OMV Australia

WELL COMPLETION REPORT (INTERPRETIVE DATA)

Baleen-3 & 3/ST1

Permit VIC/L21

Offshore Gippsland Basin

August 2003

OMV Australia

OMV Australia

Basin Oil Pty Ltd
ABN 36 000 628 017
(A wholly owned subsidiary of OMV Australia Pty Ltd)

Level 28, 44 St Georges Tce
Perth WA 6000

Tel: (61 8) 9223 5000
Fax: (61 8) 9223 5004

PERMIT VIC/L21

OFFSHORE GIPPSLAND BASIN
VICTORIA
AUSTRALIA

BALEEN-3 and BALEEN-3/ST1

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CONFIDENTIAL

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Reviewed by C Higgins — Operations Geologist **Date** 21/08/03

Approved by [signature] — Exploration Manager **Date** 28/08/03

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WELL SUMMARY CARD – BALEEN-3 & BALEEN-3/ST1

WELL	**BALEEN-3 & BALEEN-3/ST1**	**SPUD**	14:00 hrs, 24th May, 2002
WELL TYPE	Horizontal Development	**TD REACHED**	21:00 hrs, 4th June, 2002
BLOCK/LICENCE	VIC/L21	**RIG RELEASE**	00:30 hrs, 20th June, 2002
RIG	Ocean Bounty	**COMPLETION**	Sand screen (from 902.0 mMDRT (-660.0 mTVDSS) to 1554.0 mMDRT (-710.0 mTVDSS)
WATER DEPTH	52.5 m (LAT)	**STATUS**	Gas production well
RT (Sea level)	25.0 m	**TRAP TYPE**	Fault bounded anticline
TD (LAT)	1555.0 mMDRT (-710.4 mTVDSS)	**OPERATOR**	Basin Oil Pty Ltd. (a wholly owned subsidiary of OMV Australia Pty. Ltd.)

SURFACE LATITUDE	38° 00' 20.99" S	**SURFACE Y coord**	5 792 541.3 mN
SURFACE LONGITUDE	148° 26' 34.42" E	**SURFACE X coord**	626 675.9 mE
OBJECTIVE LATITUDE	38° 00' 40.79" S	**OBJECTIVE Y coord**	5 791 944.0 mN
OBJECTIVE LONGITUDE	148° 25' 59.33" E	**OBJECTIVE X coord**	625 810.7 mE
		Spheroid/Datum	ANS / AGD66 AMG Zone 55 S (CM 147° East)
SEISMIC REFERENCE	Surface: Inline 209, Xline 3786 Objective: Inline 221, Xline 3617 (Baleen 3D 2000)	**OBJECTIVE OFFSET**	-602.85 mN, -872.13 mE

WELL CONSTRUCTION

HOLE SIZE mm (inch)	CASING SIZE mm (inch)	SHOE DEPTH mMDRT (mTVDSS)	TYPE	LOT/FIT sg EMW
915 (36)	762 x 509 (30 x 20)	112 (-87.0)	X-52	N/A
444 (17 ½)	340 (13 3/8)	327.4 (-301.1)	K-55	1.74 (FIT)
311 (12 ¼)	244 (9 5/8)	866.1 (-655.0)	L-80	1.41 (FIT)
216 (8 ½)	168 (6 5/8)	1554.0 (-710.0)	Production liner (Excluder 2000 Sand screen)	N/A

CORES

No cores were cut in Baleen-3 or Baleen-3/ST1.

LWD LOGS

LOG TYPE	RUN	INTERVAL mMDRT (mTVDSS)	HOLE SIZE mm (in)
ORIGINAL HOLE			
DGR/EWRP4/DM/DDS	1	112.0 – 336.0 (-87.0 to -309.6)	444 (17 ½)
DGR/EWRP4/DM/DDS	2	336.0 – 458.0 (-309.6 to -424.9)	311 (12 ¼)
DGR/EWRP4/DM/DDS	3	458.0 – 871.0 (-424.9 to -655.6)	311 (12 ¼)
DGR/EWRP4/DDS/SLD/CNP/PM	4	871.0 – 1352.0 (-655.6 to -648.1)	216 (8 ½)
SIDETRACK			
DGR/EWRP4/SLD/CNP/DDS/PM	5	1137.0 – 1555.0 (-652.2 to -710.4)	216 (8 ½)

WIRELINE LOGS

No wireline logs were run.

LWD LOG INTERPRETATION (Weighted Averages)

ZONE	INTERVAL mMDRT (mTVDSS)	THICKNESS (mMD)	Net Pay (m)	POR Av (%)	Av Sw (%)
Gurnard Formation	875.0 – 1372.8 & 1496.0 – 1537.0 (-656.6 to -669.6 & -679.6 to -682.0)	538.7	480.1	35.3	N/A due to complex lithology & severe gas effect

DRILL STEM TESTS

DST	Formation	Interval	Flow rate	Choke	GOR
1	Gurnard	Sand screen from 902.0 mMDRT (-660.0 mTVDSS) to 1554.0 mMDRT (-710.0 mTVDSS)	27.1 MMscf/d	No choke, max. flow rate	N/A

FORMATION TOPS

AGE	FORMATION	MEASURED DEPTH (mMDRT)	SUBSEA (mTVDSS)	THICKNESS (mTVT)	PREDICTED DEPTH (mSS)	DIFFERENCE (m)	DIFFERENCE High/ low
Early Miocene	Gippsland Limestone	77.5	-52.5	559.0	-55.0	2.5	H
Late Oligocene	Lakes Entrance Fm	727	-611.5	38.4	-601.0	10.5	L
(Late) Middle Eocene	Latrobe Group - Gurnard Fm	841.4	-649.9	2	-654.8	4.9	H
	SG2 (Top Porosity)	850.6	-651.9	3.6	-654.8	2.8	H
	SG3	869.8	-655.5	2.5	-656.9	1.4	H
	SG4_down	888.2	-658	1.3	-658.4	0.4	H
	SG5	924.6	-659.3	1	-660.2	0.9	H
	SG6_down	965.8	-658.3	2.2	-666.1	7.8	H
	SG7	1041.2	-656.1	22.8	Np	-	
	Strzelecki Gp	1089.5	-653.9	26.4	Np	-	
	SG6_down	1127.4	-652.5	1.3	-673.4	20.9	H
	SG6_up (ST1)	1180.8	-653.8	0.2	-	-	
	SG5_up	1241.4	-654	1	-675.5	21.5	H
	SG4_up	1271.4	-655	2.2	-676.3	21.3	H
	SG3_up	1293.8	-657.2	15	-677.0	19.8	H
	SG4_down	1372.8	-672.2	16.2	-		
	SG4_up	1496	-688.4	22	-		
TOTAL DEPTH		1555	-710.4		-677.0		

np = not predicted

BIOSTRATIGRAPHY

No biostratigraphic analyses were performed.

REMARKS

Baleen-3 was drilled as a horizontal well to 1352.0 mMDRT (-648.1 mTVDSS). However, to increase the reservoir exposure to the well bore, the well was sidetracked from 1137.0 mMDRT (-652.2 mTVDSS) and drilled horizontally to a total depth of 1555.0 mMDRT (-710.4 mTVDSS). The well was cased and a production test through sand screens of the interval 902.0 mMDRT (-660.0 mTVDSS) to 1554.0 mMDRT (-710.0 mTVDSS) flowed 27.1 MMscf/d of gas.

BALEEN-3/ST1
INTERPRETIVE REPORT
Volume 2

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1.0 INTRODUCTION

1.1 WELL SUMMARY

Baleen-3 and -3/ST1 was drilled in the offshore Gippsland Basin as a crestal horizontal gas development well on the Baleen gas field. The Patricia-Baleen development in permit VIC/L21 (Figure 1) lies approximately 570 km from Geelong and 280 km from Port Welshpool. The field is on the northern edge of the basin, between the Rosedale and Lake Wellington Faults. The offshore Patricia-Baleen gas production facilities are located in 50 to 60 m of water, 23 km south of the town of Orbost in south eastern Victoria. The Baleen-3 surface location was approximately 500 m north east of Baleen-1 and the final bottom hole (toe) location was approx. 150 m south west of Baleen-1.

The primary objective was to drill and complete for commercial production, a 650 m section through the Gurnard Formation Reservoir. The programme also called for determination of deliverability, reservoir pressures, flowing pressure data and the collection of representative gas samples. All of the objectives were met and the well was suspended as a gas producer completing the subsurface development of the field. Completion schematics are included as Figures 2 to 4.

The well was spudded at 14:00 hrs on the 24th May, 2002 in 52.5 m of water and was drilled to a total depth of 1555.0 mMDRT (-710.4 mTVDSS), which was reached at 21:00 hrs, 4th June, 2002. After the conductor pipe had been installed and 444 mm (17 ½") hole had been drilled to 336.0 mMDRT (-309.6 mTVDSS), the 340 mm (13 3/8") shoe was set at 327.4 mMDRT (-301.1 mTVDSS). The BOPs and marine riser were then run. The 311 mm (12 ¼") hole was deviated from 336.0 to 871.0 mMDRT (-309.6 to -655.6 mTVDSS). Baleen-3 reached its heel at 871.0 mMDRT (-655.6 mTVDSS) with a deviation of 81.5 degrees with an azimuth of 235 degrees. The 244 mm (9 5/8") casing was run with the casing shoe set at 866.1 mMDRT (-655.0 mTVDSS).

The top of the Gurnard Formation was intersected at 841.4 mMDRT (-649.9 mTVDSS) approximately 5 m higher than prognosed. The original 216 mm (8 ½") horizontal hole was drilled to a total depth of 1352.0 mMDRT (-648.1 mTVDSS). To increase reservoir exposure to the wellbore, an open hole sidetrack was kicked off at 1137.0 mMDRT (-652.2 mTVDSS) at an angle of 92 degrees and deviated between 75 and 95 degrees to total depth of 1555.0 mMDRT (-710.4 mTVDSS). The average azimuth of the sidetracked hole is 234°.

Structural dip interpretations and correlations from Horizontal Solutions International using the true stratigraphic position method, confirm the pre-drill structural interpretation with the exception of relatively steep dips and possible small scale faulting controlling the core of the feature. Rock quality within the pre defined sub grids that comprise the Gurnard reservoir was as anticipated or better. High gas readings were recorded while drilling through the reservoir from 850.6 to 1555.0

LOCATION MAP

GIPPSLAND BASIN

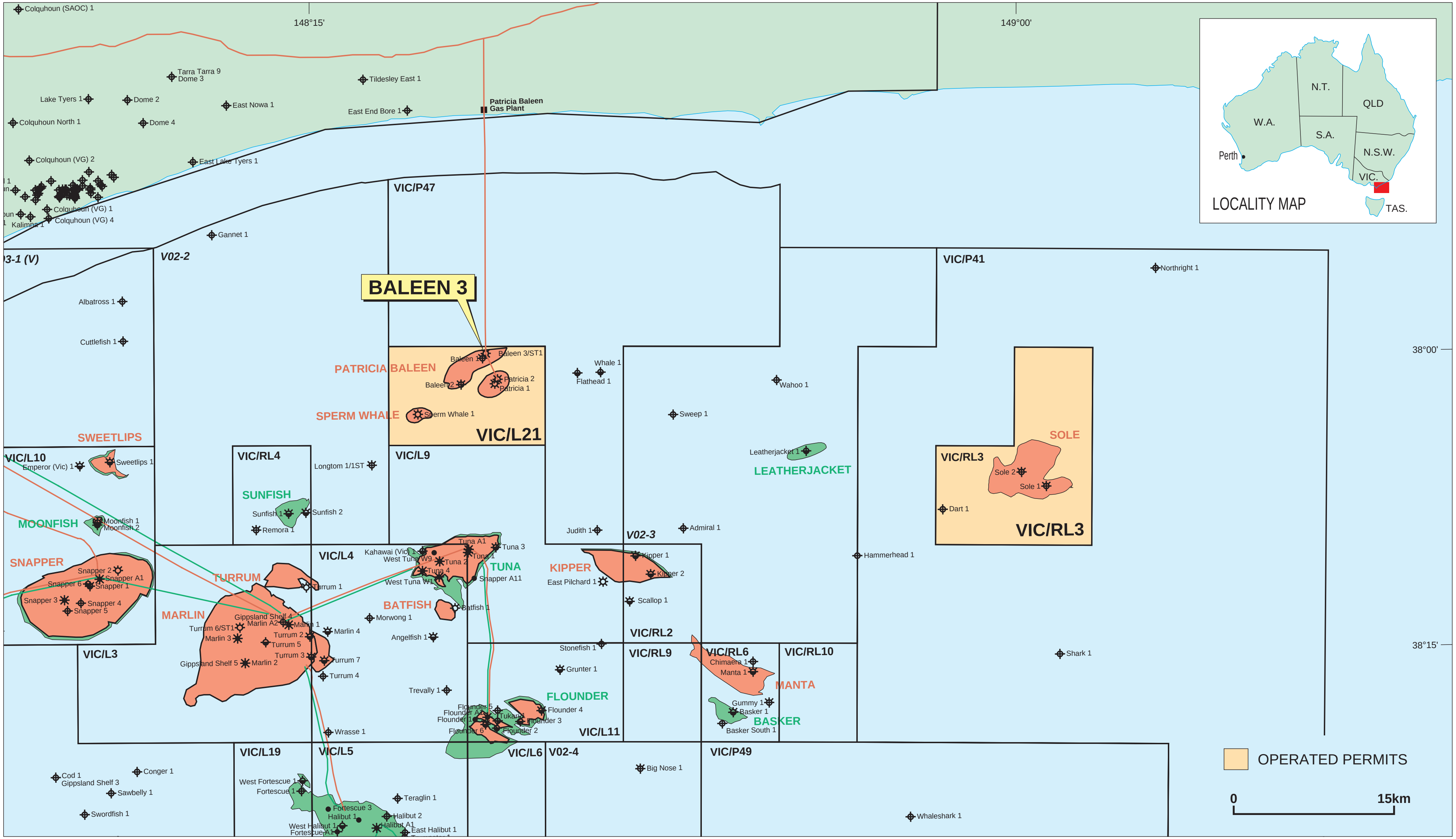


FIGURE 1

AUTHOR: OMV DATE: MARCH 2003 FILENAME: GIPPSAND \ A4S \ 390.DGN (V1)

Baleen 3
Final Well Completion.

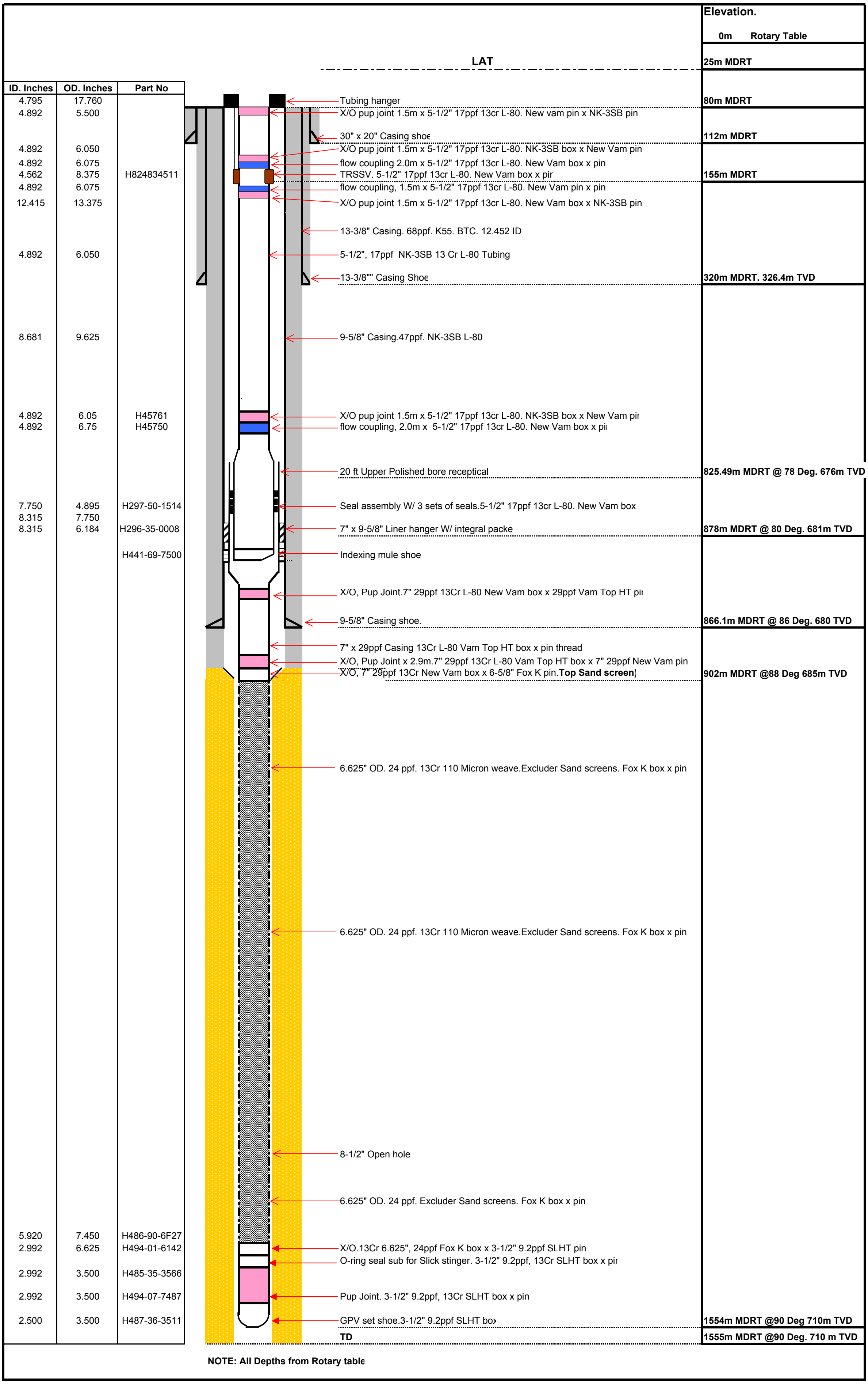
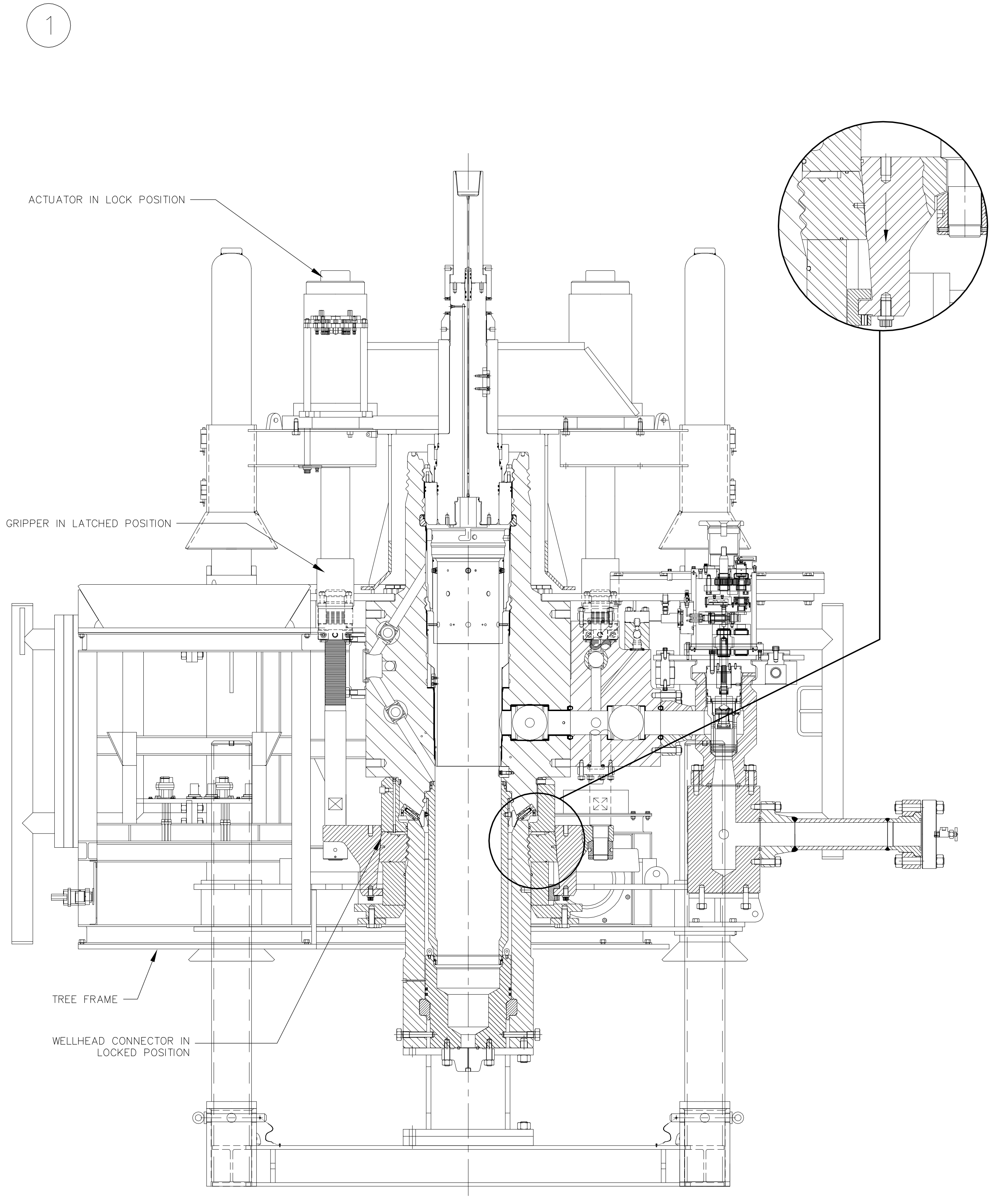
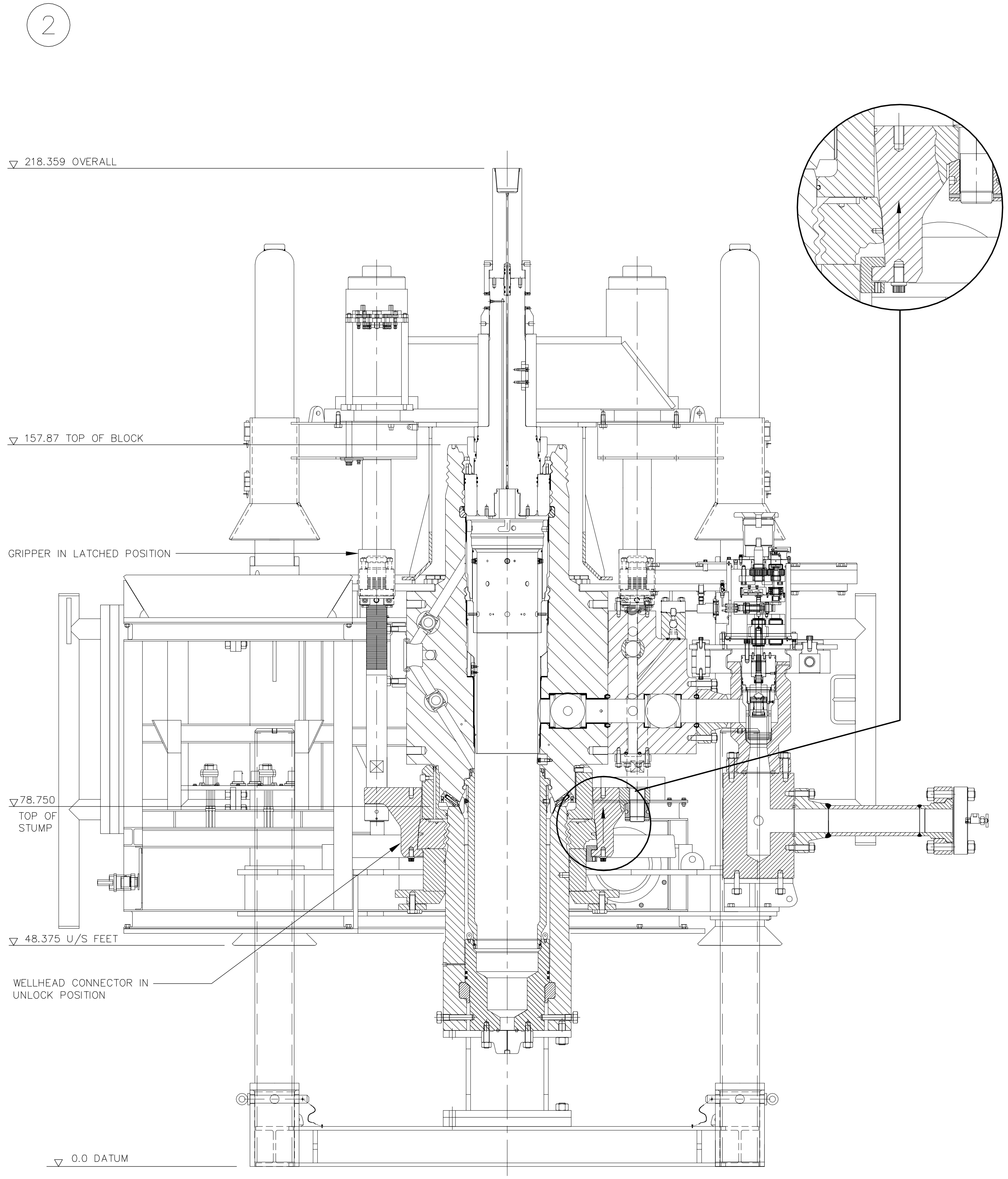


Figure 2

CAMERON



TRT LATCHED TO WELLHEAD CONNECTOR ACTUATOR

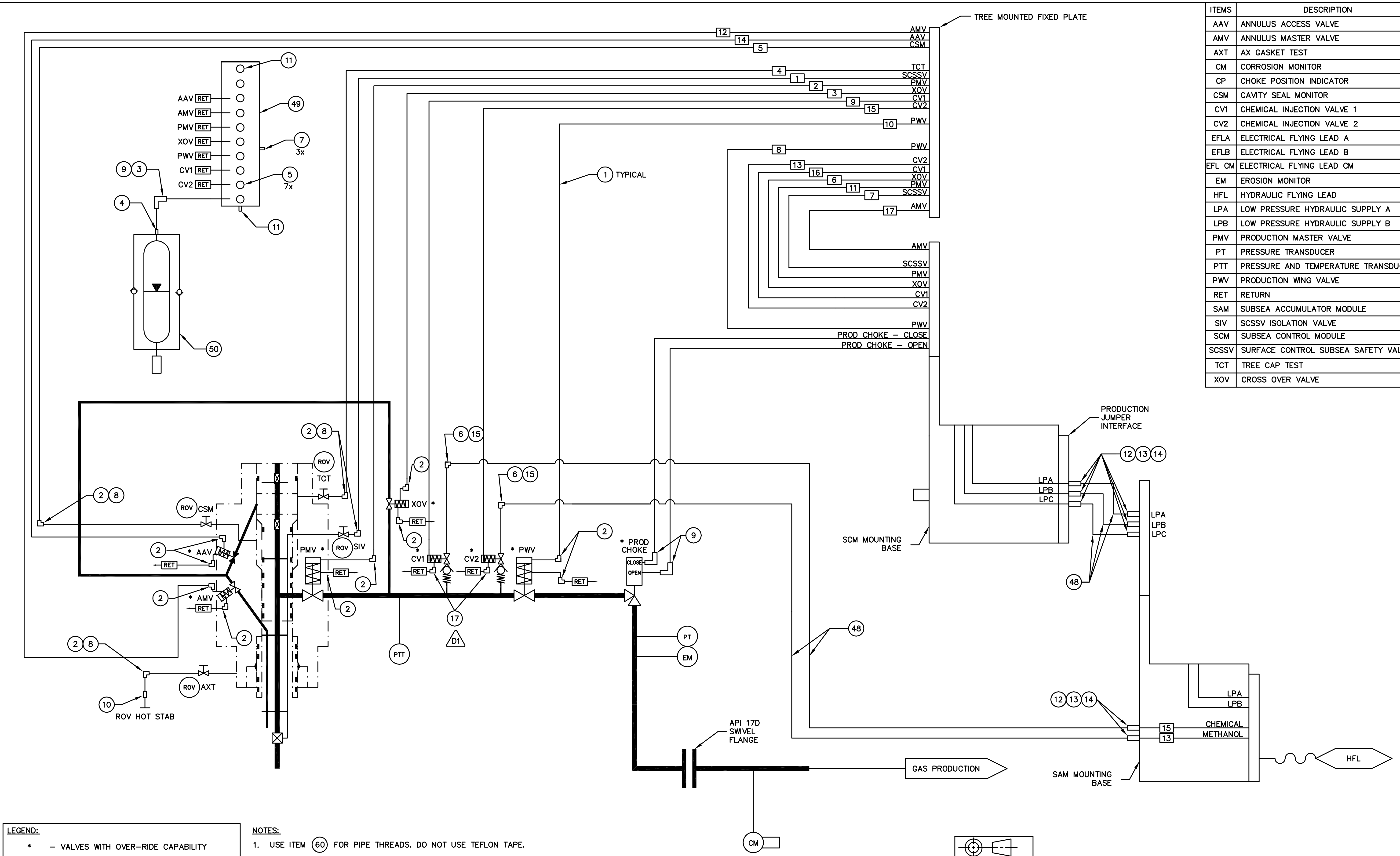


TRT LATCHED TO WELLHEAD CONNECTOR ACTUATOR

FIGURE 1.3, INSTALL SPOOL TREE ASSEMBLY ON TEST SKID

SK-156101-03	REV 01

Figure 3



ITEMS	DESCRIPTION
AAV	ANNULUS ACCESS VALVE
AMV	ANNULUS MASTER VALVE
AXT	AX GASKET TEST
CM	CORROSION MONITOR
CP	CHOKE POSITION INDICATOR
CSM	CAVITY SEAL MONITOR
CV1	CHEMICAL INJECTION VALVE 1
CV2	CHEMICAL INJECTION VALVE 2
EFLA	ELECTRICAL FLYING LEAD A
EFLB	ELECTRICAL FLYING LEAD B
EFL CM	ELECTRICAL FLYING LEAD CM
EM	EROSION MONITOR
HFL	HYDRAULIC FLYING LEAD
LPA	LOW PRESSURE HYDRAULIC SUPPLY A
LPB	LOW PRESSURE HYDRAULIC SUPPLY B
PMV	PRODUCTION MASTER VALVE
PT	PRESSURE TRANSDUCER
PTT	PRESSURE AND TEMPERATURE TRANSDUCER
PWV	PRODUCTION WING VALVE
RET	RETURN
SAM	SUBSEA ACCUMULATOR MODULE
SIV	SCSSV ISOLATION VALVE
SCM	SUBSEA CONTROL MODULE
SCSSV	SURFACE CONTROL SUBSEA SAFETY VALVE
TCT	TREE CAP TEST
XOV	CROSS OVER VALVE

LEGEND:

- * – VALVES WITH OVER-RIDE CAPABILITY
- —— – HYDRAULIC LINES
- (ROV) – ROV ACTUATED ISOLATION NEEDLE VALVES

NOTES:

1. USE ITEM (60) FOR PIPE THREADS. DO NOT USE TEFLON TAPE.
2. REMOVE 4 TUBING CONNECTORS (1/4" NPTM X 3/8" TUBE) WHICH ARE ON TOP OF CV1 & CV2 AND REPLACE WITH (19). D1

CAD PRODUCED DOCUMENT – NO MANUAL REVISIONS ALLOWED

TOLERANCE UNLESS OTHERWISE SPECIFIED

SURFACE TREATMENT ~

MATERIAL & HEAT TREAT ~

DO NOT SCALE

DRAWN BY AFANDI — DATE 27 FEB 02

CHECKED LAURENCE LIM — DATE 01 MAR 02

APPROVED KEVIN KEOSOFF — DATE 01 MAR 02

INITIAL USE B/N 2202311-01

CAMERON — Cooper Cameron (Singapore) Pte Ltd. Subsidiary of Cooper Cameron Corp. 2 Gul Circle, Singapore 629560

HYDRAULIC PIPING SCHEMATIC
5"–5M G2 SPOOL TREE
OMV, PATRICIA BALEEN GAS PROJECT

SHEET 1 OF 2 — SK–156052–01

REV: A1, B1, C1, D1

Figure 4

mMDRT (-652.2 to -710.4 mTVDSS) with a maximum of 23% total gas while drilling at 859.0 mMDRT (-654.1 mTVDSS). No hydrocarbon fluorescence was observed in the well.

A 168 mm (6 5/8") production liner consisting of "Excluder 2000" sand screens and a 140 mm (5 1/2") completion string were installed from 902.0 mMDRT (-660.0 mTVDSS) to 1554.0 mMDRT (-710.0 mTVDSS). The well was tested and a maximum flow of 27.1 MMscf/d (Appendix 2) before being suspended. Anchors were pulled and the rig was released at 00:30 hrs, 20th June, 2002.

Analysis of the pressure data indicates an effective horizontal permeability of 75-95 mD. Deliverability analysis yielded an estimated stabilised absolute open-flow (AOF) potential of 150 MMscf/d, better than the initial production performance predicted from the 2001 reservoir simulation modelling.

1.2 VIC L/21 PRODUCTION LICENSE HISTORY

A summary of the exploration history prior to the year 2000 may be referred to in the Baleen-2 Interpretive Well Completion Report.

In late 1999, OMV gained full control of Cultus Petroleum NL and acquired a 100% interest in the Patricia-Baleen retention lease VIC/RL5. The commerciality of the Patricia-Baleen development followed the drilling of the Baleen-2 appraisal well in October 1999.

A 3D seismic survey covering 85 square kilometres full fold data was recorded over the Patricia and Baleen fields in January 2000. Sail-line spacing is 12.5 metres with each 3D line having a 12.5 metre group spacing. After processing, a 3D migrated data set was generated with a 6.25 metre inline and 12.5 metre crossline grid spacing.

The recording of the 3D seismic survey provided confidence in determining the reserves for the Patricia Field as a clear gas/water contact; this is evident on seismic data across the field. A hydrocarbon/water contact had not been identified in the discovery well. Patricia-1 drilled in 1987 contained gas down to –718 mSS and mapping of the 2000 3D data indicated that gas extends down to some –728 mSS, the mapped spill point.

The VIC/RL5 retention lease was converted to a production license on 27th December 2001 when VIC/L21 was awarded. Santos Limited and Diamond Gas Resources Pty Ltd entered the license participation in April 2002 and May 2001 respectively.

1.3 REGIONAL STRUCTURE AND STRATIGRAPHY

Please refer to the Baleen-2 Interpretive Well Completion Report for details on the regional structure and stratigraphy of this area.

2.0 STRATIGRAPHY AND RESERVOIR SUB-DIVISION

A generalised stratigraphic column for the basin is included as Figure 5.

Predicted vs actual stratigraphic tops are presented in Table 1 and Figure 6, and were defined using a combination of lithologic descriptions from cuttings (refer to Appendix 3 - Basic Data Report), LWD logs and drilling data from the well.

Five LWD runs were made in Baleen-3 and -3/ST1. The first three comprised GR-Resistivity recorded from 112.0 to 336.0 mMDRT (-87.0 to -309.6 mTVDSS), 336.0 to 458.0 mMDRT (-309.6 to -424.9 mTVDSS) and 458.0 to 871.0 mMDRT (-424.9 to -655.6 mTVDSS) respectively. The fourth run was a GR-Resistivity-Density-Neutron and was made from 871.0 to 1352.0 mMDRT (-655.6 to -648.1 mTVDSS). The final run comprised GR-Resistivity-Density-Neutron and was made in the sidetrack from 1137.0 to 1555.0 mMDRT (-652.2 to -710.4 mTVDSS). These logs were used for correlation to nearby wells and to interpret formation boundaries and lithology. The available data and the stratigraphic interpretation are displayed on the composite well log (Enclosure 1), the reservoir cross section in (Enclosure 2) and the Gurnard Formation Reservoir Schematic Figure 7.

The Gurnard Formation in Baleen-3 was intersected at 841.4 mMDRT (-649.9 mTVDSS), 4.9 m high to prognosis. Sub grid unit 2 (top porosity) was encountered at 850.6 mMDRT (-651.9 mTVDSS), 2.8 m high to prognosis. Top Gurnard and top SG2 were not coincident as predicted. Sub grid units 3, 4 and 5 were intersected 0.4 to 1.4 m high to prognosis. Sub grid unit 6 was found at 965.8 mMDRT (-658.3 mTVDSS), 7.8 m high to prognosis. The original well then passed through Sub grid 7 at 1041.2 mMDRT (-656.1 mTVDSS) and the Strzlecki Group at 1089.5 mMDRT (-653.9 mTVDSS) which were not predicted. The Baleen-3 well bore is interpreted to have passed through a fault and then re encountered the SG6 unit at 1127.4 mMDRT (-652.5 mTVDSS) some 20.9 m high to prognosis, due to significant steepening of structural dips. The original well bore then progressed rapidly up section and penetrated the top Gurnard again at 1310 mMDRT. Due to the steeper than expected dips and apparent loss of net production interval the well was sidetracked down dip from 1137.0 mMDRT (-652.2 mTVDSS) to intersect a longer sand interval. In the sidetrack hole, SG6 was intersected going up at 1180.8 mMDRT (-653.8 mTVDSS), then SG5 (up), 21.5 m high to predicted, SG4 (up), 21.3 m high and then SG3 (up) at 1293.8 mMDRT (-657.2 mTVDSS), 19.8 m higher than expected. The well then tracked down to SG4 and back up to SG3 where it reached a final total depth of 1555.0 mMDRT (-710.4 mTVDSS).

Analysis of LWD gamma ray, resistivity, neutron and density data (see Table 2 and Enclosure 3) indicated that Baleen-3/ST1 intersected a gas sands in the Gurnard Formation. Over the gross

GIPPSLAND BASIN
GENERALISED STRATIGRAPHY

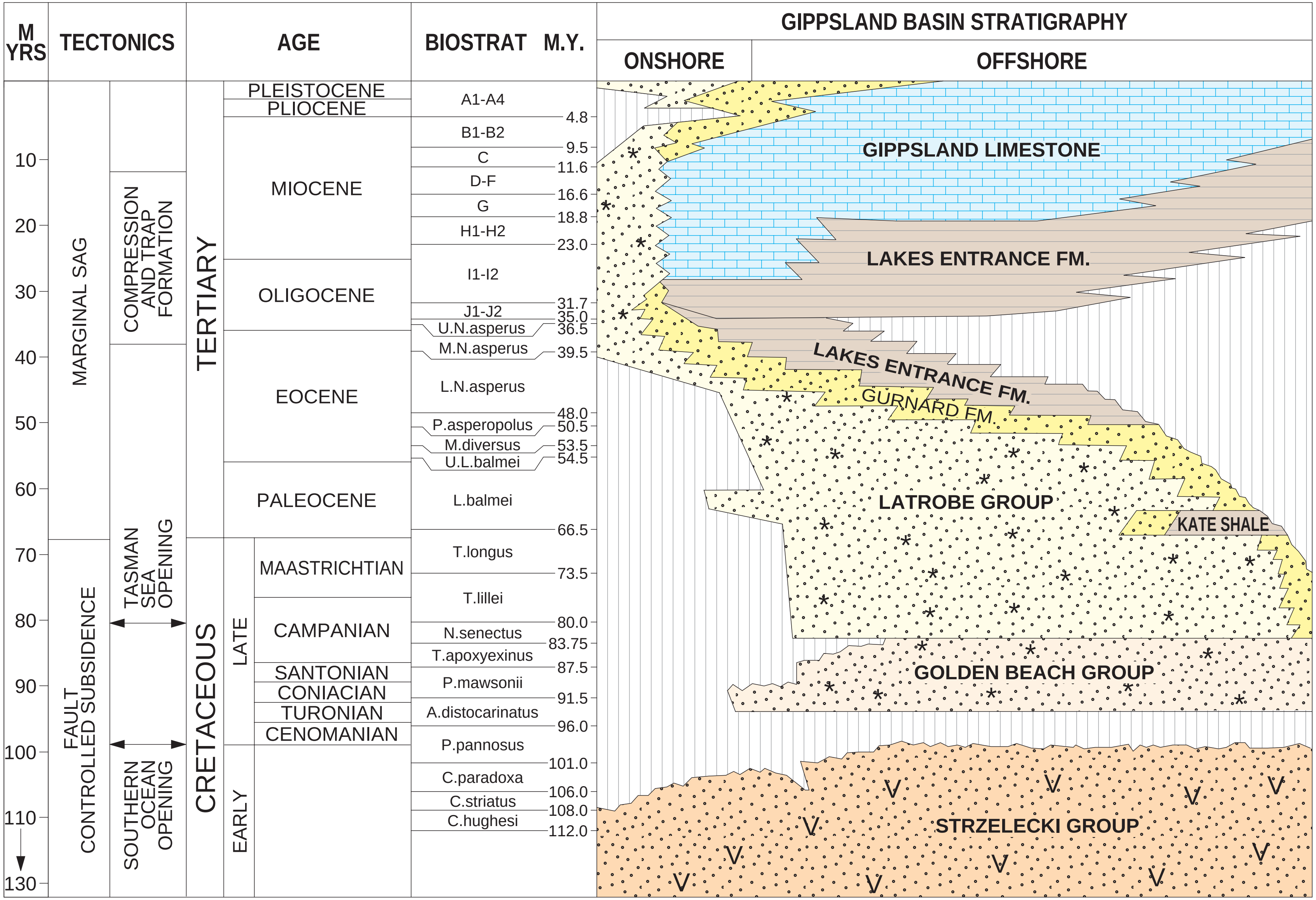


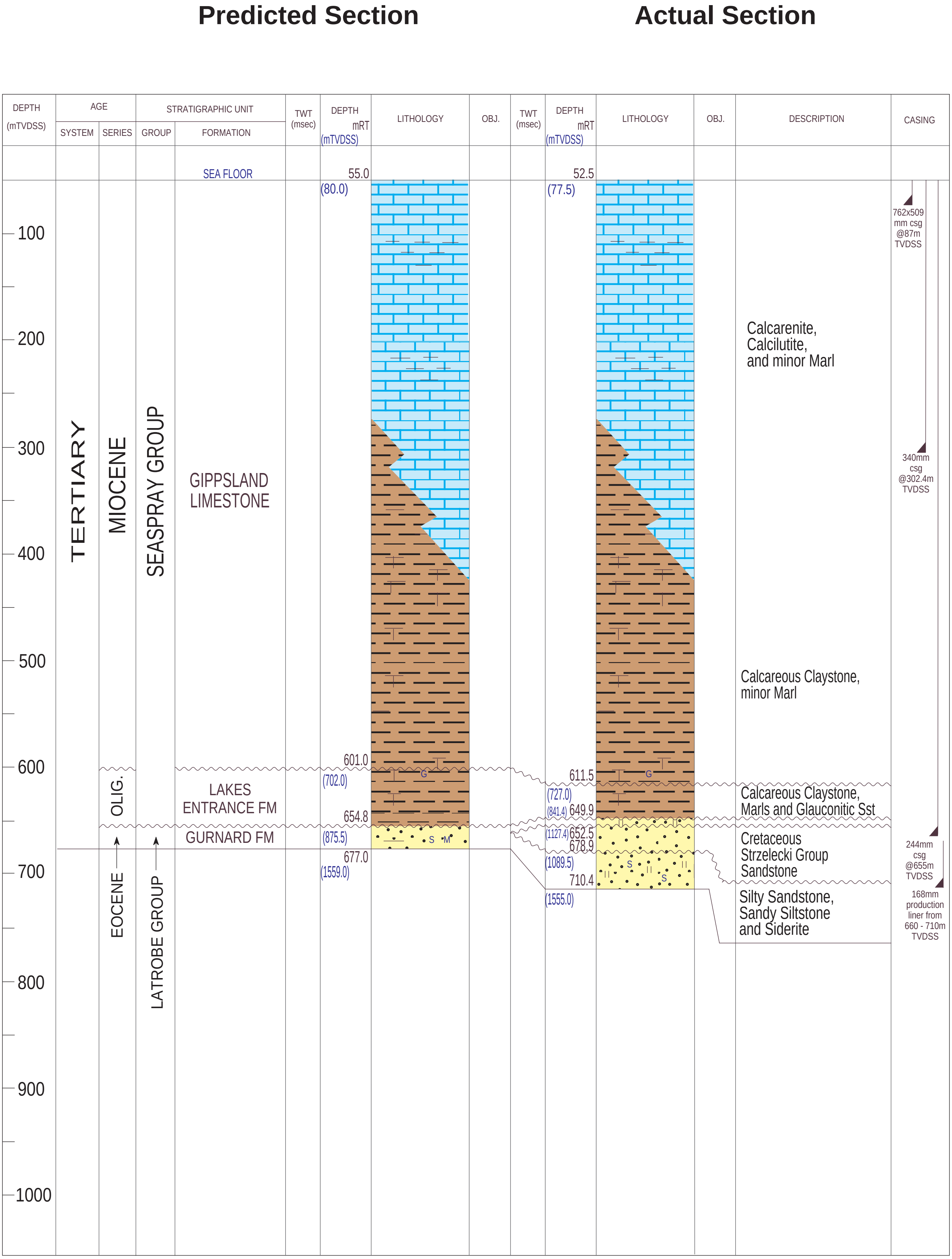
FIGURE 5

AUTHOR: OMV   DATE: JANUARY 2002   FILENAME: GIPPSLAND \ A4S \ 29.DGN

OMV

BALEEN-3 / ST1

PREDICTED vs ACTUAL SECTION

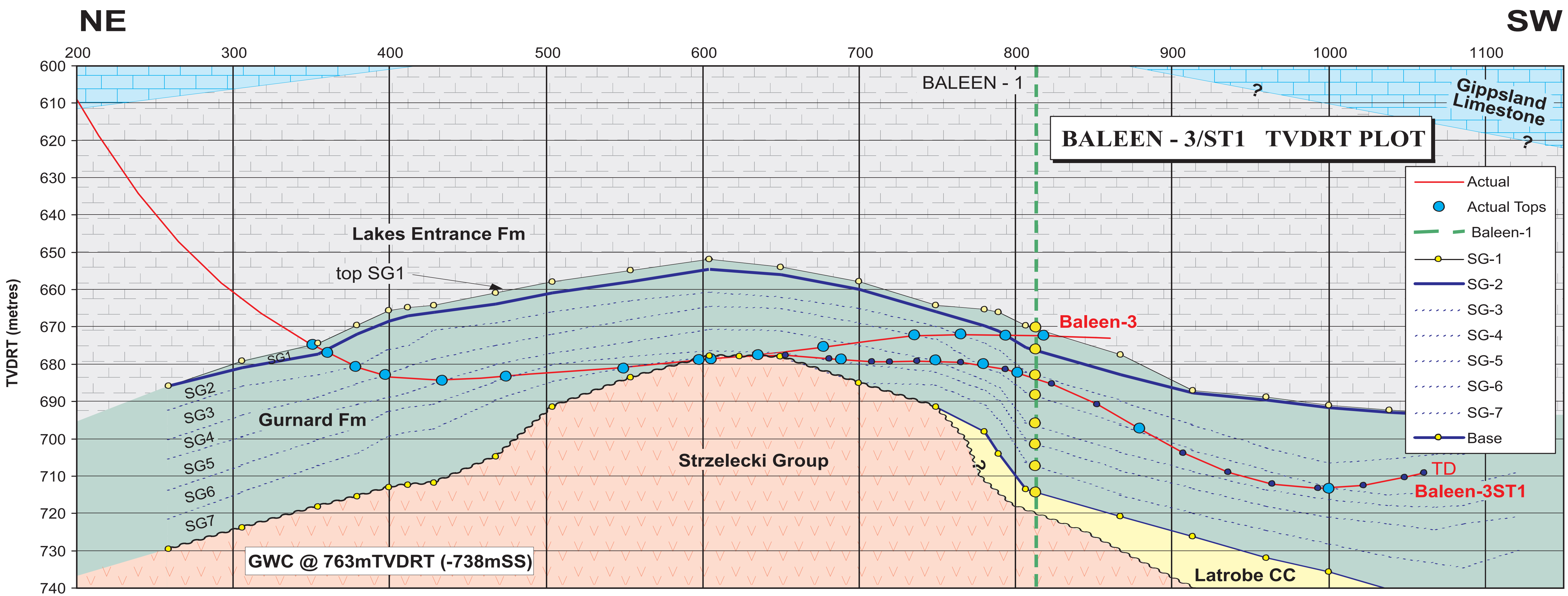


AUTHOR: OMV DATE: JUNE 2003 FILENAME: GIPPSLAND \ VICL21 \ A4S \ 396.DGN

FIGURE 6

GURNARD FORMATION RESERVOIR

(VERTICAL SECTION IN METRES @ 235.6 DEGREES)



interval of 538.7 m from 875.0 to 1372.8 mMDRT, (-656.6 to -669.6 mTVDSS) and 1496.0 to 1537.0 mMDRT (-679.6 to -682.0 mTVDSS) there is net pay of 480.1 m (89.1%). Average log porosity in the pay interval is 35.3%.

Structural dip interpretations and correlations from HSI (Horizontal Solutions International) (Appendix 1) indicate the Lakes Entrance Formation to have relatively low dips varying from 4 degrees north to 1.3 degrees south. Dips in the upper Gurnard Formation are interpreted by HSI to be 2 to 2.5 degrees north. While drilling down section through SG3, 4, 5 and 6, dips were interpreted to be between 4.5 to 11 degrees north. There was a loss of section (due to steep dips or a small fault) and the well bore, by correlation, intersected the mid SG7 unit and the beds were dipping 6.2 degrees north. As a result of these steep dips the Strzlecki Group was unexpectedly intersected at 1089.5 mMDRT (-653.9 mTVDSS). There was a 16 m loss of section and the wellbore re-entered the SG6 at 1127.4 mMDRT (-652.5 mTVDSS). The wellbore proceeded up section and penetrated the top Gurnard at 1310.0 mMDRT (original hole) with an apparent dip of 14 degrees south. It was decided to sidetrack the well in order to increase the reservoir exposure to the well bore and production screens. The sidetrack kicked off at 1137.0 mMDRT (-652.2 mTVDSS) in the SG6 unit. The top of the SG6 was intersected at 1180.8 mMDRT (-653.8 mTVDSS), then the SG unit 5, 4 and 3 were cut. Dips were interpreted to be 4 to 19 degrees south, considerably higher than predicted. At total depth of 1555.0 mMDRT (-710.4 mTVDSS) the wellbore was in the SG3 unit and dips were interpreted to be 1 to 3 degrees south.

Table 1 Predicted versus Actual Formation Tops Baleen-3/ST1

	PREDICTED	ACTUAL			DIFFERENCE	
FORMATION TOPS	DEPTH (mTVDSS)	DEPTH (mMDRT)	DEPTH (mTVDSS)	THICKNESS (mTVT)	(m)	High/ Low
Gippsland Limestone	-55.0	77.5	-52.5	559.0	2.5	H
Lakes Entrance Fm	-601.0	727.0	-611.5	38.4	10.5	L
Latrobe Group - Gurnard Fm	-654.8	841.4	-649.9	2.0	4.9	H
SG2 (Top Porosity)	-654.8	850.6	-651.9	3.6	2.8	H
SG3	-656.9	869.8	-655.5	2.5	1.4	H
SG4_down	-658.4	888.2	-658.0	1.3	0.4	H
SG5	-660.2	924.6	-659.3	1.0	0.9	H
SG6_down	-666.1	965.8	-658.3	2.2	7.8	H
SG7	np	1041.2	-656.1	2.2	-	
Strzelecki Gp	np	1089.5	-653.9	1.4	-	
SG6_down	-673.4	1127.4	-652.5	1.3	20.9	H
SG6_up (ST1)	-	1180.8	-653.8	0.2	-	
SG5_up	-675.5	1241.4	-654.0	1.0	21.5	H
SG4_up	-676.3	1271.4	-655.0	2.2	21.3	H
SG3_up	-677.0	1293.8	-657.2	15.0	19.8	H
SG4_down	-	1372.8	-672.2	16.2		
SG4_up	-	1496.0	-688.4	22.0		
TOTAL DEPTH	-677.0	1555.0	-710.4			

np = not predicted; Note: see Appendix 1 “Stratigraphic Correlation Report” for details of the sub grid (SG) zonation.

Gippsland Limestone 77.5 (seafloor) – 727.0 mRT

Tertiary (Early Miocene) -52.5 (seafloor) to -611.5mTVDSS

Thickness: 649.5 m (559.0 mTVT)

Upper boundary pick: Seafloor

Lithology: The interval from 336.0 to 727.0 mMDRT comprises mainly argillaceous calcilutite with interbedded calcarenite and calcisiltite with rare calcareous claystone. The lithology is:

Argillaceous Calcilutite: light greenish grey to medium olive grey, medium dark grey in parts, amorphous, soft, dispersive in part, 20 to 30% siliceous clay matrix, 10 to 20% calcisilt, trace glauconite silt. Grades to argillaceous calcisiltite in parts.
Interbedded with *Calcarenite:* very light to light grey, light to medium yellowish grey, firm, silty to fine grained calcite, trace to 10% fossil fragments (shell, bryozoa, echinoid spicules), 5 to 15% calcilutite matrix, re-crystallized in part, trace light to dark green glauconite, nil to trace pyrite. Grades to calcisiltite in parts.

and *Calcisiltite:* light grey, light to medium yellowish grey, soft to firm, rare hard, trace to 10% fossil fragments (shell, bryozoa, echinoid spicules), trace to 10% fine grained calcite, 5 to 10% calcilutite matrix, re-crystallized in part, trace light to dark green glauconite, nil to trace pyrite.

with minor *Calcareous Claystone:* light to dominantly medium olive grey, occasionally dark olive grey, soft to firm, amorphous to sub-blocky, 20 to 30% micrite content, grades to marl / argillaceous calcilutite.

Calcimetry: From 336.0 to 595.0 mMDRT calcite ranged from 50 to 84% and averaged 68.5%. From 595.0 to 725.0 mMDRT the calcite ranged from 28 to 70% and averaged 52.6%. There was no dolomite recorded.

Drilling characteristics: From 112.0 to 336.0 mMDRT the drill rate was highly variable, (reflecting the interbedded nature of the section) and was from 20 to

450 m/hr and averaged approximately 60 m/hr. From 336.0 to 727.0 mMDRT the drill rate ranged from 5 to 100 m/hr and averaged 20 m/hr.

Hydrocarbon shows: No significant gas and no fluorescence were recorded.

Lakes Entrance Formation 727.0 – 841.4 mMDRT

Tertiary (Late Oligocene) -611.5 to -649.9 mTVDSS

Thickness: 114.4 m (38.4 mTVT)

Upper boundary pick: The top of the Lakes Entrance Formation is marked by an increase in gamma ray from 60 to 80 API. Resistivity decreases from approx. 4 to 2 ohmm. The lithology becomes dominated by calcareous claystones with lesser marls and fine grained limestones.

Lithology: This unit is characterised by calcareous claystone with interbedded marl and minor argillaceous calcisiltite.

Calcareous Claystone: medium grey to medium olive grey, occasionally dark olive grey, greenish grey in parts, brownish yellow in parts, soft to firm, very soft in parts, amorphous to sub blocky, 15 to 30% micrite content, trace forams, trace fossil fragments, trace quartz silt to very fine sand, trace carbonaceous wisps, trace (becoming 1-3% near base) very fine pelloidal glauconite. Grades to claystone.

Marl: light grey to light olive grey, medium olive grey, very soft to soft, dispersive, amorphous, 40 to 50% siliceous clay, trace chert, trace disseminated pyrite, trace calcisilt, trace forams. Grades to calcareous claystone.

With minor *Argillaceous Calcilutite:* light greenish grey to medium olive grey, soft to firm, amorphous, slightly dispersive, 20 to 40% siliceous clay, trace to 5% calcisilt. trace glauconite. Commonly grades to marl / calcareous claystone.

Calcimetry: Calcimetric values are lower than the overlying Gippsland Limestone, ranging from 8 to 62% and average 28.5%.

Log properties:	The gamma ray is generally between 60 and 100 API for the top 75 m. It then increases from 100 to 150 API through to the underlying formation. The resistivity is steady at between 1 to 2.5 ohmm.
Drilling characteristics:	The drill rate is non-diagnostic and varies from 10 to 100 m/hr.
Hydrocarbon shows:	No significant gas or fluorescence shows. Total gas ranges from 0.08 to 0.51% and is entirely methane and ranges from 608 to 3898 ppm.

Latrobe Group

Gurnard Formation

Tertiary (Late Middle Eocene)

The Gurnard Formation reservoir of the Latrobe Group is subdivided into a number of OMV named informal sub grid units. SG2 (top porosity) was expected at top Gurnard but was intersected slightly lower and an upper unit was intersected.

Gurnard Formation (upper)

841.4 to 850.6 mMDRT
-649.9 to -651.9 mTVDSS
Thickness: 9.2 m (2 mTVT)

Upper boundary pick:	The top pick is an increase in resistivity from 2.5 to 3.5 ohmm and an initial decrease in gamma ray from 130 to 120 API. The lithology becomes mainly very fine grained silty sandstone with minor sandy siltstone and claystone
Lithology:	The upper part of the Gurnard Formation is characterised by silty sandstone with minor sandy siltstone and rare claystone at the top.
	Silty Sandstone: light to dark yellowish brown, medium brownish grey, loose and friable, minor firm, clear to translucent, occasionally very light grey, quartz grains, very fine to fine, trace medium, poorly to moderately sorted, sub angular to sub rounded, 15 to 30% quartz silt, 5 to 15% clay content, trace to 3% glauconite, trace to 1% mica (muscovite and biotite), trace multicoloured lithics, fair inferred porosity.

Sandy Siltstone: light to medium yellowish brown, dark brown, soft to firm, very soft in parts, blocky, 15 to 25% very fine quartz, 10 to 20% clay content, trace micrite content, trace to 3% glauconite, trace mica, trace siderite.

Claystone: medium grey to medium olive grey, occasionally dark olive grey, greenish grey in parts, soft to firm, amorphous to sub blocky, 2 to 10% micrite content, trace forams, trace to 5% quartz silt to very fine sand, trace carbonaceous wisps, 3 to 5% very fine to fine pelloidal glauconite.

Log properties: The gamma ray is high for the section and ranges from 110 to 150 API. Resistivity increases from 3 to approx. 16 ohmm near the base of the 9 metre interval.

Drilling characteristics: There is an increase in drill rate at the top of the Gurnard from approx. 20 to 60 m/hr.

Hydrocarbon shows: There were no significant total gas changes until near the base of this interval at the top of the highly porous SG2.

Sub grid Unit 2 (Top Porosity)

850.6 to 869.8 mMDRT
-651.9 to -655.5 mTVDSS
Thickness: 19.2 m (3.6 mTVT)

Upper boundary pick: The top is based on correlation to Baleen-1 and Patricia-1 ROXAR 3D modelling tops. The Resistivity increases significantly from 3 to approx. 9 ohmm reflecting the higher porosity and gas saturation of the SG2.

Lithology: This sub grid unit comprises mainly silty sandstone with generally very good porosities.

Silty Sandstone: light to dark yellowish brown, medium brownish grey, loose and friable, minor firm, clear to translucent, occasionally very light grey, quartz grains, very fine to fine, trace medium, poorly to moderately sorted, sub angular to sub rounded, 15 to 30% quartz silt, 5 to 15% clay content, trace to 3% glauconite, trace to 1% mica (muscovite and biotite), trace multicoloured lithics, fair to good inferred porosity.

Log properties: The gamma ray is variable and ranges from 100 to 150 API at the top of the unit decreasing to range from 65 to 130 API near the base. The clay content of the section does not appear to be as high as indicated by the gamma ray and the sands appear to be more porous. The resistivity ranges from 16 to 25 ohmm. There is intermittently poor and fair quality data from 861 to 875 mRT due to wellbore rugosity and washout near the 244 mm (9 5/8”) casing shoe. There was no petrophysical analysis over this interval.

Hydrocarbon shows: The total gas values ranged from 0.26 to 22.8%. The gas was very dry with methane being the only constituent. Values of methane ranged from 1700 to 111860 ppm. The max. gas of 22.8% occurred at 859 mMDRT.

Sub grid Units 3, 4, 5, 6 and 7

The following sub grid units were defined in Baleen-1 and Patricia-1 and used in the ROXAR 3D reservoir model. The sub grid boundaries were identified in the well using the Horizontal Solutions International true stratigraphic position technique (Appendix 1) There are no characteristic drilling parameters observed in this horizontally drilled section, however some zones of slow drill rates are indicative of siderite and/or pyrite cemented layers.
Below the 244 mm (9 5/8”) casing shoe at 866.1 mMDRT density and neutron measurements are added to the logs.

Hydrocarbon shows: From 869.6 to 1089.5 mMDRT the total gas ranged from 0.04 to approx. 10%, with methane values ranging from 52 to 75000 ppm. The total gas averaged approx. 3 to 7%. A peak of 10.5% (75,900 ppm methane) occurred at 1050.0 mMDRT.

Sub grid Unit 3

869.8 to 888.2 mMDRT
-655.5 to -658.0 mTVDSS
Thickness: 18.4 m (2.5 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally very good porosity.

Silty Sandstone: medium to dark yellowish brown, dusky yellowish brown, loose to minor firm aggregates, silt size to fine grained, rare medium grained, dominantly very fine to fine, poor to moderately sorted, angular to sub-rounded, 15 to 25% quartz silt, 5 to 10% clay content, (suspect clays being dispersed in mud), trace to minor sideritic cemented aggregates and nodules, trace to 3% micro-mica (biotite and muscovite), trace to 2% dark green glauconite, trace feldspar, trace nodular and disseminated pyrite, minor multicoloured lithics, fair to good inferred porosity.

Sandy Siltstone: dark yellowish brown to dark brown, soft, very soft in parts, sub-blocky, 15 to 25% very fine quartz, trace to 5% siderite content, 10 to 15% clay matrix, trace glauconite, trace mica, trace nodular and disseminated pyrite.

With minor *Sideritic Sandstone:* medium to dark yellowish brown, loose to friable, minor firm, very fine to lower medium grained, mainly lower fine, poorly to moderately sorted, angular to sub rounded, 10 to 20% quartz silt, 15 to 25% siderite (?) cement in part, 15 to 20% dusky yellowish brown siderite nodules, trace to 5% clay content, 5 to 10% dark green glauconite, trace to 1% mica (muscovite and biotite), trace multicoloured lithics, poor to fair inferred porosity.

Log properties:

The resistivities of this unit range from 10 to 16 ohmm and are very steady and regular. The gamma ray values range from 100 to 140 API and average approx 110 API. This is lower than the underlying SG4 unit. High density measurements at 874 mMDRT and 884 mMDRT are indicative of siderite layers.

Petrophysical analyses of the interval from 875.0 to 888.2 mMDRT indicates a net 10 m pay out of 13.2 m gross (net to gross ratio of 75.7%) with an average porosity of 37.6%.

Sub grid Unit 4

888.2 to 924.6 mMDRT
-658.0 to -659.3 mTVDSS
Thickness: 36.4 m (1.3 mTVT)

Lithology: This subgrid unit comprises lithologies as above, namely silty sandstone with minor sandy siltstone and sideritic sandstone, with generally very good porosity and excellent net to gross pay.

Log properties: The resistivity from the top of the sub grid unit to 904.0 mMDRT ranges from 9 to 18 ohmm and decreases to 4 to 6 ohmm below 904.0 mMDRT to the base of the subgrid unit. There is a high resistivity siderite layer at 918.0 mMDRT. The gamma ray ranges from 120 to 185 API and averages approx. 160 API. Density values range from 1.95 to 2.35 g/cc and average approx. 2.05 to 2.15 g/cc.

Reservoir properties of this subgrid unit are excellent. Petrophysical analyses indicates there is net pay of 36.0 m out of 36.4 m resulting in a net to gross ratio of 98.9%. The average log derived porosity is 34.2%.

Sub grid Unit 5

924.6 to 965.8 mMDRT
-659.3 to -658.3 mTVDSS
Thickness: 41.2 m (1 mTVT)

Lithology: This subgrid unit is also similar to the above unit comprising mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally very good inferred porosities and very good net to gross pay reservoir.

Log properties: The resistivity is very steady and ranges from 6 to 11 ohmm and increases to range from 10 to 20 ohmm near the base of the sub grid unit. There is a high resistivity siderite layer at 965.0 mMDRT. The gamma ray decreases from 160 to 115 API and the density measurements range from 2.25 to 1.90 g/cc.

Reservoir properties are very good. There is log derived net pay of 39.7 m out of 41.2 m gross (net to gross ratio is 96%) and average porosity is 34.7%.

Sub grid Unit 6

965.8 to 1041.2 mMDRT
-658.3 to -656.1 mTVDSS
Thickness: 75.4 m (2.2 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone and sideritic sandstone with minor sandy siltstone with generally very good porosities and fair net to gross pay.

Log properties: The log character is highly variable due to the interbedded nature of the sub grid unit. The gamma ray ranges from 120 to 190 API. Resistivity measurements range from 10 to 30 ohmm and the density from 1.95 to 2.65 g/cc. There are several highly resistive / high density siderite layers and also a number of high density / low resistivity layers of pyrite (?).

Reservoir properties are fair. There is net pay of 54.2 m out of 75.4 m gross (net to gross ratio is 72%) and average porosity is 33.6%.

Sub grid Unit 7

1041.2 to 1089.5 mMDRT
-656.1 to -653.9 mTVDSS
Thickness: 48.3 m (2.2 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally good porosities and good net to gross pay.

Log properties: The log character is irregular and indicative of the interbedded nature of the unit. The gamma ray varies from 110 to 170 API. Resistivity values range from 20 to 10 ohmm and the density from 1.95 to 2.65 g/cc. There is a high resistivity / low density (tight) siderite layer at 1045.0 mMDRT.

Reservoir properties are good. There is log derived net pay of 45.2 m out of 48 m gross (net to gross ratio is 94%) and average porosity is 33%.

Strzlecki Group
Mesozoic (Latest Early Cretaceous)

1089.5 to 1127.4 mMDRT
-653.9 to -652.5 mTVDSS
Thickness: 37.9 m (1.4 mTVT)

Upper boundary pick:	The top has a low gamma ray decreasing from 160 to 120 API and the density readings are low. The resistivity increases from 15 to 25 ohmm. The top is also based on correlation to Baleen-1 and Patricia-1.
Lithology:	Sandstone with minor silty sandstone. *Sandstone:* clear to translucent, very light grey, loose, coarse to very coarse quartz grains, trace medium, angular to sub-rounded, minor white clay matrix, very good inferred porosity. *With minor Silty Sandstone:* medium to dark yellowish brown, dusky yellowish brown, clear to translucent quartz grains, loose to minor hard aggregates, dominantly loose to friable, silt size to fine grained, rare medium grained, dominantly very fine to fine, poor to moderately sorted, angular to sub-rounded, 10 to 25% quartz silt, 5 to 10% clay content, trace to minor sideritic cemented aggregates and nodules, trace to 2% micro-mica (biotite and muscovite), trace dark green glauconite, trace feldspar, trace disseminated pyrite, trace multicoloured lithics, good inferred porosity.
Log properties:	The gamma ray is variable and ranges from 115 to 165 API. The resistivity ranges from 15 to 30 ohmm and the density from 2 to 2.3 g/cc. There were high resistivity peaks at 1098.0 m, 1110.5 m and 1120.8 mMDRT. Log analyses from 1089.2 to 1097.0 mMDRT resulted in net pay of 5.3 m out of 7.8 m (net to gross ratio of 68%). The average log derived porosity was 32.2%. The faulted section from 1097.0 to 1127.4 mMDRT comprised net pay of 28.9 m out of 30.4 m gross (net to gross ratio of 95%). The average log derived porosity was 34.8%.
Hydrocarbon shows:	The total gas values ranged from 0.16 to 10.3%. The gas was very dry with methane being the only constituent.

From 1137.0 to 1240.0 mMDRT the total gas ranged from 0.03 to 14.3%, averaging approx. 7% and the methane values ranged from 300 to 103901 ppm, averaging approx. 45300 ppm. From 1240.0 to 1555.0 mMDRT (total depth) the total gas ranged from 0.03 to 8.5% and averaged approx. 2.5%. The methane values for this section ranged from 1794 to 58150 ppm and averaged approx. 15500 ppm.

Sidetrack kicked off at 1137.0 mMDRT

Sub grid Unit 6 (Down)

1127.4 to 1180.8 mMDRT
-652.5 to -653.8 mTVDSS
Thickness: 53.4 m (1.3 mTVT)

Lithology:

This sub grid unit comprises mainly silty sandstone with minor sandy siltstone with generally good porosities in the sandstone and excellent net to gross pay.

Silty Sandstone: light to medium yellowish brown, dusky yellowish brown, light to medium olive grey, clear to translucent quartz grains, loose, silt size to fine grained, dominantly fine, moderately sorted, angular to sub-rounded, 15 to 25% quartz silt, 5 to 10% clay content, trace to 2% micro-mica (biotite and muscovite), trace to 1% dark green glauconite, trace feldspar, trace to 1% disseminated and nodular pyrite, trace multicoloured lithics, good inferred porosity.

Sandy Siltstone: dark yellowish brown to dark brown, dusky yellowish brown, soft to firm, sub-blocky, 15 to 25% very fine quartz, trace to 5% siderite content, 10 to 15% clay matrix, trace glauconite, trace mica, trace nodular and disseminated pyrite.

Log properties:

The log character from 1137 mMDRT is relatively steady and the gamma ray is approximately 120 to 140 API. Resistivity values are fairly constant at approx. 15 ohmm and the density averages approx. 2.15 g/cc. There are high resistivity (tight) siderite layers at 1143.0 mMDRT and 1145.0 mMDRT.

Reservoir properties are excellent. There is net pay of 52.3 m out of 53.4 m gross (net to gross ratio of 98%) and average porosity is 36%.

Sub grid Unit 6 (Down)

1180.8 to 1241.4 mMDRT
-653.8 to -654.0 mTVDSS
Thickness: 60.6m (0.2mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone as above with generally good inferred porosities and very good net to gross pay.

Log properties: The log character is highly variable and the gamma ray ranges from 110 to 175 API. Resistivity ranges from 6 to 25 ohmm and density ranges from 2 to 2.3 g/cc. There are high resistivity (tight) siderite layers at 1182.4 mMDRT, 1186.0 mMDRT and 1189.2 mMDRT.

Reservoir properties are excellent. There is net pay of 59.4 m out of 60.6 m gross (net to gross ratio of 98%) and average porosity is 35.6%.

Sub grid Unit 5 (up)

1241.4 to 1271.4 mMDRT
-654.0 to -655.0 mTVDSS
Thickness: 30.0 m (1 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone as above with generally good inferred porosities and very good net to gross pay.

Log properties: The log character is variable and the gamma ray ranges from 130 to 170 API and averages approx. 160 API. Resistivity ranges from 6 to 20 ohmm and density ranges from 2 to 2.3 g/cc. There are high resistivity (tight) siderite layers at 1268.0 mMDRT, 1269.0 mMDRT and 1271.2 mMDRT.

Reservoir properties are very good. There is net pay of 27.3 m out of 30 m gross (net to gross ratio of 91%) and average porosity is 35.1%.

Sub grid Unit 4 (up)

1271.4 to 1293.8 mMDRT
-655.0 to -657.2 mTVDSS
Thickness: 22.4 m (2.2 mTVT)

Upper boundary pick: The gamma ray decreases from 140 to 110 API. Resistivity also decreases to 20 ohmm near the top of SG4 above a resistive siderite layer.

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone with generally good inferred porosities and very good net to gross pay.

Log properties: The log character is variable and the gamma ray ranges from 130 to 170 API and averages approx. 160 API, similar to the underlying unit. Resistivity has a relatively small range from 15 to 20 ohmm and density ranges from 1.95 to 2.45 g/cc.
Reservoir properties are good. There is net pay of 18.6 m out of 22.4 m gross (net to gross ratio of 83%) and average porosity is 37.5%.

Sub grid Unit 3 (up)

1293.8 to 1372.8 mMDRT
-657.2 to -672.2 mTVDSS
Thickness: 79.0 m (15.0 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally good inferred porosities and very good net to gross pay.

Silty Sandstone: medium to dark yellowish brown, dusky yellowish brown, loose to minor firm aggregates, silt size to fine grained, rare medium grained, dominantly very fine to fine, poor to moderately sorted, angular to sub-rounded, 15 to 25% quartz silt, 5 to 10% clay content, (suspect clays being dispersed in mud), trace to minor sideritic cemented aggregates and nodules, trace to 3% micro-mica (biotite and muscovite), trace to 2% dark green glauconite, trace feldspar, trace nodular and disseminated pyrite, minor multicoloured lithics, fair to good inferred porosity.

With minor *Sandy Siltstone:* dark yellowish brown to dark brown, soft, very soft in parts, sub-blocky, 15 to 25% very fine quartz, trace to 5% siderite content, 10 to 15% clay matrix, trace glauconite, trace mica, trace nodular and disseminated pyrite.

Sideritic Sandstone: medium to dark yellowish brown, loose to friable, minor firm, very fine to lower medium grained, mainly lower fine, poorly to moderately sorted, angular to sub rounded, 10 to 20% quartz silt, 15 to 25% siderite (?) cement in part, 15 to 20% dusky yellowish brown siderite nodules, trace to 5% clay content, 5 to 10% dark green glauconite, trace to 1% mica (muscovite and biotite), trace multicoloured lithics, poor to fair inferred porosity.

Log properties: The log character is regular and the gamma ray ranges from 110 to 150 and averages approximately 130 API. Resistivity ranges from 12 to 18 ohmm and density ranges from 1.9 to 2.25 g/cc, increasing to 2.4 g/cc near the base. There are significant resistive highs at 1323, 1329, 1341, 1350.7, 1355 and 1363.6 mMDRT.

Reservoir properties are very good. There is net pay of 75.2 m out of 79.0 m gross (net to gross ratio is 95%) and average porosity is 37.3%.

Sub grid Unit 4 (down) 1372.8 to 1496.0 mMDRT
-672.2 to -688.4 mTVDSS
Thickness: 123.2 m (16.2 mTVT)

Lithology: This sub grid unit is similar to the overlying description and comprises mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally good inferred porosities and very good net to gross pay.

Log properties: The log character is variable and the gamma ray ranges from 130 to 190 and averages approximately 160 API. Resistivity ranges from 8 to 15 ohmm and density ranges from 1.95 to 2.15 g/cc. There are poor hole conditions from 1480.0 to 1490.0 mMDRT where the log measurements are unreliable.

There are several resistive highs, of which the most significant is at 1440 mMDRT.

Reservoir properties are good. There are no interpreted log derived properties.

Sub grid Unit 4 (up)

1496.0 to 1555.0 mMDRT (TD)
-688.4 to -710.4 mTVDSS
Thickness: 59.0 m (22.0 mTVT)

Lithology: This sub grid unit comprises mainly silty sandstone with minor sandy siltstone and sideritic sandstone with generally good inferred porosities and very good net to gross pay.

Log properties: The log character is variable and the gamma ray ranges from 110 to 160 API. Resistivity ranges from 8 to 20 ohmm and density ranges from 1.85 to 2.5 g/cc.

Reservoir properties are fair. There is net pay of 28 m out of 40.9 m gross (net to gross ratio of 68%) and average porosity is 36.2%.

3.0 STRUCTURE AND TRAP

The Patricia and Baleen culminations are located on the north eastern flank of the Gippsland Basin, dominated by normal faults and tilted fault blocks. East-west wrench movement during the Middle to Late Paleocene resulted in anticlinal structuring and reactivation of many of the normal faults as high angle reverse faults. The Patricia and Baleen structures are interpreted to have developed at this time. The gas accumulations are in elongate compressional anticlines with reverse fault closure to the north and are separated by a structural saddle. The Baleen-3/ST1 well was drilled on the crest of the north western culmination of the anticlinal structure (Figure 8).

Structural dip interpretations and correlations from HSI (Horizontal Solutions International, Appendix 1 of this report) indicate the Lakes Entrance Formation to have relatively low dips varying from 4 degrees north to 1.3 degrees south. Dips in the upper Gurnard Formation are interpreted by HSI to be 2 to 2.5 degrees north. While drilling down section through SG3, 4, 5 and 6, dips were interpreted to be between 4.5 to 11 degrees north. There was a loss of section (due to steep dips or a small fault) and the well bore, by correlation, intersected the mid SG7 unit and the beds were dipping 6.2 degrees north. The Strzlecki Group was intersected at 1089.5 mMDRT (-653.9 mTVDSS), the wellbore re entered the SG6 at 1127.4 mMDRT (-652.5 mTVDSS). The wellbore tracked up section and penetrated the top Gurnard at 1310.0 mMDRT (original hole) with an apparent dip of 14 degrees south. The well was sidetracked in order to increase the reservoir exposure to the well bore and production screens. The sidetrack was initiated at 1137.0 mMDRT (-652.2 mTVDSS) in the SDG 6 unit. The top of the SG6 was intersected at 1180.8 mMDRT (-653.8 mTVDSS), then the SG unit 5, 4 and 3 were cut. Dips were interpreted to be 4 to 19 degrees south, considerably higher than predicted. At total depth (1555.0 mMDRT (-710.4 mTVDSS)) the wellbore was completed in the SG3 unit and dips were interpreted to be 1 to 3 degrees south.

The stratigraphic interpretation of the horizontal sections for both Baleen-3 and Baleen-3/ST1 are displayed graphically in Appendix 1 and diagrammatically in Figure 7.

TOP GURNARD

DEPTH STRUCTURE MAP

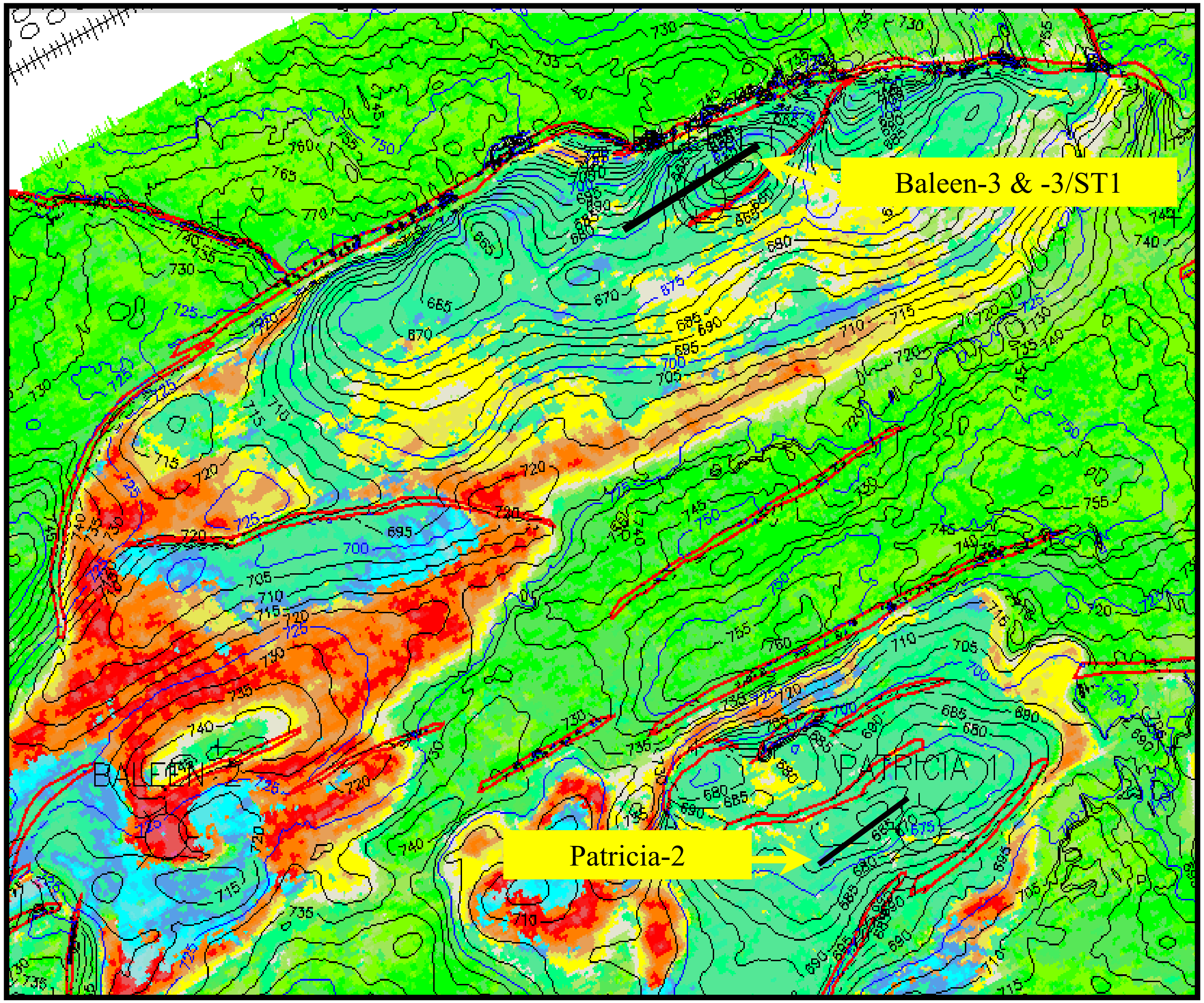


FIGURE 8

AUTHOR: OMV DATE: JULY 2003 FILENAME: TIMOR \ A4S \ 416.PPT

4.0 HYDROCARBONS

4.1 HYDROCARBON INDICATIONS WHILE DRILLING

No hydrocarbon fluorescence was observed during drilling of the Baleen-3 and 3/ST1 well and only gas is indicated on the LWD logs. Moderate to high gas readings were recorded by BHI gas detection equipment while drilling through the Gurnard Formation reservoir. The variations were due to hydrostatic mud pressure and poor porosity occasionally encountered in low permeability zones.

From 111.5 to 334.0 mMDRT, there were no returns to surface and consequently no mud gas was recorded. The total gas over the interval 334.0 to 850.0 mMDRT ranges from 0.08 to 0.5% and comprises only methane. Near the upper part of the Gurnard Formation from 850.0 to 870.0 mMDRT the total gas values ranged from 0.26 to 10%. The gas is very dry with methane being the only constituent. From 870.0 to 1090.0 mMDRT, the total gas ranged from 0.04 to 22.8%, and averaged approx. 3 to 7% with methane values ranging from 50 to 111860 ppm. The gas peak of 22.8% (111860 ppm) occurred at 871.0 mMDRT near top of sub grid unit 3 / base of sub grid unit 2. From 1090.0 to 1137.0 mMDRT, the total gas values ranged from 0.16 to 10.3% and comprised only methane. From 1137.0 to 1240.0 mMDRT, the total gas ranged from 0.03 to 14.3%, averaging approx. 7%. From 1240.0 to 1555.0 mMDRT (total depth) the total gas ranged from 0.03 to 8.5% and averaged approx. 2.5%.

Refer to the gas on the Composite Log (Enclosure 1), the Mudlog (Enclosure 1 in Basic Data Volume) and the final BHI report (Appendix 4 in Basic Data Volume).

4.2 LOG ANALYSIS

A petrophysical analysis was performed on LWD (recorded) logs from Baleen-3/ST1 – see Enclosure 3.

Due to the presence of severe gas effect on the density and neutron logs and the complex lithology (mica, glauconite, pyrite, siderite etc.) present within the formation, the basic nature of the logging tools and bedding effects in the horizontal section, a standard deterministic analysis was not possible. This was anticipated before the well was drilled and baseline resistivity curves were recorded for future reference. The “quicklook” analysis graded the Gurnard Formation into sections of poor, average and good reservoir quality.

Apparent porosity (PHIX) was calculated from the density-neutron cross plot using the Bateman and Konen method and intervals were assigned a pay quality according to their position on the cross plot (Appendix 2). Samples showing strong gas effect were assigned "good pay" status, samples which showed a high density response indicative of siderite cemented horizons were assigned "non pay" status and the remainder were assigned "pay".

LWD logs indicated that Baleen-3/ST1 intersected gas bearing reservoir quality Gurnard Formation. Over the gross interval from 875.0 to 1127.4 mMDRT, 1127.4 to 1372.8 mMDRT and 1496.0 to 1537.0 mMDRT (total 538.7 m) there is net pay of 480.1m (89.1%). Average apparent (total) porosity in the pay interval is 35.3% as detailed in Table 2 below.

Table 2 Summary of Baleen-3/ST1 Petrophysical Analysis Results

Interval A	875.0 – 1372.8 mMDRT
Interval.B	1496.0 - 1537.0 mMDRT
Interval	Gurnard Formation
Total gross Interval	538.1m
Net pay	480.1m
Average porosity (%)	35.3
Average water saturation (%)	N/A due to complex mineralogy severe gas effect and basic logging suite in horizontal hole with bedding effects
Net / Gross ratio (%)	89.2

These results exceed expectations as the average ambient core prosity for the entire Baleen-2 and Patricia-1 core is 32.1% (std. dev. 6.8%) and 88.9% (std. dev. 6.8%) respectively.

Prior to the 2002 development drilling program on the Baleen and Patricia fields, water saturations had been determined from Elan-plus log interpretations conducted on the Gurnard reservoir by Schlumberger and saturation/height functions determined during special core analysis.

Pre-development summary of core data by flow unit for calibration wells is shown below in Table 3.

Table 3 Summary of Core Data by Flow Unit, Patricia-Baleen Field

	POROSITY		PERMEABILITY	
	Baleen-2	Patricia-1	Baleen-2	Patricia-1
GFU1 mean	na	na	na	na
GFU2 mean	31.3	35.5	94.0	191.0
GFU3 mean	36.0	36.0	251.0	379.0
GFU4 mean	35.2	38.4	249.0	319.0
GFU5 mean	24.9	28.8	28.0	135.0
GFU6 mean	29.4	32.8	85.0	124.0
GFU7 mean	35.7	35.6	167.0	51.0
GFU8 mean	36.4	32.3	355.0	129.0
GFU9 mean	na	32.6	na	101.0
BZC mean	na	25.7	na	25.0
Overal mean	32.1	33.9	162.0	42.0
OverStandard Deviation	6.8	6.8	136.0	165.0

Notes: Baleen-2 plugged with bias to reservoir rock.
Patricia-1 plugged on rigid spacing – explains larger std. dev observed for most P-1 GFU's.
Of the total Gurnard Fm penetrated (143.5 m) there is 62.9 m (48.2%) recovered as core.
Upper part of GFU6 in B-2 more heavily cemented w/ siderite than at P-1.
GFU's 3,4,7&8 are apparently the best quality, GFU6 improves at P-1 and B-1 (from logs)

The calibration of reservoir parameters for the Gurnard Formation had most recently been provided by the Elan-plus log interpretation of Baleen-2 with 11.2 m gross (10.6 m net) gas pay having 26% effective (29.7% total) porosity and 93.0 mD average log calculated permeability (N/G 86%) in the proven gas column (Patricia Baleen Geology and Petrophysics Review, August 2000).

Prior to the development of Patricia and Baleen, reservoir permeability was identified as the key parameter influencing both the quantum and rate of gas recovery. Significant variation in permeability values estimated from core, log and DST data suggested that it is one of the reservoir parameters known with least confidence. An estimation of permeability in Baleen-3 is provided in the following section, 4.3 Production Testing.

4.3 PRODUCTION TESTING

The Baleen-3 well was production tested between 9th and 14th June 2002 to clean the well up prior to suspension and to determine key well and reservoir parameters from the bottom hole pressure response. The test duration was 63 hours (excluding operational downtime and waiting on daylight), compared with the pre-test programme of 74 hours, due to reductions in the duration of some flow/shut-in periods. This was due to faster stabilisation times resulting from higher-than-expected reservoir quality.

A short initial flow and pressure build-up was conducted to determine the static reservoir pressure prior to testing. Extrapolation of the shut-in trend yielded an initial reservoir pressure of 7314.2 kPa (1,060.8 psia) at gauge reference depth of 902.0 mMDRT (-660.0 mTVDSS), some 37.9 kPa (5.5 psi) lower than the pressure regime established from wireline formation pressure testing of the Baleen-2 appraisal well in 1999. This depletion is believed to be due to the effect on the regional aquifer pressure from continued production from the Bass Strait oil/gas fields.

The well was beaned-up to maximum choke to promote effective clean-up of the entire horizontal production interval. Intermittent brine slugs were observed at surface (and from bottom hole pressure data), which decreased in volume and frequency during the clean-up flow period. A coiled tubing-conveyed temperature logging pass confirmed the presence of free water lying in low-points (sumps) in the wellbore trajectory profile.

At maximum choke, a maximum flowrate of 27.1 MMscf/d was measured (upstream choke pressure of 4481.8 kPa (650 psia) through the test separator (outside critical flow conditions), somewhat lower than the effective capacity of the test equipment. Well production was limited by both the restrictive presence of the coiled tubing string (maximum OD 56 mm (2.2") at the gauges) inside the 140 mm (5.5") tubing (ID 124 mm (4.892")) and the circuitous pipe work route between the flow head and the test separator. In addition, prevailing wind conditions required flow to the aft flare boom, located on the opposite side of the rig to the test area and this caused additional pressure drops within the surface pipe work.

Analysis of the two pressure build-up periods yielded an estimated horizontal effective permeability of 95 mD, higher than initially expected. Total well bore skin of +7 to +8 was interpreted to be due to filtrate invasion (and pressure drop through the sand-screens) and was also slightly higher than expectations. A reduction in skin between the clean-up and main flow periods, combined with continued brine production throughout the main flow period, suggested that clean-up had not completely finished prior to termination of the test.

A pressure match of the entire test yielded an estimated horizontal effective permeability of 75 mD, slightly lower than the value derived from pressure build-up analysis. This more conservative estimate was used as a basis for deliverability calculations. Deliverability analysis yielded stabilised absolute open-flow (AOF) potential of 150 MMscf/d (flow potential at 103.4 kpa (15 psi) bottom hole pressure), based on extrapolation of data from four separate rate/pressure measurements. Given that the well was interpreted to have penetrated all reservoir sub grids, thus minimising potential compartmentalisation in the event of laterally extensive impermeable siderite bands, deliverability analysis indicated that the well should exceed production performance predicted from the 2001 reservoir simulation modelling study.

Removing the effect of the coiled tubing from vertical lift performance (tubing hydraulics), it was estimated that the well would flow at a maximum initial rate of 68 MMscf/d, assuming a minimum initial tubing-head pressure of 1723.8 kPa (250 psia).

Refer to the OMV DST interpretation report in Appendix 2 for more details.

5.0 CONTRIBUTIONS TO GEOLOGICAL CONCEPTS

The sequence encountered was as expected with only the Lakes Entrance Formation 10.5m low to prognosis.

The Gurnard Formation in Baleen-3 was intersected 4.9 m high to prognosis. Sub grid unit 2 (top porosity) was encountered 2.8 m high to prognosis. Top Gurnard and top SG2 were not co-incident as predicted.

Sub grid units 3, 4 and 5 were intersected 0.4 to 1.4 m high to prognosis. Sub grid unit 6 was found at 965.8 mMDRT (-658.3 mTVDSS), 7.8 m high to prognosis. The original well then passed through sub grid 7 at 1041.2 mMDRT (-656.1 mTVDSS) and the Strzlecki Group at 1089.5 mMDRT (-653.9 mTVDSS) which were not predicted. The Baleen-3 well bore is interpreted to have passed through a fault and then re-encountered the SG6 unit at 1127.4 mMDRT (-652.5 mTVDSS) some 20.9 m high to prognosis, due to significant steepening of structural dips. The original well bore then progressed rapidly up section and penetrated the top Gurnard again at 1310.0 mMDRT.

Due to the steeper than expected dips and apparent loss of intersected production interval, the well was sidetracked down dip from 1137.0 mMDRT (-652.2 mTVDSS) to intersect a longer sand interval. SG6 was intersected going up at 1180.8 mMDRT (-653.8 mTVDSS), then SG5 (up), 21.5 m high to predicted, SG4 (up), 21.3 m high and then SG3 (up) at 1293.8 mMDRT (-657.2 mTVDSS), 19.8 m higher than expected. The well then tracked down to SG4 and back up to SG3 where it reached a final total depth of 1555.0 mMDRT (-710.4 mTVDSS).

Log analysis indicated that Baleen 3/ST1 intersected good quality gas pay in the Gurnard Formation. Over the gross interval of 538.7 m from 875.0 to 1372.8 mMDRT, (-656.6 to -669.6 mTVDSS) and 1496.0 to 1537.0 mMDRT (-679.6 to -682.0 mTVDSS) there is net pay of 480.1 m (89.1%). Average apparent (total) log porosity in the pay interval is 35.3%. These results met or exceeded expectations as the average ambient core porosity for Baleen-2 was 32.1%.

Structural dip interpretations and correlations from Horizontal Solutions International using the true stratigraphic position method, confirm the pre-drill structural interpretation with the exception of relatively steep dips and possible small scale faulting controlling the core of the feature.

A 6 5/8" production liner consisting of "Excluder 2000" sand screens was installed and 140 mm 5 1/2" completion tubing was landed. The well was tested over the interval 896.9 mMDRT to 1385.0 mMDRT and a maximum flow of 27.1 MMscf/d was recorded. The well was subsequently suspended as a gas producer.

6.0 REFERENCES

BARBER, P.B., 2000: Patricia-Baleen Gurnard Sedimentological Model. *Unpublished.*

BALEEN-2 WELL COMPLETION REPORT, 2002: *Unpublished.*

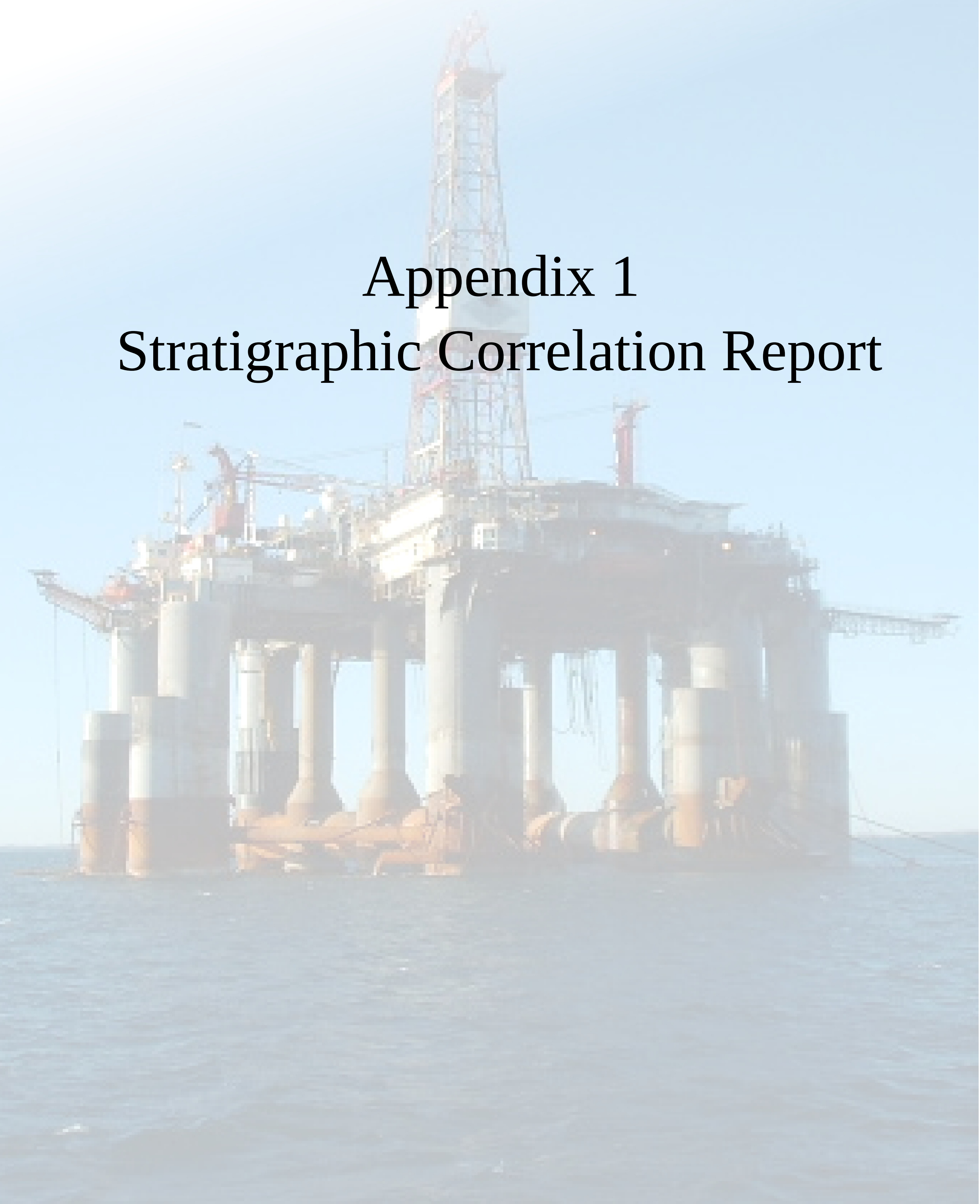
BALEEN-3 BASIS FOR WELL DESIGN AND EVALUATION PROGRAMME, 2002: *Unpublished.*

BALEEN-3 DRILLING PROGRAMME, 2002: *Unpublished.*

PATRICIA BALEEN GEOLOGY & PETROPHYSICS REVIEW, 2000: *Unpublished.*

OMV Australia

Appendix 1
Stratigraphic Correlation Report



OMV Baleen #3
Gamma Ray/Resistivity Log Interpretation Summary
Horizontal Solutions International
Richard A. Leach, Geologist

<u>Intermediate Casing Interval</u>

Gippsland Limestone:
Well interpretation of Gamma Ray (GR) and Resistivity data began at 119’ MD, in the Gippsland Limestone, using the Baleen #1 GR log for primary correlation of the GR data, and the Patricia #1 Resistivity Log for correlation of resistivity. The Baleen #1 did not log resistivity that high into the section. Correlation of individual units in the Gippland Limestone interval was difficult, if not impossible due to stratigraphic variation, as supported by the differences seen between the Baleen #1 and Patricia #1 GR logs. However, there were a few good marker beds that provided good correlation at several levels within the formation and the general character of the logs provided placement of the Baleen #3 section in a reasonable position, as seen on both the Gamma and the Reisistivity Full Scale Charts. Amplitudes of both the GR and Resistivity responses compared favorably with the two offset logs throughout the section. While trying to accommodate some of the GR “markers”, I was forced to use dips varying from 6.0° South to 10.0° North, but that is not unusual at inclinations less than 60° due to the trigonometry involved in calculations. Stratigraphic variation can account for much of the high dips seen.

Lakes Entrance Formation:
The Top of the Lakes Entrance Formation was encountered at 719.6m MD (632.8m TVD; 237.3m VS). The Baleen #1 GR log was utilized for primary correlation of the GR data, and the Patricia #1 Resistivity Log for correlation of resistivity. The Lakes Entrance Formation appears to be more consistent than the interval above and provided a very good correlation throughout. Dips varied from 4.0° North at the top of the interval, to 1.7° South in the middle of the section. From the GR marker at the top of the Lower Lakes Entrance to the top of the Gurnard Formation, the dip was 2.0° North.

Gurnard Formation:
The Top of the Gurnard Formation, SG1 member, was encountered at 841.4m MD (674.9m TVD; 351.0m VS), after crossing an 8.0m fault. The Baleen #1 logs were utilized for primary correlation of both the GR and Resistivity data, with the Patricia #1 Resistivity Log being used for correlation support. The section at the Top of the Gurnard SG1 interval correlated very well (an overlay) with the Baleen #1 Resistivity log. However, 1.5 meters into the SG2 interval, the resistivity increased sharply, more resembling the character seen in the Patricia #1 log. The last GR data before casing point was interpreted as near the Top of the SG2 interval and exhibited a resistivity of approximately 11 ohms. Dips in the upper portion of the Gurnard section were from 2.0° to 2.5° North. The Last GR data before casing was at 859.4m MD. The last Resistivity data was at 862.4m MD.

At the Last Survey depth (838.1m MD) the inclination was 76.3°, therefore, all dips used below that point are not reliable and their interpretation could change depending on the inclination of the wellbore after that point.

Horizontal Section – Original Lateral

Upon drilling out the cement at the casing shoe and obtaining new survey data, it was determined that the wellbore had encountered the SG2 at 850.6 MD. Subsequently, the wellbore proceeded down section, encountering the SG3, SG4, SG5 and SG6 members before encountering a fault, which put the wellbore 4.5 meters deeper in section, below the SG7 Top. Dips prior to the fault were interpreted to be between 4.5° and 11.0° North. Following the fault, the wellbore was interpreted to be 3.5 meters TVD above the Top of the Latrobe Formation, dipping at a rate of 6.2° North. The Latrobe Fm. was encountered at 1089m MD.

After penetrating only 8 meters (MD) of the Latrobe Fm., the wellbore encountered another fault at 1097m MD. At the time there was a question as to the placement of the data past the fault. However, shortly thereafter, the data provided a good correlation in the SG5 interval. The final interpretation shows a 16-meter fault that put the wellbore slightly above the Top SG6 marker. The wellbore continued down-section, then turned around and traversed quickly up-section with. The wellbore penetrated the Top of the Gurnard Formation at 1310.6m MD, with an apparent dip of 14° South.

At that point, the decision was made to sidetrack the well in order to attempt to keep the wellbore within the Target Interval for a longer distance.

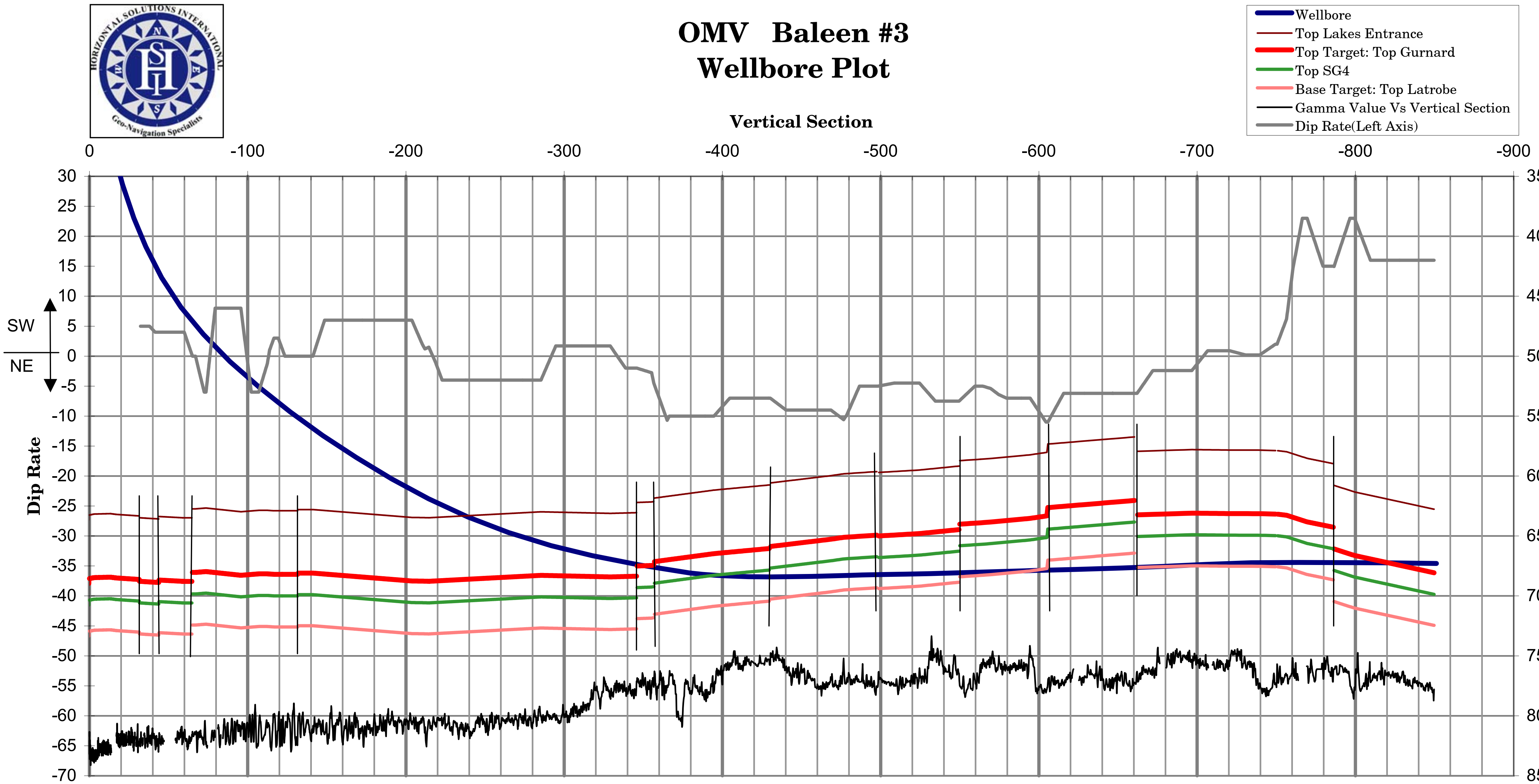
Horizontal Section – Sidetrack #1 Lateral

The sidetrack lateral was kicked off using a tie in survey of 1115.3m MD. The sidetrack lateral began in the lower part of SG5, heading down-section into the SG6 interval before turning around and traversing up-section through SG5, SG4 and SG3. Dips in this interval varied from 4.0° to 19° South. The wellbore turned around at approximately 1.2 meters above the Top SG3 marker and began started heading back down-section at 1312.6m MD, with beds dipping 9.0° South. The wellbore continued traversing down-section until 1430.4m MD, 2.5 meters TVD below The Top SG4 marker, where it turned back up-section with beds dipping 8.5° South. From that point on, the wellbore continued to traverse up-section, ending near the Top of the SG3 member. The dip had decreased to 3.0° South by 1470m MD and varied from 1.0 to 3.0 South from 1470 to the Total Depth of the well. The last Gamma Ray data was at 1544.6m MD. Density and Resistivity data ended at 1541.2m and 1538.6m MD, respectively.

After climbing through the SG4 interval in the initial part of the Sidetrack lateral, the wellbore stayed within 2.5 meters TVD of the SG3 interval until Total Depth was reached.

* “Faults” picked in this, and any other interpretation by Horizontal Solutions International utilizing the Latnav geonavigation software, should be read as an indication of missing section. They may be interpreted by the client as actual faults encountered in

the wellbore, unconformities in the section, or simply as localized stratigraphic variations relative to the offset well provided for correlation (in this case the Baleen #1 well).



OMV Baleen #3
Wellbore Plot
Vertical Section
Geo-Navigation Specialists
HORIZONTAL SOLUTIONS INTERNATIONAL
Wellbore
Top Lakes Entrance
Top Target: Top Gurnard
Top SG4
Base Target: Top Latrobe
Gamma Value Vs Vertical Section
Dip Rate(Left Axis)
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
30
25
20
15
10
5
0
-5
-10
-15
-20
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-35
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-45
-50
-55
-60
-65
-70
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Dip Rate
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400
450
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600
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700
750
800
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TVD

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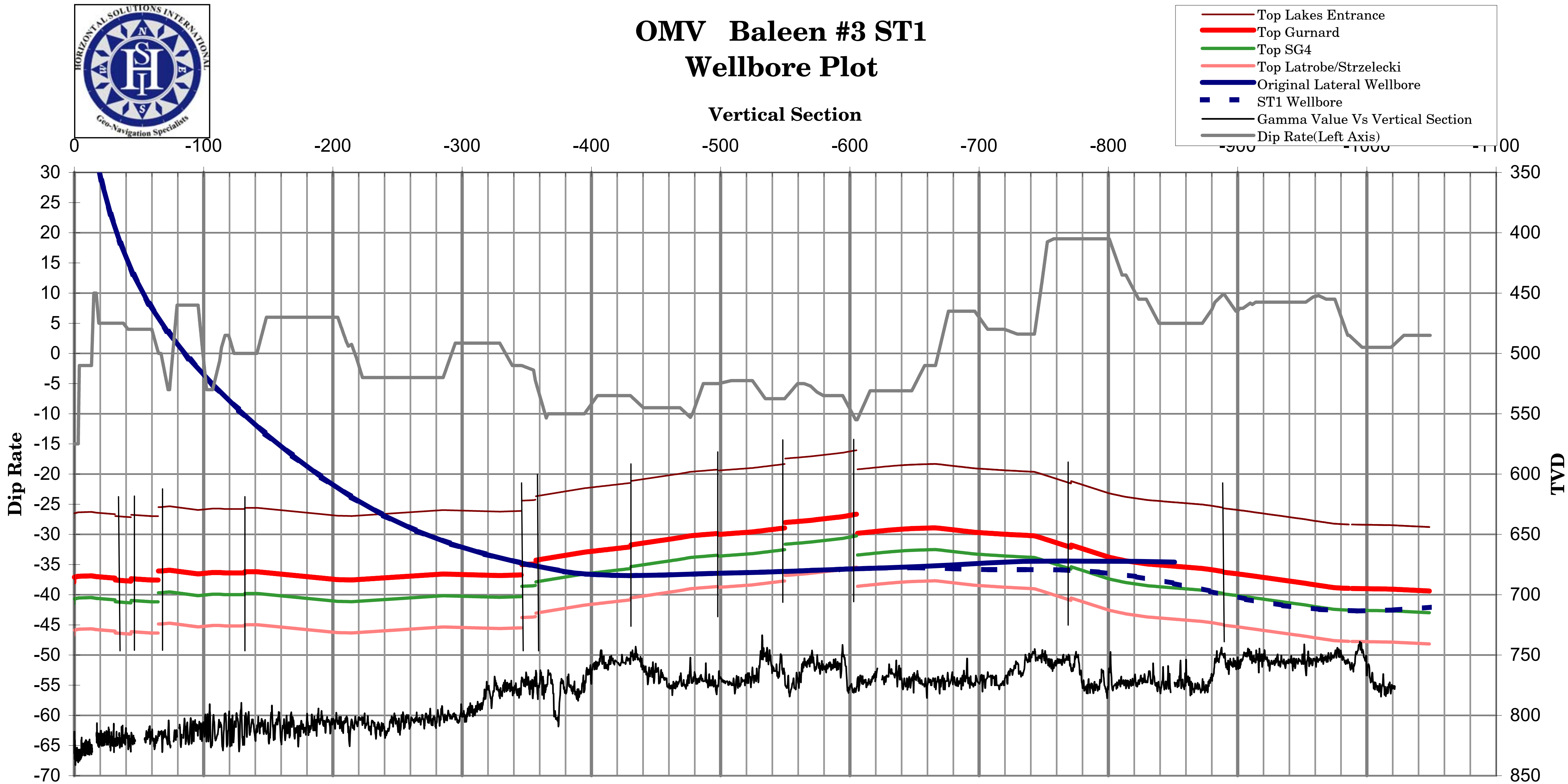
HORIZONTAL SOLUTIONS INTERNATIONAL
Geo-Navigation Specialists
OMV Baleen #3 ST1
Wellbore Plot
Vertical Section
Top Lakes Entrance
Top Gurnard
Top SG4
Top Latrobe/Strzelecki
Original Lateral Wellbore
ST1 Wellbore
Gamma Value Vs Vertical Section
Dip Rate(Left Axis)
Dip Rate
TVD
0
-100
-200
-300
-400
-500
-600
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-800
-900
-1000
-1100
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15
10
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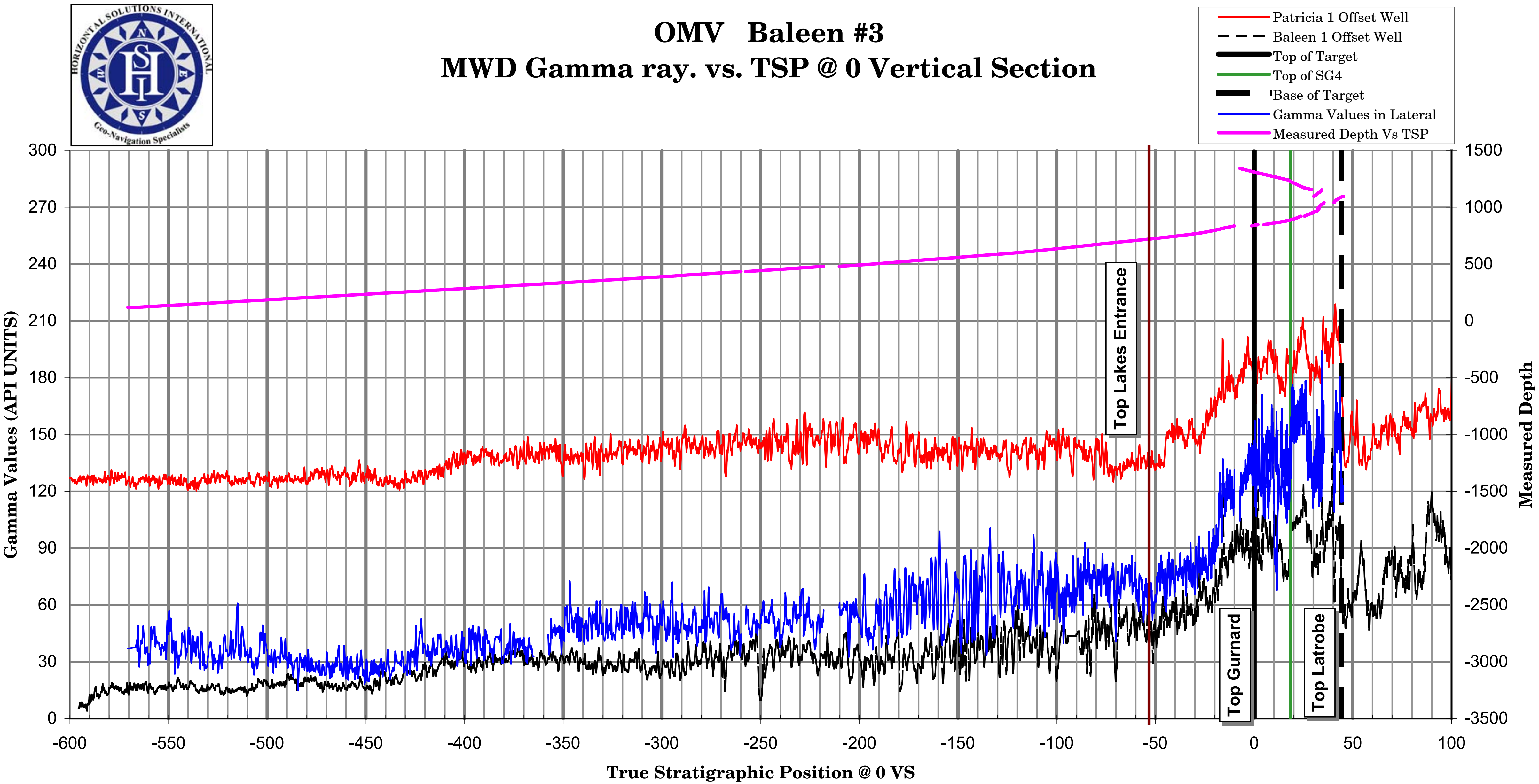
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MWD Gamma ray. vs. TSP @ 0 Vertical Section
HORIZONTAL SOLUTIONS INTERNATIONAL
Geo-Navigation Specialists
Patricia 1 Offset Well
Baleen 1 Offset Well
Top of Target
Top of SG4
Base of Target
Gamma Values in Lateral
Measured Depth Vs TSP
Gamma Values (API UNITS)
Measured Depth
True Stratigraphic Position @ 0 VS
Top Lakes Entrance
Top Gurnard
Top Latrobe
300
270
240
210
180
150
120
90
60
30
0
1500
1000
500
0
-500
-1000
-1500
-2000
-2500
-3000
-3500
-600
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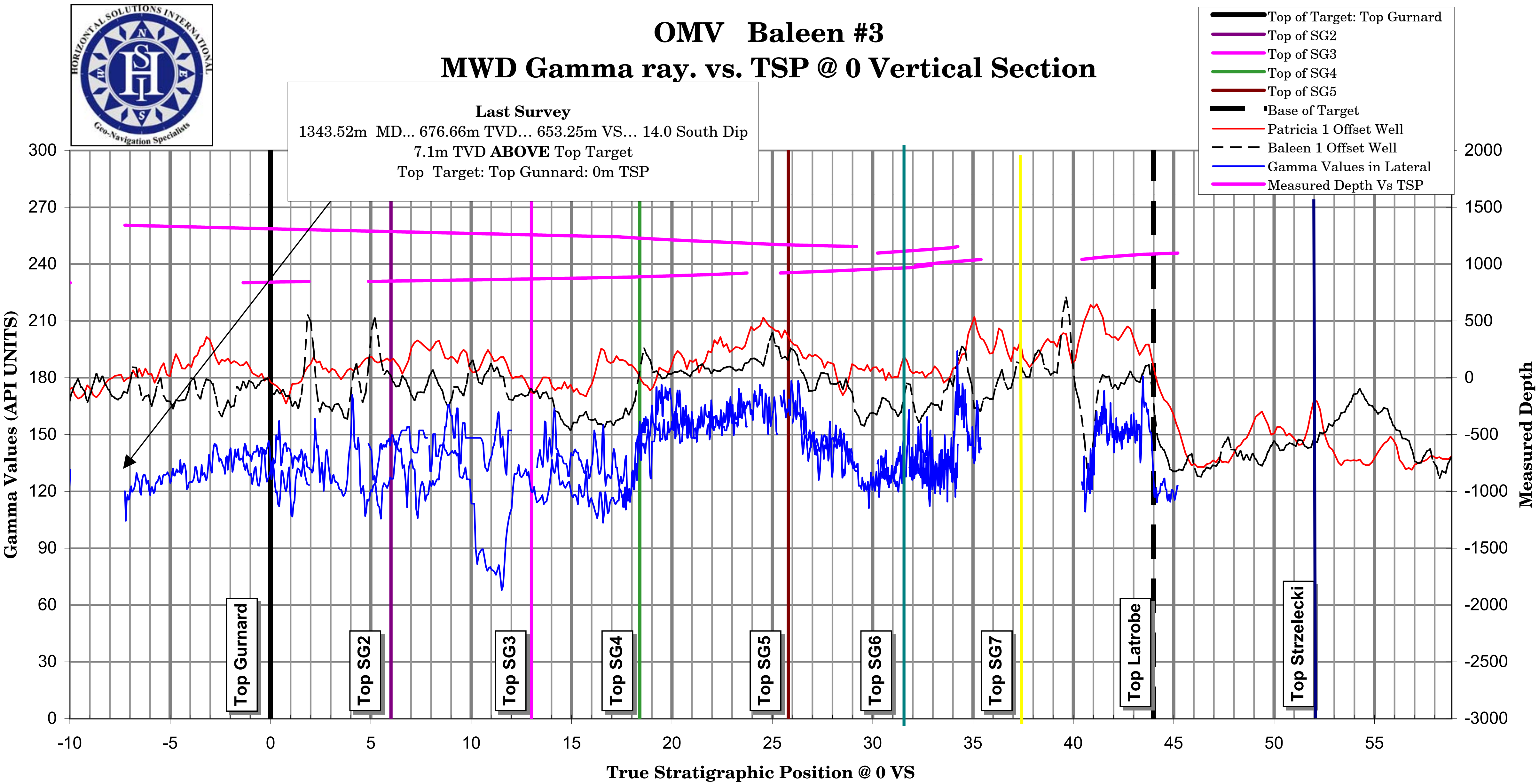
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7.1m TVD ABOVE Top Target
Top Target: Top Gunnard: 0m TSP
Top of Target: Top Gurnard
Top of SG2
Top of SG3
Top of SG4
Top of SG5
Base of Target
Patricia 1 Offset Well
Baleen 1 Offset Well
Gamma Values in Lateral
Measured Depth Vs TSP
Top Gurnard
Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
Top SG7
Top Latrobe
Top Strzelecki
Gamma Values (API UNITS)
Measured Depth
True Stratigraphic Position @ 0 VS

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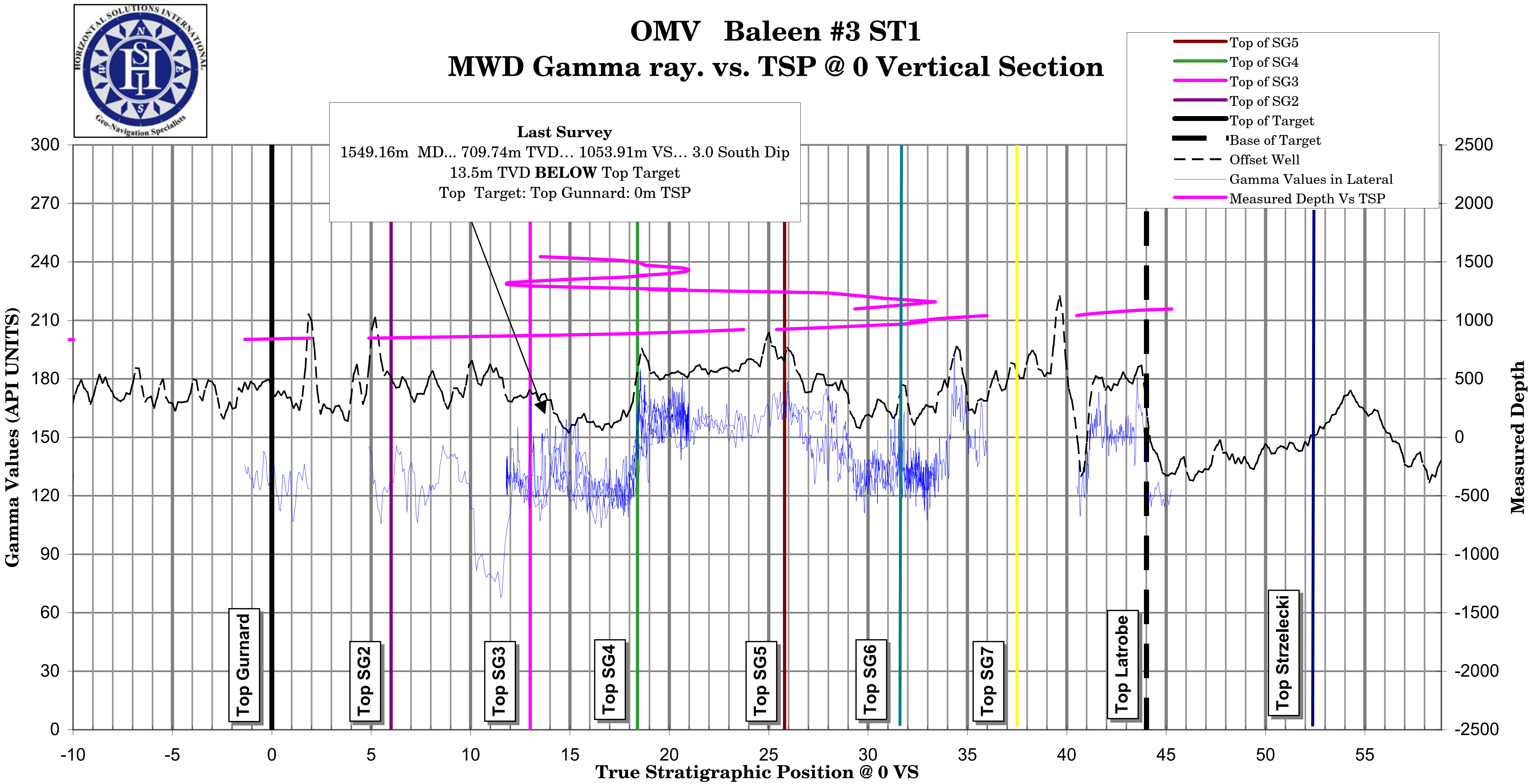
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13.5m TVD BELOW Top Target
Top Target: Top Gunnard: 0m TSP
Top of SG5
Top of SG4
Top of SG3
Top of SG2
Top of Target
Base of Target
Offset Well
Gamma Values in Lateral
Measured Depth Vs TSP
Gamma Values (API UNITS)
Measured Depth
True Stratigraphic Position @ 0 VS
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Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
Top SG7
Top Latrobe
Top Strzelecki

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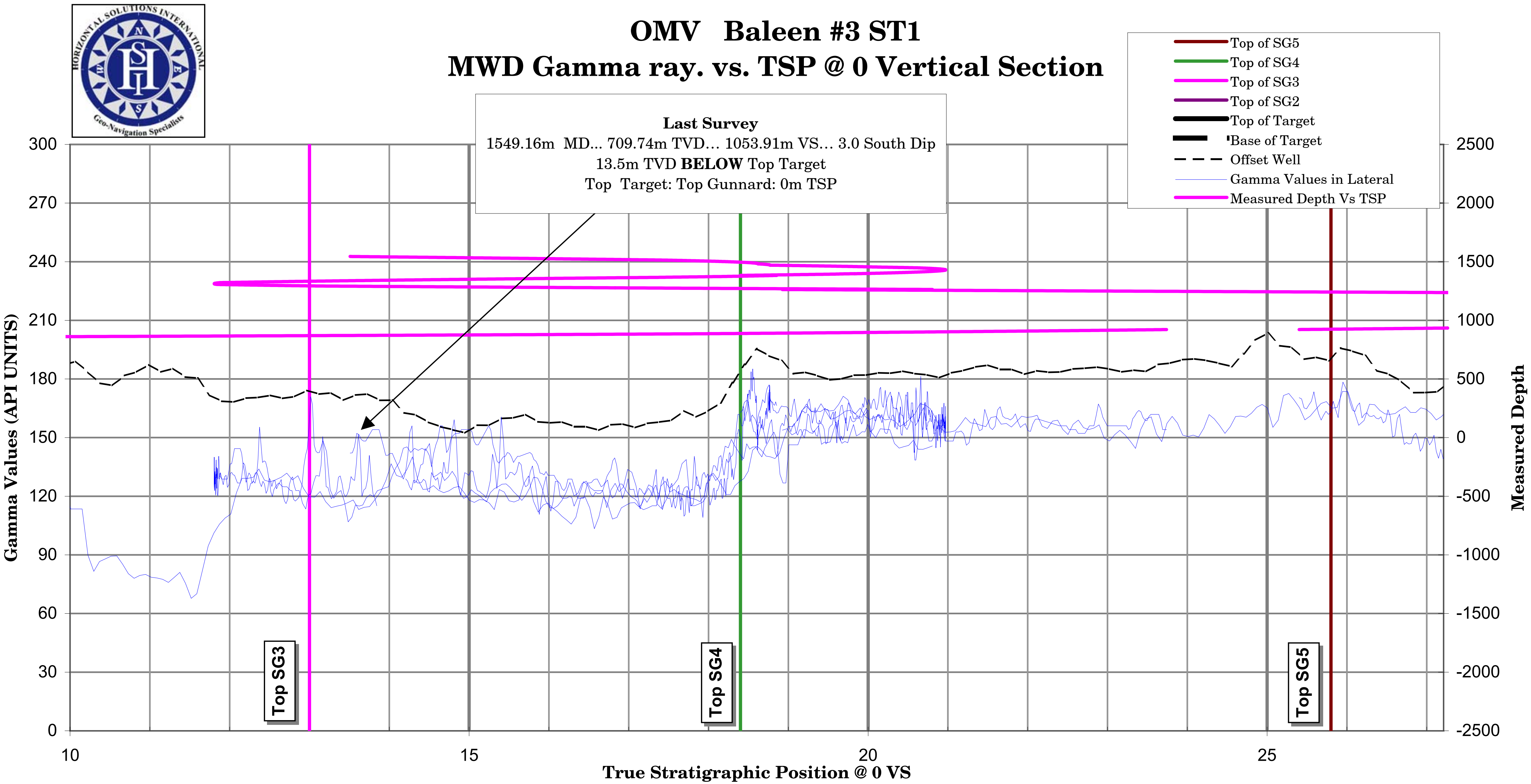

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MWD Gamma ray. vs. TSP @ 0 Vertical Section
Last Survey
1549.16m MD... 709.74m TVD... 1053.91m VS... 3.0 South Dip
13.5m TVD BELOW Top Target
Top Target: Top Gunnard: 0m TSP
Top of SG5
Top of SG4
Top of SG3
Top of SG2
Top of Target
Base of Target
Offset Well
Gamma Values in Lateral
Measured Depth Vs TSP
Gamma Values (API UNITS)
Measured Depth
True Stratigraphic Position @ 0 VS
Top SG3
Top SG4
Top SG5
300
270
240
210
180
150
120
90
60
30
0
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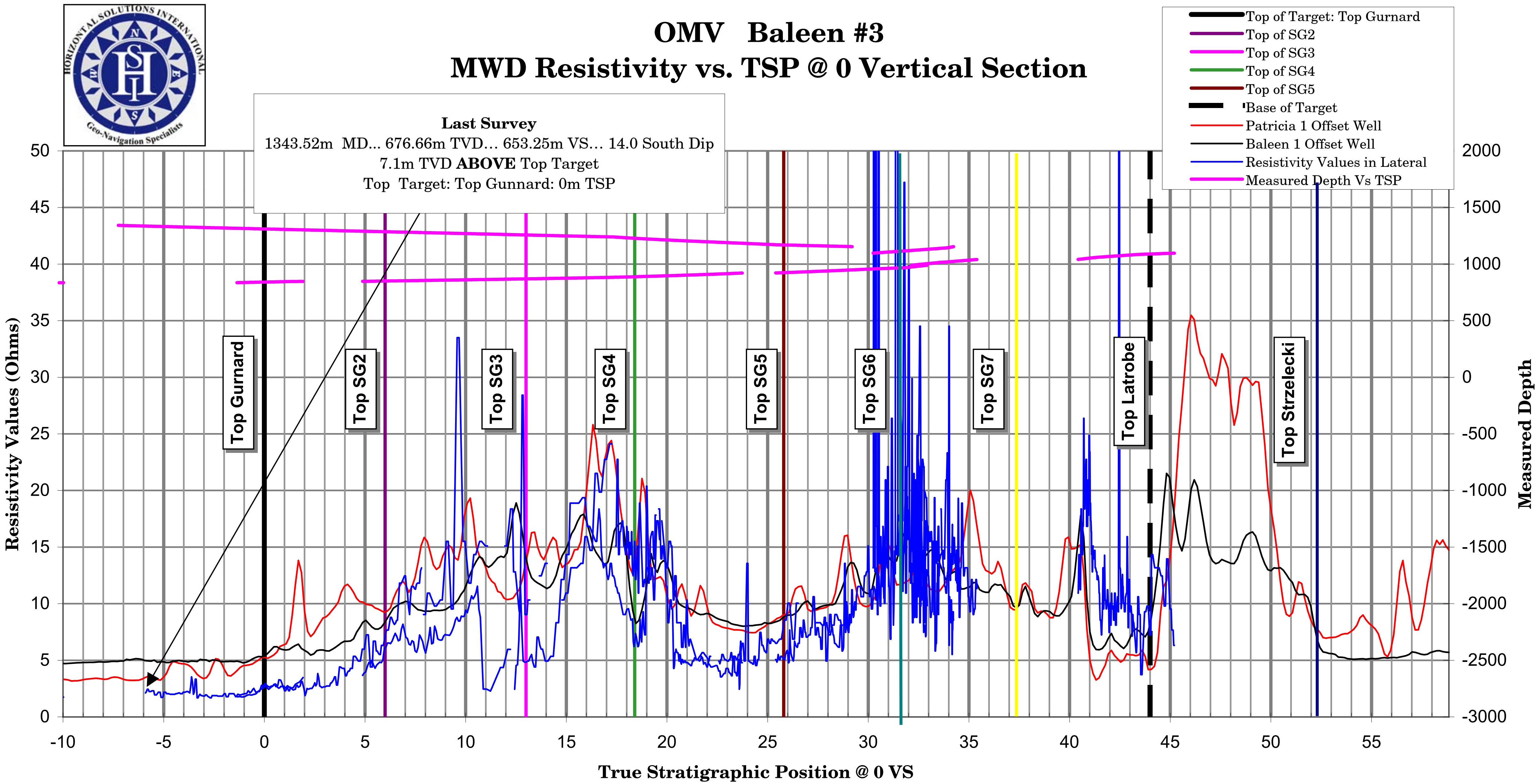

OMV Baleen #3
MWD Resistivity vs. TSP @ 0 Vertical Section
Horizontal Solutions International
Geo-Navigation Specialists
Last Survey
1343.52m MD... 676.66m TVD... 653.25m VS... 14.0 South Dip
7.1m TVD ABOVE Top Target
Top Target: Top Gunnard: 0m TSP
Top of Target: Top Gurnard
Top of SG2
Top of SG3
Top of SG4
Top of SG5
Base of Target
Patricia 1 Offset Well
Baleen 1 Offset Well
Resistivity Values in Lateral
Measured Depth Vs TSP
Top Gurnard
Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
Top SG7
Top Latrobe
Top Strzelecki
Resistivity Values (Ohms)
Measured Depth
True Stratigraphic Position @ 0 VS

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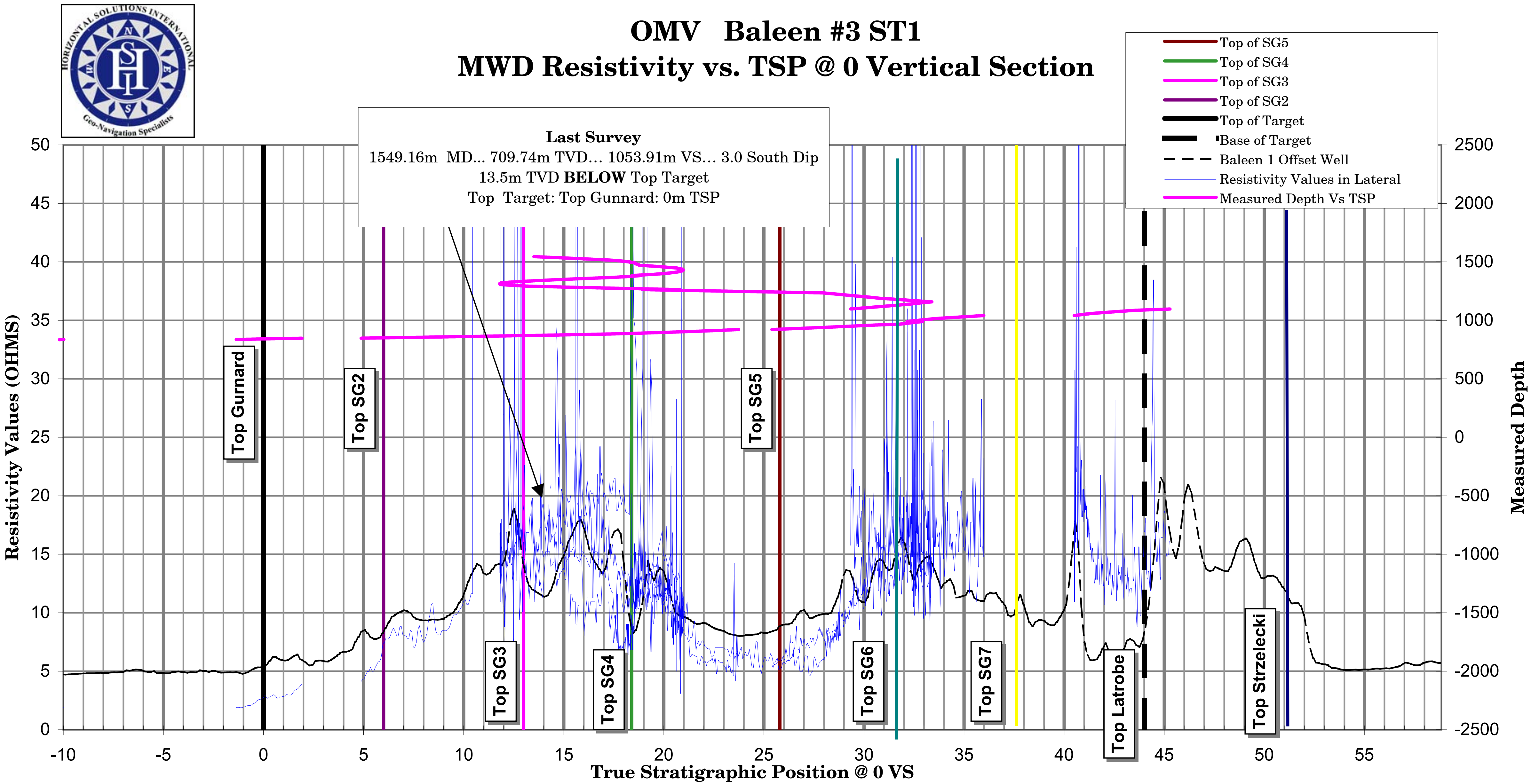

OMV Baleen #3 ST1
MWD Resistivity vs. TSP @ 0 Vertical Section
HORIZONTAL SOLUTIONS INTERNATIONAL
Geo-Navigation Specialists
Last Survey
1549.16m MD... 709.74m TVD... 1053.91m VS... 3.0 South Dip
13.5m TVD BELOW Top Target
Top Target: Top Gunnard: 0m TSP
Top of SG5
Top of SG4
Top of SG3
Top of SG2
Top of Target
Base of Target
Baleen 1 Offset Well
Resistivity Values in Lateral
Measured Depth Vs TSP
Top Gurnard
Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
Top SG7
Top Latrobe
Top Strzelecki
Resistivity Values (OHMS)
Measured Depth
True Stratigraphic Position @ 0 VS

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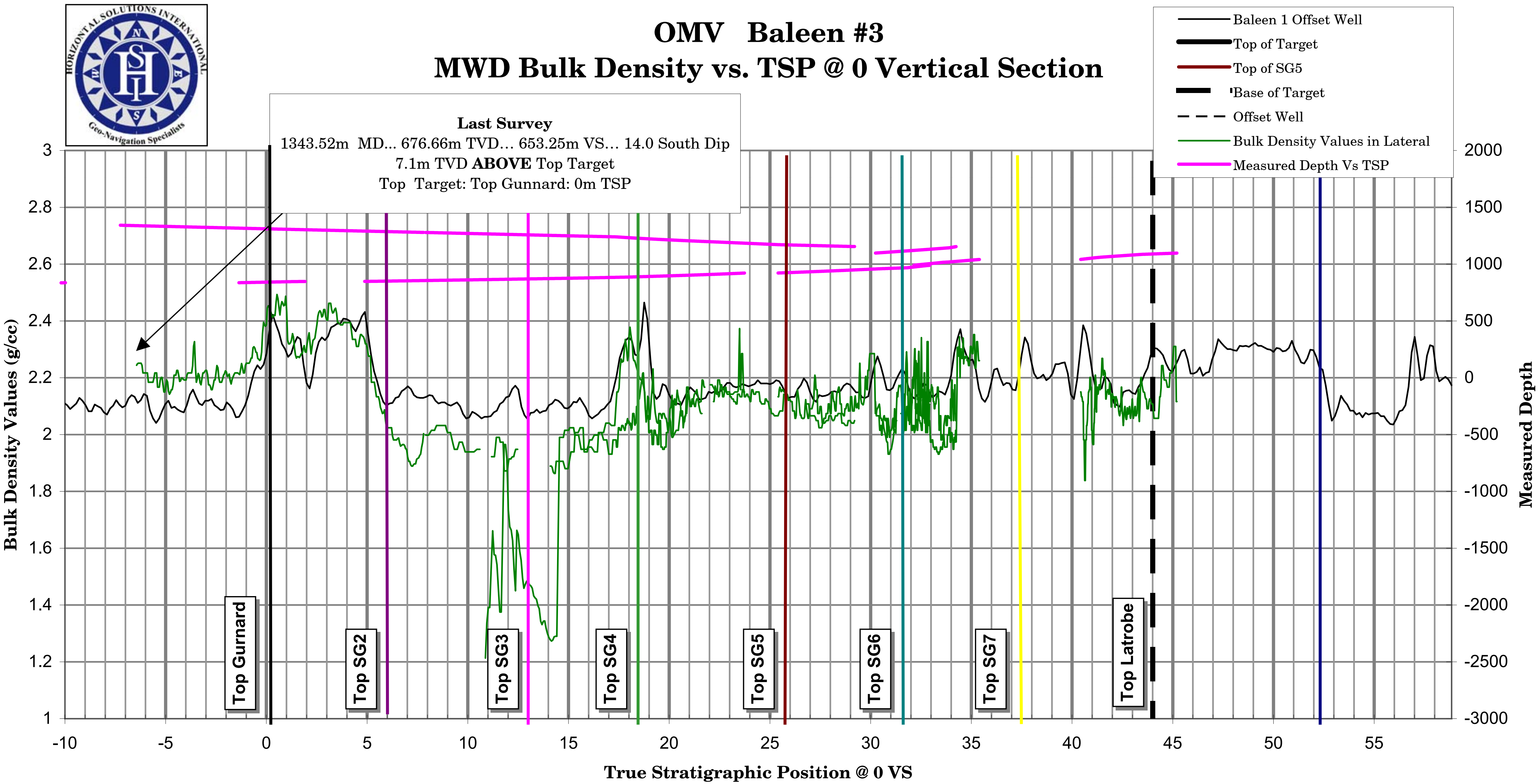

OMV Baleen #3
MWD Bulk Density vs. TSP @ 0 Vertical Section
HORIZONTAL SOLUTIONS INTERNATIONAL
Geo-Navigation Specialists
Last Survey
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7.1m TVD ABOVE Top Target
Top Target: Top Gunnard: 0m TSP
Baleen 1 Offset Well
Top of Target
Top of SG5
Base of Target
Offset Well
Bulk Density Values in Lateral
Measured Depth Vs TSP
Top Gurnard
Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
Top SG7
Top Latrobe
Bulk Density Values (g/cc)
Measured Depth
True Stratigraphic Position @ 0 VS

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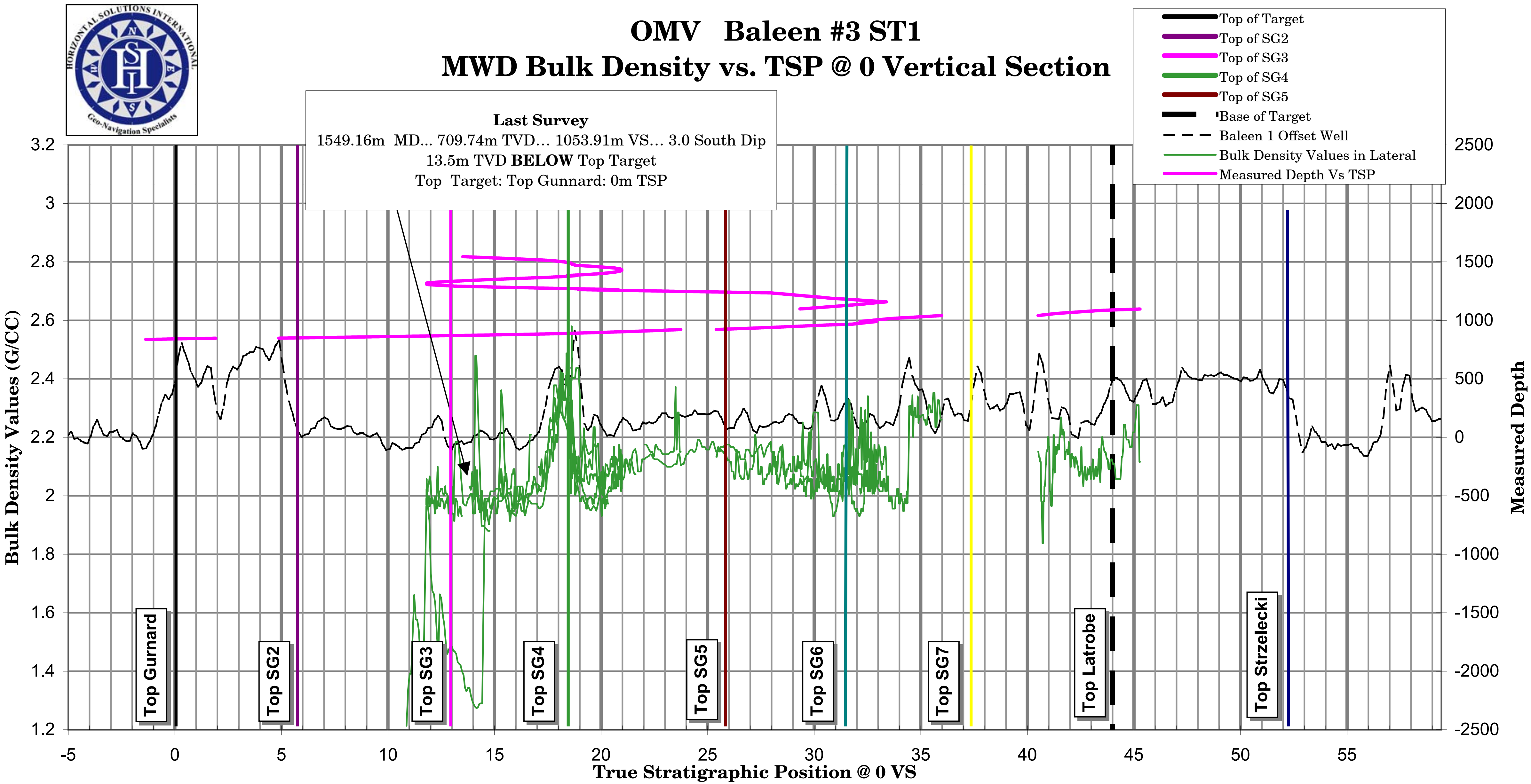
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MWD Bulk Density vs. TSP @ 0 Vertical Section
Last Survey
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13.5m TVD BELOW Top Target
Top Target: Top Gunnard: 0m TSP
Top of Target
Top of SG2
Top of SG3
Top of SG4
Top of SG5
Base of Target
Baleen 1 Offset Well
Bulk Density Values in Lateral
Measured Depth Vs TSP
Top Gurnard
Top SG2
Top SG3
Top SG4
Top SG5
Top SG6
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Top Strzelecki
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Measured Depth
True Stratigraphic Position @ 0 VS

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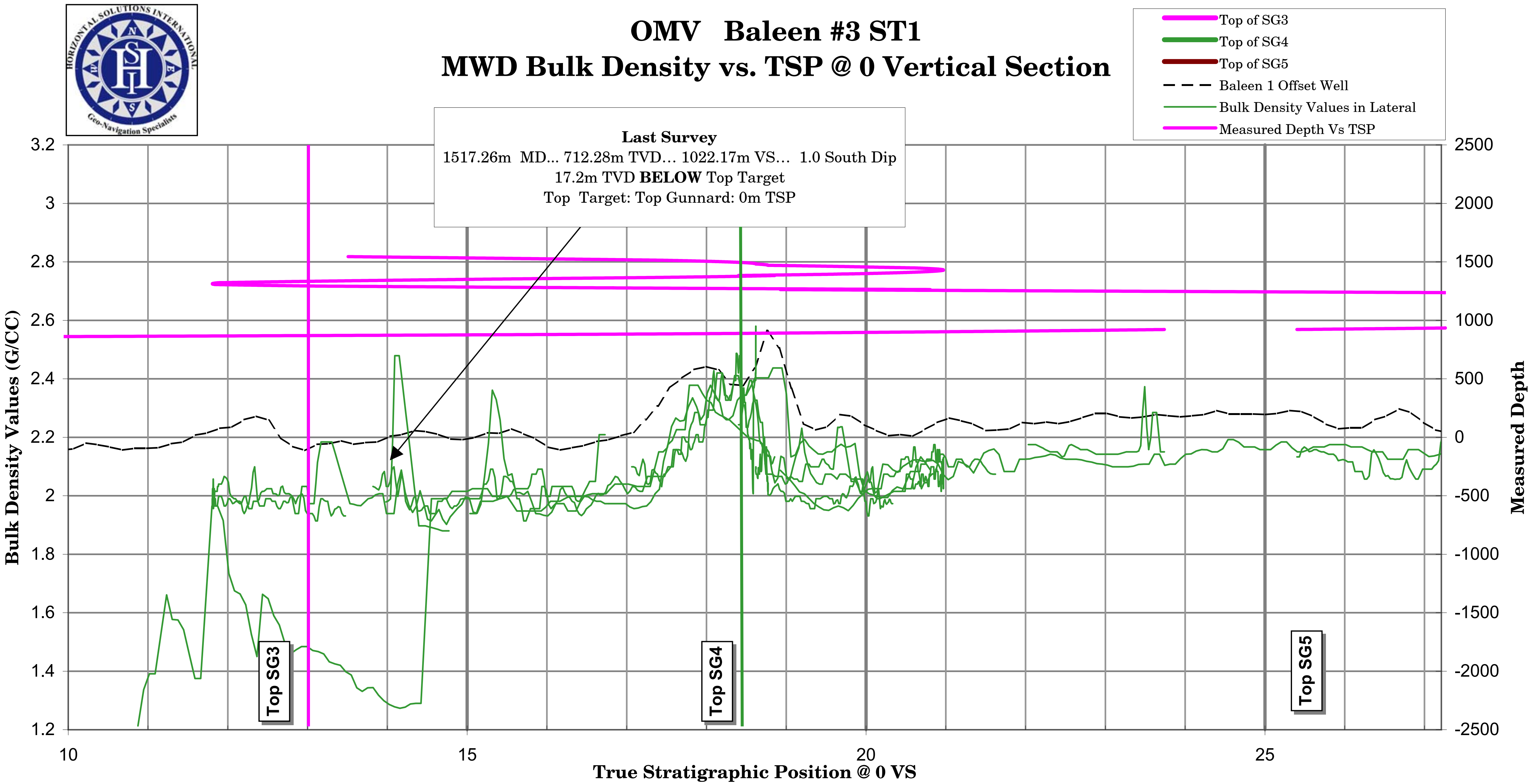

OMV Baleen #3 ST1
MWD Bulk Density vs. TSP @ 0 Vertical Section
Top of SG3
Top of SG4
Top of SG5
Baleen 1 Offset Well
Bulk Density Values in Lateral
Measured Depth Vs TSP
Last Survey
1517.26m MD... 712.28m TVD... 1022.17m VS... 1.0 South Dip
17.2m TVD BELOW Top Target
Top Target: Top Gunnard: 0m TSP
Bulk Density Values (G/CC)
Measured Depth
True Stratigraphic Position @ 0 VS
Top SG3
Top SG4
Top SG5
3.2
3
2.8
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
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OMV Australia

Appendix 2

DST Interpretation Report

OMV Australia Pty Ltd

VIC / L21

BALEEN-3 DEVELOPMENT WELL

PRODUCTION TEST REPORT & PRESSURE TRANSIENT ANALYSIS

Andy Ion

June 2002

OMV Australia Pty Ltd

ABN 94 082 932 027

Basin Oil Pty Ltd
(ABN 36 000 628 017)
Level 29
44 St Georges Terrace
Perth WA 6000

Tel: 61 8 9223 5000
Fax 61 8 9223 5004

VIC / L21

PATRICIA-BALEEN FIELD

BALEEN-3 DEVELOPMENT WELL

PRODUCTION TEST REPORT & PRESSURE TRANSIENT ANALYSIS

Prepared by

Andy Ion
Senior Reservoir Engineer
OMV Australia Ltd.

June 2002

C O N T E N T S

LIST OF FIGURES

ACKNOWLEDGEMENTS

Thanks to Mr Heimo Heinzle (OMV-AG) for provision of front cover photograph.

1 EXECUTIVE SUMMARY

The Baleen-3 well was production-tested between 9th-14th June 2002 in order to clean the well up prior to suspension and to determine key well and reservoir parameters from the bottomhole pressure response. The actual test duration was 63 hours (excluding operational downtime and waiting on daylight), as compared to the pre-test programme of 74 hours, due to reductions in the duration of some flow/shut-in periods. This was due to faster stabilisation times resulting from higher-than-expected reservoir quality.

A short initial flow and pressure build-up was conducted to determine the static reservoir pressure prior to testing. Extrapolation of the shut-in trend yielded an initial reservoir pressure of 1,060.8 psia at gauge reference depth of 902mMDRT (659 mTVDSS), some 5.5 psi lower than the pressure regime established from wireline formation pressure testing of the Baleen-2 appraisal well in 1999. This depletion is believed to be due to the effect of production from the Bass Strait oil/gas fields on the regional aquifer pressure.

The well was beaned-up to maximum choke to promote effective clean-up of the entire horizontal production interval. Intermittent brine slugs were observed at surface (and from bottomhole pressure data), which decreased in volume and frequency during the clean-up flow period. A coiled tubing-conveyed temperature logging pass confirmed the presence of free water lying in low-points (sumps) in the wellbore trajectory profile.

At maximum choke, a maximum flowrate of 27.1 MMscf/d was measured (upstream choke pressure of 650 psia) through the test separator (outside critical flow conditions), somewhat lower than the effective capacity of the test equipment. Well production was limited by both the restrictive presence of the coiled tubing string (maximum OD 2.2” at the gauges) inside the 5.5” tubing (ID 4.892”) and the circuitous pipework route between the flowhead and the test separator. In addition, prevailing wind conditions required flow to the aft flare boom, located on the opposite side of the rig to the test area, which caused additional pressure drops within the surface pipework.

Analysis of the two pressure build-up periods yielded an estimated horizontal effective permeability of 95 mD, higher than initially expected. Total wellbore skin of +7 to +8 was interpreted to be due to filtrate invasion (and pressure drop through the sand-screens) and was also slightly higher than expectations. A reduction in skin between the clean-up and main flow periods, combined with continued brine production throughout the main flow period, suggested that clean-up had not completely finished prior to termination of the test.

A pressure match of the entire test yielded an estimated horizontal effective permeability of 75 mD, slightly lower than the value derived from pressure build-up analysis. This more conservative estimate was used as a basis for deliverability calculations.

Deliverability analysis yielded stabilised absolute open-flow (AOF) potential of 150 MMscf/d (flow potential at 15 psi bottomhole pressure), based on extrapolation of data from four separate rate/pressure measurements. Given that the well was interpreted to have penetrated all reservoir sub-grids, thus minimising potential compartmentalisation in the event of laterally extensive impermeable siderite bands, deliverability analysis indicated that the well should exceed production performance predicted from the 2001 reservoir simulation modelling study.

Removing the effect of the coiled tubing from vertical lift performance (tubing hydraulics), it was estimated that the well would flow at a maximum initial rate of 68 MMscf/d, assuming a minimum initial tubing-head pressure of 250 psia.

2 PRODUCTION TEST OBJECTIVES & PROGRAMME

The well test programme was designed to provide the maximum amount of reservoir/well information for the minimum rig time. At the completion of testing operations, the well had to be secured for suspension as a future production well.

The following specific objectives were listed in the Completion & Testing Programme :

- Determine initial static reservoir pressure.
- Clean up well to remove residual mud/filtrate and promote flow contribution from total length, whilst minimising skin damage and plugging of sand screens.
- Determine rate-dependent wellbore skin factor.
- Determine well deliverability.
- Estimate average formation permeability.
- Estimate static & flowing pressure gradients.
- Obtain valid separator fluid samples.
- Secure well for future production.

Each of these objectives was addressed in the test programme, which comprised the following flow and shut-in periods (actual figures exclude lost time due to operational problems and waiting on daylight for first hydrocarbons to surface) :

	Test Period Duration (hrs)	
	Programmed	*Actual*
Initial Flow	0.2	0.2
Initial Shut-In	2.0	2.0
Clean-Up Flow	24.0	33.4
Second Shut-In	6.0	4.2
Main Flow : Rate ‘A’	9.0	4.2
Main Flow : Rate ‘B’	9.0	4.5
Main Flow : Rate ‘C’	12.0	6.9
Third Shut-In	12.0	3.0
Maximum Flow : Rate ‘D’	-	4.5
	74	**63**

Table 2.1

Whilst the BS&W (bulk sediment & water) dropped off quickly, intermittent slugging continued throughout the programmed duration of the clean-up flow and was exacerbated by coiled tubing logging of the horizontal production interval. The clean-up was therefore extended to remove more brine from the wellbore prior to deliverability testing.

Traces of mud were observed at surface throughout the test and likely emanated from the original, uncased production hole, drilled prior to lowside-sidetracking the well. Figure 1 shows a cross-sectional view of the well trajectory through the reservoir interval.

Both the second and third shut-in periods were significantly shortened due to the rapidity of the onset of radial flow and subsequent transition to linear flow. Each of the main flow periods were also reduced due to rapid pressure stabilisation at each flowrate.

A final ‘maximum-rate’ flow period was added to the programme to provide a fourth rate/pressure point to assist in deliverability analysis.

3 GAUGE/TOOLSTRING CONFIGURATION

Due to the requirement for unloading of completion brine using nitrogen, downhole surface read-out (SRO) and memory gauges were run on coiled tubing to provide pressure and temperature data close to reservoir Datum depth. In addition to the standard pressure/temperature gauges, a temperature logging tool was also run to investigate potential flow anomalies within the horizontal production interval.

The gauges were attached to the bottom of the coiled tubing using a conventional rope-socket assembly. SRO data was transmitted to surface via electric-line run inside the coiled tubing.

Three separate pressure/temperature measurements were recorded :

- SRO gauge – data transmitted to surface.
- SRO interface gauge – back-up to SRO, memory data mode only.
- Memory gauge – primary recorded data source.

The pressure gauges were all sapphire type model SS-2500, as supplied by Spartek Systems. The stated specifications of these gauges were as follows :

- Sensor type – Sapphire (1004)
- Accuracy – 0.022% full scale (full scale 6,000 psi --> accuracy = 1.32 psi).
- Resolution – 0.0003% full scale (full scale 6,000 psi --> resolution = 0.02 psi).

The SRO gauge was located directly beneath the rope-socket with the memory gauge beneath and the temperature logging tool on the bottom of the toolstring. The profile of the temperature logging tool was rounded to mitigate against tool hang-up whilst running in hole.

The length of each gauge was approximately two feet (0.61 metres), making the entire gauge-string approximately six feet (1.83 metres) in length. The top-gauge was located approximately five feet (1.52 metres) below the rope-socket.

Figure 2 shows a schematic view of the completion configuration.

4 OPERATIONAL SUMMARY

4.1 Initial Flow Period (FP #1)

The objective of this flow period was to create a pressure reduction within the wellbore, resulting in a short inflow from the reservoir and an associated pressure drawdown. A subsequent pressure build-up would then establish the initial reservoir pressure by extrapolation of the pressure trend.

At 23:53 on 9th June, the well was opened up to the surge-tank and coiled tubing run in hole. The toolstring would not pass a depth of 77 mMDRT, which corresponded to the depth of an isolation sleeve located within the tubing hanger (the sleeve had been set for pressure-testing and was designed to be retrieved at the end of testing operations). The sleeve was recovered using wireline.

At 21:13 on 10th June, the well was opened again and coiled tubing successfully run in hole to the reference gauge depth of 902 mMDRT (659 mTVDSS). Nitrogen was pumped whilst running in hole and a total of 122 barrels of brine unloaded to the surge-tank. The well was shut-in at 01:01 on 11th June for pressure build-up.

Whilst running in hole, the SRO & interface gauges failed. This was later determined to be due to bad electrical connections within the rope-socket, likely caused by liquid ingress. Data later downloaded from the memory gauge was valid and was used for subsequent analysis.

4.2 Initial Shut-In Period (PBU #1)

The well was shut-in with gauges at reference depth for a period of two hours, in order to provide sufficient time for pressure build-up. At 03:00 on 11th June, coiled tubing was pulled out of hole to recover memory gauge data and rectify SRO gauge problems.

4.3 Second Flow Period : Clean-Up Flow (FP #2)

At 10:35 on 12th June, coiled tubing was run in hole to the reference gauge depth of 902 mMDRT (659 mTVDSS). The well was opened at 12:42 on a 16/64" choke, gradually beaned-up to fully-open over a five-hour period and diverted to the test separator.

Due to intermittent surging of brine/mud slugs, the well was beaned-back to 60/64" choke and stabilised prior to sampling. A single separator gas sample was acquired when reasonably stable flow conditions were achieved. No condensate was observed.

At 17:30, the coiled tubing was run in hole to TD to evaluate any potential pressure/ temperature anomalies within the wellbore prior to commencing the second shut-in period. Whilst pulling back out of hole, an increase in the frequency and volume of returned brine slugs was observed from the downhole/surface pressure gauges and from tank level measurements. This was interpreted to be due to unloading of liquid lying in sumps/troughs in the wellbore trajectory as the gauges were pulled through the low points (on the lowside of the hole).

Due to this increased level of instability, the clean-up flow was extended until 22:04, when the well was shut-in at the choke for the second pressure build-up period.

During clean-up flow, Draeger measurements of 0.15% CO_2 and nil H_2S were recorded. Water analysis indicated all produced liquid was completion brine. A total of 39 barrels of brine was measured during the period the well was flowed through the test separator.

4.4 Second Shut-In Period (PBU #2)

The pressure build-up response was monitored at both the downhole gauge and the upstream side of the choke. Once sufficient data had been acquired to meet test objectives, the shut-in period was terminated.

4.5 Third Flow Period : Main Flow (FP #3-#4-#5)

The well was opened up at 02:13 on 13th June for the main flow period, which comprised three sequential flow periods at increasing choke settings. Flow was stabilised before switching to a fixed 32/64" choke.

Two PVT gas samples were acquired after one hour of stable flow. No condensate production was noted (not even a sheen on top of water level observations). Flow continued until a stable pressure point was determined for deliverability analysis.

At 06:04, the well was beaned-up gradually using an adjustable choke before switching to a fixed 48/64" choke. At 07:25, coiled tubing was pulled out of hole to commence a flowing gradient survey. Ten-minute stops were made at six ascending depths in order to determine the dynamic fluid gradient within the wellbore. At the conclusion of the survey, the gauge was returned to the gauge reference depth and stable flow continued until a further stabilised pressure point was determined for deliverabilily analysis.

At 10:34, the well was beaned-up gradually using an adjustable choke before switching to a fixed 60/64" choke. A second coiled tubing pass was conducted to investigate the potential contributing flow interval prior to shutting-in the well for the final pressure build-up period. Increased levels of brine slugging were again observed as the tool was pulled through the sumps in the wellbore trajectory. Flow was continued until a stable pressure point was achieved for deliverability analysis.

At 17:35, the well was shut-in for the third pressure build-up.

4.6 Third Shut-In Period (PBU #3)

The pressure build-up response was monitored at both the downhole gauge and the upstream side of the choke. Once sufficient data had been acquired to meet test objectives, the shut-in period was terminated.

4.7 Fourth Flow Period : Maximum Flow (FP #6)

A final 'maximum rate' flow period was added to the programme to provide a further deliverability point at high rate.

The well was opened up at 21:02 for the final (maximum rate) flow period. The well was beaned-up to 128/64" choke and flowed until a stable pressure was achieved for deliverability analysis.

The well was shut-in at 01:21 on 14th June, at which point the production test was effectively terminated.

In summary, key flowing parameters during the test sequence were as follows :

	Choke (64ths)	**Gas Rate** (MMscf/d)	**U/S choke** (psia)	**D/S choke** (psia)	**Critical Flow ?**	**Sep Press** (psia)
FP #2 (mid)	192	24.8	604	546	No	384
FP #2 (end)	60	18.4	841	381	Yes	282
FP #3	32	6.2	954	312	Yes	318
FP #4	48	13.4	905	363	Yes	325
FP #5	60	18.2	839	383	Yes	279
FP #6	128	27.1	651	582	No	420

5 DATA ANALYSIS – INPUT DATA ASSUMPTIONS

In order to perform analysis of the bottomhole pressure data, a number of assumptions were required.

5.1 Reservoir Model & Properties

Based on analysis of the high-quality 3D seismic dataset and data from offset vertical wells, the reservoir geometry was assumed to be known with some degree of certainty. The preferred reservoir model was assumed to comprise a single horizontal homogeneous layer bounded above and below by horizontal no-flow boundaries. In the absence of clear major faulting in the vicinity of the wellbore, an infinitely-acting boundary model was applied.

An alternative reservoir model comprising a vertical well located between two parallel faults was investigated, but did not yield significantly different results to the preferred model.

A uniform reservoir thickness of 35 metres was applied based on stratigraphic information acquired from the Baleen-1 exploration well and assuming some thinning of the reservoir at the crest, based on log data acquired from the Baleen-3 well.

The following input data was also applied, either estimated from known/analogous reservoir data or calculated from an equation-of-state relationship :

Formation Porosity (%)	35
Initial Reservoir Pressure (psia)	1,060.8
Reservoir Temperature (ºF)	117
Water Saturation (%)	35
Water/Gas Ratio (bbls/MMscf)	4 (water of condensation + completion brine)
Gas Z Constant	0.9174
Gas Compressibility (1/psi)	1.026 E-03
Water Compressibility (1/psi)	2.839 E-06
Rock Compressibility (1/psi)	7.500 E-05 *
Total Compressibility (1/psi)	7.426 E-04
Gas Viscosity (cP)	0.0132
Water Viscosity (cP)	0.5994

Table 5.1

** The rock compressibility value was an estimate, based on experience from the Stag Field, which is also a shallow, glauconitic, high porosity (micro-porosity), silty reservoir of similar geological age and depositional environment.*

5.2 Fluid Properties

Gas composition data used to calculate gas compressibility was based on the analysis of a separator gas sample obtained from the Patricia-1 well. Whilst on-site analysis of produced gas from the Baleen-3 test indicated a different proportion of methane and carbon dioxide, application of this data was not considered appropriate until final PVT analysis of the preserved separator samples was available.

The assumed gas composition was as follows, based on the analysis of a DST separator sample recovered from the Patricia-1 exploration well (% mol) :

CO2	N2	C1	C2	C3	C4	C5	C6+	Total
1.32	0.66	97.72	0.28	0.005	0.003	0.003	0.005	100.00

Table 5.2

5.3 Well Properties

A wellbore radius of 4.25 inches was assumed based on the bit-size used to drill the production interval. Indications of good hole conditions during drilling and from acoustic caliper measurements supported this assumption.

6 DATA ANALYSIS – INTERPRETATION

6.1 Test Overview

Figure 3 shows the pressure data recorded by the SRO/interface/memory gauges during the initial flow and build-up periods (Run #1). No data was available from the SRO/interface gauges during the build-up as both gauges failed as coiled tubing was run in hole. This was believed to be due to bad electrical connections at the rope-socket. Following the programmed two-hour initial shut-in period, the gauges were pulled out of hole to replace the SRO/interface gauges prior to continuing the test.

Figure 4 shows the pressure data recorded by the SRO/interface/memory gauges during the remainder of the production test (Run #2). Prior to opening up the well for clean-up, the SRO gauge pressure measured 1,022 psia, approximately 39 psi lower than the initial reservoir pressure interpreted from the initial shut-in period.

Subsequent correlation of SRO data with downloaded memory data confirmed a -39 psi shift had occurred in SRO data. This was later attributed to corruption of gauge calibration files. Memory data was used for interpretation.

Figure 5 shows the master pressure dataset used for test analysis – flow anomalies and fluctuations associated with logging and survey operations have been manually omitted for ease of analysis.

Figure 6 shows the downhole gauge and surface pressures during the test, whilst Figure 7 highlights the differential pressure across the choke at each choke setting.

6.2 Initial Reservoir Pressure

The initial reservoir pressure was estimated to be 1,060.8 psia at the reference gauge depth of 902 mMDRT (659 mTVDSS), based on extrapolation of the pressure build-up trend. Since the gauges were located within the reservoir interval, no pressure corrections were required between gauge depth and reservoir depth. The analysable portion of the pressure build-up is shown in Figure 8.

Figure 9 shows the Baleen-3 initial reservoir pressure superimposed on historical pressure data obtained from the Patricia-Baleen exploration/appraisal wells. This plot indicates that a further 5-6 psi depletion has occurred since the last formation pressure data was acquired during wireline logging of the Baleen-2 appraisal well in 1999. This loss in pressure is believed to be due to depletion of the regional aquifer by production from the Bass Strait oil/gas fields.

No additional analysis of the initial pressure build-up data was possible due to uncertainty in the data quality resulting from pumping of nitrogen and gauge movement during the build-up period.

6.3 Pressure Build-Up Analysis

The primary interpretation of reservoir quality data derived from analysis of the second and third pressure build-up periods. Both periods yielded analysable data of high quality.

6.3.1 Second Pressure Build-Up Period

Figure 10 shows the pressure build-up data obtained. Radial flow behaviour was clearly apparent once the effects of wellbore storage had diminished (wellbore storage effects due to surface shut-in). The duration of the shut-in period was reduced from the programmed duration once clear linear flow characteristics were evident from log-log trend analysis. Analysis of the radial flow data component yielded a spherical effective permeability (product of horizontal and vertical permeabilities) of 14 mD and total wellbore skin of +8.7, likely due to formation damage from residual mud-cake and filtrate invasion, plus some pressure loss through the sand-screens.

Semi-log analysis of the same data yielded a spherical permeability of 14 mD and a wellbore skin of +9.8, in good agreement with the previous interpretation (Figure 11). Extrapolation of the radial flow data yielded an infinite-time build-up pressure of 1,049.4 psia, 11.4 psi less than the initial reservoir pressure determined from the initial flow/shut-in. This was not interpreted to be due to depletion, but related to limited drainage volume of the horizontal well within a relatively thin reservoir interval. Extrapolation of the late-time hemi-radial flow trend (effect of upper/lower boundary felt) yielded an infinite-time build-up pressure of 1,058.5 psia.

Figure 12 shows the results of the best pressure match achieved on the log-log response. Horizontal and vertical effective permeabilities of 93 mD and 1.9 mD respectively were calculated with a total skin of +8.

An interpreted wellbore storage coefficient of 0.192 bbls/psi, and associated wellbore volume of 189 bbls, approximated the volume of the completion annulus (tubing minus CT volume) and openhole wellbore, which was estimated to be 200 barrels.

6.3.2 Third Pressure Build-Up Period

Figure 13 shows the pressure build-up data obtained. Radial flow behaviour was clearly apparent once the effects of wellbore storage had diminished. The duration of the shut-in period was reduced from the programmed duration once clear linear flow characteristics were evident from log-log trend analysis. Analysis of the radial flow data component yielded a spherical effective permeability of 14 mD and total wellbore skin of +7.0.

Semi-log analysis of the same data yielded a spherical permeability of 14 mD and wellbore skin of +7.0, equal to the log-log interpretation (Figure 14). Extrapolation of the radial flow data yielded an infinite-time build-up pressure of 1,049.6 psia, 11.2 psi less than the initial reservoir pressure determined from the initial flow/shut-in. This was not interpreted to be due to depletion, but related to limited drainage volume of the horizontal well within a relatively thin reservoir interval. Extrapolation of the late-time hemi-radial flow trend (effect of upper/lower boundaries felt) yielded an infinite-time build-up pressure of 1,055.6 psia.

Figure 15 shows the results of the best pressure match achieved on the log-log response. Horizontal and vertical effective permeabilities of 97 mD and 1.7 mD respectively were calculated with a total skin of +7.

Due to the more advanced level of clean-up and more accurate flow metering during the preceding flow period, interpretation from the third PBU was confirmed as the preferred analysis.

6.4 Total Test Pressure Match

Estimation of key parameters was achieved using regression analysis.

Figures 16, 17 & 18 show the three best pressure matches achieved with the calculated well/reservoir results overlaid. Whilst the quality of all matches is reasonable, Interpretation #1 was considered the best due to the superior match of the pressure build-up trends and final flow period.

Accurate matching of the clean-up flow was not considered to be important due to the uncertainty in production rate whilst well effluent was diverted directly to the burners. Since well clean-up continued throughout the production test, the determination of single 'best-fit' parameters to match the entire test was somewhat approximate.

The 'most-likely' analysis, Interpretation #1, yielded the following 'most-likely' results :

Effective Horizontal Permeability (Kh)	75 mD
Effective Vertical Permeability (Kv)	1.3 mD (Kv/Kh = 1.7%)
Total Wellbore Skin factor (S)	+ 5.4
Horizontal Production Length (L)	2,200 feet (670 metres) – 94% of gross interval
Vertical Well Position (Zwd)	0.06 (heel close to top-porosity surface)
Non-Darcy Rate-Dependent Skin (D)	4.176 E-06 /Mscf

Table 6.4

The interpreted values of wellbore storage coefficient (Cs) and initial pressure (Pi) were dismissed due to : a) changing gas/liquid proportions in the wellbore and, b) imperfect matching of the late-time PBU trends, respectively. The low value of rate-dependent skin was considered reasonable based on the expected low frictional losses due to the horizontal well geometry and relatively low production rates.

Based on the spread of results from all three interpretations, horizontal effective permeability up to 150 mD was interpreted with a corresponding reduction in the productive interval length. Due to the relatively consistent reservoir quality interpreted along the wellbore, and confirmation from production logging that the toe of the well (located in good-quality sub-grid 3 formation) was contributing to flow, these results were discounted in favour of Interpretation #1, which was used as a basis for subsequent deliverability modelling.

6.5 Flowing Gradient Survey

Between 07:20 – 08:35, July 13th (during Flow Period #4), a flowing gradient survey was conducted. Coiled tubing was pulled out of hole with ten-minute stops made at selected depths to record stabilised flowing pressures. Some gauge pressure inconsistency was noted due to intermittent slugging, but a constant flowing gradient was determined with some confidence.

A pressure correction was applied to gauge data to account for a gradual increase in FBHP during the survey. Figure 19 shows the extent of this increase by way of an interpolation between gauge pressure data before and after the survey, when the gauge was at the reference depth. The following data was obtained :

Depth (mMDRT)	Depth (mTVDSS)	Pressure (psia)	Corr. Pressure (psia)	Temp (ºF)
902.0	658.7	1,021.96	1,021.96	115.4
850.0	651.7	1,020.58	1,020.73	115.3
800.0	639.2	1,019.92	1,020.12	115.1
750.0	621.7	1,018.01	1,018.41	114.9
650.0	568.3	1,012.60	1,013.20	114.0
550.0	500.2	1,005.51	1,006.26	112.5
400.0	371.9	994.20	995.20	109.6

Table 6.5

Figure 20 shows the data obtained from the survey. A flowing fluid gradient of 0.0928 psi/m was determined from line-fitting through key pressure data points. This compares with a static gradient of 0.0911 psi/m, as determined from the observed differential between the upstream choke pressure and bottomhole gauge pressure during the shut-in periods (confirming low frictional losses at selected flowrate).

Some degree of inaccuracy in the data was expected due to the different lengths of coiled tubing in the wellbore at each survey depth, resulting in varying frictional losses, however the quantum of this discrepancy was considered to be negligible due to the similarity in the gradients listed above.

The flowing gradient data was compared against various flow correlations to determine the most appropriate correlation for use in IPR/VLP deliverability modelling.

6.6 Well Deliverability Analysis

6.6.1 Flow-After-Flow Transient Analysis

Stabilised flow was achieved at four different choke settings (Flow Periods #3-#4-#5 prior to third PBU and Flow Period #6 after third PBU) in order to determine a deliverability curve that could be used for the prediction of well productivity with declining reservoir pressure. The four flow periods, A – D, are highlighted in Figure 4.

Figure 21 shows a Cartesian plot of the four flow periods superimposed. Data anomalies relating to coiled tubing logging, flowing gradient survey, choke blockage and liquid slugging were manually omitted to facilitate analysis of the valid data.

The pressure trend corresponding to Rate ‘A’ exhibited a gradual upward trend, interpreted to be due to clean-up effects related to low gas velocities insufficient to lift liquids that had accumulated in the wellbore during the preceding shut-in period. Due to this effect, this data point was attributed less reliability than the other three rate/pressure points.

Rates ‘B’ & ‘D’ exhibited a similar degree of stability after 4.5 hours of flow at their respective choke settings. The Rate ‘C’ flow period was extended as a result of increased slugging resulting from coiled tubing logging of the horizontal production interval. The longer flow period resulted in a more reliable deliverability point, albeit affected by minor fluctuations in FBHP due to slugging.

Figure 22 illustrates the semilog (radial flow) analyses of the four individual pressure responses simultaneously. Due to differences in the interpreted gradient of the radial flow portions of each dataset, a single line of averaged gradient was fitted through one dataset, then three lines of equal gradient fitted to the remaining datasets. The assigned gradient indicated a spherical permeability of 8.1 mD (this analysis is subordinate to the results of PBU interpretations).

Figure 23 shows the relationship derived between skin and flowrate. Using the calculated non-Darcy flow coefficient (F) of 0.0036, the semilog trends were collapsed on to a single line by removing the effect of rate-dependency (Figure 24).

6.6.2 Flow-After-Flow 'LIT' Analysis

The following pressures and rates were used as a basis for this theoretical analysis :

	Choke (64ths)	**BHP @ Start** (psia)	**BHP @ End** (psia)	**Gas Flowrate** (MMscf/d)
Rate 'A'	32	1,049.3	1,036.6	6.2
Rate 'B'	48	1,036.6	1,019.9	13.2
Rate 'C'	60	1,019.9	1,006.6	18.1
Rate 'D'	96	1,048.2	982.4	26.6

Table 6.6

LIT (laminar-inertial-turbulent) analysis of the 'stabilised' data yielded an AOF (production at 15 psia FBHP) estimate of 131 MMscf/d. Transient analysis of the data was also conducted based on the assumption of an 640-acre drainage area and a Dietz shape factor of 10.8 (well located in upper half of 2x1 areal geometry). A transient AOF of 156 MMscf/d was estimated. AOF and deliverability relationships from both analyses are shown in Figures 25 & 26.

6.6.3 Flow-After-Flow 'C&n' Analysis

An empirical analysis of deliverability was conducted to derive the C-coefficient and n-exponent that form the basis of the deliverability equation :

$$Q = C * (P_r^2 - P_{wf}^2)^n$$

where : *Q = gas flowrate*
P_r = average reservoir pressure
P_{wf} = bottomhole flowing pressure

The flowing rates and pressures presented in Table 6.5 were used in the analysis. Figures 27 & 28 show the AOF and deliverability plots derived from this analysis. AOF using the input data ('extended') was estimated to be 168 MMscf/d, whereas the stabilised AOF (using calculated stabilised rate at last flowing pressure) was estimated to be 150 MMscf/d.

Given the better quality of match of all four points using the 'C&n' technique, it was concluded that the most reliable estimate of stabilised AOF (at 15 psia bottomhole flowing pressure) for the well was 150 MMscf/d.

6.6.4 Vertical Lift Performance

A vertical lift performance curve was generated based on the THP-BHP data obtained during each flow period. The tubing component was most accurately modelled using the 'PetroleumExperts3' annular flow correlation, whilst the pressure drop within the surface pipework (standard process pipe ID 2.3" plus Coflexip pipe ID 2.5") was approximated by a pressure drop across a single choke (notional 1.3" size determined by iteration).

A second vertical lift performance curve was then generated, omitting the surface choke and assuming tubing flow with no coiled tubing in hole, to model lift behaviour when flowing direct to the 12" subsea flowline in full production mode. Further hydraulic modelling, including pressure losses along the subsea flowline to the onshore process plant, was conducted to define total network flow potential including the Patricia-2 well, but this work was considered to be outwith the scope of this document.

Figure 29 shows the well IPR and the calculated VLP, assuming a range of initial THP from 250 psia (estimated minimum initial THP) to 1,000 psia. The intersection of the IPR/VLP curves defines the operating point of the well and indicates a maximum potential flowrate (at initial reservoir pressure) of 68 MMscf/d. This figure does not take account of additional pressure losses between the wellhead and the onshore plant.

6.7 <u>Temperature Logging</u>

The temperature logging tool was run across the horizontal production interval twice during the test sequence, firstly towards the end of the clean-up flow, then again at the conclusion of the multi-rate flow period (Flow Period #5).

In both cases, the gauges were run to a depth ten metres short of the completion mule shoe and then pulled back through the sand screens to the 9-5/8" casing shoe at a constant rate of 10 metres/minute.

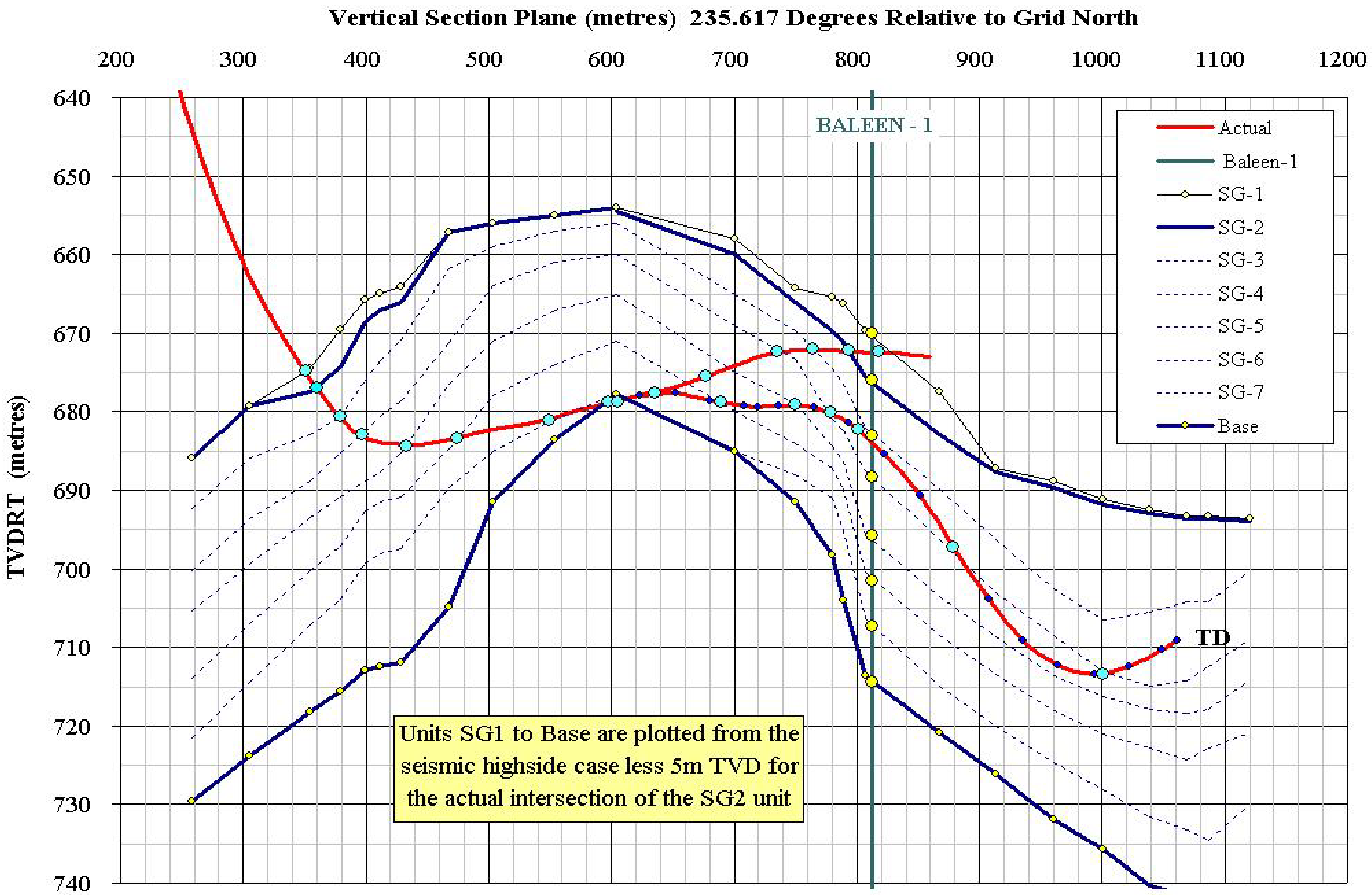
Figures 30 & 31 show the raw data obtained during each of the two logging runs. Figure 32 focusses on the time interval where the gauges were being pulled out of hole and shows the wellbore trajectory superimposed to highlight the position of the gauge during the logging runs.

The data presented is sourced from the temperature probe located inside the EMR memory gauge housing. In addition to this standard memory data, a temperature log was run on the bottom of the gauge string (probe mounted externally in fluid stream) to provide data of higher accuracy/resolution. Since the data acquired did not significantly differ from the recorded memory data, it is not presented in this report, but is included in digital format in Appendix B.

Both runs show the effect of free water lying in the lowside of the hole and the associated temperature increase as the gauge was pulled through the troughs. Comparison of the data obtained during the two runs shows the reduction in slugging during the production test.

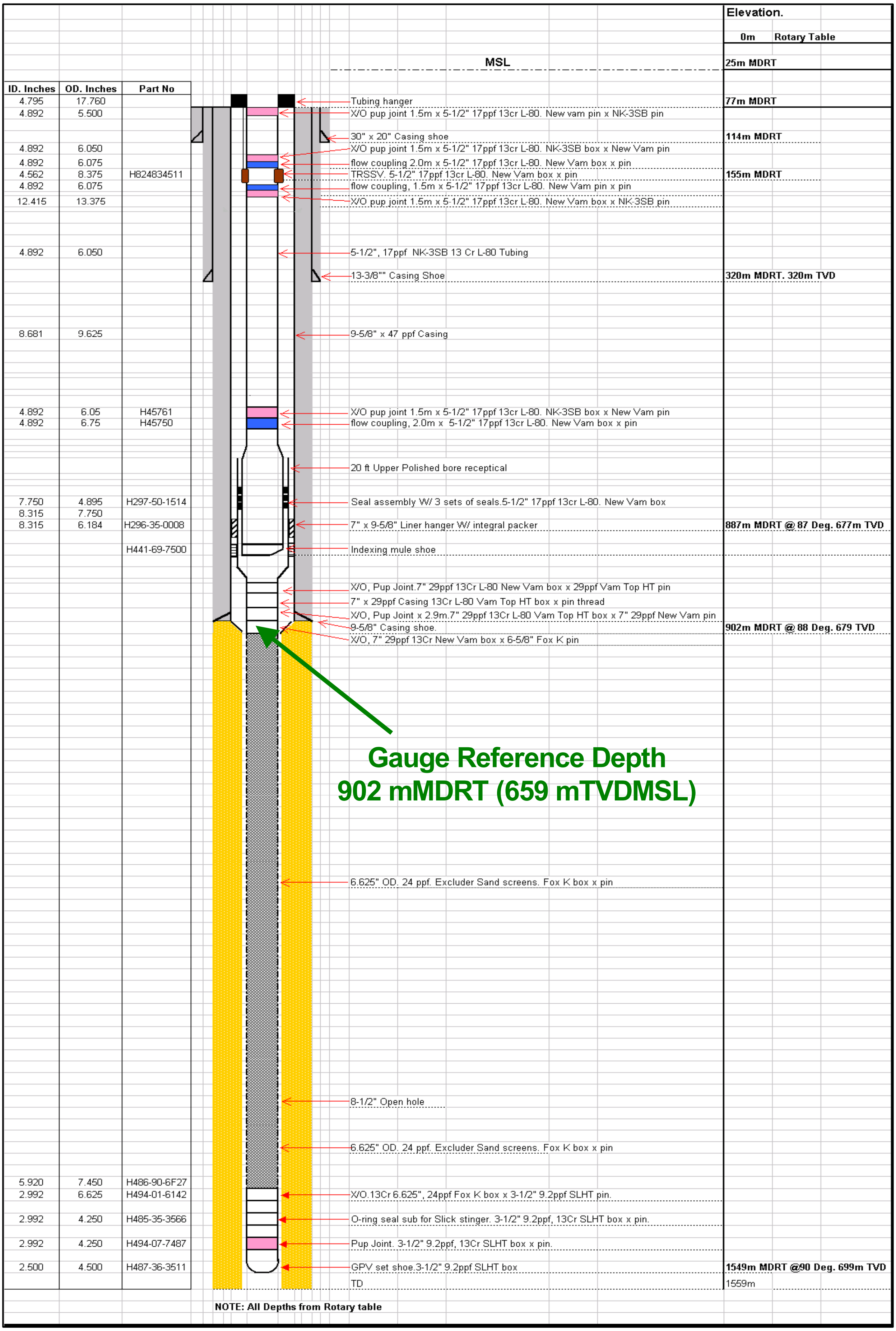
No reliable data was obtained with respect to identifying gas ingress to the wellbore from expansion-cooling (Joule-Thomson Effect) due to the extent of slugging.

7 FIGURES



Baleen-3 Wellbore Schematic

Figure 1



Completion Schematic (proposed) ***Figure 2***

OMV Australia

Initial Flow & Shut-In Periods : Gauge Data

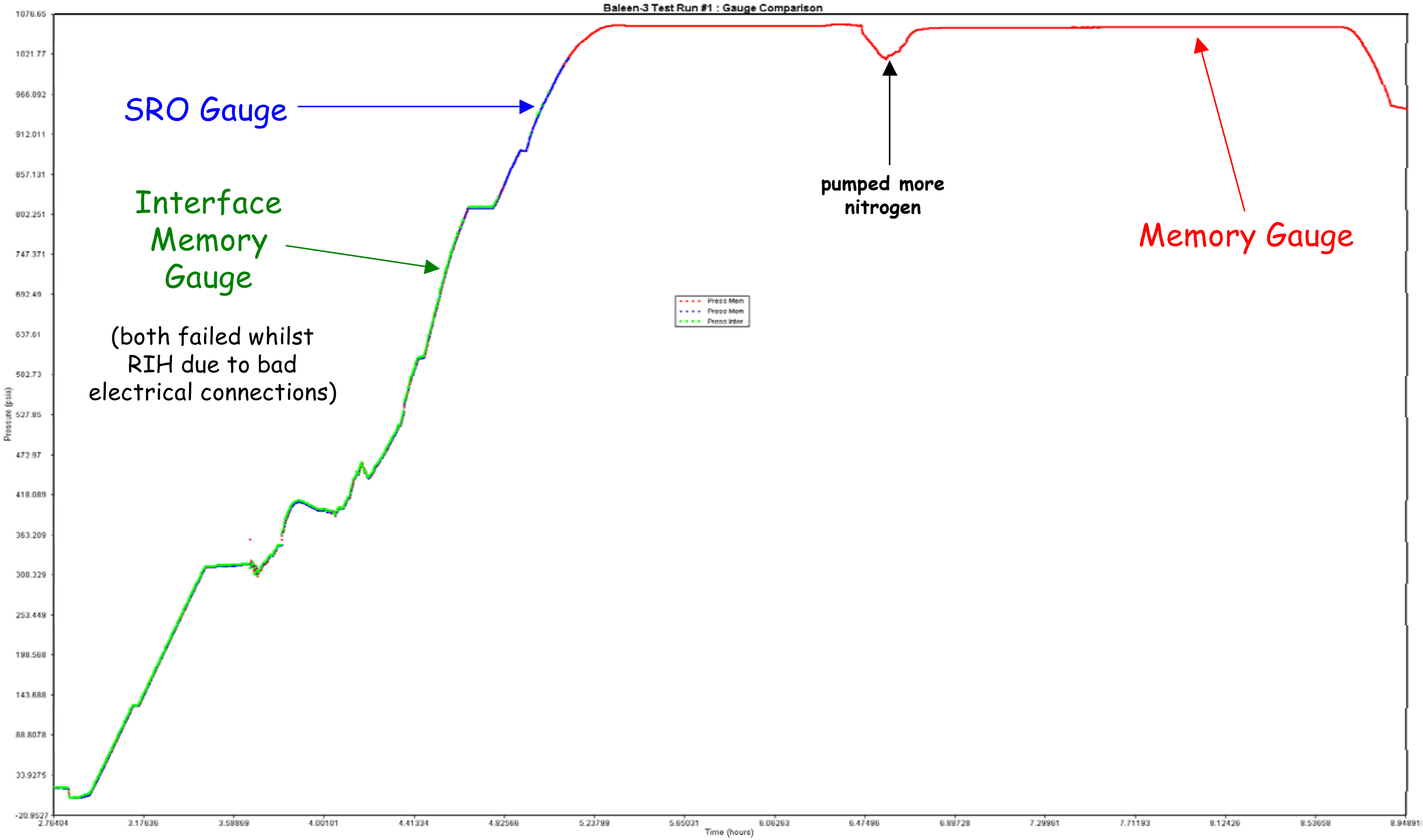


Figure 3

Baleen-3 Test Overview : Gauge Data

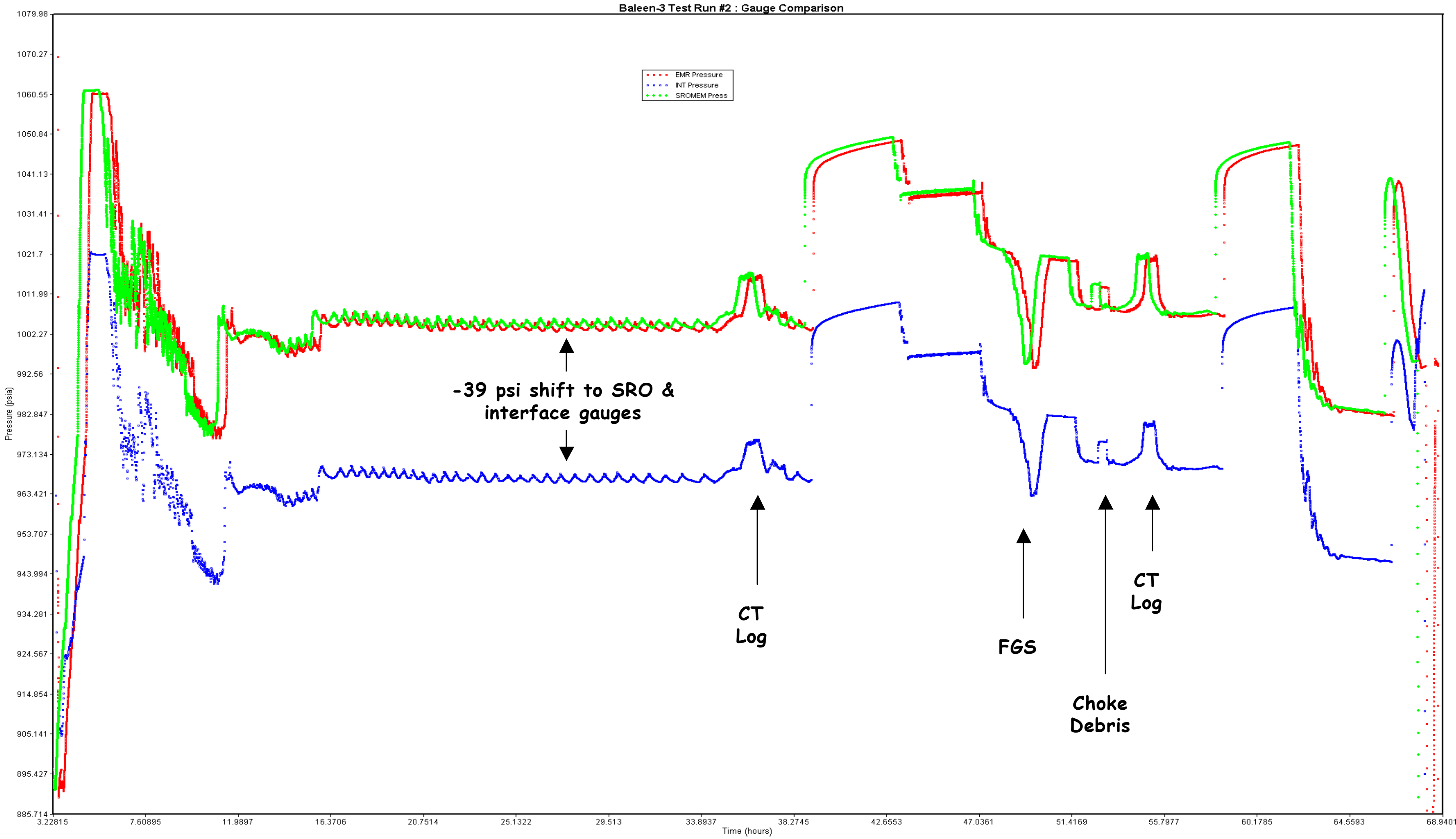


Figure 4

OMV Australia

Baleen-3 Test Overview : Master Dataset

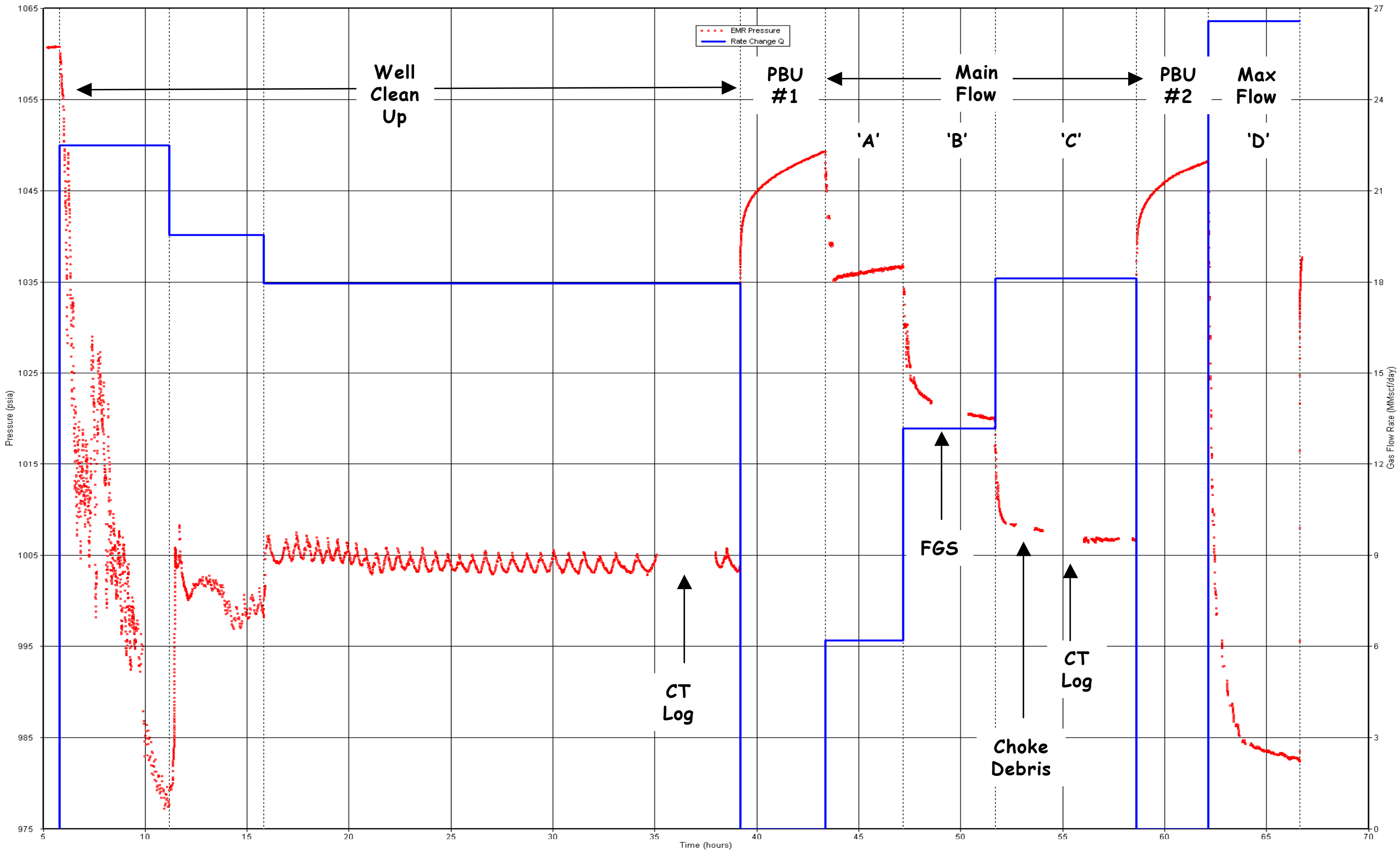


Figure 5

OMV Australia

Baleen-3 Test Overview : BHP v. THP Data

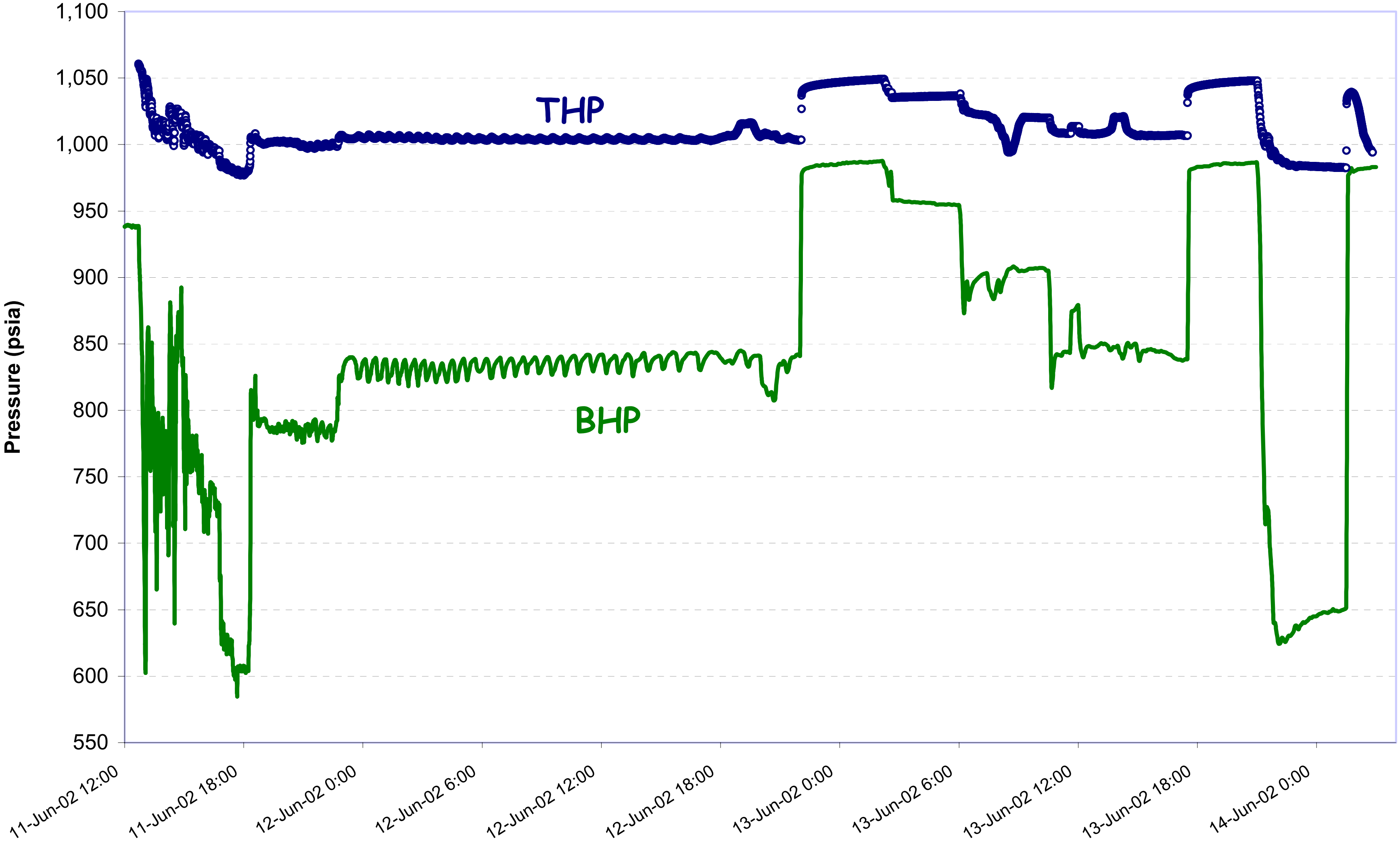


Figure 6

OMV Australia

Baleen-3 Test Overview : Expro Surface Data

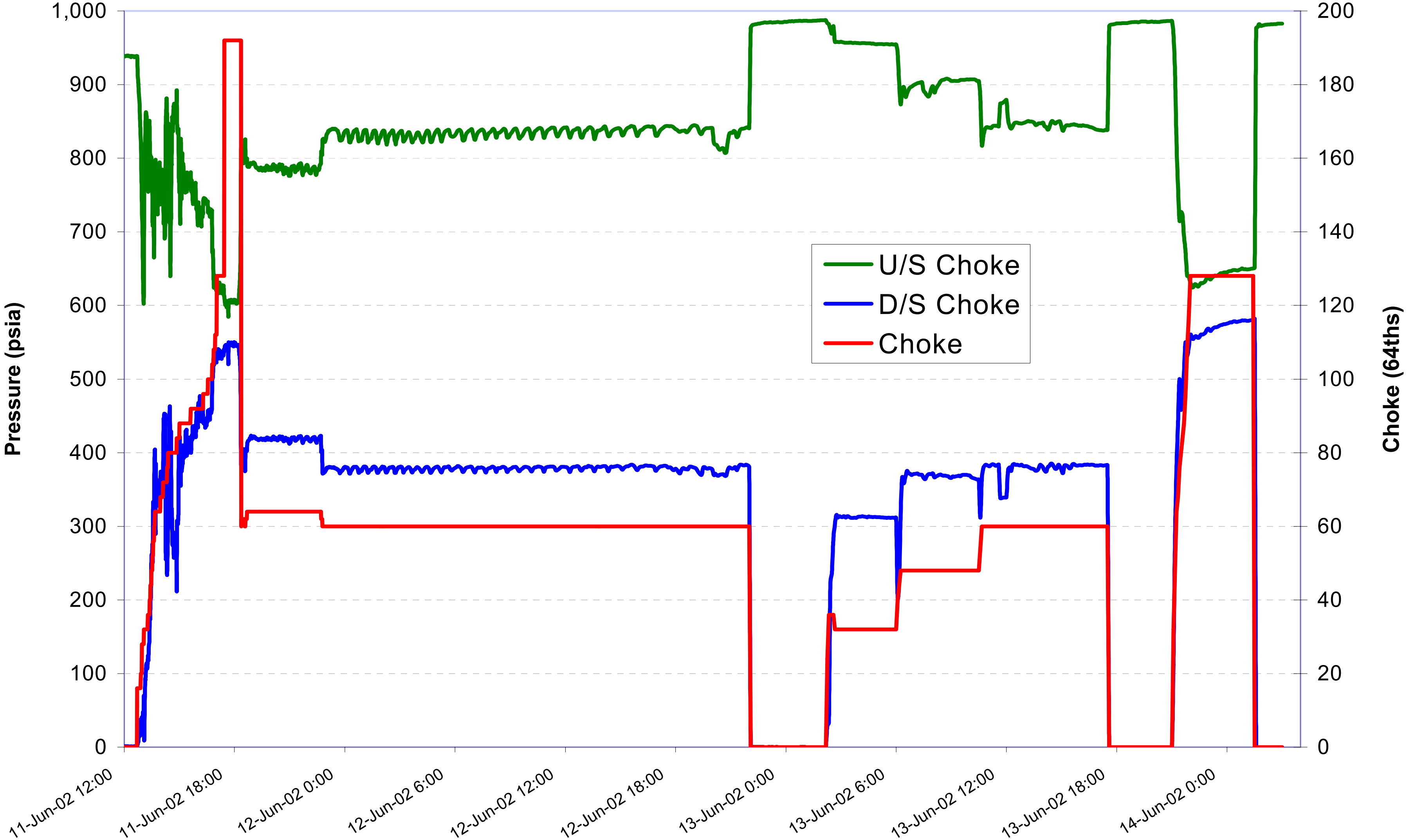


Figure 7

OMV Australia

Initial Pressure Build-Up Analysis

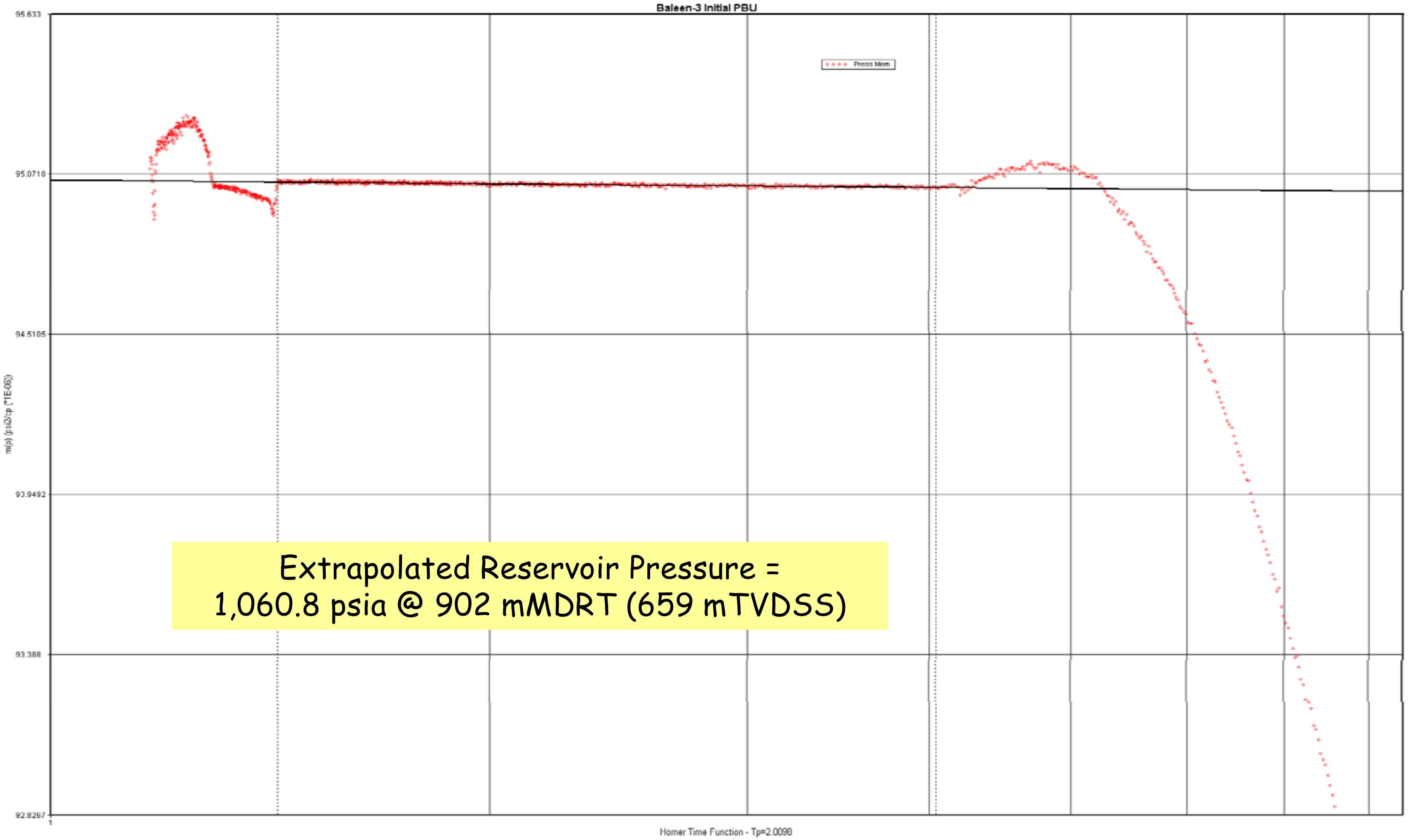


Figure 8

OMV Australia

Baleen-3 Reservoir Pressure v. Historical Trend

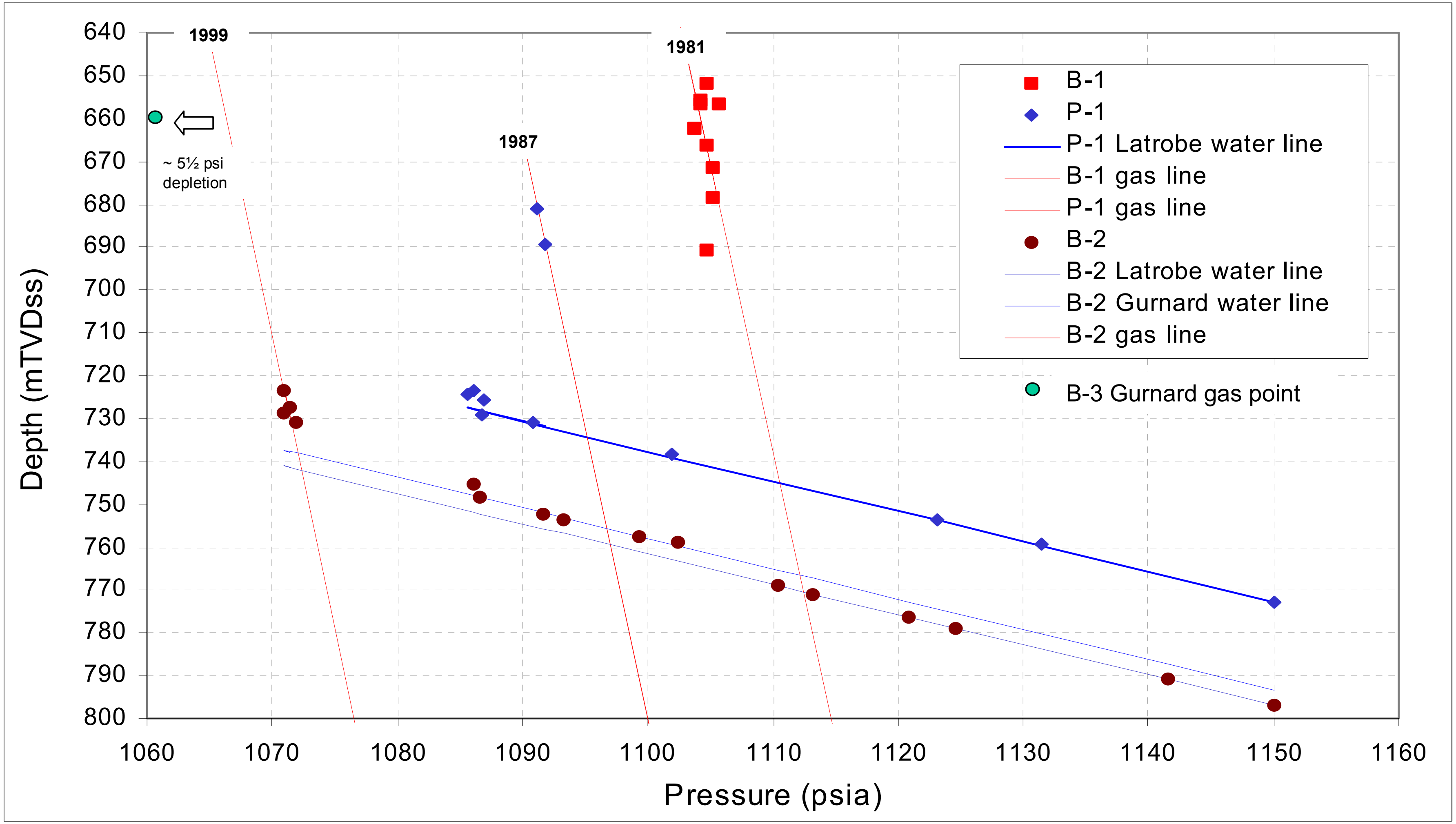


Figure 9

OMV Australia

PBU #2 : Log-Log Plot

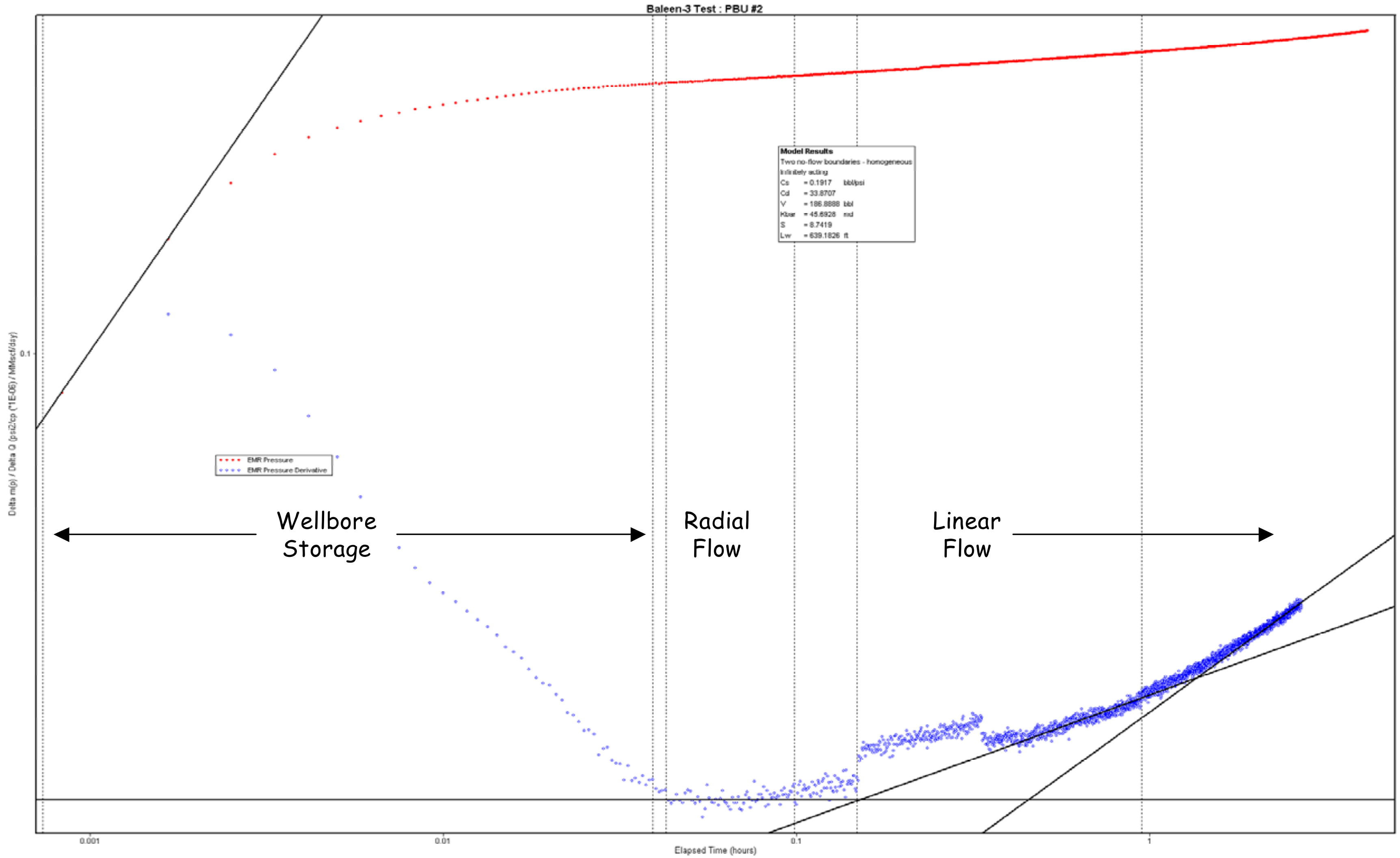


Figure 10

OMV Australia

PBU #2 : Radial Flow Plot

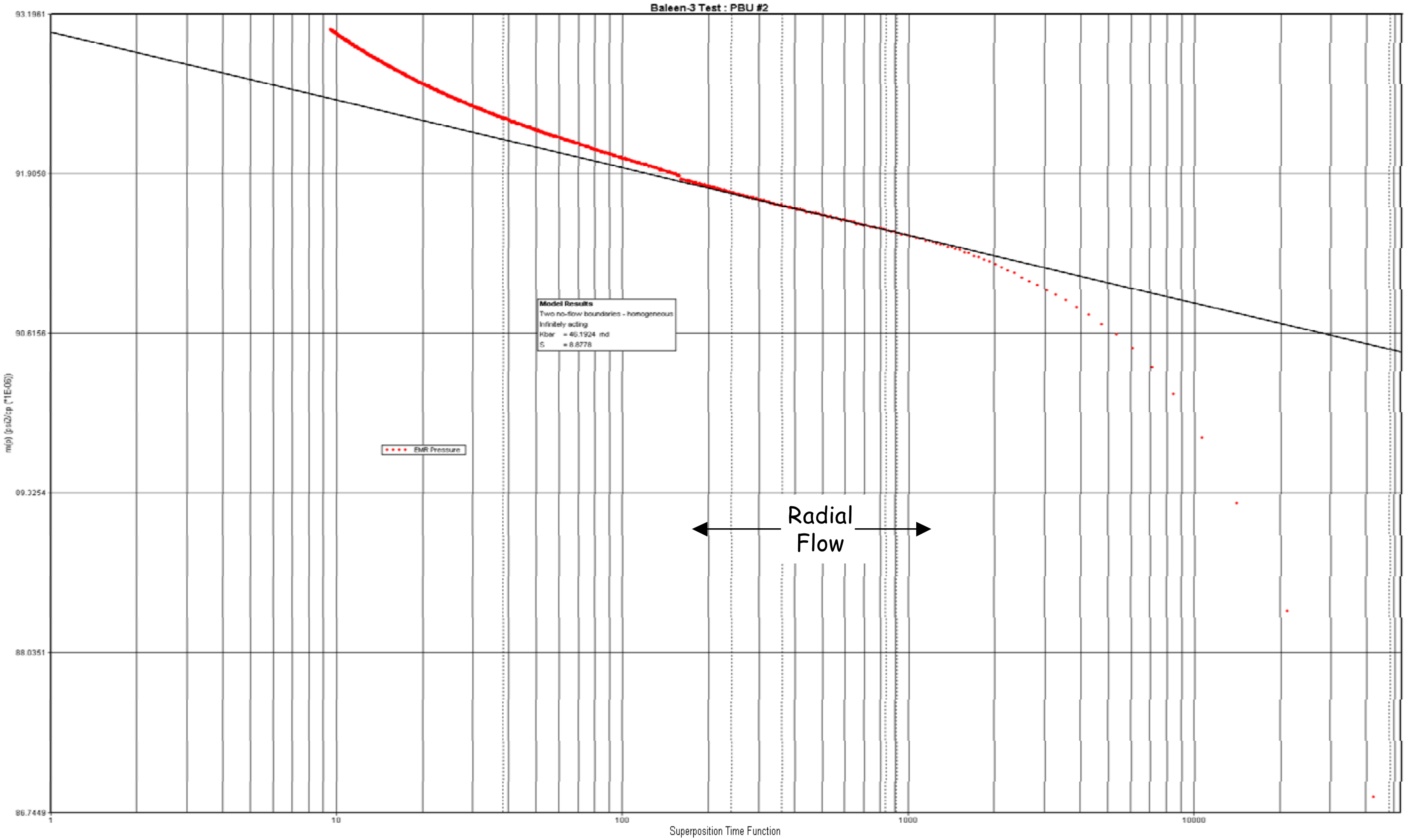


Figure 11

OMV Australia

PBU #2 : Pressure Match

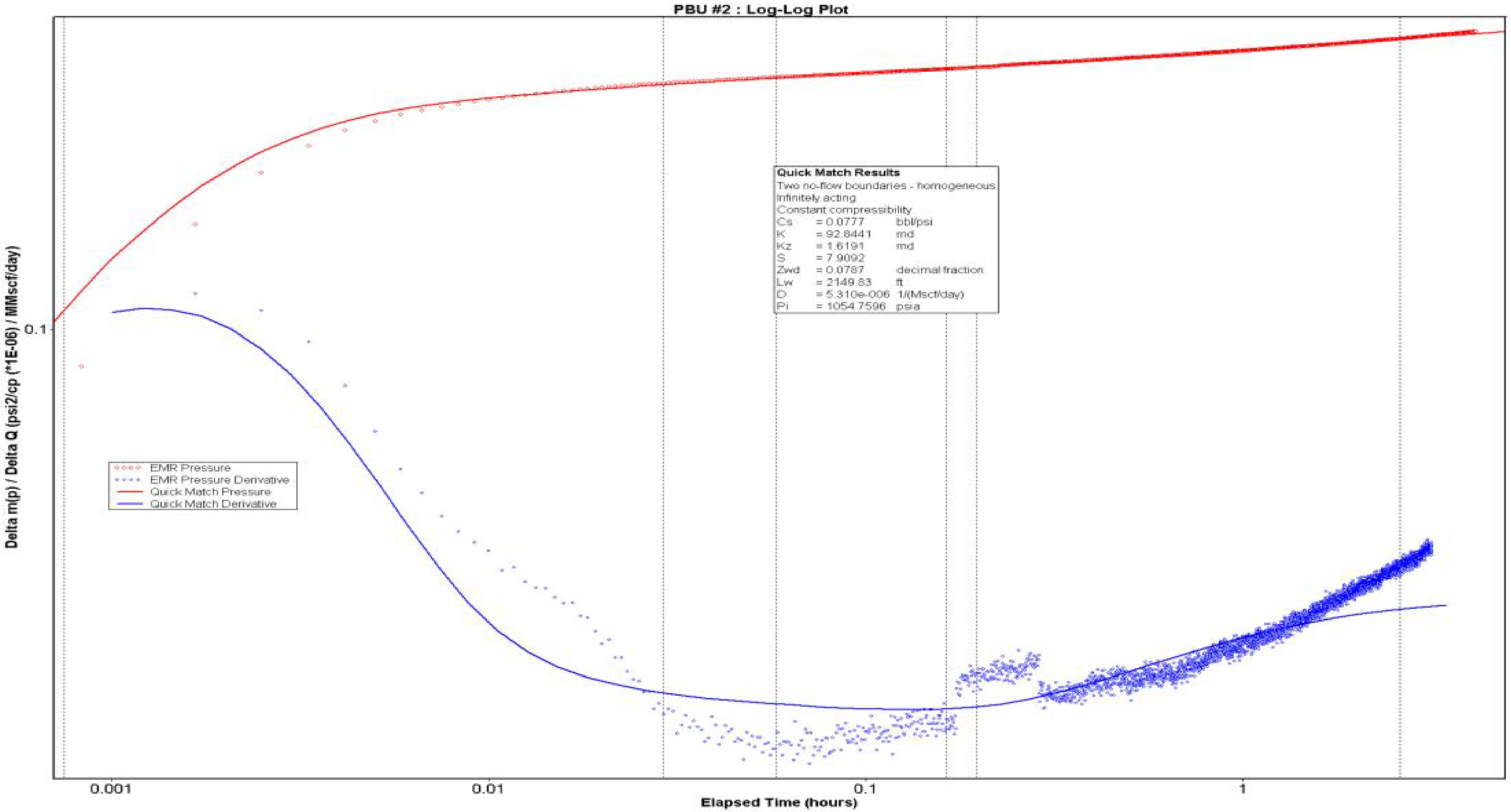


Figure 12

OMV Australia

PBU #3 : Log-Log Plot

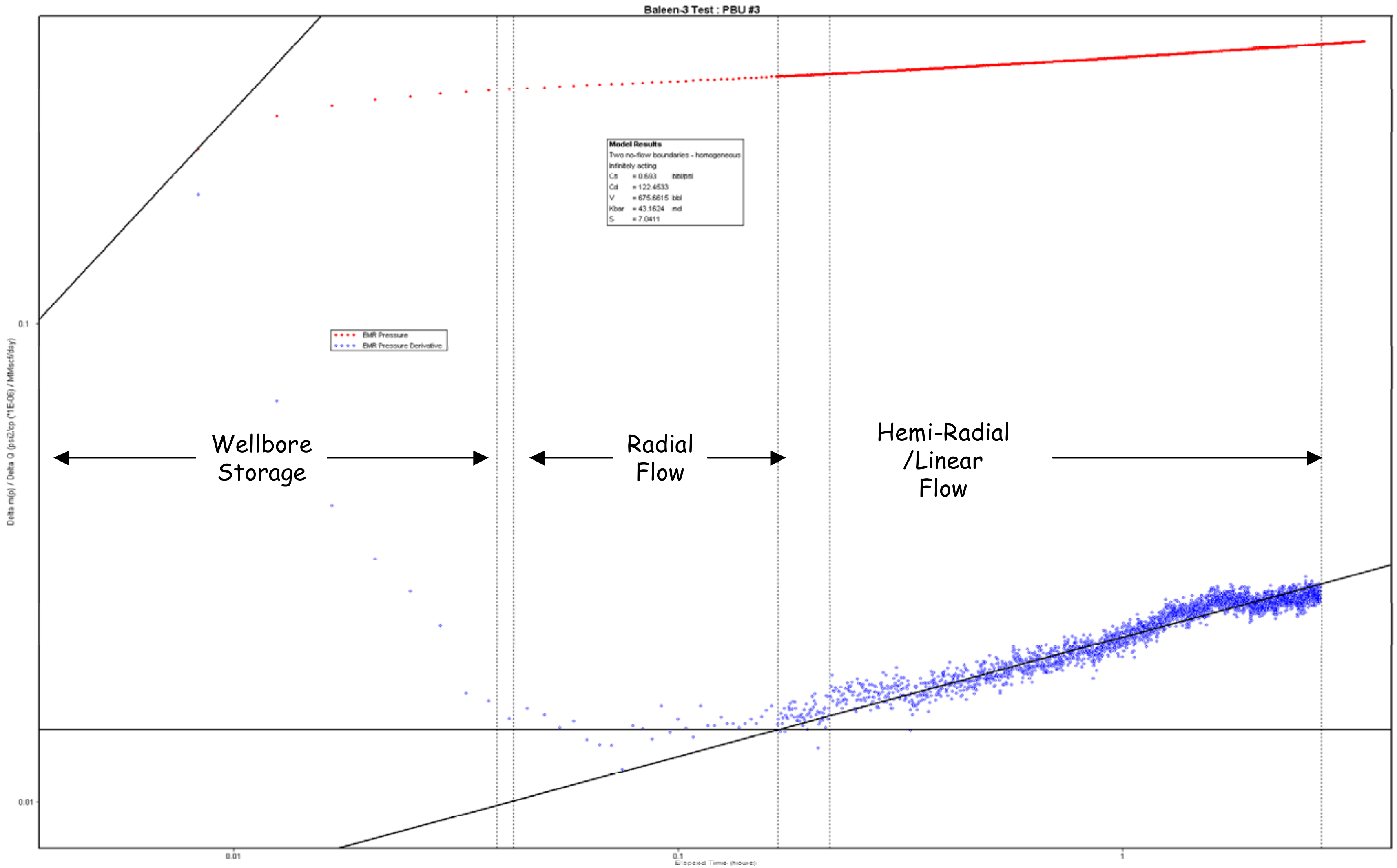


Figure 13

OMV Australia

PBU #3 : Radial Flow Plot

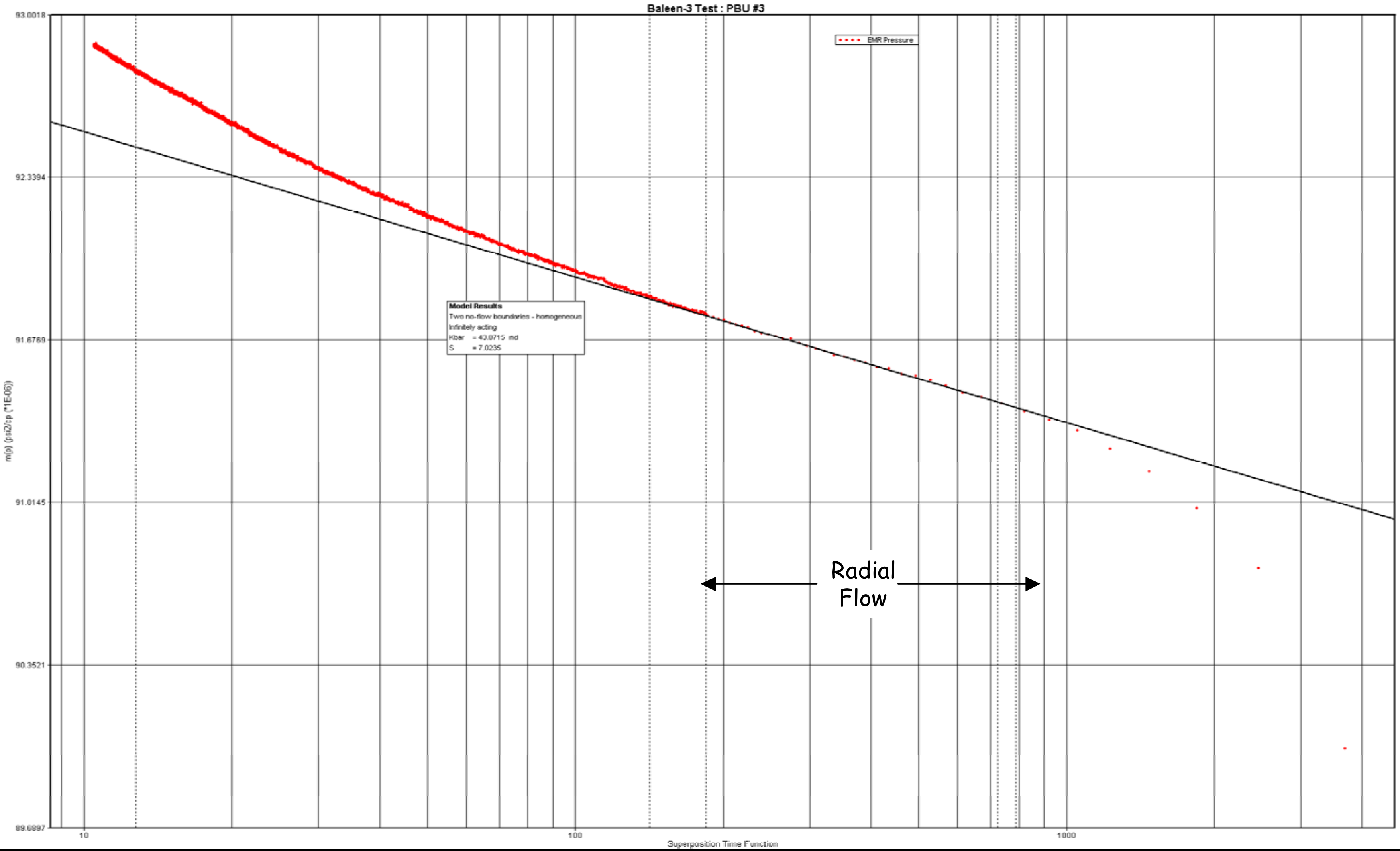


Figure 14

OMV Australia

PBU #3 : Pressure Match

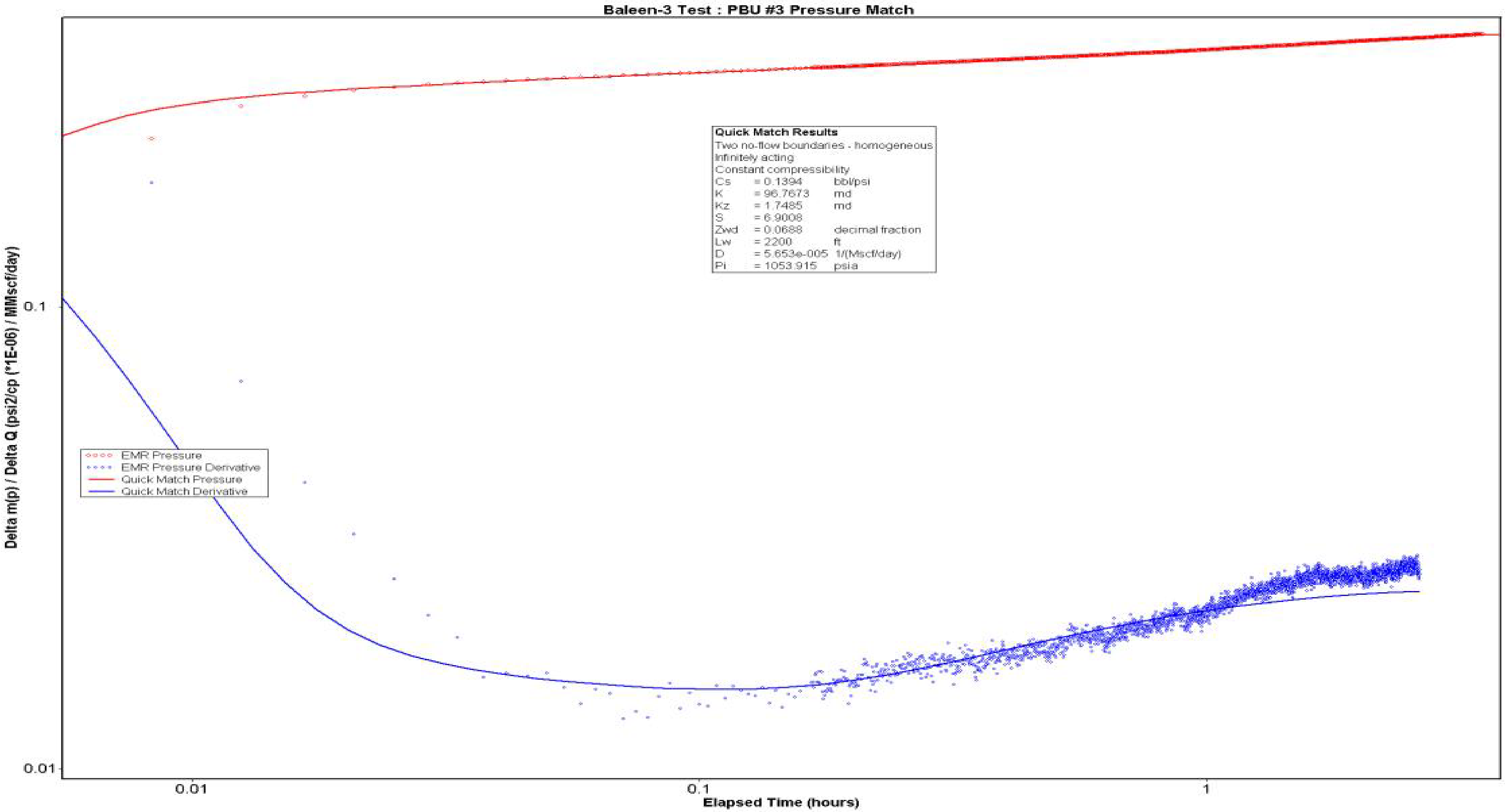


Figure 15

OMV Australia

Pressure Match : Interpretation #1

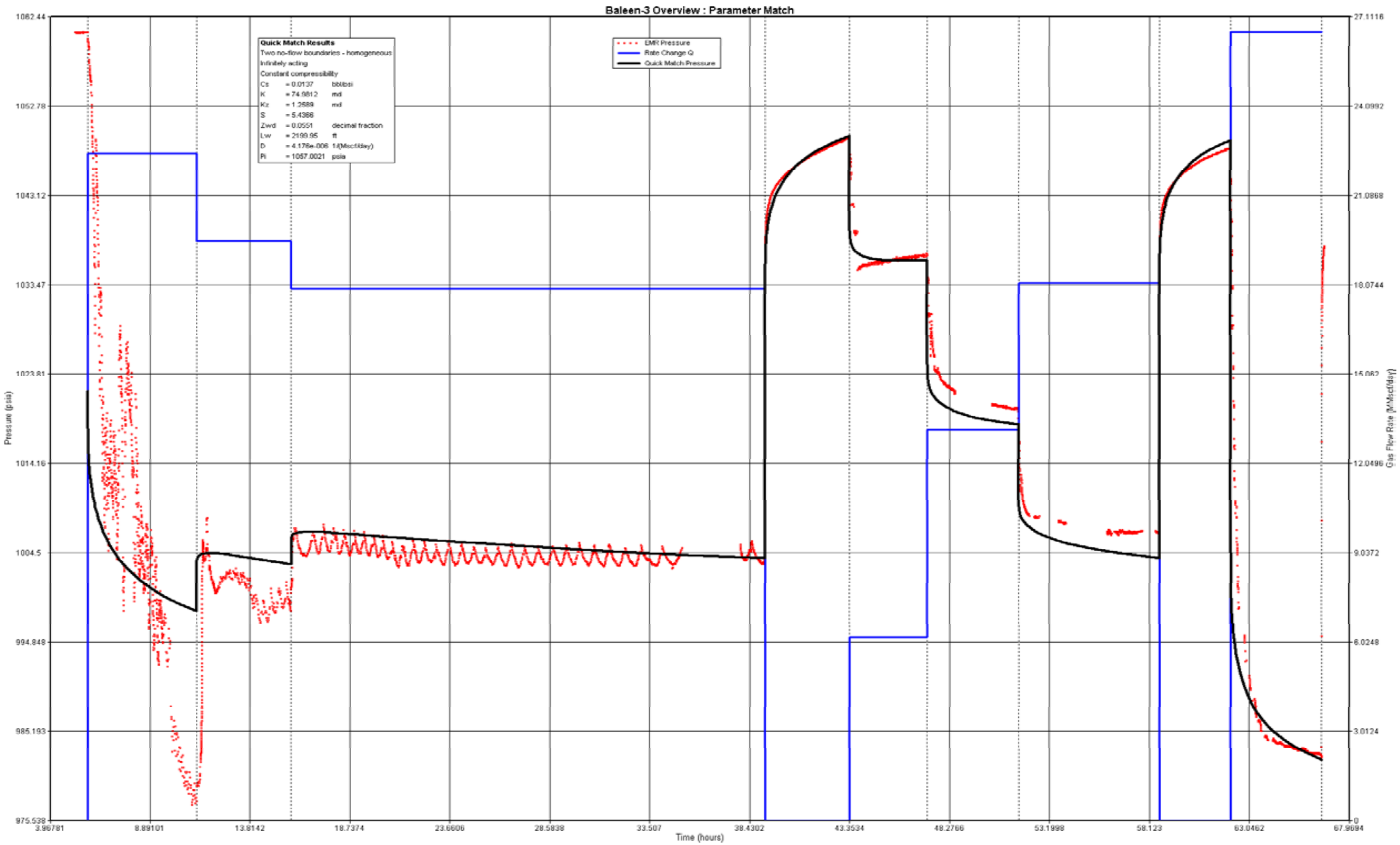


Figure 16

OMV Australia

Pressure Match : Interpretation #2

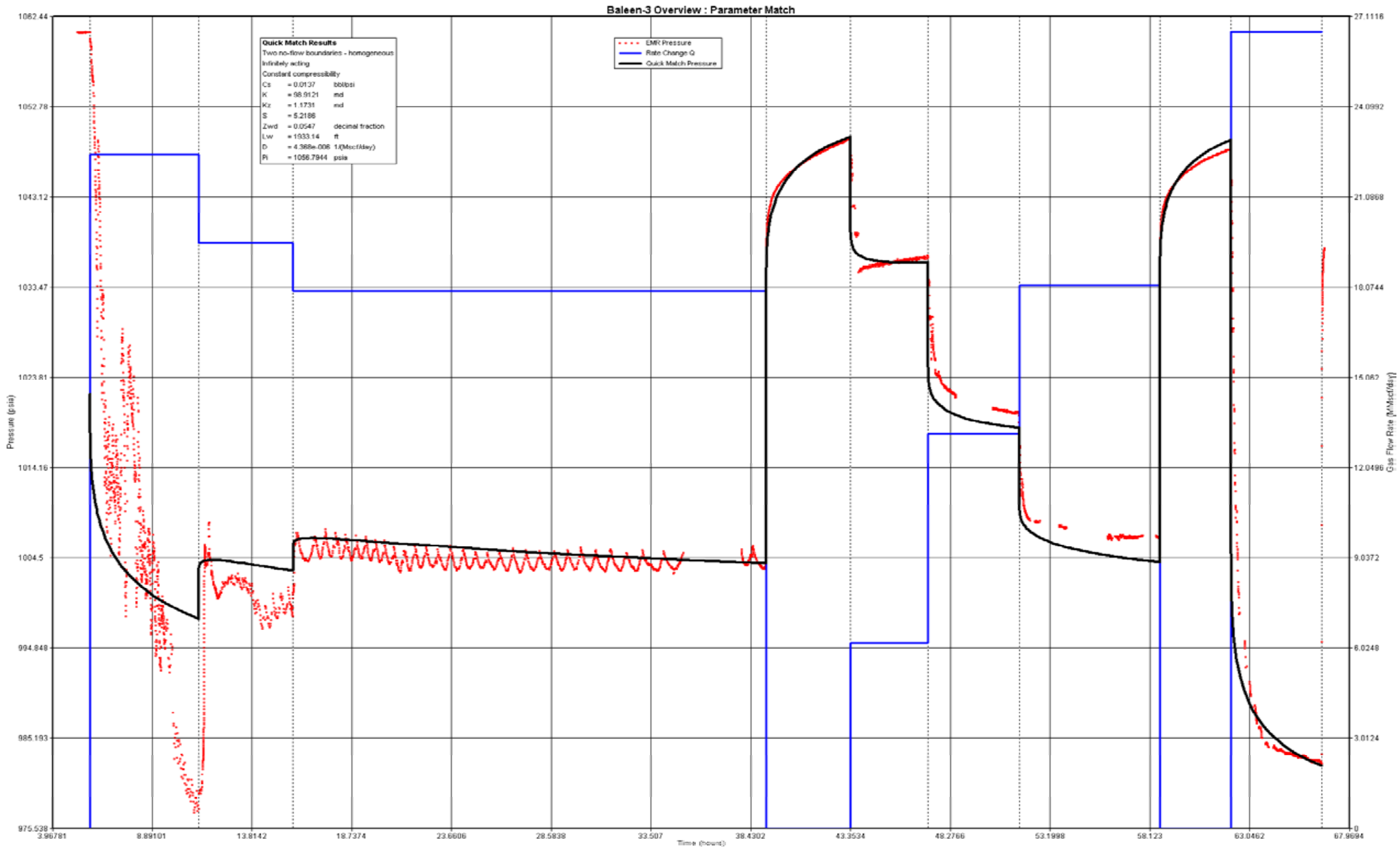


Figure 17

OMV Australia

Pressure Match : Interpretation #3

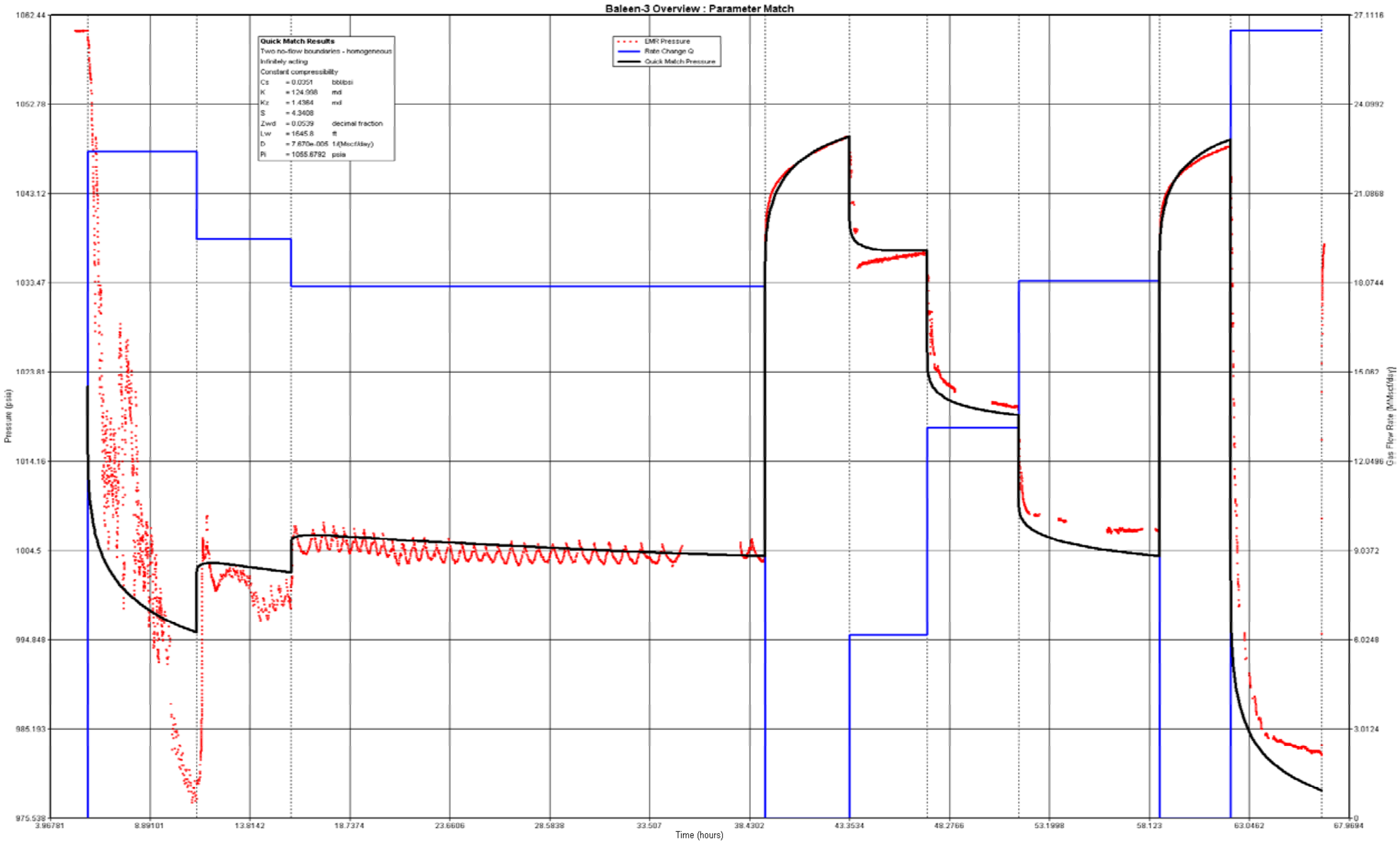


Figure 18

OMV Australia

Baleen-3 Flowing Gradient Survey : Overview

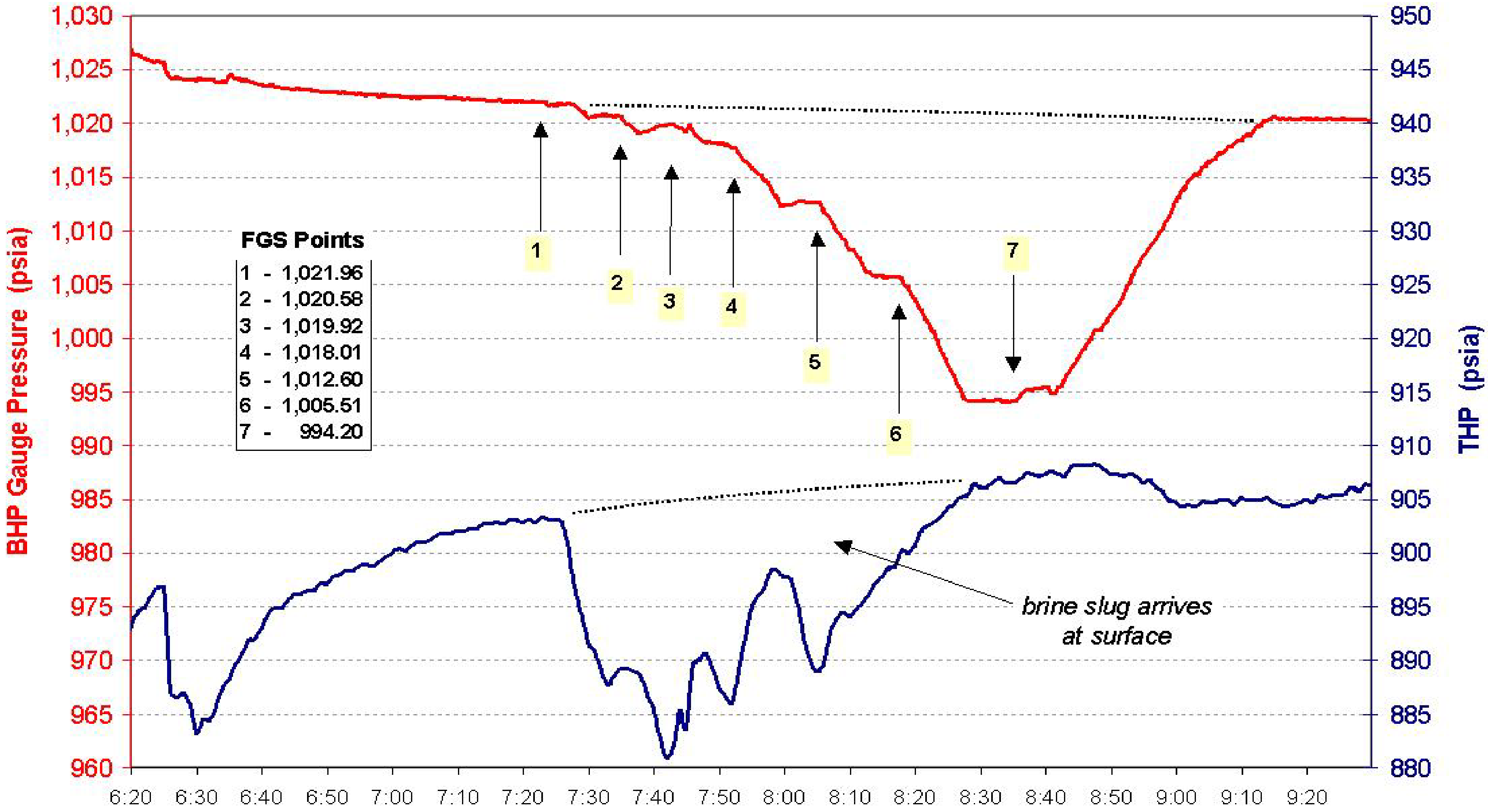


Figure 19

OMV Australia

Baleen-3 Flowing Gradient Survey : Gradient Plot

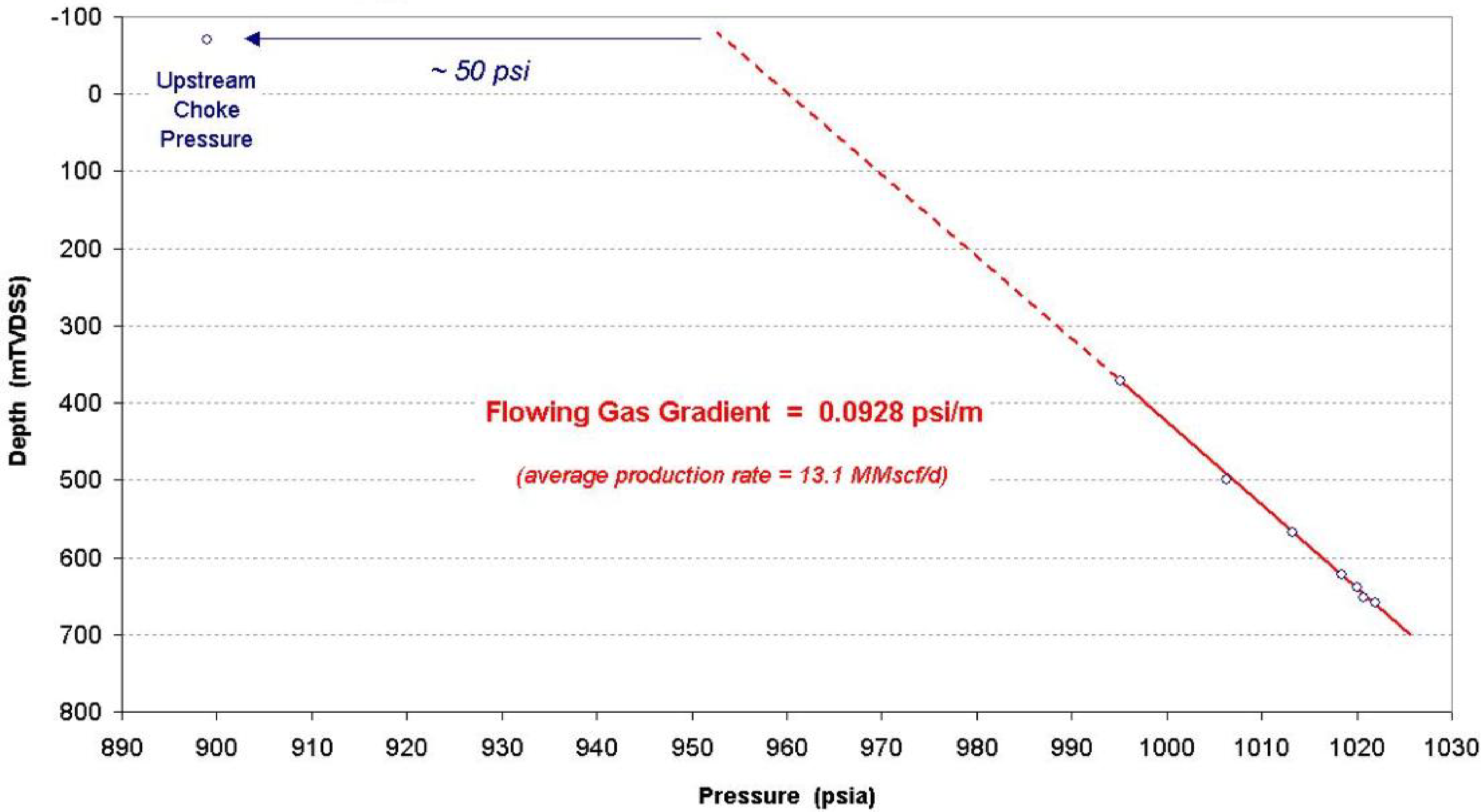


Figure 20

OMV Australia

Multi-Rate Flow Test : Cartesian Plot

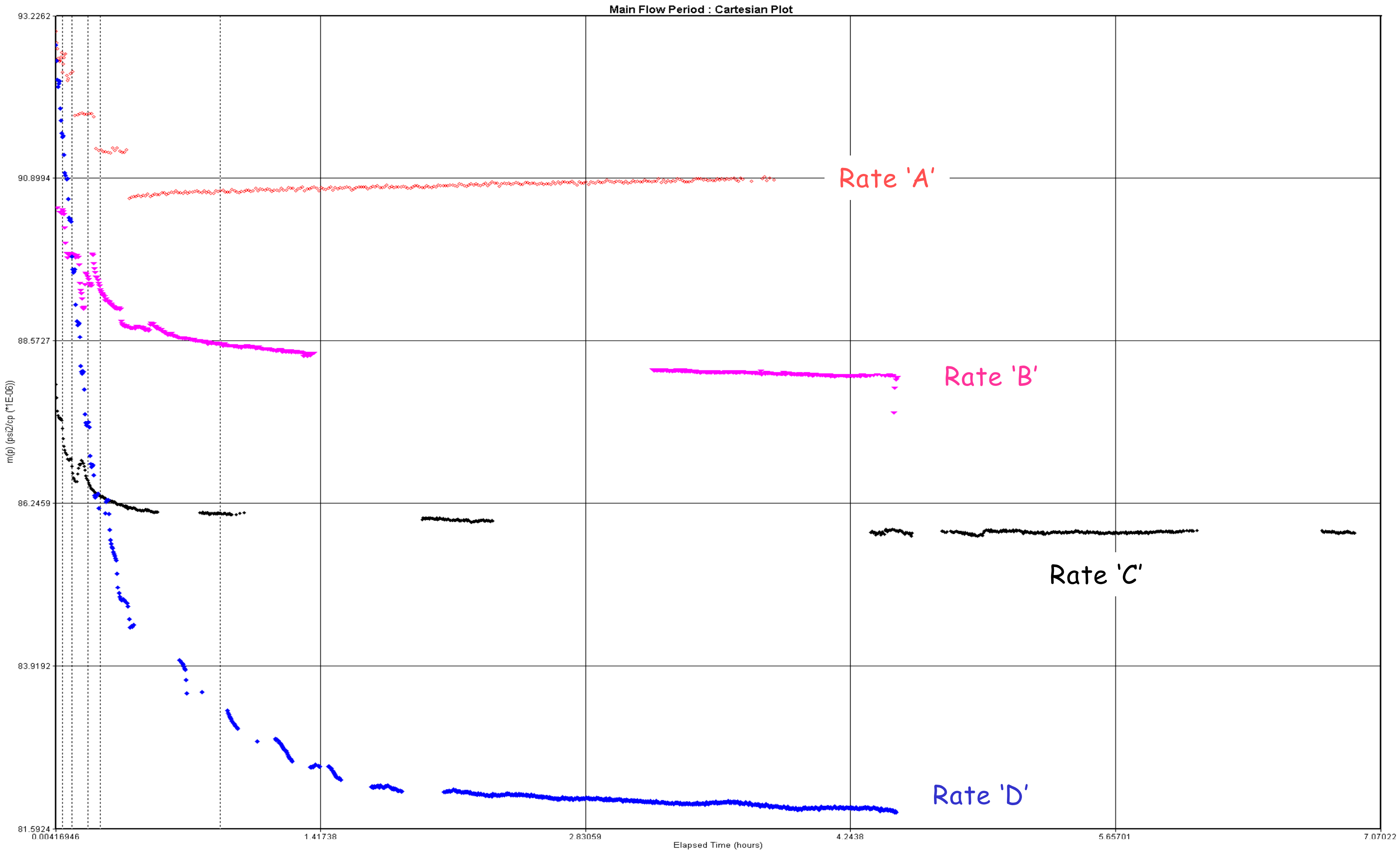


Figure 21

OMV Australia

Multi-Rate Flow : Radial Flow Plot

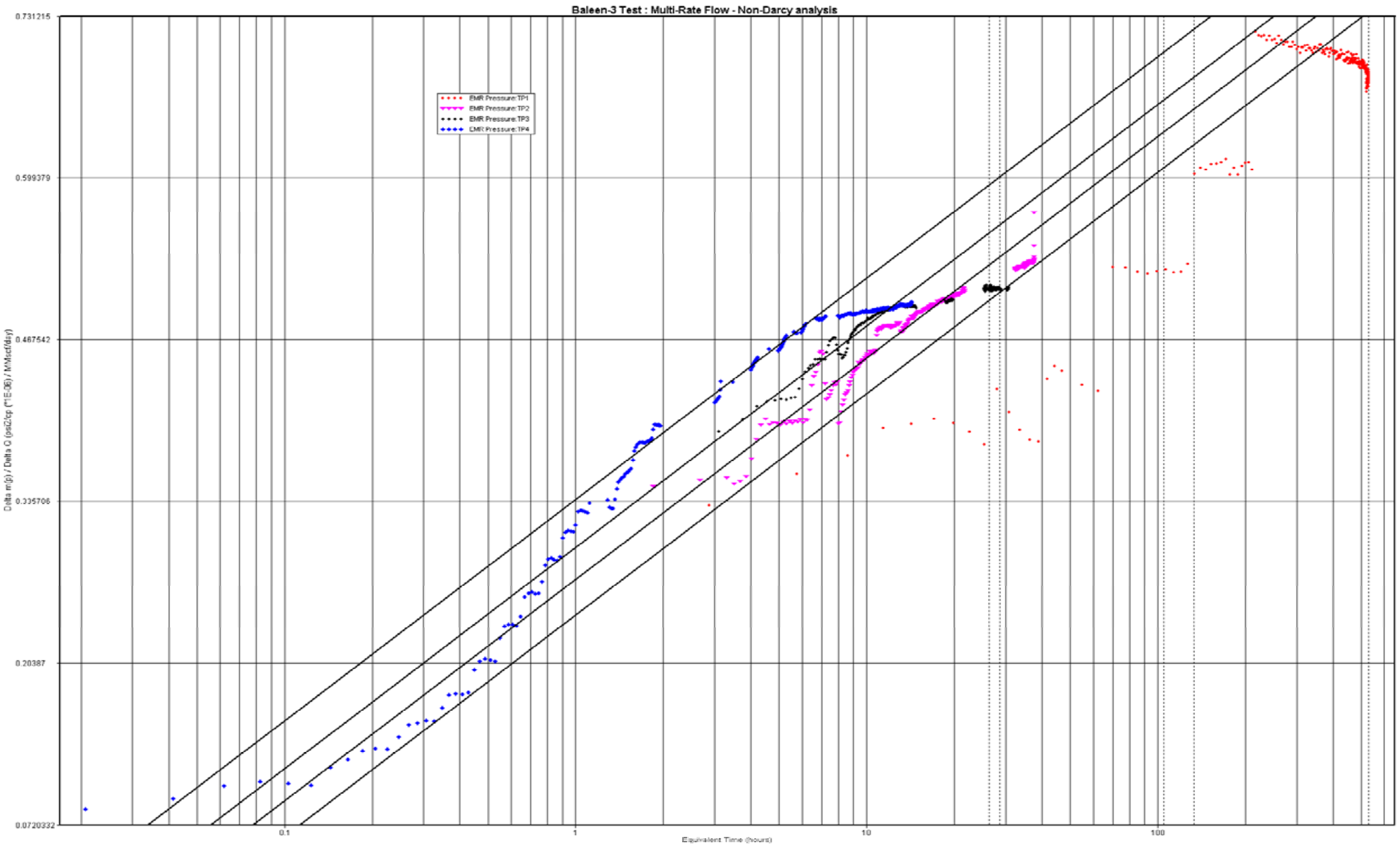


Figure 22

OMV Australia

Multi-Rate Flow : Skin Calculation

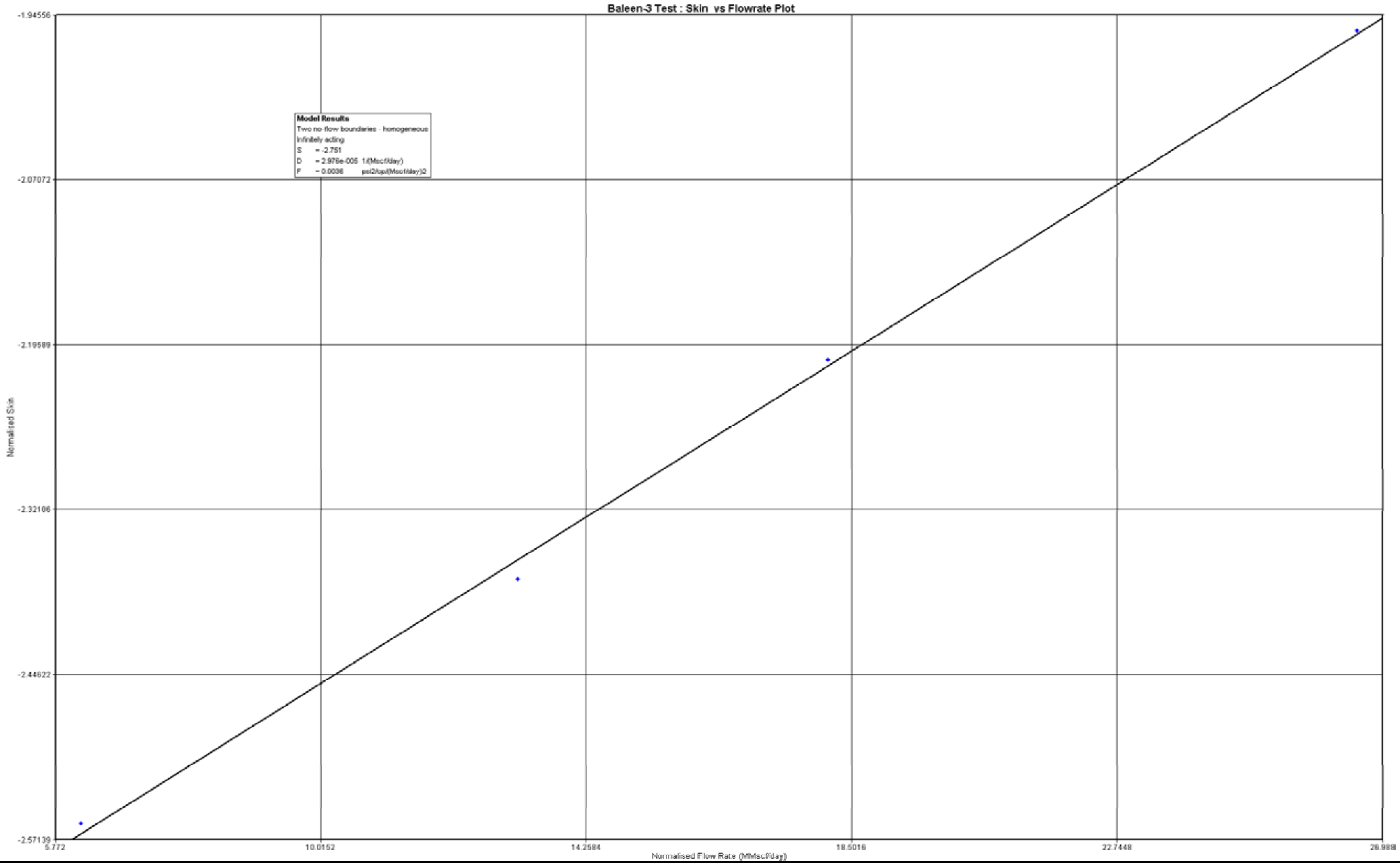


Figure 23

OMV Australia

Multi-Rate Flow : Radial Flow Plot (inc. non-Darcy Skin)

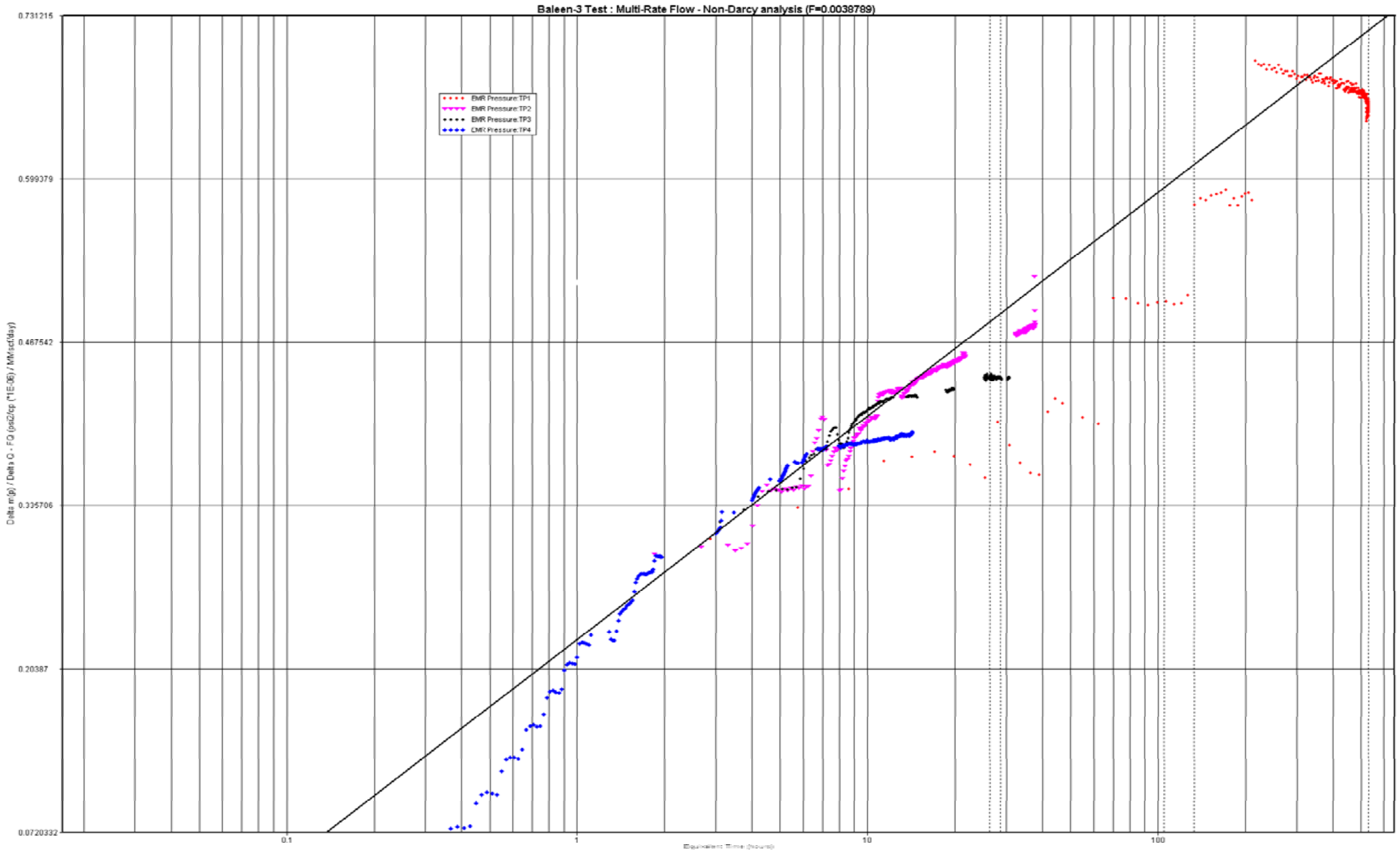


Figure 24

OMV Australia

Deliverability Analysis : LIT v. Transient

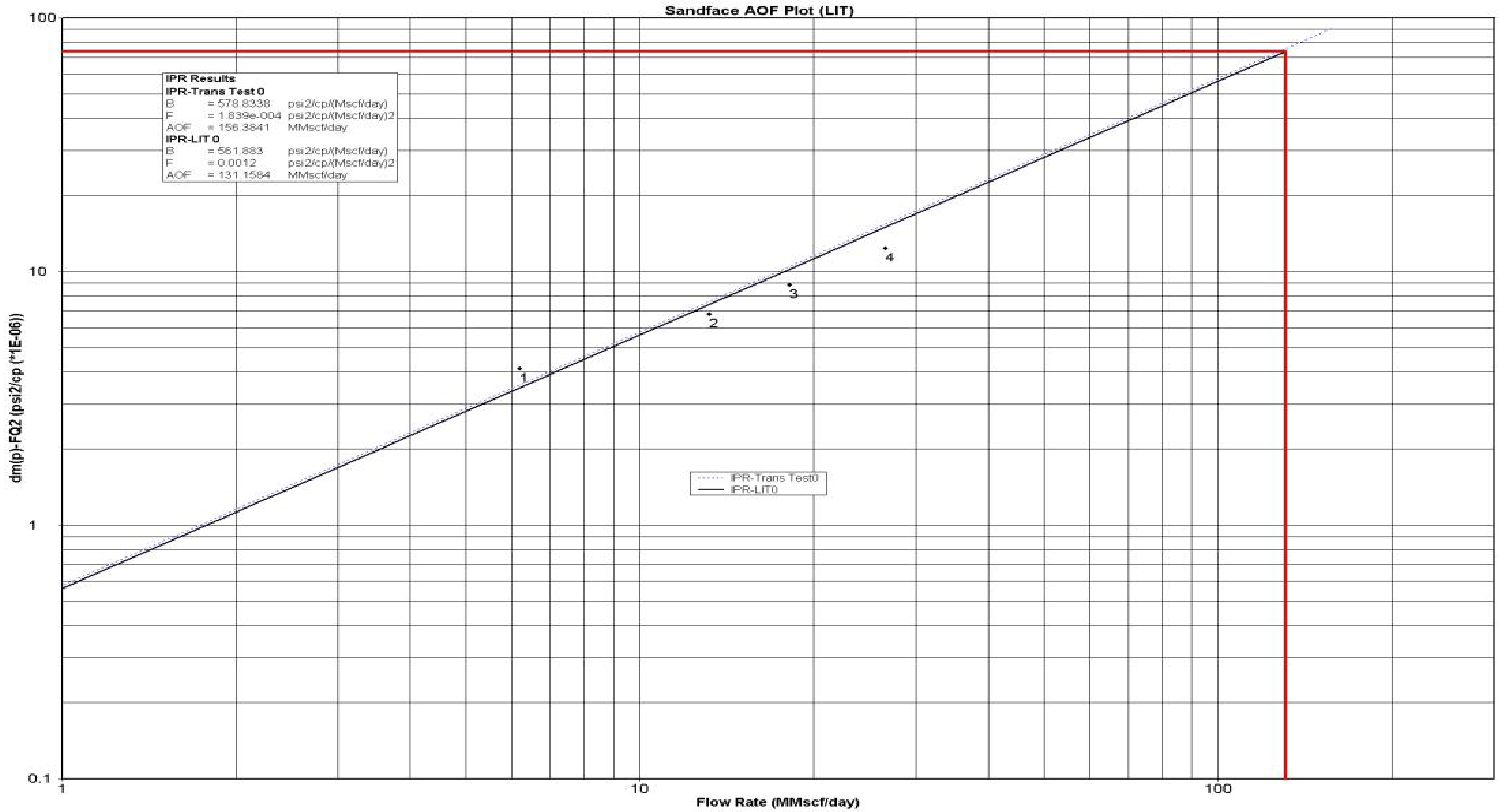


Figure 25

OMV Australia

Deliverability Analysis : LIT v. Transient

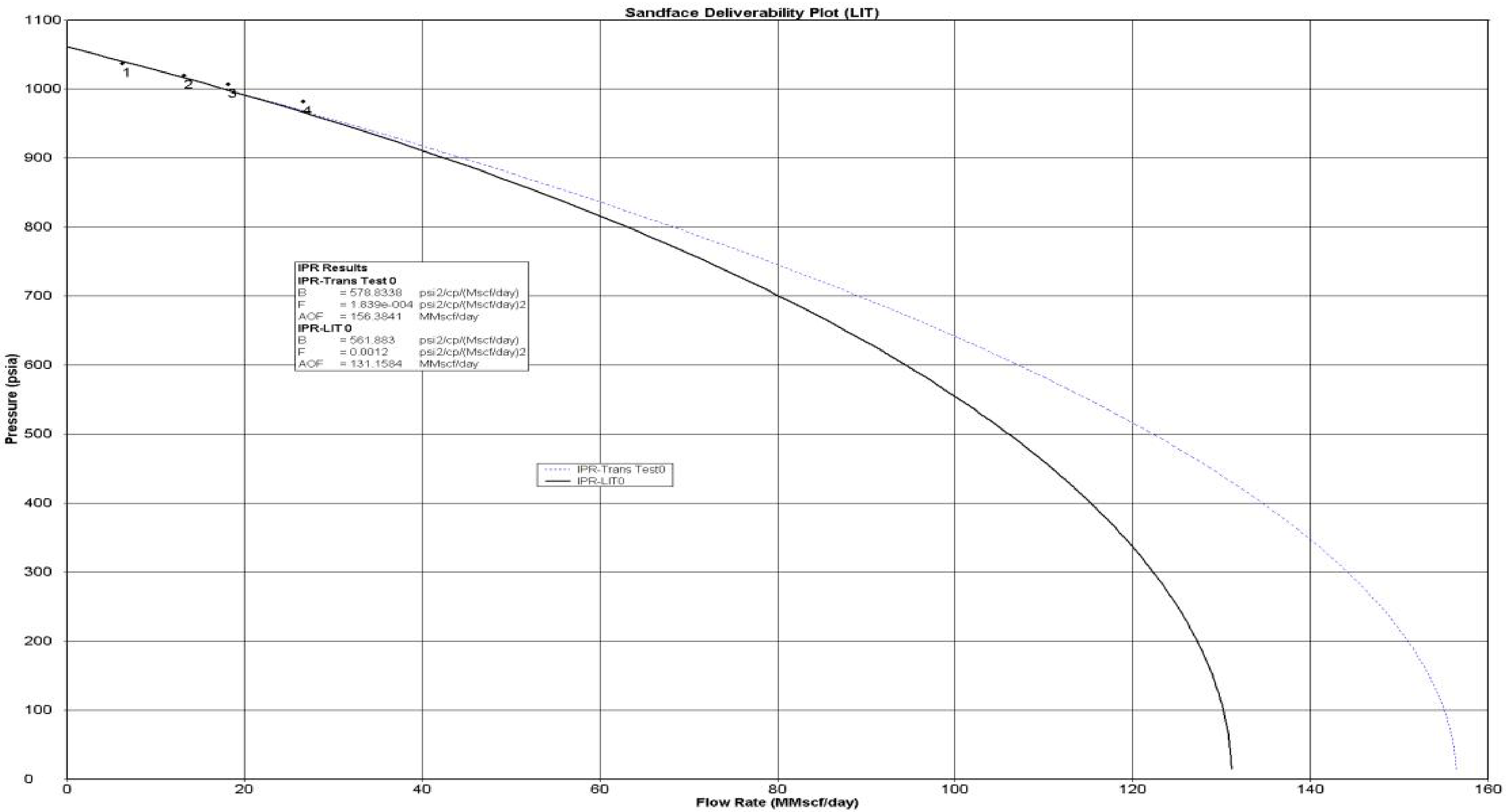


Figure 26

OMV Australia

Deliverability Analysis (C & n) : LIT v. Transient

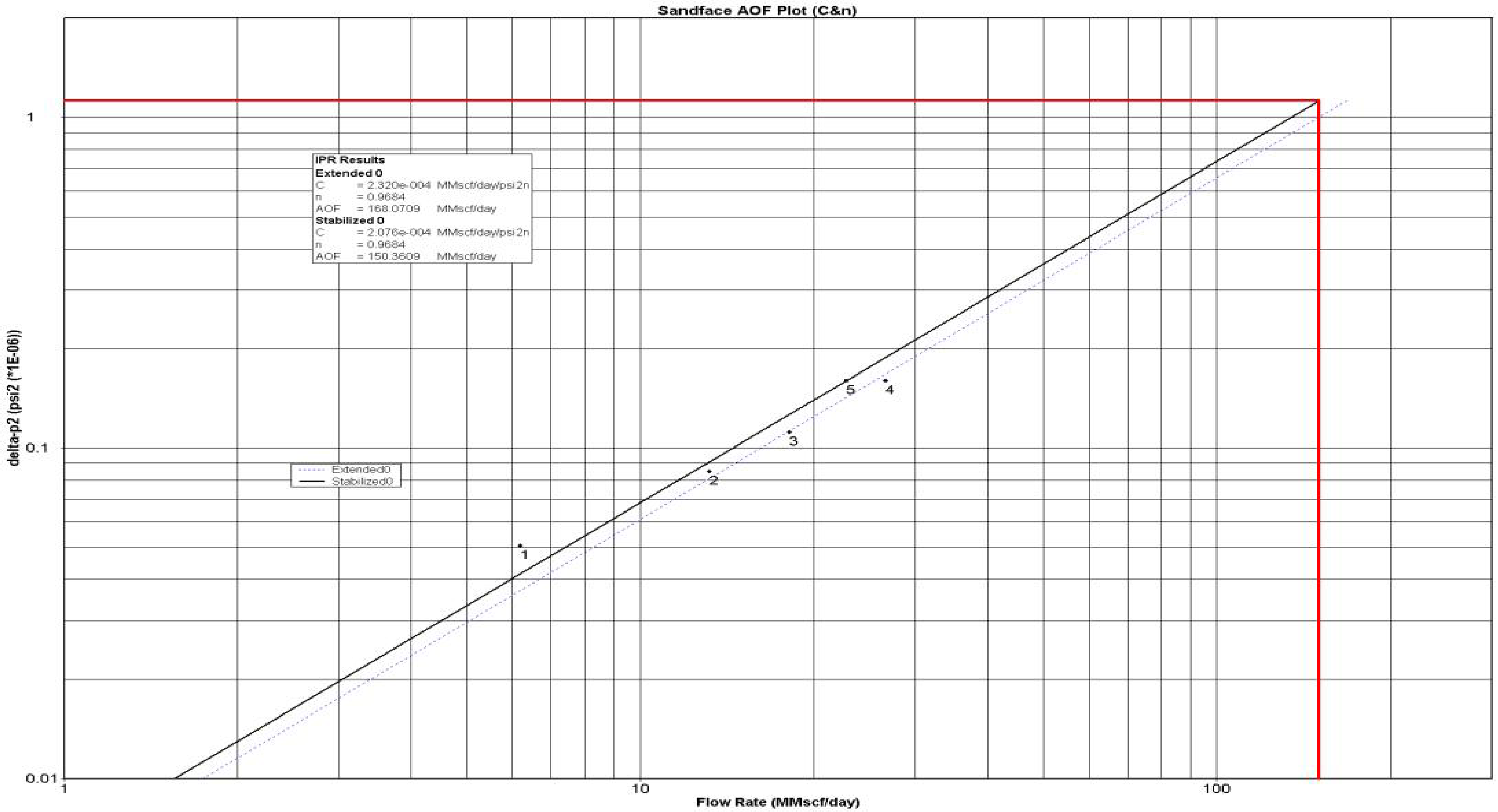


Figure 27

OMV Australia

Deliverability Analysis (C & n) : LIT v. Transient

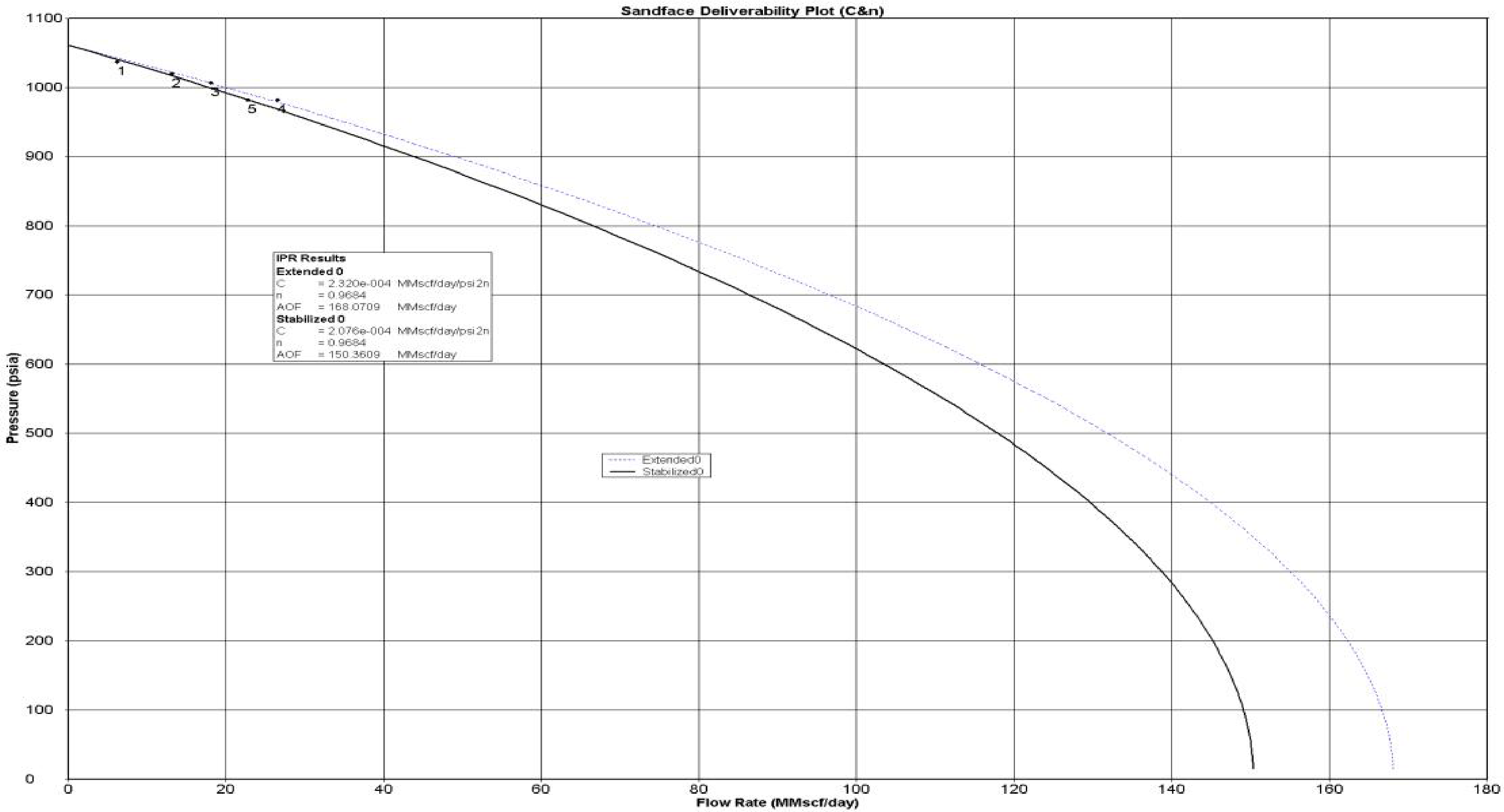


Figure 28

OMV Australia

IPR/VLP Analysis

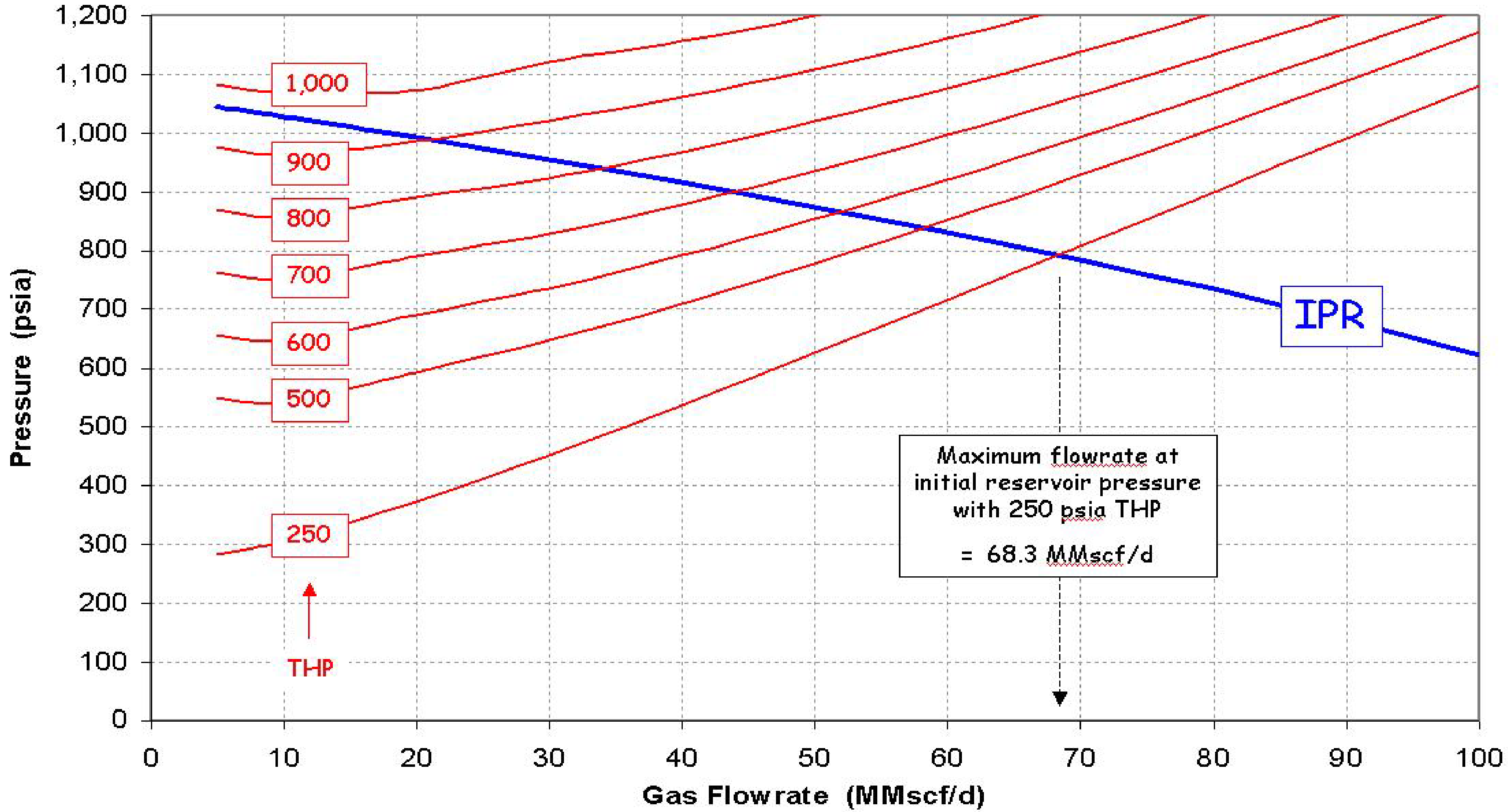


Figure 29

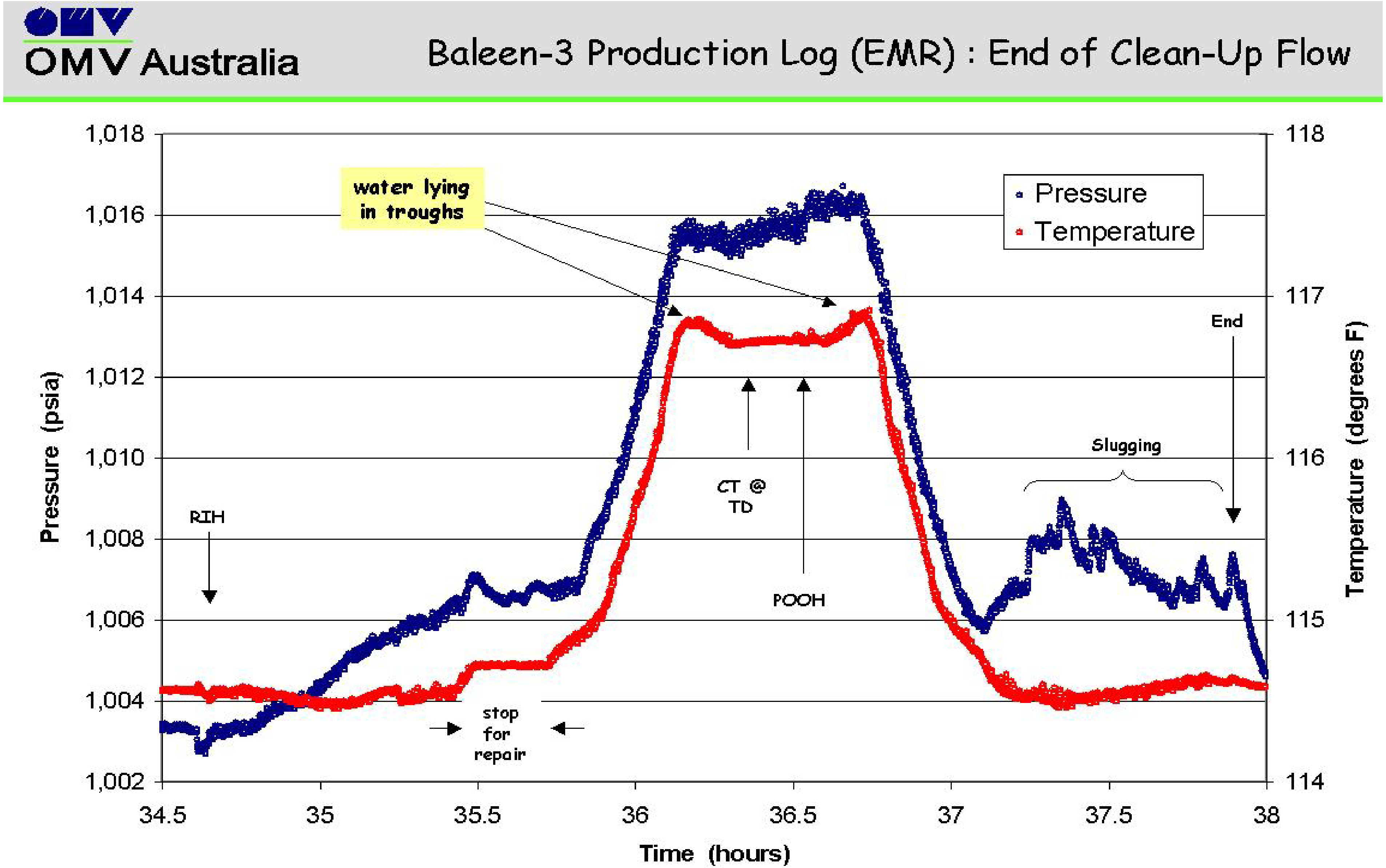

OMV Australia
Baleen-3 Production Log (EMR) : End of Clean-Up Flow
Pressure
Temperature
water lying in troughs
RIH
stop for repair
CT @ TD
POOH
Slugging
End
Pressure (psia)
Temperature (degrees F)
Time (hours)
1,018
1,016
1,014
1,012
1,010
1,008
1,006
1,004
1,002
118
117
116
115
114
34.5
35
35.5
36
36.5
37
37.5
38

Figure 30

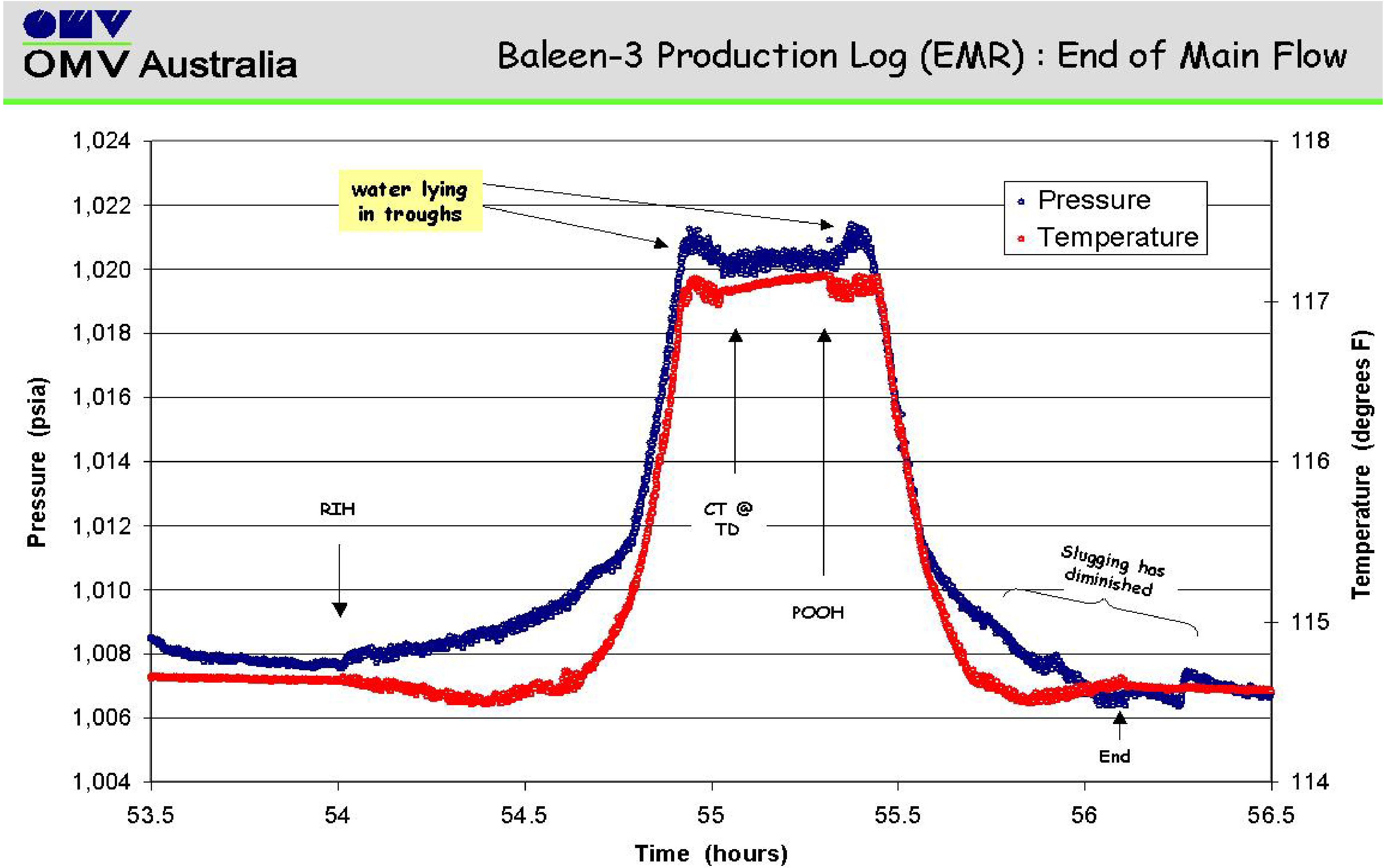

OMV Australia
Baleen-3 Production Log (EMR) : End of Main Flow
water lying in troughs
Pressure
Temperature
RIH
CT @ TD
POOH
Slugging has diminished
End
Pressure (psia)
Temperature (degrees F)
Time (hours)
1,024
1,022
1,020
1,018
1,016
1,014
1,012
1,010
1,008
1,006
1,004
118
117
116
115
114
53.5
54
54.5
55
55.5
56
56.5

Figure 31

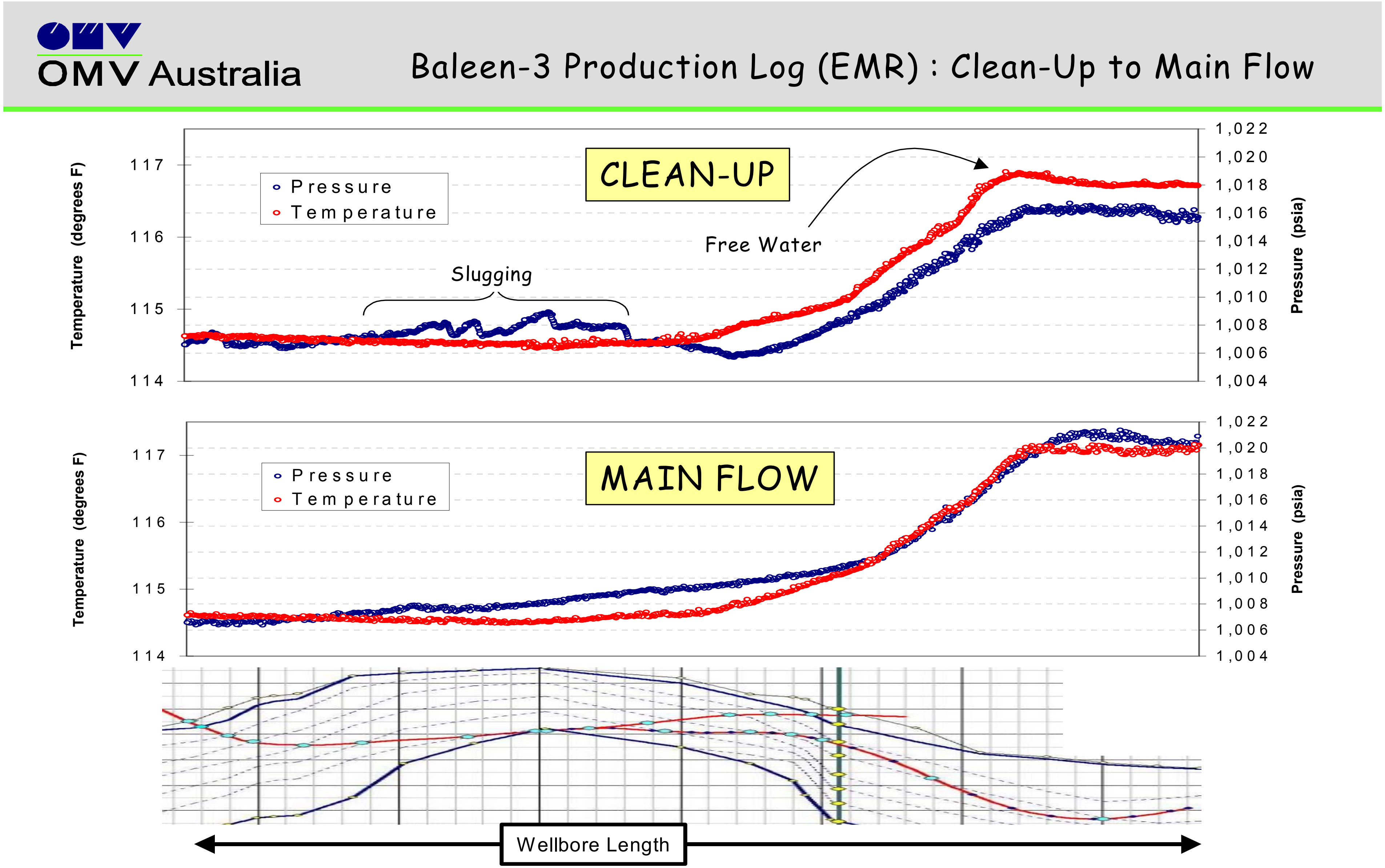

OMV Australia
Baleen-3 Production Log (EMR) : Clean-Up to Main Flow
CLEAN-UP
Pressure
Temperature
Slugging
Free Water
Temperature (degrees F)
Pressure (psia)
117
116
115
114
1,022
1,020
1,018
1,016
1,014
1,012
1,010
1,008
1,006
1,004
MAIN FLOW
Pressure
Temperature
Wellbore Length

Figure 32

APPENDIX A

Expro Surface Test Data

BALEEN-3 PRODUCTION TEST
Expro Surface Data
Sequence of Events (abbreviated)

Date	Time	Choke (/64)	UcP (psia)	DcP (psia)	UcT (F)	SepP (psig)	SepT (F)	Qgas (MMscfd)	GasCum (MMscf)	Qw (bpd)	WtrCum (bbls)
10-Jun-02	21:13	Opened well to tank on 96/64"adjustable choke.									
10-Jun-02	21:15	96	6.67	5.50	61.66	2.37	60.90	0.00	0.00	0.00	0.00
10-Jun-02	21:20	Coil tubing commenced RIH with gauge toolstring @5m/minute.									
10-Jun-02	21:20	96	6.67	5.13	61.34	2.12	60.81	0.00	0.00	0.00	0.00
10-Jun-02	21:25	96	6.67	4.64	61.23	2.12	60.78	0.00	0.00	0.00	0.00
10-Jun-02	21:30	96	6.47	4.45	61.09	2.31	60.78	0.00	0.00	0.00	0.00
10-Jun-02	21:35	96	6.67	4.64	60.98	2.00	60.78	0.00	0.00	0.00	0.00
10-Jun-02	21:40	96	6.47	4.64	60.87	2.37	60.72	0.00	0.00	0.00	0.00
10-Jun-02	21:45	96	6.26	4.70	60.76	2.37	60.70	0.00	0.00	0.00	0.00
10-Jun-02	21:50	96	6.47	4.03	60.69	2.37	60.71	0.00	0.00	0.00	0.00
10-Jun-02	21:51	Coil tubing @200m, preparing to pump N2.									
10-Jun-02	21:55	96	5.85	4.45	60.61	2.31	60.70	0.00	0.00	0.00	0.00
10-Jun-02	21:56	Coil tubing commenced pumping N2 @ 400 scf/m.									
10-Jun-02	22:00	96	6.26	4.33	60.53	2.37	60.63	0.00	0.00	0.00	0.00
10-Jun-02	22:04	Return rate at surge tank = 8208 bbl/d.									
10-Jun-02	22:05	Return rate at surge tank = 11952 bbl/d.									
10-Jun-02	22:05	Coil tubing continued RIH with gauge toolstring @5m/minute.									
10-Jun-02	22:05	96	95.80	62.90	61.53	2.31	60.60	0.00	0.00	0.00	0.00
10-Jun-02	22:06	Return rate at surge tank = 3312 bbl/d.									
10-Jun-02	22:07	Return rate at surge tank = 4176 bbl/d.									
10-Jun-02	22:08	Return rate at surge tank = 2304 bbl/d.									
10-Jun-02	22:09	Return rate at surge tank = 7920 bbl/d.									
10-Jun-02	22:10	Coil tubing stopped pumping N2.									
10-Jun-02	22:10	Coil tubing stopped RIH @283mRT.									
10-Jun-02	22:10	Shut in well at choke manifold.									
10-Jun-02	22:10	SG of displaced gas = 0.97, N2 SG=0.967.									
10-Jun-02	22:10	Return rate at surge tank = 720 bbl/d.									
10-Jun-02	22:10	0	122.59	91.11	66.24	2.68	60.50	0.00	0.00	0.00	0.00
10-Jun-02	22:15	0	230.52	5.93	67.40	2.37	60.50	0.00	0.00	0.00	0.00
10-Jun-02	22:20	0	245.04	4.39	66.07	2.31	60.48	0.00	0.00	0.00	0.00
10-Jun-02	22:21	Coil tubing continued RIH with gauge toolstring @5m/minute.									
10-Jun-02	22:24	Opened well to tank on 16/64"adjustable choke.									
10-Jun-02	22:24	Return rate at surge tank = 2736 bbl/d.									
10-Jun-02	22:25	Return rate at surge tank = 1296 bbl/d.									
10-Jun-02	22:25	16	245.45	10.89	65.05	2.31	60.37	0.00	0.00	0.00	0.00
10-Jun-02	22:26	Return rate at surge tank = 2160 bbl/d.									
10-Jun-02	22:27	Return rate at surge tank = 1728 bbl/d.									
10-Jun-02	22:28	Return rate at surge tank = 864 bbl/d.									
10-Jun-02	22:30	Increase choke to 72/64" adjustable.									
10-Jun-02	22:30	72	3.60	1.26	62.66	2.31	60.36	0.00	0.00	0.00	0.00
10-Jun-02	22:31	Increase choke to 84/64" adjustable.									
10-Jun-02	22:32	Coil tubing @300mRT.									
10-Jun-02	22:34	Return rate at surge tank = 7344 bbl/d.									
10-Jun-02	22:35	Return rate at surge tank = 9369 bbl/d.									
10-Jun-02	22:35	84	80.47	49.41	69.49	2.00	60.29	0.00	0.00	0.00	0.00
10-Jun-02	22:36	Return rate at surge tank = 6624 bbl/d.									
10-Jun-02	22:37	Return rate at surge tank = 4464 bbl/d.									
10-Jun-02	22:38	Coil tubing @320mRT. Stopped pumping N2.									
10-Jun-02	22:39	Return rate at surge tank = 3312 bbl/d.									
10-Jun-02	22:40	Return rate at surge tank = 4752 bbl/d.									
10-Jun-02	22:40	84	110.93	76.15	74.07	2.12	60.23	0.00	0.00	0.00	0.00
10-Jun-02	22:41	Return rate at surge tank = 1728 bbl/d.									
10-Jun-02	22:42	Coil tubing @350mRT.									
10-Jun-02	22:44	Shut in well at choke manifold. Total returns = 65.1 bbls.									
10-Jun-02	22:45	0	75.57	3.96	75.34	2.06	60.25	0.00	0.00	0.00	0.00
10-Jun-02	22:48	Coil tubing @400mRT.									
10-Jun-02	22:50	0	82.92	3.78	74.58	2.00	60.20	0.00	0.00	0.00	0.00
10-Jun-02	22:55	0	85.99	3.72	73.12	2.12	60.18	0.00	0.00	0.00	0.00
10-Jun-02	22:58	Coil tubing @500mRT.									
10-Jun-02	23:00	0	87.42	3.78	71.77	2.19	60.21	0.00	0.00	0.00	0.00
10-Jun-02	23:05	0	89.47	4.39	70.28	2.19	60.31	0.00	0.00	0.00	0.00
10-Jun-02	23:10	0	88.44	4.03	69.31	2.37	60.23	0.00	0.00	0.00	0.00
10-Jun-02	23:15	0	88.03	3.90	68.24	2.61	60.28	0.00	0.00	0.00	0.00
10-Jun-02	23:17	Coil tubing @624mRT.									
10-Jun-02	23:20	0	3.40	0.35	66.57	2.31	60.23	0.00	0.00	0.00	0.00
10-Jun-02	23:25	0	5.03	0.41	66.55	2.19	60.22	0.00	0.00	0.00	0.00
10-Jun-02	23:30	0	5.65	0.47	66.11	2.43	60.22	0.00	0.00	0.00	0.00
10-Jun-02	23:35	0	5.65	0.53	65.62	2.25	60.21	0.00	0.00	0.00	0.00
10-Jun-02	23:40	0	5.65	0.65	64.99	2.31	60.20	0.00	0.00	0.00	0.00

10-Jun-02 23:45	0	5.44	0.35	64.46	2.31	60.18	0.00	0.00	0.00	0.00
10-Jun-02 23:50	0	5.44	0.41	63.92	2.12	60.17	0.00	0.00	0.00	0.00
10-Jun-02 23:55	0	5.44	0.65	63.43	2.00	60.18	0.00	0.00	0.00	0.00
11-Jun-02 0:00	0	5.03	0.35	62.99	2.31	60.17	0.00	0.00	0.00	0.00
11-Jun-02 0:05	0	5.24	0.65	62.61	2.37	60.13	0.00	0.00	0.00	0.00
11-Jun-02 0:10	0	5.44	0.35	62.24	2.61	60.13	0.00	0.00	0.00	0.00
11-Jun-02 0:15	Coil tubing @902mRT waiting to pump N2.									
11-Jun-02 0:15	0	5.24	0.65	61.93	2.31	60.10	0.00	0.00	0.00	0.00
11-Jun-02 0:20	0	4.83	0.35	61.66	2.37	60.04	0.00	0.00	0.00	0.00
11-Jun-02 0:25	0	4.62	0.35	61.32	2.31	60.04	0.00	0.00	0.00	0.00
11-Jun-02 0:30	0	5.24	0.65	61.14	2.31	60.01	0.00	0.00	0.00	0.00
11-Jun-02 0:32	Opened well to tank on 128/64" adjustable choke.									
11-Jun-02 0:33	Coil tubing commenced pumping N2 @ 300scf/d.									
11-Jun-02 0:35	128	2.38	0.41	60.69	2.00	59.99	0.00	0.00	0.00	0.00
11-Jun-02 0:40	128	2.58	0.28	60.63	2.00	59.89	0.00	0.00	0.00	0.00
11-Jun-02 0:45	128	3.40	1.02	60.42	2.19	59.88	0.00	0.00	0.00	0.00
11-Jun-02 0:50	128	4.62	1.02	60.21	2.37	59.84	0.00	0.00	0.00	0.00
11-Jun-02 0:51	Return rate at surge tank = 6336 bbl/d.									
11-Jun-02 0:52	Return rate at surge tank = 8352bbl/d.									
11-Jun-02 0:53	Return rate at surge tank = 9216bbl/d.									
11-Jun-02 0:54	Return rate at surge tank = 12240bbl/d.									
11-Jun-02 0:55	Return rate at surge tank = 13248bbl/d.									
11-Jun-02 0:55	Decreased choke to 28/64" adjustable.									
11-Jun-02 0:55	28	190.66	131.04	81.77	2.25	59.82	0.00	0.00	0.00	0.00
11-Jun-02 0:56	Return rate at surge tank = 6480bbl/d.									
11-Jun-02 0:57	Return rate at surge tank = 3600bbl/d.									
11-Jun-02 0:58	Return rate at surge tank = 7056bbl/d.									
11-Jun-02 0:59	Return rate at surge tank = 9792bbl/d.									
11-Jun-02 0:59	Coil tubing stopped pumping N2.									
11-Jun-02 1:00	Return rate at surge tank = 4752bbl/d.									
11-Jun-02 1:00	28	695.19	247.32	88.36	2.31	59.80	0.00	0.00	0.00	0.00
11-Jun-02 1:01	Return rate at surge tank = 720bbl/d.									
11-Jun-02 1:01	Shut in well at choke manifold. Total returns = 121.7 bbls.									
11-Jun-02 1:05	0	833.59	3.04	84.53	2.00	59.78	0.00	0.00	0.00	0.00
11-Jun-02 1:10	0	864.67	2.98	81.91	2.37	59.77	0.00	0.00	0.00	0.00
11-Jun-02 1:15	0	878.57	3.53	78.79	2.06	59.75	0.00	0.00	0.00	0.00
11-Jun-02 1:20	0	887.57	3.72	76.08	2.31	59.75	0.00	0.00	0.00	0.00
11-Jun-02 1:25	0	890.02	3.35	73.79	2.31	59.77	0.00	0.00	0.00	0.00
11-Jun-02 1:30	0	888.58	3.72	71.74	2.37	59.72	0.00	0.00	0.00	0.00
11-Jun-02 1:35	0	888.58	3.41	70.13	2.19	59.69	0.00	0.00	0.00	0.00
11-Jun-02 1:40	0	888.38	3.41	68.78	2.37	59.68	0.00	0.00	0.00	0.00
11-Jun-02 1:45	0	888.79	3.66	67.43	2.31	59.66	0.00	0.00	0.00	0.00
11-Jun-02 1:50	0	887.77	3.17	66.22	2.37	59.59	0.00	0.00	0.00	0.00
11-Jun-02 1:55	0	887.77	2.98	65.10	2.00	59.61	0.00	0.00	0.00	0.00
11-Jun-02 2:00	0	887.77	2.98	64.19	2.31	59.58	0.00	0.00	0.00	0.00
11-Jun-02 2:05	0	887.57	3.23	63.47	2.31	59.56	0.00	0.00	0.00	0.00
11-Jun-02 2:10	0	887.36	3.41	62.83	2.31	59.55	0.00	0.00	0.00	0.00
11-Jun-02 2:15	0	887.36	2.98	62.29	2.12	59.53	0.00	0.00	0.00	0.00
11-Jun-02 2:20	0	887.36	3.41	61.90	2.12	59.58	0.00	0.00	0.00	0.00
11-Jun-02 2:25	0	887.16	3.35	61.52	2.06	59.51	0.00	0.00	0.00	0.00
11-Jun-02 2:30	0	887.16	3.41	61.21	2.00	59.46	0.00	0.00	0.00	0.00
11-Jun-02 2:35	0	887.36	3.41	60.91	2.06	59.57	0.00	0.00	0.00	0.00
11-Jun-02 2:40	0	887.36	3.29	60.66	2.25	59.52	0.00	0.00	0.00	0.00
11-Jun-02 2:45	0	887.16	3.35	60.49	2.12	59.48	0.00	0.00	0.00	0.00
11-Jun-02 2:50	0	887.36	3.41	60.31	2.31	59.50	0.00	0.00	0.00	0.00
11-Jun-02 2:55	0	887.36	3.47	60.18	2.31	59.52	0.00	0.00	0.00	0.00
11-Jun-02 3:00	Coil tubing commenced POOH to repair SRO gauges.									
11-Jun-02 3:00	0	887.16	3.41	59.98	2.06	59.48	0.00	0.00	0.00	0.00
11-Jun-02 3:05	0	887.16	3.41	59.80	2.06	59.47	0.00	0.00	0.00	0.00
11-Jun-02 3:10	0	888.79	3.53	59.67	2.31	59.40	0.00	0.00	0.00	0.00
11-Jun-02 3:15	0	894.31	3.41	59.59	2.12	59.37	0.00	0.00	0.00	0.00
11-Jun-02 3:20	0	893.70	3.66	59.44	2.37	59.34	0.00	0.00	0.00	0.00
11-Jun-02 3:25	0	893.29	3.04	59.25	2.00	59.25	0.00	0.00	0.00	0.00
11-Jun-02 3:30	0	893.70	3.35	59.14	2.00	59.25	0.00	0.00	0.00	0.00
11-Jun-02 3:35	0	893.70	3.23	59.10	2.00	59.19	0.00	0.00	0.00	0.00
11-Jun-02 3:40	0	892.88	2.98	58.99	2.19	59.13	0.00	0.00	0.00	0.00
11-Jun-02 3:45	0	892.67	3.11	58.94	2.00	59.15	0.00	0.00	0.00	0.00
11-Jun-02 3:50	0	892.47	3.29	58.90	2.06	59.15	0.00	0.00	0.00	0.00
11-Jun-02 3:55	0	893.08	3.04	58.87	2.25	59.12	0.00	0.00	0.00	0.00
11-Jun-02 4:00	0	894.51	2.98	58.83	2.06	59.12	0.00	0.00	0.00	0.00
11-Jun-02 4:05	0	896.15	2.98	58.83	2.25	59.12	0.00	0.00	0.00	0.00
11-Jun-02 4:07	Coil tubing at surface.									
11-Jun-02 4:10	Closed SSLV.									
11-Jun-02 4:10	0	897.17	2.98	58.81	2.00	59.13	0.00	0.00	0.00	0.00
11-Jun-02 4:15	0	895.54	3.35	58.74	2.00	59.12	0.00	0.00	0.00	0.00
11-Jun-02 4:20	0	893.90	3.35	58.70	2.31	59.06	0.00	0.00	0.00	0.00
11-Jun-02 4:24	Closed master valve on STT.									

11-Jun-02 4:24 Bled off pressure above STT master valve via choke manifold.
11-Jun-02 4:25 0 891.86 3.41 58.69 2.31 59.10 0.00 0.00 0.00 0.00
11-Jun-02 4:30 Closed swab valve on STT.
11-Jun-02 4:30 0 12.60 6.72 57.64 2.37 59.08 0.00 0.00 0.00 0.00
11-Jun-02 4:35 0 2.38 0.41 57.91 2.06 59.09 0.00 0.00 0.00 0.00
11-Jun-02 4:40 0 2.79 0.65 57.94 2.37 59.04 0.00 0.00 0.00 0.00
11-Jun-02 4:45 0 2.79 0.35 57.94 2.06 59.04 0.00 0.00 0.00 0.00
11-Jun-02 4:50 0 2.79 0.35 58.02 2.06 58.99 0.00 0.00 0.00 0.00
11-Jun-02 4:55 0 2.38 0.35 58.06 2.00 58.98 0.00 0.00 0.00 0.00
11-Jun-02 4:57 Opened swab valve and bled off pressure in coil tubing via choke.
11-Jun-02 5:00 0 2.58 0.35 58.02 2.06 58.98 0.00 0.00 0.00 0.00
11-Jun-02 5:02 Closed sawb valve on STT.
11-Jun-02 5:05 0 2.79 0.41 58.11 2.31 59.01 0.00 0.00 0.00 0.00
11-Jun-02 5:10 0 1.97 0.41 58.15 2.37 58.94 0.00 0.00 0.00 0.00
11-Jun-02 5:15 0 2.17 0.41 58.23 2.06 58.94 0.00 0.00 0.00 0.00
11-Jun-02 5:20 0 2.17 0.41 58.28 2.06 58.92 0.00 0.00 0.00 0.00
11-Jun-02 5:22 Broke out SRO and memory gauges from coil tubing toolstring.
11-Jun-02 5:25 0 2.38 0.35 58.33 2.06 58.92 0.00 0.00 0.00 0.00
11-Jun-02 5:30 0 2.38 0.35 58.44 1.69 59.03 0.00 0.00 0.00 0.00
11-Jun-02 5:35 0 2.38 0.41 58.54 1.51 59.03 0.00 0.00 0.00 0.00
11-Jun-02 5:40 0 2.17 0.41 58.60 1.94 59.03 0.00 0.00 0.00 0.00
11-Jun-02 5:45 0 2.58 0.35 58.71 2.00 59.09 0.00 0.00 0.00 0.00
11-Jun-02 5:50 0 2.38 0.35 58.77 2.00 59.18 0.00 0.00 0.00 0.00
11-Jun-02 5:55 0 2.38 0.47 58.85 2.37 59.24 0.00 0.00 0.00 0.00
11-Jun-02 6:00 0 2.38 0.35 58.96 2.31 59.25 0.00 0.00 0.00 0.00
11-Jun-02 6:05 0 2.38 0.53 59.01 2.19 59.28 0.00 0.00 0.00 0.00
11-Jun-02 6:10 0 2.17 0.35 59.09 2.00 59.31 0.00 0.00 0.00 0.00
11-Jun-02 6:15 0 2.58 0.41 59.18 2.37 59.35 0.00 0.00 0.00 0.00
11-Jun-02 6:20 0 2.58 0.53 59.21 2.31 59.40 0.00 0.00 0.00 0.00
11-Jun-02 6:25 Closed choke manifold.
11-Jun-02 6:25 0 2.17 0.65 59.33 2.12 59.47 0.00 0.00 0.00 0.00
11-Jun-02 6:30 0 2.58 0.35 59.33 2.25 59.48 0.00 0.00 0.00 0.00
11-Jun-02 6:35 0 2.79 0.04 59.35 2.00 59.53 0.00 0.00 0.00 0.00
11-Jun-02 6:40 0 2.79 0.35 59.39 2.25 59.51 0.00 0.00 0.00 0.00
11-Jun-02 6:45 0 2.58 0.35 59.40 2.31 59.53 0.00 0.00 0.00 0.00
11-Jun-02 6:50 0 2.79 0.28 59.36 2.25 59.48 0.00 0.00 0.00 0.00
11-Jun-02 6:55 0 2.38 0.35 59.44 2.31 59.55 0.00 0.00 0.00 0.00
11-Jun-02 7:00 Suspended all hot permit and shut down cranes operation.
11-Jun-02 7:00 Radio checked, Driller, Flare Watchers, Subsea Engineers, Test Crews.
11-Jun-02 7:00 0 2.58 0.00 59.41 2.31 59.53 0.00 0.00 0.00 0.00
11-Jun-02 7:05 0 2.38 0.28 59.41 2.37 59.51 0.00 0.00 0.00 0.00
11-Jun-02 7:10 0 2.38 0.47 59.41 2.37 59.53 0.00 0.00 0.00 0.00
11-Jun-02 7:15 0 2.79 0.00 59.42 2.74 59.52 0.00 0.00 0.00 0.00
11-Jun-02 7:20 0 2.79 0.00 59.42 2.37 59.42 0.00 0.00 0.00 0.00
11-Jun-02 7:25 0 2.58 0.00 59.37 2.00 59.39 0.00 0.00 0.00 0.00
11-Jun-02 7:30 Opened swab valve.
11-Jun-02 7:30 0 2.58 0.00 59.35 2.06 59.42 0.00 0.00 0.00 0.00
11-Jun-02 7:35 0 2.58 0.00 59.31 2.31 59.40 0.00 0.00 0.00 0.00
11-Jun-02 7:40 0 2.38 0.00 59.33 2.00 59.39 0.00 0.00 0.00 0.00
11-Jun-02 7:45 0 2.38 0.00 59.36 1.63 59.45 0.00 0.00 0.00 0.00
11-Jun-02 7:50 0 4.62 0.00 59.44 1.63 59.45 0.00 0.00 0.00 0.00
11-Jun-02 7:51 Opened choke manifold.
11-Jun-02 7:53 Commenced flushing surface lines and lubricator with brine.
11-Jun-02 7:54 Returned at choke manifold.
11-Jun-02 7:55 Closed choke manifold.
11-Jun-02 7:55 0 5.44 3.66 59.51 2.00 59.52 0.00 0.00 0.00 0.00
11-Jun-02 7:57 Commenced pressure testing through CTU lubricator , SSLV, and choke.
11-Jun-02 8:00 0 425.75 3.78 60.33 2.12 59.58 0.00 0.00 0.00 0.00
11-Jun-02 8:05 0 3073.133.29 60.82 2.31 59.66 0.00 0.00 0.00 0.00
11-Jun-02 8:10 0 3042.682.92 60.55 2.37 59.73 0.00 0.00 0.00 0.00
11-Jun-02 8:11 Good test. Bled down pressure to 900 psi to equalise across master valve.
11-Jun-02 8:12 Opened STT master valve and locked open.
11-Jun-02 8:14 Observed leak at injector head quick union.
11-Jun-02 8:15 0 913.73 4.27 59.79 1.14 60.11 0.00 0.00 0.00 0.00
11-Jun-02 8:20 0 913.12 3.17 59.96 2.31 59.78 0.00 0.00 0.00 0.00
11-Jun-02 8:25 0 912.91 2.68 59.94 2.31 59.75 0.00 0.00 0.00 0.00
11-Jun-02 8:30 0 912.50 2.80 59.91 2.00 59.75 0.00 0.00 0.00 0.00
11-Jun-02 8:35 0 912.50 2.86 59.80 2.31 59.68 0.00 0.00 0.00 0.00
11-Jun-02 8:40 0 900.44 2.55 59.80 2.37 59.69 0.00 0.00 0.00 0.00
11-Jun-02 8:45 Unlocked STT master valve and closed.
11-Jun-02 8:45 0 901.67 2.25 59.73 2.31 59.67 0.00 0.00 0.00 0.00
11-Jun-02 8:50 Bled off pressure via choke manifold to gas line flare. Opened choke.
11-Jun-02 8:50 0 2.58 0.65 58.23 2.00 59.73 0.00 0.00 0.00 0.00
11-Jun-02 8:55 0 3.20 0.00 58.93 2.61 59.73 0.00 0.00 0.00 0.00
11-Jun-02 9:00 0 3.20 0.00 59.21 2.68 59.69 0.00 0.00 0.00 0.00
11-Jun-02 9:05 0 3.20 0.00 59.25 2.31 59.71 0.00 0.00 0.00 0.00
11-Jun-02 9:10 0 2.99 0.00 59.21 2.31 59.71 0.00 0.00 0.00 0.00

11-Jun-02	9:15	0	2.58	0.00	59.14	2.61	59.72	0.00	0.00	0.00	0.00
11-Jun-02	9:20	0	2.79	0.35	59.10	2.31	59.75	0.00	0.00	0.00	0.00
11-Jun-02	9:25	0	2.79	0.59	58.99	2.12	59.58	0.00	0.00	0.00	0.00
11-Jun-02	9:30	0	2.79	1.02	58.91	2.00	59.51	0.00	0.00	0.00	0.00
11-Jun-02	9:35	0	2.58	1.63	58.80	2.00	59.47	0.00	0.00	0.00	0.00
11-Jun-02	9:40	0	2.38	1.33	58.74	2.31	59.40	0.00	0.00	0.00	0.00
11-Jun-02	9:45	0	2.38	0.71	58.69	2.00	59.35	0.00	0.00	0.00	0.00
11-Jun-02	9:50	0	2.58	1.26	58.69	2.00	59.36	0.00	0.00	0.00	0.00
11-Jun-02	9:55	Closed Choke manifold.									
11-Jun-02	9:55	0	2.38	1.33	58.65	2.06	59.34	0.00	0.00	0.00	0.00
11-Jun-02	10:00	0	4.62	1.69	58.67	2.00	59.35	0.00	0.00	0.00	0.00
11-Jun-02	10:03	Commenced pressure testing through CTU lubricator , SSLV, and choke.									
11-Jun-02	10:05	0	2924.31	3.04	61.80	1.63	59.37	0.00	0.00	0.00	0.00
11-Jun-02	10:10	0	3011.80	2.80	60.88	2.00	59.41	0.00	0.00	0.00	0.00
11-Jun-02	10:15	0	3132.01	2.00	60.65	2.06	59.50	0.00	0.00	0.00	0.00
11-Jun-02	10:19	Good test. Bled down pressure to 900 psi to equalise across master valve.									
11-Jun-02	10:20	0	2009.48	1.63	60.17	1.63	59.55	0.00	0.00	0.00	0.00
11-Jun-02	10:24	Opened STT master valve and locked open.									
11-Jun-02	10:25	0	896.97	1.63	60.00	1.94	59.68	0.00	0.00	0.00	0.00
11-Jun-02	10:30	0	901.26	1.76	59.91	2.00	59.82	0.00	0.00	0.00	0.00
11-Jun-02	10:32	Opened SSLV.									
11-Jun-02	10:35	Coil tubing commenced RIH with gauge toolstring at 15m/minute to 900mRT.									
11-Jun-02	10:35	0	898.40	1.33	60.05	2.19	59.94	0.00	0.00	0.00	0.00
11-Jun-02	10:40	Function tested rig deluge system.									
11-Jun-02	10:40	0	899.42	1.20	60.31	2.19	60.09	0.00	0.00	0.00	0.00
11-Jun-02	10:45	0	906.57	1.08	60.58	1.69	60.23	0.00	0.00	0.00	0.00
11-Jun-02	10:50	0	911.48	0.65	60.91	2.00	60.38	0.00	0.00	0.00	0.00
11-Jun-02	10:55	0	914.14	1.33	61.29	2.12	60.53	0.00	0.00	0.00	0.00
11-Jun-02	11:00	Coil tubing at 195mRT.									
11-Jun-02	11:00	0	916.18	0.65	61.62	1.94	60.77	0.00	0.00	0.00	0.00
11-Jun-02	11:05	0	917.82	0.77	61.97	2.00	61.12	0.00	0.00	0.00	0.00
11-Jun-02	11:10	0	919.86	1.51	62.33	1.94	61.67	0.00	0.00	0.00	0.00
11-Jun-02	11:15	0	923.75	0.41	62.72	2.06	62.53	0.00	0.00	0.00	0.00
11-Jun-02	11:20	0	927.02	1.08	63.10	2.00	63.70	0.00	0.00	0.00	0.00
11-Jun-02	11:25	0	928.86	1.02	63.48	2.06	64.92	0.00	0.00	0.00	0.00
11-Jun-02	11:26	Coil tubing at 500mRT.									
11-Jun-02	11:30	0	931.52	1.51	63.83	2.06	66.10	0.00	0.00	0.00	0.00
11-Jun-02	11:35	0	933.56	1.94	64.19	2.06	67.16	0.00	0.00	0.00	0.00
11-Jun-02	11:40	0	937.04	1.69	64.50	2.06	68.10	0.00	0.00	0.00	0.00
11-Jun-02	11:45	0	938.26	1.69	64.80	1.94	68.87	0.00	0.00	0.00	0.00
11-Jun-02	11:50	0	938.26	1.39	65.11	2.31	69.43	0.00	0.00	0.00	0.00
11-Jun-02	11:55	0	938.87	1.20	65.41	2.31	69.90	0.00	0.00	0.00	0.00
11-Jun-02	12:00	Coil tubing on depth at 902mRT.									
11-Jun-02	12:00	0	938.26	1.08	65.61	2.37	70.14	0.00	0.00	0.00	0.00
11-Jun-02	12:05	0	939.08	1.33	65.78	2.31	70.30	0.00	0.00	0.00	0.00
11-Jun-02	12:10	JHA prior to flowing well.									
11-Jun-02	12:10	0	939.49	1.08	65.99	2.31	70.32	0.00	0.00	0.00	0.00
11-Jun-02	12:15	0	939.28	1.08	66.14	2.00	70.34	0.00	0.00	0.00	0.00
11-Jun-02	12:20	0	938.46	0.77	66.29	2.25	70.41	0.00	0.00	0.00	0.00
11-Jun-02	12:25	Standby boat Captain aware of duty and informed flaring is to commence.									
11-Jun-02	12:25	Main compressors on load, propane pilots on, and started steam generator.									
11-Jun-02	12:25	0	939.08	0.90	66.41	2.31	70.55	0.00	0.00	0.00	0.00
11-Jun-02	12:30	Assigned dedicated person to check lines and equipment while flowing.									
11-Jun-02	12:30	Rig water screens operating, Burner boom water screens operating.									
11-Jun-02	12:30	Halliburton unit lined up to pump kill fluid.									
11-Jun-02	12:30	Applied 200 psi in annulus.									
11-Jun-02	12:30	0	938.67	1.08	66.51	2.00	70.70	0.00	0.00	0.00	0.00
11-Jun-02	12:35	0	938.46	1.08	66.64	2.31	70.90	0.00	0.00	0.00	0.00
11-Jun-02	12:40	0	938.46	0.65	66.75	2.00	71.05	0.00	0.00	0.00	0.00
11-Jun-02	12:42	Opened well through separator bypass on 16/64" adjustable choke to flare									
11-Jun-02	12:45	16	903.71	7.28	62.85	1.88	71.15	0.00	0.00	0.00	0.00
11-Jun-02	12:50	16	868.14	28.68	64.98	1.57	71.20	0.00	0.00	0.00	0.00
11-Jun-02	12:53	Commenced increasing adjustable choke to 20/64".									
11-Jun-02	12:54	Adjustable choke at 20/64".									
11-Jun-02	12:55	20	794.75	34.02	65.16	1.51	71.32	0.00	0.00	0.00	0.00
11-Jun-02	12:57	Commenced increasing adjustable choke to 24/64".									
11-Jun-02	12:58	Adjustable choke at 24/64".									
11-Jun-02	13:00	Commenced increasing adjustable choke to 28/64". Nitrogen to surface.									
11-Jun-02	13:00	28	680.06	36.28	65.15	1.39	71.65	0.00	0.00	0.00	0.00
11-Jun-02	13:01	Adjustable choke at 28/64".									
11-Jun-02	13:03	Commenced increasing adjustable choke to 32/64".									
11-Jun-02	13:04	Adjustable choke at 32/64".									
11-Jun-02	13:05	Brine at surface.									
11-Jun-02	13:05	32	750.60	10.34	67.78	2.00	71.92	0.00	0.00	0.00	0.00
11-Jun-02	13:10	Gas to surface.									
11-Jun-02	13:10	32	855.67	97.37	70.74	2.19	71.84	0.00	0.00	0.00	0.00
11-Jun-02	13:15	32	827.46	106.63	68.55	3.35	71.36	0.00	0.00	0.00	0.00

11-Jun-02 13:16 Commenced increasing adjustable choke to 36/64".
11-Jun-02 13:17 Adjustable choke at 36/64".
11-Jun-02 13:20 36 831.14 130.18 66.93 3.29 70.55 0.00 0.00 0.00 0.00
11-Jun-02 13:22 Commenced increasing adjustable choke to 40/64".
11-Jun-02 13:20 Draeger 0.3% CO2 and 0ppm H2S.
11-Jun-02 13:23 Adjustable choke at 40/64".
11-Jun-02 13:25 Commenced increasing adjustable choke to 44/64".
11-Jun-02 13:25 40 794.75 174.21 66.53 3.29 68.84 0.00 0.00 0.00 0.00
11-Jun-02 13:26 Adjustable choke at 44/64".
11-Jun-02 13:28 Commenced increasing adjustable choke to 48/64".
11-Jun-02 13:29 Adjustable choke at 48/64".
11-Jun-02 13:30 Well slugging gas, brine and mud traces.
11-Jun-02 13:30 48 791.48 261.79 67.75 3.17 67.58 0.00 0.00 0.00 0.00
11-Jun-02 13:31 Commenced increasing adjustable choke to 52/64".
11-Jun-02 13:32 Adjustable choke at 52/64".
11-Jun-02 13:34 Commenced increasing adjustable choke to 56/64".
11-Jun-02 13:35 Adjustable choke at 56/64".
11-Jun-02 13:35 56 744.46 332.81 70.08 2.61 68.24 0.00 0.00 0.00 0.00
11-Jun-02 13:37 Commenced increasing adjustable choke to 60/64".
11-Jun-02 13:38 Adjustable choke at 60/64".
11-Jun-02 13:39 Commenced increasing adjustable choke to 64/64".
11-Jun-02 13:40 Adjustable choke at 64/64". Draeger 0.15% CO2 and 0ppm H2S.
11-Jun-02 13:40 64 727.90 402.60 75.79 2.68 68.67 0.00 0.00 0.00 0.00
11-Jun-02 13:45 Intermittent flaring at gas line.
11-Jun-02 13:45 64 769.40 360.59 74.63 2.55 68.98 0.00 0.00 0.00 0.00
11-Jun-02 13:50 64 776.56 348.33 76.13 2.68 69.20 0.00 0.00 0.00 0.00
11-Jun-02 13:55 64 794.34 353.78 76.62 2.68 69.38 0.00 0.00 0.00 0.00
11-Jun-02 13:57 Commenced increasing adjustable choke to 68/64".
11-Jun-02 13:58 Adjustable choke at 68/64".
11-Jun-02 14:00 Well slugging gas, brine and mud traces.
11-Jun-02 14:00 68 744.05 357.83 76.42 2.25 69.51 0.00 0.00 0.00 0.00
11-Jun-02 14:05 68 782.28 361.88 77.37 1.57 69.62 0.00 0.00 0.00 0.00
11-Jun-02 14:06 Commenced increasing adjustable choke to 72/64".
11-Jun-02 14:07 Adjustable choke at 72/64".
11-Jun-02 14:10 72 713.80 446.57 77.77 0.00 69.70 0.00 0.00 0.00 0.00
11-Jun-02 14:15 BS&W at downstream choke manifold showed 1% sand, 2% mud and 97% water.
11-Jun-02 14:15 72 828.48 286.32 82.09 1.94 69.53 0.00 0.00 0.00 0.00
11-Jun-02 14:20 Commenced increasing adjustable choke to 76/64".
11-Jun-02 14:20 76 858.74 233.89 78.12 2.25 69.69 0.00 0.00 0.00 0.00
11-Jun-02 14:21 Adjustable choke at 76/64".
11-Jun-02 14:22 Commenced increasing adjustable choke to 80/64".
11-Jun-02 14:23 Adjustable choke at 80/64".
11-Jun-02 14:25 Draeger 0.15% CO2 and 0ppm H2S.
11-Jun-02 14:25 80 828.69 334.65 75.80 2.92 69.86 0.00 0.00 0.00 0.00
11-Jun-02 14:30 BS&W atchoke manifold showed 0.5% sand, 1.5% mud and 98% water.
11-Jun-02 14:30 Well slugging gas, brine and mud.
11-Jun-02 14:30 Draeger 0.15% CO2 and 0ppm H2S.
11-Jun-02 14:30 80 700.71 417.69 75.56 2.74 70.11 0.00 0.00 0.00 0.00
11-Jun-02 14:35 80 790.87 324.78 81.12 2.61 70.45 0.00 0.00 0.00 0.00
11-Jun-02 14:39 Manipulated adjustable choke to prevent from plugging.
11-Jun-02 14:40 80 852.00 292.15 78.19 2.68 70.95 0.00 0.00 0.00 0.00
11-Jun-02 14:45 Unable to take BS&W due to dry gas.
11-Jun-02 14:45 80 872.44 261.73 76.71 3.11 71.46 0.00 0.00 0.00 0.00
11-Jun-02 14:50 Commenced increasing adjustable choke to 84/64".
11-Jun-02 14:50 80 862.62 262.83 75.38 3.66 71.51 0.00 0.00 0.00 0.00
11-Jun-02 14:51 Adjustable choke at 84/64".
11-Jun-02 14:55 84 833.18 303.49 74.68 2.86 71.36 0.00 0.00 0.00 0.00
11-Jun-02 14:59 Commenced increasing adjustable choke to 88/64".
11-Jun-02 15:00 Adjustable choke at 88/64". BS&W at choke showed 4% mud and 96% water.
11-Jun-02 15:00 Intermittent flaring at gas line. Draeger 0.15% CO2,0ppm H2S.
11-Jun-02 15:00 Well slugging gas, brine and mud.
11-Jun-02 15:00 88 753.66 401.31 74.58 2.61 71.01 0.00 0.00 0.00 0.00
11-Jun-02 15:05 88 808.45 405.97 80.40 2.92 70.74 0.00 0.00 0.00 0.00
11-Jun-02 15:10 88 761.84 389.35 79.11 4.03 70.49 0.00 0.00 0.00 0.00
11-Jun-02 15:15 BS&W at downstream choke manifold showed 8% mud and 92% water.
11-Jun-02 15:15 88 767.56 397.69 77.76 4.64 70.32 0.00 0.00 0.00 0.00
11-Jun-02 15:20 88 775.13 416.03 78.13 4.64 70.14 0.00 0.00 0.00 0.00
11-Jun-02 15:25 88 780.44 420.75 79.28 3.96 70.03 0.00 0.00 0.00 0.00
11-Jun-02 15:30 BS&W at downstream choke manifold showed 8% mud and 92% water.
11-Jun-02 15:30 Well slugging gas, brine and mud.
11-Jun-02 15:30 88 767.77 412.23 78.05 3.72 69.87 0.00 0.00 0.00 0.00
11-Jun-02 15:35 88 761.23 410.39 78.79 3.96 69.82 0.00 0.00 0.00 0.00
11-Jun-02 15:36 Commenced increasing adjustable choke to 92/64".
11-Jun-02 15:37 Adjustable choke at 92/64".
11-Jun-02 15:40 92 769.81 421.06 79.80 3.72 69.70 0.00 0.00 0.00 0.00
11-Jun-02 15:45 BS&W at downstream choke manifold showed 4% mud and 96% water.
11-Jun-02 15:45 92 737.71 433.20 78.32 3.60 69.59 0.00 0.00 0.00 0.00

11-Jun-02	15:50	92	744.46	433.82	79.92	3.72	69.53	0.00	0.00	0.00	0.00	
11-Jun-02	15:55	92	731.17	454.49	79.24	3.47	69.70	0.00	0.00	0.00	0.00	
11-Jun-02	16:00	BS&W showed 4% mud, 96% water. Draeger 0.15% CO2,0ppm H2S.										
11-Jun-02	16:00	Well slugging gas, brine and mud.										
11-Jun-02	16:00	Still intermittent flaring at gas line.										
11-Jun-02	16:00	92	708.69	434.31	78.39	3.72	69.76	0.00	0.00	0.00	0.00	
11-Jun-02	16:05	92	730.97	460.62	80.90	4.33	69.79	0.00	0.00	0.00	0.00	
11-Jun-02	16:10	92	722.18	464.54	79.37	5.07	69.62	0.00	0.00	0.00	0.00	
11-Jun-02	16:15	BS&W at downstream choke manifold showed 2% mud and 98% water.										
11-Jun-02	16:15	92	720.13	452.03	79.51	5.44	69.28	0.00	0.00	0.00	0.00	
11-Jun-02	16:17	Commenced increasing adjustable choke to 96/64".										
11-Jun-02	16:18	Adjustable choke at 96/64".										
11-Jun-02	16:20	96	745.89	442.28	80.23	4.33	68.94	0.00	0.00	0.00	0.00	
11-Jun-02	16:25	96	740.37	433.94	79.23	3.29	68.62	0.00	0.00	0.00	0.00	
11-Jun-02	16:30	BS&W at downstream choke manifold showed 3% mud and 97% water.										
11-Jun-02	16:30	Well slugging gas, brine and mud.										
11-Jun-02	16:30	96	740.99	447.31	79.48	3.29	68.29	0.00	0.00	0.00	0.00	
11-Jun-02	16:32	Commenced increasing adjustable choke to 100/64".										
11-Jun-02	16:33	Adjustable choke at 100/64".										
11-Jun-02	16:35	100	725.65	451.97	79.29	3.72	68.01	0.00	0.00	0.00	0.00	
11-Jun-02	16:40	100	720.34	444.92	79.36	2.98	67.71	0.00	0.00	0.00	0.00	
11-Jun-02	16:45	BS&W at downstream choke manifold showed 4% mud and 96% water.										
11-Jun-02	16:45	100	723.61	455.28	79.58	2.92	67.52	0.00	0.00	0.00	0.00	
11-Jun-02	16:46	Commenced increasing adjustable choke to 104/64".										
11-Jun-02	16:47	Adjustable choke at 104/64".										
11-Jun-02	16:50	104	674.96	502.57	79.11	2.92	67.31	0.00	0.00	0.00	0.00	
11-Jun-02	16:51	Commenced increasing adjustable choke to 108/64".										
11-Jun-02	16:52	Adjustable choke at 108/64".										
11-Jun-02	16:55	108	636.93	530.66	79.97	3.35	67.10	0.00	0.00	0.00	0.00	
11-Jun-02	16:56	Commenced increasing adjustable choke to 112/64".										
11-Jun-02	16:57	Adjustable choke at 112/64".										
11-Jun-02	17:00	Well slugging gas, water and mud. Still intermittent flaring at gas line.										
11-Jun-02	17:00	BS&W at choke showed 3% mud,97% water. Draeger 0.15% CO2,0ppm H2S.										
11-Jun-02	17:00	Increased adjustable choke gradually to 128/64".										
11-Jun-02	17:00	112	620.17	522.50	79.07	3.04	66.95	0.00	0.00	0.00	0.00	
11-Jun-02	17:02	Adjustable choke at 128/64".										
11-Jun-02	17:05	128	626.50	533.48	79.01	2.92	66.72	0.00	0.00	0.00	0.00	
11-Jun-02	17:10	128	631.00	539.55	79.54	3.72	66.53	0.00	0.00	0.00	0.00	
11-Jun-02	17:15	Unable to measure BS&W due to dry gas.										
11-Jun-02	17:15	128	627.53	537.10	79.39	3.41	66.37	0.00	0.00	0.00	0.00	
11-Jun-02	17:20	128	627.73	537.10	79.28	3.72	66.16	0.00	0.00	0.00	0.00	
11-Jun-02	17:24	Diverted flow to 128/64" fixed choke.										
11-Jun-02	17:25	Increased adjustable choke to 128/64" while flowing at 128/64" fixed.										
11-Jun-02	17:25	128	617.10	539.92	78.68	3.47	66.02	0.00	0.00	0.00	0.00	
11-Jun-02	17:27	Opened 3" choke manifold bypass.										
11-Jun-02	17:30	Well slugging gas, brine and mud. Unable to measure BS&W due to dry gas.										
11-Jun-02	17:30	192	600.34	541.70	78.39	3.78	65.89	0.00	0.00	0.00	0.00	
11-Jun-02	17:35	192	605.86	546.48	78.59	3.72	65.67	0.00	0.00	0.00	0.00	
11-Jun-02	17:40	Diverted flow through test separator.										
11-Jun-02	17:40	192	584.60	520.11	78.34	120.8	61.50	0.00	0.00	0.00	0.00	
11-Jun-02	17:43	Installed 4.25" orifice into separator gas meter run.										
11-Jun-02	17:43	SG of produced gas = 0.576.										
11-Jun-02	17:45	192	606.47	548.01	78.64	368.5	67.80	14.64	0.05	0.00	0.00	
11-Jun-02	17:50	Diverted flow through test separator.										
11-Jun-02	17:50	192	606.88	549.73	78.55	373.9	67.58	24.72	0.14	0.00	0.00	0.00
11-Jun-02	17:55	192	605.24	547.64	78.50	371.3	67.54	24.82	0.22	0.00	0.00	0.00
11-Jun-02	18:00	Draeger 0.1% CO2 and 0ppm H2S.										
11-Jun-02	18:00	192	605.24	548.75	78.45	373.2	67.51	24.81	0.31	0.00	0.00	0.00
11-Jun-02	18:05	192	604.02	545.07	78.78	366.2	67.10	24.94	0.40	0.00	0.00	0.00
11-Jun-02	18:10	192	603.81	546.30	78.69	368.9	67.44	24.76	0.48	0.00	0.00	0.00
11-Jun-02	18:15	Raised 4.25" orifice from separator from gas meter run.										
11-Jun-02	18:15	192	622.01	532.92	78.77	358.5	67.27	19.84	0.55	0.00	0.00	0.00
11-Jun-02	18:20	192	738.53	446.27	81.42	304.1	64.80	0.00	0.55	0.00	0.00	0.00
11-Jun-02	18:22	Diverted flow to 60/64" adjustable choke.										
11-Jun-02	18:23	Diverted flow to 62/64" fixed choke.										
11-Jun-02	18:25	62	801.90	405.73	81.80	278.9	59.85	0.00	0.55	0.00	0.00	
11-Jun-02	18:30	62	793.93	399.11	81.24	277.6	58.07	0.00	0.55	0.00	0.00	
11-Jun-02	18:33	Diverted flow to 60/64" adjustable choke.										
11-Jun-02	18:35	60	825.82	375.37	81.60	257.4	56.92	0.00	0.55	0.00	0.00	
11-Jun-02	18:36	Diverted flow to 62/64" adjustable choke.										
11-Jun-02	18:40	62	798.43	402.17	81.05	277.5	56.79	0.00	0.55	0.00	0.00	
11-Jun-02	18:41	Diverted flow to 64/64" fixed choke.										
11-Jun-02	18:45	64	788.41	416.34	80.85	286.0	56.99	0.00	0.55	0.00	0.00	
11-Jun-02	18:50	64	791.28	419.35	80.96	287.6	56.91	0.00	0.55	0.00	0.00	
11-Jun-02	18:54	Installed 3.5" orifice into separator gas meter run.										
11-Jun-02	18:54	Raised 3.5" orifice from separator from gas meter run.										
11-Jun-02	18:55	64	792.09	422.04	81.05	293.2	56.76	3.95	0.56	0.00	0.00	

11-Jun-02	18:58	Installed 3.75" orifice into separator gas meter run.										
11-Jun-02	19:00	Well slugging gas, brine and trace mud.										
11-Jun-02	19:00	64	793.93	421.43	81.15	293.4	56.68	11.89	0.61	0.00	0.00	0.00
11-Jun-02	19:05	64	793.52	421.55	81.17	292.5	56.59	19.82	0.67	0.00	0.00	0.00
11-Jun-02	19:10	64	788.21	418.98	81.02	290.9	56.55	19.82	0.74	0.00	0.00	0.00
11-Jun-02	19:15	64	787.19	418.42	80.91	286.6	56.45	19.65	0.81	0.00	0.00	0.00
11-Jun-02	19:20	64	783.71	417.20	80.77	286.2	56.27	19.54	0.88	0.00	0.00	0.00
11-Jun-02	19:25	64	787.19	419.35	80.80	286.9	56.44	19.51	0.95	0.00	0.00	0.00
11-Jun-02	19:30	64	783.31	417.63	80.77	286.9	56.27	19.56	1.01	0.00	0.00	0.00
11-Jun-02	19:35	64	786.58	418.91	80.93	284.9	56.44	19.41	1.08	0.00	0.00	0.00
11-Jun-02	19:40	64	782.90	417.32	81.00	286.8	56.53	19.48	1.15	0.00	0.00	0.00
11-Jun-02	19:45	64	790.05	420.45	81.10	286.6	56.84	19.37	1.22	0.00	0.00	0.00
11-Jun-02	19:50	64	784.32	417.57	81.10	286.9	56.44	19.63	1.29	0.00	0.00	0.00
11-Jun-02	19:55	64	787.80	419.47	81.13	285.5	56.64	19.44	1.35	0.00	0.00	0.00
11-Jun-02	20:00	SG of produced gas = 0.576. Draeger 0.1% CO2 and 0ppm H2S.										
11-Jun-02	20:00	Manual dump valve on separator water line opened.										
11-Jun-02	20:00	64	784.12	417.14	81.28	282.2	56.36	19.48	1.42	0.00	0.00	0.00
11-Jun-02	20:05	64	790.05	420.88	81.44	286.2	56.81	19.42	1.49	0.00	0.00	0.00
11-Jun-02	20:10	64	785.35	418.30	81.16	288.2	56.49	19.67	1.56	0.00	0.00	0.00
11-Jun-02	20:15	64	789.64	420.51	81.33	285.2	56.74	19.56	1.62	0.00	0.00	0.00
11-Jun-02	20:20	64	783.10	416.71	81.18	281.6	56.22	19.53	1.69	0.00	0.00	0.00
11-Jun-02	20:25	64	789.84	420.75	81.33	286.0	56.74	19.38	1.76	0.00	0.00	0.00
11-Jun-02	20:30	Manual dump valve on separator water line closed. Tank cum 2 bbls.										
11-Jun-02	20:30	64	786.99	419.90	80.95	289.2	56.23	19.72	1.83	0.00	2.00	0.00
11-Jun-02	20:35	64	791.07	421.74	80.78	286.8	56.21	19.62	1.90	0.00		0.00
11-Jun-02	20:40	64	777.99	415.30	80.66	286.8	55.99	19.62	1.96	0.00		0.00
11-Jun-02	20:45	64	786.17	419.04	80.80	283.5	56.31	19.24	2.03	0.00		0.00
11-Jun-02	20:50	64	780.23	416.52	80.57	286.3	55.96	19.55	2.10	0.00		0.00
11-Jun-02	20:55	64	784.73	418.30	80.68	284.3	56.33	19.31	2.17	0.00		0.00
11-Jun-02	21:00	Well slugging gas , brine and trace mud.										
11-Jun-02	21:00	64	776.76	413.09	80.69	277.2	56.33	19.22	2.23	0.00		0.00
11-Jun-02	21:05	64	785.35	417.81	81.07	280.8	56.69	19.07	2.30	0.00		0.00
11-Jun-02	21:10	64	787.39	419.53	80.94	288.6	56.17	19.62	2.37	0.00		0.00
11-Jun-02	21:15	64	789.64	421.18	81.04	287.6	55.93	19.77	2.44	0.00		0.00
11-Jun-02	21:20	64	782.28	416.28	80.74	287.6	55.87	19.70	2.50	0.00		0.00
11-Jun-02	21:25	64	783.92	418.36	80.84	285.9	56.20	19.39	2.57	0.00		0.00
11-Jun-02	21:30	64	791.89	422.53	80.93	288.6	56.06	19.64	2.64	0.00	2.00	0.00
11-Jun-02	21:35	64	793.12	422.47	80.77	292.3	55.69	19.93	2.71	0.00		0.00
11-Jun-02	21:40	64	782.90	416.95	80.77	288.2	55.72	19.88	2.78	0.00		0.00
11-Jun-02	21:45	64	785.55	417.57	80.70	280.9	56.31	19.32	2.84	0.00		0.00
11-Jun-02	21:50	64	784.12	418.30	80.63	286.6	55.84	19.54	2.91	0.00		0.00
11-Jun-02	21:55	64	790.25	421.31	80.72	289.0	55.82	19.65	2.98	0.00		0.00
11-Jun-02	22:00	SG of produced gas = 0.578. Draeger 0.1% CO2 and 0ppm H2S.										
11-Jun-02	22:00	Manual dump valve on separator water line open/close. Tank cum 6 bbls.										
11-Jun-02	22:00	64	787.39	420.26	80.41	289.6	55.40	19.86	3.05	0.00	6.00	0.00
11-Jun-02	22:05	64	780.85	415.66	80.64	280.5	55.33	19.57	3.12	0.00		0.00
11-Jun-02	22:10	64	779.83	416.28	80.62	282.8	56.09	19.21	3.18	0.00		0.00
11-Jun-02	22:15	64	786.37	420.20	80.67	287.0	55.99	19.36	3.25	0.00		0.00
11-Jun-02	22:20	64	788.41	420.82	80.83	289.3	55.79	19.66	3.32	0.00		0.00
11-Jun-02	22:25	64	779.01	416.03	80.52	287.3	55.52	19.74	3.39	0.00		0.00
11-Jun-02	22:30	64	782.69	417.07	80.75	280.2	56.26	19.25	3.46	0.00	6.00	0.00
11-Jun-02	22:35	64	784.12	418.85	80.72	286.9	56.01	19.47	3.52	0.00		
11-Jun-02	22:40	64	791.48	422.53	80.96	289.2	55.95	19.61	3.59	0.00		
11-Jun-02	22:42	Raised 3.75" orifice from separator from gas meter run.										
11-Jun-02	22:43	Diverted flow to 62/64" adjustable choke.										
11-Jun-02	22:45	62	807.02	403.83	81.43	277.2	55.42	3.97	3.60	0.00		
11-Jun-02	22:47	Diverted flow to 60/64" fixed choke.										
11-Jun-02	22:48	Installed 3.75" orifice into separator gas meter run.										
11-Jun-02	22:50	60	826.44	372.86	81.35	258.3	54.05	7.34	3.63	0.00		
11-Jun-02	22:55	60	822.15	373.90	81.04	254.0	53.65	17.47	3.69	0.00		
11-Jun-02	23:00	SG of produced gas = 0.578. Draeger 0.1% CO2 and 0ppm H2S.										
11-Jun-02	23:00	BSW=100% brine and trace mud.										
11-Jun-02	23:00	Manual dump valve on separator water line open/close. Tank cum 7.9bbls.										
11-Jun-02	23:00	60	830.94	378.44	81.15	256.5	53.63	17.41	3.75	0.00	7.90	0.00
11-Jun-02	23:05	60	835.23	379.73	81.21	261.7	53.14	17.74	3.81	0.00		
11-Jun-02	23:10	60	837.88	380.52	81.12	262.7	52.84	17.92	3.88	0.00		
11-Jun-02	23:15	60	838.70	380.52	81.32	264.0	52.73	17.98	3.94	0.00		
11-Jun-02	23:20	60	839.93	379.79	81.23	264.1	52.52	18.05	4.00	0.00		
11-Jun-02	23:25	60	839.93	379.91	81.07	264.1	52.31	18.08	4.06	0.00		
11-Jun-02	23:30	Manual dump valve on separator water line open/close. Tank cum 9 bbls.										
11-Jun-02	23:30	60	839.73	378.74	81.16	263.6	52.21	18.10	4.13	52.80	9.00	2.92
11-Jun-02	23:35	60	838.09	377.40	81.37	263.4	52.32	18.08	4.19	52.80		
11-Jun-02	23:40	60	832.37	375.98	81.10	261.0	52.22	17.98	4.25	52.80		
11-Jun-02	23:45	60	823.98	372.92	80.97	257.8	52.38	17.79	4.31	52.80		
11-Jun-02	23:50	60	824.60	375.49	80.93	254.6	52.69	17.49	4.37	52.80		
11-Jun-02	23:55	60	830.53	378.01	81.19	256.0	52.66	17.54	4.43	52.80		
12-Jun-02	0:00	Manual dump valve on separator water line open/close. Tank cum 10.5 bbls.										

12-Jun-02 0:00	60	836.25	380.65	80.99	260.6	52.48	17.79	4.50	72.00	10.50	4.10
12-Jun-02 0:05	60	837.68	379.73	81.00	263.0	52.26	17.98	4.56	72.00		
12-Jun-02 0:10	60	835.64	379.05	81.27	261.7	52.21	18.05	4.62	72.00		
12-Jun-02 0:15	60	821.74	371.75	80.90	257.0	52.21	17.84	4.68	72.00		
12-Jun-02 0:20	60	824.19	374.51	81.12	251.0	52.90	17.39	4.74	72.00		
12-Jun-02 0:25	60	830.12	378.13	81.22	256.4	52.89	17.47	4.80	72.00		
12-Jun-02 0:30	Manual dump valve on separator water line open/close. Tank cum 10.5 bbls.										
12-Jun-02 0:30	60	836.66	380.46	81.26	260.7	52.64	17.72	4.87	72.00	10.50	4.12
12-Jun-02 0:35	60	838.09	380.95	81.18	262.7	52.35	18.00	4.93	72.00		
12-Jun-02 0:40	60	837.88	379.60	81.07	263.2	52.13	18.06	4.99	72.00		
12-Jun-02 0:45	60	822.76	372.43	81.00	258.1	52.16	17.86	5.05	72.00		
12-Jun-02 0:50	60	826.03	376.29	81.26	254.6	52.93	17.55	5.11	72.00		
12-Jun-02 0:55	60	824.60	375.62	81.18	254.9	52.69	17.51	5.17	72.00		
12-Jun-02 1:00	BSW=100% brine and trace mud.										
11-Jun-02 23:00	SG of produced gas = 0.578. Draeger 0.1% CO2 and 0ppm H2S.										
12-Jun-02 1:00	Manual dump valve on separator water line open/close. Tank cum 11.3 bbls.										
12-Jun-02 1:00	BSW=100% water,trace mud. Gas SG = 0.578. Draeger 0.1% CO2,0ppm H2S.										
12-Jun-02 1:00	60	835.02	380.34	81.26	258.4	52.96	17.52	5.24	19.20	11.30	1.10
12-Jun-02 1:05	60	838.29	381.26	81.23	262.1	52.43	17.89	5.30	19.20		
12-Jun-02 1:10	60	838.29	379.91	81.16	263.0	52.14	18.03	5.36	19.20		
12-Jun-02 1:15	60	822.15	372.98	80.96	257.3	52.08	17.93	5.42	19.20		
12-Jun-02 1:20	60	825.21	375.74	81.10	253.6	52.86	17.43	5.48	19.20		
12-Jun-02 1:25	60	826.44	376.54	81.28	257.1	52.86	17.55	5.54	19.20		
12-Jun-02 1:30	Manual dump valve on separator water line open/close. Tank cum 12.0 bbls.										
12-Jun-02 1:30	BSW=100% brine and trace mud.										
12-Jun-02 1:30	60	832.37	379.60	81.19	258.2	52.87	17.65	5.61	33.60	12.00	1.91
12-Jun-02 1:35	60	837.07	381.26	81.26	262.0	52.48	17.85	5.67	33.60		
12-Jun-02 1:40	60	836.66	380.16	81.28	262.5	52.26	18.01	5.73	33.60		
12-Jun-02 1:45	60	825.62	374.33	81.27	260.0	52.33	17.92	5.79	33.60		
12-Jun-02 1:50	60	823.57	374.08	81.34	249.2	52.38	17.59	5.85	33.60		
12-Jun-02 1:55	60	828.07	377.58	81.28	256.7	52.91	17.46	5.91	33.60		
12-Jun-02 2:00	Took water sample #1 (500ml Pyrex) from separator water line.										
12-Jun-02 2:00	Manual dump valve on separator water line open/close. Tank cum 12.25 bbls.										
12-Jun-02 2:00	BSW=100% brine and trace mud.										
12-Jun-02 2:00	60	833.18	379.85	81.60	259.4	52.79	17.71	5.98	12.00	12.25	0.69
12-Jun-02 2:05	60	837.48	380.95	81.72	262.0	52.76	17.87	6.04	12.00		
12-Jun-02 2:10	60	834.61	378.93	81.59	261.7	52.53	18.00	6.10	12.00		
12-Jun-02 2:15	60	822.96	373.35	81.59	257.5	52.59	17.79	6.16	12.00		
12-Jun-02 2:20	60	825.21	375.68	81.51	252.7	53.20	17.40	6.22	12.00		
12-Jun-02 2:25	60	831.55	379.48	81.71	258.4	53.12	17.58	6.28	12.00		
12-Jun-02 2:30	BSW=100% brine and trace mud.										
12-Jun-02 2:30	Manual dump valve on separator water line open/close. Tank cum 14.00 bbls.										
12-Jun-02 2:30	60	834.82	380.34	81.73	261.1	52.96	17.84	6.35	84.00	14.00	4.78
12-Jun-02 2:35	60	837.68	380.58	81.67	262.8	52.73	17.97	6.41	84.00		
12-Jun-02 2:40	60	833.39	378.62	81.49	261.0	52.58	17.96	6.47	84.00		
12-Jun-02 2:45	60	823.57	372.49	81.70	258.8	52.75	17.79	6.53	84.00		
12-Jun-02 2:50	60	826.03	376.90	81.64	254.9	53.35	17.45	6.59	84.00		
12-Jun-02 2:55	60	833.39	380.34	81.61	259.4	53.16	17.63	6.65	84.00		
12-Jun-02 3:00	BSW=100% brine,trace mud. Gas SG = 0.578. Draeger 0.1% CO2,0ppm H2S.										
12-Jun-02 3:00	Manual dump valve on separator water line open/close. Tank cum 15.25 bbls.										
12-Jun-02 3:00	60	835.43	380.34	81.66	262.4	52.84	17.89	6.72	60.00	15.25	3.40
12-Jun-02 3:05	60	837.07	380.89	81.80	262.3	52.79	17.98	6.78	60.00		
12-Jun-02 3:10	60	825.62	374.76	81.49	259.4	52.64	17.93	6.84	60.00		
12-Jun-02 3:15	60	824.39	375.98	81.18	252.9	52.90	17.53	6.90	60.00		
12-Jun-02 3:20	60	828.48	377.95	81.33	256.6	52.86	17.54	6.96	60.00		
12-Jun-02 3:25	60	833.39	379.73	81.67	260.0	52.90	17.74	7.02	60.00		
12-Jun-02 3:30	BSW=100% brine and trace mud.										
12-Jun-02 3:30	Manual dump valve on separator water line open/close. Tank cum 16.0 bbls.										
12-Jun-02 3:30	60	835.43	380.65	81.70	262.4	52.73	17.92	7.09	36.00	16.00	2.03
12-Jun-02 3:35	60	830.53	378.01	81.49	261.3	52.64	17.92	7.15	36.00		
12-Jun-02 3:40	60	821.33	373.16	81.60	256.9	52.86	17.69	7.21	36.00		
12-Jun-02 3:45	60	825.42	376.41	81.75	255.6	53.44	17.37	7.27	36.00		
12-Jun-02 3:50	60	827.25	377.27	81.69	257.9	53.16	17.61	7.33	36.00		
12-Jun-02 3:55	60	833.18	380.16	81.77	260.0	53.14	17.71	7.39	36.00		
12-Jun-02 4:00	Manual dump valve on separator water line open/close. Tank cum 16.8 bbls.										
12-Jun-02 4:00	BSW=100% brine and trace mud.										
12-Jun-02 4:00	60	835.23	379.85	81.93	262.1	52.97	17.90	7.45	38.40	16.80	2.17
12-Jun-02 4:05	60	829.71	377.27	81.87	260.0	52.85	17.92	7.52	38.40		
12-Jun-02 4:10	60	823.78	373.90	81.65	258.9	52.98	17.78	7.58	38.40		
12-Jun-02 4:15	60	821.53	374.64	81.75	255.0	53.35	17.41	7.64	38.40		
12-Jun-02 4:20	60	829.71	378.62	81.92	256.3	53.45	17.49	7.70	38.40		
12-Jun-02 4:25	60	835.02	380.52	82.04	261.1	53.29	17.81	7.76	38.40		
12-Jun-02 4:30	Manual dump valve on separator water line open/close. Tank cum 17.4 bbls.										
12-Jun-02 4:30	60	837.68	380.95	81.98	262.9	53.00	17.99	7.82	28.80	17.40	1.62
12-Jun-02 4:35	60	834.41	378.19	81.86	262.0	52.78	18.03	7.89	28.80		
12-Jun-02 4:40	60	821.94	372.55	82.03	257.7	53.01	17.80	7.95	28.80		
12-Jun-02 4:45	60	822.76	374.76	81.93	253.7	53.61	17.41	8.01	28.80		

12-Jun-02 4:50	60	829.30	378.25	81.89	257.7	53.45	17.58	8.07	28.80		
12-Jun-02 4:55	60	834.61	380.03	82.00	260.5	53.35	17.76	8.13	28.80		
12-Jun-02 5:00	BSW=100% brine and trace mud. Gas SG = 0.578. Draeger 0.1% CO2,0ppm H2S.										
12-Jun-02 5:00	Manual dump valve on separator water line open/close. Tank cum 19.25 bbls.										
12-Jun-02 5:00	60	837.48	380.71	81.92	262.7	53.07	17.96	8.19	40.80	19.25	2.30
12-Jun-02 5:05	60	838.70	380.95	82.26	263.1	53.03	18.11	8.26	40.80	19.25	2.27
12-Jun-02 5:10	60	830.73	376.17	81.98	261.6	52.91	18.11	8.32	40.8	19.25	2.25
12-Jun-02 5:15	60	822.76	373.23	81.99	258.7	53.14	17.86	8.38	40.8	19.25	2.25
12-Jun-02 5:20	60	828.69	377.64	82.14	256.7	53.66	17.54	8.44	40.8	19.25	2.28
12-Jun-02 5:25	60	835.02	380.4	82.25	260.7	53.5	17.81	8.5	40.8	19.25	2.33
12-Jun-02 5:30	Manual dump valve on separator water line open/close. Tank cum 20.3 bbls.										
12-Jun-02 5:30	BSW=100% brine and trace mud.										
12-Jun-02 5:30	60	837.07	380.28	82.13	262.6	53.29	18.01	8.57	50.4	20.3	2.83
12-Jun-02 5:35	60	838.09	380.83	82.15	263.4	53.12	18.08	8.63	50.4	20.3	2.8
12-Jun-02 5:40	60	838.5	381.32	82.15	263.3	52.98	18.15	8.69	50.4	20.3	2.79
12-Jun-02 5:45	60	831.14	376.9	82.14	262.2	52.95	18.09	8.76	50.4	20.3	2.78
12-Jun-02 5:50	60	829.3	375.8	81.88	261.7	53.06	17.93	8.82	50.4	20.3	2.79
12-Jun-02 5:55	60	829.5	377.82	81.72	258.7	53.25	17.69	8.88	50.4	20.3	2.81
12-Jun-02 6:00	Manual dump valve on separator water line open/close. Tank cum 20.5 bbls.										
12-Jun-02 6:00	BSW=100% brine and trace mud. SG of produced gas = 0.576.										
12-Jun-02 6:00	60	831.14	379.3	81.98	257.6	53.06	17.78	8.94	9.6	20.5	0.54
12-Jun-02 6:05	60	834.61	380.65	81.71	261.7	53.09	17.89	9	9.6	20.5	0.54
12-Jun-02 6:10	60	837.88	381.87	81.66	262.0	52.93	18.01	9.07	9.6	20.5	0.54
12-Jun-02 6:15	60	838.5	380.52	81.62	263.6	52.65	18.07	9.13	9.6	20.5	0.53
12-Jun-02 6:20	60	834.82	378.74	81.87	262.4	52.7	18.11	9.19	9.6	20.5	0.53
12-Jun-02 6:25	60	824.39	373.78	81.67	258.7	52.85	17.93	9.25	9.6	20.5	0.53
12-Jun-02 6:30	Manual dump valve on separator water line open/close. Tank cum 20.5 bbls.										
12-Jun-02 6:30	BSW=100% brine and trace mud.										
12-Jun-02 6:30	60	824.6	375.74	81.72	254.6	53.19	17.66	9.32	0	20.5	0
12-Jun-02 6:35	60	831.75	379.36	81.77	257.9	53.29	17.7	9.38	0	20.5	0
12-Jun-02 6:40	60	835.23	380.34	81.86	261.3	53.01	17.9	9.44	0	20.5	0
12-Jun-02 6:45	60	837.27	380.46	82.14	262.4	52.97	18.05	9.5	0	20.5	0
12-Jun-02 6:50	60	838.5	381.08	81.84	263.0	52.86	18.14	9.56	0	20.5	0
12-Jun-02 6:55	60	839.52	380.52	82.04	263.4	52.8	18.17	9.63	0	20.5	0
12-Jun-02 7:00	Manual dump valve on separator water line open/close. Tank cum 20.9 bbls.										
12-Jun-02 7:00	BSW=100% brine,trace mud. Gas SG = 0.576. Draeger 0.1% CO2,0ppm H2S.										
12-Jun-02 7:00	SG of produced water = 1.096. pH = 7 and 110,000ppm Chl.										
12-Jun-02 7:00	60	831.55	376.35	81.97	260.8	52.81	18.11	9.69	19.2	20.9	1.06
12-Jun-02 7:05	60	825.01	373.1	82.09	258.3	52.93	17.92	9.75	19.2	20.9	1.06
12-Jun-02 7:10	60	830.53	377.64	81.86	257.3	53.34	17.65	9.81	19.2	20.9	1.07
12-Jun-02 7:15	60	835.02	379.73	81.97	259.7	53.18	17.86	9.88	19.2	20.9	1.09
12-Jun-02 7:20	60	837.27	379.66	82.11	261.3	53.06	18.02	9.94	19.2	20.9	1.07
12-Jun-02 7:25	60	838.7	380.34	82.16	261.7	52.98	18.11	10	19.2	20.9	1.07
12-Jun-02 7:30	Manual dump valve on separator water line open/close. Tank cum 1.3 bbls.										
12-Jun-02 7:30	BSW=100% brine and trace mud. pH = 7 and 115,000ppm Chl.										
12-Jun-02 7:30	60	838.7	379.66	82.27	261.7	52.9	18.15	10.06	19.2	21.3	1.06
12-Jun-02 7:35	60	834.82	377.7	82.25	260.7	53.07	18.12	10.13	19.2	21.3	1.06
12-Jun-02 7:40	60	826.03	373.1	82.56	257.7	53.2	17.95	10.19	19.2	21.3	1.06
12-Jun-02 7:45	60	829.91	377.21	82.11	255.4	53.44	17.75	10.25	19.2	21.3	1.07
12-Jun-02 7:50	60	833.79	378.81	82.08	258.4	53.31	17.85	10.31	19.2	21.3	1.08
12-Jun-02 7:55	60	835.64	379.11	82.18	260.5	53.19	18.01	10.38	19.2	21.3	1.08
12-Jun-02 8:00	Manual dump valve on separator water line open/close. Tank cum 22.6 bbls.										
12-Jun-02 8:00	BSW=100% brine and trace mud. pH = 7 and 115,000ppm Chl.										
12-Jun-02 8:00	60	837.68	380.77	82	261.1	53.02	18.07	10.44	62.4	22.6	3.46
12-Jun-02 8:05	60	839.93	380.77	81.93	262.0	52.92	18.1	10.5	62.4	22.6	3.45
12-Jun-02 8:10	60	836.46	378.93	82.15	261.4	52.82	18.17	10.56	62.4	22.6	3.45
12-Jun-02 8:15	60	827.87	373.84	82.41	259.0	53.18	18.03	10.63	62.4	22.6	3.44
12-Jun-02 8:20	60	834	378.87	82.26	257.4	53.5	17.83	10.69	62.4	22.6	3.46
12-Jun-02 8:25	60	835.02	378.81	82.02	260.8	53.2	17.97	10.75	62.4	22.6	3.5
12-Jun-02 8:30	Manual dump valve on separator water line open/close. Tank cum 23.1 bbls.										
12-Jun-02 8:30	BSW=100% brine and trace mud. pH = 7 and 115,000ppm Chl.										
12-Jun-02 8:30	60	836.66	379.97	82.11	260.7	53.16	18.04	10.81	24	23.1	1.34
12-Jun-02 8:35	60	838.7	380.89	82.21	261.3	53.18	18.08	10.88	24	23.1	1.33
12-Jun-02 8:40	60	839.93	380.65	82.58	262.6	53.19	18.15	10.94	24	23.1	1.33
12-Jun-02 8:45	60	837.48	378.99	82.4	262.0	53.14	18.2	11	24	23.1	1.32
12-Jun-02 8:50	60	828.07	373.59	82.58	259.0	53.29	18.07	11.07	24	23.1	1.32
12-Jun-02 8:55	60	828.48	376.78	82.75	254.6	53.61	17.83	11.13	24	23.1	1.33
12-Jun-02 9:00	Manual dump valve on separator water line open/close. Tank cum = 23.6 bbls.										
12-Jun-02 9:00	BSW=100% brine,trace mud. Gas SG = 0.576. Draeger 0.1% CO2,0ppm H2S.										
12-Jun-02 9:00	SG of produced water = 1.096. pH = 7 and 115,000ppm Chl.										
12-Jun-02 9:00	60	832.57	377.95	82.91	258.0	53.93	17.79	11.19	24	23.6	1.35
12-Jun-02 9:00	60	832.57	377.95	82.91	258.0	53.93	17.79	11.19	24	23.6	1.35
12-Jun-02 9:05	60	835.02	378.81	82.68	259.7	53.82	17.93	11.25	24	23.6	1.35
12-Jun-02 9:10	60	838.09	380.46	82.94	260.9	53.76	18.06	11.31	24	23.6	1.34
12-Jun-02 9:15	60	839.93	380.52	82.89	262.8	53.68	18.13	11.38	24	23.6	1.33
12-Jun-02 9:20	60	839.93	380.4	83.06	263.3	53.78	18.21	11.44	24	23.6	1.32
12-Jun-02 9:25	60	835.02	377.58	82.8	262.0	53.66	18.16	11.5	24	23.6	1.32

12-Jun-02	9:30	Brine rate 38.4 bpd and cum = 24.4 bbls.									
12-Jun-02	9:30	BSW=100% brine, pH = 7 and Chl contents from refrac 115,000ppm.									
12-Jun-02	9:30	60	826.85	374.64	82.65	259.0	53.73	17.96	11.57	38.4	24.4	2.11
12-Jun-02	9:35	60	829.1	377.27	82.75	255.4	54.06	17.71	11.63	38.4	24.4	2.14
12-Jun-02	9:40	60	831.34	378.74	82.53	258.3	53.88	17.82	11.69	38.4	24.4	2.17
12-Jun-02	9:45	60	835.64	380.46	82.4	260.5	53.72	17.96	11.75	38.4	24.4	2.16
12-Jun-02	9:50	60	838.7	380.77	82.8	262.1	53.66	18.09	11.81	38.4	24.4	2.14
12-Jun-02	9:55	60	840.13	380.65	82.62	263.2	53.56	18.17	11.88	38.4	24.4	2.12
12-Jun-02	10:00	Brine rate 28.8 bpd and cum = 25.0 bbls.									
12-Jun-02	10:00	BSW=100% brine. brine SG = 1.092 at 50 F,pH=7,Chls 115,000ppm.									
12-Jun-02	10:00	60	840.34	379.91	83	264.1	53.67	18.26	11.94	28.8	25	1.58
12-Jun-02	10:05	60	835.43	377.33	83.21	262.4	53.99	18.19	12	28.8	25	1.58
12-Jun-02	10:10	60	826.44	374.27	83.23	258.4	54.11	17.98	12.07	28.8	25	1.58
12-Jun-02	10:15	60	830.12	378.01	83.19	257.3	54.59	17.75	12.13	28.8	25	1.6
12-Jun-02	10:20	60	835.84	380.22	83.22	260.1	54.46	17.88	12.19	28.8	25	1.62
12-Jun-02	10:25	60	837.68	380.09	83.6	262.1	54.41	18.06	12.25	28.8	25	1.61
12-Jun-02	10:30	Brine rate 33.8 bpd and cum = 25.7 bbls.									
12-Jun-02	10:30	BSW=100% brine, pH = 7 and Chl from refrac 115,000ppm.									
12-Jun-02	10:30	60	839.73	381.26	83.6	262.7	54.36	18.15	12.32	33.8	25.7	1.87
12-Jun-02	10:35	60	840.95	381.14	83.72	264.1	54.49	18.18	12.38	33.8	25.7	1.86
12-Jun-02	10:40	60	840.75	380.58	83.4	264	54.32	18.2	12.44	33.8	25.7	1.86
12-Jun-02	10:45	60	836.05	378.87	83.17	262.8	54.16	18.17	12.51	33.8	25.7	1.86
12-Jun-02	10:50	60	827.46	374.21	83.3	259.4	54.3	17.97	12.57	33.8	25.7	1.86
12-Jun-02	10:55	60	832.78	379.24	83.35	258.0	54.69	17.79	12.63	33.8	25.7	1.88
12-Jun-02	11:00	Brine rate 28.8 bpd and cum = 26.3 bbls.									
12-Jun-02	11:00	BSW=100% brine, SG of produced gas = 0.578. Draeger 0.1% CO2 and 0ppm H2S.									
12-Jun-02	11:00	brine SG = 1.092 at 50 F, pH = 7 and Chl from refrac 115,000ppm.									
12-Jun-02	11:00	60	836.86	380.52	83.37	261.1	54.54	17.95	12.69	28.8	26.3	1.62
12-Jun-02	11:05	60	838.7	380.71	83.62	262.4	54.52	18	12.75	28.8	26.3	1.6
12-Jun-02	11:10	60	840.13	381.26	84.02	263.3	54.65	18.1	12.82	28.8	26.3	1.6
12-Jun-02	11:15	60	841.56	381.26	84.18	263.7	54.7	18.14	12.88	28.8	26.3	1.59
12-Jun-02	11:20	60	841.77	381.08	84.02	264.3	54.69	18.16	12.94	28.8	26.3	1.59
12-Jun-02	11:25	60	841.16	379.79	83.94	264.1	54.65	18.19	13.01	28.8	26.3	1.59
12-Jun-02	11:30	Brine rate 14.4 bpd and cum = 26.6 bbls.									
12-Jun-02	11:30	BSW=100% brine, pH = 7 and Chl contents from refrac 115,000ppm.									
12-Jun-02	11:30	60	833.18	375.8	83.98	261.7	54.75	18.13	13.07	14.4	26.6	0.79
12-Jun-02	11:35	60	829.3	376.6	84.08	258.9	54.92	17.9	13.13	14.4	26.6	0.79
12-Jun-02	11:40	60	832.78	378.07	84.14	258.4	55.22	17.73	13.19	14.4	26.6	0.8
12-Jun-02	11:45	60	837.48	380.46	84.18	260.7	55.23	17.88	13.26	14.4	26.6	0.81
12-Jun-02	11:50	60	840.13	380.83	84.38	262.8	55.19	18.02	13.32	14.4	26.6	0.81
12-Jun-02	11:55	60	841.56	380.89	84.14	263.1	54.98	18.1	13.38	14.4	26.6	0.8
12-Jun-02	12:00	Brine rate 33.6 bpd and cum = 27.3 bbls.									
12-Jun-02	12:00	BSW=100% brine. brine SG = 1.094 at 49 F, pH=7,Chls 115,000ppm.									
12-Jun-02	12:00	60	841.77	380.4	83.92	263.7	54.82	18.19	13.44	33.6	27.3	1.86
12-Jun-02	12:05	60	841.56	380.34	84	263.7	54.77	18.17	13.51	33.6	27.3	1.85
12-Jun-02	12:10	60	835.02	377.89	83.7	261.1	54.73	18.12	13.57	33.6	27.3	1.85
12-Jun-02	12:15	60	827.87	373.9	83.61	259.4	54.82	17.89	13.63	33.6	27.3	1.85
12-Jun-02	12:20	60	832.78	378.56	83.53	256.4	55.13	17.6	13.69	33.6	27.3	1.88
12-Jun-02	12:25	60	837.07	380.52	83.62	260.5	55.03	17.87	13.75	33.6	27.3	1.91
12-Jun-02	12:30	Brine rate 33.6 bpd and cum = 28.0 bbls.									
12-Jun-02	12:30	BSW=100% brine, pH = 7 and Chl contents from refrac 115,000ppm.									
12-Jun-02	12:30	60	838.29	380.77	83.6	262.4	54.8	18.01	13.82	33.6	28	1.88
12-Jun-02	12:35	60	839.52	381.26	83.48	263.3	54.71	18.1	13.88	33.6	28	1.87
12-Jun-02	12:40	60	841.16	381.69	83.49	263.5	54.59	18.12	13.94	33.6	28	1.86
12-Jun-02	12:45	60	840.13	380.46	83.64	263.6	54.53	18.17	14.01	33.6	28	1.85
12-Jun-02	12:50	60	828.89	375.68	83.41	260.1	54.55	18.04	14.07	33.6	28	1.85
12-Jun-02	12:55	60	828.28	376.66	83.5	254.6	54.6	17.77	14.13	33.6	28	1.86
12-Jun-02	13:00	Brine rate 33.6 bpd and cum = 28.7 bbls.									
12-Jun-02	13:00	BSW=100% brine. SG of produced gas = 0.577.									
12-Jun-02	13:00	brine SG = 1.094 at 49 F, pH = 6 and Chl from refrac 115,000ppm.									
12-Jun-02	13:00	60	833.59	379.66	83.77	257.7	55.08	17.71	14.19	33.6	28.7	1.89
12-Jun-02	13:05	60	837.48	380.52	83.6	261.1	54.9	17.93	14.25	33.6	28.7	1.9
12-Jun-02	13:10	60	838.5	380.34	83.95	262.7	54.92	18.09	14.32	33.6	28.7	1.87
12-Jun-02	13:15	60	841.36	381.99	83.94	263.0	54.9	18.12	14.38	33.6	28.7	1.86
12-Jun-02	13:20	60	842.18	381.26	84	264.1	54.87	18.2	14.44	33.6	28.7	1.85
12-Jun-02	13:25	60	840.95	381.26	83.92	264.3	54.95	18.19	14.51	33.6	28.7	1.85
12-Jun-02	13:30	Brine rate 19.2 bpd and cum = 29.1 bbls.									
12-Jun-02	13:30	BSW=100% brine, pH = 6 and Chl contents from refrac 110,000ppm.									
12-Jun-02	13:30	Chl contents from Mud Engineer 100,000ppm.									
12-Jun-02	13:30	60	837.88	378.62	83.8	263.6	54.98	18.18	14.57	19.2	29.1	1.06
12-Jun-02	13:35	60	825.82	374.7	83.43	259.0	55.01	18	14.63	19.2	29.1	1.06
12-Jun-02	13:40	60	831.34	378.93	83.3	256.2	55.09	17.74	14.69	19.2	29.1	1.07
12-Jun-02	13:45	60	837.07	381.32	83.03	260.0	54.85	17.82	14.76	19.2	29.1	1.08
12-Jun-02	13:50	60	837.48	380.95	83.1	261.7	54.59	18	14.82	19.2	29.1	1.08
12-Jun-02	13:55	60	838.29	380.52	82.84	262.8	54.49	18.08	14.88	19.2	29.1	1.07
12-Jun-02	14:00	Brine rate 28.8 bpd and cum = 29.7 bbls.									
12-Jun-02	14:00	BSW=100% brine. Draeger 0.1% CO2 and 0ppm H2S.									

12-Jun-02	14:00	brine SG = 1.096 at 52 F, pH = 6 and Chl from refrac 110,000ppm.										
12-Jun-02	14:00	60	839.73	381.5	82.51	263.0	54.16	18.12	14.94	28.8	29.7	1.59
12-Jun-02	14:05	60	842.59	381.81	82.9	263.4	54.27	18.15	15.01	28.8	29.7	1.59
12-Jun-02	14:10	60	843	381.75	82.99	264.1	54.26	18.2	15.07	28.8	29.7	1.59
12-Jun-02	14:15	60	836.66	379.73	83.1	262.9	54.27	18.14	15.13	28.8	29.7	1.58
12-Jun-02	14:20	60	830.12	374.76	83.02	261.9	54.47	18	15.2	28.8	29.7	1.59
12-Jun-02	14:25	60	830.53	378.87	82.86	257.8	54.6	17.75	15.26	28.8	29.7	1.6
12-Jun-02	14:30	Brine rate 24.0 bpd and cum = 30.2 bbls.										
12-Jun-02	14:30	BSW=100% brine, pH = 6 and Chl contents from refrac 115,000ppm.										
12-Jun-02	14:30	60	835.64	381.26	82.94	261.0	54.54	17.83	15.32	24	30.2	1.35
12-Jun-02	14:35	60	837.88	380.58	82.99	262.0	54.41	18.02	15.38	24	30.2	1.35
12-Jun-02	14:40	60	839.11	381.26	83.27	262.7	54.38	18.11	15.44	24	30.2	1.33
12-Jun-02	14:45	60	840.13	381.38	83.43	263.1	54.52	18.12	15.51	24	30.2	1.33
12-Jun-02	14:50	60	840.75	381.99	83.13	264.1	54.38	18.18	15.57	24	30.2	1.32
12-Jun-02	14:55	60	841.16	381.5	83.12	265.4	54.36	18.25	15.63	24	30.2	1.32
12-Jun-02	15:00	Brine rate 19.2 bpd and cum = 30.6 bbls.										
12-Jun-02	15:00	BSW=100% brine. SG of produced gas = 0.577.										
12-Jun-02	15:00	brine SG = 1.098 at 56 F, pH = 6 and Chl from refrac 100,000ppm.										
12-Jun-02	15:00	60	839.11	380.52	83.27	264.5	54.37	18.25	15.7	19.2	30.6	1.05
12-Jun-02	15:05	60	831.14	376.97	83.32	261.4	54.57	18.06	15.76	19.2	30.6	1.05
12-Jun-02	15:10	60	832.16	378.87	83.3	257.9	54.63	17.86	15.82	19.2	30.6	1.06
12-Jun-02	15:15	60	837.07	380.52	83.19	262.0	54.86	17.87	15.88	19.2	30.6	1.07
12-Jun-02	15:20	60	839.93	381.38	83.1	263.6	54.69	18.07	15.95	19.2	30.6	1.07
12-Jun-02	15:25	60	841.56	381.44	83.06	264.6	54.54	18.13	16.01	19.2	30.6	1.06
12-Jun-02	15:30	Brine rate 28.8 bpd and cum = 31.2 bbls.										
12-Jun-02	15:30	BSW=100% brine, pH = 6 and Chl contents from refrac 110,000ppm.										
12-Jun-02	15:30	60	842.18	382.67	83.27	264.4	54.53	18.16	16.07	28.8	31.2	1.59
12-Jun-02	15:35	60	843.82	383.59	83.37	265.4	54.58	18.19	16.14	28.8	31.2	1.59
12-Jun-02	15:40	60	843.41	383.53	83.23	265.1	54.5	18.23	16.2	28.8	31.2	1.58
12-Jun-02	15:45	60	842.38	381.81	83.37	265.3	54.46	18.25	16.26	28.8	31.2	1.58
12-Jun-02	15:50	60	836.25	378.62	83.38	263.4	54.52	18.18	16.33	28.8	31.2	1.58
12-Jun-02	15:55	60	829.91	376.23	83.21	261.3	54.76	18	16.39	28.8	31.2	1.58
12-Jun-02	16:00	Brine rate 19.2 bpd and cum = 31.6 bbls.										
12-Jun-02	16:00	BSW=100% brine. brine SG = 1.098 at 56 F,pH=6,Chl from refrac 105,000ppm.										
12-Jun-02	16:00	60	834	379.11	83.5	260.44	54.96	17.8	16.45	19.2	31.6	1.07
12-Jun-02	16:00	Brine rate 19.2 bpd and cum = 31.6 bbls.										
12-Jun-02	16:00	BSW=100% brine. brine SG = 1.098 at 56 F, pH=6,Chl from refrac 105,000ppm.										
12-Jun-02	16:00	60	834	379.11	83.5	260.4	54.96	17.8	16.45	19.2	31.6	1.07
12-Jun-02	16:05	60	837.68	380.95	83.67	262.4	55.08	17.91	16.51	19.2	31.6	1.08
12-Jun-02	16:10	60	838.91	381.26	83.37	264.4	54.75	18.1	16.57	19.2	31.6	1.07
12-Jun-02	16:15	60	840.75	381.44	83.19	265.1	54.49	18.19	16.64	19.2	31.6	1.06
12-Jun-02	16:20	60	842.38	382.85	83.34	265.7	54.43	18.2	16.7	19.2	31.6	1.06
12-Jun-02	16:25	60	843	382.79	83.45	265.1	54.39	18.25	16.76	19.2	31.6	1.06
12-Jun-02	16:30	Brine rate 24.0 bpd and cum = 32.1 bbls.										
12-Jun-02	16:30	BSW=100% brine, pH = 6 and Chl contents from refrac 110,000ppm.										
12-Jun-02	16:30	60	843.2	381.99	83.29	266.0	54.46	18.29	16.83	24	32.1	1.31
12-Jun-02	16:35	60	843	381.99	83.46	265.8	54.31	18.31	16.89	24	32.1	1.31
12-Jun-02	16:40	60	842.59	382.24	83.46	265.5	54.48	18.25	16.96	24	32.1	1.31
12-Jun-02	16:45	60	843.41	381.5	83.68	265.8	54.48	18.27	17.02	24	32.1	1.32
12-Jun-02	16:50	60	840.95	380.95	83.51	264.7	54.42	18.28	17.08	24	32.1	1.31
12-Jun-02	16:55	60	830.94	375.49	83.24	261.4	54.41	18.13	17.15	24	32.1	1.31
12-Jun-02	17:00	Brine rate 24 bpd and cum = 32.6 bbls.										
12-Jun-02	17:00	BSW=100% brine. Draeger 0.1% CO2 and 0ppm H2S.										
12-Jun-02	17:00	brine SG = 1.092 at 49 F, pH = 6 and Chl from refrac 105,000ppm.										
12-Jun-02	17:00	Commenced taking PVT gas sample no. 1.2 into bottle s/n 1278-C1-F.										
12-Jun-02	17:00	60	830.32	377.7	83.4	256.7	54.37	17.93	17.21	24	32.6	1.32
12-Jun-02	17:00	60	830.32	377.7	83.4	256.7	54.37	17.93	17.21	24	32.6	1.32
12-Jun-02	17:05	60	834.2	379.48	83.43	259.7	54.77	17.84	17.27	24	32.6	1.34
12-Jun-02	17:10	60	837.68	381.14	83.48	261.7	54.6	17.99	17.33	24	32.6	1.35
12-Jun-02	17:15	60	839.93	381.44	83.17	263.2	54.44	18.11	17.39	24	32.6	1.33
12-Jun-02	17:20	Completed taking PVT gas sample no. 1.2.										
12-Jun-02	17:20	60	841.56	381.99	83.18	264.1	54.23	18.17	17.46	24	32.6	1.32
12-Jun-02	17:25	60	843.2	382.3	83.38	264.8	54.21	18.25	17.52	24	32.6	1.32
12-Jun-02	17:30	Brine rate 24.0 bpd and cum = 33.1 bbls.										
12-Jun-02	17:30	BSW=100% brine, pH = 6 and Chl contents from refrac 105,000ppm.										
12-Jun-02	17:30	Coil tubing commence RIH with SRO gauges.										
12-Jun-02	17:30	60	843.82	381.87	83.29	265.3	54.15	18.28	17.58	24	33.1	1.31
12-Jun-02	17:35	60	844.02	379.91	82.48	266.3	53.94	18.34	17.65	24	33.1	1.31
12-Jun-02	17:40	60	843.2	380.16	81.6	266.1	53.07	18.38	17.71	24	33.1	1.31
12-Jun-02	17:45	60	843.61	379.42	81.7	266.5	52.81	18.37	17.78	24	33.1	1.31
12-Jun-02	17:50	60	843	376.9	81.8	266.8	52.81	18.43	17.84	24	33.1	1.31
12-Jun-02	17:55	60	841.36	376.35	81.51	266.0	52.64	18.43	17.9	24	33.1	1.3
12-Jun-02	18:00	BSW=100% brine, pH = 6 and Chl contents from refrac 103,000ppm.										
12-Jun-02	18:00	brine SG = 1.086 at 61 F. Draeger 0.1% CO2 and 0ppm H2S.										
12-Jun-02	18:00	Brine rate 9.6 bpd and cum = 33.3 bbls.										
12-Jun-02	18:00	60	839.52	378.19	81.29	264.1	52.44	18.29	17.97	9.6	33.3	0.52
12-Jun-02	18:05	60	838.29	376.54	81.39	264.4	52.53	18.28	18.03	9.6	33.3	0.53

12-Jun-02	18:10	60	836.66	373.35	81.56	264.8	52.59	18.3	18.09	9.6	33.3	0.53
12-Jun-02	18:15	60	835.84	371.81	81.94	264.8	52.55	18.31	18.16	9.6	33.3	0.52
12-Jun-02	18:20	60	837.07	377.09	82.51	263.2	53.35	18.15	18.22	9.6	33.3	0.52
12-Jun-02	18:25	60	837.27	379.24	82.8	262.4	53.45	18.08	18.28	9.6	33.3	0.53
12-Jun-02	18:30	Brine rate 4.8 bpd and cum = 33.4 bbls.										
12-Jun-02	18:30	60	837.68	377.58	82.94	264.1	53.66	18.21	18.35	4.8	33.4	0.27
12-Jun-02	18:35	60	835.23	378.07	82.91	261.9	53.79	18.14	18.41	4.8	33.4	0.26
12-Jun-02	18:40	60	836.66	377.21	81.96	263.5	53.45	18.12	18.47	4.8	33.4	0.26
12-Jun-02	18:45	60	839.32	380.89	82.05	262.4	53.19	18.2	18.54	4.8	33.4	0.26
12-Jun-02	18:50	60	842.38	381.14	81.88	264.7	53.03	18.25	18.6	4.8	33.4	0.26
12-Jun-02	18:55	60	844.23	380.4	81.67	266.1	52.68	18.37	18.66	4.8	33.4	0.26
12-Jun-02	19:00	Brine rate 4.8 bpd and cum = 33.5 bbls. brine SG = 1.084 at 62 F.										
12-Jun-02	19:00	BSW=100% brine, pH = 6 and Chl contents from refrac 109,000ppm.										
12-Jun-02	19:00	60	845.04	379.91	81.69	266.8	52.58	18.44	18.73	4.8	33.5	0.26
12-Jun-02	19:05	60	844.43	379.11	81.12	267.8	52.32	18.48	18.79	4.8	33.5	0.26
12-Jun-02	19:10	60	843.61	376.66	81.44	267.1	52.25	18.47	18.86	4.8	33.5	0.26
12-Jun-02	19:14	Coil tubing at depth 1535m RT.										
12-Jun-02	19:15	60	839.52	373.41	82.35	265.7	52.71	18.44	18.92	4.8	33.5	0.26
12-Jun-02	19:20	60	834.2	370.89	82.24	264	53	18.31	18.98	4.8	33.5	0.26
12-Jun-02	19:24	Coil tubing commence POOH.										
12-Jun-02	19:25	60	832.98	369.91	82.48	263.7	53.27	18.25	19.05	4.8	33.5	0.26
12-Jun-02	19:30	Brine rate 24 bpd and cum = 34 bbls. Draeger 0.1% CO2 and 0ppm H2S.										
12-Jun-02	19:30	60	837.88	380.09	82.5	261.1	53.4	18.03	19.11	24	34	1.31
12-Jun-02	19:35	60	839.73	380.22	82.67	264.5	53.5	18.13	19.17	24	34	1.33
12-Jun-02	19:40	60	840.95	378.5	82.81	265.4	53.46	18.31	19.24	24	34	1.32
12-Jun-02	19:45	60	841.16	378.31	82.97	265.4	53.56	18.32	19.3	24	34	1.31
12-Jun-02	19:50	60	841.16	379.3	82.96	265.4	53.63	18.31	19.36	24	34	1.31
12-Jun-02	19:55	60	841.36	378.62	82.97	265.7	53.61	18.31	19.43	24	34	1.31
12-Jun-02	20:00	BSW=100% brine, pH = 6 and Chl contents from refrac 100,000ppm.										
12-Jun-02	20:00	Brine rate 19.2 bpd and cum = 34.4 bbls. brine SG = 1.090 at 62 F.										
12-Jun-02	20:00	60	840.54	376.97	83.34	266.1	53.83	18.33	19.49	19.2	34.4	1.05
12-Jun-02	20:05	60	821.12	369.48	83.22	259.4	54.01	18.09	19.55	19.2	34.4	1.05
12-Jun-02	20:10	60	818.47	371.51	83.16	252.3	54.81	17.52	19.61	19.2	34.4	1.06
12-Jun-02	20:15	60	817.65	369.12	83.57	243.8	55.49	17.03	19.67	19.2	34.4	1.1
12-Jun-02	20:20	60	813.56	368.5	83.3	243.8	55.36	17.09	19.73	19.2	34.4	1.13
12-Jun-02	20:25	60	811.51	370.16	83.21	248.6	55.96	17.05	19.79	19.2	34.4	1.12
12-Jun-02	20:30	BSW=100% brine, pH = 6 and Chl contents from refrac 118,000ppm.										
12-Jun-02	20:30	Brine rate 19.2 bpd and cum = 35.8 bbls. brine SG = 1.091 at 62 F.										
12-Jun-02	20:30	60	813.15	370.53	83.21	249.7	55.61	17.17	19.85	19.2	35.8	1.13
12-Jun-02	20:35	60	813.56	370.71	83.61	251.6	55.77	17.29	19.91	19.2	35.8	1.12
12-Jun-02	20:40	60	807.43	368.44	83.51	248.4	55.72	17.17	19.97	19.2	35.8	1.11
12-Jun-02	20:45	Coil tubing at depth 902m RT.										
12-Jun-02	20:45	60	808.24	368.93	83.61	251.6	55.98	17.15	20.03	19.2	35.8	1.12
12-Jun-02	20:50	60	822.15	376.23	83.45	254.3	56.32	17.14	20.09	19.2	35.8	1.12
12-Jun-02	20:55	60	832.98	380.34	83.7	261.7	55.38	17.81	20.15	19.2	35.8	1.12
12-Jun-02	21:00	Brine rate 86 bpd and cum = 37.6 bbls. Draeger 0.1% CO2 and 0ppm H2S.										
12-Jun-02	21:00	60	835.02	379.24	83.93	264.1	55.15	18.09	20.21	86.4	37.6	4.85
12-Jun-02	21:05	60	834.2	378.19	84.03	264.1	55.09	18.15	20.28	86.4	37.6	4.77
12-Jun-02	21:10	60	837.27	378.93	84.24	265.2	55.09	18.19	20.34	86.4	37.6	4.76
12-Jun-02	21:15	60	835.43	380.4	84.27	263.8	55.15	18.13	20.4	86.4	37.6	4.75
12-Jun-02	21:20	60	828.89	376.29	83.94	262.8	55.17	18.07	20.47	86.4	37.6	4.77
12-Jun-02	21:25	60	830.73	380.22	83.4	257.7	54.95	17.88	20.53	86.4	37.6	4.78
12-Jun-02	21:30	Brine rate 0 bpd and cum = 37.6 bbls.										
12-Jun-02	21:30	60	837.48	383.28	82.79	263.5	54.38	17.94	20.59	0	37.6	0
12-Jun-02	21:35	60	839.73	383.59	82.99	265.6	54.03	18.14	20.65	0	37.6	0
12-Jun-02	21:40	60	839.93	382.73	82.72	266.4	53.72	18.24	20.72	0	37.6	0
12-Jun-02	21:45	60	840.54	382.73	82.92	266.1	53.51	18.28	20.78	0	37.6	0
12-Jun-02	21:50	60	841.77	383.71	83.27	266.0	53.65	18.31	20.84	0	37.6	0
12-Jun-02	21:55	60	841.97	382.85	82.91	267.0	53.58	18.36	20.91	0	37.6	0
12-Jun-02	22:00	Brine rate 48 bpd and cum = 38.6 bbls.										
12-Jun-02	22:00	60	841.16	380.65	82.84	267.0	53.35	18.37	20.97	48	38.6	2.62
12-Jun-02	22:04	Shut in well at choke manifold. Inspected sand catcher, trace sand.										
12-Jun-02	22:05	0	976.7	3.04	84.7	5.19	40.78	10.99	21.01	0	38.6	0
12-Jun-02	22:10	0	980.58	0.53	80.53	2.31	37.72	0	21.01	0	38.6	0
12-Jun-02	22:15	0	981.4	0.22	76.39	2.31	42.57	0	21.01	0	38.6	
12-Jun-02	22:20	0	982.01	0.22	73.34	2.31	45.81	0	21.01	0	38.6	
12-Jun-02	22:25	0	982.22	0.22	71.22	2.31	47.88	0	21.01	0	38.6	
12-Jun-02	22:30	0	982.83	0.22	69.58	2.31	49.35	0	21.01	0	38.6	
12-Jun-02	22:35	0	983.03	0.22	68.19	2.31	50.3	0	21.01	0	38.6	
12-Jun-02	22:40	0	983.44	0.22	67.06	2.37	50.92	0	21.01	0	38.6	
12-Jun-02	22:45	0	983.85	0.28	65.99	2.37	51.41	0	21.01	0	38.6	
12-Jun-02	22:50	0	984.46	0	65.03	2.37	51.73	0	21.01	0	38.6	
12-Jun-02	22:55	0	984.26	0	64.12	2.31	51.93	0	21.01	0	38.6	
12-Jun-02	23:00	0	984.06	0	63.34	2.19	52.08	0	21.01	0	38.6	
12-Jun-02	23:05	0	984.67	0.28	62.65	2.37	52.17	0	21.01	0	38.6	
12-Jun-02	23:10	0	984.87	0	62.02	2.06	52.25	0	21.01	0	38.6	
12-Jun-02	23:15	0	984.26	0.22	61.48	2	52.25	0	21.01	0	38.6	

12-Jun-02	23:20	0	984.67	0	60.99	2	52.36	0	21.01	0	38.6	
12-Jun-02	23:25	0	984.46	0	60.6	2	52.42	0	21.01	0	38.6	
12-Jun-02	23:30	0	984.87	0.22	60.18	2.06	52.53	0	21.01	0	38.6	
12-Jun-02	23:35	0	985.08	0	59.79	1.76	52.69	0	21.01	0	38.6	
12-Jun-02	23:40	0	984.67	0	59.41	1.63	52.87	0	21.01	0	38.6	
12-Jun-02	23:45	0	984.67	0	59.04	2	53.09	0	21.01	0	38.6	
12-Jun-02	23:50	0	984.67	0	58.72	1.63	53.24	0	21.01	0	38.6	
12-Jun-02	23:55	0	985.48	0	58.49	1.69	53.47	0	21.01	0	38.6	
13-Jun-02	0:00	0	985.28	0	58.21	1.63	53.72	0	21.01	0	38.6	
13-Jun-02	0:05	0	985.48	0	58	2.06	54	0	21.01	0	38.6	
13-Jun-02	0:10	0	986.1	0	57.78	2.06	54.25	0	21.01	0	38.6	
13-Jun-02	0:15	0	985.69	0	57.6	2.25	54.46	0	21.01	0	38.6	
13-Jun-02	0:20	0	986.51	0	57.4	2.37	54.58	0	21.01	0	38.6	
13-Jun-02	0:25	0	985.89	0	57.23	2.31	54.73	0	21.01	0	38.6	
13-Jun-02	0:30	0	986.3	0	56.99	2.19	54.79	0	21.01	0	38.6	
13-Jun-02	0:35	0	986.3	0	56.81	2.31	54.85	0	21.01	0	38.6	
13-Jun-02	0:40	0	986.51	0	56.64	2.37	54.96	0	21.01	0	38.6	
13-Jun-02	0:45	0	986.71	0	56.42	2.31	55.01	0	21.01	0	38.6	
13-Jun-02	0:50	0	986.3	0.22	56.23	2.49	55.03	0	21.01	0	38.6	
13-Jun-02	0:55	0	986.3	0.22	56.05	2.31	55.04	0	21.01	0	38.6	
13-Jun-02	1:00	0	986.92	0.22	55.9	2.37	54.92	0	21.01	0	38.6	
13-Jun-02	1:05	0	986.92	0.04	55.74	2.74	54.86	0	21.01	0	38.6	
13-Jun-02	1:10	0	986.51	0	55.56	2.06	54.8	0	21.01	0	38.6	
13-Jun-02	1:15	0	986.51	0	55.47	2.06	54.82	0	21.01	0	38.6	
13-Jun-02	1:20	0	986.51	0	55.35	1.82	54.79	0	21.01	0	38.6	
13-Jun-02	1:25	0	986.3	0	55.28	2	54.77	0	21.01	0	38.6	
13-Jun-02	1:30	0	986.92	0	55.29	1.82	54.77	0	21.01	0	38.6	
13-Jun-02	1:35	0	986.71	0	55.29	1.63	54.79	0	21.01	0	38.6	
13-Jun-02	1:40	0	986.92	0	55.29	2.06	54.81	0	21.01	0	38.6	
13-Jun-02	1:45	0	987.12	0	55.34	2.06	54.84	0	21.01	0	38.6	
13-Jun-02	1:50	0	987.12	0	55.36	2.37	54.93	0	21.01	0	38.6	
13-Jun-02	1:55	0	987.33	0.04	55.36	2.37	54.95	0	21.01	0	38.6	
13-Jun-02	2:00	0	987.33	0	55.31	2.31	55.03	0	21.01	0	38.6	
13-Jun-02	2:05	0	987.53	0	55.33	2.31	55.04	0	21.01	0	38.6	
13-Jun-02	2:10	0	987.53	0	55.28	2.25	55.04	0	21.01	0	38.6	
13-Jun-02	2:13	Opened well through separator on 24/64" adjustable choke to flare line.										
13-Jun-02	2:15	24	983.44	29.97	55.65	19.85	55.57	0	21.01	0	38.6	
13-Jun-02	2:16	Diverted flow to 28/64" adjustable choke.										
13-Jun-02	2:18	Diverted flow to 32/64" adjustable choke.										
13-Jun-02	2:20	36	981.81	33.28	58.05	23.96	49.48	0	21.01	0	38.6	
13-Jun-02	2:25	Diverted flow to 34/64" adjustable choke.										
13-Jun-02	2:25	36	975.47	223.28	60.32	220.4	45.01	0	21.01	0	38.6	
13-Jun-02	2:30	36	968.93	236.09	62.46	229.9	39.04	0	21.01	0	38.6	
13-Jun-02	2:35	Diverted flow to 32/64" fixed choke.										
13-Jun-02	2:35	36	979.35	283.19	63.47	272.5	38.23	0	21.01	0	38.6	
13-Jun-02	2:40	32	958.09	302.57	65.38	293.3	36.71	0	21.01	0	38.6	
13-Jun-02	2:44	Lowered 2.25" orifice into separator gas line.										
13-Jun-02	2:45	32	958.09	315.33	66.55	306.3	37.06	1.21	21.01	0	38.6	
13-Jun-02	2:50	32	958.09	311.83	67.26	302.8	36.94	6.26	21.04	0	38.6	0
13-Jun-02	2:55	32	957.68	313.92	67.87	305.0	36.96	6.15	21.06	0	38.6	0
13-Jun-02	3:00	No liquids at surface. SG of produced gas = 0.578.										
13-Jun-02	3:00	32	958.3	312.75	68.27	303.4	37.17	6.2	21.08	0	38.6	0
13-Jun-02	3:05	32	957.89	312.63	68.48	303.4	37.28	6.23	0.01	0	38.6	
13-Jun-02	3:10	32	957.27	313.92	68.82	304.8	37.31	6.18	0.04	0	38.6	0
13-Jun-02	3:15	32	956.87	311.77	68.92	302.1	37.48	6.19	0.06	0	38.6	0
13-Jun-02	3:20	32	956.87	313.8	69.14	304.4	37.49	6.18	0.08	0	38.6	0
13-Jun-02	3:25	32	956.87	313.12	69.42	303.6	37.57	6.18	0.1	0	38.6	0
13-Jun-02	3:30	32	957.07	311.77	69.65	302.3	37.65	6.18	0.12	0	38.6	0
13-Jun-02	3:35	32	956.66	311.59	69.57	302.0	37.74	6.18	0.14	0	38.6	0
13-Jun-02	3:40	32	956.46	311.65	69.58	302.8	37.71	6.18	0.16	0	38.6	0
13-Jun-02	3:45	32	956.66	311.77	69.69	302.7	37.75	6.18	0.19	0	38.6	0
13-Jun-02	3:50	32	956.46	311.65	69.75	302.8	37.77	6.18	0.21	0	38.6	0
13-Jun-02	3:55	32	956.46	312.94	69.82	304.1	37.77	6.18	0.23	0	38.6	0
13-Jun-02	4:00	32	956.26	313.12	69.9	304.0	37.84	6.18	0.25	0	38.6	0
13-Jun-02	4:05	32	956.05	313.24	69.96	304.2	37.85	6.18	0.27	0	38.6	0
13-Jun-02	4:10	32	956.46	313.8	70.02	304.4	37.85	6.18	0.29	0	38.6	0
13-Jun-02	4:15	Commenced taking PVT gas sample 1-3 (cylinder# 2750-C1-F).										
13-Jun-02	4:15	32	956.46	313.18	70.06	304.2	37.95	6.18	0.32	0	38.6	0
13-Jun-02	4:20	32	956.05	312.69	70.16	303.8	37.95	6.18	0.34	0	38.6	0
13-Jun-02	4:25	32	956.05	312.26	70.22	303.1	38.03	6.18	0.36	0	38.6	0
13-Jun-02	4:30	Completed taking PVT gas sample 1-3 (cylinder# 2750-C1-F).										
13-Jun-02	4:30	Commenced taking PVT gas sample 1-4 (cylinder# 1851-C1-F).										
13-Jun-02	4:30	32	956.05	313.49	70.35	304.4	37.96	6.17	0.38	0	38.6	0
13-Jun-02	4:35	32	956.05	312.69	70.45	303.8	38.07	6.17	0.4	0	38.6	0
13-Jun-02	4:40	32	955.64	312.82	70.56	303.3	38.12	6.17	0.42	0	38.6	0
13-Jun-02	4:45	Completed taking PVT gas sample 1-4 (cylinder# 1851-C1-F).										
13-Jun-02	4:45	32	955.85	312.57	70.66	303.4	38.18	6.17	0.44	0	38.6	0

13-Jun-02 4:50	32	955.03	312.69	70.55	303.4	38.25	6.17	0.47	0	38.6	0
13-Jun-02 4:55	32	954.82	312.57	70.67	303.3	38.24	6.17	0.49	0	38.6	0
13-Jun-02 5:00	No liquids at surface. SG of produced gas = 0.578										
13-Jun-02 5:00	32	955.03	312.39	70.66	303.4	38.28	6.16	0.51	0	38.6	0
13-Jun-02 5:05	32	955.03	312.57	70.65	303.8	38.31	6.16	0.53	0	38.6	0
13-Jun-02 5:10	32	955.03	312.14	70.74	303.1	38.31	6.17	0.55	0	38.6	0
13-Jun-02 5:15	32	955.03	312.2	70.81	303.1	38.42	6.16	0.57	0	38.6	0
13-Jun-02 5:20	32	954.82	311.77	70.67	303.1	38.44	6.17	0.59	0	38.6	0
13-Jun-02 5:25	32	955.03	311.83	70.66	302.7	38.45	6.16	0.61	0	38.6	0
13-Jun-02 5:30	32	955.23	311.53	70.65	302.0	38.34	6.17	0.64	0	38.6	0
13-Jun-02 5:35	32	954.82	311.83	70.72	302.5	38.39	6.17	21.74	0	38.6	0
13-Jun-02 5:40	32	954.62	311.65	70.88	302.7	38.39	6.16	21.76	0	38.6	0
13-Jun-02 5:45	32	955.03	311.83	70.99	302.5	38.49	6.16	21.79	0	38.6	0
13-Jun-02 5:50	32	954.62	311.77	70.95	302.1	38.5	6.17	21.81	0	38.6	0
13-Jun-02 5:55	32	954.41	311.53	70.93	302.7	38.55	6.15	21.83	0	38.6	0
13-Jun-02 6:00	32	954.41	311.83	71.01	302.5	38.53	6.16	21.85	0	38.6	0
13-Jun-02 6:01	Raised orifice plate from separator gas meter run.										
13-Jun-02 6:03	Diverted flow to 36/64" adjustable choke.										
13-Jun-02 6:04	Commenced increasing adjustable choke to 40/64".										
13-Jun-02 6:05	Adjustable choke at 40/64".										
13-Jun-02 6:05	40	942.96	203.4	70.87	177.0	35.96	0	21.85	0	38.6	0
13-Jun-02 6:07	Commenced increasing adjustable choke to 44/64".										
13-Jun-02 6:08	Adjustable choke at 44/64".										
13-Jun-02 6:10	44	903.71	222.85	71.55	183.3	34.81	0	21.85	0	38.6	
13-Jun-02 6:12	Commenced increasing adjustable choke to 48/64".										
13-Jun-02 6:13	Adjustable choke at 48/64".										
13-Jun-02 6:15	48	873.05	315.45	73.06	249.2	39.88	0	21.85	0	38.6	
13-Jun-02 6:19	Lowered 3.0" orifice into separator gas line.										
13-Jun-02 6:20	48	893.29	366.23	74.84	307.4	46.45	4.53	21.87	0	38.6	
13-Jun-02 6:25	Raised orifice plate from separator gas meter run.										
13-Jun-02 6:25	48	896.76	358.26	74.69	303.1	44.66	9.4	21.9	0	38.6	0
13-Jun-02 6:26	Diverted flow to 48/64" fixed choke.										
13-Jun-02 6:27	Lowered 3.0" orifice into separator gas line.										
13-Jun-02 6:30	BS&W = 2% mud,98% brine. Commenced flow to surge tank.										
13-Jun-02 6:30	48	883.27	368.07	75.16	307.2	44.57	10.19	21.93	0	38.6	0
13-Jun-02 6:35	48	888.38	375.37	75.71	310.4	45.18	12.67	21.98	0	38.6	0
13-Jun-02 6:40	48	893.08	372.18	75.88	309.1	45.87	12.76	22.02	0	38.6	0
13-Jun-02 6:45	48	896.15	371.45	76.13	309.8	45.67	12.94	22.07	0	38.6	0
13-Jun-02 6:50	48	897.17	369.48	76.46	308.2	45.69	13.06	22.11	0	38.6	0
13-Jun-02 6:55	48	898.8	370.71	76.5	309.1	45.88	13.1	22.16	0	38.6	0
13-Jun-02 7:00	BS&W = 2% mud and 98% brine, pH = 6 and Chl from refrac 110,000ppm.										
13-Jun-02 7:00	Brine rate 38.4 bpd and cum = 39.4 bbls. brine SG = 1.090 at 62 F.										
13-Jun-02 7:00	SG of produced gas 0.586. Draeger 0.1% CO2 and 0ppm H2S.										
13-Jun-02 7:00	48	900.03	371.02	76.83	309.3	46.08	13.1	22.2	38.4	39.4	2.93
13-Jun-02 7:05	48	901.06	371.63	77.04	309.8	46.16	13.08	22.25	38.4	39.4	2.93
13-Jun-02 7:10	48	902.08	371.88	77.04	310.1	46.26	13.11	22.29	38.4	39.4	2.94
13-Jun-02 7:15	48	902.69	370.16	77.04	308.9	46.24	13.13	22.34	38.4	39.4	2.93
13-Jun-02 7:20	48	902.89	370.16	76.99	309.5	46.21	13.13	22.39	38.4	39.4	2.93
13-Jun-02 7:25	Commenced conducting flowing gradient survey with coil tubing.										
13-Jun-02 7:25	48	903.1	369.79	77.4	309.5	46.37	13.14	22.43	38.4	39.4	2.93
13-Jun-02 7:30	BS&W = 100% brine, pH = 6 and Chl from refrac 100,000ppm.										
13-Jun-02 7:30	Brine rate 24.0 bpd and cum = 39.9 bbls.										
13-Jun-02 7:30	48	891.65	365.56	77.77	306.7	46.78	13.08	22.48	24	39.9	1.83
13-Jun-02 7:35	48	889.2	364.21	78.12	308.1	47.35	12.98	22.52	24	39.9	1.83
13-Jun-02 7:40	48	885.52	368.75	78.26	308.2	47.76	12.91	22.57	24	39.9	1.85
13-Jun-02 7:45	48	883.68	370.71	78.14	307.6	48.56	12.69	22.61	24	39.9	1.86
13-Jun-02 7:50	48	887.57	371.2	78.59	308.3	49.22	12.64	22.65	24	39.9	1.89
13-Jun-02 7:55	48	894.92	370.77	79.13	309.1	49.05	12.88	22.7	24	39.9	1.9
13-Jun-02 8:00	BS&W = 100% brine, pH = 6 and Chl from refrac 115,000ppm.										
13-Jun-02 8:00	Brine rate 38.4 bpd and cum = 40.7 bbls. brine SG = 1.092 at 45 F.										
13-Jun-02 8:00	48	897.79	371.75	79.66	309.5	49.45	12.87	22.74	38.4	40.7	2.98
13-Jun-02 8:05	48	888.99	366.36	79.47	308.5	49.39	12.97	22.79	38.4	40.7	2.98
13-Jun-02 8:10	48	894.1	367.95	79.74	309.1	49.5	12.94	22.83	38.4	40.7	2.96
13-Jun-02 8:15	48	897.79	368.5	80.25	308.8	50	12.92	22.88	38.4	40.7	2.97
13-Jun-02 8:20	48	900.65	369.85	80.15	309.8	49.83	13.06	22.92	38.4	40.7	2.97
13-Jun-02 8:25	48	904.12	370.53	80.8	310.1	50.04	13.1	22.97	38.4	40.7	2.94
13-Jun-02 8:30	BS&W = 100% brine, pH = 6 and Chl from refrac 115,000ppm.										
13-Jun-02 8:30	Brine rate 38.4 bpd and cum = 41.5 bbls.										
13-Jun-02 8:30	48	906.17	369.12	80.8	310.5	50.2	13.19	23.02	38.4	41.5	2.93
13-Jun-02 8:35	48	906.57	368.5	80.13	309.1	49.78	13.24	23.06	38.4	41.5	2.91
13-Jun-02 8:40	48	907.39	368.87	79.78	309.5	49.32	13.3	23.11	38.4	41.5	2.9
13-Jun-02 8:45	48	908.21	368.13	79.09	311.5	49	13.32	23.15	38.4	41.5	2.89
13-Jun-02 8:50	48	907.39	368.07	78.56	311.7	48.31	13.38	23.2	38.4	41.5	2.88
13-Jun-02 8:55	48	906.57	366.11	78.23	311.5	48	13.4	23.25	38.4	41.5	2.87
13-Jun-02 9:00	BS&W = 100% brine, pH = 6 and Chl from refrac 110,000ppm.										
13-Jun-02 9:00	Brine rate 4.8 bpd and cum = 41.6 bbls.										
13-Jun-02 9:00	48	904.74	365.62	78.21	311.1	47.83	13.36	23.29	4.8	41.6	0.36

13-Jun-02	9:05	48	904.74	367.83	77.97	310.2	47.66	13.33	23.34	4.8	41.6	0.36
13-Jun-02	9:10	48	905.15	367.15	77.5	310.5	47.34	13.33	23.39	4.8	41.6	0.36
13-Jun-02	9:15	Completed flowing gradient survey with coil tubing. CT at 902mRT.										
13-Jun-02	9:15	Collected water sample 1.5 from separator water line.										
13-Jun-02	9:15	48	904.74	367.83	77.55	310.7	47.15	13.35	23.43	4.8	41.6	0.36
13-Jun-02	9:20	48	904.94	368.32	78.42	310.1	47.49	13.34	23.48	4.8	41.6	0.36
13-Jun-02	9:25	48	905.35	368.87	78.58	310.3	47.76	13.3	23.52	4.8	41.6	0.36
13-Jun-02	9:30	BS&W = 100% brine, pH = 6 and Chl from refrac 115,000ppm.										
13-Jun-02	9:30	Brine rate 0 bpd and cum = 41.6 bbls.										
13-Jun-02	9:30	48	906.37	368.01	78.25	310.6	47.76	13.32	23.57	0	41.6	0
13-Jun-02	9:35	48	906.57	369.42	78.28	310.6	47.61	13.36	23.62	0	41.6	0
13-Jun-02	9:40	48	906.57	369.79	77.97	310.5	47.51	13.33	23.66	0	41.6	0
13-Jun-02	9:45	48	906.57	369.73	77.91	309.8	47.32	13.32	23.71	0	41.6	0
13-Jun-02	9:50	48	906.98	369.79	77.98	310.1	47.37	13.32	23.76	0	41.6	0
13-Jun-02	9:55	48	906.78	369.36	78.1	310.1	47.39	13.3	23.8	0	41.6	0
13-Jun-02	10:00	BS&W = 100% brine, pH = 6 and Chlfrom refrac 100,000ppm.										
13-Jun-02	10:00	Brine rate 0 bpd and cum = 41.6 bbls.										
13-Jun-02	10:00	48	906.98	368.87	77.97	310.7	47.43	13.37	23.85	0	41.6	0
13-Jun-02	10:05	48	907.19	366.6	77.79	311.5	47.29	13.36	23.89	0	41.6	0
13-Jun-02	10:10	48	907.19	365.56	77.81	311.5	47.16	13.4	23.94	0	41.6	0
13-Jun-02	10:15	48	906.98	365.07	77.93	311.1	47.18	13.4	23.99	0	41.6	0
13-Jun-02	10:20	48	906.37	364.45	77.6	311.2	47.13	13.4	24.03	0	41.6	0
13-Jun-02	10:25	48	904.94	363.41	77.69	309.9	47.02	13.39	24.08	0	41.6	0
13-Jun-02	10:30	BS&W = 100% brine, pH = 6 and Chlfrom refrac 105,000ppm.										
13-Jun-02	10:30	Brine rate 0 bpd and cum = 41.6 bbls.										
13-Jun-02	10:30	48	904.94	363.35	77.88	309.9	47.12	13.35	24.13	0	41.6	0
13-Jun-02	10:31	Raised orifice plate from separator gas meter run.										
13-Jun-02	10:33	Diverted flow through 50/64" adjustable choke.										
13-Jun-02	10:34	Commenced increasing adjustable choke to 54/64".										
13-Jun-02	10:35	Adjustable choke at 54/64".										
13-Jun-02	10:35	54	882.86	311.77	77.48	218.1	44.59	0	24.13	0	41.6	0
13-Jun-02	10:36	Commenced increasing adjustable choke to 58/64".										
13-Jun-02	10:37	Adjustable choke at 58/64".										
13-Jun-02	10:39	Commenced increasing adjustable choke to 60/64".										
13-Jun-02	10:40	Adjustable choke at 60/64".										
13-Jun-02	10:40	60	818.26	365.01	78.05	250.3246.65		0	24.13	0	41.6	
13-Jun-02	10:43	Diverted flow through 60/64" fixed choke.										
13-Jun-02	10:45	Lowered 3.75" orifice into separator gas meter run.										
13-Jun-02	10:45	60	830.12	378.87	78.44	253.9	49.44	3.48	24.14	0	41.6	
13-Jun-02	10:50	60	839.32	382.98	78.97	259.5	49.02	17.73	24.2	0	41.6	0
13-Jun-02	10:55	60	842.18	383.53	79.27	262.8	49.18	18	24.26	0	41.6	0
13-Jun-02	11:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 110,000ppm.										
13-Jun-02	11:00	Brine rate 67.2 bpd and cum = 43.0 bbls.										
13-Jun-02	11:00	60	841.56	382.12	79.33	264.4	49.27	18.09	24.33	67.2	43	3.73
13-Jun-02	11:05	60	841.56	381.38	79.5	264.8	49.28	18.14	24.39	38.4	43.8	2.12
13-Jun-02	11:10	60	841.16	383.28	79.67	263.7	49.49	18.08	24.45	38.4	43.8	2.12
13-Jun-02	11:15	60	843.61	384.26	80.01	264.5	49.66	18.1	24.51	38.4	43.8	2.12
13-Jun-02	11:20	60	844.23	383.9	80.18	264.8	49.82	18.04	24.58	38.4	43.8	2.12
13-Jun-02	11:25	60	843.82	382.18	80.08	265.8	49.82	18.18	24.64	38.4	43.8	2.13
13-Jun-02	11:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 115,000ppm.										
13-Jun-02	11:30	Brine rate 38.4 bpd and cum = 43.8 bbls.										
13-Jun-02	11:30	60	844.23	382.98	79.94	265.2	49.83	18.17	24.7	38.4	43.8	2.11
13-Jun-02	11:35	60	843.41	383.9	79.83	265.8	49.81	18.28	24.77	38.4	43.8	2.11
13-Jun-02	11:38	Sudden increase in wellhead pressure, possibly fixed choke partially plug.										
13-Jun-02	11:40	60	874.28	338.15	80.54	234.2	48.74	17.36	24.83	38.4	43.8	2.1
13-Jun-02	11:45	60	874.68	338.39	80.12	233.2	47.82	16.22	24.88	38.4	43.8	2.21
13-Jun-02	11:50	60	875.71	339.06	79.81	233.1	47.4	16.17	24.94	38.4	43.8	2.37
13-Jun-02	11:55	60	877.34	339.19	79.99	233.9	47.3	16.24	25	38.4	43.8	2.37
13-Jun-02	12:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 105,000ppm.										
13-Jun-02	12:00	Brine rate 0 bpd and cum = 43.8 bbls. SG brine 1.08 at 48 F.										
13-Jun-02	12:00	SG of produced gas 0.580. Draeger 0.1% CO2 and 0ppm H2S.										
13-Jun-02	12:00	60	878.98	339.13	79.74	234.5	47.07	16.3	25.05	0	43.8	0
13-Jun-02	12:02	Raised orifice plate from separator gas meter run.										
13-Jun-02	12:02	Diverted flow to 60/64" adj choke. Retrieved fixed choke for plugging.										
13-Jun-02	12:04	Inspection revealed small metal debri lodged on fixed choke.										
13-Jun-02	12:05	60	852	376.9	79.65	260.7	48.19	3.29	25.06	0	43.8	0
13-Jun-02	12:08	Diverted flow through 60/64" fixed choke.										
13-Jun-02	12:10	Lowered 3.75" orifice into separator gas meter run.										
13-Jun-02	12:10	60	843.61	380.22	79.98	265.5	49.16	3.64	25.08	0	43.8	0
13-Jun-02	12:15	60	839.93	374.94	79.97	264.1	49.64	18.16	25.14	0	43.8	0
13-Jun-02	12:20	60	843	383.28	79.91	260.5	49.78	18.07	25.2	0	43.8	0
13-Jun-02	12:25	60	847.29	384.57	80.42	264.1	50.09	18.07	25.27	0	43.8	0
13-Jun-02	12:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 100,000ppm.										
13-Jun-02	12:30	Brine rate 24 bpd and cum = 44.3 bbls.										
13-Jun-02	12:30	60	848.31	383.41	80.42	265.9	50.09	18.21	25.33	24	44.3	1.33
13-Jun-02	12:35	60	848.31	383.9	80.3	266.3	50.04	18.3	25.39	24	44.3	1.32
13-Jun-02	12:40	60	847.5	383.22	80.64	265.9	50.3	18.3	25.46	24	44.3	1.31

13-Jun-02	12:45	60	847.5	382.85	80.56	265.9	50.38	18.25	25.52	24	44.3	1.31
13-Jun-02	12:50	60	847.29	383.65	80.62	265.5	50.52	18.25	25.58	24	44.3	1.32
13-Jun-02	12:55	Commenced conducting flowing gradient survey. RIH coil tubing to 1535mRT.										
13-Jun-02	12:55	60	847.91	381.87	80.31	266.0	50.52	18.26	25.65	24	44.3	1.32
13-Jun-02	13:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 95,000ppm.										
13-Jun-02	13:00	Brine rate 0 bpd and cum = 44.3 bbls.										
13-Jun-02	13:00	60	848.52	381.63	79.76	266.5	50.22	18.31	25.71	0	44.3	0
13-Jun-02	13:05	60	849.54	381.93	79.78	266.8	50	18.34	25.77	0	44.3	0
13-Jun-02	13:10	60	850.56	380.71	79.71	267.2	49.89	18.38	25.84	0	44.3	0
13-Jun-02	13:15	60	849.74	379.79	79.77	267.0	49.86	18.37	25.9	0	44.3	0
13-Jun-02	13:20	60	850.15	378.56	79.63	267.5	49.83	18.41	25.96	0	44.3	0
13-Jun-02	13:25	60	849.54	378.13	79.63	267.5	49.92	18.4	26.03	0	44.3	0
13-Jun-02	13:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 105,000ppm.										
13-Jun-02	13:30	Brine rate 28.8 bpd and cum = 44.9 bbls.										
13-Jun-02	13:30	60	848.31	377.58	78.55	267.6	49.61	18.42	26.09	28.8	44.9	1.56
13-Jun-02	13:35	60	845.25	375.49	79.6	266.2	49.75	18.4	26.16	28.8	44.9	1.56
13-Jun-02	13:40	60	845.45	375.56	78.74	266.2	49.55	18.33	26.22	28.8	44.9	1.56
13-Jun-02	13:45	60	847.5	378.25	78.08	266.5	49.07	18.36	26.28	28.8	44.9	1.57
13-Jun-02	13:50	60	847.5	383.53	78.07	264.8	48.73	18.3	26.35	28.8	44.9	1.57
13-Jun-02	13:55	Coil tubing at 1535 mRT. Stopped for 10 min.										
13-Jun-02	13:55	60	847.5	382.61	77.99	266.2	48.64	18.35	26.41	28.8	44.9	1.57
13-Jun-02	14:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 95,000ppm.										
13-Jun-02	14:00	Brine rate 0 bpd and cum 44.9 bbls. Collected sample from sep water line.										
13-Jun-02	14:00	60	848.52	379.97	79.37	266.8	49.18	18.36	26.47	0	44.9	0
13-Jun-02	14:05	60	843.41	375.62	79.98	265.2	49.79	18.33	26.54	0	44.9	0
13-Jun-02	14:10	60	842.18	374.51	80.01	265.2	50.1	18.25	26.6	0	44.9	0
13-Jun-02	14:12	Commenced POOH coil tubing to 902 mRT.										
13-Jun-02	14:15	60	838.91	380.4	80.3	260.5	50.24	18.17	26.67	0	44.9	0
13-Jun-02	14:20	60	842.59	381.99	80.41	263.0	50.64	18.03	26.73	0	44.9	0
13-Jun-02	14:25	60	848.31	385.25	80.37	264.4	50.54	18.15	26.79	0	44.9	0
13-Jun-02	14:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 95,000ppm.										
13-Jun-02	14:30	Brine rate 0 bpd and cum = 44.9 bbls.										
13-Jun-02	14:30	60	850.77	384.33	80.52	267.6	50.59	18.26	26.85	0	44.9	0
13-Jun-02	14:35	60	848.11	380.83	80.62	267.3	50.67	18.35	26.92	0	44.9	0
13-Jun-02	14:40	60	847.29	377.95	80.57	267.3	50.62	18.34	26.98	0	44.9	0
13-Jun-02	14:45	60	848.92	378.93	80.54	267.9	50.63	18.41	27.05	0	44.9	0
13-Jun-02	14:50	60	849.95	383.77	80.5	266.2	50.54	18.27	27.11	0	44.9	0
13-Jun-02	14:55	60	849.95	381.26	80.47	268.1	50.47	18.38	27.17	0	44.9	0
13-Jun-02	15:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 100,000ppm.										
13-Jun-02	15:00	Brine rate 24 bpd and cum = 45.4 bbls.										
13-Jun-02	15:00	Coil tubing at 902mRT. Completed conducting flowing gradient survey.										
13-Jun-02	15:00	60	843.2	376.66	80.43	266.0	50.47	18.36	27.24	24	45.4	1.31
13-Jun-02	15:05	60	837.27	372.18	80.24	264.1	50.6	18.19	27.3	24	45.4	1.31
13-Jun-02	15:10	60	841.77	382.67	80.2	261.1	50.44	18.15	27.36	24	45.4	1.32
13-Jun-02	15:15	60	844.43	382.92	80.26	264.1	50.65	18.11	27.43	24	45.4	1.32
13-Jun-02	15:20	60	845.04	381.38	80.24	265.4	50.53	18.27	27.49	24	45.4	1.33
13-Jun-02	15:25	60	844.43	378.62	79.98	266.5	50.46	18.26	27.55	24	45.4	1.31
13-Jun-02	15:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 95,000ppm.										
13-Jun-02	15:30	Brine rate 24 bpd and cum = 45.9 bbls.										
13-Jun-02	15:30	60	845.66	379.66	79.82	266.9	50.31	18.32	27.62	24	45.9	1.31
13-Jun-02	15:35	60	845.66	384.02	80.1	265.1	50.37	18.23	27.68	24	45.9	1.31
13-Jun-02	15:40	60	846.07	384.57	79.81	265.9	50.21	18.21	27.74	24	45.9	1.32
13-Jun-02	15:45	60	845.25	383.04	80.01	266.4	50.21	18.25	27.81	24	45.9	1.32
13-Jun-02	15:50	60	845.25	382.3	80.18	265.1	50.3	18.21	27.87	24	45.9	1.31
13-Jun-02	15:55	60	844.23	382.92	80.47	264.6	50.49	18.19	27.93	24	45.9	1.32
13-Jun-02	16:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 100,000ppm.										
13-Jun-02	16:00	Brine rate 24 bpd and cum = 46.4 bbls.										
13-Jun-02	16:00	60	844.43	382.98	80.53	265.5	50.69	18.18	28	24	46.4	1.32
13-Jun-02	16:05	60	844.02	382.92	80.42	266.3	50.59	18.23	28.06	24	46.4	1.32
13-Jun-02	16:10	60	844.84	382.98	80.53	266.8	50.62	18.22	28.12	24	46.4	1.32
13-Jun-02	16:15	60	844.23	383.59	80.46	266.5	50.68	18.26	28.19	24	46.4	1.32
13-Jun-02	16:20	60	844.02	383.53	80.29	266.2	50.58	18.24	28.25	24	46.4	1.31
13-Jun-02	16:25	60	843.61	384.08	80.13	265.9	50.46	18.18	28.31	24	46.4	1.32
13-Jun-02	16:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 100,000ppm.										
13-Jun-02	16:30	Brine rate 24 bpd and cum = 46.9 bbls.										
13-Jun-02	16:30	60	842.79	383.41	80.37	266.2	50.52	18.19	28.37	24	46.9	1.32
13-Jun-02	16:35	60	842.18	383.77	80.16	265.7	50.47	18.17	28.44	24	46.9	1.32
13-Jun-02	16:40	60	841.77	383.59	80.26	265.2	50.48	18.15	28.5	24	46.9	1.32
13-Jun-02	16:45	60	840.75	383.53	80.13	264.1	50.44	18.09	28.56	24	46.9	1.32
13-Jun-02	16:50	60	839.52	382.36	80.12	264	50.48	18.03	28.63	24	46.9	1.33
13-Jun-02	16:55	60	838.91	382.67	80.4	263.1	50.55	18.03	28.69	24	46.9	1.33
13-Jun-02	17:00	BS&W = 100% brine, pH = 6 and Chl contents from refrac 105,000ppm.										
13-Jun-02	17:00	Brine rate 24 bpd and cum = 47.4 bbls.										
13-Jun-02	17:00	60	838.29	382.61	80.21	263.5	50.57	17.97	28.75	24	47.4	1.33
13-Jun-02	17:05	60	838.09	382.98	80.32	262.9	50.6	17.99	28.81	24	47.4	1.34
13-Jun-02	17:10	60	838.09	382.98	80.31	262.8	50.67	17.92	28.88	24	47.4	1.33
13-Jun-02	17:15	60	837.48	382.55	80.29	262.8	50.65	17.97	28.94	24	47.4	1.34

13-Jun-02	17:20	60	837.88	382.79	80.16	262.4	50.65	17.92	29	24	47.4	1.34
13-Jun-02	17:25	60	838.7	383.22	80.14	262.8	50.62	17.97	29.06	24	47.4	1.34
13-Jun-02	17:30	BS&W = 100% brine, pH = 6 and Chl contents from refrac 110,000ppm.										
13-Jun-02	17:30	Brine rate 19.2 bpd and cum = 47.8 bbls.										
13-Jun-02	17:30	60	838.5	382.98	80.26	263.5	50.75	18.18	29.13	19.2	47.8	1.07
13-Jun-02	17:35	0	979.76	0.1	79.97	2.06	36.31	3.8	29.13	0	47.8	0
13-Jun-02	17:40	0	981.19	0	75.96	2.25	41.1	0	29.13	0	47.8	0
13-Jun-02	17:45	0	981.6	0	72.82	2.37	44.36	0	29.13	0	47.8	
13-Jun-02	17:50	0	982.01	0	70.41	2.43	46.75	0	29.13	0	47.8	
13-Jun-02	17:55	0	982.62	0.22	68.29	2.31	48.43	0	29.13	0	47.8	
13-Jun-02	18:00	0	983.24	0	66.45	2.25	49.71	0	29.13	0	47.8	
13-Jun-02	18:05	0	983.24	0	64.61	2.74	50.69	0	29.13	0	47.8	
13-Jun-02	18:10	0	983.24	0	63.08	2.37	51.4	0	29.13	0	47.8	
13-Jun-02	18:15	0	983.24	0	61.88	2.06	51.94	0	29.13	0	47.8	
13-Jun-02	18:20	0	983.65	0	60.85	2.12	52.37	0	29.13	0	47.8	
13-Jun-02	18:25	0	983.65	0	59.95	2.19	52.73	0	29.13	0	47.8	
13-Jun-02	18:30	0	983.65	0	59.23	2.12	53.08	0	29.13	0	47.8	
13-Jun-02	18:35	0	983.65	0	58.65	2	53.35	0	29.13	0	47.8	
13-Jun-02	18:40	0	984.26	0	58.14	2.12	53.65	0	29.13	0	47.8	
13-Jun-02	18:45	0	984.46	0	57.79	2.12	53.92	0	29.13	0	47.8	
13-Jun-02	18:50	0	984.87	0	57.35	2.37	54.1	0	29.13	0	47.8	
13-Jun-02	18:55	0	984.87	0	57.06	2.43	54.27	0	29.13	0	47.8	
13-Jun-02	19:00	0	985.08	0	56.8	2.37	54.38	0	29.13	0	47.8	
13-Jun-02	19:05	0	985.08	0	56.55	2.06	54.47	0	29.13	0	47.8	
13-Jun-02	19:10	0	984.67	0	56.33	2.37	54.54	0	29.13	0	47.8	
13-Jun-02	19:15	0	985.28	0.22	56.2	3.04	54.65	0	29.13	0	47.8	
13-Jun-02	19:20	0	985.89	0.22	55.95	2.92	54.63	0	29.13	0	47.8	
13-Jun-02	19:25	0	985.89	0.22	55.72	2.8	54.59	0	29.13	0	47.8	
13-Jun-02	19:30	0	985.69	0.16	55.44	2.74	54.47	0	29.13	0	47.8	
13-Jun-02	19:35	0	985.69	0.16	55.14	2.43	54.35	0	29.13	0	47.8	
13-Jun-02	19:40	0	985.28	0.16	54.87	2	54.26	0	29.13	0	47.8	
13-Jun-02	19:45	0	985.28	0.22	54.71	2.12	54.2	0	29.13	0	47.8	
13-Jun-02	19:50	0	985.48	0.16	54.54	2.06	54.08	0	29.13	0	47.8	
13-Jun-02	19:55	0	985.69	0.16	54.44	2.43	54.06	0	29.13	0	47.8	
13-Jun-02	20:00	0	985.28	0	54.33	2.06	54.03	0	29.13	0	47.8	
13-Jun-02	20:05	0	985.48	0	54.22	2.31	53.99	0	29.13	0	47.8	
13-Jun-02	20:10	0	985.28	0	54.22	2	53.98	0	29.13	0	47.8	
13-Jun-02	20:15	0	985.28	0	54.2	1.76	54	0	29.13	0	47.8	
13-Jun-02	20:20	0	985.28	0	54.21	1.69	54.03	0	29.13	0	47.8	
13-Jun-02	20:25	0	985.69	0	54.28	2.06	54.06	0	29.13	0	47.8	
13-Jun-02	20:30	0	985.89	0	54.31	2.37	54.16	0	29.13	0	47.8	
13-Jun-02	20:35	0	986.1	0	54.35	2.37	54.21	0	29.13	0	47.8	
13-Jun-02	20:40	0	986.1	0	54.39	2.31	54.31	0	29.13	0	47.8	
13-Jun-02	20:45	0	986.3	0	54.42	2.31	54.32	0	29.13	0	47.8	
13-Jun-02	20:50	0	986.3	0	54.46	2.06	54.44	0	29.13	0	47.8	
13-Jun-02	20:55	0	986.3	0	54.48	2.25	54.46	0	29.13	0	47.8	
13-Jun-02	21:00	0	986.51	0	54.54	2.06	54.53	0	29.13	0	47.8	
13-Jun-02	21:02	Opened well on 16/64" adjustable choke to aft flare boom.										
13-Jun-02	21:03	Increased adjustable choke to 24/64".										
13-Jun-02	21:04	Increased adjustable choke to 28/64".										
13-Jun-02	21:05	Increased adjustable choke to 32/64".										
13-Jun-02	21:05	32	967.9	111.9	57.56	81.42	48.85	0	29.13	0	47.8	
13-Jun-02	21:06	Increased adjustable choke to 36/64".										
13-Jun-02	21:07	Increased adjustable choke to 40/64".										
13-Jun-02	21:08	Increased adjustable choke to 44/64".										
13-Jun-02	21:10	Increased adjustable choke to 48/64".										
13-Jun-02	21:10	48	919.05	279.51	63.47	182.9233.91		0	29.13	0	47.8	
13-Jun-02	21:11	Increased adjustable choke to 52/64".										
13-Jun-02	21:13	Increased adjustable choke to 56/64".										
13-Jun-02	21:14	Increased adjustable choke to 60/64".										
13-Jun-02	21:15	Increased adjustable choke to 64/64".										
13-Jun-02	21:15	64	823.17	377.09	68.61	265.8437.63		0	29.13	0	47.8	
13-Jun-02	21:19	Increased adjustable choke to 68/64".										
13-Jun-02	21:20	68	762.86	437.44	70.89	292.4545.15		0	29.13	0	47.8	
13-Jun-02	21:25	Increased adjustable choke to 76/64".										
13-Jun-02	21:25	76	715.43	499.93	71.75	338.7	48.85	0	29.13	0	47.8	
13-Jun-02	21:29	Increased adjustable choke to 80/64".										
13-Jun-02	21:30	Brine rate 79.9 bpd and cum = 49.5 bbls.										
13-Jun-02	21:30	80	727.29	458.53	73.71	314.6650.44		0	29.13	79.9	49.5	
13-Jun-02	21:33	Increased adjustable choke to 84/64".										
13-Jun-02	21:35	84	723	465.1	73.97	314.2952.09		0	29.13	79.9	49.5	
13-Jun-02	21:37	Increased adjustable choke to 88/64".										
13-Jun-02	21:40	88	693.97	509.19	73.64	346.4954.11		0	29.13	79.9	49.5	
13-Jun-02	21:42	Increased adjustable choke to 92/64".										
13-Jun-02	21:43	Increased adjustable choke to 96/64".										
13-Jun-02	21:45	96	674.14	549.79	73.98	378.9356.33		0	29.13	79.9	49.5	
13-Jun-02	21:46	Increased adjustable choke to 100/64".										

13-Jun-02 21:48 Increased adjustable choke to 104/64".
13-Jun-02 21:50 Increased adjustable choke to 108/64".
13-Jun-02 21:50 108 640 531.64 74.66 358.3857.53 0 29.13 79.9 49.5
13-Jun-02 21:52 Increased adjustable choke to 112/64".
13-Jun-02 21:54 Increased adjustable choke to 116/64".
13-Jun-02 21:55 116 640 542.06 75.06 367.8959.46 0 29.13 79.9 49.5
13-Jun-02 21:56 Diverted flow through 128/64" fixed choke.
13-Jun-02 21:59 Lowered 4.25" orifice into separator gas meter run.
13-Jun-02 22:00 SG of produced gas 0.578. Draeger 0.15% CO2 and 0ppm H2S.
13-Jun-02 22:00 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 115,000ppm.
13-Jun-02 22:00 Brine rate 100.8 bpd and cum = 51.6 bbls. brine SG 1.090 at 53 F.
13-Jun-02 22:00 128 631.21 560.16 74.99 384.9460.2 10.35 29.16 100.8 51.6
13-Jun-02 22:05 128 624.66 555.74 75.12 384.4560.78 26.09 29.25 100.8 51.6 9.73
13-Jun-02 22:10 128 624.87 554.27 75.39 380.0961.36 25.65 29.34 100.8 51.6 3.86
13-Jun-02 22:15 128 628.75 557.82 75.79 383.2261.81 25.64 29.43 100.8 51.6 3.93
13-Jun-02 22:20 128 628.14 558.25 75.9 385.9262.07 25.94 29.52 100.8 51.6 3.93
13-Jun-02 22:25 128 625.69 555.92 76.03 382.2462.37 25.83 29.61 100.8 51.6 3.89
13-Jun-02 22:30 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 116,000ppm.
13-Jun-02 22:30 Brine rate 81.6 bpd and cum = 53.3 bbls.
13-Jun-02 22:30 128 627.53 557.03 76.28 382.5562.72 25.73 29.7 81.6 53.3 3.16
13-Jun-02 22:35 128 630.39 560.52 76.31 387.5862.82 25.85 29.79 81.6 53.3 3.17
13-Jun-02 22:40 128 630.18 560.58 76.91 388.6263.34 26.07 29.88 81.6 53.3 3.16
13-Jun-02 22:45 128 631.41 561.38 77 386.2963.54 26.03 29.97 81.6 53.3 3.13
13-Jun-02 22:50 128 633.25 563.1 77.43 389.3563.99 26.06 30.06 81.6 53.3 3.13
13-Jun-02 22:55 128 637.54 567.64 77.15 392.3663.89 26.26 30.15 81.6 53.3 3.13
13-Jun-02 23:00 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 113,000ppm.
13-Jun-02 23:00 Brine rate 52.8 bpd and cum = 54.4 bbls. brine SG 1.090 at 53 F.
13-Jun-02 23:00 128 637.95 568.37 77.31 395.6764.07 26.51 30.24 52.8 54.4 2.01
13-Jun-02 23:05 128 635.3 565.37 77.36 393.3464.29 26.4 30.34 52.8 54.4 1.99
13-Jun-02 23:10 128 637.54 567.39 77.55 393.5964.38 26.33 30.43 52.8 54.4 2
13-Jun-02 23:15 128 639.18 569.17 77.63 395 64.46 26.39 30.52 52.8 54.4 2.01
13-Jun-02 23:20 128 640.61 570.46 77.74 396.4164.61 26.49 30.61 52.8 54.4 2
13-Jun-02 23:25 128 640 570.4 77.67 397.1464.64 26.55 30.7 52.8 54.4 1.99
13-Jun-02 23:30 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 110,000ppm.
13-Jun-02 23:30 Brine rate 48.0 bpd and cum = 55.4 bbls.
13-Jun-02 23:30 128 641.23 571.07 78.18 397.3964.93 26.52 30.8 48 55.4 1.81
13-Jun-02 23:35 128 642.25 572.48 77.97 398.7465.07 26.58 30.89 48 55.4 1.81
13-Jun-02 23:40 128 643.88 573.4 77.88 399.1164.94 26.62 30.98 48 55.4 1.81
13-Jun-02 23:45 128 643.68 573.53 78.08 399.2964.98 26.74 31.07 48 55.4 1.8
13-Jun-02 23:50 128 644.9 574.51 78.15 400.4565.2 26.74 31.17 48 55.4 1.8
13-Jun-02 23:55 128 644.9 574.63 78.32 400.7 65.47 26.8 31.26 48 55.4 1.8
14-Jun-02 0:00 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 113,000ppm.
14-Jun-02 0:00 Brine rate 48.0 bpd and cum = 56.4 bbls.
14-Jun-02 0:00 128 645.11 575.43 78.15 401.8765.24 26.8 31.35 48 56.4 1.79
14-Jun-02 0:05 128 646.34 575.98 78.21 402.4265.24 26.87 31.45 48 56.4 1.79
14-Jun-02 0:10 128 646.95 577.08 78.34 403.8365.46 26.9 31.54 48 56.4 1.79
14-Jun-02 0:15 128 647.15 577.02 78.37 403.4 65.49 26.93 31.63 48 56.4 1.78
14-Jun-02 0:20 128 648.17 578.06 78.64 403.8365.73 26.98 31.73 48 56.4 1.78
14-Jun-02 0:25 128 648.17 578.37 78.58 404.8765.73 26.98 31.82 48 56.4 1.78
14-Jun-02 0:30 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 110,000ppm.
14-Jun-02 0:30 Brine rate 28.8 bpd and cum = 57.0 bbls.
14-Jun-02 0:30 128 647.77 577.51 78.68 404.6965.72 27.04 31.91 28.8 57 1.07
14-Jun-02 0:35 128 647.56 577.82 78.88 404.3265.94 26.96 32.01 28.8 57 1.06
14-Jun-02 0:40 128 648.58 578.49 78.83 405.7365.94 26.99 32.1 28.8 57 1.07
14-Jun-02 0:45 128 648.99 578.92 79.09 405.4266.12 26.97 32.19 28.8 57 1.07
14-Jun-02 0:50 128 650.43 579.96 78.86 405.4866.01 27 32.29 28.8 57 1.07
14-Jun-02 0:55 128 649.2 579.54 78.8 406.4766.01 27.11 32.38 28.8 57 1.07
14-Jun-02 1:00 BS&W showed 100% brine, pH = 6.5 and Chl from refrac 108,000ppm.
14-Jun-02 1:00 Brine rate 28.8 bpd and cum = 57.6 bbls. Collected water sample no. 1.7.
14-Jun-02 1:00 128 649.4 579.78 78.82 406.1666.01 27.14 32.48 28.8 57.6 1.06
14-Jun-02 1:05 128 648.79 579.29 78.61 405.6766.05 27.11 32.57 28.8 57.6 1.06
14-Jun-02 1:10 128 648.99 579.04 78.83 405.0566.06 27.07 32.66 28.8 57.6 1.06
14-Jun-02 1:15 128 649.61 579.72 78.7 405.4866.01 27.09 32.76 28.8 57.6 1.06
14-Jun-02 1:20 128 650.02 580.15 78.96 405.8566.18 27.1 32.85 28.8 57.6 1.06
14-Jun-02 1:25 128 650.43 580.52 78.97 407.2 66.14 27.1 32.95 28.8 57.6 1.06
14-Jun-02 1:30 Raised orifice plate from separator gas meter run.
14-Jun-02 1:30 0 651.45 581.87 78.94 405.4866.11 21.81 33.02 28.8 57.6 1.06
14-Jun-02 1:31 Shut in well at choke manifold.

End of Test.

APPENDIX B

Bottomhole Pressure/Temperature Gauge Data (digital format)

Disk 1 : B3 Gauge Data.zip

B3 EMR Gauge.txt	Master Memory Gauge (pressure - psia, temp - °F)
B3 Interface Gauge.txt	SRO Interface Gauge (pressure - psia, temp - °F)
B3 SRO-Memory Gauge.txt	SRO Memory Gauge (pressure - psia, temp - °F)

Disk 2 : B3 Expro-TempLog.zip

B3 Expro Data.txt	Surface Test Data
B3 Temp Log.tpr	Master Memory Gauge (temp - °F)

Please refer to the "Appendix 2 data" folder on this CD to view these files.

OMV Australia

Enclosure 1
Well Composite Log (1:500)

OMV Australia

COMPOSITE WELL LOG

BALEEN-3/ST1

SCALE 1:500

WELL : BALEEN-3/ST1
BASIN : Offshore Gippsland Basin
PERMIT : VIC/L21

WATER DEPTH : 52.5 m (BLAT) 53.1 m (MSL)
ROTARY TABLE : 25 m (LAT)
NB: LAT is approx. 0.6 m BMSL

SPUDDED : 14:00hrs, 24 May 2002
TD REACHED : 21:00hrs, 04 June 2002
RIG RELEASE : 00:30hrs, 20 June 2002

RIG : Ocean Bounty
DRILLING CONTRACTOR : Diamond Offshore
WIRELINE LOGS :
MWD : Sperry-Sun
MUD LOGGING : Baker Hughes Inteq
DRILLING METHOD : ROTARY - HORIZONTAL

SURFACE LOCATION

LATITUDE : 38° 00' 20.99"S
LONGITUDE : 148° 26' 34.42"E
EASTING : 626675.9 mE
NORTHING : 5792541.3 mN
SPHERICAL DATUM : UTM ZONE 55, CM 147 °E, ANS/AGD 66

TOTAL DEPTH : 1555 mRT (Driller) 710.4 mTVDSS (Driller)

WELL STATUS : Production Well

SEISMIC STATION : SURFACE: Inline 209, Xline 3786 (Baleen 3D 2000)

WELLSITE GEOLOGISTS : P.Boothby/R.Tolliday
DRAFTED BY : C.Ellis
COMPILED / INTERPRETED BY : R.Tolliday/M.Gunson/M.Adamson
FILENAME:

FEWD LOGS

SUITE	RUN No.	LOG	DATE	INTERVAL (m)	MUD TYPE	SALINITY (mg/l) DENSITY (g/cm) VISCOSITY (sec/qt)	Rm (ohmm) at Deg C	Rmf (ohmm) at Deg C	Rmc (ohmm) at Deg C	MAX BHT TEMP °C	CIRC TIME (mins)	TIME SINCE CIRC (hrs)
1	1	DGR/EWRP4/DM/DDS (B3)	24-25/05/02	112-336	SEA WATER/HI-VIS SWEEPS	-/N/A/-	-	-	-	24	N/A	N/A
2	2	DGR/EWRP4/DM/DDS (B3)	29/05/02	336-458	KCL-PHPA-GLYCOL	37,000/1.06/92	0.06 @ 23	0.04 @ 23	0.14 @ 23	28	N/A	N/A
3	3	DGR/EWRP4/DM/DDS (B3)	29-31/05/02	458-871	KCL-PHPA-GLYCOL	36,000/1.06/54	0.14 @ 26	0.10 @ 26	0.17 @ 49	49	N/A	N/A
4	4	DGR/EWRP4/DDS/SLD/CNP/PM (B3)	01-03/06/02	871-1352	KCL/FLO-PRO	80,000/1.08/64	0.08 @ 26	0.06 @ 23	0.13 @ 26	52	N/A	N/A
5	5	DGR/EWRP4/DDS/SLD/CNP/PM (B3-ST1)	03-05/06/02	1137-1555	KCL/FLO-PRO	84,000/1.18/64	0.08 @ 26	0.06 @ 23	0.10 @ 26	54	N/A	N/A
						//						

FLUID SAMPLES

SUITE/RUN - SAMPLE NO.	DEPTH (mRT)	TYPE	VOLUME	RECOVERY
N/A				

OPEN-HOLE RECORD		CASING RECORD	
BIT SIZE (mm)	INTERVAL (mRT)	SIZE (mm)	SHOE DEPTH (mRT)
914	77.5 - 112	761x508	112
444	112 - 336	340	327.4
311	336 - 871	244	866.1
216	871 - 1555	168	1554

FORMATION SAMPLES

TYPE	DEPTH (mRT)	SAMPLING INTERVAL (m)
Cuttings (B3)	336-1130	4m - 10m
Cuttings (B3)	1130-1352	5m - 12m
Cuttings (B3-ST1)	1137-1140	3m
Cuttings (B3-ST1)	1140-1550	10m
Cuttings (B3-ST1)	1550-1555	5m

PRODUCTION TEST

No.	CHOKE (mm)	DEPTH (mRT)	RECOVERY / FLOW: OIL	GAS	COND.	WATER	GOR
1	MAX FLOW	902-1554	n/a		n/a	n/a	n/a

CONVENTIONAL CORES

Number	INTERVAL	CUT (m)	RECOVERY (m)	RECOVERY (%)
	No cores were cut			

SIDEWALL CORING SUMMARY

Run No.	Shot	Recovered: Sample	Recovered: Empty	Lost	Misfired
None shot					

LITHOLOGY

ROCK TYPES: CONGLOMERATE, SANDSTONE, SILTSTONE, CLAYSTONE/SHALE, MARL, SIDERITE, LIMESTONE, CALCILUTITE, CALCARENITE, CALCIRUDITE, CARBONATE, DOLOMITE

CEMENTS / MATRIX: ANHYDRITIC / STYOLITIC, SIDERITIC NODULE, SILICEOUS / CALCAREOUS, DOLOMITIC / PYRITIC

ACCESSORIES: G GLAUCONITE, PYRITE, CHERT, COAL / CARBONACEOUS MATTER, m MICACEOUS, Q QUARTZ, F FELDSPAR, L LITHIC FRAGMENTS

FOSSILS: FORAMINIFERA (GENERAL), INOCERAMUS, OOLITHS / OOIDS (GENERAL), RADIOLARIA, SKELETAL / SHELL FRAGMENTS

HYDROCARBON INDICATIONS: LIVE OIL SHOW IN CORE, CUTTINGS, MUD; HYDROCARBON CUT; HYDROCARBON FLUORESCENCE; OIL SHOW WITH FLUORESCENCE AND CUT; DEAD OIL SHOW; GAS SHOW; TESTED GAS SHOW WITH RECOVERY; TESTED OIL SHOW WITH RECOVERY

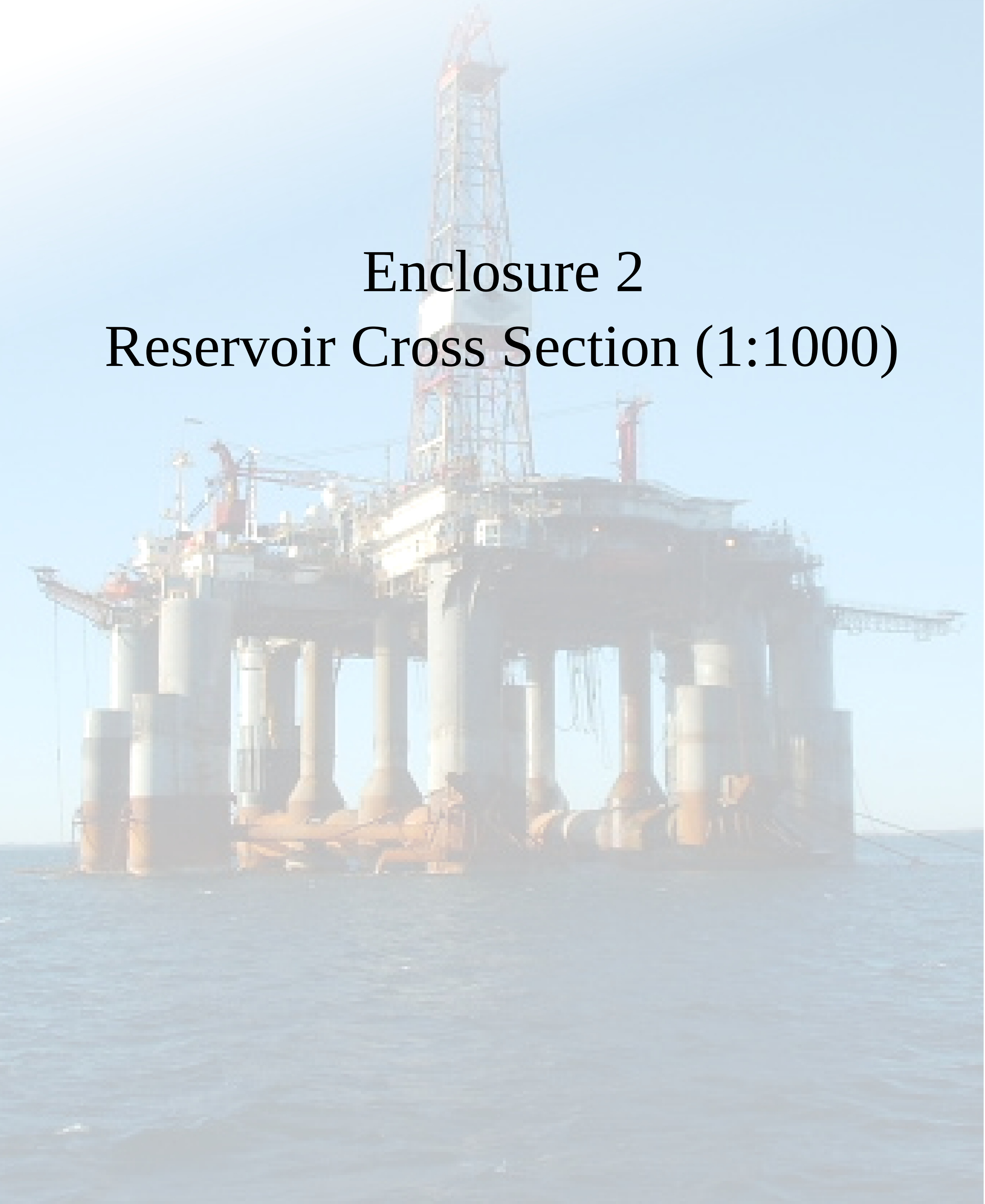
SIDEWALL CORE; NO RECOVERY; MECHANICAL SIDEWALL CORE; NO RECOVERY; CASING SHOE; CEMENT PLUG

CORED INTERVAL (RECOVERED) (NON-RECOVERY); MDT SAMPLE RECOVERY; MDT PRESSURE: G GOOD, L LOST SEAL, S SUPERCHARGE, D DRY TEST, F TOOL FAILURE

HOLE GAINS (s) BBLS/HR STATIC (d) BBLS/HR DYNAMIC; HOLE LOSS; PRODUCTION TEST INTERVAL; PERFORATIONS

OMV Australia

Enclosure 2
Reservoir Cross Section (1:1000)



OMV Australia

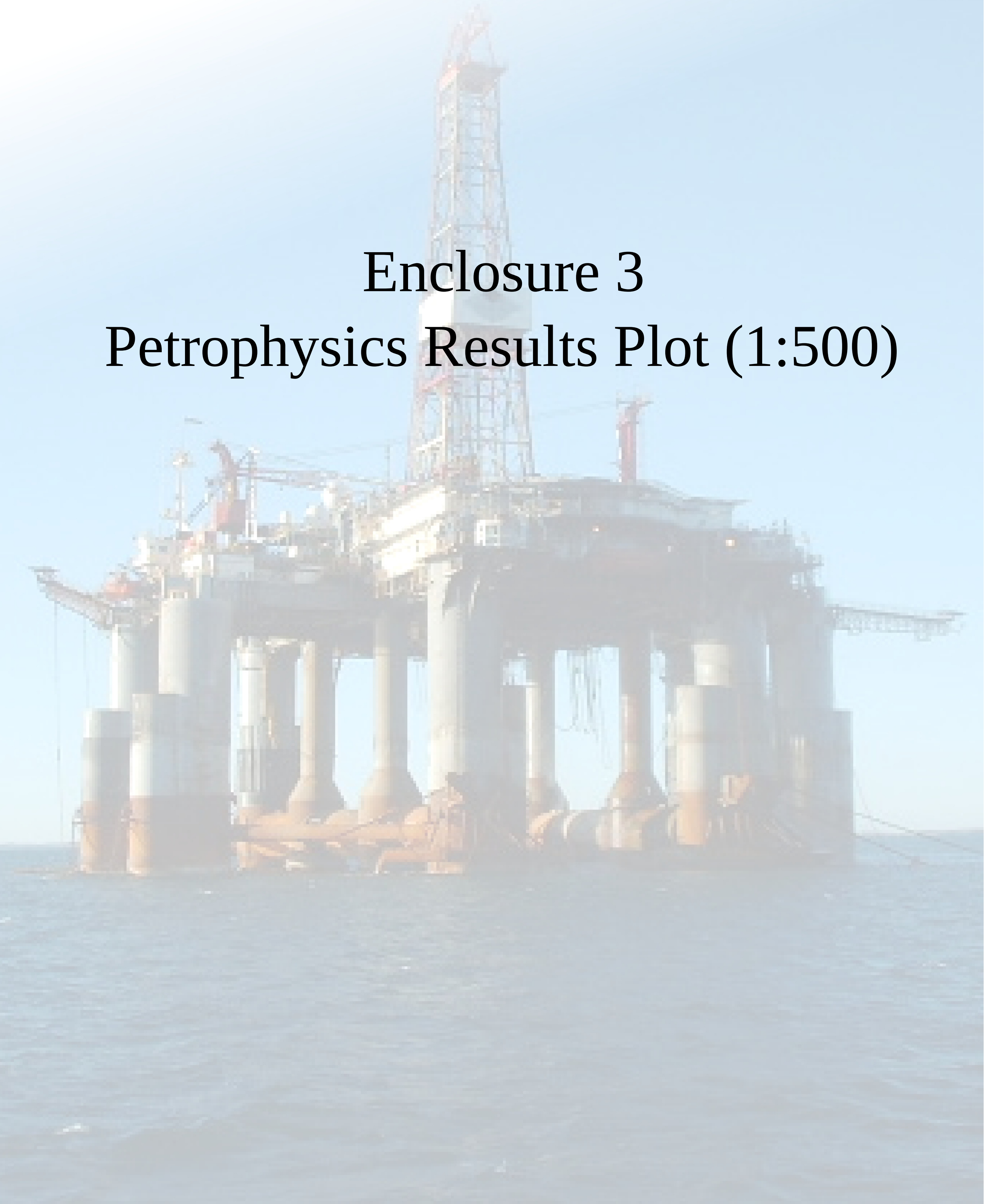
ENCLOSURE 2

BALEEN-3/ST1 RESERVOIR CROSS-SECTION

Datum: Depth	Vertical Scale: 1:1000	Author: madamson
Top Limit: 1116.0	Vertical Units: METRES	Date: 13-Jun-2002
Bottom Limit: 1555.5	Horizontal Scale: 1:1000	Time: 16:17:19
Vertical Reference: DEPTH	Horizontal Units: METRES	

OMV Australia

Enclosure 3
Petrophysics Results Plot (1:500)



Log Composite

Well: BALEEN-3ST1

COMPANY: OMV	DATUM FOR ELEVATION:
LOCATION: N.W.S.	SURFACE ELEVATION: −999.25
LATITUDE: 38.0000	MEASUREMENT REF.: DF
LONGITUDE: 148.0000	ELEVATION MEAS. REF.: −
X COORDINATE: −	DRILLED DEPTH: 1555.00
Y COORDINATE: −	VERTICAL UNITS: METRES
HORIZONTAL UNITS: METRES	DATE LOGGED: xx/05/02
DATE PLOTTED: 05−Jun−2002	VERTICAL SCALE: 1:500

DEPTH (METRES)	RM	RMC	RMF	DFD	BHT	SHT	BIT SIZE
875.00−1537.00	− @ −	− @ −	− @ −	−	−	−	−