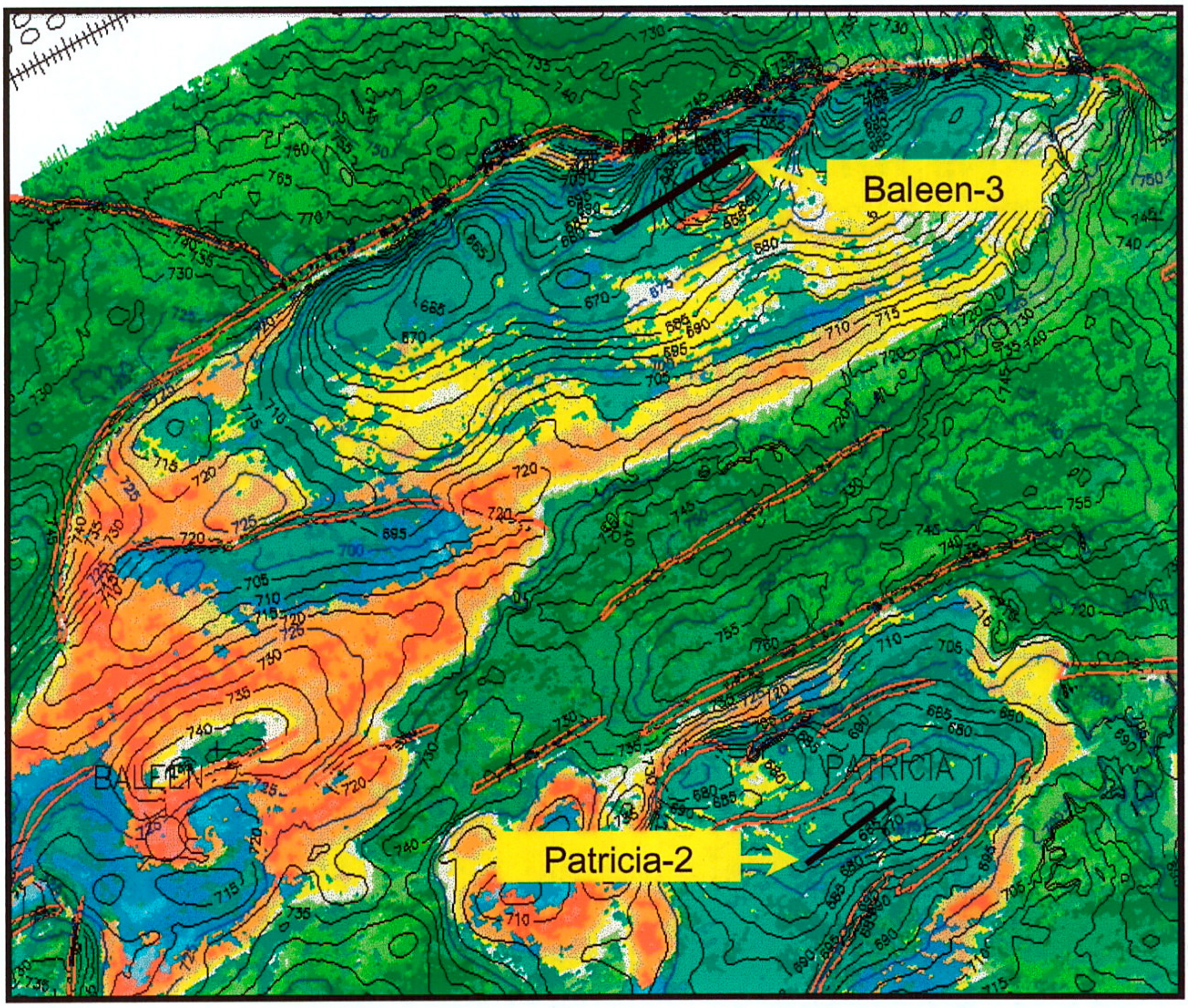

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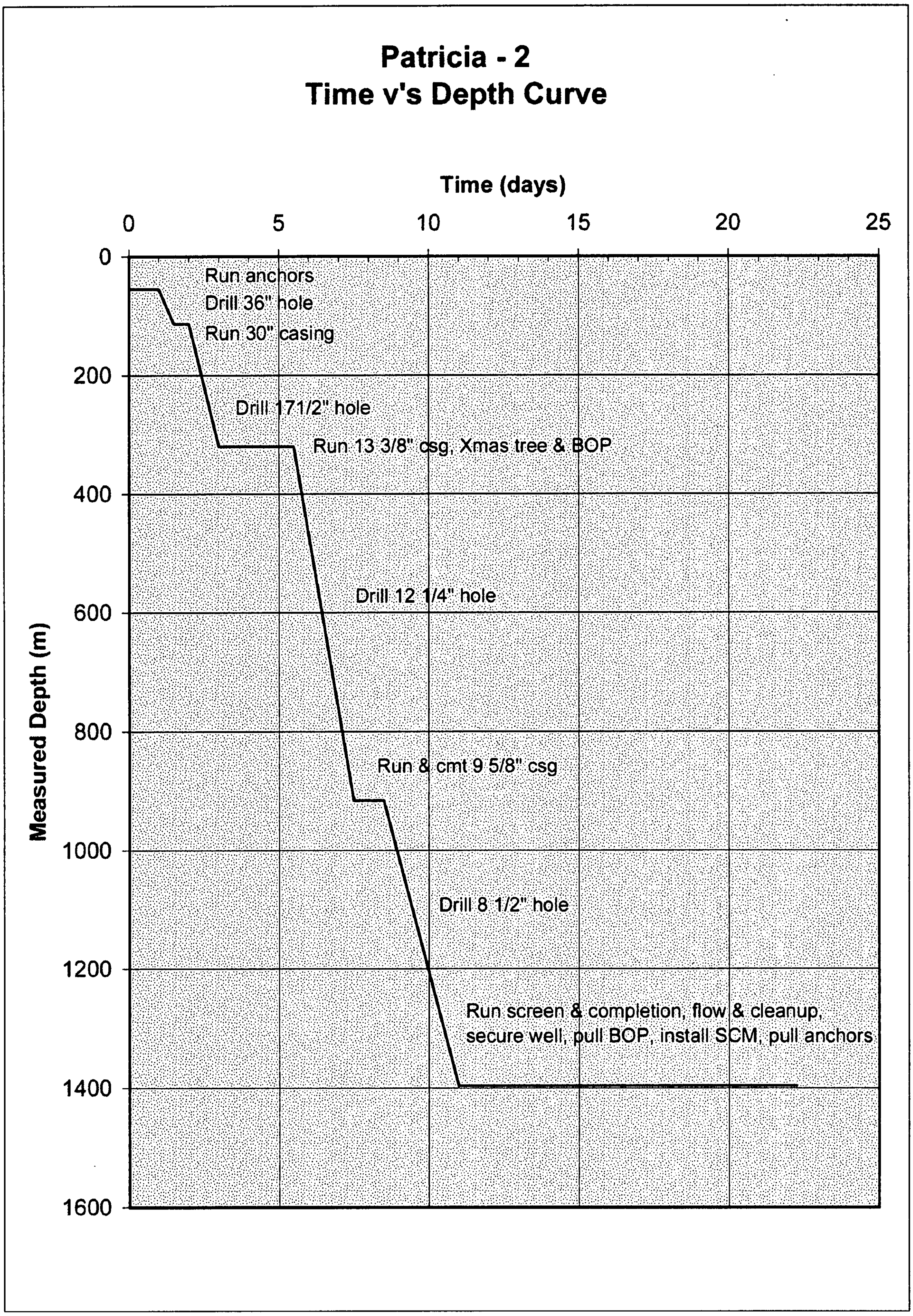
2.6 Predicted Time/Depth Curve



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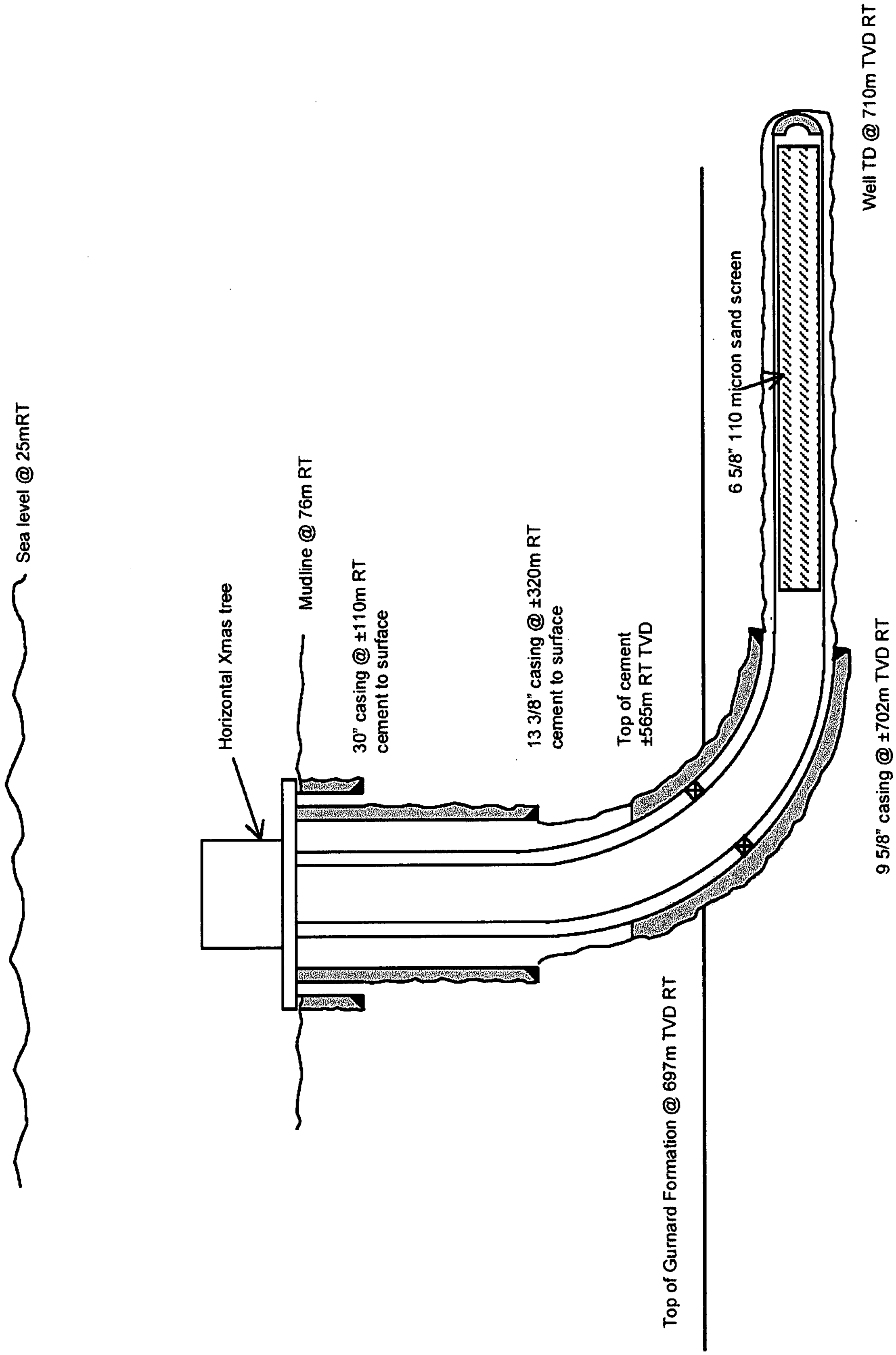
2.7 Well Completion Schematic



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3.0 GEOLOGY

3.1 Geological Prognosis

SYSTEM	STAGE	BIOZONE	FORMATION	LITHOLOGY	DEPTH mTVDSS	DEPTH mMDRT
Tertiary	Early Miocene	Middle to Upper *P. tuberculatus (Operculodinium Superzone)*	Gippsland Limestone	Calcilutite becoming interbedded with calcareous claystone at the base	(seabed) 51m	76m
Tertiary	Late Oligocene	Middle to Upper *P. tuberculatus (Operculodinium Superzone)*	Lakes Entrance Formation	Interbedded calcareous claystone and calcarenite	611m	682m
Tertiary	(Late) Middle Eocene	Lower *N asperus (D.heterophlcta)*	LATROBE GROUP Gurnard Formation	Dominantly silty sandstone interbedded with sandy siltstone and claystone interspersed with 1 – 2m siderite cemented zones	672 to 685	835 - 1397
Tertiary	Late Paleocene	Upper *L.balmei*	LATROBE GROUP Coarse Clastics	Clean sandstone with thin claystone and siltstone interbeds	Not penetrated (720)	Not penetrated
Early Cretaceous	Late Albian	Upper *C. paradoxa*	STRZELECKI GROUP	Claystone grading to silty sandstone	Not penetrated (775)	Not penetrated

The prognosis is based on depths calculated from mean sea level (MSL) as this is the datum for the seismic survey information. MSL is approximately 0.6 metres above Lowest Astronomical Tide (LAT).

The Latrobe Group Coarse Clastics and the Strzelecki Group are not expected to be intersected in the well. Due to the potential presence of H_2S within the Latrobe Formation the upper/lower hard depth limits around the proposed well trajectory are set to ensure that the Latrobe is not penetrated. The depths to these units are given for information only.

3.2 Anticipated Stratigraphy

Patricia - 2 is predicted to intersect a Tertiary sedimentary section ranging in age from Early Miocene to Middle Eocene. A brief summary of the predicted stratigraphy is given below.

The section to be penetrated is expected to be the same as that encountered at the nearby Baleen – 1, Baleen – 2 wells and particularly the adjacent Patricia-1 well.

Gippsland Limestone Miocene

Fine grained marine carbonates, which gradually coarsen upward from calcareous claystones and marl through cacilutite to calcarenites. The sequence contains variable amounts of diverse species of foraminifera and skeletal metazoa. GR, density and sonic logs from Patricia-1 suggest the section is quite interbedded at a scale of 2m to 5m. Generally the hole condition is good with only small amounts of hole enlargement except over the section from 200mSS to 265mSS which may have been due to multiple trips through this section with the BHA. The resistivity of the formation reflects the bedded nature of the unit and generally varies between 1 and 6 ohm-m.

The calcarenites in the upper part of the formation are light olive grey, soft to friable, fine to medium grained, poorly sorted, with 5%-20% micrite, 0%-5% clay. There are traces of pyrite, glauconite, quartz and dolomite grains, porosity is nil to fair. The middle part of the formation is characterised by calcisiltites, which are grey to dark grey, firm to hard, common very fine to fine grained fossil fragments, 10%-30% micrite, 10%-30% clay, is matrix supported and has nil visual porosity. The lower part of the formation is dominated by calcisiltites as above interbedded with grey calcareous claystones. The claystones are dark grey, firm to hard, with occasional traces of pyrite and glauconite.

Lakes Entrance Formation Oligocene to Early Miocene

The dominant lithology is calcareous claystone with some lesser marls and calcilulites. The increasing abundance and persistence of glauconite help to differentiate it from the overlying formation. The upper boundary is marked by an increase in the GR and clay content. There is a gradual (over 20-30m) decrease in calcimetry from approximately 60% to 30% $CaCO_3$ across the upper boundary. The GR increases by approx. 10-15 GAPI units compared to the overlying Gippsland Limestone. The resistivity character also changes and is fairly uniform between 1.5 and 2.0 ohm-m for the upper 25m-30m.

The claystones in the upper part of the formation are medium-grey, calcareous with 10%-30% micrite, trace to 10% calcite silt, trace to 40% glauconite increasing with depth, abundant fossil fragments and traces of pyrite. There are also traces to common siderite nodules and composites.

The lower part of the formation which is defined at its top by a GR peak of 120 GAPI (662mSS in Patricia-1) and an average value of 90 GAPI has a thickness of 12m in Patricia-1. This is slightly thinner than the intersection at Baleen-1 where it was 16m. This lower section of the formation is also marked by a resistivity increase at the depth of the GR peak and it remains fairly constant between 2.0 and 3.0 ohm-m. These resistivity values are slightly higher than at Baleen-1 where the section has resistivity between 1.5 and 2 ohm-m. The base of the Formation is marked by an increase in resistivity and density, which are due to a combination of the proximity of a gas filled reservoir and a zone of heavy siderite cementation.

Gurnard Formation Mid to Late Eocene

This is the primary objective for the well and contains the majority of gas reservoired in the Gas-field. It consists of very fined grained and often silty sandstone with abundant clays. At Baleen-1 there is a more argillaceous section 8m-10m thick mid formation. At Patricia-1 the more clay rich zone is less pronounced. Generally the sands have a high clay content but this may not be observed in drill cuttings, rather the clays are likely to be lost to the drilling fluid. The sands also contain variable amounts of glauconite (5%-30%), biotite, muscovite, lithics, heavy minerals and siderite. The siderite appears to be patchy and often forms distinct bands up to 0.5m thick and makes the sands completely impermeable. These highly resistive and dense bands can be correlated between the Patricia-1 and Baleen-1 wells in many cases. They tend to have a slightly lower GR response than the background glauconitic sandstones. The sandstones are olive black, firm to friable, very fine grained occasionally grading to silt, very well sorted, with trace to fair visual porosity (average core porosity >30%). In the 2 cored intersections (Patricia-1 and Baleen-2) there are very few sedimentary features preserved because the entire reservoir has been heavily bioturbated. Often burrows are filled or lined by pyrite.

The upper few metres of the formation (674mSS to 680mSS in Patricia-1) are characterised by oxidised iron nodules and occasional sideritic, clayey siltstone. The upper few metres have a distinctive increasing resistivity response from less than 2 ohm-m to 6 ohm-m at the top of porosity. It should be noted this distinctive section, which is observed in the previous 3 well penetrations is shown on the 3D impedance cube data slightly thicker at the Patricia-2 heel location. The basal few metres of the formation contained abundant pyrite nodules, a quantity of pebbles and siderite in the Patricia-1 core.

The planned well path does not include penetration of the base Gurnard Formation so these descriptions of the basal part of the formation and underlying units are for information only.

Latrobe Group 'Coarse Clastics' Early to Mid Eocene

The 'Coarse Clastic' assemblages are typically conglomeratic sandstones immediately below the Gurnard Formation grading downwards to fine and medium grained, clayey sandstones. The porosity and permeability are dominantly very good. Subordinate thin beds of micaceous and clayey siltstones are often present.

Strzelecki Group Latest Early Cretaceous

This group of sediments represents the regional economic basement. It comprises non-marine lithic sandstones and claystones. They are blue grey, fine to medium grained and moderately well sorted. Variable kaolinite up to 30% is present with minor coals. The shales are brown grey to black, carbonaceous, sub-fissile and hard.

3.3 Total Depth Criteria

The total depth of the proposed Patricia - 2 well is 1397m MDRT (approximately 710m TVDRT) in the Gurnard Formation reservoir. The objective is to provide a 500m section of near horizontal well bore, optimally positioned to maximise gas recovery from the reservoir. The minimum acceptable horizontal section through the reservoir should be 400m. No more than 500m is required to be drilled as this is the maximum length of the completion screens available.

The total depth may be increased if the 9 $^5/_8$" casing shoe is set lower than anticipated, or if an unexpected section of non net is encountered at the heel of the proposed production interval.

4.0 FORMATION EVALUATION PROGRAM

4.1 Sampling

A summary of the sampling requirements is presented in Appendix 4

- Cuttings
  Drill cuttings are to be collected at 5m intervals once the marine riser is installed. Additional samples may be collected at the discretion of the Well Site Geologist. Samples are to be air dried and not dried in an oven.

- Conventional Cores
  There are no conventional cores planned.

- Sidewall Cores
  There are no sidewall cores planned.

- Formation Fluids
  No wireline logging is planned so it is unlikely that any fluid sampling will be conducted on wireline. Sampling during testing operations will be addressed in the detailed Testing Program.

- Mud
  Three mud samples should be collected at the beginning, mid-way and at the end of the production drain hole sections. A preliminary analysis by the Mud Engineer should accompany each sample. Mud filtrate should be collected and composited over the production drainhole sections and placed in stout Pyrex glass jars. The resistivity of the fitrate should be recorded on the sample and in the manifest.

- General
  All samples are to be clearly identified. The contact person to be annotated on labels is Mark Adamson (telephone (08) 9223 5000).

4.2 Mudlogging

A mud logging unit will be required to carry out routine geological examination and description of cuttings and to monitor drilling rig parameters. A Data Engineer is required at all times and a mud logger is required while drilling operations are in progress. A sample catcher will also be required until such time as the drilling rate slows to the point where the mud logger can manage sample collection and logging of the samples.

4.3 Logging While Drilling

Formation Evaluation While Drilling (FEWD) will be run on Patricia - 2 well in the 17½", 12¼" and 8½" hole sections.

17 ½" Hole Section
8" RLL-DGR-EWR tools will be run in the 17 ½" hole for the kick off at 200mRT.

12¼" Hole Section

8" RLL-DGR-EWR tools will be run to steer the well to the 9 $^5/_8$" casing point in the upper part of the Gurnard Formation. The objective will be to drill the well such that the well bore is inclined at ~88° and the 9 5/8" casing shoe can be positioned in the upper few meters of the Gurnard Formation just below the interpreted depth of top porosity.

8½" Hole Section

6 ¾" RLL-DGR-EWR-CNP-SLD-ALSD tools will be run to monitor the well's progress along the intended path keeping track of the Gurnard Formation sub units penetrated and provide data for petrophysical and other studies. The FEWD contractor will provide real time down hole data and models of simulated formation responses based on the offset well data to assist geo-steering the well should the actual section differ significantly from the planned section. The purpose of the geosteering capacity is to allow remedial inclination changes along the production drainhole if the stratigraphic position of the wellbore falls outside the optimum window.

4.4 Wireline Logging

No open hole wireline logging is planned. A wireline logging unit will be available on the rig and a single string of basic logging tools will be on hand for unforeseen circumstances. The wireline logging contractor will also provide the drill string free point/ stuck point tools, back off and severance charges should they be required.

4.5 Other Logging

In order to optimise data acquisition during well clean up and flow testing, it is planned to run downhole pressure/temperature gauges (coiled tubing-conveyed) to provide real-time surface read-out of data during the flowing and shut-in periods. In addition to acquiring pressure data close to reservoir depth, the gauges will also be used to obtain static and flowing gradient surveys at various depths within the wellbore.

4.6 Log Data Transmission

The real time FEWD data will be written to LAS format and emailed to the Perth office of OMV Australia Pty Ltd. Additionally, graphics files of the basic log prints will be forwarded by email. In the event of poor communications precluding the use of email, a facsimile copy of the main logs will be sent via fax to OMV Perth office. A disk and/or tape of the log data will be flown off the rig and transmitted to Perth office by the most expedient means. A dedicated telephone line and data link will be in place for the transmission of geological, FEWD and drillstem testing data.

4.7 Well Test Program

The Patricia - 2 well will be flow-tested after installation of the completion to allow the removal of any residual mud and filtrate from the wellbore (clean-up) and in order to estimate well deliverability and inflow performance. A separate Test Program will be issued prior to commencement of testing operations.

For planning purposes, the following approximate test period durations are estimated :

Initial Flow	10 mins
Initial Shut-In	60 mins
Clean-Up Flow	24 hours
Second Shut-in	6 hours
Stabilised Flow (Low Choke)	9 hours
Stabilised Flow (Medium Choke)	9 hours
Stabilised Flow (High Choke)	12 hours
Final Shut-In	12 hours

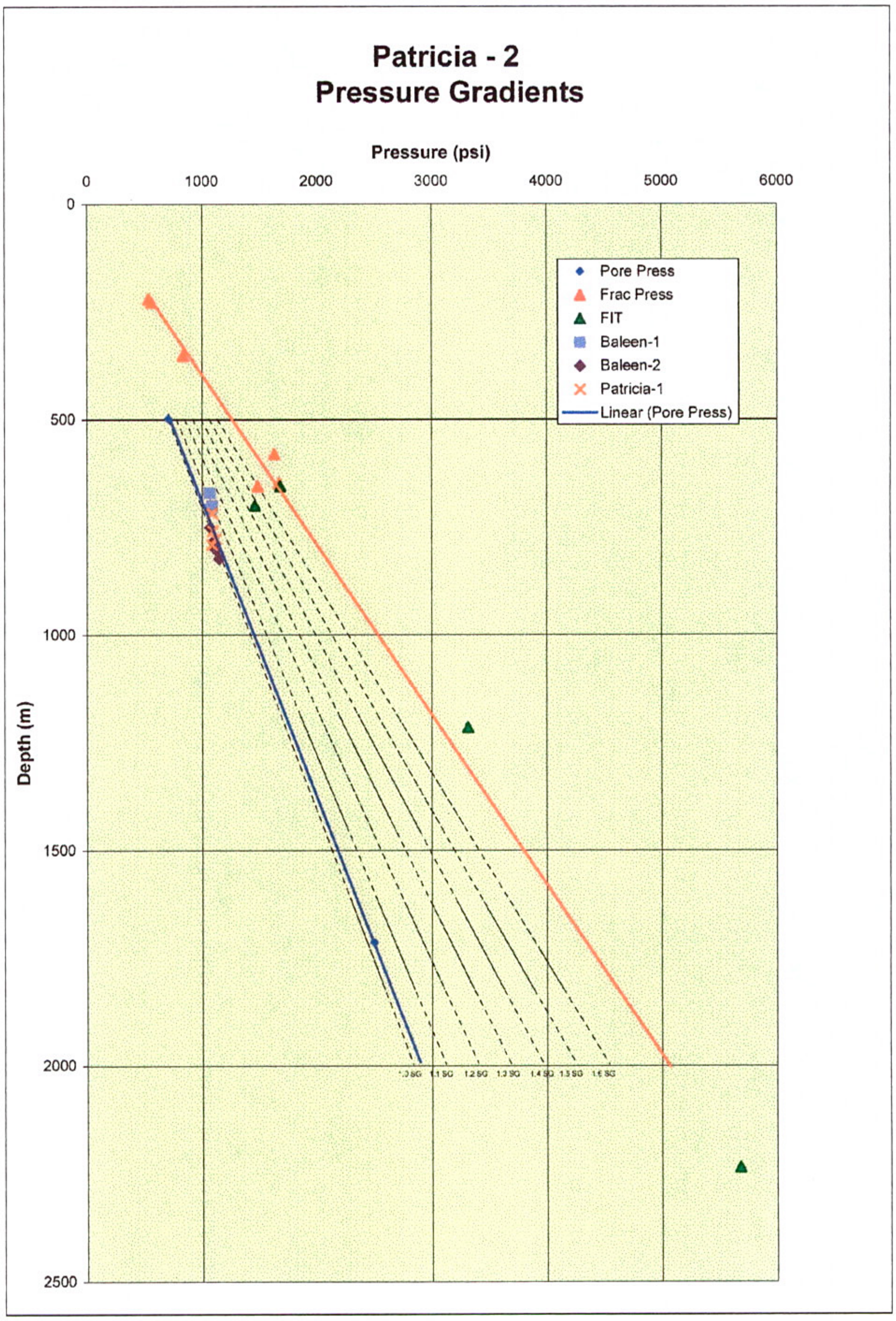
Total Well Test Duration ~ 3 days

5.0 ENGINEERING DATA

Drilling parameters, BHA designs and calculations within the drilling program should be recalculated and modified as necessary at the well site to reflect actual input parameters and well conditions.

5.1 Pore and Fracture Pressures

A normal pore pressure gradient is expected at Patricia - 2 as found at Baleen – 1, Baleen – 2 and Patricia – 1, 2.5km north northwest, 3.2km west and adjacent respectively. Pore and fracture pressure data for adjacent wells is depicted below.



5.2 Temperature

A static bottom hole temperature of approximately 48°C is expected at TD with an average temperature gradient of 4.8°C/100m and a mudline temperature of 18°C.

	17½" Hole	12¼" Hole	8½" Hole
Depth (mRT TVD)	320	702	710
Est. Temp (static)	~29°C	~48°C	~48.4°C

5.3 Casing Design Summary

Casing Specs				Safety Factors		
Casing Size	**Weight**	**Grade**	**Connection Type**	**Burst** (min 1.1)	**Collapse** (min 1.0	**Tension** (min 1.6)
30" x 20" shoe (Conductor)	1½/1" wall	X-52	Lynx HD & SA	N/A	N/A	N/A
20" ext hsg x 13 $^3/_8$" (Surface csg)	68 lb/ft	K55	BT&C	3.5	7.4	3.1
9 $^5/_8$" (Production csg)	47lb/ft	L80	NK3SB	6.8	8.2	3.5
Kick tolerance at TD of 12 ¼" hole will be:	~90bbls assuming a LOT of 1.65SG MWE					
Kick tolerance at TD of 8 ½" hole will be:	>500bbls assuming an FIT of 1.4SG MWE					

5.4 Drilling Hazards

5.4.1 Shallow Gas

No shallow gas was intersected in any of the offset wells. Given the proximity of the offset well Patricia - 1, there is little to no risk of shallow gas being encountered in the Patricia - 2 well.

5.4.2 H_2S and CO_2

No drilling problems with these gases have been experienced in any of the offset wells. Drill stem testing of the Gurnard Formation in the Baleen-1 well did not suggest any H_2S from that formation, however, testing of the underlying Latrobe Group Coarse Clastics in Patricia-1 resulted in H2S concentrations of up to 75ppm being recorded. It is not proposed to penetrate the Latrobe Coarse Clastics in Patricia - 2.

Equipment to identify the presence of H_2S will be on-site and used during drilling and flow-testing operations to monitor for harmful levels in the produced gas stream.

5.4.3 Lost Circulation

The Gippsland Limestone comprises the majority of section to be drilled in the 12¼" hole section. This Miocene unit is composed of fine grained marine carbonates which gradually coarsen upward from calcareous claystones and marl through calcilutite to calcarenites. Losses, particularly near the seabed, can be expected, however this section will be drilled riserless so should not pose a problem. The underlying Lakes Entrance Formation provides the seal to the reservoir and is not expected to be a problem regarding losses.

The target Gurnard Formation comprises very fine-grained argillaceous sandstones and silts. It has a high porosity (28%-33%) but low to moderate permeability (3-500mD), and some small filtrate losses are expected. Minimise losses by keeping mud overbalance to a safe minimum since additional pressure loss across the sand face due to formation damage will lead to reduced well productivity.

5.4.4 Faults

There are no major faults to be penetrated by the well as planned. One major fault, the northern bounding fault which trends E-W, dips to the south at high angle and is expected to be at least 600m to the north of the planned well trajectory. Several much smaller, antithetic faults mapped to the north and just south of the Patricia-2 location, trend ENE-WSW. Faults to the north of the well location dip steeply to the SSE and those to the south, steeply to the NNW. These smaller faults have throws of approximately 5m-10m and should be approximately 150m to 200m or more from the planned wellbore.

The possibility of intersecting small-scale faults below the resolution of seismic data is always present.

5.4.5 Dipping Beds

No steeply dipping beds are interpreted for the well. The steepest dips are likely to occur at top reservoir level and range from 2 degrees to 5 degrees to the north east at the heel location and 0 to 3 degrees in the toe location. The dip direction at the toe is to the west/southwest.

5.4.6 Well Trajectory

To accomplish the objective of placing a 500m near-horizontal drainhole in the upper part of the reservoir in the most advantageous structural position, a medium-rate turn deviated well is to be drilled to provide the heel position in the top few metres of the Gurnard Formation and the toe some distance below the top seal. By virtue of the structural configuration and the near-horizontal trajectory of the well bore, most of the mapped reservoir units in the upper half of the reservoir will be penetrated (Figure 2.2).

The objective is to intersect several upper reservoir sand layers, whilst retaining some stand-off from the base of reservoir / top Latrobe Group Coarse Clastics. This plan will minimise the risk of restricted flow from only a few reservoir layers should any localised siderite layering prove sufficiently continuous to restrict vertical gas movement in the vicinity of the wellbore. It will also minimise the risk of producing gas (or water) from the underlying Latrobe Group Coarse Clastics, which has a high probability of H_2S contamination. The planned elevation of the toe of the well is some 45 metres above the interpreted GWC, although gas-on-rock is mapped directly beneath the toe location. The nearest water-bearing reservoir is mapped 150 metres to the west.

5.4.7 Horizontal Stress Regime

The region around Patricia-Baleen appears to have a compressive stress regime as evidenced by the inversion of older, steep normal faults in the Tertiary. Both Patricia and Baleen structures are set up by high angle reverse faults along their northern sides. Some degree of wrenching is also inferred from the en-echelon pattern of faults and more northerly orientation of connecting faults and fault ends. A brief investigation of the public information on the northern part of the basin suggests that the maximum horizontal stress ($\sigma 1$) is oriented at 130 or 310 degrees. A brief evaluation of the borehole image data from Baleen-2 was completed and shows the local stress regime is almost co-incident with the regional setting. At Baleen-2, $\sigma 1$ appears to be oriented at 127 degrees (or 307 degrees).

In a compressional environment, the most stable direction in which to drill a horizontal well is parallel to the maximum horizontal compressive stress. Also affecting the optimum direction is the degree of strike slip or wrenching. Given the data available, the optimum direction for the drainhole to be drilled to minimise the problems due to wellbore stability would be 130 degrees +/- 45 degrees.

Whilst the proposed well trajectory is not perfectly aligned with this direction, it is not anticipated that any major drilling problems will ensue.

6.0 DRILLING PROGRAM

6.1 Rig Move

The Ocean Bounty will be towed from the previous location to Patricia - 2 in VIC/L21. All times of operational activities shall be recorded on the Daily Drilling and IADC reports.

The site survey indicates that the Patricia - 2 location lies on a flat sandy seabed which will provide good anchor holding capabilities. No debris or obstructions have been identified.

The drilling unit will be positioned with a rig heading of 257° to allow connection from the subsea Xmas tree to the pipeline. The proposed location is:

Lat:	38° 01' 39.97" S
Long:	148° 26' 57.83" E

The gas pipeline may have been installed before the rig arrives in which case the anchoring procedure will be revised.

After running anchors, tension and take final position. The surface positioning tolerance depends on the progress made in running the pipeline. If the pipeline has been laid the well will be positioned 8m west of the pipeline and at 90° to the pipeline tie in point. If the pipeline has not been laid the tolerance is 5m radius from proposed surface location. (the pipeline will then be laid in the correct location to the tree)

The actual location co-ordinates and elevation will be provided by the positioning contractor and confirmed by the OMV Survey Representative on the rig. The final coordinates and rig heading will be reported on Daily Drilling and IADC reports. Positioning will include an accurate measurement of vertical elevation with reference to the spheroid. From this, the exact elevation of the rotary table is to be recorded referenced to LAT. The tidal state and water depth will be recorded at the times the above measurements are taken.

Ensure the BOP is dressed with a Vetco H4 connector.

Ensure 10 ¾" rams are fitted in the lower ram cavity.

Surface test 18.3/4" BOP stack as per test schedule in Appendix 3.

Make up 30" conductor in PGB and hang off in moon pool.

6.2 36" Hole/ 30" Casing

6.2.1 Objectives

The objective of the section is to drill a stable hole to accept the 30" conductor, which will provide structural support for the wellhead and remaining casing strings.

6.2.2 Hazards

There are no hazards anticipated, however, in the unlikely event that shallow gas is encountered the Diamond Offshore Well Control procedures will be used.

6.2.3 Drilling Fluids

The 36" hole will be drilled with seawater and high viscosity prehydrated bentonite (PHB) sweeps as detailed in the Drilling Fluids Program. If drill water supplies are limited alternate guar gum sweeps with gel sweeps. At section TD (~110mRT) the hole will be displaced to prehydrated gel mud *(Refer to Appendix 2 - Drilling Fluids Summary for details of sweeps and TD displacement)*

6.2.4 BHA No1 (36")

COMPONENT	APPROX LENGTH (M)	BOTTOM CONNECTION	TOP CONNECTION
26" tri-cone bit (3 x 28 jets)	0.7	-	7.5/8" Reg Pin
36" hole opener (3 x 22 jets)	1.8	7.5/8" Reg Box	7.5/8" Reg Pin
9-1/2" bit sub w/ Totco ring installed	0.7	7.5/8" Reg Box	7.5/8" Reg Box
9-1/2" DC x 3	54.0	7.5/8" Reg Pin	7.5/8" Reg Box
X/O	0.7	7.5/8" Reg Pin	6.5/8" Reg Box
8" DC x 6	27.0	6.5/8" Reg Pin	6.5/8" Reg Box
X/O	0.7	6.5/8" Reg Pin	4.1/2" IF Box
HWDP x 18	108.0	4.1/2" IF Pin	4.1/2" IF Box

6.2.5 Survey Program

Take a Totco survey at TD.

6.2.6 Evaluation

Mud logging: Drilling parameters and tide levels will be monitored. Drilling parameters are to be correlated with drill floor recorders.

No formation evaluation will be undertaken in this hole section.

6.2.7 Drilling Procedure

1 Pick up drill pipe, HWDP and drill collars and make up 36" BHA. Measure and record the bit to hole opener spacing.
2 Deploy ROV and place tethered buoy to mark hole.
3 Run BHA assembly and tag seabed.

Note: *Record water depth and time on the Daily Drilling and IADC reports. Use tide tables to give the tide corrected water depth and record referenced to LAT. Set tide markers and begin monitoring tide.*

4 Take Totco survey to confirm string is vertical prior to spudding.
5 Spud well and drill to ±110mRT or as necessary to place the PGB ~1.5m above the seafloor when the casing shoe is on bottom, using seawater and the high viscosity sweep regime recommended in the Drilling Fluids Program.
6 The ROV should remain deployed while drilling this section to monitor the well for indications of lost circulation, shallow gas and effectiveness of hole cleaning.
7 At TD take Totco reading, circulate the hole clean and displace hole to PHB mud. Pick up until the HO is just below the seabed and run back to bottom. If no hole problems are encountered displace hole to PHB mud and pull out to run the conductor.
8 Use ROV to set 2nd tethered buoy hole marker on the other side of the hole and diametrically opposed to the 1st marker.

6.2.8 Casing Summary

Casing size	Qty	Description	Weight/Grade/ Connections
30"	1	Cameron 30" housing on extension joint	456ppf (1.5" WT), X-52, Lynx HD box down
30"	1	Intermediate casing joint	310ppf (1" WT), X-52, Lynx HD pin up, Lynx SA box down
30"	1	Shoe joint w/ 20" float shoe.	310ppf (1" WT), X-52, Lynx SA pin up

Centraliser Program: NA

6.2.9 Cement Program

Displacement	Recipe / Excess	From	To	Density (SG)
Circulation/ Spacer	~180bbl seawater			1.03
Tail/grout Slurry	Class G neat NF-5 0.25gal/10bbl $CaCl_2$ 1% bwoc Mix water Seawater Yield: 1.17 ft^3/sk Thickening time: 2 hours Excess: 200% excess	Casing shoe	seabed	1.91

6.2.10 Casing and Cementing Procedure

1 Pick up 30" casing/PGB assembly. Run 3 joint DP stinger below 30" housing running tool. Check float and lower to fill with SW.
2 Run 30" casing and observe the conductor entering the hole with ROV. Fill each joint with S.W.
3 Check the PGB inclination is less than 1°. If inclination is >1°, use guide wire tension and/or rig positioning in an attempt to reduce inclination to <1°.

4 Rig up to cement and circulate the casing with a minimum of 1.5 times casing volume of seawater.
5 Cement casing with 200% excess over open hole volume and observe returns with ROV.
6 Displace cement to within 5 metres of the shoe and wait until the surface cement samples have become firm.
7 Confirm PGB angle is <1° and release running tool, confirming the PGB angle after release of running tool.
8 Record distance from top of 30" housing to rotary table, PGB angle & heading and observation of returns in the Daily Drilling and Cementing Reports
9 Pull back with running tool and drill pipe stinger and wash the 30" wellhead housing area on way out.
10 If any problems were noted with the primary cementation, remedial grouting will be conducted.

6.3 17 ½" Hole/ 13 ³/₈" Casing

6.3.1 Objectives

The 17½" hole section will allow a 13 ³/₈" casing string to be set in the Gippsland Limestone, which comprises calcilutite interbedded with calcareous claystone at the base. This will enable a closed mud system to be used with an inhibitive mud through the build section in the 12 ¼" hole. The 18 ¾" wellhead will be run on the 13 ³/₈" casing, upon which the horizontal Xmas tree and BOP will be set.

6.3.2 Hazards

The 17½" hole section will be drilled riserless. Shallow gas is not anticipated but the ROV will be deployed on bubble watch and the shallow gas procedures outlined in the Diamond Offshore Well Control Procedures will be in effect while drilling the 17½" hole section.

Losses, particularly near the seabed can be expected

6.3.3 Drilling Fluids

The 17½" hole will be drilled with seawater and high viscosity gel sweeps as detailed in the Drilling Fluids Program. If drill water supplies are limited alternate guar gum sweeps with gel sweeps. For ROP's <100m/hr pump 3 x 50bbl sweeps per stand, with ROP >100m/hr pump 2 x 100bbl sweeps per stand. At section TD (~325mRT) the hole will be circulated clean and displaced to unflocculated PHB mud. *(Refer to Appendix 2 - Drilling Fluid Summary).*

6.3.4 BHA No 2 (17½")

COMPONENT	APPROX LENGTH (M)	BOTTOM CONNECTION	TOP CONNECTION
17½" tricone bit	0.44	-	7-5/8" Reg Pin
9 $^5/_8$" Sperry Drill Lobe 6/7, 5 stage	~9.06	7-5/8" Reg Box	7-5/8" Reg Box
X/O sub	0.88	7-5/8" Reg Pin	6-5/8" Reg box
8" RLL w/DGR + EWR	6.60	6-5/8" Reg Pin	6-5/8" Reg box
8" MPT	6.25	6-5/8" Reg Pin	6-5/8" Reg box
Float sub	0.71	6-5/8" Reg Pin	6-5/8" Reg box
3 x 8" DC's	27.0	6-5/8" Reg Pin	6-5/8" Reg box
8 ¼" Drilling Jar	9.69	6-5/8" Reg Pin	6-5/8" Reg box
2 x 8" DC's	18.0	6-5/8" Reg Pin	6-5/8" Reg box
X/O	0.6	6-5/8" Reg Pin	4-1/2" IF Box
HWDP x 15	135.0	4-1/2" IF Pin	4-1/2" IF Box

Bit:	Tricone	IADC:	1.1.5/1.1.7
Nozzels:	3 x 26	Flowrate:	~1100gpm

6.3.5 Survey Program

MWD survey every stand and as required during build section.

6.3.6 Evaluation

Mud logging: Drilling parameters and tide levels to be monitored. Drilling parameters are to be correlated with drill floor recorders.
Wireline logging: No wireline logs will be run in this hole section.

6.3.7 Drilling Procedure

1 Make up 18.3/4" wellhead housing and extension to running tool, with a 2 joint drill pipe stinger and SSR plugs below, and rack back/lay out.
2 Lay down 36" BHA components and make up 17½" BHA with 9 $^5/_8$" mud motor and directional MWD.
3 Attach soft line guides to BHA and run in hole. Use ROV to assist stabbing BHA into the 30" housing if necessary.
4 Record TOC and drill out the cement and 20" shoe, using seawater and hi-vis pills as per the Drilling Fluids Program.

Note: *The ROV should be deployed throughout this section to observe for indications of shallow gas and lost circulation.*

5 Drill ahead in rotary mode to the kick off point at 200mRT using seawater and hi-vis pills. Orientate and kick off building angle at the required rate along an azimuth of 232° as per Sperry Sun Directional Program to achieve ~9° inclination by 325m MD or appropriate depth for setting the actual length of 13.3/8"" casing required with a 5m rat hole.

Note: *Strict control of hi vis sweeps is necessary to efficiently clean the hole, to minimise cuttings load-up and ECD. Refer to Drilling Fluid Summary Appendix 2.*
It is important to minimise doglegs through this interval.

6 At section TD circulate the hole clean with a 100bbl hi-vis sweep and conduct wiper trip to the 20" shoe. Upon returning to bottom sweep hole clean and displace the open hole to PHB mud (unflocculated).
7 SLM out to run casing.
8 Jet the 30" wellhead housing on way out.

6.3.8 Casing Summary

CASING SIZE	QTY	DESCRIPTION	WEIGHT/GRADE/CONNS
13 3/8"	1	Cameron 18-3/4" STM10 W/H & 20" housing ext. swaged to 13 3/8" with pup joint.	205ppf (1" WT), X-56, BT&C pin down
13 3/8"	~16 jnts	Intermediate joints	68lb/ft, K55, BT&C
13 3/8"	1 jnt	Float Collar joint - Bakerlocked	68lb/ft, K55, BT&C
13 3/8"	1 jnt	Shoe track joint - Bakerlocked	68lb/ft, K55, BT&C
13 3/8"	1 jnt	Shoe joint w/ float shoe Bakerlocked.	68lb/ft, K55, BT&C

6.3.9 Centraliser Program

Cent #	TYPE	SPACING	DEPTH (MRT)	COMMENTS
1	Bow	Joint # 1	~317	Over stop ring
2	Bow	Joint # 1	~311	Over stop ring
3	Bow	Joint # 2	~305	Over stop ring
4	Bow	Joint # 2	~299	Over stop ring
5	Bow	Joint # 3	~293	Over stop ring
6	Bow	Joint # 3	~287	Over stop ring

* The centraliser program assumes casing shoe is at 320mRT

6.3.10 Cement Program

DISPLACEMENT	RECIPE / EXCESS	INTERVAL	DENSITY (SG)
Circulation/ Spacer	~180bbls seawater/20bbls sea water		1.03
Lead Slurry	Class G + extender Liq econolite 20 gal/10bbl NF-5 0.25 gal/10bbl Mix water Sea water Yield: 2.23 ft^3/sk Thickening Time: 5 hrs Excess in OH 50%	180 – 80mRT.	1.50
Tail Slurry	Class G neat $CaCl_2$ 1% bwoc NF-5 0.25 gal/10bbl Mix water Sea water Yield: 1.17 ft^3/sk Thickening Time: 1 ½ hrs Excess in OH 50%	320 – 180mRT.	1.91

6.3.11 Casing and Cementing Procedure

1 Rig up casing handling equipment and fillup/circulating tool to run 13.3/8" casing.
2 Run 13 3/8" shoe, intermediate and float collar joints, checking floats in shoe and collar. Install centralisers as per program.
3 Run 13 3/8" casing with soft line on shoe joint, filling with seawater whenever possible. Stab into 30" housing observing with ROV.
4 Continue running casing filling with seawater whenever possible. Stop and fill the casing completely with seawater every 5 joints.
5 Make up last joint with "no cross coupling" installed.
6 Make up 18-3/4" wellhead housing x 20" extension joint swaged to 13.3/8", with special bushing installed, to running tool (with 2 joint stinger and plugs below) and make up to the "no cross coupling".
7 Run on S135 drill pipe landing string filling each stand of drillpipe with seawater.
8 Break circulation and wash down last joint prior to landing. Measure in last stand and land 18¾" wellhead in the 30" housing observing with ROV. Confirm latching with 25 kips overpull.
9 Establish circulation and circulate 1½ times casing capacity (±180 bbls) with seawater.
10 Rig up and test cementing lines to 3000psi.
11 Pump 20 bbl sea water and cement 13.3/8" casing with 50% excess over open hole volume and observe returns with the ROV.
12 Displace slurry with seawater, bump plug with 500 psi over circulating pressure and pressure up to 2500psi for 10 mins to test casing. Do not over displace the calculated volume by more than half the capacity of the shoe track if the plug does not bump. In any event cease pumping if the pressure stops increasing.
13 Check floats are holding and release running tool. POOH and flush 18¾" wellhead housing area on way out.
14 Check slope indicators on PGB with ROV and record readings.

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15 Lay down 17½ " drilling assembly.

6.4 Run Horizontal Xmas tree

Run Cameron horizontal Xmas tree, with wear bushing installed, as per Cameron procedures.

6.5 Run BOP and Riser

Note: *Prior to running the BOP will have been dressed with a Vetco H4 connector and stump tested as per Appendix 3. Ensure new ring gaskets are fitted in the LMRP and wellhead connectors and a bullseye is mounted above the flex-joint. Function test BOP prior to running.*

1 Run BOP stack and riser as per Diamond Offshore procedures testing the K & C lines to 5000 psi every 3 joints. Run Cameron IWOCS umbilical with BOP as per Cameron procedures.
2 Pick up slip joint and make up tensioner and K & C lines. Pressure test K & C lines to 5000 psi.
3 Deploy ROV.
4 Land BOP observing with ROV and latch. Confirm latching with 50 KIPS overpull and record slope indicator reading after landing stack.
5 Rig up diverter and function test.
6 Confirm seal by testing the wellhead connector and casing to 1000 psi against the blind/shear rams.
7 Function test BOP on both pods.
8 Install IWOCS junction plate on Xmas Tree with ROV as per Cameron procedures

6.6 12¼" Hole Section

6.6.1 Objectives

The 12 ¼" hole section will allow a $9^5/_8$" casing string to be run through the build section of the well to isolate the reactive claystones in the Lakes Entrance Formation, which may also be tectonically stressed. It will also provide protection during the drilling of the reservoir section in 8½" hole.

6.6.2 Hazards

Hole cleaning may be a problem between 40 and 55° in build section.

Tectonic stress resulting in cavings and possible packoff.

Increased torque and drag resulting from dogleg angle in the build to 88°

6.6.3 Drilling Fluids

The 12¼" hole section will be drilled with a KCL/PHPA/Glycol drilling fluid to provide inhibition of the reactive and dispersive elements of the Lakes Entrance Formation exposed in the hole section. It is anticipated that a weight of 1.16 - 1.17SG will be required prior to reaching the top of the Lakes Entrance Formation to counter borehole breakout and cavings. (Refer to Appendix 2 Drilling Fluid Summary or Drilling Fluids Program for full details)

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6.6.4 Bottom Hole Assemblies

BHA No 3 (12¼")

COMPONENT	APPROX LENGTH (M)	BOTTOM CONNECTION	TOP CONNECTION
12¼" Tricone bit	~0.33	-	6.5/8" Reg Pin
8" Sperry Drill 4/5 Lobe, 5.3 stg	9.7	6.5/8" Reg Box	6.5/8" Reg Box
8" RLL w/DGR+EWR	6.60	6.5/8" Reg Pin	6.5/8" Reg Box
8" MPT	6.25	6.5/8" Reg Pin	6.5/8" Reg Box
Float sub	0.71	6.5/8" Reg Pin	6.5/8" Reg Box
X-over sub	1.11	6.5/8" Reg Pin	4.1/2" IF Box
3 x HWDP	27.0	4.1/2" IF Pin	4.1/2" IF Box
6-3/4" Jar	9.0	4.1/2" IF Pin	4.1/2" IF Box
3 x HWDP	27.0	4.1/2" IF Pin	4.1/2" IF Box
16 x DP	150.0	4.1/2" IF Pin	4.1/2" IF Box
30 x HWDP	270.0	4.1/2" IF Pin	4.1/2" IF Box

Bit:	Tri-cone	IADC	1.1.7 or 1.3.5
Nozzles:	4 x 20	Flowrate:	~800gpm

6.6.5 Survey Program

FEWD survey as required during build section.

6.6.6 Evaluation

Mud logging: Continuous monitoring of return drilling fluid, drilling parameters, tide and pit levels.

Cuttings: 5m sample interval, washed / air dried.

Coring: No cores planned.

FEWD: Directional-Gamma-Resistivity

Wireline logging : No wireline logging planned.

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6.6.7 Drilling Procedure

1. Make up 9 $^5/_8$" casing hanger/adapter, running tool and subsea launch mandrel and lay out or rack back in derrick
2. Make up 12 ¼" BHA as per the Sperry Sun Directional Plan.
3. Run Flex joint wear bushing
4. Run in hole and tag and record top of cement inside 13 $^3/_8$" casing.
5. Drill out cement and shoe and clean out rathole using seawater and sweeps of mud from the previous section. Use low WOB and <50 rpm to minimise string vibration. Drill 3m of new formation while displacing to KCL/PHPA/Glycol mud system. Circulate to balance and condition mud and pull back into the casing shoe.
6. Perform a Leak Off Test, (a formation strength of 1.65 – 1.7SG equivalent mud weight is anticipated).
7. Perform SCRs and CLFLs.
8. Run in and drill ahead along 232° azimuth building angle as required per Sperry Sun Directional Program, to land in the Gurnard Formation at section TD at ±915m MDRT (±702m TVDRT). Inclination at this point should be ~88°.

   Note: *Doglegs will be kept to a minimum and if doglegs exceeding 6°/30m are deemed necessary the OMV Drilling Supervisor should be informed and authorise the change. If the inclination falls behind the planned rate the planned tangent section can be used to catch up. Record pick up and slack off weights on each connection to confirm proper hole cleaning.*

9. At TD, circulate hole clean, make wiper trip to 13 $^3/_8$" shoe as required, and SLM out to run casing.

   Note: *Target lateral tolerance for landing point is 25m either side of the planned trajectory with a ±2.5m tolerance on TVD. The planned trajectory is based upon the most likely case, however, the actual trajectory will be dependent on the stratigraphy and structure encountered and will be the subject of operational decisions taken at the time.*

6.6.8 Casing Summary

CASING SIZE	QTY	DESCRIPTION	WEIGHT/GRADE/CONNS
9 $^5/_8$"	1	STM-10 18 ¾" x 9 $^5/_8$" casing hanger w/ hanger adapter attached with pup joint installed.	47lb/ft, L80, New Vam pin down
9 $^5/_8$"	1	Cross-over	47lb/ft, L80, NK3SB pin x New Vam box
9 $^5/_8$"	~65 jnts	Intermediate joints	47lb/ft, L80, NK3SB
9 $^5/_8$"	1 jnt	Float Collar joint - Bakerlocked	47lb/ft, L80, NK3SB
9 $^5/_8$"	1 jnt	Shoe track joint - Bakerlocked	47lb/ft, L80, NK3SB
9 $^5/_8$"	1 jnt	Shoe joint w/ float shoe Bakerlocked.	47lb/ft, L80, NK3SB

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6.6.9 Centraliser Program

Cent #	TYPE	SPACING	DEPTH (MRT)	COMMENTS
1	Bow	Joint # 1	~913	Over stop ring
2	Bow	Joint # 1	~907	Over stop ring
3	Bow	Joint # 2	~901	Over stop ring
4	Bow	Joint # 2	~895	Over stop ring
5	Bow	Joint # 3	~889	Over stop ring
6	Bow	Joint # 3	~883	Over stop ring
7	Bow	Joint # 4	~874	Over stop ring
8	Bow	Joint# 5	~862	Over stop ring
9	Bow	Joint# 6	~850	Over stop ring
10	Bow	Joint# 7	~838	Over stop ring
11	Bow	Joint# 8	~826	Over stop ring
12	Bow	Joint# 9	~814	Over stop ring
13	Bow	Joint# 10	~802	Over stop ring
14	Bow	Joint# 11	~790	Over stop ring

* The centraliser program assumes casing shoe is at 915m MDRT

6.6.10 Cement Program

DISPLACEMENT	RECIPE / EXCESS	INTERVAL	DENSITY (SG)
Circulation Spacer/flush/ Spacer	~300bbls mud/ 10bbls drill water/ 60bbls Superflush 102/ 10bbls drill water		1.03
Tail Slurry	Class G neat Halad-413L 20 gal/10bbls NF-5 0.25 gal/10bbls Mix water Drill water Yield: 1.16 ft^3/sk Thickening Time: 2 ½ hrs Excess in OH 20%	903 – 603m MDRT.	1.90

6.6.11 Casing and Cementing Procedure

1. Pull wellhead, Xmas tree and Flex-joint wear bushings.
2. Rig up handling equipment and casing fill up and circulating tool to run 9 $^5/_8$" casing.
3. Run 9 $^5/_8$" shoe, intermediate and float collar joints. Confirm operation of the float equipment once the float collar is run. Install centralisers as per program.
4. Run 9 $^5/_8$" casing filling with mud whenever possible while running. Stop and fill casing completely every 5 joints.

5 Continue running casing up to the hanger joint. Pick up the pre-assembled hanger/running tool, make up to the casing string and run on S135 drill pipe
6 Make up cement head, break circulation and wash down the last joint of casing prior to landing the hanger. Land hanger in 18 ¾" wellhead housing as per Cameron procedures. Compensate running string. Confirm that hanger is correctly landed from pipe tally.
7 Establish circulation and circulate ~1½ times casing capacity with mud (±300 bbls).
8 Rig up and test cementing lines to 3000psi.
9 Pump 10bbls drill water spacer, 60bbls Superflush 102 and 10bbls drill water spacer. Cement 9 $^5/_8$" casing with 20% excess over open hole volume.
10 Displace slurry with mud, bump plug with 500 psi over circulating pressure and pressure up to 3,000psi for 10 mins to test casing. Do not over displace the calculated volume by more than the capacity of the shoe track if the plug does not bump. In any event cease pumping if the pressure stops increasing.
11 Bleed off pressure and check floats are holding.
12 Backoff and recover casing running tool and flush 18¾" wellhead housing area on way out.
13 Run and set seal assembly as per Cameron procedures manual.
14 Pressure test seal assembly and BOP stack as per Appendix 3
15 POOH with seal assembly running tools.
16 Run wellhead, Xmas tree and flex-joint wear bushings
17 Lay down 12 ¼" drilling assembly.

6.7 8½" Hole Section

6.7.1 Objectives

The 8½" hole section will provide access to the Patricia gas reservoir.

6.7.2 Hazards

Minor seepage losses may be experienced through the Gurnard Formation.

6.7.3 Drilling Fluids

The 8½ " hole section will be drilled with a 3% KCL "Flo-Pro NT" drill-in fluid system. The fluid will provide inhibition of the clays in the reservoir as well as controlling fluid loss through the target reservoir. It is anticipated that a weight of 1.08 - 1.15SG will be sufficient to drill to TD and the fluid loss will be maintained below 5cc/30min through the reservoir section. (Refer to Appendix 2 Drilling Fluid Summary or Drilling Fluids Program for full details)

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6.7.4 Bottom Hole Assemblies

BHA No 4 (8½")

COMPONENT	APPROX LENGTH (M)	BOTTOM CONNECTION	TOP CONNECTION
8½"Tricone bit	~0.25	-	4½" Reg Pin
6 ¾" Sperry Drill Lobe 6/7, 5 stg	8.81	4½" Reg Box	4½" IF Box
6 ¾" RLL w/DGR+EWR+CNP+SLD	13.20	4½" IF Pin	4½" IF Box
6 ¾" MPT	6.21	4½" IF Pin	4½" IF Box
ASLD tool	4.00	4½" IF Pin	4½" IF Box
Float sub	0.74	4½" IF Pin	4½" IF Box
3 x HWDP	27.00	4½" IF Pin	4½" IF Box
6 ¾" Jar	9.00	4½" IF Pin	4½" IF Box
3 x HWDP	27.00	4½" IF Pin	4½" IF Box
72 x DP	660.00	4½" IF Pin	4½" IF Box
30 x HWDP	270.00	4½" IF Pin	4½" IF Box

Bit:	Tricone	IADC	1.1.7 or 4.1.7
Nozzles:	3 x 16	Flowrate:	~600gpm

6.7.5 Survey Program

FEWD survey as required during the horizontal section.

6.7.6 Evaluation

Mud logging: Continuous monitoring of return drilling fluid, drilling parameters, tide and pit levels.

Cuttings:	5m sample interval, washed / air dried.
Coring:	No cores planned.
FEWD:	Directional-Gamma-Resistivity-Density-Neutron
Wireline logging:	No wireline logging planned.

6.7.7 Drilling Procedure

1. Make up 8.½" BHA as per Sperry Sun Directional Program.
2. Run in hole, tag and record top of cement inside 9 $^5/_8$" casing.
3. Drill out cement and shoe, and clean out rathole with low WOB and RPM to minimise drill string vibration, using mud from the previous section.
4. Drill 3m of new formation while circulating to the Flo-Pro drill-in system and circulate to balance and condition mud.

5 Pull back into the casing shoe and conduct a Formation Integrity Test, (a result of ±1.4 SG equivalent mud weight will be sufficient to confirm integrity of cement around the shoe).

6 Determine SCRs and CLFs.

7 Run in and drill horizontal section to TD as per the Directional Program noting pick up and slack off values on each connection to confirm proper hole cleaning. Take surveys as required to maintain well trajectory.

8 At TD, circulate hole clean and make wiper trip to the 9 $^5/_8$" casing shoe and circulate hole clean.

Note: *Prior to tripping out, the hole should be circulated a minimum of 3 x bottoms up while rotating the drillstring at 120 RPM. A hi/low vis sweep combination should be used at TD to improve cleaning in the horizontal and vertical sections of hole. While circulating prior to tripping observe the shakers to note "cuttings waves" and frequency of arrival at surface. Back reaming should only be used as a last resort.*

Note: *It is important to establish drill pipe frictional torque values. Ensure that drill pipe rotational tests are performed at 10 rpm and 20 rpm, both at TD and the 9 $^5/_8$" casing shoe on the last trip out of the hole.*

9 Displace open hole to a Flo-Pro SF pill, which will extend ~120m above the 9 $^5/_8$" shoe. The FLO-PRO SF pill will have the same density as the FLO-PRO NT system used to drill the 8 ½" section. The pill will consist of completion brine and 2.0 lb/bbl FLO-VIS NT.

Note: *The solids-free pill serves several purposes:*

- *Helps control fluid loss to the formation while tripping in and out of the hole.*
- *Acts as a push pill during displacement.*
- *Reduces the amount of drill solids and calcium carbonate in the open hole, which provides a solids-free environment for the completion assembly.*
- *Reduces the amount of solids to be removed during clean up.*

6.8 Clean up pills

The casing displacement procedure listed is designed to reduce filtration costs and to optimise the final completion operations. Clean the surface mud equipment according to a rig cleanup checklist. Have all spacers and the completion fluid on location before starting.

After placing the FLO-PRO SF pill, slowly SLM out to ±100m above the casing shoe.

The displacement sequence is as follows, do not stop pumping once the displacement has begun:

Mix and pump 25 bbl hi-vis spacer

Mix and pump 50 bbl surfactant wash pill (SAFE SURF WN)

Mix and pump 25 bbl brine-base hi-vis spacer

Follow this spacer with uninhibited KCL brine.

Note: *The pump rate during the displacement should be at the maximum allowable rate combined with pipe rotation to reduce channelling.*

3. SLM out with 8 ½" BHA to run completion.

Use the same density uninhibited brine as the FLO-PRO NT system being displaced to eliminate possible channelling during displacements and to maintain the same hydrostatic head on the formation.

6.9 Well Completion

Refer to the Patricia - 2 Completion Program for details for running the sand screens, completion and cleanup procedures.

APPENDIX 1 – CASING DESIGN SUMMARY

Casing String	Design Criteria: Burst Design (Min Safety Factor 1.1)	Collapse Design (Min Safety Factor 1.0)	Tension Design (Min Safety Factor 1.6)
Conductor: 30" x 20" shoe Lynx HD & Lynx SA	N/A	N/A	N/A
Surface casing: 20" W/H extension x 13-3/8" Casing 68lb/ft, K55, BT&C	**Internal Pressure:** Lesser of: • Max pore pressure from next hole section minus head of methane **or;** • LOT pressure at the shoe	**Internal pressure:** • Casing is 50% evacuated **External Pressure:** • Hydrostatic pressure due to SW + mud while running	Use buoyed casing weight plus Greater of: • 200,000lbs **or** • Load due to pressure test of 2500 psi
Production casing: 9 5/8" Casing 47lb/ft, L80, NK3SB	**Internal Pressure:** Greater of: • Pressure from bottom of hole minus head of methane plus hydrostatic of packer fluid acting at top of liner packer • Maximum pore pressure from bottom of hole minus head of methane **External Pressure** • Hydrostatic pressure due to 9.7ppg mud	**Internal Pressure:** • Casing is 50% evacuated **External Pressure:** • Hydrostatic pressure due to mud while running • Consideration of effects of the biaxial stresses due to buoyed weight of casing in drilling fluid	Use buoyed casing weight plus the Greater of : • 200,000lbs **or** • Load due to pressure test of 3000 psi

Notes: Buoyed weight of casing is low therefore effects of biaxial stresses are negligible.

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Hole Parameters					
Hole Size (ins)	Hole Depth (mRT TVD)	Casing Set (mRT TVD)	Pore Press (SG)	Mud Weight (SG)	LOT (SG EMW)
36"	~110	~110			
17½"	325	320	1.03	1.08	1.65
12¼"	677	677	1.03	1.16	1.7
8½"	710	710	1.03	1.08-1.14	

Casing Specs			Casing Performance				Safety Factors		
Casing Size(ins)	Weight	Grade	Connection Type	Burst (psi)	Collapse (psi)	Tension (kips)	Burst	Collapse	Tension
30" x 20" shoe	1½/1" wall	X-52	Lynx HD & SA	1500	N/A	2080	N/A	N/A	N/A
20" ext hsg x 13 3/8"	68 lb/ft	K55	BT&C	3450	1950	1069	3.5	7.4	3.1
9 5/8"	47 lb/ft	L80	NK3SB	6870	4750	1086	6.8	8.2	3.5

Notes: Kick tolerance at TD of 12 ¼" hole will be: ~90bbls assuming a LOT of 1.65SG MWE
Kick tolerance at TD of 8 ½" hole will be: >500bbls assuming an FIT of 1.40G MWE

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APPENDIX 2 - DRILLING FLUID SUMMARY

MI DRILLING FLUIDS

DRILLING FLUID PROPOSAL B
PRICED SUMMARY
Well: Patrica 2

Prepared date/by:	28-Feb-02 / Dave Bennett	OMV verification:		Date :	15-Apr-02
Verified date/by:	28-Feb-02 / Tim Monteath			Rev. No:	4
Approved date/by:		OMV Approval:		Total cost US$:	114,903

OMV

36 Section: Seawater / Hi Vis Sweeps

Depth meters	MW sg	Funnel Visc. sec	6 rpm	pH	Gel 10s lb100sqft	Gel 10m lb100sqft
76 – 110	alap	>100	> 40	9 - 10	>15	>40

Csg Shoe 110
Length: 34

COMMENTS:
This section will be drilled with Seawater and high viscosity sweeps at a rate of 50 bbl every 10 m. Flocculated prehydrated bentonite will be utilised for this. Guar Gum will be held in contingency for Hi Vis Sweeping and used if required.

At TD or anytime the pipe is tripped, sweep the hole clean with a 100 bbl Hi Vis Pill & then over-displace (1.5 x open hole volume) the hole to Hi - Vis prehydrated bentonite (not flocculated) prior to pulling out for any wiper trip or to run casing.

PRODUCTS TYPE	Unit	Size	Concentrations Sweeps	Concentrations Displ vol	Tot Unit
Bentonite	lb	100	22.0	35.0	135
Caustic Soda	kg	25	0.2	0.2	2
Soda Ash	kg	25	0.2	0.2	2
Total section cost				US$	1,314

VOLUMES	bbl
DISPL. VOL.	198
SWEEPS	300
TOT. VOL.	498
NEW MUD	498
Max Angle, deg.	0
Dilut. fac	n/a

17 1/2 Section: Seawater / Hi Vis Sweeps

Depth meters	MW sg	Funnel Visc. sec	6 rpm	pH	Gel 10s lb100sqft	Gel 10m lb100sqft
110 – 323	alap	>100	> 30	9 - 10	>15	>30

Csg Shoe 318
Length: 213

COMMENTS:
This section will be drilled with Seawater and high viscosity sweeps at a rate of 50 bbl every 10 m. Flocculated prehydrated bentonite will be utilised for this. Guar Gum will be held in contingency for Hi Vis Sweeping and used if required.

At TD or anytime the pipe is tripped, sweep the hole clean with a 100 bbl Hi Vis Pill & then over-displace (1.5 x open hole volume) the hole to Hi - Vis prehydrated bentonite (not flocculated) prior to pulling out for any wiper trip or to run casing.

PRODUCTS TYPE	Unit	Size	Concentrations Sweeps	Concentrations Displ vol	Tot Unit
Bentonite	lb	100	20.0	30.0	324
Caustic Soda	kg	25	0.2	0.1	4
Soda Ash	kg	25	0.2	0.1	5
Lime	kg	25	0.5	0.0	10
Total section cost				US$	3,208

VOLUMES	bbl
DISPL. VOL.	312
SWEEPS	1150
TOT. VOL.	1553
NEW MUD	1563
Max Angle, deg.	0
Dilut. fac	n/a

12 1/4 Built Section: 5% KCl / PHPA / Glycol

Depth meters	MW sg	YP lb100sqft	PV cP	Gel 10s lb100sqft	Gel 10m lb100sqft	6 rpm	pH	API FL ml	Glycol %	KCl %wt	PHPA ppb	LGS %vol	MBT ppb
318 – 918	1.08 - 1.10	6 rpm dependent	< 25	>12	< 35	16 - 19	8.7 - 9.2	< 8	3	5	1.0 - 1.5	< 5	< 12

Csg Shoe 913
Length: 600

COMMENTS
This section is to drilled with a 5% KCl / PHPA / Glycol mud system. Pretreat mud against cement contamination with sodium bicarbonate and maintain pH below 10 with citric acid.
Claystone inhibition will be achieved through the maintainance of 5% KCl, 3% Glycol and polyacrylamide cuttings encapsulation.
Excellent hole cleaning is essential through this section of hole and will be based on the 6 rpm readings, maintaining 16 - 19 dial units with premixed Duotec.
API Fluid Loss control will be achieved (< 8 cc) by maintaining the Polypac UL concentration at 0.8 - 1.5 ppb.

Optimise use of solids control equipment to maintain LGS below 5%. Ensure shakers bed angle is ≤ 3 degrees, for unimpeded cuttings movement off screens.

PRODUCTS TYPE	Unit	Size	Concentrations New	Concentrations Maint	Tot Unit
Barite	lb	100	17.0	2.0	372
Caustic Potash	kg	25	0.2	0.1	11
OS-1	kg	25	0.3	0.2	18
Polypac UL	kg	25	1.0	0.3	46
Polyplus	lb	50	1.2	0.3	59
KCl	mt	1	18.0	2.0	18
Sodium Bicarbonate	kg	25	0.2	0.1	11
Duotec	kg	25	1.8	0.4	78
Glydril LC	kg	220	3%	0.5%	47
Total section cost				US$	61,956

VOLUMES	bbl
SURFACE	500
RISER	90
CASING/HOLE - KOP	119
OPEN HOLE	287
DILUTION	960
HOLE TOT	496
TOT. VOL.	1956
RECEIVED	0
NEW MUD	1956
MUD LEFT	996
Max Angle, deg.	89
Dilut. fac	1.6

APPENDIX 2 - DRILLING FLUID SUMMARY (Continued)

8 1/2 — Horizontal Section: Flo-Pro

Depth meters	MW sg	YP lb100sqft	PV cP	Gel 10s lb100sqft	Gel 10m lb100sqft	6 rpm / 3 rpm	Brookfield 0.3 rpm LSRV	API FL ml	pH	KCl % wt	MBT ppb		
913 1395	1.08	low end dependent	10 - 12	>24	< 38	>25 >22	> 60,000 cps (> 80,000 cps optimum)	< 5	9.5	3 - 4	< 5		

Liner set 1372

Length: 482

COMMENTS
This section is to drilled with a 3% KCl / Flo-Pro drill-in mud system.
Drill out cement with mud remaining from the previous section.
Do not use barite for any weight requirements or slugs, use KCl, salt &/or calcium carbonate.
Excellent hole cleaning is essential through this horizontal hole and will be based on the 0.3 rpm LSRV, maintaining >60,0000 cps with premixed Flo-Vis Plus.
The API Fluid Loss will be maintained less than 5 ml through the addition of Dualtrol.
Optimise use of solids control equipment to maintain mimimum drill solids.
Ensure mud is conditioned to specification prior to final pulling out for commencing completion operations.

PRODUCTS TYPE	Unit	Size	Concentrations New	Concentrations Maint	Tot Unit
Cal Carbonate (M)	kg	25	15.0	1.0	430
Cal Carbonate (C)	kg	25	10.0	1.0	295
Caustic Potash	kg	25	0.3	0.1	10
Sodium Bicarbonate	kg	25	0.2	0.0	5
Dualflo	lb	50	3.0	0.5	104
Flo-Vis Plus	kg	25	2.0	0.5	67
Glute 25	lt	25	0.2	0.1	8
KCl	mt	1	12.0	2.0	9
OS-1	kg	25	0.2	0.1	8
Total section cost				US$	46,066

VOLUMES	bbl
SURFACE	500
RISER	90
CASING	201
OPEN HOLE	111
DILUTION	578
HOLE TOT	402
TOT. VOL	1480
RECEIVED	0
NEW MUD	1480
MUD LEFT	902
Max Angle, deg	89
Dilut. fac	1.20

Clean up pills and displacements prior to completion operations

COMMENTS
After reaching TD, conducting a wiper trip and circulating the hole clean, spot FLOPRO SF in open hole and 500 ft inside previous csg shoe.
Pull up to 300ft inside previous csg shoe and pump the following sequence of clean up pills.
(1) 25 bbls HiVis spacer
(2) 50 bbl SAFE -SURF WN surfactant pill
(3) 25 bbl brine based HiVis spacer
The clean up pills should be followed immediately by pumping uninhibited 1.08 SG KCL brine.
At the end of this operation the open hole is left covered by FLOPRO SF and the casing is filled with uninhibited KCL brine in readiness for running screens.

PRODUCTS TYPE	Unit	Size	Concentrations New	Concentrations Maint	Tot Unit	VOLUMES	bbl
KCL	mt	1			11		
Flovis Plus	kg	25			7		
Duotec	kg	25			4		
SAFE SURF WN	kg	200			4		
Total section cost				US$	2,359		

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APPENDIX 3 - PRESSURE TESTING

The Ocean General BOP configuration is as follows:

Component	Type / Pressure Rating
Annular	Shaffer Spherical – 5,000 psi (34.5 mPa)
Annular	Shaffer Spherical – 5,000 psi (34.5 mPa)
LMRP connector	18-3/4" Vetco H-4
Top rams: Shear / Blind rams	Shaffer SL - 10,000 psi (69 mPa)
Upper choke line entry	10,000 psi (69 mPa)
Middle upper rams: Variable rams	Shaffer SL - 10,000 psi (69 mPa)
Middle lower rams: 5" pipe rams	Shaffer SL - 10,000 psi (69 mPa)
Kill line entry	10,000 psi (69 mPa)
Lower rams 10 ¾" pipe rams	Shaffer SL - 10,000 psi (69 mPa)
Lower choke line entry	10,000 psi (69 mPa)
Wellhead connector	18-3/4" Vetco H4

Pressure Test Schedule

Item	Surface Test psi (mPa)	13.3/8" Casing psi (mPa)	9.5/8" Casing psi (mPa)
Annular Preventer	2,500 (17.5)		2,500 (17.5)
Pipe Rams	5,000 (34.5)		5,000 (34.5)
Blind/Shear Ram	5,000 (34.5)		5,000 (34.5)
Choke & Kill Lines / Manifold	5,000 (34.5)	5,000 (34.5)	5,000 (34.5)
Standpipe, TDS IBOP	5,000 (34.5)	5,000 (34.5)	5,000 (34.5)
Seal Assembly			5,000 (34.5)
Casing Test (at plug bump)		2,500 (17.25)	3,000 (20.7)
Maximum Anticipated Surface Pressure (MASP)		993 (6.8)	1,005 (6.9)
70% of Casing Burst (Information only)		3,500 (24.25)	4,809 (33.7)
LOT/FIT		LOT	FIT

Note: The low pressure test shall be 200 psi (1.4 mPa). All pressure tests shall be held for 10 minutes.

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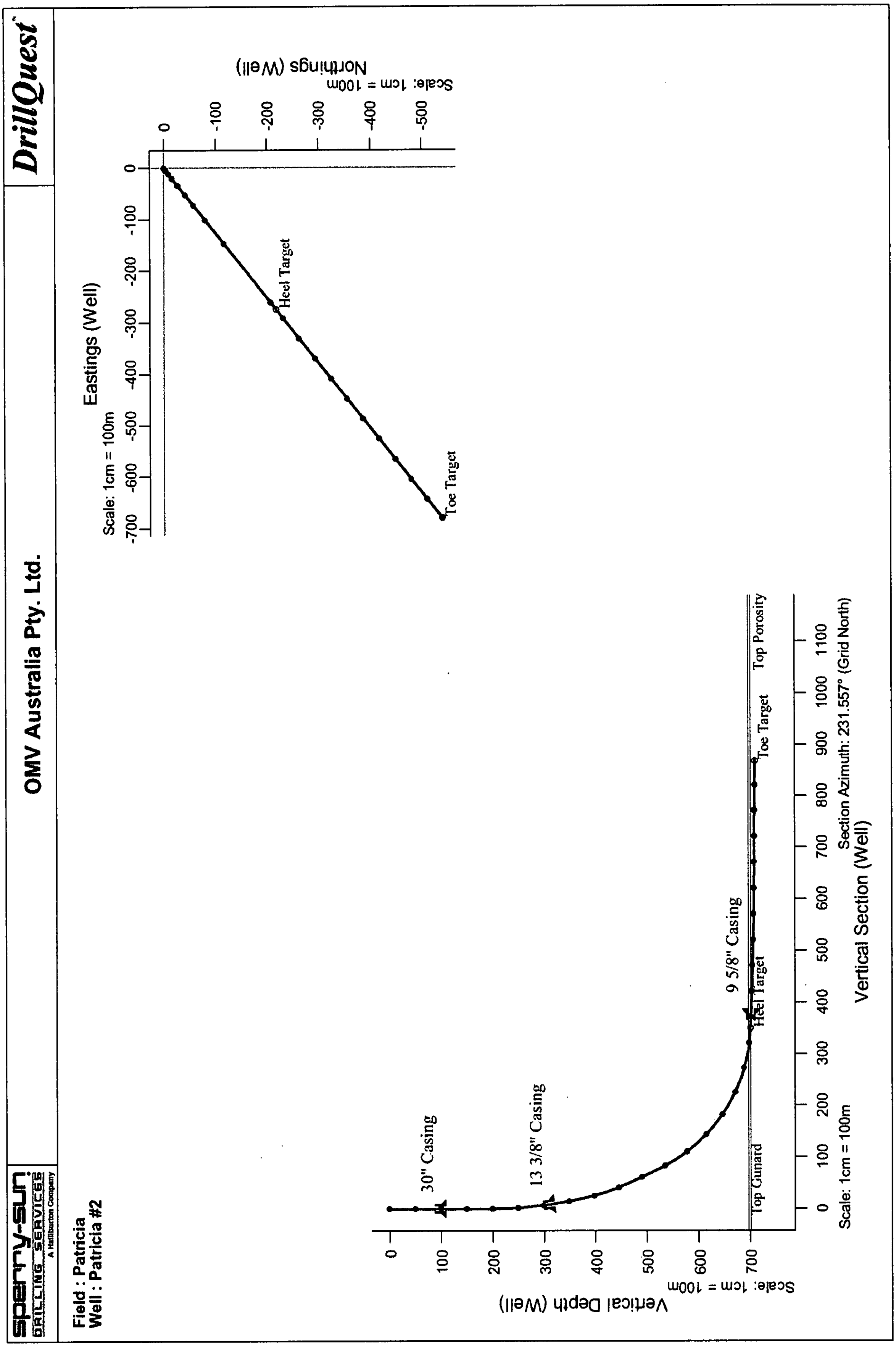
APPENDIX 4 – DIRECTIONAL DETAILS



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Proposal Report for Patricia - Patricia #2 : Revision #4

Measured Depth (m)	Incl.	Azim.	Sub-Sea Depth (m)	Vertical Depth (m)	Local Coordinates Northings (m)	Local Coordinates Eastings (m)	Global Coordinates Northings (m)	Global Coordinates Eastings (m)	Dogleg Rate (°/30m)	Vertical Section	Comment
0.00	0.000	0.000	-25.00	0.00	0.00 N	0.00 E	5790097.80 N	627209.00 E		0.00	
109.00	0.000	0.000	84.00	109.00	0.00 N	0.00 E	5790097.80 N	627209.00 E	0.00	0.00	30" Casing
200.00	0.000	0.000	175.00	200.00	0.00 N	0.00 E	5790097.80 N	627209.00 E	0.00	0.00	
250.00	3.707	231.442	224.97	249.97	1.01 S	1.26 W	5790096.79 N	627207.74 E	2.22	1.62	
300.00	7.415	231.442	274.72	299.72	4.03 S	5.05 W	5790093.77 N	627203.95 E	2.22	6.46	
320.49	8.934	231.442	295.00	320.00	5.84 S	7.33 W	5790091.96 N	627201.67 E	2.22	9.37	13 3/8" Casing
350.00	11.122	231.442	324.06	349.06	9.05 S	11.35 W	5790088.75 N	627197.65 E	2.22	14.51	
400.00	14.829	231.442	372.77	397.77	16.04 S	20.13 W	5790081.76 N	627188.87 E	2.22	25.74	
402.30	15.000	231.442	375.00	400.00	16.41 S	20.59 W	5790081.39 N	627188.41 E	2.22	26.33	
450.00	22.155	231.442	420.18	445.18	25.88 S	32.46 W	5790071.92 N	627176.54 E	4.50	41.52	
468.69	24.958	231.442	437.31	462.31	30.53 S	38.30 W	5790067.27 N	627170.70 E	4.50	48.98	
500.00	24.958	231.442	465.70	490.70	38.77 S	48.64 W	5790059.03 N	627160.36 E	0.00	62.20	
532.86	24.958	231.442	495.49	520.49	47.41 S	59.48 W	5790050.39 N	627149.52 E	0.00	76.06	
550.00	28.101	231.460	510.82	535.82	52.18 S	65.47 W	5790045.62 N	627143.53 E	5.50	83.72	
600.00	37.268	231.497	552.86	577.86	68.98 S	86.57 W	5790028.82 N	627122.43 E	5.50	110.69	
650.00	46.434	231.521	590.07	615.07	89.72 S	112.65 W	5790008.08 N	627096.35 E	5.50	144.01	
700.00	55.601	231.539	621.49	646.49	113.87 S	143.05 W	5789983.93 N	627065.95 E	5.50	182.84	
750.00	64.767	231.553	646.32	671.32	140.82 S	176.99 W	5789956.98 N	627032.01 E	5.50	226.17	
800.00	73.934	231.565	663.93	688.93	169.88 S	213.59 W	5789927.92 N	626995.41 E	5.50	272.91	
834.88	80.330	231.573	671.70	696.70	191.00 S	240.22 W	5789906.80 N	626968.78 E	5.50	306.90	Top Gunard
850.00	83.101	231.576	673.88	698.88	200.30 S	251.94 W	5789897.50 N	626957.06 E	5.50	321.86	
878.25	88.280	231.582	676.00	701.00	217.80 S	274.00 W	5789880.00 N	626935.00 E	5.50	350.02	Heel Target, Current Target
894.91	88.280	231.582	676.50	701.50	228.15 S	287.05 W	5789869.65 N	626921.95 E	0.00	366.67	Top Porosity
900.00	88.280	231.582	676.65	701.65	231.31 S	291.03 W	5789866.49 N	626917.97 E	0.00	371.76	
914.91	88.280	231.582	677.10	702.10	240.57 S	302.71 W	5789857.23 N	626906.29 E	0.00	386.66	9 5/8" Casing

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Measured Depth (m)	Incl.	Azim.	Sub-Sea Depth (m)	Vertical Depth (m)	Local Coordinates Northings (m)	Local Coordinates Eastings (m)	Global Coordinates Northings (m)	Global Coordinates Eastings (m)	Dogleg Rate (°/30m)	Vertical Section	Comment
950.00	88.280	231.582	678.15	703.15	262.36 S	330.19 W	5789835.44 N	626878.81 E	0.00	421.74	
1000.00	88.280	231.582	679.65	704.65	293.42 S	369.35 W	5789804.38 N	626839.65 E	0.00	471.71	
1050.00	88.280	231.582	681.16	706.16	324.48 S	408.51 W	5789773.32 N	626800.49 E	0.00	521.69	
1067.86	88.280	231.582	681.69	706.69	335.57 S	422.49 W	5789762.23 N	626786.51 E	0.00	539.54	
1100.00	89.351	231.582	682.36	707.36	355.54 S	447.67 W	5789742.26 N	626761.33 E	1.00	571.68	
1104.16	89.490	231.582	682.40	707.40	358.12 S	450.93 W	5789739.68 N	626758.07 E	1.00	575.83	
1150.00	89.490	231.582	682.81	707.81	386.60 S	486.84 W	5789711.20 N	626722.16 E	0.00	621.67	
1200.00	89.490	231.582	683.25	708.25	417.67 S	526.01 W	5789680.13 N	626682.99 E	0.00	671.67	
1250.00	89.490	231.582	683.70	708.70	448.74 S	565.19 W	5789649.06 N	626643.81 E	0.00	721.67	
1300.00	89.490	231.582	684.14	709.14	479.81 S	604.36 W	5789617.99 N	626604.64 E	0.00	771.67	
1350.00	89.490	231.582	684.59	709.59	510.88 S	643.53 W	5789586.92 N	626565.47 E	0.00	821.67	
1396.54	89.490	231.582	685.00	710.00	539.80 S	680.00 W	5789558.00 N	626529.00 E	0.00	868.21	Toe Target, Current Target

All data is in Metres unless otherwise stated. Directions and coordinates are relative to Grid North.
Vertical depths are relative to Well. Northings and Eastings are relative to Well.
Global Northings and Eastings are relative to UTM Zone 55S on Australian Geodetic Datum 1966, Meters.

The Dogleg Severity is in Degrees per 30 metres.
Vertical Section is from Well and calculated along an Azimuth of 231.557° (Grid).

Coordinate System is UTM Zone 55S on Australian Geodetic Datum 1966, Meters.
Grid Convergence at Surface is -0.893°.

Based upon Minimum Curvature type calculations, at a Measured Depth of 1396.54m.,
The Bottom Hole Displacement is 868.21m., in the Direction of 231.557° (Grid).

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Formation Tops

Measured Depth (m)	Vertical Depth (m)	Sub-Sea Depth (m)	Northings (m)	Eastings (m)	Dip Deg.	Dip Dir. Deg.	Formation Name
834.88	696.70	671.70	191.00 S	240.22 W	0.000	0.000	Top Gunard
894.91	701.50	676.50	228.15 S	287.05 W	0.000	0.000	Top Porosity

Casing details

From		To		
Measured Depth (m)	Vertical Depth (m)	Measured Depth (m)	Vertical Depth (m)	Casing Detail
<Surface>	<Surface>	109.00	109.00	30" Casing
<Surface>	<Surface>	320.49	320.00	13 3/8" Casing
<Surface>	<Surface>	914.91	702.10	9 5/8" Casing

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APPENDIX 5 – SAMPLING REQUIREMENTS

Sample Type	No of Sample Sets	Min. Sample Recovery	Container Type	Container Supplied by	Collect for	Sample Interval	Comments
Cuttings washed and air dried	1 (set A)1	5g	Samplex Tray	Mudlogging Contractor	Wellsite Geologist	Every 5m from 1st return to total depth	Label with operator, well name and depth
	1 (set B)	100g	Paper Envelope		OMV Australia		
	1 (set C)	100g	Paper Envelope		AGSO		
	1 (set D)	100g	Paper Envelope		VICNRE		
	1 (set E)	100g	Paper Envelope		Trinity Gas Resources		
	1 (set F)	100g	Paper Envelope		Santos		
Cuttings Washed Wet	Not required						
Cuttings Unwashed Wet	Not required						
Sidewall Cores	Not required						
Conventional Core	Not planned						
Water	Not Planned						
Drill Water	3	1 litre	Plastic or glass bottle	Mudlogging Contractor	OMV Australia		Sampled for comparison purposes
Oil*	Not Planned						
Gas*	Refer to Testing Program						Samples will be collected in the flow rate tests per Res Eng instructions
Mud	1	1 litre	Plastic bottle	Mudlogging Contractor	OMV Australia	Start, middle and end of horizontal section	All samples held on rig till end of well then dispatched at instruction of Operations Geologist
Mud Additives	1	100g	Ziplock bag	Mudlogging Contractor	OMV Australia	All mud chemicals on rig	Only dry chemicals to be sampled. Liquid mud additives as for oil samples.

Notes:-

- Samples containing, or likely to contain, oil and or gas must not be transported by aircraft.
- Wellsite Geologist's dried samples in Samplex trays to OMV Australia at end of well

APPENDIX 6 – SAMPLE DISTRIBUTION

Samples to be dispatched at the end of the well directly to the recipients as noted in Appendix 5. All samples to be fully manifested, copy of transmittal placed inside and outside each box and faxed/emailed to Operations Geologist and Logistics Co-ordinator.

"Hot shot" samples (non-hydrocarbon) will be sent to appropriate laboratory/recipient by company personnel where possible or courier pouch. Transmittals sent to Operations Geologist.

Sample Distribution Addresses:

OMV Australia Pty Ltd

Rock samples (cuttings, cores and sidewall cores) to be sent to:

Rock samples to:
OMV Australia Pty Ltd Sample Store
C/o Kestrel Information Management Pty Ltd
39 McDowell Street
Welshpool WA 6106
Tel 08-9350 3170
Fax 08-9350 3179
Attn: Barry Lloyd

Fluid samples to:
To be advised

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Government

Cuttings, samples to be sent to:

Victorian Department of Natural Resources and Environment
Core and Cuttings Store
South Road
Werribee
VIC 3030
Telephone: 03 9412 5055

Australian Geological Survey Organisation
AGSO Data Repositories
Cnr Jerrabomberra Avenue and Hindmarsh Drive
Symonston ACT 2609
Tel: 02-6249 9222
Fax: 02-6269 9903 Attn: Eddie Resiak

Joint Venture

Trinity Gas Resources Pty Ltd
Level 9, Chancery House
37 St Georges Tce
Perth, WA 6000
Tel: (08) 9225 5078
Fax: (08) 9225 5111
Attn: Mr Tomoyuki Watanabe

Santos
Level 8, Santos House
91 King William Street
Adelaide, SA 5000
Tel: (08) 8224 7128
Fax: (08) 8224 7710
Attn: Mr Andy Pietsch

APPENDIX 7 – DATA DISTRIBUTION

Operational Reports

	OMV-Australia	OMV-AG	Trinity Gas Resources	Santos	AGSO	VicDNRE
Daily Drilling Report	✔	✔	✔	✔	✔	✔
Daily Mud Properties Report	✔	✔				
Daily Geological Report	✔	✔	✔	✔	✔	✔
Daily Mudlog Update	✔	✔	✔	✔	✔	✔
Daily Pore Pressure Log Update	✔	✔	✔	✔		
Image of FEWD logs (fax/email)	✔	✔	✔	✔		✔
Basic FEWD Data (LAS file)	✔	✔				✔
Basic FEWD Pressure Data (Excel/text file)	✔	✔	✔	✔		✔

Final Data Distribution

	OMV Aust	OMV AG	Trinity Gas Resources	Santos	AGSO	VicDNRE	TOTAL
Wireline data CD	2	1	1	1	1	1	6
Wireline Log Print	2	1	1	1	1	1	6
Mudlog Data CD	2	1	1	1	1	1	6
Mudlog Report (includes prints)	2	1	1	1	1	1	6
FEWD Report (includes prints)							
WCR Drilling	2	1	1	1	1	1	6
WCR Geological Basic Data	2	1	1	1	1	1	6
WCR Geological Interpretive Data	2	1	1	1	1	1	6
VSP Data	2	1	1	1	1	1	6
VSP Report	2	1	1	1	1	1	6

Notes

1. All communications to and from the rig will be via OMV Australia Pty Ltd.
2. The PE (or in his absence, the WSG) is responsible for ensuring all log data sets are depth matched and the final data disks are delivered with verification listings.
3. The WSG, PE and Drilling Engineer are responsible for removal of all data (reports, samples, tapes and disks, log prints and films) from the rig at the end of the well. Data is to be returned to OMV Australia Pty Ltd, Perth office.

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APPENDIX 8 – OPERATIONAL DATA REPORTING

Rig to OMV Australia Pty Ltd, by e-mail (or fax if communications are poor)

Drilling	ron.king@omv.com.au colin.allport@omv.com.au steve.crocker@omv.com.au
Geology	mark.adamson@omv.com.au
OMV Australia Pty Ltd, Fax	(08) 9223 5004
Operations Fax	(08) 9223 5009
Fax for Logs	(08) tba

Forwarded by OMV Australia Pty Ltd

- Daily Drilling Report
- Directional Report
- Daily Geological Report
- Daily Mudlogging Report
- FEWD Report

To: Joint Venture

Trinity Gas Resources
Attention: Mr T. Watanabe
Phone: (08) 9225 5078
Fax: (09) 9225 5111
Email: watanabe@diamondgas.com.au

Santos Ltd
Attention: Mr A.Pietsch
Phone: (08) 8224 7128
Fax: (08) 8224 7710
Email: andy.pietsch@santos.com.au

To: Government

Mr Eugene Petrie
Petroleum Resources
Australian Geological Survey Organisation
Cnr Jerrabomberra Avenue and Hindmarsh Drive
Symonston ACT 2609
Phone: (02) 6249 9111
Fax: (02) 6249 9962
Email: drilling.reports@agso.gov.au

Horacio Haag
Manager Petroleum Regulation
Minerals and Petroleum Regulation Unit
250 Victoria Parade
East Melbourne
Victoria 3002
Phone: (03) 9412 5101
Fax:
Email: horacio.haag@nre.vic.gov.au

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OMV Australia Pty Ltd

Australia
Offshore Gippsland Basin

Permit VIC/L21

Patricia 2

Completion & Testing Program
Revision 0
May 2002

Prepared By: ....
Lindsay Taylor
Principal Production Technologist
Date: 27 May 02.

Reviewed By: p.p. ....
Mike Mulliner
Well Test Engineer
Date 27 May 02.

Reviewed By: ....
Ron King
Drilling Superintendent
Date: 27 May 02

Reviewed By: ....
Andy Ion
Reservoir Engineer
Date: 27/5/02

Approved By: ....
Colin Allport
Drilling manager
Date: 27 May 2002.

Approved By: ....
Graham Dwyer
Operations Manager
Date: 27 May 02

DISTRIBUTION LIST	
EXTERNAL	
VicNRE	Copy No. 1
Drilling Contractor - Office	Copy No. 2
Drilling Contractor - Wellsite	Copy No. 3
Drilling Fluid Contractor	Copy No. 4
Mud Logging Contractor	Copy No. 5
Tubular Handling Contractor	Copy No. 6
Testing Contractor	Copy No. 7
Completion Services Contractor	Copy No 8
OMV	
Operations Manager	Copy No. 9
Drilling Manager	Copy No. 10
Exploration Manager	Copy No. 11
Drilling Superintendent	Copy No. 12
Senior Drilling Engineer	Copy No. 13
OMV Drilling Supervisor	Copy No. 14
Materials & Logistics Coordinator	Copy No. 15
Senior Reservoir Engineer	Copy No. 16
Production Technologist	Copy No. 17
Well Test Engineer	Copy No. 18
Senior Operations Geologist	Copy No. 19
Wellsite Geologist	Copy No. 20
Drilling Library	Copy No. 21
JOINT VENTURES	
Trinity Gas resources	Copy No 22
Santos Limited	Copy No. 23
OMV Timor Sea Pty Ltd	Copy No 24
File	Original

REVISION LIST

Rev No.	Description	Date
0	. Issued	27th May 2002

CONTENTS.

1 INTRODUCTION

Patricia 2 is a sub sea development well located in Bass Strait, off the coast of Victoria.

The program is written to follow on directly from the Patricia 2 Drilling Programme and details the proposed well completion, cleanup, testing and suspension program using the Ocean Bounty semi submersible drilling rig.

The scope of work involves installing 6-5/8" Excluder 2000 sand screens in the 8-1/2" near horizontal well bore, running the 5-$^1/_2$" completion string, clean up and testing operations and securing the well prior to release of the drilling rig. The well will be left ready for production operations.

1.1 General

CHANGES TO WELL COMPLETION AND TEST PROGRAMME

The Well Completion and Testing Program will be as approved by OMV management prior to commencing well completion and testing operations. If, during the completion or testing operations, a significant change to the Well Testing Program is required, a revision will be agreed to and written approval obtained from OMV management. All significant changes will require the same technical and management approvals as this document.

Minor procedural changes such as may be required to enhance safety or operational requirements, may be initiated offshore and signed off by the OMV Drilling Supervisor and Diamond Offshore OIM, in consultation with the Well Test Engineer.

OMV Drilling Manager and Drilling Superintendent are to be informed of any variations from the approved Well Testing and Completion Programme.

Control and Responsibilities of Well Completion and Testing

The Diamond Offshore OIM is in overall charge and responsible for the safety of the rig and its personnel. The OIM is to ensure that the Well Operations Procedures for Well Testing in the Ocean Bounty Well Operations Manual are adhered to.

The OMV Drilling Supervisor is operationally responsible for carrying out the Well Completion and Testing Program, and for ensuring that the well completion and testing operations are performed by Diamond Offshore and the individual Service Companies in accordance with the agreed procedures.

The responsibility for relevant aspects of the Well Completion Operations will be delegated by the OMV Drilling Supervisor to the on-site OMV Well Completions Engineer who will supervise the individual Service Companies involved in the well completion operations, and provide technical support to the OMV Drilling Supervisor.

The responsibility for relevant aspects of the Well Testing Operations will be delegated by the OMV Drilling Supervisor to the on-site OMV Well Test Engineer who will supervise the individual Service Companies involved in the well testing operations, and provide technical support to the OMV Drilling Supervisor, particularly during the flowing period, when produced fluids will be passed through the test separator for measurement and disposal.

OMV Reservoir Engineer will be responsible for ensuring that all data and samples necessary to meet the well objectives are collected and correctly documented. The OMV Reservoir Engineer will also be responsible for determining optimum flowing and shut in periods to minimise rig time while meeting the well test objectives.

1.2 Program Objectives

- To Install 6-5/8" Excluder 2000 sand screens in the horizontal well bore.
- Install 5-1/2" well completion string
- Determine initial static reservoir pressures.
- Clean up wells to remove residual mud/filtrate & promote flow contribution from total length while minimising skin damage and plugging of the sand screens.
- Determine rate-dependent wellbore skin factor.
- Determine well deliverability.
- Estimate average formation permeability.
- Estimate static and flowing pressure gradients.
- Obtain representative reservoir fluid sample.
- Secure the well for future production.

2 WELL AND RESERVOIR DATA

Well Drilling Data	
Point of Reference	LAT.
Water Depth	51m
Rotary Table elevation above sea level	25 m
Sea bed below RT	76m
Proposed Total Depth	1433m MDRT, 710m TVD
Proposed 9-5/8" Casing Shoe	915m MDRT. 702m TVD
Proposed TOP of screens	917m MDRT. 702m TVD
Proposed TOP of Liner Hanger	895m MDRT, 701m TVD
Proposed Sand Screen Shoe	1423m MDRT, 710m TVD
Top target formation	895m MDRT, 701m TVD
Production Casing	9-5/8", L80, 47ppf, NK3SB
Production Tubing	5-1/2", 13Cr, 17 ppf, NK3SB
Hole deviation	As per directional program.
Reservoir Data (Expected)	
Gross sand interval above GWC	65 m
Gas-Water Contact	730mSS (MSL)
Sand Net to Gross	90%
Porosity range	21% - 34%
Permeability expected	30 mD
Permeability range	1-100 mD
Formation fluid expected	Gas
Gas gravity	0.57
Reservoir pressure	1,075 psia
Pressure gradient	Hydrostatic (normally pressured)
Reservoir temperature	50°C
Expected H_2S content	Nil
Expected CO_2 content in gas phase	0.5-1.5 % mole

3 PRIMARY REFERENCE DOCUMENTS

The completion of Patricia 2 will be carried out in accordance with the following primary reference document:

Safety Case Bridging Document: Doc No. HSE-00-ZD-004. Issue date.???????

And the following key reference documents:

Patricia Drilling Programme

Ocean Bounty Well Operations Manual (DOGC Doc. EHS-OG-01)

OMV Emergency Response Plan – HSE-00-ZD-002

OMV Oil Spill Contingency Plan – HSE-00-ZD-003

Statutory regulations that must be adhered to include:

Petroleum (Submerged Lands) Acts 1967 and related Regulations

Petroleum (Submerged Lands) Acts – Specific Requirements as to Offshore Petroleum Exploration and Production.

4 OPERATIONAL SUMMARY

Continually monitor the well for losses/gains.

Establish parameters for running Sand Screens and 2-$^{7}/_{8}$" Inner wash pipe.

RIH with Sand Screens and 2-$^{7}/_{8}$" wash pipe.

Make up the required amount 7" casing and check 7" crossover pup joints.

Make up liner hanger / packer assembly with running tool and RIH on drill pipe.

Circulate and displace the open hole/sand screen annulus and spot a Wellzyme A pill in the open hole around the screens.

Set and test Liner Hanger and top packer.

Release Liner Hanger running tool and POOH to the top of the liner hanger.

Circulate and displace the casing with filtered KCL brine.

POOH with liner hanger running tool

Run the 5-$^{1}/_{2}$" NK-3SB production tubing, space out. Land and secure tubing hanger. A 7" Sub Sea Test Tree will be installed above the Tuning Hanger running tool and a 7" lubricator valve will be installed in the 7" landing string to provide well security.

Install 7" flow head, rig up and test surface equipment.

Rig up coil tubing on test head.

Rig up and test nitrogen equipment.

RIH with coil tubing to approximately top of liner.

Pump nitrogen to kick off, clean up and test well as per following summary:

A single zone gas test in the Gurnard formation to obtain flow rates, BHP, BHT and sand production, if any.

Planned test periods are:

Initial flow and shut in,

Clean-up and shut in

Multi-rate flow test and gradient survey and shut in

Reservoir pressure/temperature data will be obtained from downhole surface read-out gauges run on coil tubing with internal electric conductor line

Safety of the surface equipment will be provided by an ESD system with remote shut-down stations.

Produced sand, liquid (if any) and gas samples will be collected for analyses

POOH with coil tubing and rig down.

Rig up wire line BOP & lubricator and test.

Run and set SSR plug in then tuning hanger and test.

Bleed off gas in running string through the test equipment and displace with brine.

Rig down wire line.

Retrieve running string.

Make up, run and install internal tree cap in the Xmas Tree and test.

Rig up wire line, Run, install and test SSR plug in the Internal tree cap

Rig down wire line and retrieve the running string

Disconnect IWOCS plate from Xmas Tree and install cover plate with ROV.

Retrieve BOP.

Install Corrosion Cap on Xmas Tree.

Secure rig, retrieve anchors and release rig.

5 SUMMARY OF EQUIPMENT AND CONTRACTORS

Equipment and contractors required for Patricia 2 well test are summarised as follows:

Contractor	Equipment Type	Equipment Description
Baker	Completion equipment and running tools	Sand Screen, Liner Hanger, Seal assembly, TRSSV. Wireline tools and plugs for TRSCSSV
Cameron	Sub Sea Xmas Tree and running tools	Tubing Hanger, Internal tree cap, SSR plugs,
EXPRO	Sub Sea and surface Test package	7" Sub Sea lubricator valve, Xmas tree and Surface test Equipment
TBA	Fishing	Test String Fishing Equipment
PCS	Tubular Handling Equipment	Tubular Handling Equipment for completion string and sand screens
BJ Services	Coil tubing	1-$^{1}/_{2}$ " Coil tubing w/mono-conductor line
BJ Services	Gauges	Downhole surface readout gauges
BJ Services	Nitrogen	Converter and 2000 gals liquid N2 tank.
EXPRO	Fluid Sampling	PVT Gas Sampling Cylinders 6 x 20 litre PVT Oil Sampling Cylinders 6 x 640 cc
Scottech	Filtration	Fluid Filter Unit
MI	Fluids and LCM	Wellbore Fluids Materials for LCM Pill

6 RUNNING 6-5/8" EXCLUDER 2000 SAND SCREENS

6.1 PRE RUNNING CHECKS

Drill pipe to be accurately strapped and recorded.

Clean all box and pins on the sand screens, 2-$^7/_8$" wash pipe, cross over pup joints and 7" Vam Top HT casing space out joints (Do not re-dope) strap and record on tally sheets provided

Strap liner hanger components and record on tally sheet provided.

Check all ODs, IDs and Serial Numbers and record on tally sheet provided.

Drift all assemblies and tubulars [2-$^7/_8$" wash pipe. (2.349"), 5-$^1/_2$" NK-3SB x 17 ppf tubing (4.767") and 7" Vam Top HT x 29ppf casing (6.059")] and record on tally sheet provided.

Establish minimum acceptable setting depth for the Liner and Top Packer at approximately 40m inside 9-5/8" shoe. The liner hanger should be located in approximately the middle of a casing joint.

Establish DP frictional torque values, ensure that DP Rotational Tests are performed, at both 10RPM and 20RPM with the Drill String/Wiper trip string, at both TD, and at the 9-$^5/_8$"casing Shoe on the last trip out of the hole.

Baker Engineer to establish pump and circulating pressures thru the 2-$^7/_8$" wash string and around the screens to avoid pre-setting the liner hanger and or damaging the integral top packer.

All flow rates and pressures are to be monitored.

Check all tubular handling equipment to ensure that all equipment is available and in good working order. .

Ensure the stab in safety valve dressed with the correct cross over is on the rig floor.

Ensure that tubing drifts for 5-$^1/_2$"NK-3SB tubing are available on the rig floor to drift tubing when running.

Ensure Bestolife 2000 tubing dope is available on the rig floor.

6.2 Running Procedures

6.2.1 Hold a JAS prior to work commencing ensuring all safety aspects of the operation is covered.

6.2.2 Rig up the power tong and Torque turn unit, ensure the make up and back up tongs have non marking insert dies and the Torque turn unit is programmed for the correct make up torque for 6-$^5/_8$" Fox K connections.

Note: See Appendix 4 for Make Up Torque values.

6.2.3 Pick up and RIH Shoe track assembly (GPV Set Shoe, pup joint, O-ring Seal Sub, X/O, 3-$^1/_2$" SLHT pin x 6-$^5/_8$" Fox K box.)

Note: Check the float valves in the GPV by observing that the pipe does not fill up through the shoe, and that when filled from the top, mud will flow out of the shoe.

6.2.4 Run 500m of Excluder2000 sand screens as per Baker procedures

Note: Applying torque to the sand screens should be avoided. If torque is required, the Baker engineer is to advise the maximum allowable torque

6.2.5 Make up assembly. 6-5/8" Fox K (pin) x 7" New Vam (box) and 7" New Vam (pin) x Vam Top HT (box) crossovers.

6.2.6 Make up 7" Vam Top HT casing as required to set top of the Excluder 2000 sand screen at approximately 1m below the 9-5/8" casing shoe as advised by the Reservoir Engineer and the liner hanger approximately 20m above the 9-5/8" casing shoe. Hang in rotary table.

6.2.7 Make up cross over pup joint 2.9m 7" Vam Top HT (pin) x 7" New Vam (box) to 7" Vam Top HT casing joints.

Note. Any difficulties running the sand screens are to be reported to the Baker and OMV engineers.

Note: See Appendix 4 for Make Up Torque values

6.2.8 Rig up False Rotary & Handling Tools to run 2 $^7/_8$" inner wash string inside Sand Screen Liner.

6.2.9 Run the inner wash string (with slick joint stinger assembly on bottom) and space out so that slick joint stinger is stabbed into the O-ring seal sub in the shoe track joint.

Note: Ensure slick joint stinger remains stabbed in the o-ring seal sub.

Note: Fill up 2-$^7/_8$" " wash pipe every 5 stands.

6.2.10 Pick up the SLZXP Liner Hanger/Packer assembly, C/W with running tool installed and make up tail pipe to the 2-7/8" inner wash string. Insure 2 $^7/_8$" H.D. Tubing Swivel is functioning. Lower string and make up to the 7" casing connection using a chain tong to start the connection.

Note: Be careful not to prematurely back off the HR Setting Tool.

6.2.11 Rig down the false table and 2-7/8" handling equipment.

6.2.12 LEAVE THE CASING SLIPS SET ON THE CASING and pick up assembly to check if the setting tool and all other liner hanger connections are made up properly. Check SLZXP hanger / packer assembly for any damage. Adjust the setting nut to have a gap of 7/16" to the SLZXP extension. If assembly is correct then pull the slips.

6.2.13 Record pick up and slack off weights.

Note: Ensure the drill pipe stab in safety valve is on the rig floor.

6.2.14 Lower hanger assembly through the rotary and set the DP slips on the lift nipple, DO NOT SET SLIPS OPN THE SLZXP Packer or PBR extension. Keep the hanger / packer centred while lowering through the table to avoid damage to the element, slips

6.2.15 Rig up and circulate 1.5 times the contents of the liner with un-inhibited clean brine using the rig pumps. Maximum circulating pressure not to exceed 65% (978psi) of Hydraulic Pusher Tool shear pressure. Check no leaks at Pusher Tool Junk Cover.

6.2.16 RIH on DP. Drift DP while RIH. Fill the pipe every 5 stands.

6.2.17 Circulate liner volume with clean un-inhibited brine with the liner shoe at the 9 5/8" casing shoe. Note the slackoff and pick up string weights. Maximum circulating pressure not to exceed 65% (978 psi) of Hydraulic Pusher Tool shear pressure.

6.2.18 Continue to RIH.

Note: During running in open hole the string must always be pulled into tension, before breaking circulation, and when washing or reaming the sand screens to bottom. The HR Tool will not release when in tension. The surface pressure should not exceed 65% (978 psi) of the recorded Hydraulic Pusher Tool shear pressure. Returns should be seen at surface before continuing running in hole.

Note: When running in open hole fill up the drill pipe every 5 stands without interrupting the smooth running of the liner in the hole.

Note: The Baker Engineer will advise the combination of maximum set down weight on the rig. If maximum set down weights are reached while "working " the sand screens and Liner to bottom, and if some torque is generated, then all torque should be let out of the string in a controlled manner prior to picking up the running string to avoid mechanically releasing HR Running Tool.

6.2.19 Run the sand screens and liner hanger to the required setting depth, record pick-up and slack-off weights to determine drag and mark the pipe at the rotary table, this will be the setting depth of the liner hanger. A minimum of 400m of sand screens is required through the Gurnard producing formation.

Note: Ensure final movement is upwards to have the liner in tension.

6.2.20 Note: The SLZXP Hanger / Packer element shall be as close as possible in the middle of a casing joint. Mark the drill pipe at the rotary table. To indicate the setting depth of the liner hanger

6.2.21 Rig up to circulate. Break circulation with clean un-inhibited brine and pump the 1.5 times the volume of the running string and open hole. Pump a Hi-Vis pill followed by clean un-inhibited brine to displace to the Flo-Pro SF fluid from the open hole section and circulate it out of the hole with clean un-inhibited brine. (See appendix 5 for fluid properties).

Note: While circulation a pump rate to provide a minimum of 100m / minute in the screen / open hole annulus should be used although surface pressure should not exceed 65% (978 psi) of the recorded Hydraulic Pusher Tool shear pressure.

Note: While circulating, monitor the pump pressure and returns to detect bridging in the Sand Screen / Liner x open hole and 9-5/8" annulus.

6.2.22 Circulate the open hole/sand screen volume plus 2 bbls with Wellzyme A to spot a pill in the sand screen x open hole annulus. with clean un-inhibited brine. (See appendix 5 for fluid properties).

6.2.23 Release the 1.500" setting ball.

6.2.24 Ensure HR running is in tension,. Rig up the Cement unit to the drill pipe and test the lines to 5000 psi for 5 minutes

6.2.25 Circulate the ball down slowly to the seat in the ST Landing Sub (It should take only 1 bbl to get the ball on seat). Do not slam the ball onto the ball seat

6.2.26 When the ball lands, with slow pumps and increase pressure to 2,500 psi in the method following, This will set the SLZXP hanger. (See attachment for operational shear values of the HR running tool).

6.2.27 Once the SLZXP hanger has set, hold 2500 psi and pick up weight to confirm it has fully set. Compare movement up against reference point. Bleed down drill pipe to 0psi

6.2.28 Close the pipe rams. Rig up cement unit to the kill line and pressure test the surface lines to 5000 psi.for 5 minutes. With the drill pipe open at surface pressure test the annular and SLZXP element to 1500psi with running tools in tension for 10 minutes. Observe drill pipe for returns. Record all pressures.

6.2.29 Bleed annulus pressure slowly to zero, Record returns. Open DP rams.

6.2.30 Rig up the cement unit to the drill pipe and pressure test the surface lines to 5000 psi. Pressure up the drill pipe to initiate second shear in the pusher tool at 3000psi. At this pressure the neutraliser piston will shear and the compression in the tool will be released. Until this second shear is activated in the pusher tool, the HR running tool will remain in tension and will not be released.

Note: Once the compression in the pusher tool has been released, the HR running tool will be in compression. The shear screws in the HR tool will then shear at 2450psi. Pick up drill string to confirm lost of liner weight. The HR running tool will now be in a position to be released from the SLZXP.

6.2.31 Slowly increase pressure to approximately 3900 psi, to shear the ST Landing Sub and release the ball. When circulation has been regained stop pumps and ensure the bleed off. line open. Pick up string to confirm tool released.

Note: Do not pressure up against the formation.

6.2.32 Record pick up weight, and confirm that the HR running tool has been released and record pick up and slack off weights.

6.2.33 POOH (Accurately strap drill pipe out of hole from the mark at the rotary table) with Liner hanger running tool and 2-$^7/_8$" inner wash pipe, to the top of the liner hanger

Note: If unacceptable losses occur, circulate a Seal-N-Peel LCM pill across the sand screens. (see Appendix 5. for fluid properties)

6.2.34 Strap out of hole to obtain an accurate depth of the top of liner PBR.

6.2.35 Service break all Running Tool connections on surface, prior to laying out .

7 RUNNING 5-1/2" WELL COMPLETION

7.1 PRE RUNNING CHECKS

- Ensure a nylon drift (4.767") for 5-1/2" x 17 ppf tubing is on the rig floor.
- Ensure the stab in safety valve is made up to the crossover (5-$^1/_2$" 19ppf NK-3SB pin x 4-1/2" IF box.) and is on the rig floor.
- Ensure the power tongs are dressed with non marking insert dies and the torque turn unit is programmed for 5-$^1/_2$" 17ppf 13Cr NK-3SB tubing. (See attached torque sheet).
- Ensure side door elevators and rotary table slips are for 5-$^1/_2$" tubing.
- Bestolife 2000 pipe dope is to be used on all pin and box connections.
- Rig up the TRSCSSV hydraulic control line spool on stands,
- Ensure all completion sub assemblies have been function and pressure tested, drifted, serial numbers checked and length, ODs & IDs measured and recored on the Tally Sheets provided.
- Pressure test control line to 5000 psi.
- Make up one joint of 7" 29ppf casing to the bottom of the 7" Flow head, test and layout.

RUNNING PROCEDURES

7.1.1 Hold JSA prior to running completion.

7.1.2 Make up 7" Flow Head and swivel to a joint of 7" Vam Top HT landing string. Lay out Flow head & casing.

7.1.3 Pick up the 7.50" seal unit assembly with crossover to 5-1/2" NK3SB and install in rotary with a dog collar/Hydraulic clamp.

7.1.4 Pick up 5-$^1/_2$" tubing from the Vee door, drift each joint.

Note: Using a paint brush to apply minimal Bestolife 2000 pipe dope on pin and box connections.

7.1.5 RIH with 5-$^1/_2$" NK-3SB tubing (Refer Appendix 4 for the torque make up.)

7.1.6 When the TRSCSSV assembly is picked up, and made up, connect the hydraulic control line to the TRSCSSV and pressure test to 5000 psi for 10 minutes

Note: The TRSCSSV pressure is to be monitored all times and keep at a minimum of 5000psi.

7.1.7 Continue to RIH with 5-1/2" tubing, making up across coupling control line protectors every connection and mid joint protectors every mid joint.

7.1.8 Per the tubing tally, space out the tubing with pup joints for the bottom seal of the seal assembly unit to be ± approx 4.5m (15ft) inside the upper PBR of the liner (Note: Upper PBR has 6.0m (20ft) of travel.

7.1.9 Make up the tubing hanger as per Cameron's procedures. Cut the hydraulic control line so there are at lest 6 wraps round the pup joint under the tubing hanger. Install the $^1/_2$" x $^1/_4$" swage lock fitting to the control line and tubing hanger, ensure both fittings are secure.

7.1.10 Test the control line and swag lock fittings to 5000 psi for 10 minutes.

7.1.11 Make up Tubing Hanger Running Tool to the Tubing Hanger as per Cameron procedures.

Note: Ensure the SSR Isolation Sleeve is installed in the Tubing Hanger.

7.1.12 Make up Sub Sea Test Tree as per EXPRO procedures. Connect EXPRO IWOCS umbilical to the SSTT & THRT. Pressure test the umbilical and control line to the TRSCSSV to 5000psi for 10 minutes. And verify the TRSCSSV is open and holding 5000 psi.

Note: OMV, EXPRO and Cameron engineers to space out the landing string, ensuring the Slick Joint is positioned across the lower 10-$^3/_4$" BOP rams

Note: The 7" Surface test tree/flow head is to be spaced out with ±. 3.0 m stick up from the rotary table.

Note: The TRSCSSV pressure is to be monitored all times and keep at a minimum of 5000psi.

7.1.13 RIH with 4* joints of 7" Vam Top HT landing string.

Note*: The exact number of joints of 7" casing to be determined on site and will be dependant on the final space out from the sub sea xmas tree to the rig floor.

7.1.14 Make up 7" Lubricator Valve as per EXPRO procedures.

7.1.15 RIH with 2* joints of 7" Vam Top HT landing string.

7.1.16 Note*: The exact number of joints of 7" casing to be determined on site and will be dependant on the final space out from the sub sea xmas tree to the rig RIH with 7" casing until 5.0m above the upper PBR of the liner hanger,

7.1.17 Record Pick up, Slack off and Hanging string weights.

Make up circulating swage to casing and connect to rig pumps. With the rig pumps on a slow pump rate RIH slowly while observing pump pressure and weight indicator. If the upper PBR of the liner hanger is tagged before a pump pressure increase, mark the tubing at the rotary table. If not continue to RIH until the pump pressure increases. Stop pumps. Mark the tubing at the rotary. Accurately measure space out. **Note: Do not land out Tubing Hanger.**

Pick up and layout the last 7" casing joint run for space out check.

7.1.18 Pick up and make up 7" Flow Head as per EXPRO procedures.

Note: Space out landing string as necessary to place the flow head at the desired height above the rotary table as instructed by the OMV Test Engineer,

7.1.19 Function test the flow head as per EXPRO procedures.

7.1.20 Connect cement line to kill side of flow head and test line to 5000 psi.

7.1.21 Connect coflexip flow line to flow head.

7.1.22 Pressure test flow head and flow line against the choke manifold and sub sea lubricator valve to 5000 psi.

7.1.23 Pressure 7" landing string against SSTT to 5000 psi.

7.1.24 RIH to place the Seal Assembly approximately 1.0m above the upper PBR.

7.1.25 Circulate the well to clean filtered inhibited completion brine. (See Appendix 5 for fluid properties)

7.1.26 Strap pipe into the hole until the tubing hanger lands as per Cameron procedures. Check that the travel inside the PBR is no more then 4.0m If the travel is more than 4.0m. Baker and OMV Engineers will review space out.

7.1.27 Hydraulically set and test the tubing hanger per Cameron's procedures.

Note: Control of the TRSCSSV will be transferred to the Cameron IWOCS umbilical which is connected to the Xmas Tree.

7.1.28 Function and pressure test the TRSCSSV to 5000 psi for 10 minutes. Check the TRSCSSV is open and holding 5000 psi pressure.

7.1.29 Open the annular valve on the Xmas Tree as per Cameron procedures and pressure test the tubing / casing annular between the liner hanger top packer and the tubing hanger to 1500 psi for 10 minutes.

7.1.30 Close the annular valve on completion of the test as per Cameron procedures.

8 WELL CLEAN UP & TEST

8.1.1 GENERAL

Operating Procedures

- If a conflict arises between the OMV, Diamond Offshore or Service Company procedures, this should be resolved by relevant offshore personnel, and the proposed course of action shall be approved by the OMV, Diamond Offshore and the Service Company Management.
- If a non-standard operation is required (i.e. one that is not covered in OMV, Diamond Offshore or Service Company procedures), an on-site risk assessment must be carried out and a set of written procedures agreed by all relevant parties with approval given by the OMV Drilling Supervisor and Diamond Offshore OIM prior to the operation commencing. OMV Drilling Superintendent is to be notified of any non standard operations to be performed.
- JSAs are to be prepared and reviewed prior to the commencement of any critical operations.
- No work is permitted on or around the rig floor while testing is in progress.

8.1.2 WELL TESTING SAFETY

General

Prior to the test, a General Safety Meeting will be held for all persons onboard. This meeting will be chaired by the OMV Drilling Supervisor with the Diamond Offshore OIM, Toolpusher, Well Test Engineer and all operational personnel present to cover the following:

- Pressure Testing
- Communications
- ESD Procedures
- Fire Prevention
- Work Permits
- Responsibilities and Lines of Authority
- Muster and Abandonment Procedures

Personal Briefings

The Well Test Engineer shall brief all shifts prior to going on tour on well test status including general well testing procedures, equipment involved and its basic operation. The shifts should be walked around the testing equipment for familiarisation. All key personnel (OIM, Rig Superintendent, OMV Drilling Supervisors, etc.) shall be briefed on the equipment and their responsibilities during testing. The Drillers shall be briefed on available well control techniques. Contractors involved in testing operations shall be briefed on OMV and Diamond Offshore testing policies.

Work Permits

Any work being conducted during the test period will require a permit to work. **No hot work will be conducted during the test period.**

Crane operations over pressurised lines are not permitted at any time. If during the test a crane is required for an essential operation a work permit will be required. If the crane operation is necessary in the vicinity of the well test equipment then the well will be shut in until these crane operations are complete. Crane operations over wireline or coil tubing are not permitted at any time.

Fire Fighting Equipment

- Deluge systems shall be active in the vicinity of the surface test equipment.
- Water curtains and deluge on the burner booms shall be in operation at all times when flaring is in progress.
- Portable foam extinguishers shall be available in the vicinity of the surface testing equipment.
- The fire team should be lead around the test equipment to familiarise them with the layout and the vessels containing hydrocarbon.

8.1.3 ESD and Testing Valves

- Remote ESD stations will be positioned at various locations on the rig. A location schematic of all ESD valves will be displayed in prominent locations. ESD operation is to be clearly addressed during the pre-test safety meeting for all rig crew.

- A status board on the rig floor will show the status of all valves from the testing choke manifold, Flowhead, SSTT, SSLV. This will be updated by the Driller in consultation with the Well Test Engineer or EXPRO Well Test Supervisor.

- A Production Test Operator and a Driller will be present on the rig floor at all times.

- Prior to the well being brought on-stream the EXPRO ESD system will be function tested (witnessed by the Well Test Engineer, OMV Drilling Supervisor and Diamond Offshore OIM).

8.1.4 Emergency Muster, Fire, H2S and Abandonment Drills

These drills shall be exercised prior to commencing the well test.

8.1.5 Contingencies

Contingency procedures for SSTT unlatch, fire or explosion, H_2S and Surface Line Ruptures and Leak Response are included in the attached appendixes.

8.1.6 Emergency Procedures in the Event of Bad Weather

Well testing operations will be suspended if:

The OIM and OMV Drilling Supervisor consider weather conditions are or will become unsatisfactory and which may cause a dangerous situation.

Conditions on the rig floor are considered unsafe.

Heave due to heavy weather and or tidal effects is approaching equipment clearances on the drill floor

In the event of weather preventing testing - there will be three distinct phases of suspension of operations:

Suspend testing operations and make the well safe.

Disconnect and recover the upper section of the test string.

Pull and lay down the Marine Riser and LMRP.

The OIM and the OMV Drilling Supervisor in consultation with the Drilling Superintendent, will take the decision as to what particular suspension phase is applicable.

In the event that any emergency action is taken on the rig the Drilling Supervisor shall inform the Drilling Superintendent immediately of the situation.

Additional Safety Guidelines

The standby vessel will be stationed upwind of the rig and be prepared to provide immediate assistance if required. Standby vessel crews should be drilled in the correct standby and support procedures..

Confirm that gas detection equipment is operational and properly calibrated.

Ensure that the compressors are fitted with spark arresters and emergency shut down systems are operational.

Ground all production vessels and sampling containers to avoid static electricity ignition sources.

Pressure testing will be conducted in compliance with the Ocean Bounty Permit To Work system. Pressure testing areas will be cordoned off and non-essential personnel warned to stay clear.

Assign personnel to tour the testing areas with gas detectors, and deploy breathing apparatus with procedures to follow if there is evidence of a gas leak or H_2S. In the event that during testing instream Hydrogen Sulphide (H_2S) levels above 200 ppm are detected in the gas phase, or above 10 ppm detected in air, the well shall be shut in and the situation assessed with consideration for terminating testing operations.

All doors, hatches and vents in the vicinity of the test equipment will be closed for the duration of the test.

Working on burner booms is covered under the Permit To Work system and it should be emphasised that work vests must be used when working on the booms.

Cranes will not be operated in the test area when the well is open to flow. Limited crane operations will be permitted during shut in periods at the discretion of the OMV Drilling Supervisor and the Diamond Offshore OIM.

The radio room is to be manned at all times during testing operations.

Non-essential personnel will keep clear of the rig floor and the test equipment areas during well testing operations.

The cement unit shall be connected to the kill line on the Surface Test Tree (STT) and be ready to start pumping immediately, if required.

The Driller, the Rig Superintendent or the Toolpusher must be on the rig floor at all times during flow and shut in periods.

Cordon off the area between the 'V' door and the wireline or coil tubing units during wire line or coil tubing operations.

An announcement shall be made over the rig PA notifying all personnel of status changes in well testing operations.

8.1.7 Equipment Preparation.

8.1.8 General Test Pressure

The Well Test Engineer shall witness all pressure tests and function tests of well test equipment.

Unless otherwise specified the General Test Pressure (GTP) shall be 3000psi for 10 minutes for all equipment and lines up stream of the test manifold and 1000 psi for 10 minutes for all equipment and lines down stream of the test manifold. All pressure tests shall be recorded.

8.1.9 Rig BOP Preparation

The rig BOP's shall have a full pressure test as per Appendix 3 of the Patricia 2 Drilling Programme.

8.1.10 Surface Test Package

General points regarding rig up of surface equipment is as follows:

Rig up surface test package as per deck layout diagram/s and P&ID in Appendices 8 & 9.

Ensure that the separator and sand trap have been cleaned of any debris.

Where pipe work crosses walkways, pipe should be made clearly visible (with danger tape) and trip hazards minimised. Steps are to fabricate over the pipe work.

Tag the instrument air supply valve to the separator to ensure continuous supply and that testing operations can be continued without interruption.

Pressure Testing

Obtain permits, erect barriers, display pressure test signs and make announcements on PA to warn personnel when pressure testing is about to commence.

Pressure test the surface test equipment as per EXPRO procedures and record all pressure tests on a chart recorder.

During the pressure testing check the following:

The Daniels box, gate, gate holds pressure

The choke manifold isolation valves are tested independently to ensure choke changes and inspections can be made.

The following should be included as part of pressure testing surface equipment:

Flush all surface lines and equipment from rig floor through burner heads and gas lines, before and after pressure testing.

Test entire system to 3500 kPa (500 psi) against burner heads (plugged) and gas manifold.

Test against oil burner heads to 7000 kPa (1000 psi).

Test against oil manifold to 7000kpa (1000psi)

Separator gas outlet & bypass, oil outlet & bypass plus water outlet to 7000 kPa (1000 psi).

Test Steam Exchanger coils and by-pass to 7000 Kpa (1000 psi)

Test Separator inlet to 7000 Kpa (1000 psi)

Test choke manifold, down stream valves to 7000 Kpa (1000 psi) and up stream valves to 21,000 Kpa (3000 psi)

All valves on the test tree are to be tested to 35,000 Kpa (5000 psi)

At the end of pressure testing, all lines are to be flushed and ensure all barriers and signs are removed. Also inform personnel by the PA system and sign off permits.

8.1.11 Calibration Checks

Calibrate differential pressure gauges using a manometer.

Surface pressure gauges shall be calibrated at the shore base prior to mobilisation using a dead weight tester.

Check flow meter calibrations by pumping water through each meter. Obtain two consistent results for each meter.

Check condition of measuring instruments, eg. thermometers, hydrometers etc.

Ensure all orifice plates and choke beans are in good condition and an adequate supply is on hand.

Ensure that the Daniels Box is fully functional.

Calibrate sand monitoring system.

8.1.12 Burner Heads and Deluge Checks

Ensure that all burner strainers are free from debris.

Ensure that all burner nozzles are free from debris and are not plugged.

Function test the rig deluge system.

Function test the air compressors

Function test the burner ignition system.

Function test the non-return valves on the air delivery line.

Check the integrity of the gun line valves in the pit room to ensure the brine in the pits does not become contaminated with deluge sea water.

Function test burner heads with water.

8.1.13 ESD System

Remote shutdown points for the ESD system shall be installed, on the rig floor, at the choke manifold, at the test separator, and ESD points outside the accommodation.

The separator instrument air supply will be an integral component of the ESD system. Interruption to separator air supply will activate the ESD system and shut the Flowhead.

Function test HP / LP pressure pilots using a DWT.

The ESD system is to be function tested after the Flowhead has been rigged up. Record in the Well Test Report and the IADC Report the ESD System function tests.

8.1.14 Coil Tubing and Nitrogen

Ensure crossover (10”-4 Acme box x 6-5/16” 10k Bowen pin) from the top of surface flow head/test tree is available.

Pressure test / function test the Injector and BOP as per BJ Services procedures.

Pressure test coil tubing to 3000 psi and record test results.

Program downhole pressure and temperature memory gauges

Check 7/32 mono-conductor line is functioning and downhole SRO gauge is giving a signal

Inspect joint seals of the lubricator sections.

Check all control hoses are in good working order.

Test the shear ram cutters to ensure they will sever the 1-$^{1}/_{2}$ “ Coil tubing

Function test the CTU BOPs

Make up the BOP and injector to the life frame.

Ensure cross over 10"-4 Acme box x 6-5/16" Bowen pin and collar is made up to the surface test tree/flow head.

Check shut down systems on the CTU and Nitrogen pump units engines.

Inspect drip trays on Nitrogen tanks and pumping unit.

Install water hoses on drip trays of nitrogen tank and pump to minimise risk of spillage onto the rigs decks.

Line up the Nitrogen converter, tank and test the lines.

Ensure all nitrogen line are firmly secured and tied down.

Pressure test nitrogen lines to 2000 psi and record results.

8.1.15 Flowhead

Check connections

Function all valves.

Pressure test flow head to 5000 psi.

8.1.16 Sub Sea Test Tree and Lubricator Valve

The Sub Sea Test Tree (SSTT) and the Sub Sea Lubricator Valve (SSLV) shall be prepared in accordance with Expro procedures:

Check connection of SSTT to THRT.

Pressure test SSTT to GTP and function test operation,

Pressure test the SSLV to GTP and function test operation,

Drift and record lengths and diameters of SSTT and SSLV components.

The EXPRO Sub Sea Engineer, Well Test Engineer, Rig Sub Sea Engineer shall review the SSTT and BOP schematics to ensure the proposed SSTT running configuration is compatible with internal dimensions of the BOP stack. The Sub sea landing string and BOP schematics are included in Appendix 6

8.2 RIG UP COIL TUBING AND NITROGEN

8.2.1 Hold a JSA covering all safety aspects of the operation.

8.2.2 Close the master valves, swab valve and flow line valve of the surface test tree/flow head.

8.2.3 Rig up and test Coil Tubing, Nitrogen and Surface Read out Downhole Gauges (1 x SRO gauge. 1 x Memory gauge) per BJ Services procedures. Test back-up SRO gauge. Ensure that returns are lined up via adjustable choke to surge tank.

8.2.4 Pressure test CTU BOP & Flow Head connection to 3000 psi for 10 minutes.

8.2.5 Open Swab and lower & upper master valves. Flow Head wing and kill valves closed. Ensure the TRSCSSV is open and holding 5000 psi. Continually monitor the control pressure to the TRSCSSV

8.2.6 RIH with CT to TD. Stop at each 200 metres and conduct a pick up weight test and check surface readout gauges are recording.

Note: Report any running difficulties to OMV engineers.

8.2.7 POOH to ~50m above the Liner Hanger. upper PBR and monitor BHPs

Note: If the pressure/temperature surface read-out gauge fails, the OMV Reservoir Engineer to decide if to terminate test and POOH to replace the gauge.

8.3 PRE TEST PROCEDURE

Confirm ALL Pre-test Check Lists have been completed.

Inform the following that the well test is about to commence:

All personnel on the rig.

Company Office – Perth (Drilling Superintendent, Drilling and Operations Manager)

Work Boats

Helicopters

Perth office to inform Vic NRE to be given test notice 24hrs in advance)

Notify local police well testing and flaring will commence.

Notify any fishing boats in the vicinity to stay clear.

Notify AMSA well testing and flaring will commence

Notify and other rigs platforms in the area well testing and flaring will commence

Conduct a Pre-test Safety Briefing, for all involved personnel.

Review the position of all ESD stations with the crew.

Confirm workboat is in position up wind of the rig.

Confirm burners are operational and the compressors are running.

Confirm that the water cooling/spray system is operational.

Ensure that all fire hoses are in place and charged.

Well Test Engineer to ensure that the Diamond Offshore OIM assigns a member of the Rig crew to permanently watch the flare for drop out, monitor wind direction and deluge system.

Ensure that the rig manifold is lined up correctly to provide pressure to the annulus.

Confirm all valves are lined up.

Confirm the 10-3/4" BOP rams are closed around the SSTT slick joint.

Ensure that the system valves are in the following positions. Confirm these settings on the valve status board.

Swab Valve	OPEN
Flow Wing Valve	OPEN
Kill Wing Valve	Closed
Lower / Upper Master Valve	OPEN
Check Valve	In Service
Choke	Closed On Upstream Valves

Line up flowline downstream of choke manifold to the surge tanks via Variable Choke. .

Check at regular intervals that the TRSSV is open and holding 5000 psi.

Ensure that glycol and methanol are available for injection into the well stream through the SSTT if hydrates are observed.

Initial flow of reservoir fluids to surface shall only occur in hours of daylight unless permission has been obtained from the Vic/NRE, OMV Management and Rig Management

- The EXPRO ESD system low pressure switches (PSL1 and PSL2) should be armed once sufficient flowing well head pressure exists

8.4 Flow Build Up Periods.

The duration of the flow and shut in periods detailed in the table below are indicative and will modified at the discretion of the OMV Reservoir Engineer depending on the well performance.

PVT sampling will be at the direction on the OMV Reservoir Engineer.

Flow / Shut-in Period	Expected Duration	Objective
Initial Flow Period (FP #1)	10 minutes	Establish initial draw down
Initial Shut-In (PBU #1)	2 hours	Determine initial reservoir pressure.
Flow Period #2 (FP #2)	24 hours	Clean up gradually increasing to max choke setting. Obtain 1 set of PVT samples. Run to TD with PT gauges to establish reservoir temperature profile prior to shut-in. Pull back to top of reservoir with gauges.
Second Shut-In (PBU #2)	6 hours	Provide formation pressure response data.
Flow Period #3 (FP #3)	9 hours	Stable flow conditions on small choke (Rate A). Obtain sand sample and 2 sets of PVT samples.
Flow Period #4 (FP #4)	9 hours	Stable flow conditions on medium choke (Rate B). Obtain sand sample. Gradient survey with PT gauges.
Flow Period #5 (FP #5)	12 hours	Stable flow conditions on high choke (Rate C). Obtain sand sample. Run to TD with PT gauges to establish temperature profile prior to shut-in. Pull back to top of reservoir with gauges.
Final Shut-In (PBU #3)	12 hours	Provide formation pressure response data.
Total	**~74 hours**	

8.5 WELLTEST - CLEAN-UP, FLOW AND BUILD UP PERIODS

8.5.1 Review a JSA before starting this operation.

8.5.2 Open the well on 16/64" variable choke to the surge tank for Initial Flow (FP #1)

Commence pumping Nitrogen and RIH slowly to top of Liner Hanger. When first indication that the well is starting to flow stop pumping and ensure SRO gauges are 1.0 metre above top of screens

8.5.3 Flow to surge tank for 10 minutes or as directed by the Well Test Engineer. Monitor surface pressure and returns.

8.5.4 Shut the well in at the choke manifold for Initial Build Up (PBU #1). Shut in time to be 2 hours or as directed by the Reservoir Engineer.

- Monitor and record BHSIP & WPSIP.

8.5.5 Open the well on 16/64" variable choke to the Surge Tanks for Clean Up Flow Period (FP #2)

8.5.6 Continue pumping nitrogen until the well kicks and flows naturally. Do not enter the open hole section while pumping Nitrogen. Pump nitrogen as required if the well loads up with fluid.

- Monitor and record BHFP & WHFP and fluid returns.
- Monitor and record BS&W
- Monitor and record reservoir gas at surface for H_2S and CO_2 with Draeger tube measurements immediately gas is produced to surface and repeated every 15 minutes until the well is stabilised on a fixed choke size and then at 30 minutes intervals. Any H_2S level is to be immediately reported to the Well Test Engineer who will confirm the information and then report to the Drilling Supervisor and the OIM.
- Mud logging company to continually monitor produced gas properties on their chromatograph via a line hooked to the gas out let of the separator. This line is to be shut and disconnected if any H2S is detected in the well stream.
- Collect sand samples for analysis from the sand-catcher at regular intervals through the flow period.
- Data acquisition and sampling requirements are detailed in Appendix 10.

8.5.7 Increase choke setting slowly to maximum as directed by the Reservoir Engineer.

Note: Do not shock the formation by opening the choke too quickly.

8.5.8 Take 1 set PVT samples as directed by the Reservoir Engineer when the separator is stable

8.5.9 Prior to end of FP # 2 RIH to TD with the PT gauges on coil tubing. Pull back into the 7" casing at a constant rate as directed by the Reservoir Engineer. Monitor BH pressures & temperatures along the well bore to determine any flow anomalies.

8.5.10 Shut well in at the choke manifold for 2nd Build Up (PBU #2) as directed by the Reservoir Engineer. Shut in time to be 6 hours or as directed by the Reservoir Engineer.

- Monitor and record BHSIP & WPSIP.
- Check sand-catcher for sand. Collect sample any material in the sand-catcher for analyses. Clean sand-catcher before starting the next flow period.

8.5.11 Open the well on 16/64" variable choke for the Main Flow Period. Increase choke setting for Flow Period #3 (Rate A) as directed by the Reservoir Engineer. FP #3 flow rate required approximately 15 MMscf/day.

8.5.12 Change to fixed choke when flow is stable.

8.5.13 Flow well at Rate A for 9 hours or as directed by the Reservoir Engineer.

- Monitor and record BHFP & WHFP and fluid returns.
- Monitor and record BS&W
- Monitor and record reservoir gas at surface for H_2S and CO_2 with Draeger tube measurements immediately gas is produced to surface and repeated every 15 minutes until the well is stabilised on a fixed choke size and then at 30 minutes intervals. Any H_2S level is to be immediately reported to the Well Test Engineer who will confirm the information and then report to the Drilling Supervisor and the OIM.
- Mud logging company to continually monitor produced gas properties on their chromatograph via a line hooked to the gas out let of the separator. This line is to be shut and disconnected if any H2S is detected in the well stream.
- Collect sand samples for analysis from the sand-catcher at regular intervals through the flow period.

8.5.14 Take 2 sets of PVT samples as directed by the Reservoir Engineer when the separator is stable.

8.5.15 Collect sample of sand for analysis and clean sand-catcher prior to end of flow period (FP #3). Clean sand-catcher.

8.5.16 Change to variable choke and increase setting for Flow Period #4 (Rate B) as directed by the Reservoir Engineer. FP #4 flow rate required approximately 25 MMscf/day.

8.5.17 Change to fixed choke when flow is stable.

8.5.18 Flow well at Rate B for 9 hours or as directed by the Reservoir Engineer.

8.5.19 Prior to end of FP #4, conduct flowing gradient survey with 5 – 6 gradient stops inside the 5-1/2" tubing as directed by the Reservoir Engineer.

8.5.20 If required, take further PVT samples, as directed by the Reservoir Engineer, when the separator is stable.

8.5.21 Collect sample of sand for analysis and clean sand-catcher prior to end of flow period (FP #4). Clean sand-catcher.

8.5.22 Change to variable choke and increase setting for Flow Period #5 (Rate C) as directed by the Reservoir Engineer. FP #5 flow rate required approximately 35 MMscf/day.

8.5.23 Change to fixed choke when flow is stable.

- Critical flow across the choke should be maintained at all time where possible.

8.5.24 Flow well at Rate C for 12 hours or as directed by the Reservoir Engineer.

8.5.25 Prior to end of FP #5, RIH to TD with the PT gauges on coil tubing. Pull back into the 7" casing at a constant rate as directed by the Reservoir Engineer. Monitor BH pressures & temperatures along the well bore to determine any flow anomalies.

8.5.26 Collect sample of sand for analysis and clean sand-catcher prior to end of flow period (FP #5). Clean sand-catcher.

8.5.27 Shut well in at the choke manifold for 3rd Build Up (PBU #3) as directed by the Reservoir Engineer. Shut in time to be 12 hours, or as directed by the Reservoir Engineer.

- Monitor and record BHSIP & WPSIP.

8.5.28 Check sand-catcher for sand. Collect sample any material in the sand-catcher for analyses.

8.5.29 Check TRSCSSV is open and holding 5000 psi.

8.5.30 On completion of PBU #3, as directed by the Reservoir Engineer. POOH to CTU BOP with the pressure gauges.

Note: POOH slowly through the TRSCSSV and SSTT.

8.5.31 Close Sub Sea Lubricator Valve (SSLV).

8.5.32 Bleed off any gas in the coil tubing and in 7" landing string above the SSLV through surface test equipment

8.5.33 Close flow head master and swab valves

8.5.34 Hold JSA and cover all safety aspects of the rig down of CTU and rig up of wire line equipment from the flow head

8.5.35 Rig down coil tubing and nitrogen equipment as per BJ procedures.

9 WELL SUSPENSION

9.1.1 Hold JSA and cover all safety aspects of the rig up off wire line equipment on the flow head.

9.1.2 Rig up wire line equipment on the flow head as per EXPRO procedures.

9.1.3 Make up 4-1/2" GS pulling tool on to the slick line and install wire line BOP and lubricator.

9.1.4 Open flow head swab and Master valve.

9.1.5 Test the Slick line BOP and lubricator to 5000psi for 10 minutes against the sub sea lubricator valve. Bleed off pressure to equalise across the SSLV. Note: Use clean completion brine for pressure testing.

9.1.6 Open SSLV

9.1.7 RIH with a 4-1/2" GS pulling tool on slick line, latch and pull the Isolation Sleeve from the tubing hanger and POOH. Close Sub Sea Lubricator Valve. Bleed off pressure through test equipment, as there will be some gas trapped in the 7" landing string.

9.1.8 Make up 5.312" wire line drift. Equalise pressure across the SSLV using clean completion brine. RIH with a 5.312" wire line drift and drift the THRT. POOH. Close SSLV. Bleed off pressure through test equipment, as there will be some gas trapped in the 7" landing string.

9.1.9 Make up 5.25" SSR plug to wire line. Equalise pressure across the SSLV using clean completion brine. RIH with the 5.25" OD SSR plug and land in the tubing hanger.

9.1.10 Pressure up to 3000 psi above the SSR plug to engage the metal-to-metal seal. Set lock by jarring down, bleed down pressure, release the running tool by jarring up. POOH with slick line.

9.1.11 Bleed down pressure to zero through test equipment as there will be some gas trapped in the 7" landing string, slick line BOP and lubricator. Monitor pressure for 10 minutes to ensure 5.25" SSR plug is holding pressure from below. Close swab valve and rig down slick line.

9.1.12 Open 10-3/4" BOP Rams.

9.1.13 Release tubing hanger running tool and pick up clear of the tubing hanger. Close BOP annular and reverse circulate out any gas in the 7" landing string through the surface test equipment with clean completion brine. Bleed off any pressure and observe. Open annular.

9.1.14 POOH lay out the STT/Flow Head, 7" casing landing joints and SSLV.

9.1.15 Pick up the SSTT until the Tubing hanger running tool is above the rotary table.

9.1.16 Install the running sleeve for the Internal Xmas Tree Cap (ITC). Make up the ITC to running tool as per Cameron's procedures

9.1.17 RIH on 7" landing joints and as per Cameron procedures install and set ITC in top of xmas tree. Close 10-3/4" rams on the slick joint and pressure up to 5000 psi to seat the ITC and engage the metal-to-metal seals. Hold pressure for 10 minutes to test to ITC. Observe any flow from the open 7" running string if the ITC is leaking.

9.1.18 Make up crossover, 11-$^{1}/_{2}$" Otis acme thread x 7" 29ppf Van Top HT pin to the 7" landing string.

9.1.19 Rig up the 7" side entry sub, the slick line BOP and lubricator. with a 5.75 SSR tubing hanger plug. Rig up Cementing line to the side entry sub pressure test to 5000 psi for 5 minutes. Test the slick line BOP and lubricator against the SSTT to 5000 psi for 10 minutes.

9.1.20 RIH with the 5.75" SSR plug, land in ITC. Pressure up to 3000 psi on the SSR plug and engage the SSR plug metal-to-metal seal and seat plug. Hold pressure for 10 minutes to test plug. Bleed off pressure. Jar down to set lock, Jar up to release running tool and POOH with slick line.

9.1.21 Rig down Slick line equipment,

9.1.22 Release the ITC running tool. POOH and lay out the 7" landing string, SSTT and ITC running tool.

9.1.23 Check and function test the umbilical lines to the sub sea mass tree, the Xmas tree valves and the TRSCSSV.

9.1.24 Remove IWOCS junction plate from the Xmas Tree and park on BOP with ROV.

9.1.25 Install cover plate on Production control J plate on mass tree with ROV.

9.1.26 Unlatch and move rig clear of mass tree.

9.1.27 Retrieve riser & BOP.

9.1.28 Move rig back over the xmas tree.

9.1.29 Run the xmas tree corrosion cap as per Cameron procedures. Install hot stab in corrosion cap and fill cap with corrosion inhibitor and retrieve hot stab with assistance of ROV.

9.1.30 Retrieve corrosion cap running tool.

9.1.31 Retrieve guide wires and temporary guideposts from the xmas tree as per Cameron procedures.

9.1.32 Secure rig for move as per DOGC procedures.

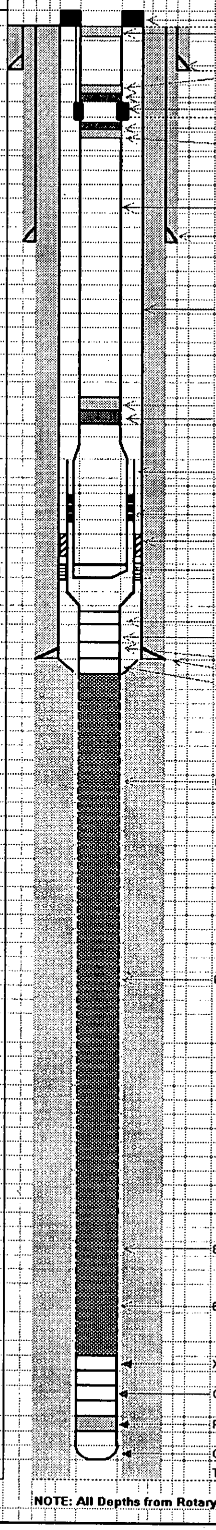
9.1.33 Pull anchors and move rig to its next location as per DOGC procedures.

APPENDIX 1 - Well Completion Run List.

Descrption	Joint No	OD Inches	ID Inches	Length	Depth Out	Depth In	
End of completion		0			1433.000	0.000	
GPV Set Shoe 3-1/2" 9.2ppf SLHT box		3.500	0.000	0.460	1423.000	0.460	
Pup Joint, 3-1/2" 9.2ppf SLHT box x pin		3.500	2.992	1.460	1421.540	1.920	
O-ring seal sub 3-1/2" 9.2ppf SLHT boxx pin		3.500	2.500	2.460	1419.080	4.380	
Cross Over. 3-1/2" 9.2ppf SLHT pin x 6-5/8" 24ppf Fox K box x pin		6.625	2.992	0.310	1418.770	4.690	
Pup Joint, 6-5/8" 24ppf 13Cr 80ksi Fox K box x pin		6.625	5.921	1.310	1417.460	6.000	
Sand screen, 6-5/8" 24ppf Fox K box x pin		7.460	5.920	500.000	917.460	506.000	9-5/8" Casing shoe.915m MDRT.702m TVDRT
Crossover 6.5/8" 24ppf 13Cr Fox K pin x 7" 29ppf 13Cr New Vam box		7.000	5.920	0.250	917.210	506.250	
Crossover. 7" 29ppf 13Cr New Vam pin x 7" 29ppf 13Cr Vam Top HT box		7.000	6.184	1.840	915.370	508.090	
7" 29ppf 13Cr Vam Top HT box Casing	1	7.000	6.184	12.000	903.370	520.090	Top Porosity 895m MDRT
7" 29ppf 13Cr Vam Top HT box Casing	2	7.000	6.184	0.000	903.370	520.090	
Crossover. 7" 29ppf 13Cr Nam HT Top pin x " 29ppf 13Cr New Vam pin		7.000	6.184	2.900	900.470	522.990	
Liner Hanger to Liner sealing element		8.135	6.184	2.226	898.244	525.216	
Liner Hanger sealing element to top of PBR		0.000	0.000	7.629	890.615	532.845	
Upper Polished Bore Receptical		8.315	7.500	0.000	890.615	532.845	
Max Depth of Seal unit					895.155	528.345	
No- Go to btm seal of seal assembly unit				4.500	890.655	532.845	
Flow coupling to No-Go				0.420	890.235	533.265	
Flow coupling. 5-1/2" 13Cr 17ppf New Vam B x P		6.050	4.895	1.880	888.355	535.145	
X/O Pup joint. 5-1/2 17ppf 13Cr pin x 5-1/2" 17ppf 13Cr NK-3SB box		6.050	4.895	1.280	887.075	536.425	
5-1/2 17ppf.13Cr NK-3SB Tubing		6.050	4.895	721.000	166.075	1257.425	
X/O Pup joint. 5-1/2 17ppf 13Cr NK-3SB pin x 5-1/2" 17ppf 13Cr New Vam box		6.050	4.895	0.900	165.175	1258.325	
5-1/2" Flow coupling. 5-1/2 17ppf 13Cr New Vam B x P		6.050	4.895	1.390	163.785	1259.715	
Baker TRSSV. 5-1/2 17ppf 13Cr New Vam B x P		8.375	4.562	2.020	161.765	1261.735	
5-1/2" Flow coupling. 5-1/2 17ppf 13Cr New Vam B X P		6.050	4.895	1.880	159.885	1263.615	
X/O Pup joint. 5-1/2 17ppf 13Cr New vam pin x 5-1/2" 17ppf 13Cr NK-3SB box		6.050	4.895	1.270	158.615	1264.885	
5-1/2 17ppf.13Cr NK-3SB Tubing		6.050	4.895	77.000	81.615	1341.885	
Pup joint. 5-1/2 17ppf.13Cr NK-3SB B x P		6.050	4.895	1.000	80.615	1342.885	
X/O Pup Joint, 5-1/2" NK-3SB P x New Vam P.		6.050	4.895	1.500	79.115	1344.385	
Tubing hanger				1.613	77.502	1345.998	

APPENDIX 2 - Proposed Completion Schematic

Elevation.	
0m	Rotary Table
MSL	25m MDRT



ID. Inches	OD. Inches	Part No	Component	Depth
4.795	17.760		Tubing hanger	
4.892	5.500		X/O pup joint 1.5m x 5-1/2" 17ppf 13cr L-80. New vam pin x NK-3SB pin	77m MDRT
			30" x 20" Casing shoe	113m MDRT
4.892	6.050		X/O pup joint 1.5m x 5-1/2" 17ppf 13cr L-80. NK-3SB box x New Vam pin	
4.892	6.075		flow coupling 2.0m x 5-1/2" 17ppf 13cr L-80. New Vam box x pin	
4.562	8.375	H824834511	TRSSV. 5-1/2" 17ppf 13cr L-80. New Vam box x pin	155m MDRT
4.892	6.075		flow coupling, 1.5m x 5-1/2" 17ppf 13cr L-80. New Vam pin x pin	
12.415	13.375		X/O pup joint 1.5m x 5-1/2" 17ppf 13cr L-80. New Vam box x NK-3SB pin	
4.892	6.050		5-1/2", 17ppf NK-3SB 13 Cr L-80 Tubing	
			13-3/8"' Casing Shoe.	320m MDRT. 320m TVD
8.681	9.625		9-5/8" x 47 ppf Casing	
4.892	6.05	H45761	X/O pup joint 1.5m x 5-1/2" 17ppf 13cr L-80. NK-3SB box x New Vam pin	
4.892	6.75	H45750	flow coupling, 2.0m x 5-1/2" 17ppf 13cr L-80. New Vam box x pin	
			20 ft Upper Polished bore receptical	895m MDRT, 701m TVD. Top of Liner
7.750	4.895	H297-50-1514	Seal assembly W/ 3 sets of seals.5-1/2" 17ppf 13cr L-80. New Vam box	
8.315	7.750			
8.315	6.184	H296-35-0008	7" x 9-5/8" Liner hanger W/ integral packer	
		H441-69-7500	Indexing mule shoe	
			X/O, Pup Joint.7" 29ppf 13Cr L-80 New Vam box x 29ppf Vam Top HT pin	
			7" x 29ppf Casing 13Cr L-80 Vam Top HT box x pin thread	
			X/O, Pup Joint x 2.9m.7" 29ppf 13Cr L-80 Vam Top HT box x 7" 29ppf New Vam pin	
			9-5/8" Casing shoe.	915m MDRT @ 88 Deg.702TVD MDRT.
			X/O, 7" 29ppf 13Cr New Vam box x 6-5/8" Fox K pin	
			6.625" OD. 24 ppf. 13Cr 110 Micron weave.Excluder Sand screens. Fox K box x pin	
			6.625" OD. 24 ppf. 13Cr 110 Micron weave.Excluder Sand screens. Fox K box x pin	
			8-1/2" Open hole	
			6.625" OD. 24 ppf. Excluder Sand screens. Fox K box x pin	
5.920	7.450	H486-90-6F27		
2.992	6.625	H494-01-6142	X/O.13Cr 6.625", 24ppf Fox K box x 3-1/2" 9.2ppf SLHT pin.	
2.992	3.500	H485-35-3566	O-ring seal sub for Slick stinger. 3-1/2" 9.2ppf, 13Cr SLHT box x pin.	
2.992	3.500	H494-07-7487	Pup Joint. 3-1/2" 9.2ppf, 13Cr SLHT box x pin.	
2.500	3.500	H487-36-3511	GPV set shoe.3-1/2" 9.2ppf SLHT box	1423m MDRT @90 Deg.710m TVD
			TD	1433m MDRT @90 Deg.710 m TVD

NOTE: All Depths from Rotary table

APPENDIX 3 - Shear Values For Liner Hanger Running Tool

Liner Equipment Shear Summary Table

DESCRIPTION	FUNCTION	NO. SIZE OF PINS	SHEAR
SLZXP PACKER, 7.500" PBR. 20 FT LG.	1st Shear	8 x 7/16"-14	39,200 lbs.
	2nd Shear	4 x 3/8"-16	14,260 lbs.
	3rd Shear	6 x 3/8"-16	21,390 lbs.
Check ZX Packer seal for cracks, damage, etc.			
Check liner hanger slips for cracks, damage, etc.			
HYDRAULIC PUSHER TOOL	1st Shear	5 x ½"-13	+/- 1,505 psi.
	2nd Shear	9 x ½"-13	+/- 2,450 psi.
HR TOOL	Hyd. release pressure	5 x ¼"-20	+/- 3,000 psi.
	Back up mech. release	2 x 5/8"	4,650 ft-lbs
Check that the tool is properly engaged, by applying right hand torque, with a pipe wrench.			
Maximum set down weight; Without rotation, while pushing liner to bottom = 140,000 lbs.			
ST LANDING SUB	Opening shear	8 x 3/8"-16	+/- 3,900 psi.

Note: All shear values in these procedures and above table to be confirmed by calculations performed Baker Engineer

APPENDIX 4 - Tubular Make Up Torques

7" 29ppf 13Cr 80 ksi New Vam.

- Minium 8,460 ft/lbs.
- Optimum. 9,400 ft/lbs
- Maximum. 1,034 ft/lbs.

7" 29ppf 13Cr 80 ksi Vam Top HT.

- Minium. 11,700 ft/lbs.
- Optimum. 13,000 ft/lbs.
- Maximum. 14,400 ft/lbs.

6-5/8" 24ppf 13Cr 80 ksi Fox K.

- Minium. 8,140 ft/lbs.
- Optimum. 8,750 ft/lbs.
- Maximum. 9,360 ft/lbs.

5-1/2" 17ppf 13Cr 80 ksi NK-3SB.

- Minium 4,640 ft/lbs.
- Optimum 5.800 ft/lbs.
- Maximum 6,960 ft/lbs.

5-1/2" 17ppf 13Cr 80 ksi New Vam

- Minium. 4,950 ft/lbs.
- Optimum. 5,500 ft/lbs.
- Maximum 6,050 ft/lbs.

3-1/2" 9.2ppf L-80 SLHT.

- Minium 3,400 ft/lbs.
- Optimum 3,900 ft/lbs.
- Maximum 4,400 ft/lbs.

2-7/8" 6.40ppf N-80 Vam FJL.

- Minium. 790 ft/lbs.
- Optimum. 870 ft/lbs.
- Maximum 950 ft/lbs.

2-7/8" 6.40ppf L-80 Vam Ace.

- Minium 1630 ft.lbs.
- Optimum 1810 ft/lbs.
- Maximum 2100 ft/lbs.

APPENDIX 5 - Well Completion Fluid Properties

1. **Clean Uninhibited Brine.**

Drillwater	as Required.
KCl	46 ppb.

2. **Filtered (10 microns) Completion Fluid (Inhibited KCl brine).**

Drillwater as Required.	
KCl	46 ppb.
Caustic Soda	For PH 10.5.
OS-1 (Sodium Sulphite)	200mg/lt.
Glute	Biocide added at 8.0 lt per 100 bbls.
Conqor	55gal per 100bbls.

3. **Wellzyme A. Pill**

KCl Brine	1.08 SG
2.5% Wellzyme A	By Volume.

4. **25 bbl Brine Base Hi Vis Pill.**

Drillwater	25 bbls.
KCl	46 ppb.
Duotec	2 ppb.

5. **Seel-N-Peel Pill in Case of Excessive Fluid Loss.**

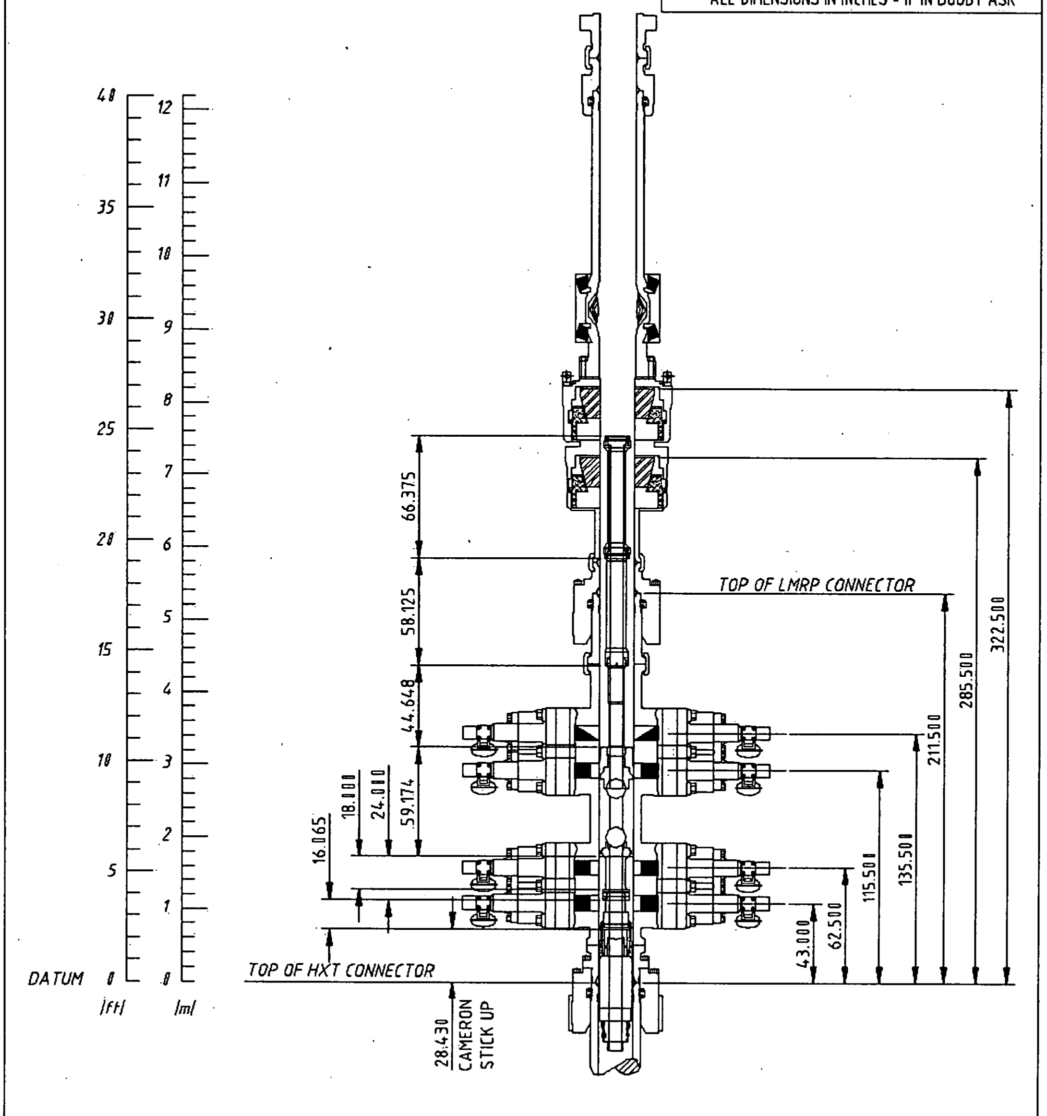
Safe-Peel	10 ppb.
Caustic Potash	0.3 ppb.
Sodium Bicardonate	0.2 ppb.
Dualflo	3.0 ppg
Flovis Plus	2.0 ppg.
Glute 25	0.2 ppg
KCl	12.0 ppg.
OS-1	0.2 ppg.
Calcium Carbonate Coarse	40 ppg.

APPENDIX 6 – Well Completion Landing String and Space Out

REV	DATE	E.C.N. No.	DESCRIPTION	BY
A	20/2/02	N/A	INITIAL RELEASE	MAB

DRAWING AND DIMENSIONAL APPROVAL			
FOR AND ON BEHALF OF	PRINT NAME	SIGNED	DATE
EXPRO			
OMV/CAMERON			
DIAMOND			

ALL DIMENSIONS IN INCHES - IF IN DOUBT ASK



DEPTH OF RAMS			
UPPER ANNULAR	23.0"	UPPER PIPE RAM	8.1"
LOWER ANNULAR	23.0"	MIDDLE PIPE RAM	8.1"
SHEAR RAM	8.1"	LOWER PIPE RAM	8.1"

RIG INFORMATION			
END USER:	OMV	FIELD:	PATRICIA BALEEN
INSTALLATION:	OCEAN BOUNTY		
WELL NO:	TBC		

DRAWN: M.A. Burns 20/2/02

CHECKED:

THE EXPRO GROUP

TITLE: OMV PATRICIA BALEEN OCEAN BOUNTY SPACEOUT (TH MODE)

REV A

ISSUE 1

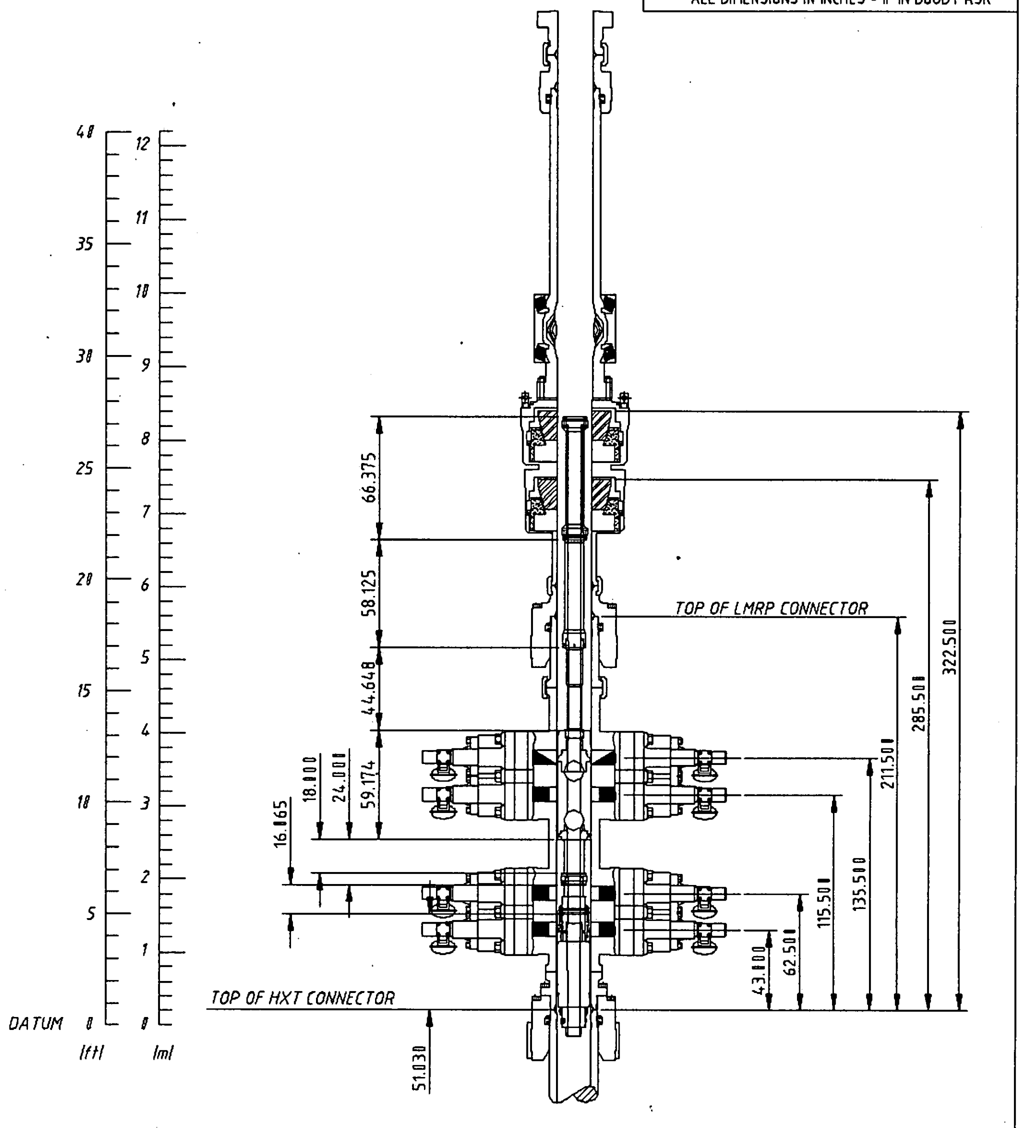
DRG No.: SS-SPO-1266

SHEET 1 OF 2

REV	DATE	E.C.N. No.	DESCRIPTION	BY
			SEE SHEET 1	

DRAWING AND DIMENSIONAL APPROVAL			
FOR AND ON BEHALF OF	PRINT NAME	SIGNED	DATE
EXPRO			
OMV/CAMERON			
DIAMOND			

ALL DIMENSIONS IN INCHES - IF IN DOUBT ASK



DEPTH OF RAMS			
UPPER ANNULAR	23.0"	UPPER PIPE RAM	8.0"
LOWER ANNULAR	23.0"	MIDDLE PIPE RAM	8.0"
SHEAR RAM	8.0"	LOWER PIPE RAM	8.0"

RIG INFORMATION			
END USER:	OMV	FIELD:	PATRICIA BALEEN
INSTALLATION:	OCEAN BOUNTY		
WELL NO:	TBC		

DRAWN: M.A. Burns 20/2/02

CHECKED:

THE EXPRO GROUP

TITLE: OMV PATRICIA BALEEN OCEAN BOUNTY SPACEOUT (TC MODE)

REV A

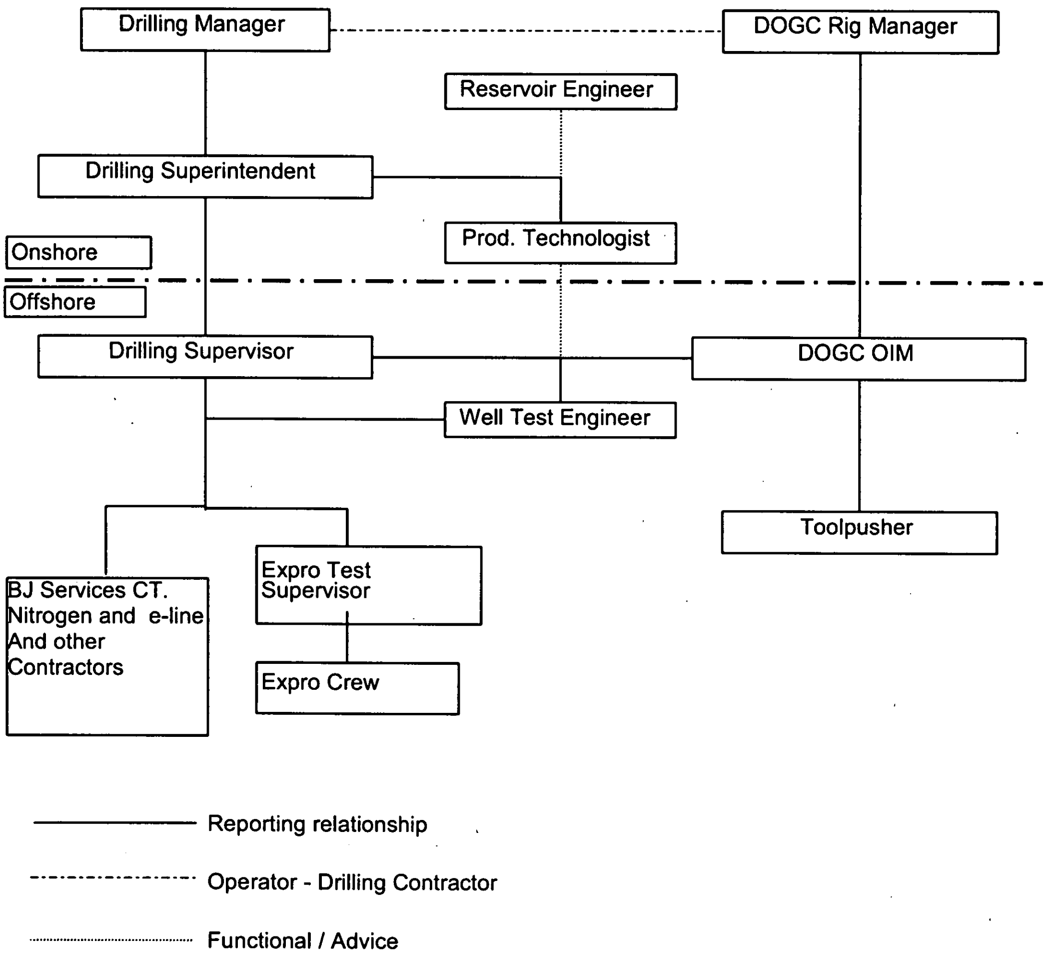
ISSUE 1

DRG No.: SS-SPO-1266

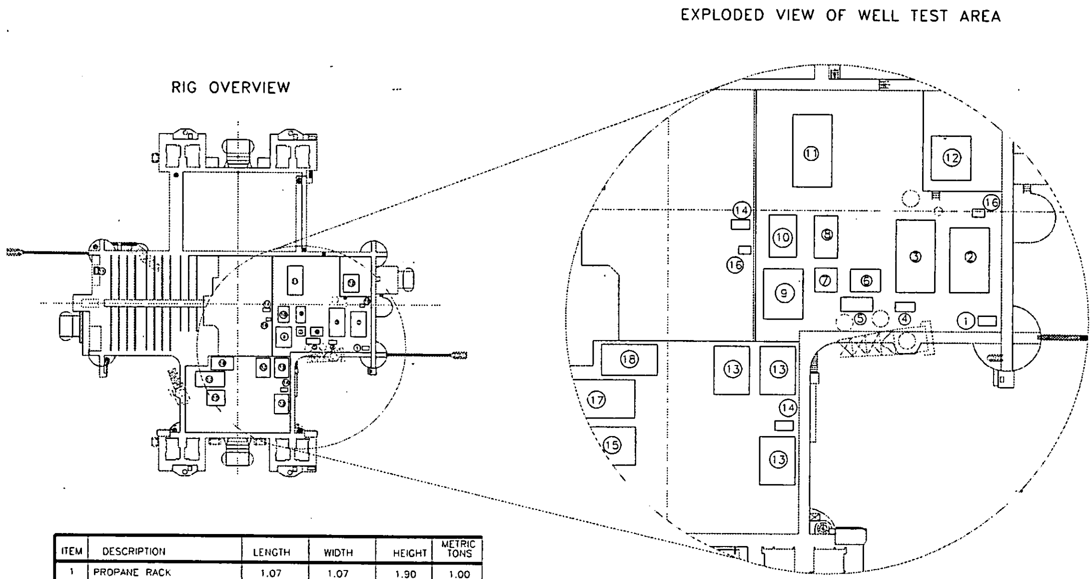
SHEET 2 OF 2

APPENDIX 7 - Well Testing Figures, Diagrams & Schematics

Figure 1 Well Testing Organogram



APENDIX 8 - Surface Equipment Layout



ITEM	DESCRIPTION	LENGTH	WIDTH	HEIGHT	METRIC TONS
1	PROPANE RACK	1.07	1.07	1.90	1.00
2	HEAT EXCHANGER	6.10	2.44	2.44	10.00
3	TEST SEPARATOR	7.40	2.44	2.80	19.00
4	SURFACE SAFETY VALVE	0.82	0.77	1.65	1.00
5	JUNK TRAP	2.44	1.52	1.22	1.00
6	3" CHOKE MANIFOLD	2.50	2.00	0.80	3.00
7	3" OIL MANIFOLD	1.80	1.80	0.40	3.00
8	TRANSFER PUMP	3.10	1.50	1.80	3.00
9	SURGE TANK	2.45	3.45	5.80	9.00
10	STOCK TANK	3.15	1.85	2.40	4.00
11	PRESSURISED LAB	6.06	2.43	2.60	8.00
12	WELL TEST CONTAINER	3.05	2.43	2.62	9.50
13	AIR COMPRESSOR	3.80	2.16	1.96	6.00
14	AIR RECEIVER	1.50	1.00	0.40	0.3
15	WIRELINE CONTAINER	3.05	2.43	2.62	10.5
16	AIR PUMP	0.80	0.70	1.00	0.1
17	SUBSEA CONTAINER	6.04	2.42	3.14	12.00

WELLTEST EQUIPMENT RIGGED UP AS PER LAY OUT DIAGRAM	
CHECKED	
DATE	
SIGNED WT SUP.	

No	DATE	REVISION	BY	AUTH

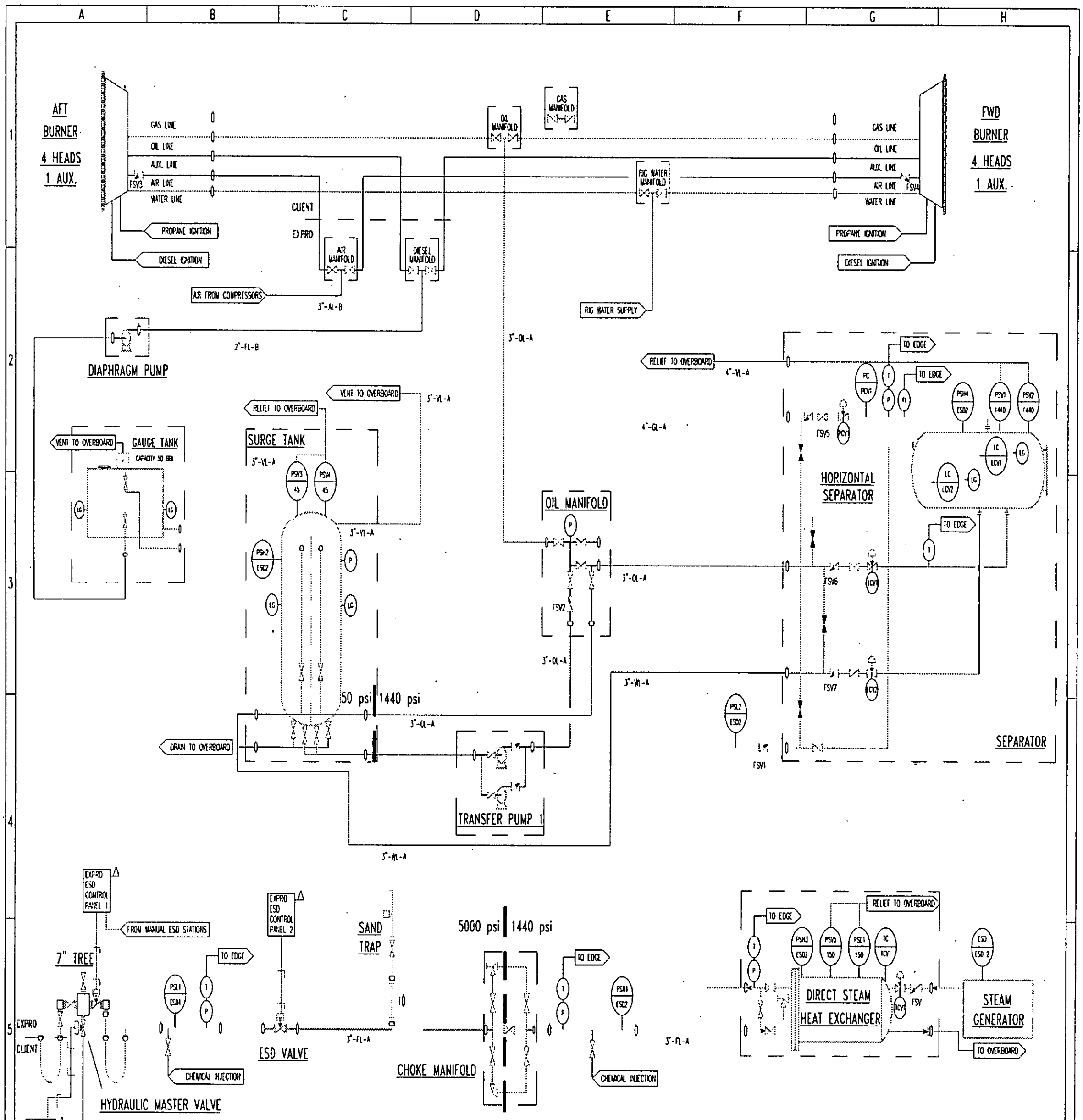
THE EXPRO GROUP

DRAWN	S. ASHTON	TITLE: WELL TEST LAY OUT DIAGRAM PATRICIA BALEEN PROJECT OCEAN BOUNTY
DATE	02/05/02	
CHECKED	D. LAWSTON	
SIGNED		
JOB No.	J02/188	CUSTOMER : OMV AUSTRALIA P/L

The EXPRO Group
West Perth, WA Australia
Telephone: 08 92135555

DRAWING No.	REV.
LAYJ02/188	0

APPENDIX 9 - Well Test Layout P&ID



MARK	DESCRIPTION
WL	WATER LINE
VL	VENT LINE
SL	STEAM LINE
OL	OIL LINE
GL	GASLINE
FL	FLUID LINE
CL	COFLEXIP
AL	AIR LINE
B	HOSES/HARD PIPING
A	HARD PIPING
FL	FLUID ID
3"	LINE ID

3"-FL-A-(B)

MARK	SETTINGS	LOCATION
PSE1	150 PSI	DIRECT HEATER
PSV5	150 PSI	DIRECT HEATER
PSV4	45 PSI	SURGE TANK
PSV3	45 PSI	SURGE TANK
PSV2	1440 PSI	SEPARATOR
PSV1	1440 PSI	SEPARATOR
PSL2	150 PSI	DOWNSTREAM CHOKE MANIFOLD
PSL1	300 PSI	UPSTREAM CHOKE MANIFOLD
PSH4	??? PSI	SEPARATOR
PSH3	120 PSI	HEATER BODY
PSH2	40 PSI	SURGE TANK
PSH1	1200 PSI	DOWNSTREAM CHOKE MANIFOLD

SAFETY SYSTEM SETTINGS

WELLTEST EQUIPMENT RIGGED UP AS PER PFD	
CHECKED	
DATE	
SIGNED WT SUP.	

No.	DATE	REVISION	BY	AUTH
2	30/04/02	AS PER RIG VISIT	SA	DL
1	24/04/02	APPLIED CHANGES AS PER MEETING MIKE WULLNER 18/4	DL	DL

THE EXPRO GROUP

DRAWN	D. Linkston	TITLE: PROCESS FLOW DIAGRAM (PFD) PATRICIA BALEEN PROJECT OCEAN BOUNTY
DATE	18/4/02	
CHECKED		
SIGNED		
JOB No.	J02/ 188	CUSTOMER : OMV AUSTRALIA P/L

EXPRO Group Australia
West Perth, Western Australia
Telephone: 08 9213 5555

DRAWING No.	REV.
PFDJ02/188	2

APPENDIX 10 - Data Acquisition & Sampling Requirements

General

The data acquired shall be recorded with the relevant date and time.

Guidelines are detailed below on data type and recommended frequency.

Original "raw data" report forms shall be completed and maintained for all well testing activities. These are in addition to that recorded by the computerised data acquisition system.

All samples, whether oil, gas or water, must be assigned a unique sample number.

A summary sheet of all samples taken should be prepared at the end of the test.

Correction factors to calculate gas rates at standard conditions of 14.73 psia and 60 degrees F.

Units as specified in section to follow.

Bottomhole Pressure/Temperature Data

At the end of the test, after gauges have been retrieved, a complete data set from each gauge will be required on diskette, in "Zipped" format.

The whole data set should be recorded on the diskette. Data start times and gauge numbers should be noted on the diskette.

The data file must include, as a minimum, Field name, Well name, Formation, DST No., depth reference (including the height of reference from LAT), gauge number, gauge location (upper/lower carrier), gauge measure point depth (TVD & MD). and perforation intervals (TVD & MD).

Include a date column in the "chronological format" 15-May-98, along with Time as 10:30:02 followed by Pressure (psia) and Temperature Deg F.

Gauge company should provide calibration records for all gauges on-site.

Wellhead Measurements

Pressure and temperature, upstream and downstream of the choke, by Data Acquisition System (pressure measurements to be confirmed by dead weight tester).

Choke size (64th) and type (fixed or adjustable).

BS&W % (by centrifuged sample).

Mercaptans, H_2S and CO_2 concentrations (by Draeger analysis and by mudloggers).

Annulus pressure. Monitor and record throughout the test to ensure the correct operation of the annulus pressure operated test tools.

Volume and Flow Rate Calculations.

Well test data shall be reported in the units specified in the units section following.

Production rates and ratios (GOR, CGR, WGR) of produced well fluids.

Cumulative production (including clean up flow) of produced well fluids.

Raw flow meter data to be recorded and reported in final report in addition to corrected data

Gas oil and water production to be reported at 30 minute intervals

Cumulative production for each flow period to be reported.

Meter calibration records to be included in the test reports.

Well Test Engineer should perform manual calculation of theoretical flowrate based on flowing parameters to verify Expro Edge system output.

All correction factors to be reported on volume calculation sheets.

Separator Data

Vessel	Pressure and temperature
Oil	Flowline temperature, density, API gravity
Water	density, salinity or chlorides, resistivity and pH
Gas	Gas meter run and orifice plate sizes Static (P_f) and differential pressure (H_w) Gas flowline temperature Gas gravity, CO_2, H_2S

Data Type and Acquisition Frequency

Data acquisition frequency will be dependent on well performance, the stability of flow rates or build up data. Data will be gathered at higher frequency by the Edge system, but guidelines for manual measurements and recording are as follows:

Data Acquisition Table

DATA TYPE	ACQUISITION FREQUENCY (MANUAL)
Wellhead	
Pressure and temperature	1 min initially (for 10 min) then 5 min and 10 minutes stabilised
BS&W	15 minutes initially 30 minutes stabilised
Mercaptans, H_2S / CO_2 content	15 minutes initially 30 minutes stabilised
Choke changes / opening and shutting the well	Every change revert to initial data sampling frequencies

Separator	
Pressure and temperature	1 min initially (for 10 min) then 5 min and 10 minutes stabilised
Oil / Gas flow rate variables	1 min initially (for 10 min) then 5 min and 10 minutes stabilised
Physical properties of fluids	30 minutes
H_2S & CO_2	30 minutes

Downhole Gauges	
Pressure	TBA by Reservoir Engineer
Temperature	TBA by Reservoir Engineer

Measurement Units

Unit	Metric units	Field units
Pressure	kPa(g) or kPa(a)	psig or psia
Temperature	Deg C	Deg F
water volume	Kiloliters	Barrels
Gas Volume	Cubic Metres	Mscf
Viscosity	Cp	Cp
Density	g/cc or SG	g/cc or SG
Rates	kl/day or kl/min	bpd or bpm
Length	Metres	Metres
OD/ID	mm	Inches

Sampling Program

Sample Type	Analysis	Number / Frequency	Sample Point	Volume	Comments
Gas	H_2S & CO_2	10-15 min initially 30 min stable	Choke	-	Draeger tube
Gas	PVT	1	Sep	20 lt	Early in flow
Gas	PVT	2	Sep	20 lt	Stable flow
Gas Condensate	PVT	1	Sep	640 cc	Early in flow (if sufficient volume)
Gas Condensate	PVT	2	Sep	640 cc	Stable Stable flow (if sufficient volume)
Water	Cl, pH, Alk	5	Sep	5 lt	Metal cont
Water		5	Sep	1 lt	Glass cont.
Sand		5	sand-catcher	1 lt	Each flow period

APPENDIX 11 - Sub Sea Test Tree Unlatch Procedures.

Any rig disconnect operation will be conducted under the direction of the OIM as per Expro procedures and advised by the Expro Sub Sea Engineer. Reference should be made to DOGC Emergency Response Manual.

Fire or Explosion

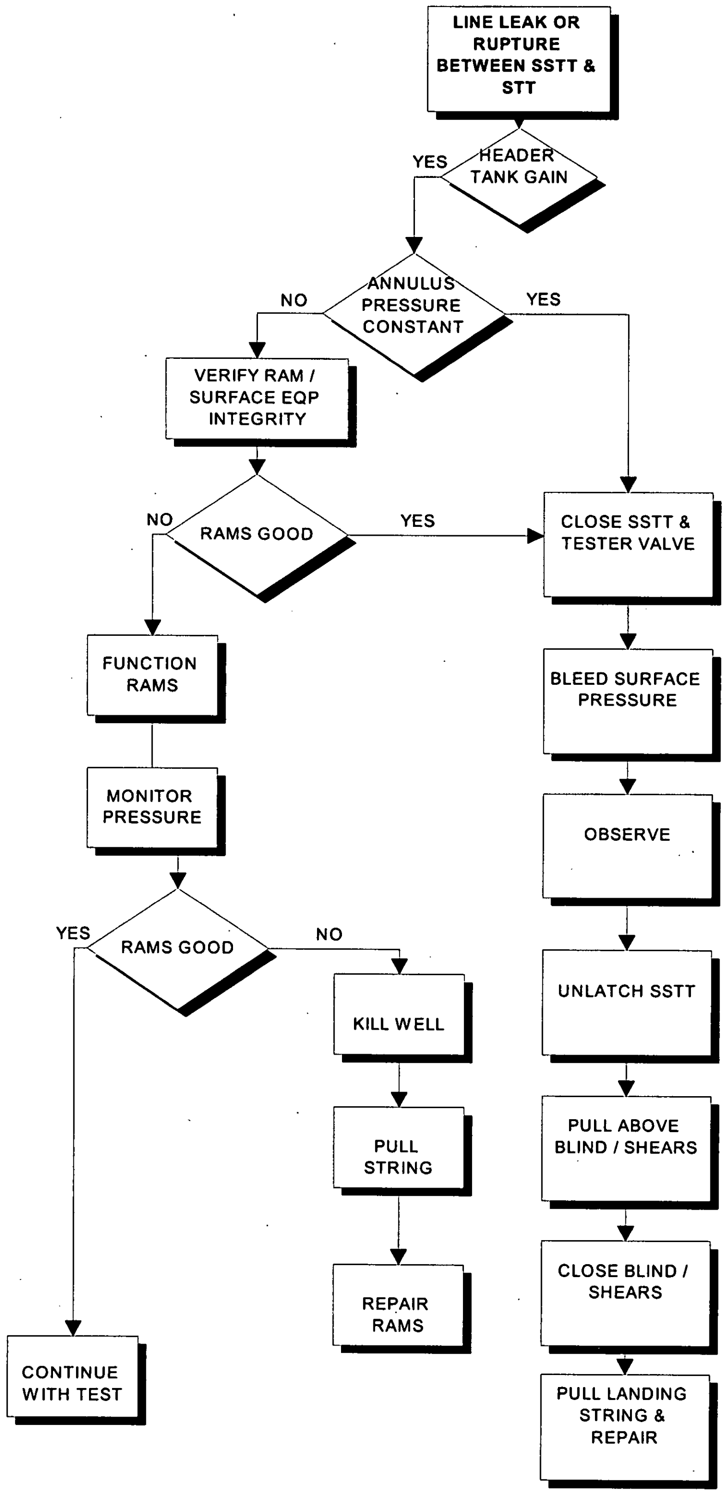
In the event of a fire (or explosion) occurring it is imperative that the alarm is raised before any other action to ensure immediate mobilisation of the Emergency Response Team. Reference should be made to DOGC Emergency Response Manual.

H_2S Procedures

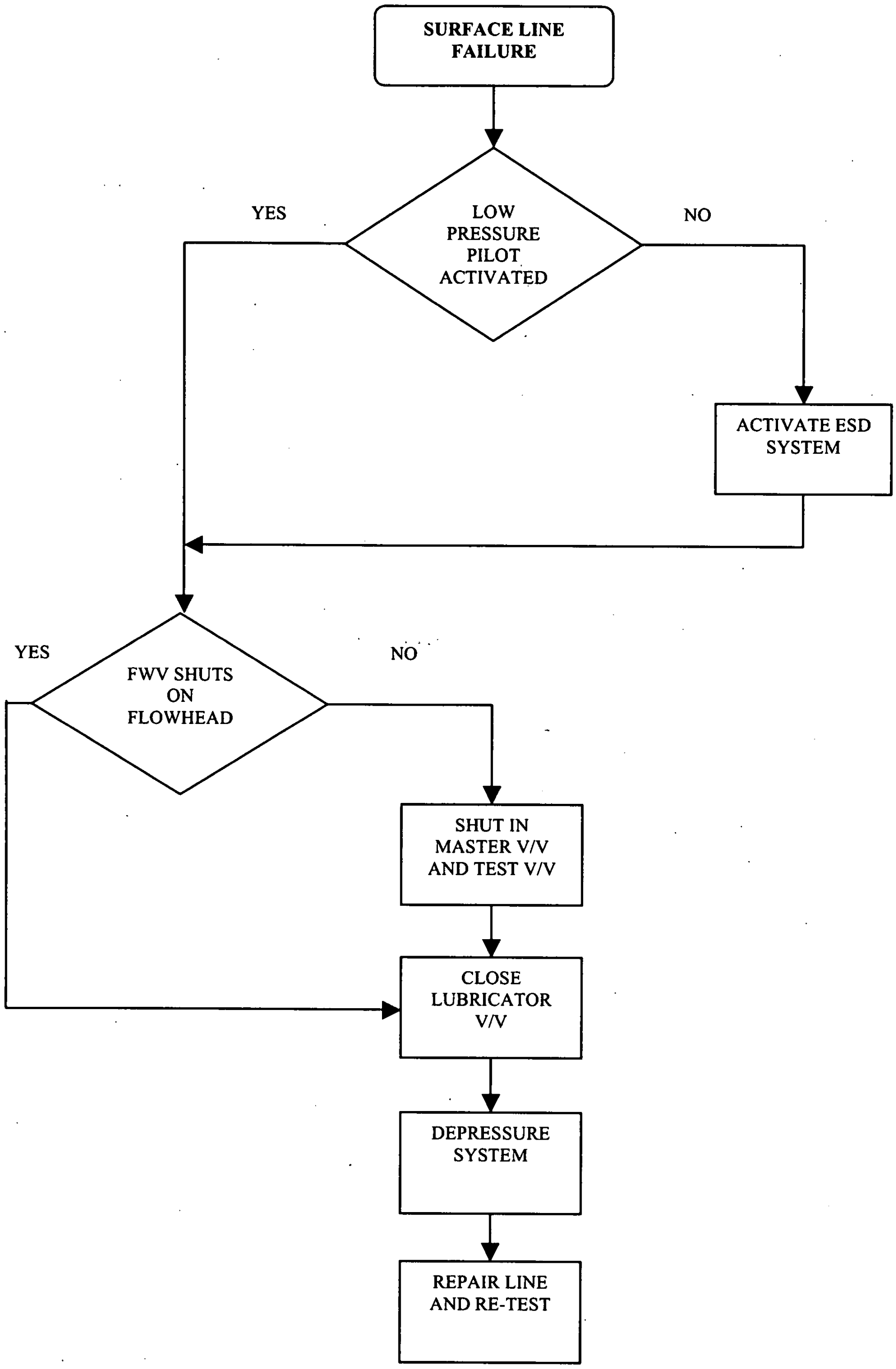
H_2S is not expected on this well. If it is detected the levels are likely to be less than 10ppm in air and DOGC H_2S procedures will be followed. The well can be flowed at up to 200ppm H_2S in stream. Reference should be made to DOGC Operations Manual.

APPENDIX 12 - Line Rupture Disc Procedures.

Response to Line Leak/Rupture between the SSTT and Flowhead



APPENDIX 13 - Surface Lines Failures Downstream Of The Flowhead



APPENDIX 14 - Specific Duties And Responsibilities

Diamond Offshore OIM

- Has overall responsibility for the conduct of all operations on site. Responsibility for specific areas is delegated to the senior Diamond Offshore rig representative on site, the Company Drilling Supervisor and the Well Test Engineer.

Company Drilling Supervisor

- Ensure that the Diamond Offshore OIM is informed of testing progress, of planned operations and in particular of any condition, which may affect safety or the environment.
- Overall operational responsibility for the rig to ensure all aspects of the well test objectives are met. Works in conjunction with Diamond Offshore OIM to manage safety of the rig and environment.
- Forewarn all relevant authorities (Maritime Safety Authority (MSA) Canberra, DME Melbourne) and associated services of the intention to conduct the well test and to produce hydrocarbons. Report the conclusion of the test
- Coordinate reporting to Company office.
- Assist Test Engineer in verification of space-outs and running of test string.
- Conduct pre-test safety meetings, reviewing all test procedures, potential hazards, contingency planning and personnel responsibilities.
- Ensure the well is secure after the test.
-

Well Test Engineer

- Act as technical liaison to the Company Drilling Supervisor.
- Review test procedures with all test personnel prior to first test.
- Provide the Company Drilling Supervisor with a daily report of testing operations and test data for transmittal to office
- Direct supervision of individual service companies in preparation and execution of the test, ensuring all Service Company equipment is available when needed, is fit for purpose, and that all Service Company personnel are available when needed.
- Liaison between Company Drilling Supervisor and Service Companies. All directions to service company personnel during testing are to be passed through the Well Test Engineer to prevent mis-communications. He will ensure the driller is informed of changes before they are carried out.
- Verification of space-outs and running of test string.
- Prepare test string configuration for each test, including overseeing strapping and drifting of all tubulars and components of the string.
- Coordinate collection of gas and sand samples.
- Supervise any Production Logging operations.
- Monitor testing operations and test data. Verify accuracy and completeness of data.

Reservoir Engineer

- Advise the required well test flow rates, duration of flow and shut-in periods in accordance with the Well Test Program. If changes are required to rates or periods the Reservoir Engineer shall advise the Well Test Engineer and Drilling Supervisor in advance of any change.
- Advise the requirement for temperature logging and/or variations to sampling requirements.
- Monitor testing operations and analyse test data. Verify accuracy and quality of data.
- Approve daily and other testing reports and test data.

Diamond Offshore Toolpushers

- Supervise drilling crew and assume responsibility for drilling equipment.

- Review test procedures and safety requirements with drilling crew prior to testing. Ensure all work is conducted in a safe manner.
- Liaise with Company Drilling Supervisor and Test Engineer in implementing detailed test procedure.
- Ensure adequate power is available all times to enable the string to be lifted and kill fluids to be pumped.

Driller

- Run Sub sea test tree and Sub sea lubricator valve in hole as per program.
- Focal point for all operations throughout the test. The driller is to be notified before any change in operations is carried out.
- Maintain and update chart on the drill floor showing the position of all valves in the string, Flowhead, and test choke manifold in conjunction with well test personnel.
- Remain on the drill floor with two floor men at all times during the test other than when relieved by the Diamond Offshore Toolpushers.
- Be familiar with emergency shut-in procedures for the test string.
- Assign Assistant Driller or derrickman to the pump room during testing to be ready to line up kill fluid to the cement unit.

Expro Test Supervisor

- Assume responsibility for installation, testing and operation of all equipment.
- Focal point for Expro testing crew. All instructions must go through the test supervisor.
- Coordinate testing operations with Company Drilling Supervisor and Well Test Engineer.
- Review test procedures with test crew and assign responsibility for emergency procedures.
- Coordinate data acquisition during testing. Well Test Engineer to advise on requirements.
- Responsible for reporting accurately test data to the Well Test Engineer as requested.

Expro Sub Sea Engineer

- Responsible for all checking and all operation of the SSTT
- Opening and Closing of SSTT and SS Lubricator valves
- Measure and record lengths and drift all SSTT and SSLV components.
- In conjunction with Rig Sub Sea Engineer ensure correct space-out and hang-off of SSTT and prepare space-out diagram
- Assist and advise driller on unlatching if required.

Cementer

- Function test and pressure test all pumps and piping. Line up for pumping kill fluids.
- Review kill procedures with Company Drilling Supervisor, Well Test Engineer, Expro Well Testing Supervisor and Mudloggers prior to start of testing. Have equipment in a state of readiness to kill and/or cement the well at short notice.
- Pressure test equipment as required.

Radio Operator

- Maintain a register of all portable radios on board. Ensure all transmitters are collected and secured prior to radio silence periods.
- Implement radio silence when instructed by the Company Drilling Supervisor. Notify Company office, supply boats, and shore based radio rooms, when going into radio silence and when communications are re-established. Announce radio silence over the PA system.
- Keep support vessels and helicopter base advised of status of testing operations.

Mud Loggers

- Monitor pit volumes during all testing operations.

Mud Engineer

- Ensure that the mud properties of the kill mud are within program specifications, prior to commencing the test.
- Monitor pit volumes during all testing operations.
- Ensure there is sufficient drill water available to flush equipment at the end of the test.
- Assist in analysing test samples.

APPENDIX 15 - Glossary Of Terms

API	American Petroleum Institute
bbl	barrels
BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BHS	Bottom Hole Sampler
BHT	Bottom Hole Temperature
BOP	Blow Out Preventer
BRT	Below Rotary Table
BS&W	Base Sediment and Water
CBL	Cement Bond Log
cc	cubic centimetres
CCL	Casing Collar Locator
CGR	Condensate Gas Ratio
CO_2	Carbon Dioxide
CT	Coil Tubing
DC	Drill Collar(s)
DP	Drill Pipe
DST	Drill Stem Test.
DWT	Dead Weight Tester
EX	Expro
ESD	Emergency Shut Down
FWV	Flow Wing Valve
GTP	General Test Pressure
HAZID	Hazard Identification
HES	Halliburton Energy Services
H_2S	Hydrogen Sulphide.
ITC	Internal Xmas Tree Cap
JHA	Job Hazard Analysis
JSA	Job Safety Analysis
KCl	Potassium Chloride
KPa	Kilo Pascals
KWV	Kill Wing Valve
LMV	Lower Master Valve
LPR	Lower Pipe Rams
m	metres
MD	Measured Depth
MDRT	Measured Depth below Rotary Table
mm	millimetres
MSL	Mean Sea Level
N2	Nitrogen
OD	Outside Diameter
PA	Public Address.
PBTD	Plug Back Total Depth
OIM	Offshore Installation Manager
POOH	Pull Out Of Hole
PPD	Pour Point Depressant

ppm	parts per million
psig	pounds per square inch gauge
PVT	Pressure, Volume and Temperature
RA	Radio Active
RD	Rupture Disc
RIH	Run In Hole
RT	Rotary Table
SIWHP	Shut In Well Head Pressure
SSLV	Sub Sea Lubricator Valve
SSTT	Sun Sea Test Tree
SSV	Surface Safety Valve
STP	Standard Temperature and Pressure
STT	Surface Test Tree
TD	Total Depth
TOC	Top Of Cement
TVD	True Vertical Depth
TVDRT	True Vertical Depth below Rotary Table
UMV	Upper Master Valve