ConocoPhillips

Innovative Energy Technologies Program

Project Annual Report 2005

Final Version – Financial Section included
September 8, 2006

1 Summary

ConocoPhillips Canada Resources Corp. (formerly Gulf) holds four oil sand leases in the Surmont area covering 210 square miles. These leases, located approximately 30 miles south-southeast of the City of Fort McMurray, contain an estimated 25 billion barrels of bitumen in place. Commercial development of these leases was until recently not possible due to limitations of the existing technology.

The initial evaluation work regarding use of the SAGD process at Surmont was performed by the Oil Sands and Research Division (OS&RD) of the Alberta Department of Energy (formerly AOSTRA). The study recognized that SAGD (as developed at UTF) could not be directly applicable to Surmont and that a research and development (R&D) program at Surmont was required to advance the SAGD technology. So, while some features of the SAGD process have been patented, many unique questions remain to be answered in order to develop this concept for Surmont. For this reason, the OS&RD study recommended that an experimental pilot be developed for Surmont to address the areas of uncertainty. Negotiations were initiated to have the Alberta Department of Energy participate in funding the pilot as part of their ongoing research commitment. ConocoPhillips was approved for IETP funding in 2005.

1.1 Project status report

Main Pilot Objectives:

- **Thief Zone Impact on the SAGD Process**: *Ongoing – Have produced over 323 e3m3 bitumen at near predicted rates. Have detected pressure interaction with the Thief Zone. Will continue to monitor well productivity, steam chamber growth, and CSOR for effects of interaction. No negative effects due to TZ interaction have been noted at this time.*
- **Deep Reservoir & Low Operating Pressure Effects on Artificial Lift & Performance**. ConocoPhillips defines low pressure as the minimum gas/steam lift pressure for stable production: *Ongoing – have shown capability of producing relatively efficiently at steam chamber pressures as low as 1000 kPag at a depth of +/- 380 mKB.*
- **Understand the effect of mudstone breccias and thin mudstone horizons on steam rise and bitumen drainage production**: *SAGD operations in the Surmont McMurray formation have been shown to be technically feasible with near predicted performance when operational problems are reduced. Rip up clasts/thin shale horizons and other reservoir heterogeneities have been shown to act as baffles to the SAGD process. Reservoir quality between the producer and injector well pairs has a significant impact on the initial stage of the SAGD steam chamber development*
- **Drill, start up & operate a 700 m commercial length well pair at low pressure**: *Completed successfully with the drilling of the "C" well pair. Results were less than expected due to the lack of available steam. This resulted in delayed steam chamber development and low operating efficiency.*
- **Establish economic performance at different operating pressures**: *Ongoing. Will continue testing performance at various pressures to determine economic parameters associated with the SAGD process*

- **Calibrate wellbore hydraulics and the thermodynamics model**: *Have utilized pilot data for thermo-hydraulic well bore model calibration. This model has been used to design the well bore configuration in the commercial Phase 1 project*
- **Endeavor to avoid the unscheduled collapse of the steam chamber when encountering top water**: *Ongoing – have not detected steam chamber collapse after pressure communication with the top water.*

1.1.1 Chronological report of all activities and operations conducted

Note: Throughout the report the Surmont Pilot wells will be referred to as the A, B, and C well pairs, or respectively the P1 – S1, P2 – S2, and P3 – S3 well pairs. P and S refer to the producer and steam injector well.

Annual Objectives / Strategy				
Date	Plant	A Well Pair	B Well Pair	C Well Pair
2004	Tracer study/ Implementation 3D seismic RST logging Cased hole logging Obs22, Obs41, Obs37	Increase steam chamber pressure to 2000kPa. Maintain good conformance and steady operations	Increase steam injection to re-establish chamber rise rate.	Return to production once A and B wellpairs have reached target pressure and re-established stable production.
2005	3D seismic Seismovie RST logging Cased hole logging Obs22, Obs20, Obs41, Obs37	Maintain 2000kPa chamber pressure and good conformance.	Maintain 2000kPa chamber pressure. Monitor TZ interaction.	Maintain production. Artificicial lift testing. Grow steam chamber to TZ.

Detailed Activities				
Date	Plant	A Well Pair	B Well Pair	C Well Pair
Jun 2004	Plant Turnaround	Rod pump failure (assembly error)		
Oct 2004		Rod pump failure (burst drain)		Rod pump installed (VSH2)
Nov 2004				Back on production
Feb 2005				Rod pump failure due to sand
Apr 2005		ESP (Schlumberger Hotline II)		
May 2005				Rod pump reinstalled, back on production

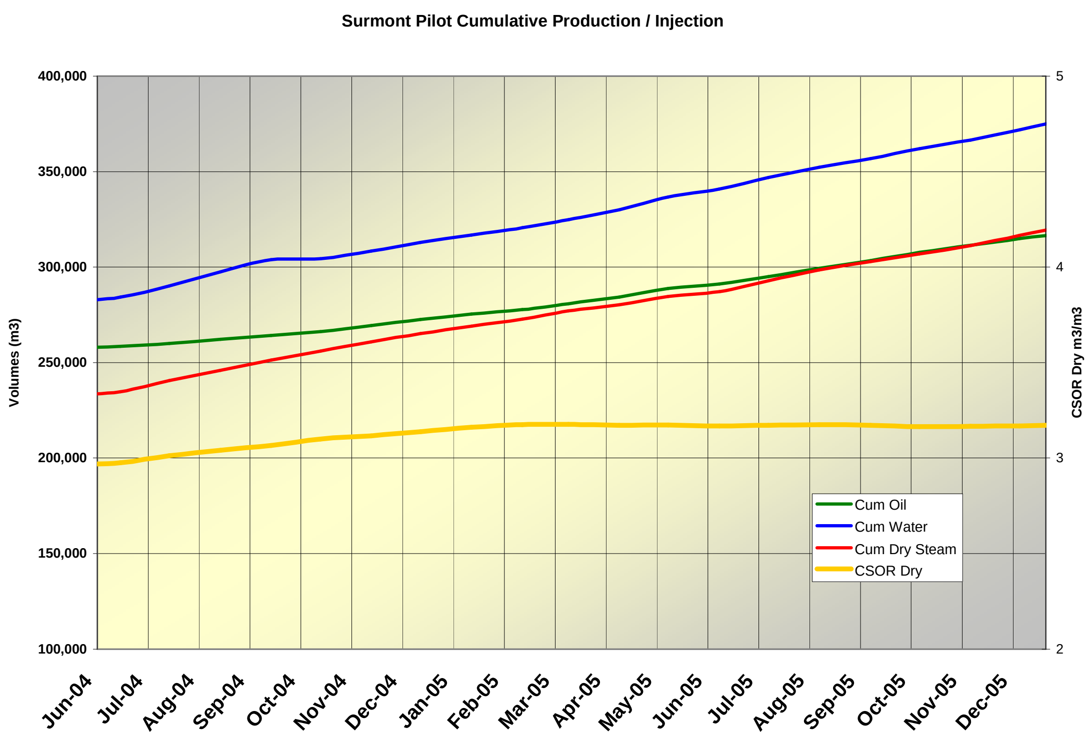
Jun 2005	Plant Turnaround		Rod pump replaced (PM)	Can-K test 36hrs
Dec 2005				HGDP installed for testing

1.1.2 Updated incremental Recovery

From June 2004 to December 31st 2005 the recovery factor for the 3 well pairs at the Surmont Pilot increased from 11.0% to 13.4%. On an individual basis the recovery factors increased by A (16.3%→19.7%), B (20.0%→24.8%), C (4.4%→5.2%). The C wellpair came online in 2000, hence the lower recovery factor. Also, the C well pair was hampered by operational upsets, constraints and various pump tests. A and B commingled recovery factor establishes 22.3% at end 2005.

1.1.3 Production

The chart below shows the cumulative bitumen/water production and steam injection for the Surmont Pilot Plant from June 2004 until December 2005. Detailed production and injection data is provided in the section ***Production performance and data***.



2 Pilot data

2.1 Data submission

2.1.1 Geology and Geophysical data

The Surmont Pilot Plant geology is summarily described below:

The Middle to Upper Devonian carbonates and evaporites constitute the basement of the McMurray Formation. Most wells across the Surmont lease terminate a few meters into the Beaverhill Lake Group (BHL) carbonates or “green” marls. The top of the BHL is a major regional unconformity and has strongly influenced the McMurray clastic deposition.

The Lower Cretaceous, Albo-Aptian McMurray Formation is part of the Mannville Group. It is comprised of unconsolidated muds, silts and sands. The formation varies from 30 m to 120 m thick across the lease. The McMurray Formation hosts bitumen-bearing sands across the Surmont Lease; these are widely overlain by water and gas sands. Along the eastern lease margin, the bitumen column thins to nil, and the McMurray sands are wet.

The Clearwater Formation (Lower Cretaceous) is typically 80 m thick across the lease. It represents a transgression of marine deposits onto the continental McMurray rocks. The Wabiskaw Member of the lower Clearwater is a first shallow marine transgressive sequence. The “glauconitic sands”, a second transgressive sequence, often hosts gas.

The Grand Rapids Formation (Lower Cretaceous). The clean lower Grand Rapids sand interval provides a source of water for the pilot plant and will provide the source water for the first commercial phase.

The Colorado Group (Lower Cretaceous) generally consists of thick shale intervals that incorporate several thinned sands.

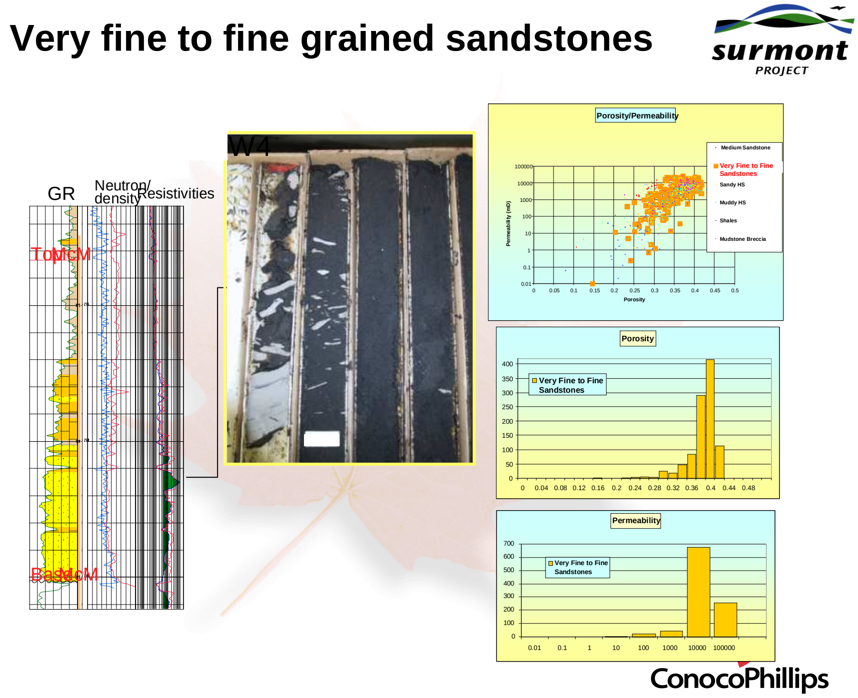
The Overburden consists of Tertiary to Quaternary sediments including glacial till locally up to 200 m thick.

The McMurray Formation is made of unconsolidated clastic sediments. The regional deposition is generally interpreted in the literature as fluvial deposits that pass upward into brackish water or estuarine deposits.

The section below details the seven main McMurray litho-facies recognized:

1. **Coarse-grained sand litho-facies:** rare on the lease, and represents only 3% of all McMurray facies. It is usually a basal channel lag.

2. **Very fine to fine-grained sand litho-facies:** represent 50% of all McMurray facies but 80% of the net continuous bitumen interval. The litho-facies is generally a massive thick-bedded sand with dispersed mud clasts. Trough cross-stratified sands usually overlie the massive sands. Very fine to fine-grained climbing ripples often form the upper part of a channel fill sequence



3. **Mudstone breccia litho-facies:** the proportion of mud clasts to the sandy matrix generally permits adequate reservoir properties to be retained. Different genetic forms are recognized. The mudstone breccias represent 6% of all McMurray facies.

4. **Sandy Heterolithic Strata (SHS) litho-facies:** consist of decimeter scale interbedded sands with thinner mud beds. The facies represents 15% of all McMurray facies. This lateral accretion deposit represents upper point bar deposition. It is commonly bioturbated.

5. **Muddy Heterolithic Strata (MHS) litho-facies:** represents late deposition in a fining upward interval on a laterally accreting point bar. The facies represents 13% of all McMurray facies. It can be entirely bioturbated.

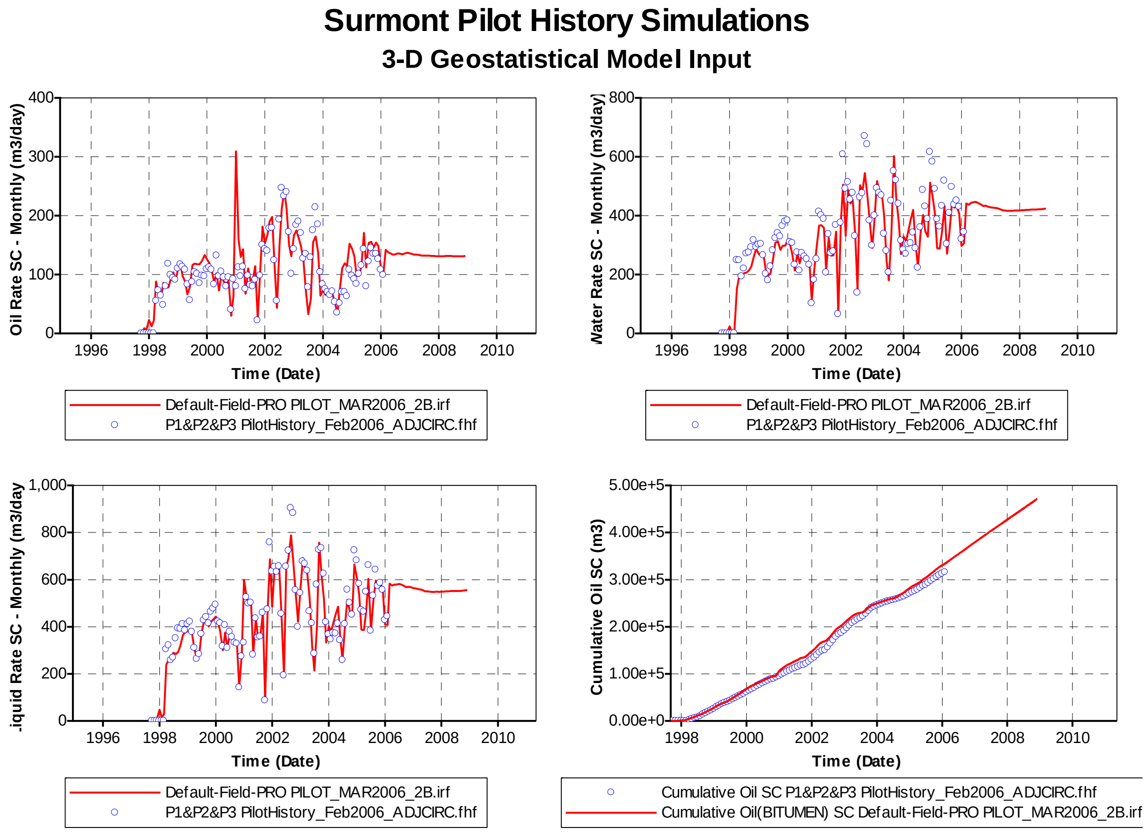
6. **Mudstone litho-facies:** this facies represents 16% of all McMurray facies. When thick and massive, it is generally interpreted as a shaly lacustrine deposit

2.1.2 Laboratory studies

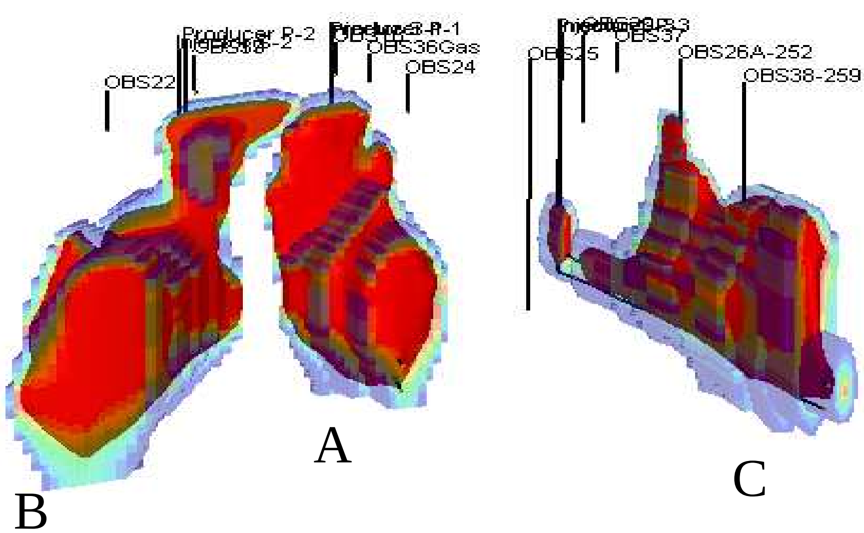
No lab studies related to the Surmont Pilot operation was performed in 2004-2005.

2.1.3 Simulations

The data acquired from the Surmont Pilot Plant is used in History Matching efforts to provide input for the long term operating strategy for the Pilot. This process also provides valuable directional strategies applied to the commercial operations. A refined gridded model is used (400K gridblocks) to accurately capture the physical (thermal) processes involved. The achieved match is within the uncertainty limits of data. Below model output from the current history match is shown.



The modelling also allows for estimating the development of the steam chambers, and for identifying conformance/coalescence issues.



2.1.4 Pressure, temperature, and other applicable reservoir data.

Initial reservoir temperature is 11degC, with a pressure of approximately 1400kPaa

The hydrocarbon type is an undersaturated oil (bitumen) with an API Gravity of 8deg. At reservoir conditions the viscosity is greater than 1E6cP.

The GOR is ~2 m3/m3 (11scf/bbl) with a bubble or dew point pressure of 1400kPa

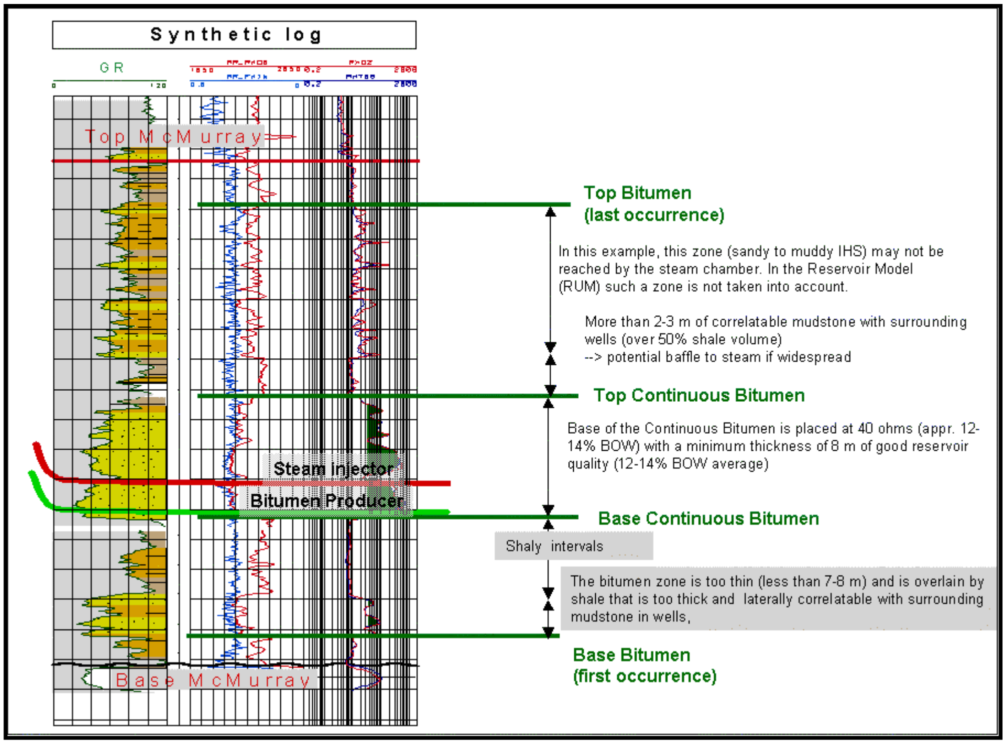
2.1.5 Other measurements, observations, tests or data

Fluid layering within the Surmont Lease and from bottom to top is as follows.

- **Bottom Water**: first occurrence of water above the Beaverhill Lake unconformity although not present everywhere. The Net Water sands are calculated using a Vsh<45%.

- **Bitumen**: bitumen-bearing sands have deep resistivity above 10 ohms-m.

Continuous Bitumen is specifically used to calculate the SAGD exploitable Bitumen and is critical for horizontal well pair placements. Usually the Continuous Bitumen bearing sands have deep resistivity above 40 ohms-m and no shale greater than 3m. The Net Continuous Bitumen sands are calculated using a Vsh<33%.



- **Top water**: occurrence of water above the bitumen. The Net Water sands are calculated using a Vsh<45%. On the lease, top water is more prevalent than bottom water.

- **Top Gas** is organized into pools that may be either structural, stratigraphic, or combination traps. Top Gas is typically recognized by the density-neutron log crossover and by resistivity contrasts. The Net Gas sands are calculated using a Vsh<65%.

Note: At Surmont there is no evidence of “perched” water within the bitumen column unlike Long Lake (Nexen)

<u>Thief Zone</u>

Water and gas bearing sands overlying the bitumen, when and where present, are referred to as steam "thief zones" that introduce operational risks affecting the economic recovery of the bitumen. The word "thief" refers to the potential loss of energy from the steam-heated bitumen reservoir to the overlaying water and gas layers, with the resulting potential reduction in resource recovery efficiency. The low pressure of those Thief Zones due to earlier gas production yields additional risk.

When the steam chamber grows to reach a top water or top gas zone, two possibilities can occur:

If the steam chamber pressure is higher than the thief zone pressure: the risk is that the steam leaks into the thief zone with drastic heat losses. In the event of depressurised top gas thief zone, there is also a risk of contamination of the gas pools by H_2S or CO_2 produced when the bitumen contacts steam/water.

If the steam chamber pressure is lower than the thief zone pressure: the risk is that the top water flows into the bitumen reservoir cooling the steam chamber, increasing the water cut and affecting the SAGD process.

2.2 Interpretation of pilot data

Please see appendix D&E for logs from the Surmont Pilot Wells.

3 Well information

The pilot project consists of three horizontal SAGD well pairs drilled in a northeast to southwest direction with all six wellheads located in LSD 14-24-83-7 W4M as follows:

- Well pair A: center well pair - production well P1; steam injection well S1; 350 m horizontal section terminates in LSD 5-24-83-7 W4M.
- Well pair B: northern well pair - production well P2; steam injection well S2; 350 m horizontal section terminates in LSD 12-24-83-7 W4M.
- Well pair C: new southern well pair - production well P3; steam injection well S3; 700 m horizontal section terminates in LSD 4-24-83-7 W4M.

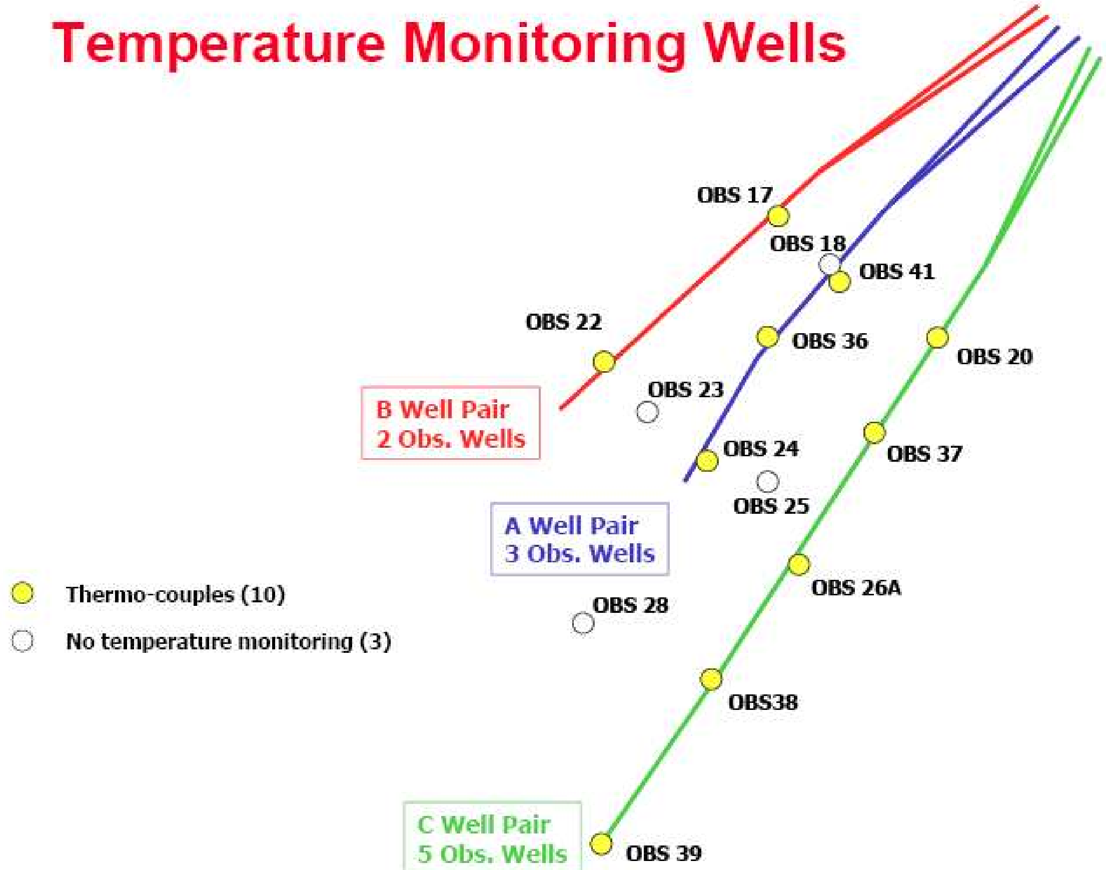
The true vertical depth of the horizontal section of A well pair's production well P1 is at an elevation of 217.0 m (+/- 1.0 m) ASL. The corresponding S1 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P1 production well.

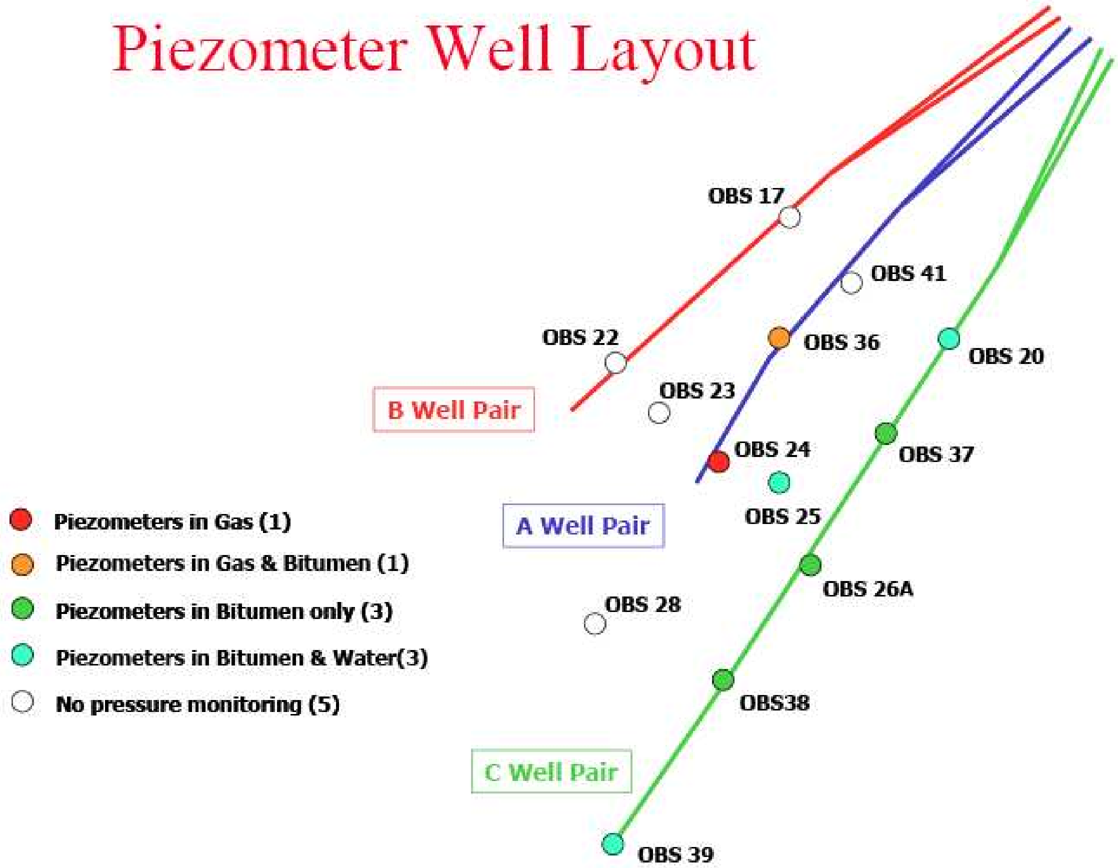
The true vertical depth of the horizontal section of B well pair's production well P2 is at an elevation of 221.0 m (+/- 1.0 m) ASL. The corresponding S2 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P2 production well.

The true vertical depth of the horizontal section of C well pair's production well P3 is at an elevation of m 227 m (+/- 1.0 m) ASL. The corresponding S3 steam injection well is located 5.0 m (+/- 1.0 m) vertically above the P3 production well.

There are four (4) observations wells located along the A well pair, two (2) along the B well pair and five (5) along the C well pair. There is also an observation well located between the A and C well pairs and a well between A and B well pair. Most of these wells either have thermocouples strings, piezometers or both thermocouple strings and piezometers installed in them. The following figures illustrate their locations and the instrumentation configurations.

3.1 Well layout map





3.2 Drilling, completion and workover operations

There were no drilling activities directly associated with the pilot during 2004-2005.

3.2.1 P1 (107/05-24-83-07W4M)

In May 2004, the existing 4.75" tubing barrel pump failed due to normal wear. It had been running since November 2002. A replacement 4.75" pump was installed along with the existing Ecoquip surface hydraulic unit. This pump failed a month later in June as the cage had fallen off due to improper torque make up. Subsequently another 4.75" tubing barrel pump was installed

In August, there was a minor workover to replace the polish rod, which was slightly bent due to alignment of the Ecoquip and causing some problems with leakage around the stuffing box. At this time, the downhole pressure measurement device (Promore ERD) malfunctioned and left only temperature measurements until the next workover in October was completed.

The surface drive Ecoquip unit was changed out for a few weeks in September with a smaller version with limited capacity to enable servicing and was returned to the original design when the service rig was on site for other work.

In October 2004, the pump failed again, likely due to a quick over pressuring of the flow line and suspected blowing of bottom hole drain. Given that there was no longer the steam requirement at this well, the high cost for a tubing pump and recent difficulties with these pumps, a 3.25" insert pump was installed next. April 2005 a Schlumberger

ESP DH pump was installed. It has been operating successfully with DH temperatures in the 190degC range.

3.2.2 P2 (108/12-24-83-07W4M)

In May 2004, the P2 well went down on pump failure after dynamometer cards indicated a problem. The pump teardown indicated general wear, particularly on the traveling valve. The pump had been running since May 2003 using a 3.25" insert type pump. A replacement 3.25" insert pump was installed. In September, the Lufkin pump jack had to be re-aligned by Weatherford so that the polish rod was stroking straight. In June 2005 the rod pump was replaced as a preventative maintenance measure. During 2005 the pump was realigned several times, but no major workovers were performed.

3.2.3 P3 (AA/04-24-83-07W4M)

For most of 2004 the P3 well was not operating due to insufficient pressure to operate gas lift and limited steam availability due to the A and B re-pressurization strategy. Additionally, the well was waiting on the CanK pump to return from lab testing. In October, a Weatherford VSH2 hydraulic surface unit was installed along with a 4.75" downhole tubing pump. Later in October, a minor workover was needed to change out the polish rod since it was leaking too much from the stuffing box. The workover revealed the previous polish rod was not fully spray coated and was upside down. The downhole spacing was also adjusted during this time. To assist in analysis and troubleshooting, a pump-off controller was installed with radio communication back to a laptop at the Pilot Plant. Due to some electrical difficulties this had only moderate success and was not used to the best of its capabilities.

The rod pump failed in February of 2005 due to severe sand production. In May 2005 a rod pump was reinstalled and the well brought back on production. A short test of the Can-K pump was tested in June 2005. In December 2005 a HGDP pump was installed, and has operated flawlessly since.

3.2.4 Steam Injection Wells

There were no workover operations on any of the steam injection wells during 2004. Although, in April 2004, three (3) separate tracers were injected into the injection wells for the purpose of monitoring possible fluid communication between the wells as would be evidenced by tracer returns taken from produced water from the production wells.

3.2.5 Water Disposal Wells

In October 2004, well 102/3-31-83-6W4M failed its packer test. The well has been locked out and is no longer used for disposal. The status of the well has been changed to observation so that no further work is required and pressures can be recorded from it to monitor the adjacent disposal well 103/3-31.

3.2.6 Source Water Supply Wells

There was no work done on the 1F1/8-25-83-7W5 well during 2004-2005. The source water well approval was amended to include volumes for the rental steam generator to the end of 2006. Source water requirements from this well beyond 2006 for the commercial or pilot projects will be amended as necessary.

3.3 Well operation.

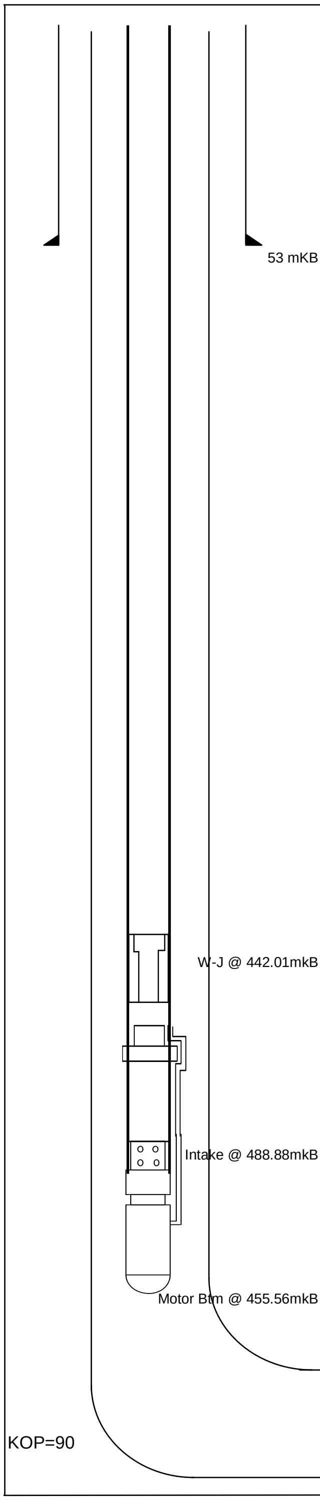
3.3.1 Well list and status

Well Pair	Status	Steam chamber conformance	Chamber pressure	TZ Interaction
P1 – S1	Producing	Toe best developed	2000kPa	Chamber nearly in contact with TZ
P2 – S2	Producing	Chamber conform along wellbore	1850kPa	Chamber nearly in contact with TZ
P3 – S3	Producing	Heel best developed	2200kPa	Chamber growing towards TZ
Obs Wells	OK			
Water source well	OK			
Disposal wells	OK			

3.3.2 Wellbore schematics

3.3.2.1 Production Wells

CONOCO PHILLIPS CANADA
HORIZONTAL DOWNHOLE WELL PROFILE



WELL NAME / UWI CPC Resdlyn P-1 Hz 106/05-24-083-07w4
FOREMAN: ALLAN GRAY DATE: April 09 - 05

KB ELEV 587.3 m **PBTD** 935 mKB **TD** 940(TVD mKB
KB - CSG 3.83 m **KB-THF** 3.58 m **KB-GR** m Permanent Rig Anchors X

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	406.4	96.73	H-40	53.0
Intermediate Casing	273.1	67.71	L-80	535.0
Permanent Tail pipe	88.9	Hydrill 533		474.31 - 908.5 MD
Production Casing				
Liner	177.8	38.7	L-80	504 - 935 MD 0.005" wire wrapped
Tubing	88.9	13.84	J-55	438.43 depth @ 442.01 pump 452.51
Perfs/ Open Hole, mKB	McMurray / ; /			
Old Perfs, mKB	Preperforated casing, Keystone wire wrapped Jt 20 & 33 blank			

FINAL TUBING STRING FROM BOTTOM UPWARD

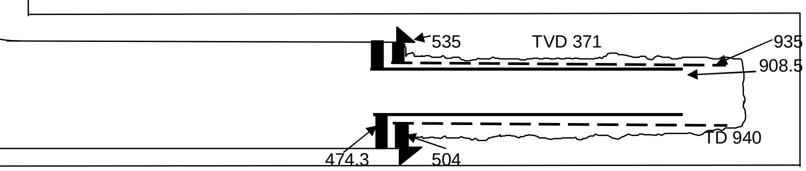
ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	1 - Reda 562 Series 42.8 HP 751V/33.1A Motor c/w rub bars	3.05	452.51
2	1 - Reda 540 Series Type LSMPM Protector	2.85	449.66
3	1 - Reda 400 Series Type BFGS-ARZ-ZS Intake	0.78	448.88
4	1 - Reda 400 Series Type DN-1750 / 78 stage pump	4.70	444.18
5	1 - "New 88.9mm Pup Jt	1.88	442.30
6	1 - "New 88.9mm W-J Nipple	0.29	442.01
7	46 Jts of "New drifted & tallied 88.9mm J-55 Tbg	438.43	3.58
8	Tubing Hanger		3.58
9			3.58
10			3.58
	THERE is "New 1/4 SS Tbg banded above and below collars and also		
	banded w/ cable in 2 places per J		442.01?

TOTAL STRING LENGTH	451.98	
K.B. TO TUBING HANGER FLANGE	3.58	
SETTING DEPTH K.B.	455.56	

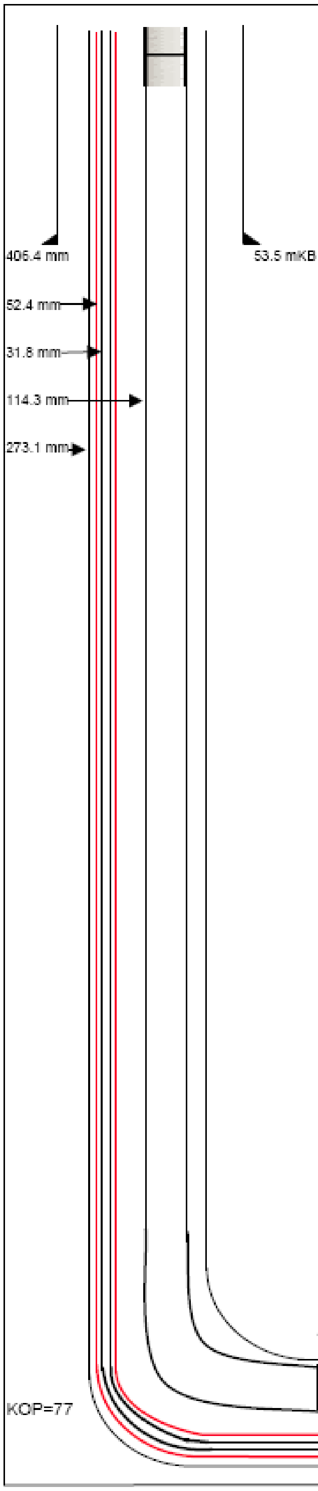
STRING WT 7500 daN WT on PACKER n/a daN WT on HANGER 7500 daN
TBG HANGER TYPE Cameron SIZE 228.6 x 114.3 SFC CSG STATUS Open/No flow
CASING BOWL W.P. 14 MPa MAKE Crown FLANGED X SCREWED ☐
TUBING SPOOL W.P. 14 MPa MAKE StreamFlow SIZE 339 x 279
MSTR VLV No. n/a TYPE SIZE mm MAKE
W.P. MPa NACE TRIM? YES ☐ NO ☐
CSG VLV No. 2 TYPE Gate SIZE 52.8 mm MAKE Crown
W.P. 14 MPa NACE TRIM? YES ☐ NO ☐

REMARKS
No Riser Spool required on well. ----11" BOP's fit onto wellhead.

There is 1/4" SS Tbg banded to Tbg to be used for Bubble gas. Tbg exits thru off side casing valve.



CONOCO PHILLIPS CANADA
HORIZONTAL DOWNHOLE WELL PROFILE



WELL NAME / UWI: CPC Resdlyn P2 Hz 108/12-24-083-07 W4
FOREMAN: Albert Florence DATE: 5/15/2004

KB ELEV 587.3 m PBTD 960 MD mKB TD 965 MD T mKB
KB - CSG m KB-THF 3.11 m KB-GR m Permanent Rig Anchors [X]

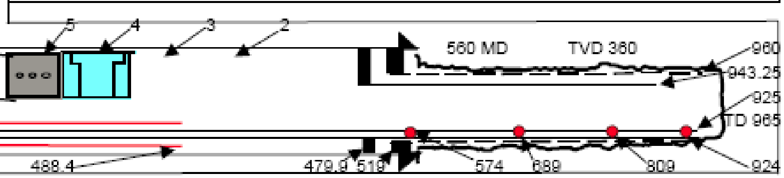
CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	406.4	96.73	H-40	53.5
Intermediate Casing	273.1	67.71	L-80	560.0
Tubing	52.4	4.84 FJ	L-80	434.1
Instrument Coil String	31.8			Surface-925 MD(inside 52.4 mm)
Permanent Tail pipe	88.9	Hydrill 511 FJ	15.63	479.89 - 943.25
Liner	177.8	38.7	L-80	519 - 560 MD 0.005 " Keystone wire
Tubing	114.3	14.14	J-55	433.0
Perfs/ Open Hole, mKB	McMurray / Pre-perforated liner 519-960 MD; /			
Old Perfs, mKB				

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String Bottom		436.11
2	W/L re-entry EUE	0.16	435.95
3	Pup 114.3 mm EUE	2.51	433.44
4	PSN API 114.3 mmx 95.25 mm EUE	0.33	433.11
5	FIKE drain 4000 # burst EUE	0.15	432.96
6	xover EUE box x 8rd box	0.20	432.76
7	33 - Jts 114.3 mm x 14.14 kg/m J-55 8rd	424.90	7.86
8	Pup 114.3 mm 8 rd	4.55	3.31
9	Tubing hanger	0.20	3.11
10			3.11
A	40 - 325 RHAFR 34 - 3 - 0 BMW # 2212		
B	28.5 mm plain rod (38.1 mm pin)		
C	28.5 mm shear 40,000 #		
D	28.5 mm co-rod 360 m		
E	6 - 28.5 mm NETB 8/rod scraperød		
F	1 - 28.5 mm plain ponie		
G	1 - 38.1 mm x 10.97 mm Spray metal polish rod		
H			
I	Need to polish rod & pony to unseat BHP (5500 daN)		
J			
	TOTAL STRING LENGTH	433.00	
	K.B. TO TUBING HANGER FLANGE	3.11	
	SETTING DEPTH K.B.	436.11	

STRING WT 7500 daN WT on PACKER n/a daN WT on HANGER 7500 daN
TBG HANGER TYPE TC-EN SIZE 228.6x114.3 SFC CSG STATUS Open/No flow
CASING BOWL W.P. 14 MPa MAKE Crown FLANGED [X] SCREWED [ ]
TUBING SPOOL W.P. 14 MPa MAKE Cooper cameron SIZE 228.6 x 103.2
MSTR VLV No. n/a TYPE SIZE mm MAKE Pumping wellhead
W.P. MPa NACE TRIM? YES [ ] NO [ ]
CSG VLV No. 2 TYPE Gate SIZE 52.4 mm MAKE Crown
W.P. 14 MPa NACE TRIM? YES [ ] NO [ ]

REMARKS: BHP insert pump String 2500 daN, 5500 to unseat. 40-325 RHAFR 34-3-0 BMW # 2212
Need to have string wt on bridle to remove/replace neck pin in Horse head
Need to remove Radigan to take BHP from well
Need 36" spool to N/U BOP stack 4000# Burst in Fike drain(BMW Lloyd)
Two tubing hangers, Lower hanger is 6" in diameter
40,000 # shear on co-rod string, between co-rod and plain rod (BMW Lloydminister 780-875-2730)



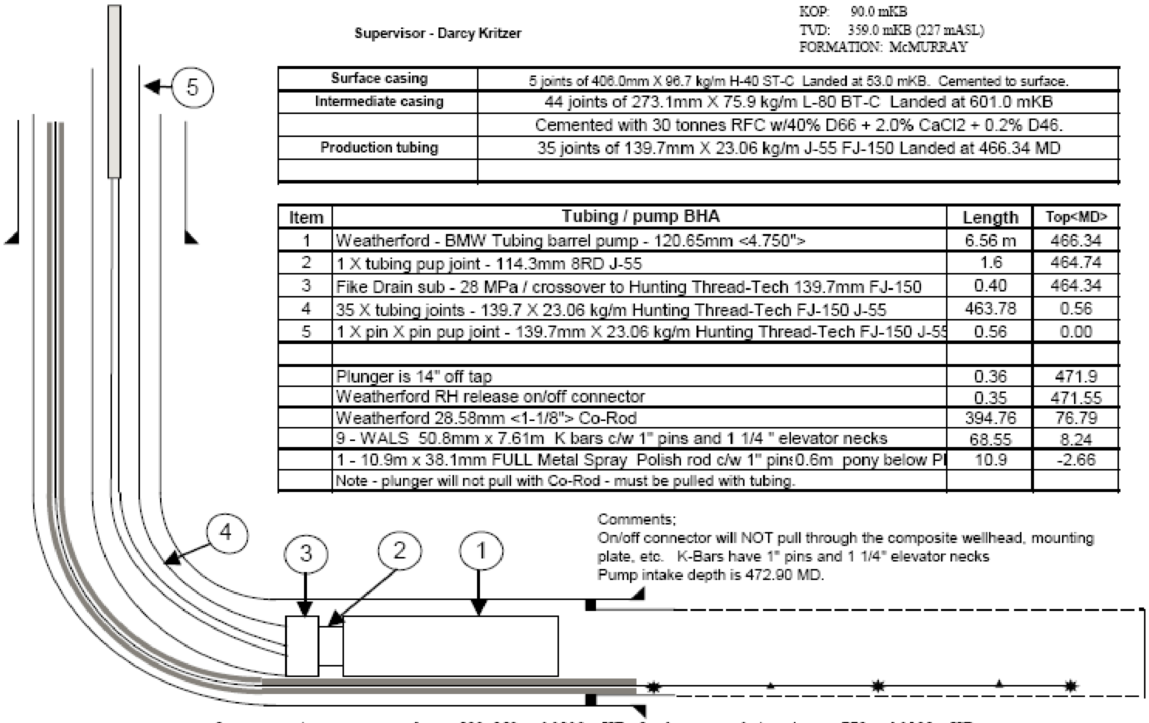
ConocoPhillips

GULF HZNTL P3 RESDELN
Surmont Pilot SAGD
Production Well.
P3 - 1AA / 04-24-083-07 / W4M

Supervisor - Darcy Kritzer

Date October 27 - 04
Allan Gray

KB: 586.13 m KB to GR 4.5 m
GL: 581.63 m KB to THF 3.31 m
TD: 1345.0 mKB
PBTD: 1340.0 mKB
KOP: 90.0 mKB
TVD: 359.0 mKB (227 mASL)
FORMATION: McMURRAY



Surface casing	5 joints of 406.0mm X 96.7 kg/m H-40 ST-C Landed at 53.0 mKB. Cemented to surface.
Intermediate casing	44 joints of 273.1mm X 75.9 kg/m L-80 BT-C Landed at 601.0 mKB
	Cemented with 30 tonnes RFC w/40% D66 + 2.0% CaCl2 + 0.2% D46.
Production tubing	35 joints of 139.7mm X 23.06 kg/m J-55 FJ-150 Landed at 466.34 MD

Item	Tubing / pump BHA	Length	Top<MD>
1	Weatherford - BMW Tubing barrel pump - 120.65mm <4.750">	6.56 m	466.34
2	1 X tubing pup joint - 114.3mm 8RD J-55	1.6	464.74
3	Fike Drain sub - 28 MPa / crossover to Hunting Thread-Tech 139.7mm FJ-150	0.40	464.34
4	35 X tubing joints - 139.7 X 23.06 kg/m Hunting Thread-Tech FJ-150 J-55	463.78	0.56
5	1 X pin X pin pup joint - 139.7mm X 23.06 kg/m Hunting Thread-Tech FJ-150 J-55	0.56	0.00
	Plunger is 14" off tap	0.36	471.9
	Weatherford RH release on/off connector	0.35	471.55
	Weatherford 28.58mm <1-1/8"> Co-Rod	394.76	76.79
	9 - WALS 50.8mm x 7.61m K bars c/w 1" pins and 1 1/4 " elevator necks	68.55	8.24
	1 - 10.9m x 38.1mm FULL Metal Spray Polish rod c/w 1" pins 0.6m pony below PI	10.9	-2.66
	Note - plunger will not pull with Co-Rod - must be pulled with tubing.		

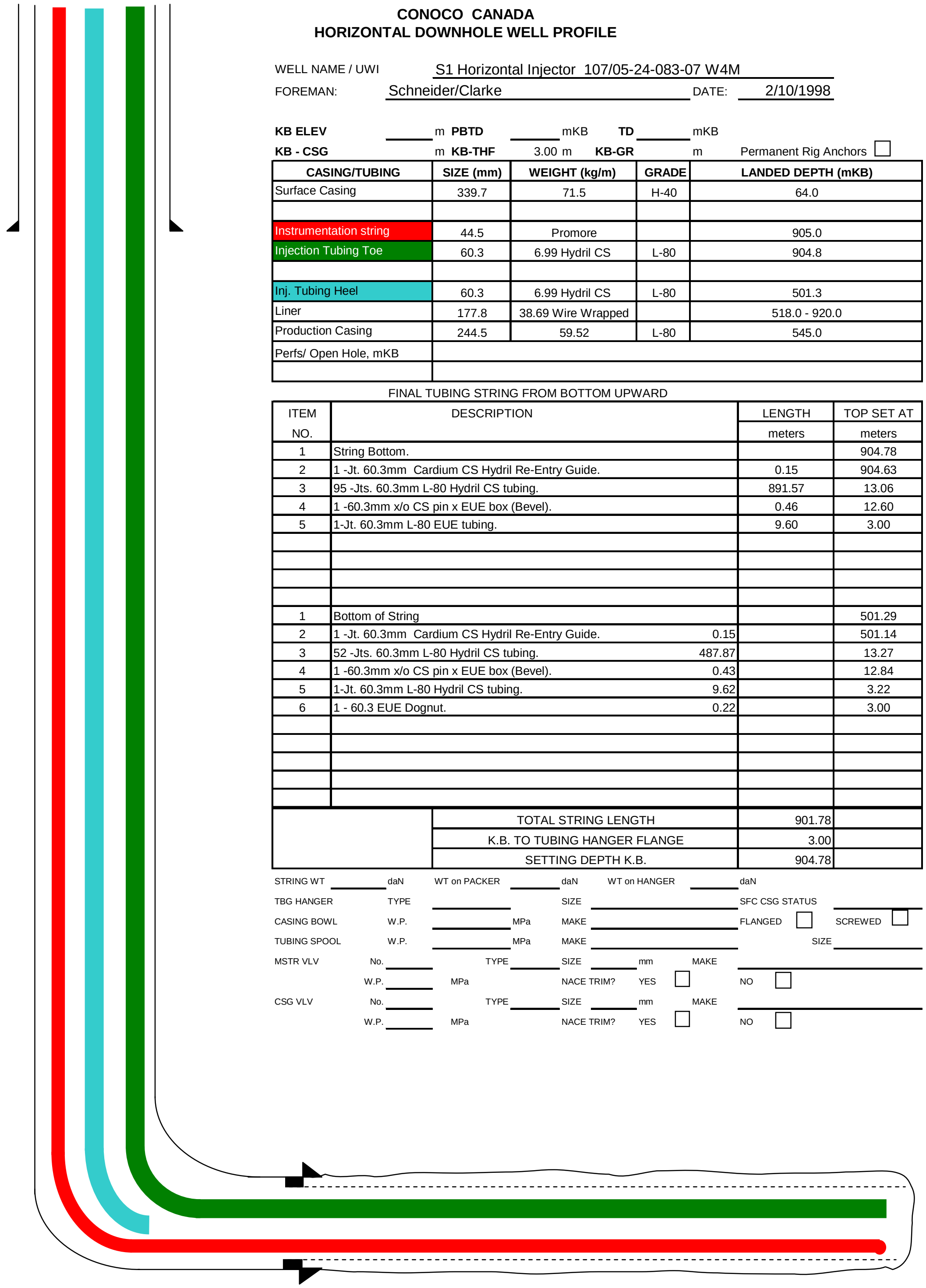
Comments;
On/off connector will NOT pull through the composite wellhead, mounting plate, etc. K-Bars have 1" pins and 1 1/4" elevator necks
Pump intake depth is 472.90 MD.

Instrument Bundle: 3 - pressure / temperature probes at 590, 950 and 1310 mKB. 2 - thermocouple junctions at 770 and 1130 mKB. **Coil Tubing** - 38.1 mm OD, X HS-70 landed at 1310 mKB.

Guide String- 61 jts of 52.4mm IJ tubing landed at 590.77 MD.

Liner Data- 273.1 mm x 177.8 mm Secure thermal liner hanger at 578.26 mKB with 50 joints (#2 through #51) of 0.005" Regent rolled programmed slotted liner. Slotted section from 633.11 - 1328.0 mKB. Base pipe consists of 177.8 mm, 34.22 kg/m, L-80, BT&C. 5 joints (# 1, 52, 53, 54 and 55) are blank. Liner landed at 1340.0 mKB.

3.3.2.2 Injection Wells



CONOCO CANADA
HORIZONTAL DOWNHOLE WELL PROFILE

WELL NAME / UWI: S1 Horizontal Injector 107/05-24-083-07 W4M

FOREMAN: Schneider/Clarke DATE: 2/10/1998

KB ELEV ______ m **PBTD** ______ mKB **TD** ______ mKB

KB - CSG m **KB-THF** 3.00 m **KB-GR** m Permanent Rig Anchors ☐

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	LANDED DEPTH (mKB)
Surface Casing	339.7	71.5	H-40	64.0
Instrumentation string	44.5	Promore		905.0
Injection Tubing Toe	60.3	6.99 Hydril CS	L-80	904.8
Inj. Tubing Heel	60.3	6.99 Hydril CS	L-80	501.3
Liner	177.8	38.69 Wire Wrapped		518.0 - 920.0
Production Casing	244.5	59.52	L-80	545.0
Perfs/ Open Hole, mKB				

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String Bottom.		904.78
2	1 -Jt. 60.3mm Cardium CS Hydril Re-Entry Guide.	0.15	904.63
3	95 -Jts. 60.3mm L-80 Hydril CS tubing.	891.57	13.06
4	1 -60.3mm x/o CS pin x EUE box (Bevel).	0.46	12.60
5	1-Jt. 60.3mm L-80 EUE tubing.	9.60	3.00
1	Bottom of String		501.29
2	1 -Jt. 60.3mm Cardium CS Hydril Re-Entry Guide.	0.15	501.14
3	52 -Jts. 60.3mm L-80 Hydril CS tubing.	487.87	13.27
4	1 -60.3mm x/o CS pin x EUE box (Bevel).	0.43	12.84
5	1-Jt. 60.3mm L-80 Hydril CS tubing.	9.62	3.22
6	1 - 60.3 EUE Dognut.	0.22	3.00

TOTAL STRING LENGTH	901.78	
K.B. TO TUBING HANGER FLANGE	3.00	
SETTING DEPTH K.B.	904.78	

STRING WT ______ daN WT on PACKER ______ daN WT on HANGER ______ daN

TBG HANGER TYPE ______ SIZE ______ SFC CSG STATUS

CASING BOWL W.P. ______ MPa MAKE ______ FLANGED ☐ SCREWED ☐

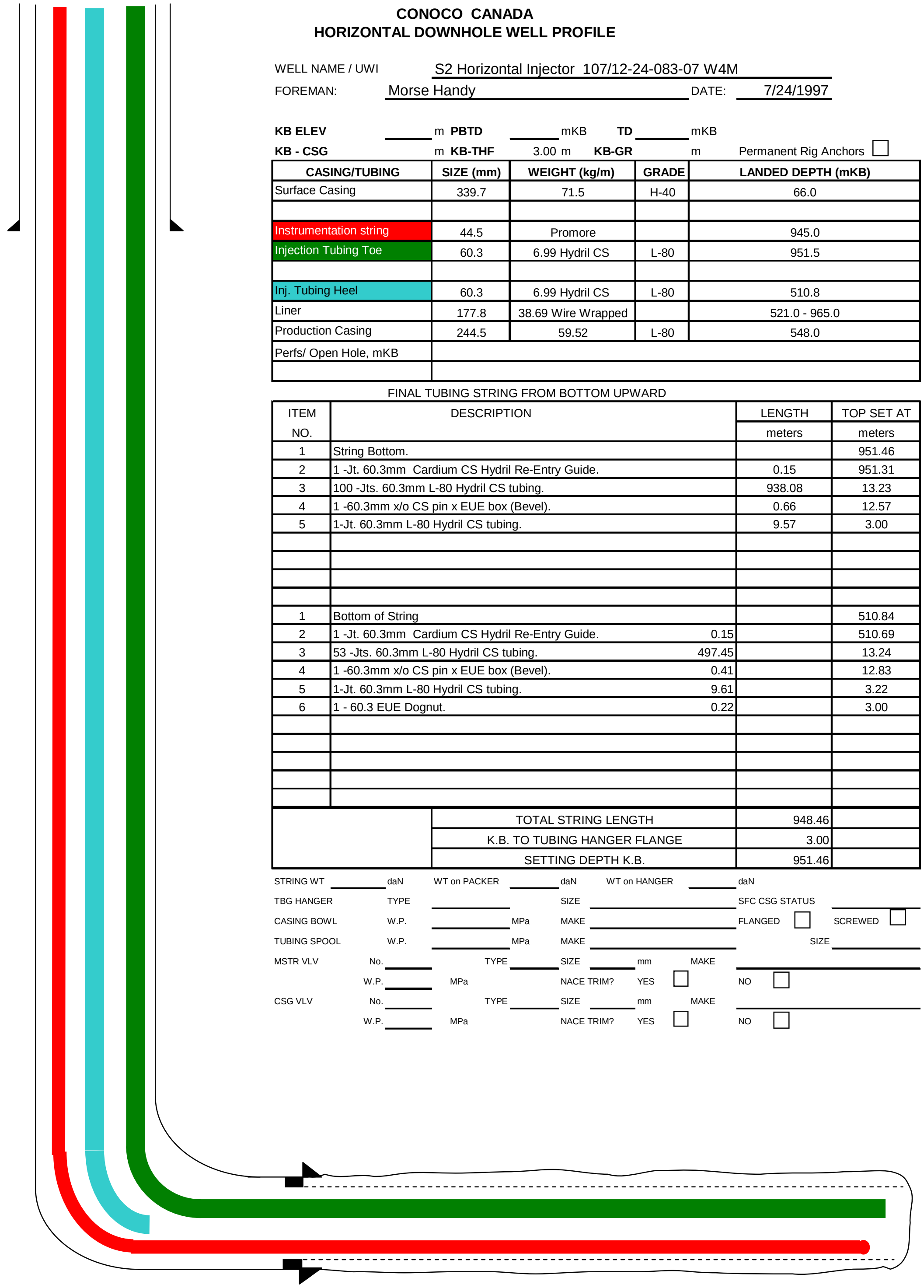
TUBING SPOOL W.P. ______ MPa MAKE ______ SIZE ______

MSTR VLV No. ______ TYPE ______ SIZE ______ mm MAKE ______

W.P. ______ MPa NACE TRIM? YES ☐ NO ☐

CSG VLV No. ______ TYPE ______ SIZE ______ mm MAKE ______

W.P. ______ MPa NACE TRIM? YES ☐ NO ☐



CONOCO CANADA
HORIZONTAL DOWNHOLE WELL PROFILE

WELL NAME / UWI: S2 Horizontal Injector 107/12-24-083-07 W4M

FOREMAN: Morse Handy DATE: 7/24/1997

KB ELEV ______ m **PBTD** ______ mKB **TD** ______ mKB

KB - CSG ______ m **KB-THF** 3.00 m **KB-GR** ______ m Permanent Rig Anchors ☐

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	LANDED DEPTH (mKB)
Surface Casing	339.7	71.5	H-40	66.0
Instrumentation string	44.5	Promore		945.0
Injection Tubing Toe	60.3	6.99 Hydril CS	L-80	951.5
Inj. Tubing Heel	60.3	6.99 Hydril CS	L-80	510.8
Liner	177.8	38.69 Wire Wrapped		521.0 - 965.0
Production Casing	244.5	59.52	L-80	548.0
Perfs/ Open Hole, mKB				

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String Bottom.		951.46
2	1 -Jt. 60.3mm Cardium CS Hydril Re-Entry Guide.	0.15	951.31
3	100 -Jts. 60.3mm L-80 Hydril CS tubing.	938.08	13.23
4	1 -60.3mm x/o CS pin x EUE box (Bevel).	0.66	12.57
5	1-Jt. 60.3mm L-80 Hydril CS tubing.	9.57	3.00
1	Bottom of String		510.84
2	1 -Jt. 60.3mm Cardium CS Hydril Re-Entry Guide. 0.15		510.69
3	53 -Jts. 60.3mm L-80 Hydril CS tubing. 497.45		13.24
4	1 -60.3mm x/o CS pin x EUE box (Bevel). 0.41		12.83
5	1-Jt. 60.3mm L-80 Hydril CS tubing. 9.61		3.22
6	1 - 60.3 EUE Dognut. 0.22		3.00
	TOTAL STRING LENGTH	948.46	
	K.B. TO TUBING HANGER FLANGE	3.00	
	SETTING DEPTH K.B.	951.46	

STRING WT ______ daN WT on PACKER ______ daN WT on HANGER ______ daN

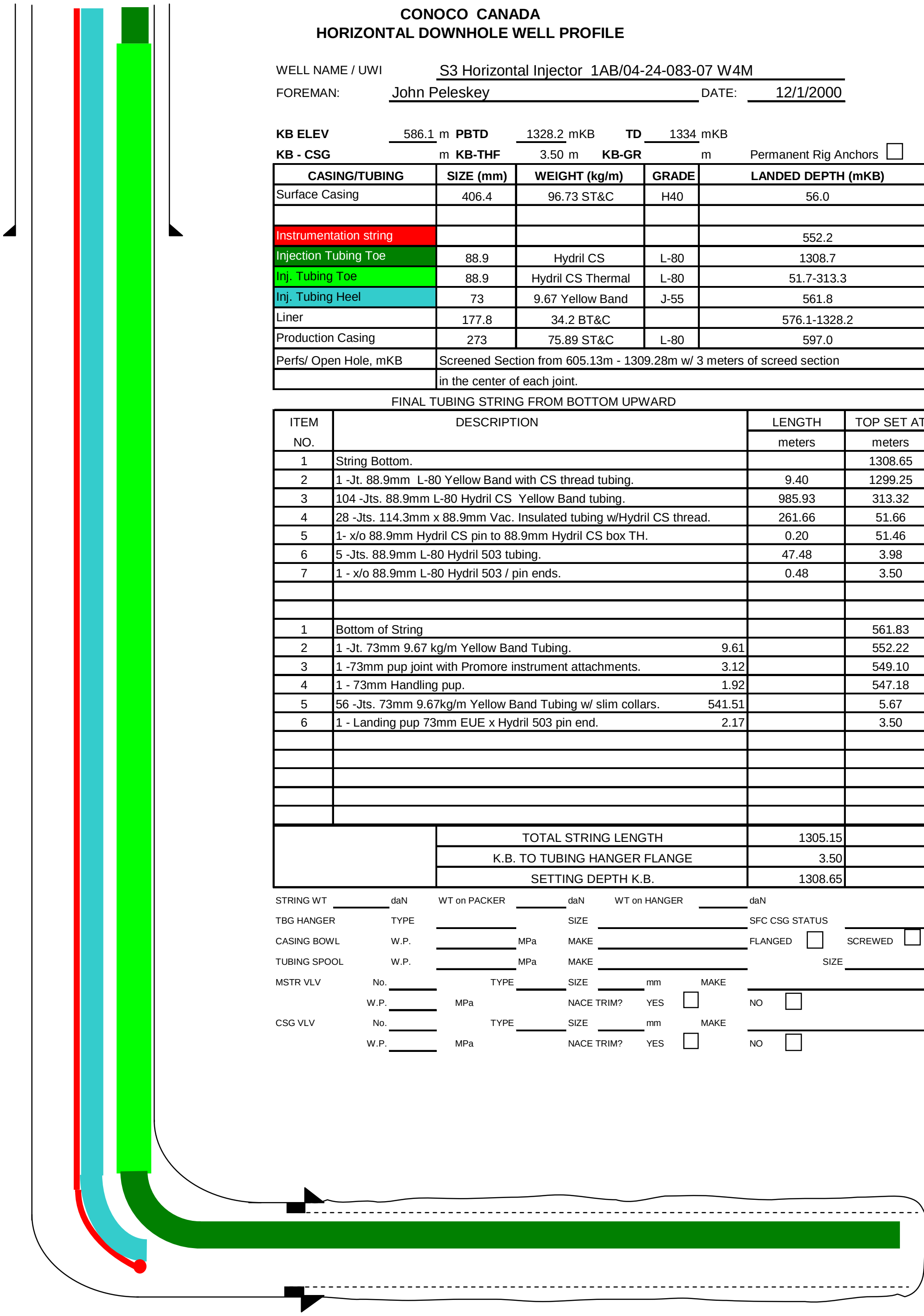
TBG HANGER TYPE ______ SIZE ______ SFC CSG STATUS

CASING BOWL W.P. ______ MPa MAKE ______ FLANGED ☐ SCREWED ☐

TUBING SPOOL W.P. ______ MPa MAKE ______ SIZE ______

MSTR VLV No. ______ TYPE ______ SIZE ______ mm MAKE ______
W.P. ______ MPa NACE TRIM? YES ☐ NO ☐

CSG VLV No. ______ TYPE ______ SIZE ______ mm MAKE ______
W.P. ______ MPa NACE TRIM? YES ☐ NO ☐



CONOCO CANADA
HORIZONTAL DOWNHOLE WELL PROFILE

WELL NAME / UWI: S3 Horizontal Injector 1AB/04-24-083-07 W4M
FOREMAN: John Peleskey DATE: 12/1/2000

KB ELEV 586.1 m **PBTD** 1328.2 mKB **TD** 1334 mKB
KB - CSG m **KB-THF** 3.50 m **KB-GR** m Permanent Rig Anchors ☐

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	LANDED DEPTH (mKB)
Surface Casing	406.4	96.73 ST&C	H40	56.0
Instrumentation string				552.2
Injection Tubing Toe	88.9	Hydril CS	L-80	1308.7
Inj. Tubing Toe	88.9	Hydril CS Thermal	L-80	51.7-313.3
Inj. Tubing Heel	73	9.67 Yellow Band	J-55	561.8
Liner	177.8	34.2 BT&C		576.1-1328.2
Production Casing	273	75.89 ST&C	L-80	597.0
Perfs/ Open Hole, mKB	Screened Section from 605.13m - 1309.28m w/ 3 meters of screed section			
	in the center of each joint.			

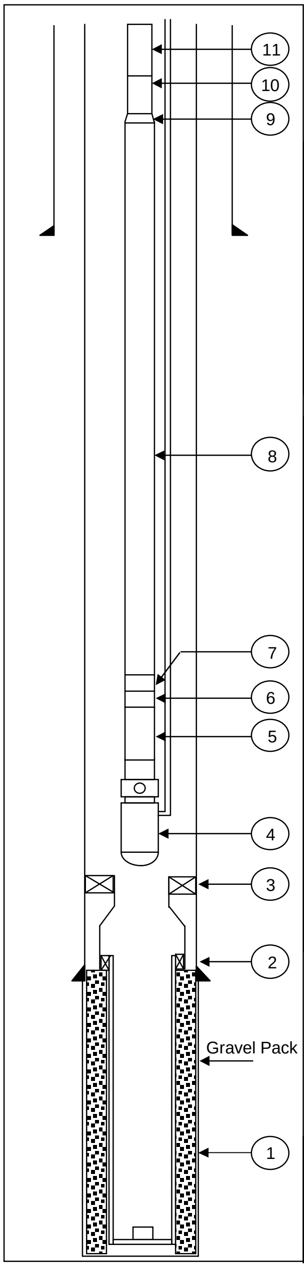
FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String Bottom.		1308.65
2	1 -Jt. 88.9mm L-80 Yellow Band with CS thread tubing.	9.40	1299.25
3	104 -Jts. 88.9mm L-80 Hydril CS Yellow Band tubing.	985.93	313.32
4	28 -Jts. 114.3mm x 88.9mm Vac. Insulated tubing w/Hydril CS thread.	261.66	51.66
5	1- x/o 88.9mm Hydril CS pin to 88.9mm Hydril CS box TH.	0.20	51.46
6	5 -Jts. 88.9mm L-80 Hydril 503 tubing.	47.48	3.98
7	1 - x/o 88.9mm L-80 Hydril 503 / pin ends.	0.48	3.50
1	Bottom of String		561.83
2	1 -Jt. 73mm 9.67 kg/m Yellow Band Tubing. 9.61		552.22
3	1 -73mm pup joint with Promore instrument attachments. 3.12		549.10
4	1 - 73mm Handling pup. 1.92		547.18
5	56 -Jts. 73mm 9.67kg/m Yellow Band Tubing w/ slim collars. 541.51		5.67
6	1 - Landing pup 73mm EUE x Hydril 503 pin end. 2.17		3.50
	TOTAL STRING LENGTH	1305.15	
	K.B. TO TUBING HANGER FLANGE	3.50	
	SETTING DEPTH K.B.	1308.65	

STRING WT ____ daN WT on PACKER ____ daN WT on HANGER ____ daN
TBG HANGER TYPE ____ SIZE ____ SFC CSG STATUS
CASING BOWL W.P. ____ MPa MAKE ____ FLANGED ☐ SCREWED ☐
TUBING SPOOL W.P. ____ MPa MAKE ____ SIZE ____
MSTR VLV No. ____ TYPE ____ SIZE ____ mm MAKE ____
W.P. ____ MPa NACE TRIM? YES ☐ NO ☐
CSG VLV No. ____ TYPE ____ SIZE ____ mm MAKE ____
W.P. ____ MPa NACE TRIM? YES ☐ NO ☐

3.3.2.3 Water Source Wells

ConocoPhillips
DOWNHOLE WELL PROFILE



WELL NAME / UWI: Gulf Resdeln 1F1 08-25-083-07 W4

FOREMAN: Dwayne Mathews DATE: 7/3/2003

KB ELEV ____ m **PBTD** 193.2 mKB **TD** 193.2 mKB

KB - CSG m **KB-THF** m **KB-GR** m Permanent Rig Anchors ☐

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	323.90			26.82
Production Casing	219.00	35.72		163.70
Liner <slotted>	139.70	20.83		146.90 - 193.20
Galvanized Tubing	101.60	Line pipe		
Perfs/ Open Hole, mKB	Clearwater / Slotted liner - 180.40 - 193.20			

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	Slotted Liner 180.40 - 193.20 mKB	12.80	180.40
2	"K" packer assembly	0.40	146.90
3	"K" packer assembly	0.40	144.50
4	ESP motor section. 50 HP, 575 volts, 54.2 amp, Ser 30-0027	1.60	141.70
5	ESP pump section. 25 stage, CGL 4000, Ser 540-PUP0137 Mod int H/B	2.00	139.70
6	Crossover from 88.9mm EUE to 101.6mm line pipe.	0.21	139.49
7	Check valve assembly	0.22	139.27
8	22 X tubing joints - 101.6mm galvanized line pipe	133.31	5.96
9	Crossover fromn 101.6mm line pipe to 88.9m 8RD EUE	0.23	5.73
10	1 X tubing pup joint - 88.9mm J-55 8RD EUE	2.42	3.31
11	1 X tubing pup joint - 88.9mm J-55 8RD EUE	3.04	0.27
	Tubing hanger with ESP cable feedthrough.	0.27	Surface
	Pump is rated for 4000 BBL / day output. <635.83 m^3>		

ConocoPhillips			
	TOTAL STRING LENGTH		
	K.B. TO TUBING HANGER FLANGE		
	SETTING DEPTH K.B.		

STRING WT 2136 daN WT on PACKER N/A daN WT on HANGER 2136 daN

TBG HANGER TYPE Cameron SIZE 229mm X 88.9mm SFC CSG STATUS N/A

CASING BOWL W.P. 21 MPa MAKE Cameron FLANGED ☒ SCREWED ☐

BONNET W.P. 14 MPa MAKE StreamFlo SIZE 279.4 / riser

MSTR VLV No. 1 TYPE Gate SIZE 79.38 mm MAKE Crown

W.P. 14 MPa NACE TRIM? YES ☐ NO ☒

CSG VLV No. 2 TYPE Ball SIZE 50.6 mm MAKE Balon

W.P. 14 MPa NACE TRIM? YES ☐ NO ☒

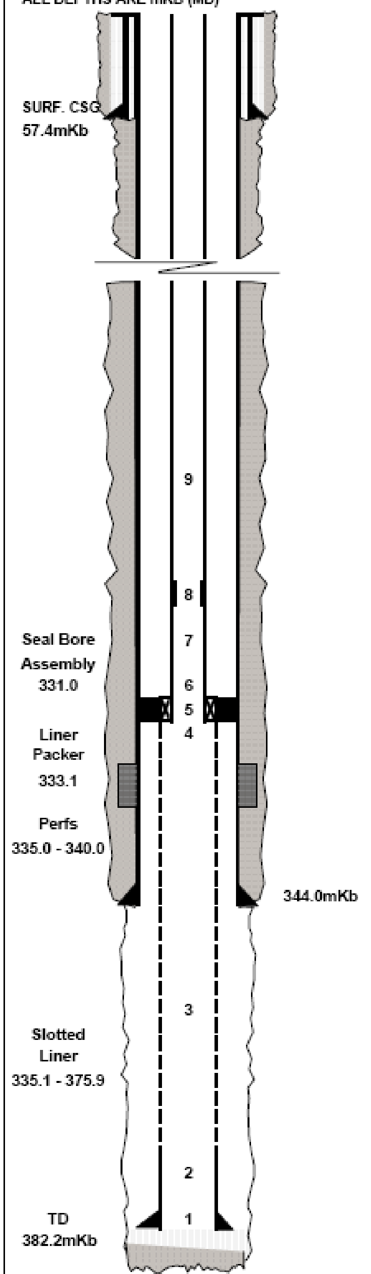
Wing valve is a Crown 50.6mm gate valve with a working pressure of 14 Mpa.
Power cable is banded to exterior of 101.6mm galvanized line pipe with 19.05mm stainless steel bands - 3 per joint.
The bottom sub on the ESP motor is tapered and will "friction grip" the ID of the "K" packer assembly. Great care must be taken if the pump is used to tag the liner top, or it may be accidentally retrieved.

As per government regulations the water source well is monitored by an offset well to observe the water table level.

3.3.2.4 Disposal Wells

CONOCO CANADA RESOURCES
WELL DIAGRAM (EXISTING CONFIGURATION)

ALL DEPTHS ARE mKB (MD)



WELL NAME:	Disposal Well 102/03-31-083-06 W4M				
PREPARED BY:	Shawn Malone rev Deepa Thomas		DATE: 02-17-2004		
ELEVATIONS (meters):					
TD	382.24	KB Elev.	541.00	KB to CF Dist. H	2.30
PBTD	372.42	Ground Elev.	537.90	KB to Ground	3.10

CASING/TUBING	SIZE (mm)	WEIGHT (Kg/m)	GRADE	DEPTHS (m)
Surface Casing	219.10	35.71	J-55	57.43
Prod. Casing	139.70	20.83	J-55	344.00
Liner	88.90	13.84	J-55	335.09 - 375.87
Tubing	73.00	9.67	J-55	331.40

BOTTOM HOLE ASSEMBLY:

ITEM	DESCRIPTION	LENGTH (m)	Top at (m KB)
	String Bottom.		375.87
1	1 - Float Shoe.	0.44	375.43
2	1 - 88.9mm Pup Joint.	1.85	373.58
3	4 - Jts. 88.9mm Slotted Tubing Liner.	38.49	335.09
4	1 - Seal Bore Extension.	1.28	333.81
5	1 - Cardium Seal Bore Permanent Packer.	0.68	333.13
6	1 - Seal Assembly 0.8m pulled up.	2.09	331.04
7	1 - Jt. 73.0mm Tubing	9.60	321.44
8	1 - PSN	0.33	321.11
9	32 - Jts. 73.0mm Tubing.	304.70	16.41
10	1 - Jt. 88.9mm Pup Joint.	1.91	14.50
11	1 - Jt. 73.0mm Tubing	9.60	4.90
12	1 - Tubing Hanger & Nipple	2.60	2.30
13			
	TOTAL STRING LENGTH	373.57	
	K.B. TO TUBING HANGER FLANGE	2.30	
	SETTING DEPTH K.B.	375.87	

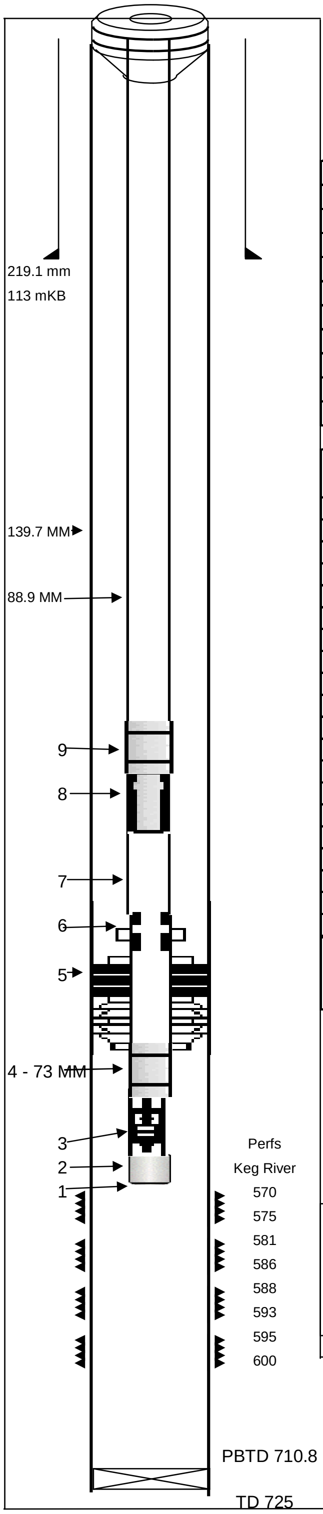
NOTE:

PUMP AND ROD ASSEMBLY

PERFORATION INTERVALS

13 SPM, 90 deg, 32 grm from 335.0 - 340.0 mKb.
Slotted Liner from 335.09 - 375.87 mKb

CONOCO PHILLIPS CANADA
HORIZONTAL DOWNHOLE WELL PROFILE



WELL NAME / UWI: Conoco Phillips Resdeln WIW 100/09-25-083-07 W4M
FOREMAN: Albert Florence DATE: 12/18/2002

KB ELEV 551.1 m **PBTD** 710.8 mKB **TD** 725 mKB
KB - CSG 3.20 m **KB-THF** 2.80 m **KB-GR** 3.5 m Permanent Rig Anchors ☐

CASING/TUBING	SIZE (mm)	WEIGHT (kg/m)	GRADE	DEPTH (mKB)
Surface Casing	219.1	35.72	J-55	113.0
Intermediate Casing				
Production Casing	139.7	20.83	J-55	725.0
Liner				
Tubing	88.9	13.84	J-55	552.2
Perfs/ Open Hole, mKB	Keg River / 570 - 575;581 - 586 ; Keg River / 588 - 593;595 - 600			
Old Perfs, mKB				

FINAL TUBING STRING FROM BOTTOM UPWARD

ITEM NO.	DESCRIPTION	LENGTH meters	TOP SET AT meters
1	String bottom		564.00
2	1 - W/L Re-entry guide 73 mm x 60.3 mm Impreglon coated (IC)	0.14	563.86
3	1 - "R" Nipple 73 mm x 57.15 mm profile 55.68 No-go (IC)	0.33	563.53
4	1 - Pup 73 mm x 9.67 kg/m (IC)	3.06	560.47
5	1 - Packer Baker AL-2 Lok-set 45B 73 mm x 139.7 mm (IC)	1.40	559.07
6	1 - On-Off L-10 114.3 mm x 88.9 mm x 58.72 mm "F" profile (IC)	0.43	558.64
7	1 - Jt. 88.9 mm x 13.84 kg/m J-55 EUE tubing	9.52	549.12
8	1 - "F" Nipple 88.9 mm x 69.85 mm (IC)	0.33	548.79
9	1 - Pup 88.9 mm x 13.84 kg/m J-55 EUE	3.11	545.68
10	57 - Jts. 88.9 mm x 13.84 kg/m J-55 EUE tubing	542.63	3.05
11	1 - Tubing hanger 88.9 mm x 139.7 mm (IC)	0.25	2.80
12			
13	Centre Element @ 559.48 Landed with 4,000 daN compression		
14			
15			
16			
17			
18			
19			
20			

TOTAL STRING LENGTH	561.20	
K.B. TO TUBING HANGER FLANGE	2.80	
SETTING DEPTH K.B.	564.00	

STRING WT 8,000 daN WT on PACKER 4000 daN WT on HANGER 4000 daN

TBG HANGER TYPE BA-2 SIZE 177.8 x 88.9 (IC) SFC CSG STATUS Open/No flow
CASING BOWL W.P. 14 MPa MAKE Stream-Flow FLANGED ☒ SCREWED ☐
TUBING SPOOL W.P. 14 MPa MAKE Stream-Flow SIZE 228 x 177.8
MSTR VLV No. 1 TYPE Gate SIZE 76.3 mm MAKE Crown
W.P. 14 MPa NACE TRIM? YES ☒ NO ☐
CSG VLV No. 2 TYPE Gate SIZE 50.8 mm MAKE Crown
W.P. 14 MPa NACE TRIM? YES ☒ NO ☐

REMARKS (Note: Additional Equipment, Tools, shear and release, surface casing test details)
Note: 80 day 3500 psi Dual recorder in with dart on Dec 21 2002 @ 1030 hrs (Remote W/L(780-623-8055)
Tubing landed in 4,000 daN compression.
Wellhead, profile nipples, packer, 73 mm pup, w/l guide all Impreglon coated(none of 88.9 mm)

3.3.2.5 Observation Wells

Please see the appendix C for the Observation well schematics.

3.3.3 Spacing and pattern

The Surmont Pilot wells are placed parallel (slight fan configuration) to each other, spaced from 100 to 160m apart.

4 Production performance and data

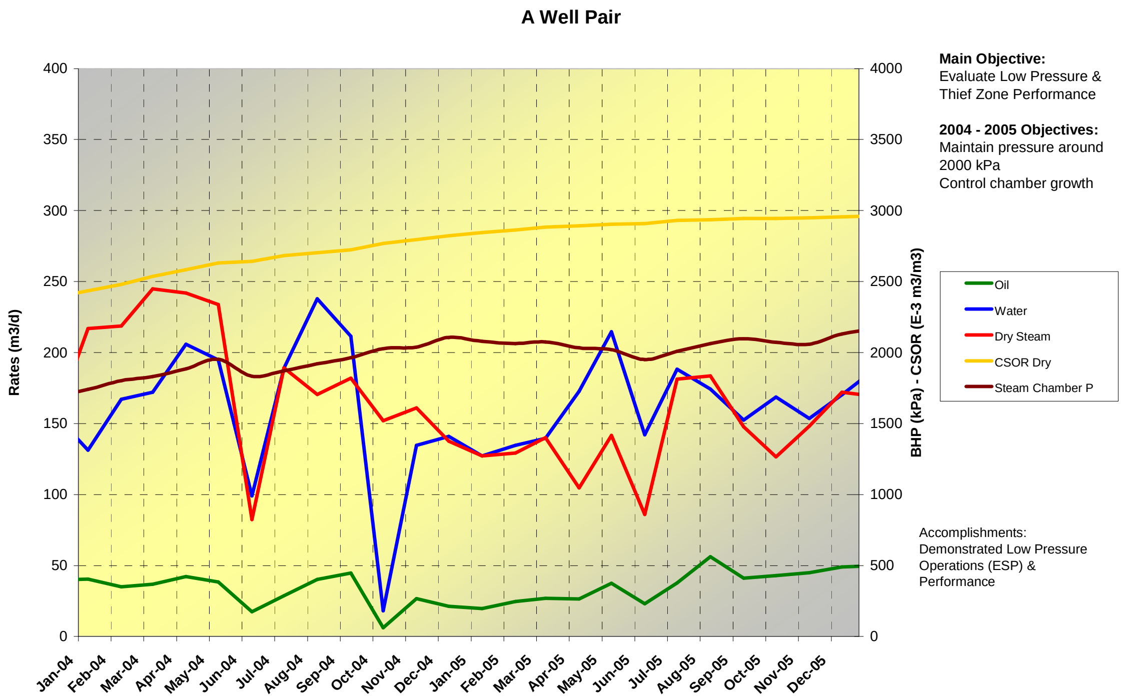
Since June 2004 a pressure stabilization strategy has been pursued:

- The steam chamber pressures will be maintained at 2000kPa to prepare for the merging of the steam chambers from the different well pairs.
- The operational strategy will attempt to operate all 3 well pairs at steady conditions.
- The subcools were targeted for 10-15degC.

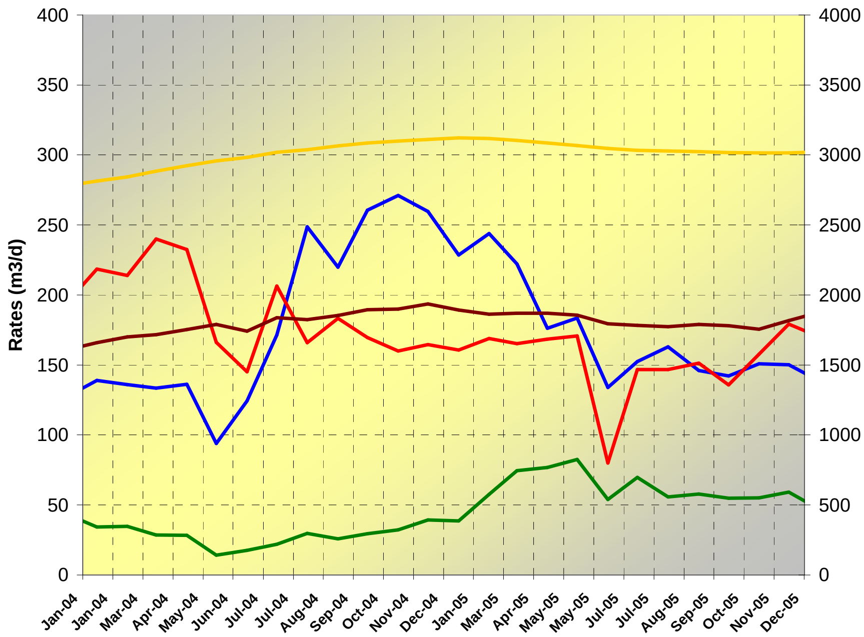
4.1 Injection and production history on an individual well and composite basis

The A and B well pairs have been producing the prognosed rates for the majority of the time considered in this report (See section on Forecasted vs. Actual rates). The C well pair has at times been suffering from operational constraints and pump failures, but has been producing as expected when it is online.

As detailed elsewhere in the report, the time period considered was the object of an operational strategy-change, and well performance should be analyzed accordingly.



B Well Pair



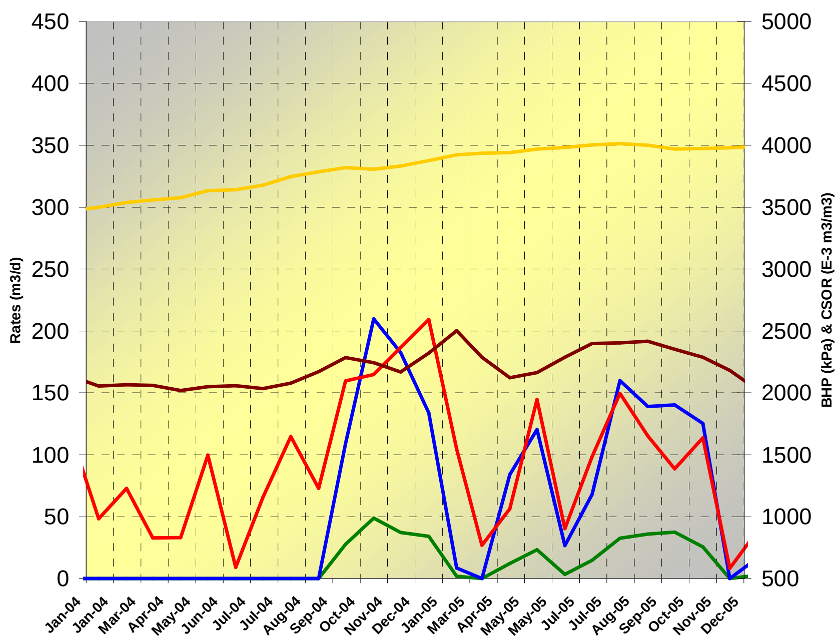
Main Objective: Evaluate Thief Zone Performance

2004 - 2005 Objectives:
Stabilize pressure around 2000kPa

Accomplishments:

1. Tested E-lift System with limited success
2. Tested Single Gas Steam Lift & Rod Pump successfully

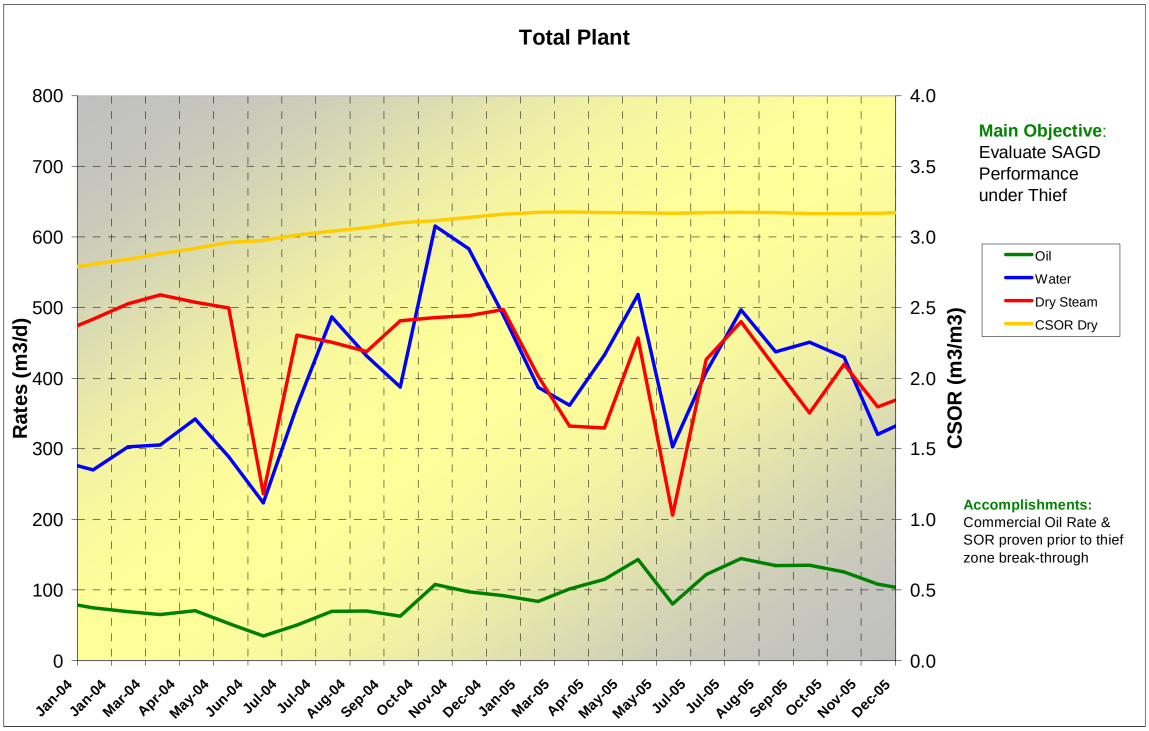
C Well Pair



Main Objective:
Achieve commercial oil rate (~110 m^3/d) depending on steam addition

2004 - 2005 Objectives:
Resume production with pump test.

Accomplishments:
Test ESP in SAGD start up mode

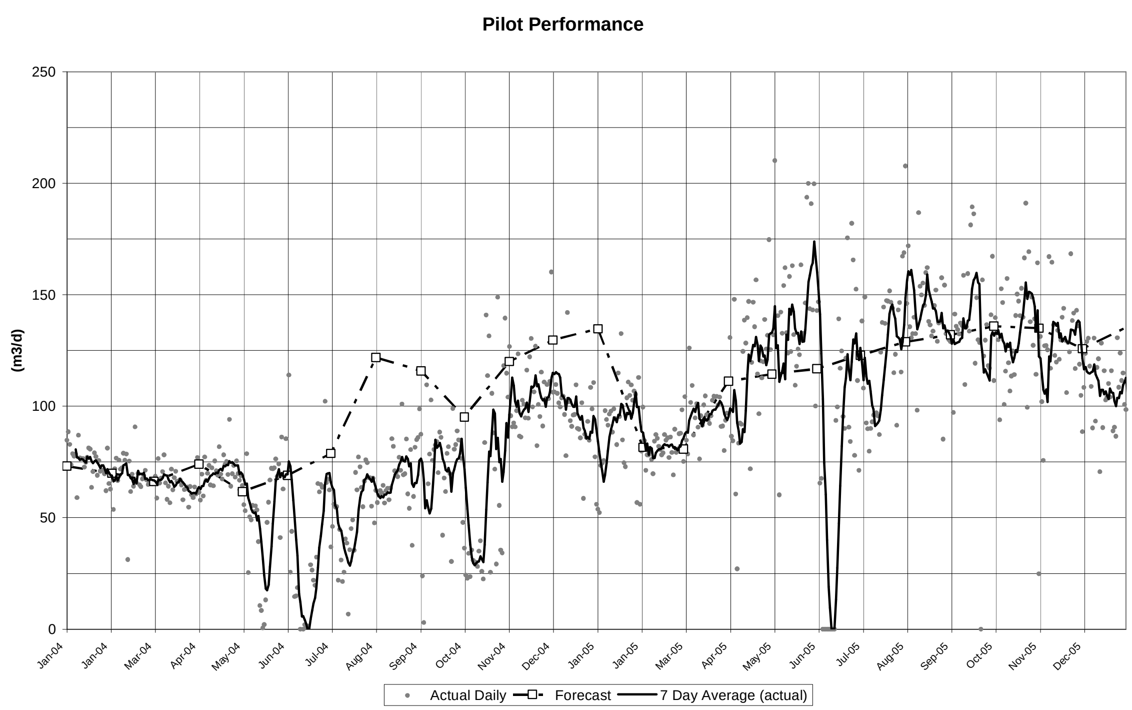


4.2 Composition of produced / injected fluids.

The injected fluid is clean steam with no other additives; 100% H_2O.

The produced fluid is bitumen, water and gas. The composition of these fluids is detailed in appendix A.

4.3 Predicted versus actual well / pilot performance



The plot shows bitumen rates. The actual production matches relatively well with the forecasted values, except for the period from July 2004 until January 2005. This is due to lower than expected performance from the Pilot wells.

In September 2003 the decision was made to increase the target Steam Chamber pressures from approximately 1200-1500kPa to the current 2000kPa. This was done by choking back the bitumen production, while maintaining the steam injection. Late 2Q2004 the Steam Chamber pressures were at the target pressures, and production was increased to balance the reservoir voidage. The production wells did not deliver the modeled flush production rates, thus the disconnect between actual and forecasted values.

4.4 Injection, production and observation well and reservoir pressures

4.4.1 Observation Well Responses

ConocoPhillips has five observation wells located along the two original SAGD wellpairs as shown in Section 3. These wells are OB 18/41, 36 and 24 along the P1/S1 wellpair, and OB 17 and 22 along the P2/S2 wellpair. A further five observation wells are located along the P3/S3 wellpair (P3/S3). These wells are OB 20, 26A, 37, 38 and 39. OB 25 is located between the P1/S1 and P3/S3 well and instrumented with piezometers in the bitumen and top water zone.

The OB 24 well has thermocouples only in the upper part of the pay zone and the OB 18 well has been non-operational for some time. The OB 18 well was replaced by the OB 41 well and drilled in the same area.

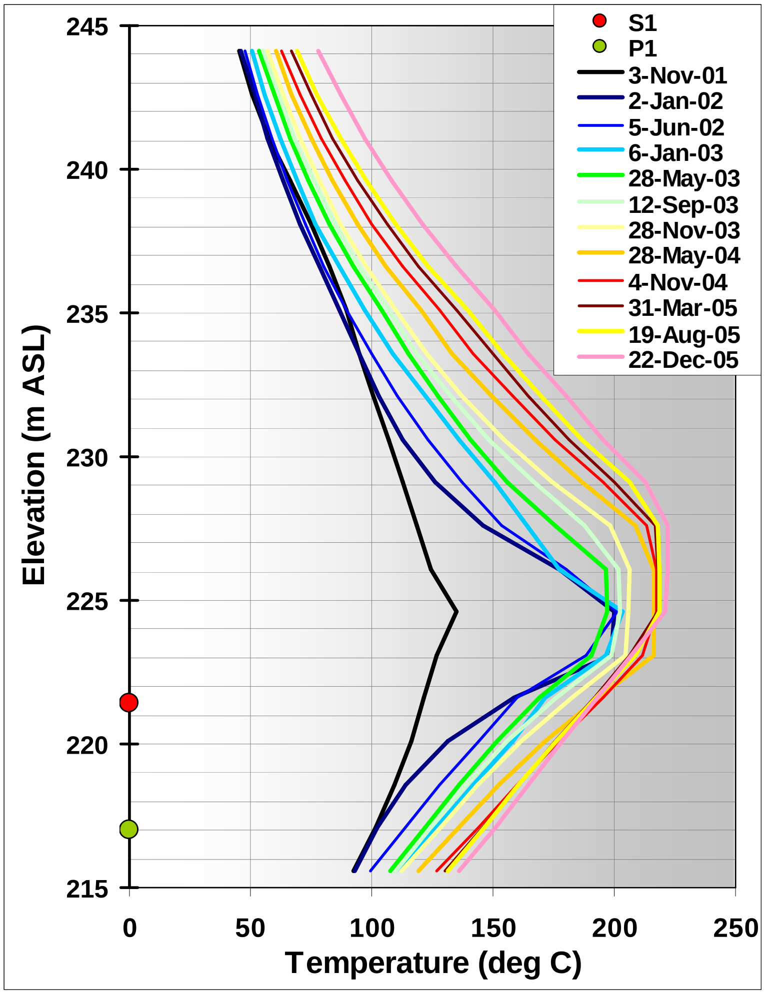
4.4.2 OB 18 (00/12-24-83-07 W4M)

Lateral separation is estimated to be 1.0 m from S1 and 0.6 m from P1 according to surveys. This observation well is still non-operational and will be abandoned shortly.

4.4.3 OB 41 (103/11-24-83-07 W4M)

Lateral separation is estimated to be 11.3 m +/- 5.6 m from S1 and 12.1 m +/- 5.5 m from P1 according to ranging surveys. The OB 41 well was drilled into an area, near the OB 18 well, which showed early steam chamber development.

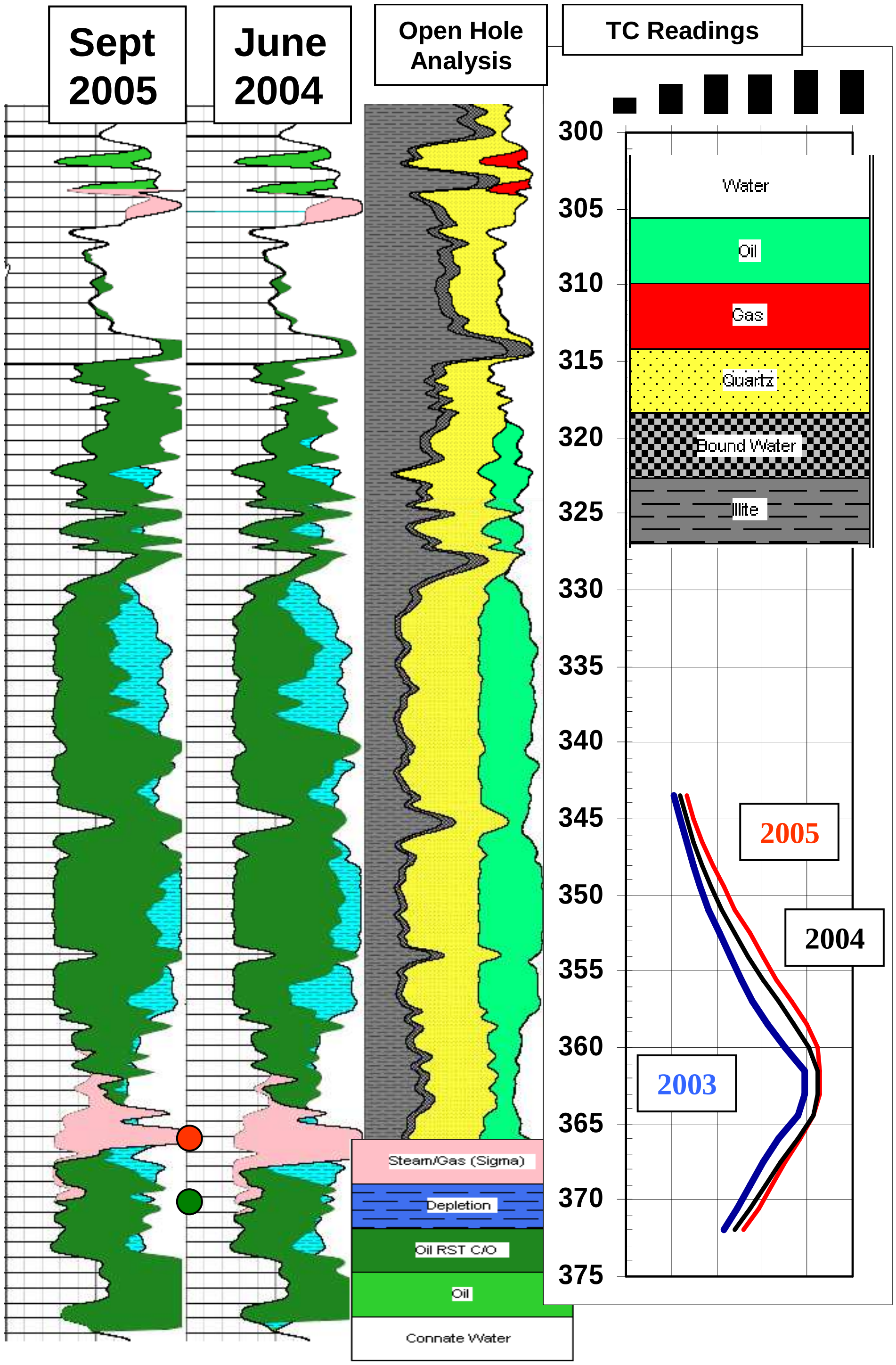
The following plot illustrates steam temperatures at the level of the OB 41 well.



A steam chamber has been present at this well since November 2001 albeit the steam rise rate has been slow. The current temperature profile indicates the 200 ºC level was 8.5 m above the injection well in December 2005.

To understand the fluid distribution at this location a neutron/carbon/oxygen logs (RST) have been run on this well in 2001, 2003, 2004 and 2005. Theses logs indicated that there is a thin steam chamber at this location. The 2004 RST log indicated a steam chamber growth of 2 m and is consistent with the thermocouple data.

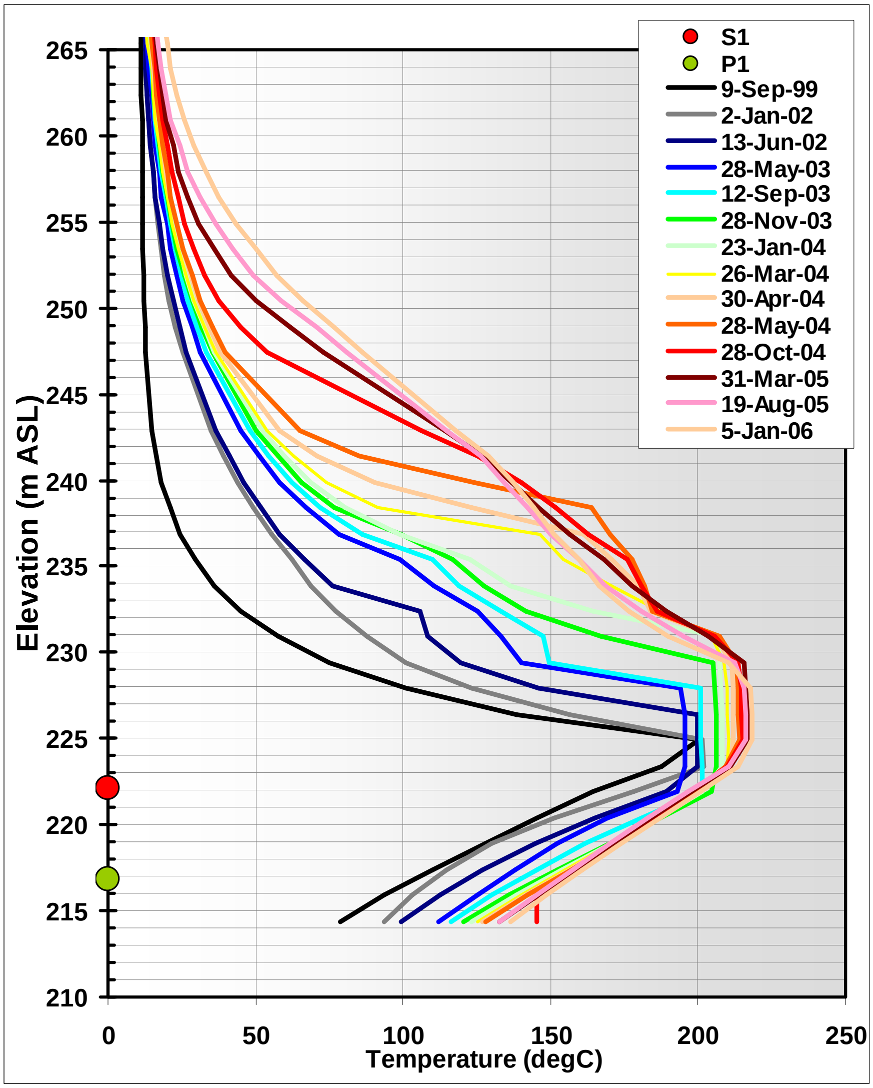
The logs are included on the following page.



Saturations are affected by annular fluids.

4.4.4 OB 36 (106/12-24-83-07 W4M)

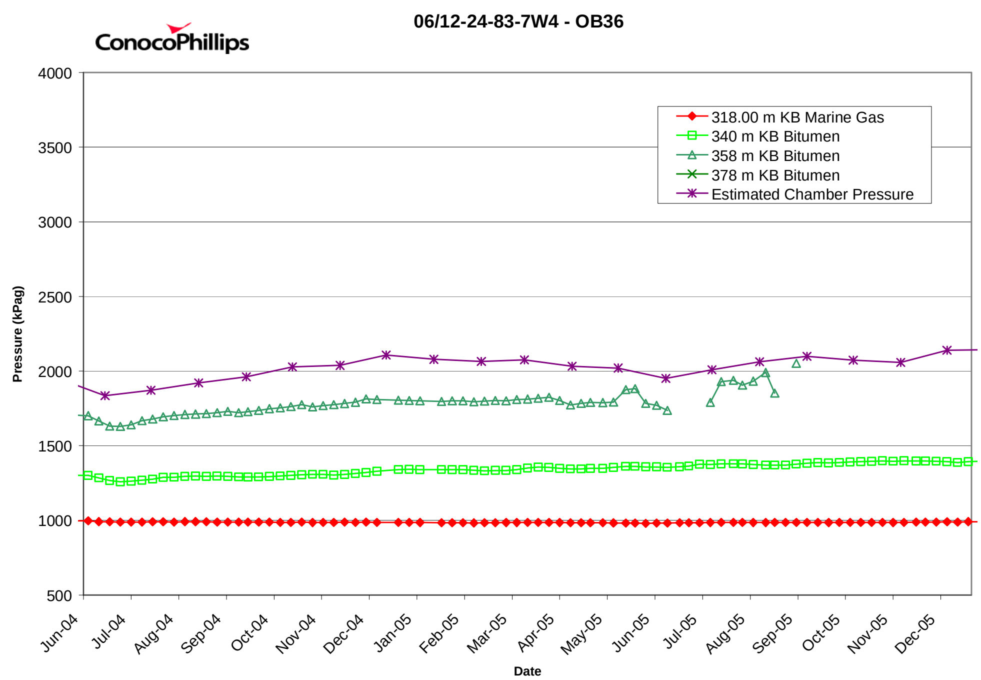
Lateral separation is estimated to be 2.1 m from S1 and 1.6 m from P1 according to surveys.



The plot that follows illustrates the temperatures observed at the OB 36 well from September 1999 to January 2006. The temperature profiles indicate that steam temperature conditions were present over the last year. Steam temperatures are observed approximately 10 m above the level of the injection well.

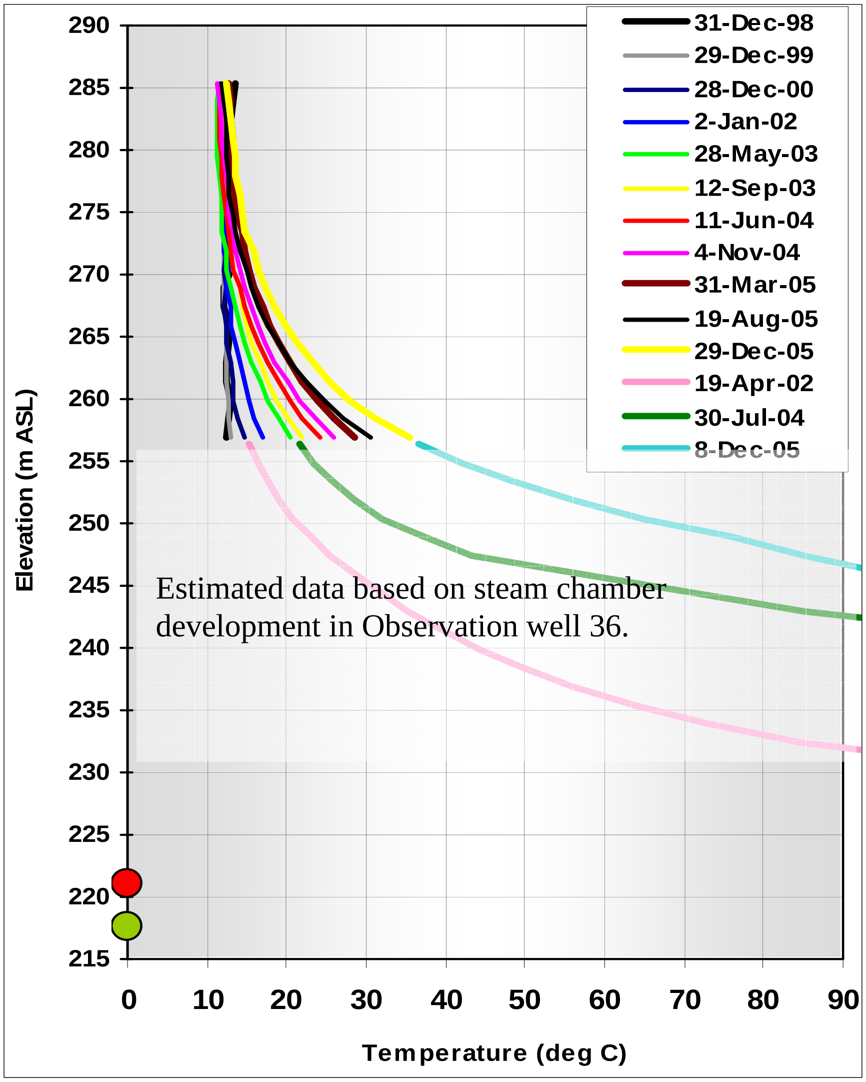
There were four piezometers installed in the OB 36 well, three in the bitumen and one in the marine gas zone. One of the bitumen piezometers has been non-operational for years. The two remaining bitumen piezometers at OB 36 provide additional information about the location of the steam chamber front and conditions ahead of the front. At the end of December 2004 the piezometer at 340 m KB still showed limited interaction with the steam chamber at the P1/S1 wellpair. The piezometer at 358 m KB indicated a response in relation to the steam chamber pressure. This piezometer stopped functioning mid 2005.

The piezometer in the gas zone at the OB 36 well in the past has been interpreted to be equalizing with the lower pressured channel gas zone. Although the two gas zones are still in communication there is a stronger correlation with the S1 steam injection pressure and the marine gas pressure response observed at this location. Although the channel gas is not monitored at this location there is a piezometer at the OB 24 well.



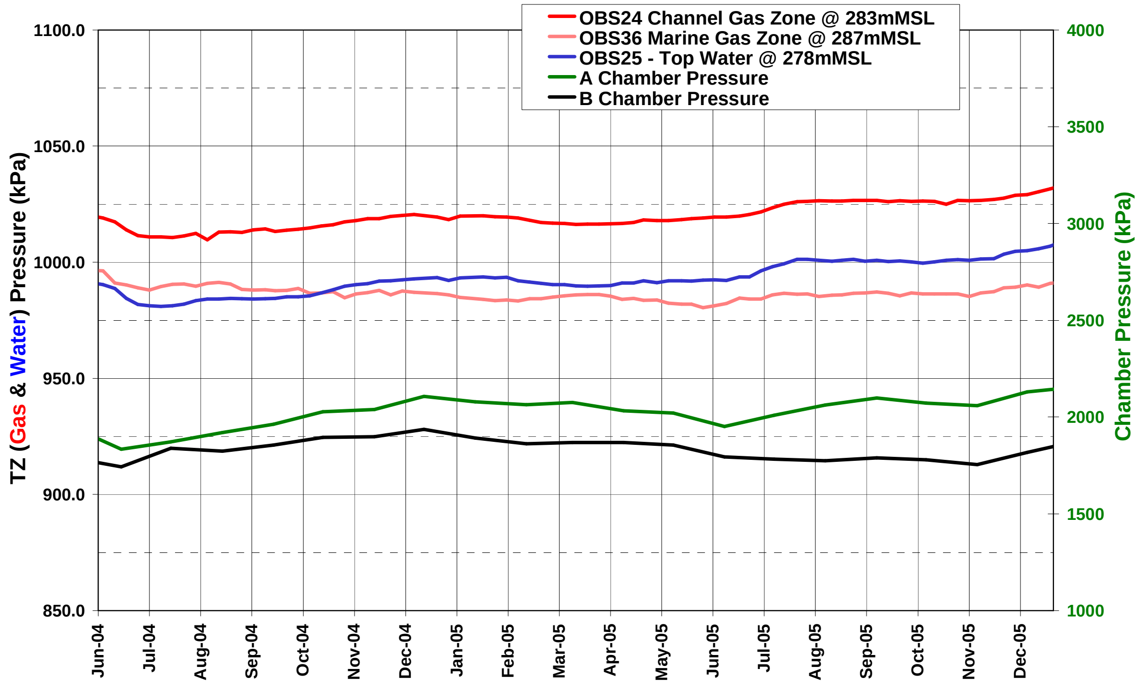
4.4.5 OB 24 (102/12-24-83-07 W4M)

Lateral separation of the OB 24 well is estimated to be 13.1 m from S1 and 13.7 m from P1 according to surveys. The thermocouple string is located at the top of the well such that the lowest thermocouple is 35 m above the S1 horizontal injection well. Because of the lateral separation of OB 24 from the P1/S1 wellpair, and the location of the thermocouples high in the pay zone, a small temperature response has been detected at the lower thermocouples at this observation well, as illustrated by the embedded plot.



It is estimated that the steam chamber development in the Observation well 24 is very similar to the Observation well 36 characteristics. The graph shows estimated temperature profiles for the reservoir section not currently covered by the thermocouple sensors.

There is only one piezometer installed at the OB 24 well. It is installed in the channel gas zone and continues to show an increasing pressure since shutting-in the gas in April 1997. As previously mentioned, this pressure response has been interpreted in the past to be equalizing with the higher pressured marine gas zone. A plot of the OB 24 pressure response follows.

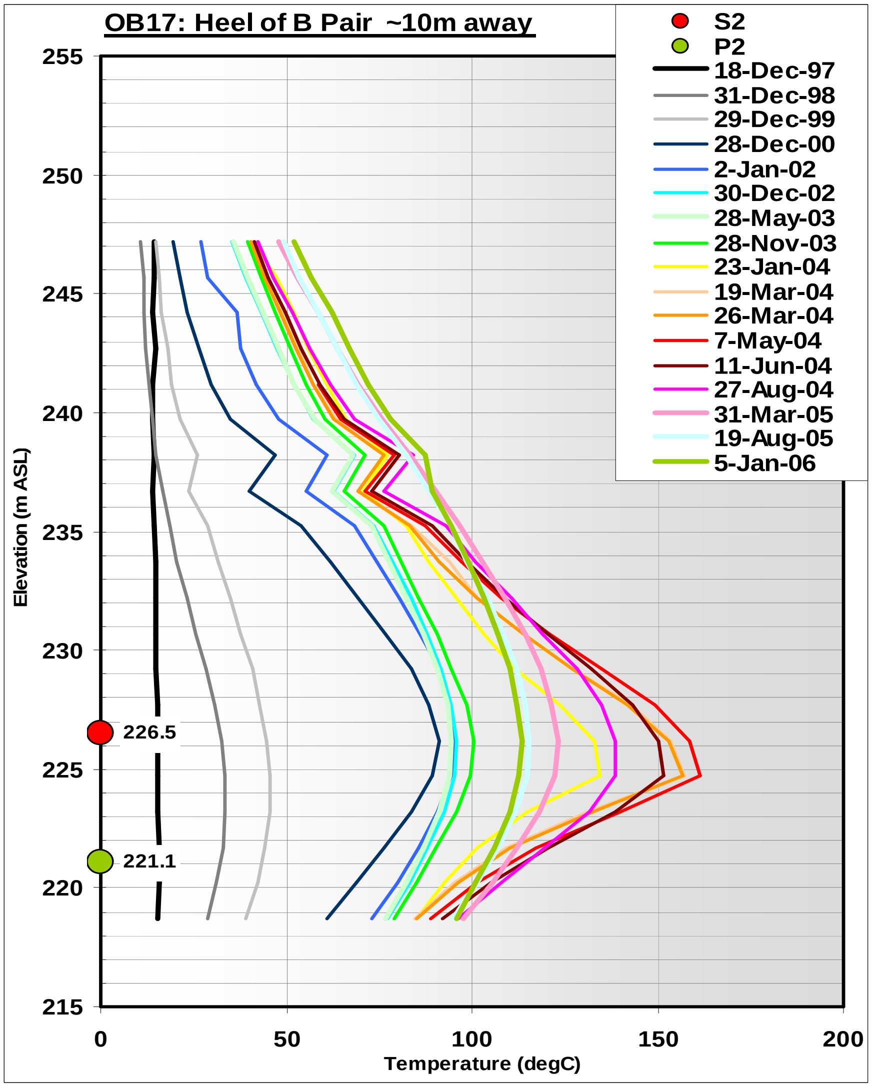


The plot also illustrates the pressure responses measured in the gas zone at both the OB 36 and OB 24 wells. There is a change in the established pressure trend when the S1 gas injection pressure is increased.

4.4.6 OB 17 (104/12-24-83-07 W4M)

Lateral separation is estimated to be 10.3 m from S2, and 8.9 m from P2 according to surveys.

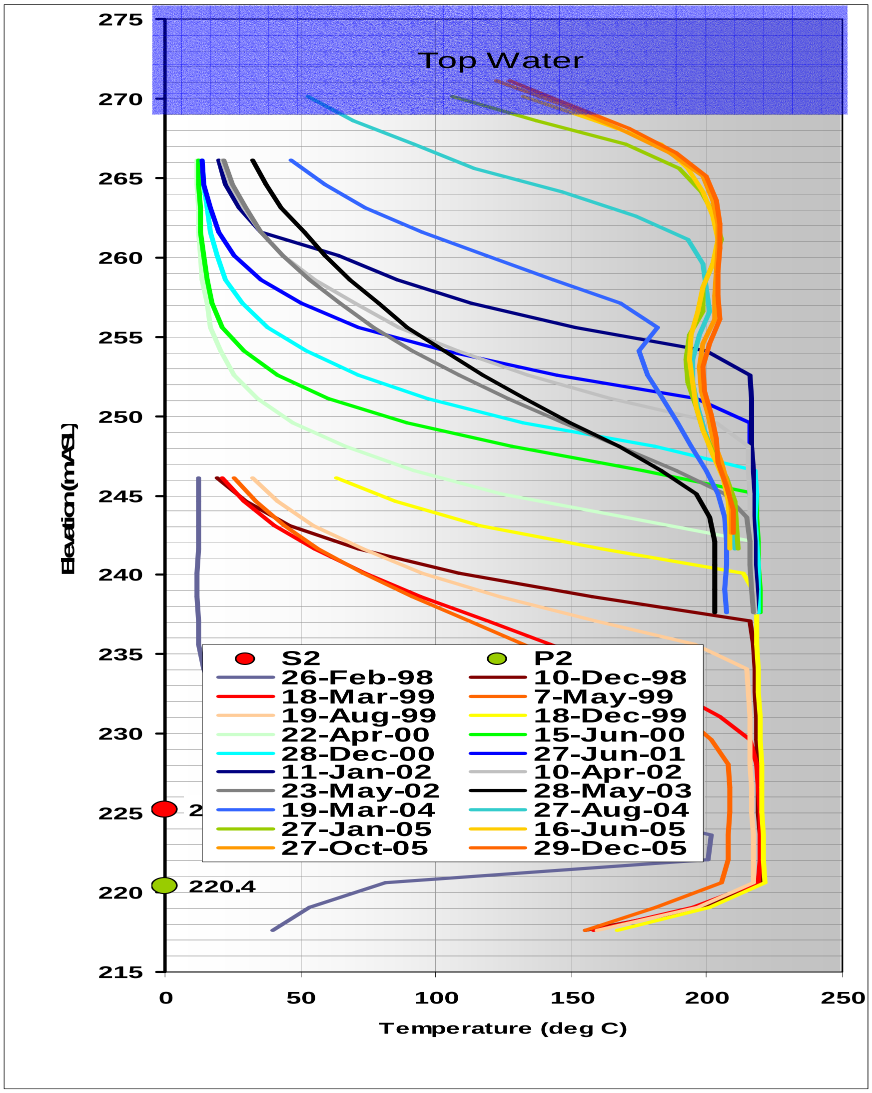
By January 2004, a significant temperature response of 147° C was detected, but a steam chamber was not detected. By May 2004, the temperature had decreased to160° C. The temperature profile then equalizes due to the steam chamber pressures strategy constraints.



There are no piezometers installed at the OB 17 well.

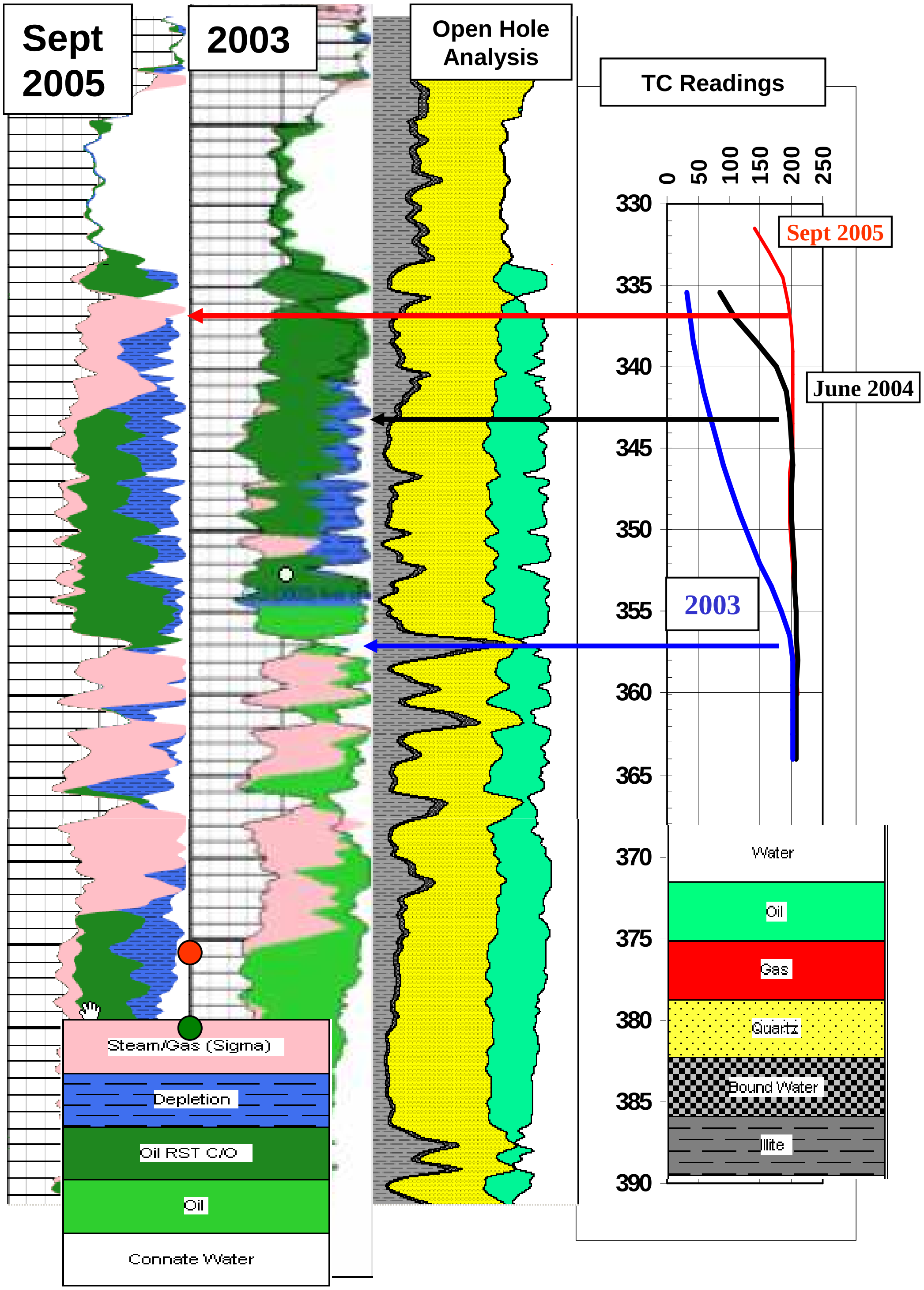
4.4.7 OB 22 (105/12-24-83-07 W4M)

Lateral separation is estimated to be 0.2 m from S2, and 0.0 m from P2 according to surveys, indicating that this well should be right at the location of the horizontal wells. The temperature profile of the well indicates that the level of the steam chamber was at 356.5 mKB in January 2004. In February the temperature 10 m above at 346 m KB began to increase indicating that steam was approaching the observation from the side. By June 25 the temperatures above the steam zone had increased by nearly 100° C and by July 30 steam was detected at two different levels at this location such that the top of the steam was approximately 6 m from the thief zone.



There are no piezometers installed at the OB 22 location.

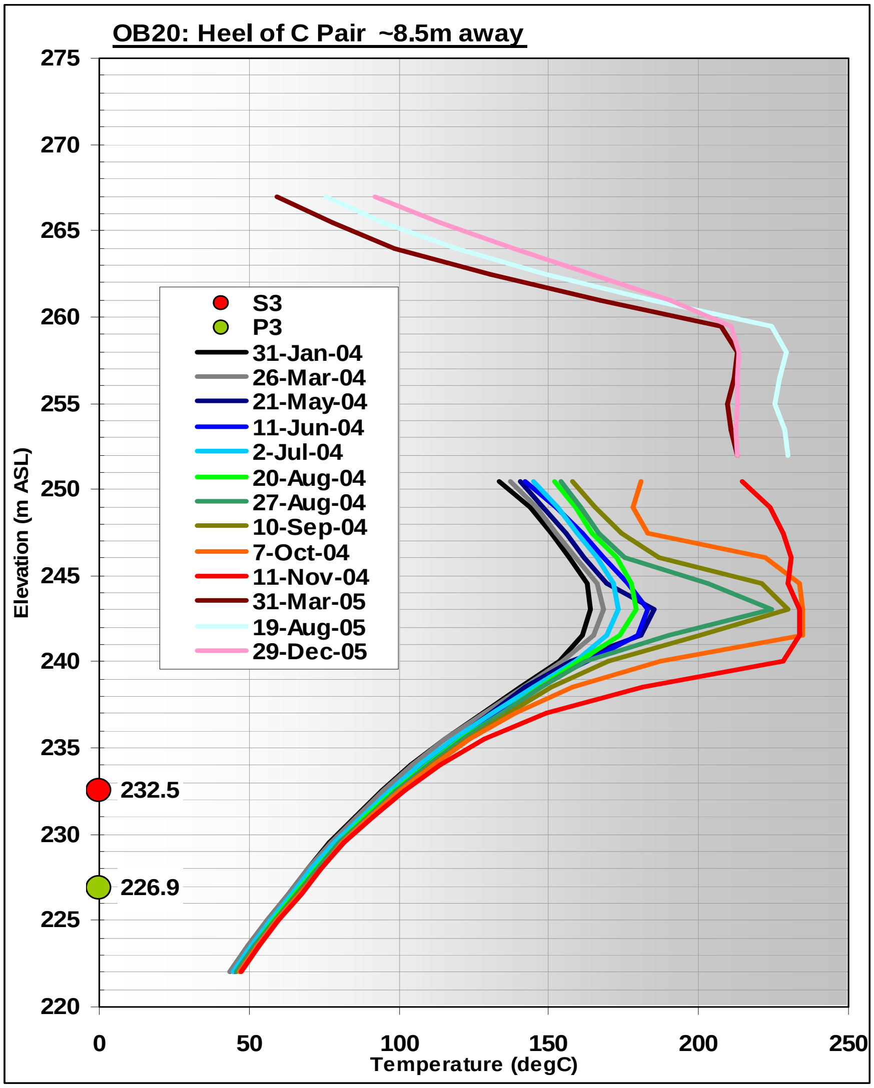
A neutron/carbon/oxygen log was also run at OB 22 run at this location in April 2003. The steam zone from the 2003 RST log matched the temperature profiles and the interval of apparent fall back in steam chamber height appears to be saturated by bitumen with some water and increasing amounts of vapour (methane & steam) towards the top of the steam chamber. To verify the above interpretation, the well was re-logged in June 2004 after raising the apparent steam chamber height. The carbon/oxygen tool failed in zone of investigation as wellbore was fluid filled and tool went over 150°C. The Sigma tool was still good for steam/gas height as when correlated to temperature it showed top of steam. There appears to be a possible gas front before steam chamber. Absence of baseline complicates the analysis in lower sections of well



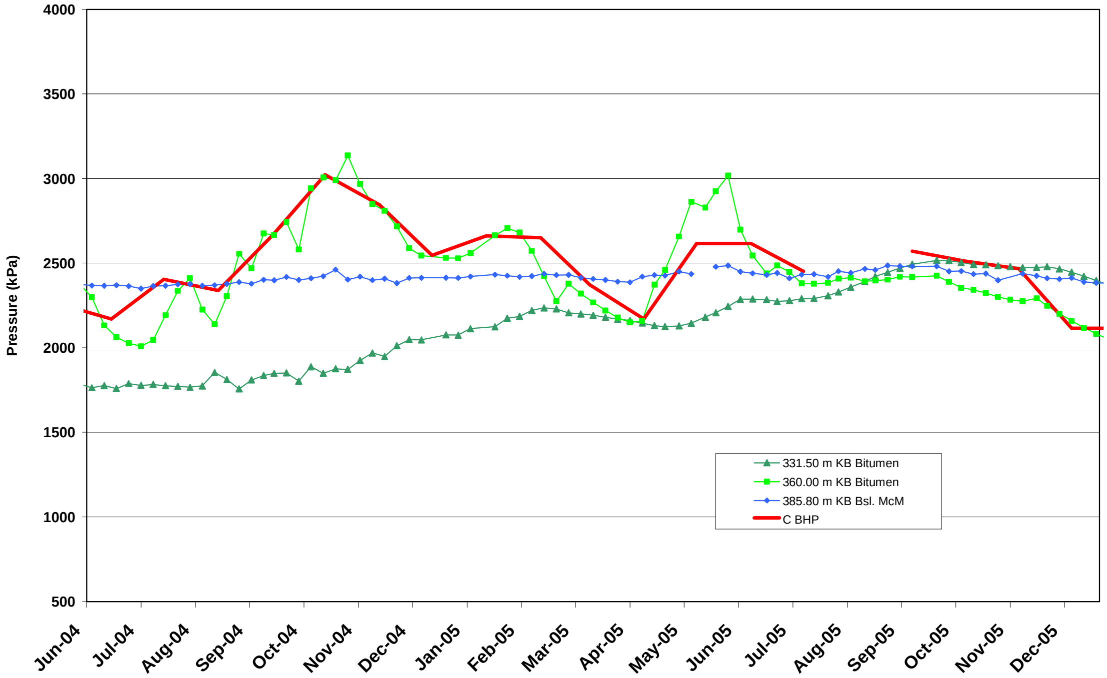
The 2005 RST is the first with full coverage without failure.

4.4.8 OB 20 (100/11-24-83-07 W4M)

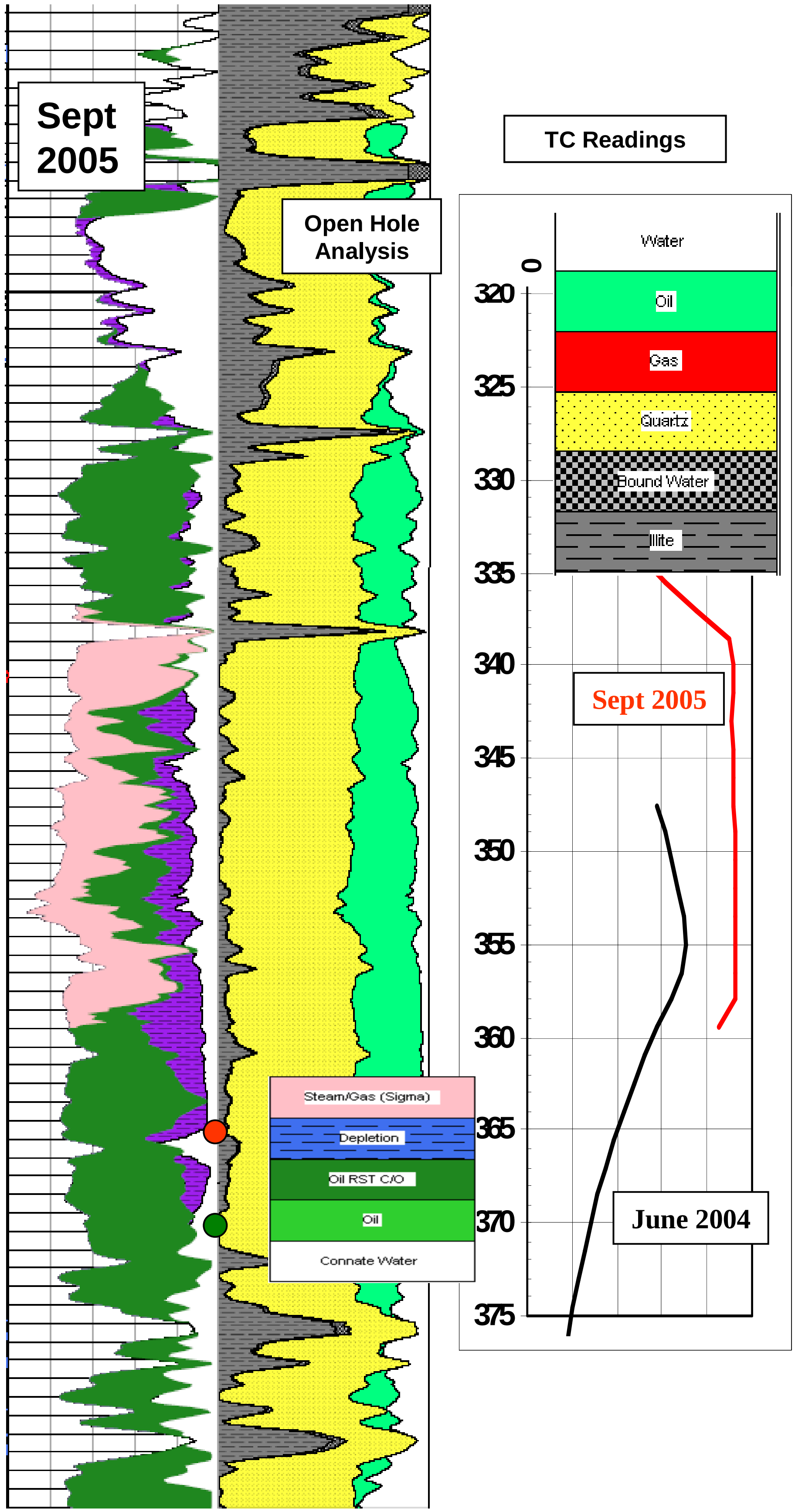
Lateral separation is 8.6 m from S3 and 8.5 m from P3. This observation well is located at the heel of the P3 horizontal well. A plot of the temperature profile at this well as shown below illustrates that steam is present approximately 27m above the injector at this location. They were moved up in 2004 to better monitor the top of the chamber. The chamber is now ~10m of the Top Water.



There are three piezometers installed in the OB 20 well, one in the Basal McMurray and two in the bitumen zone. The graph of the three piezometers and the bottom hole pressure at the S3 well indicate that piezometer at 360m KB responds to S3 gas injection pressure. Over the last two years the piezometer in the bitumen at 331.5m KB has exhibited an increasing pressure trend. Over the past two years the Basal McMurray piezometer has similarly exhibited an increasing pressure trend.



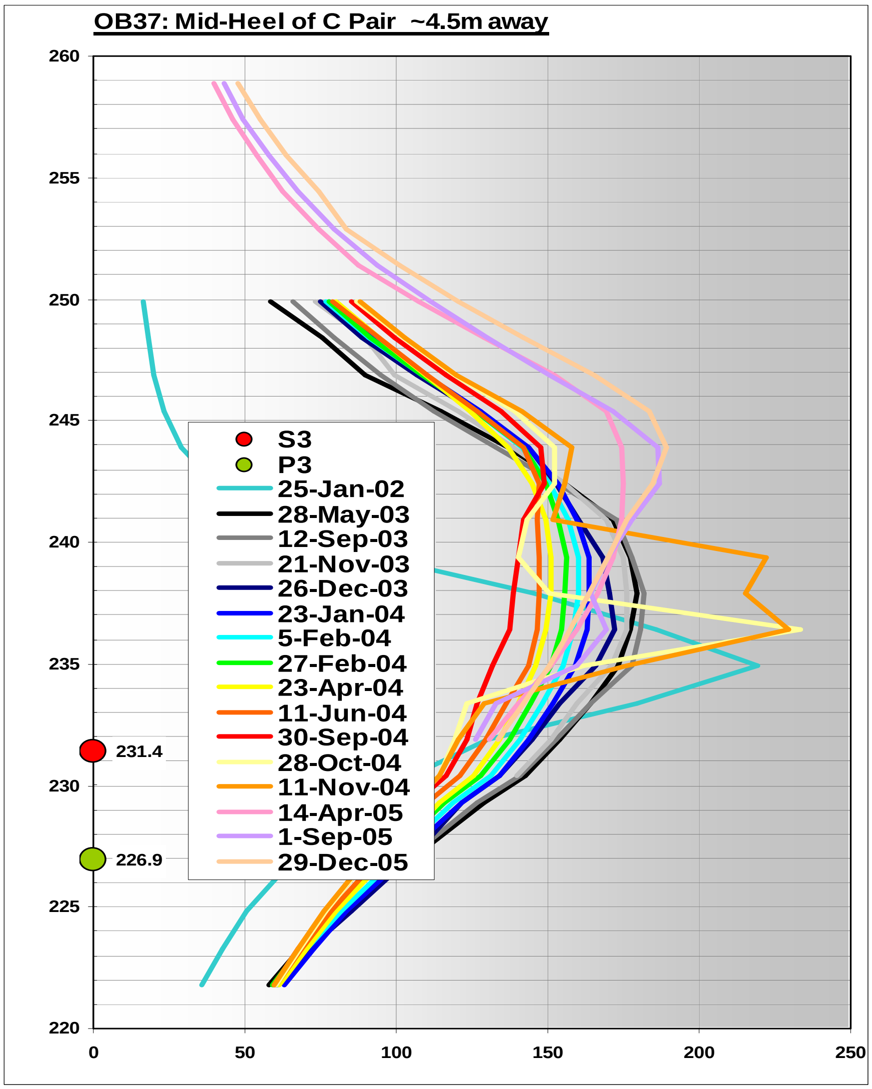
An RST log was run in 2005. The log is shown below.



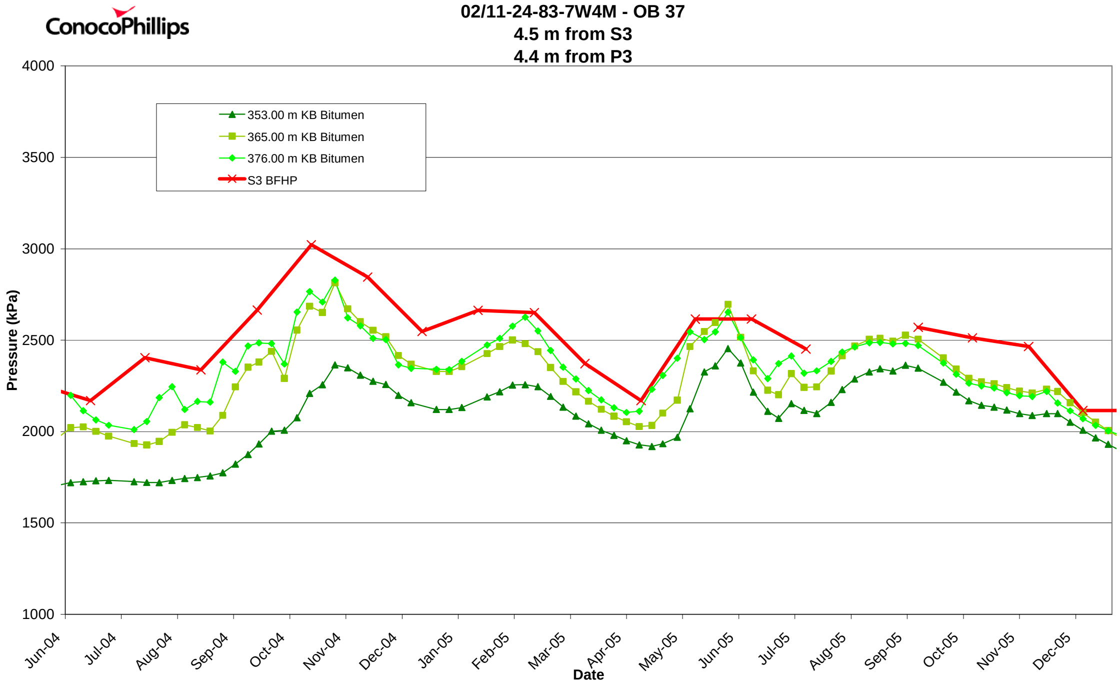
No baseline exists; the depletion is estimated from initial OH analysis. There are indications of a shale barrier.

4.4.9 OB 37 (102/11-24-83-07 W4M)

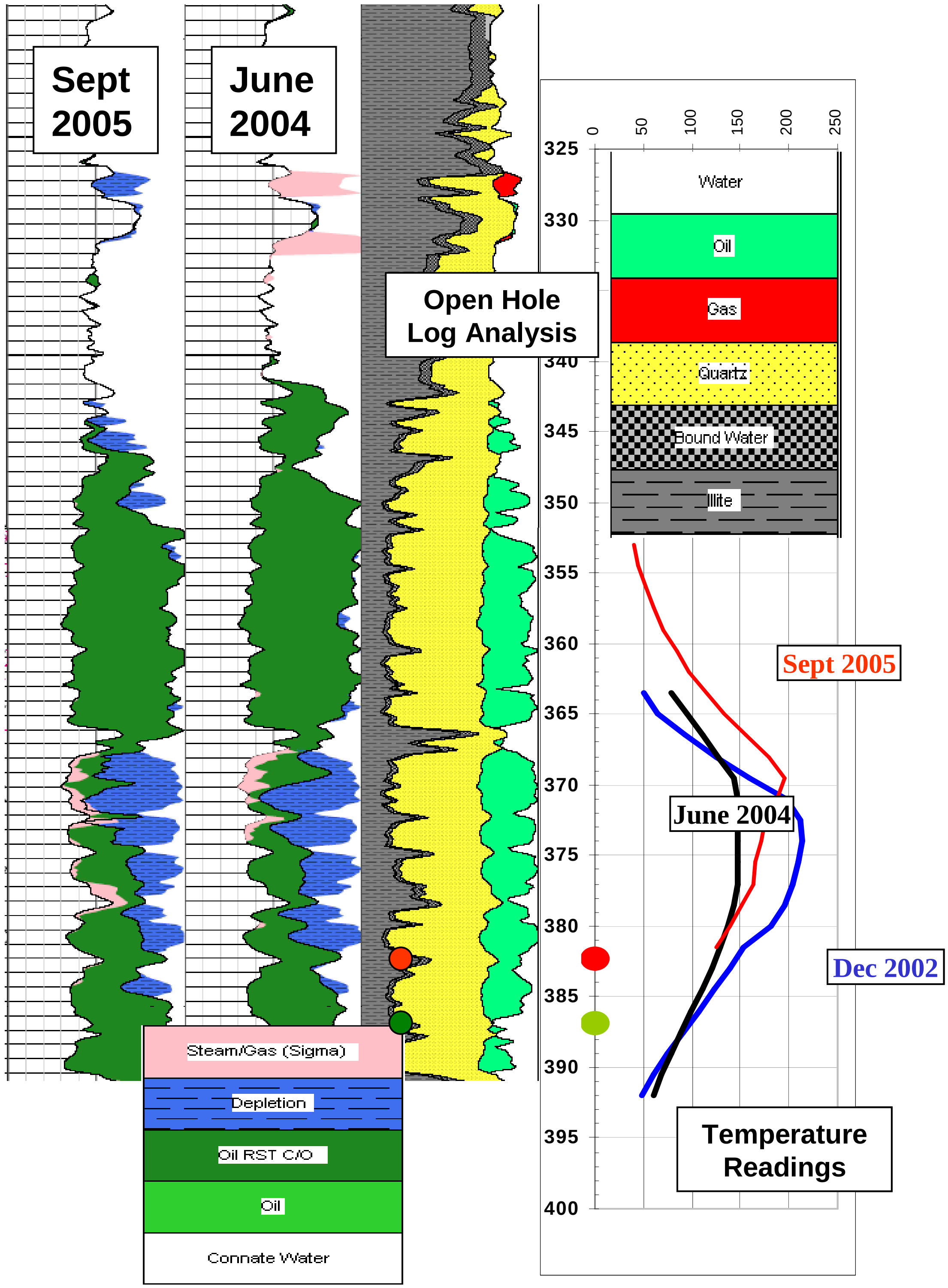
The OB 37 well is located approximately 1/4 of the way from the heel to the toe of the S3/P3 horizontal wellpair. Lateral separation is 4.5 m from S3 and 4.4 m from P3. Steam chamber temperatures were observed at this well just above the steam injector in January 2002. The temperature profile plot indicates that the steam chamber continued to develop until December 2002 after which the apparent steam chamber top continued to fall back due to restricted production, the lack of steam capacity and lift issues. In September of 2004 similar to OB 22, temperatures began to increase from above the last known vertical location of steam suggesting that steam was approaching the OB well location from the side. By December 2004 temperatures in excess of 200° C were observed 12.5 m above the injector. Conduction heating in still occurring as indicated by the increasing temperatures at the upper most thermocouples.



Three piezometers were installed in the OB 37 well in the bitumen zone. The two lower most piezometers are at 365 m KB and 376 m KB at 6 and 17 m above the level of the injection well showed a pressure response to steam injection much earlier than the upper most piezometer at 353 m KB. This piezometer is 30 m above the injector and started showing a pressure response to steam injection in September 2004. The piezometer data and gas injection pressure are illustrated in the following graph.



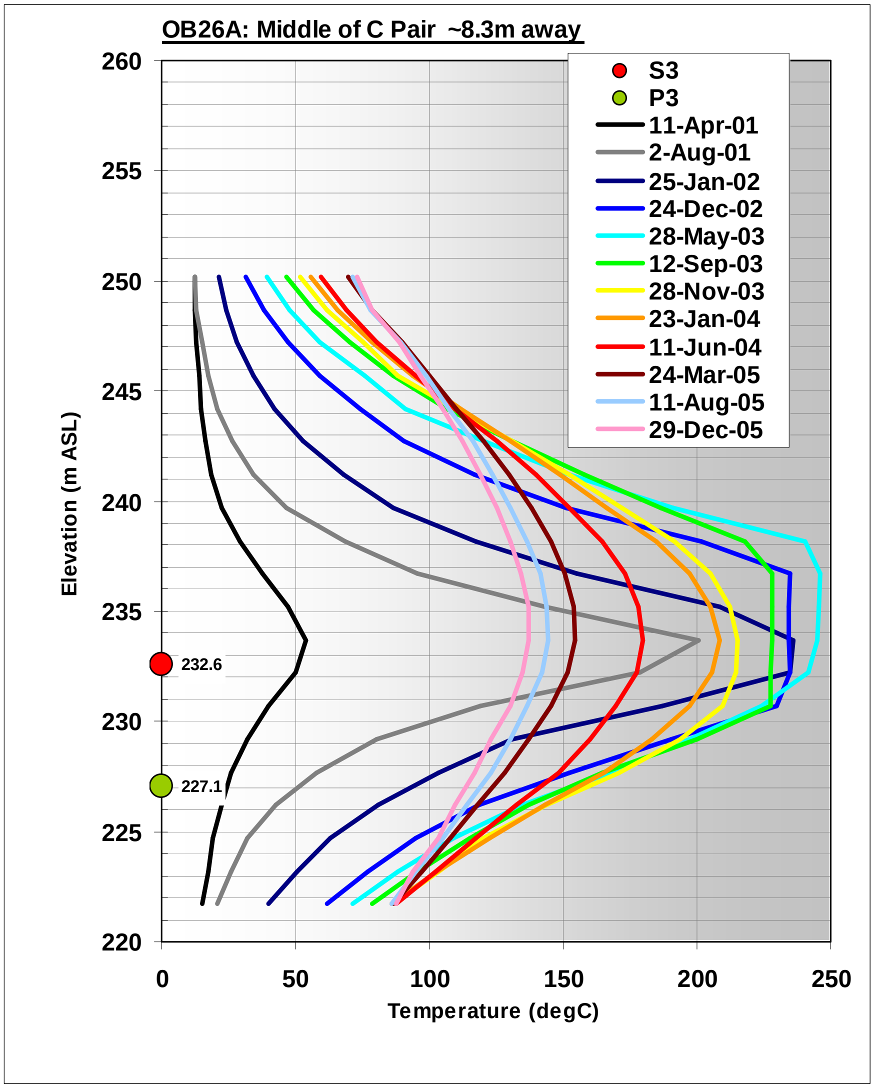
An RST log was also run at the OB 37 well in June 2004 and September 2005. This log indicated that there is a swept zone as high as 367.5 m KB in June 2004. This is in good agreement with the highest temperature of 210 °C observed at 372.5 m KB at this location from thermocouples in December 2002. The log and thermocouple profile is illustrated on the following page. Other indications are that shale could prevent bitumen mobilization. The RST results are otherwise ambiguous due to baseline problems.



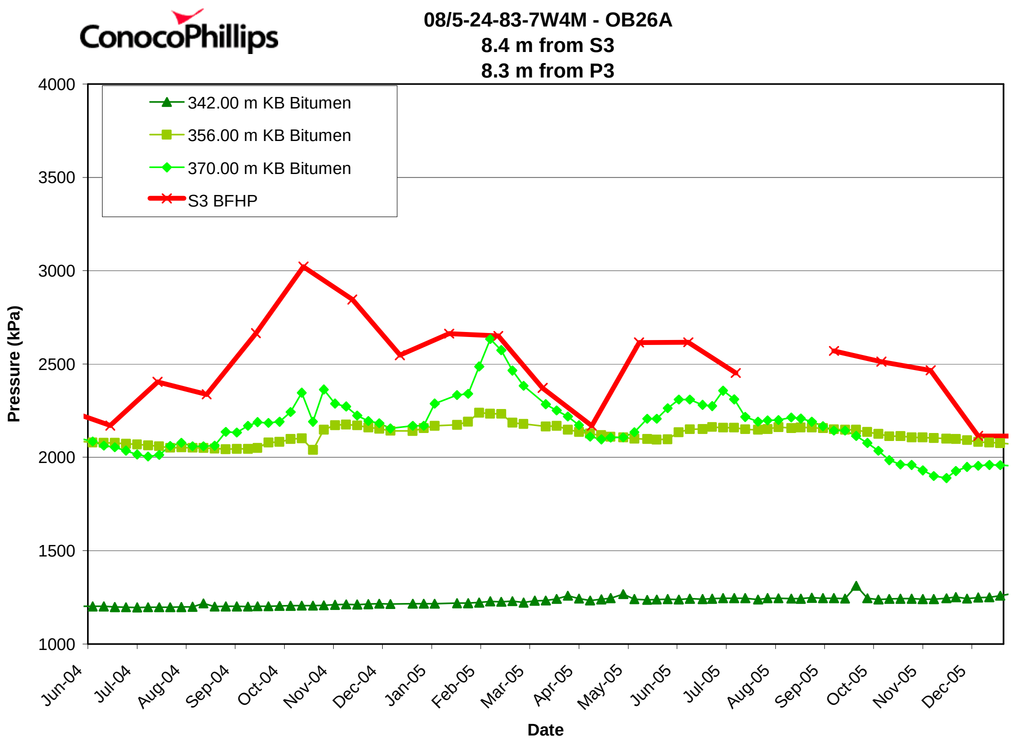
Sept 2005
June 2004
Open Hole Log Analysis
325
330
340
345
350
355
360
365
370
375
380
385
390
395
400
0
50
100
150
200
250
Water
Oil
Gas
Quartz
Bound Water
Illite
Sept 2005
June 2004
Dec 2002
Temperature Readings
Steam/Gas (Sigma)
Depletion
Oil RST C/O
Oil
Connate Water

4.4.10 OB 26A (108/5-24-83-07 W4M)

Lateral separation of OB 26A is 8.4 from S3 and 8.3 m from P3. This observation well is located ½ way down the horizontal trajectory of the S3/P3 well pair. Steam temperatures were first observed at this location in November 2001. The temperature profile plot illustrates the steady growth of the steam chamber at this location until May 2003, when the steam chamber was 6.2 m above the S3 injection well. Since May 2003 and throughout 2004 the steam chamber continued to fall back although conduction heating is still occurring as indicated by the higher temperatures at the upper thermocouples.

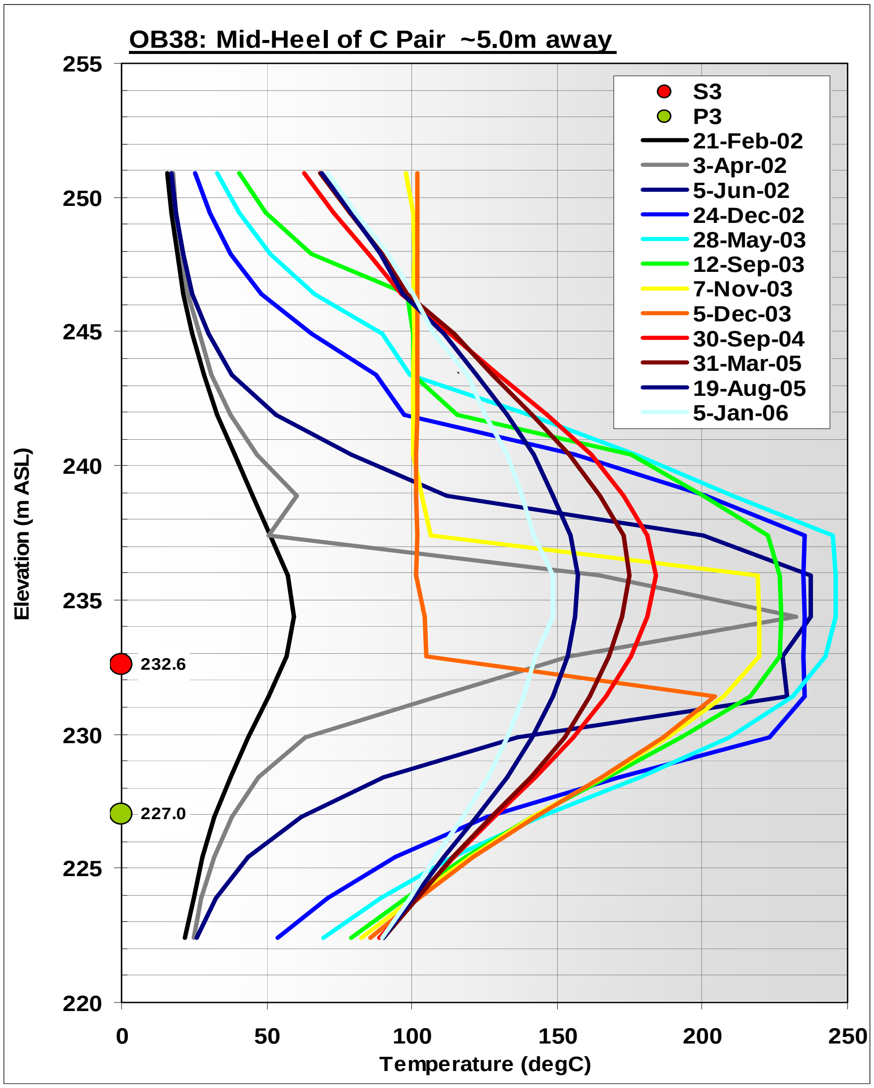


There are three piezometers installed in the bitumen at the OB 26A well. The two lower most piezometers, which are 6 and 20 m above the level of the injection well exhibited pressure responses to steam injection pressures, as illustrated in the plot that follows.

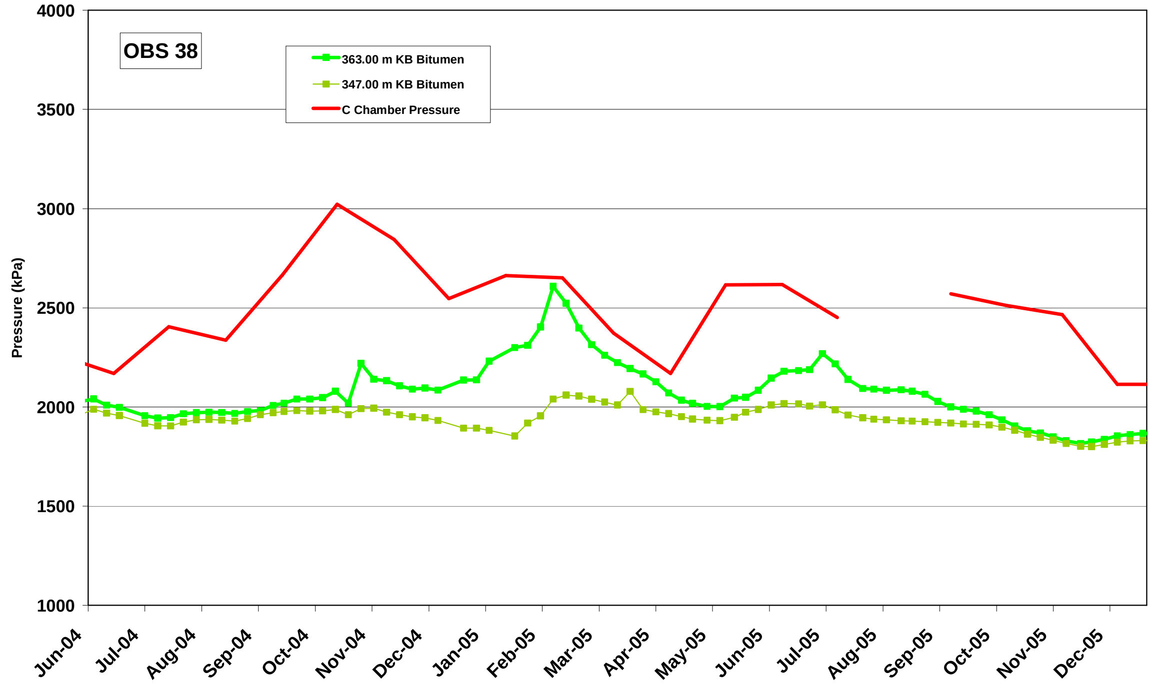


4.4.11 OB 38 (109/5-24-83-07 W4M)

Lateral separation of the OB 38 well is 4.4 m from S-3 and 5.0 m from P-3. This well is located ¾ of the way down the trajectory of the S3/P3 horizontal well pair. This well was displaying the lowest temperature response until April 2002. However, between April 2002 to October 2003 the OB 38 thermocouple data had been indicating the presence of a steam chamber. The thermocouple string was pulled in December 2003 due to a possible casing leak at this well. In June 2004 the thermocouple string was re-installed after confirming the lack of a casing leak. The temperature data since June indicates that the steam chamber has continued to fall back at this location.

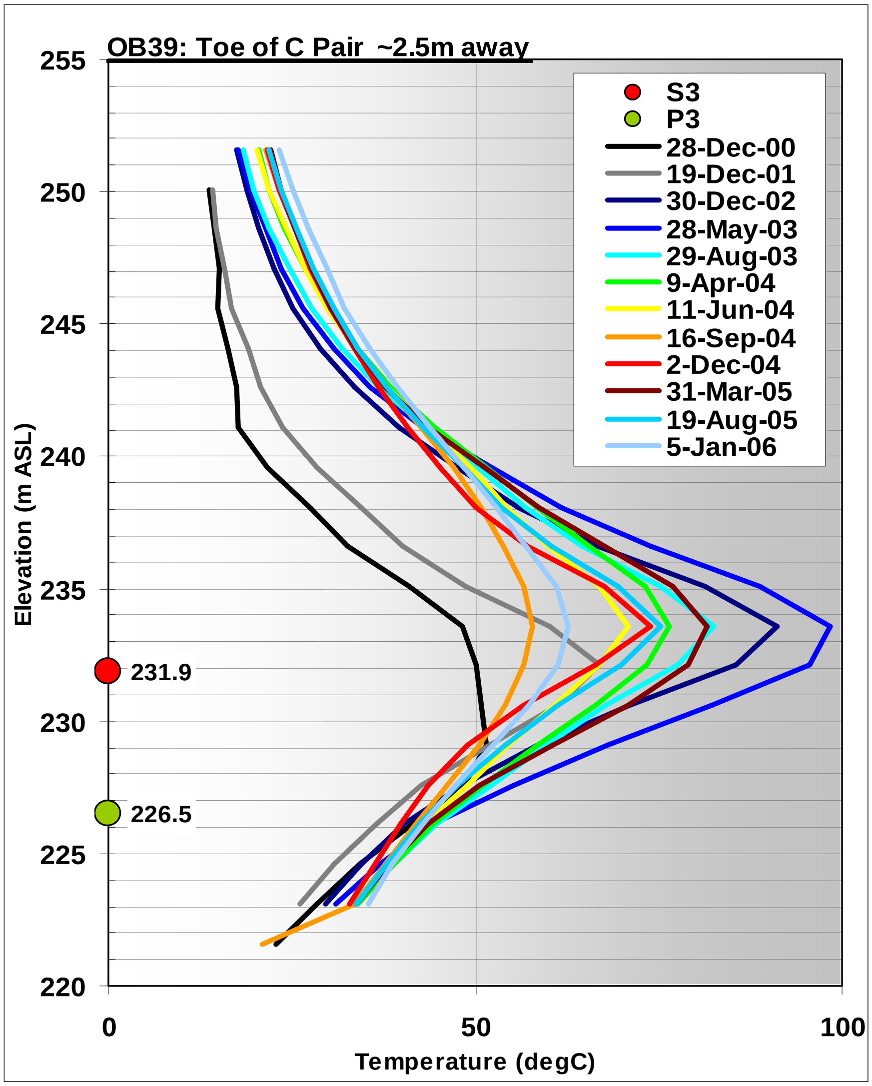


There are two piezometers installed in the bitumen zone at the OB 38 well, one at 363 m KB and one at 347 m KB. Both these piezometers, which are 12 and 29 m above the level of the injection well, are exhibiting a pressure response to the steam injection pressure.

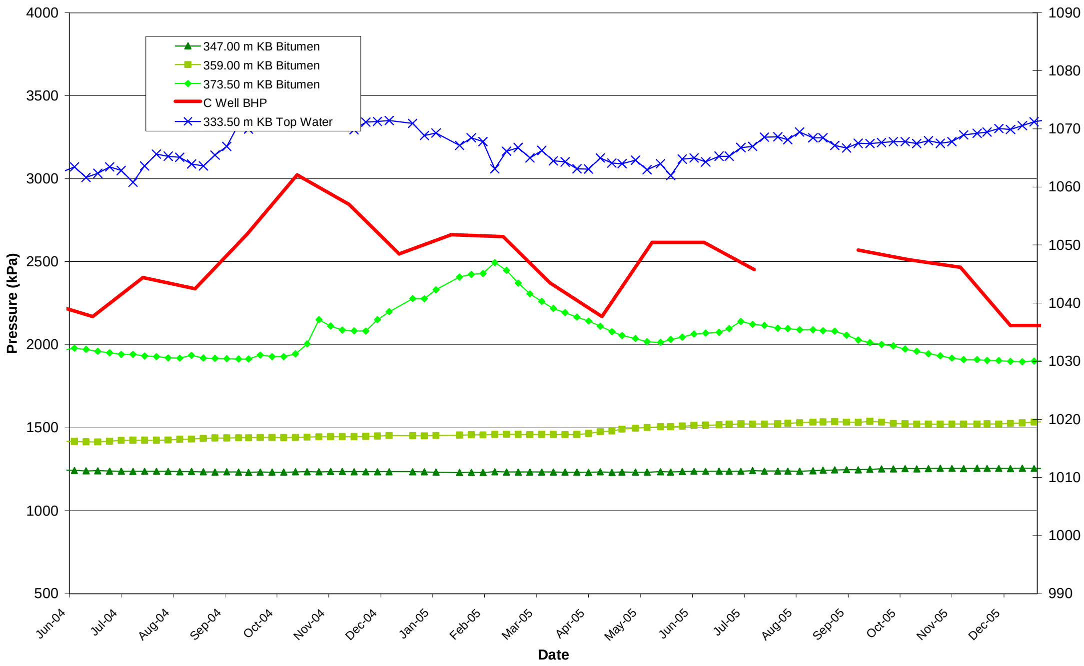


4.4.12 OB 39 (100/4-24-83-07 W4M)

The OB 39 well is at the end of the S3/P3 horizontal wellpair. Lateral separation is 3.2 m from S3 and 1.8 m from P3. Although this observation well is the closest well to the horizontal wellpair, it is not exhibiting a steam chamber. This well did initially exhibit a temperature response due to conduction heating but has not developed a steam chamber due to the presence of mudstone between the injector and producer.

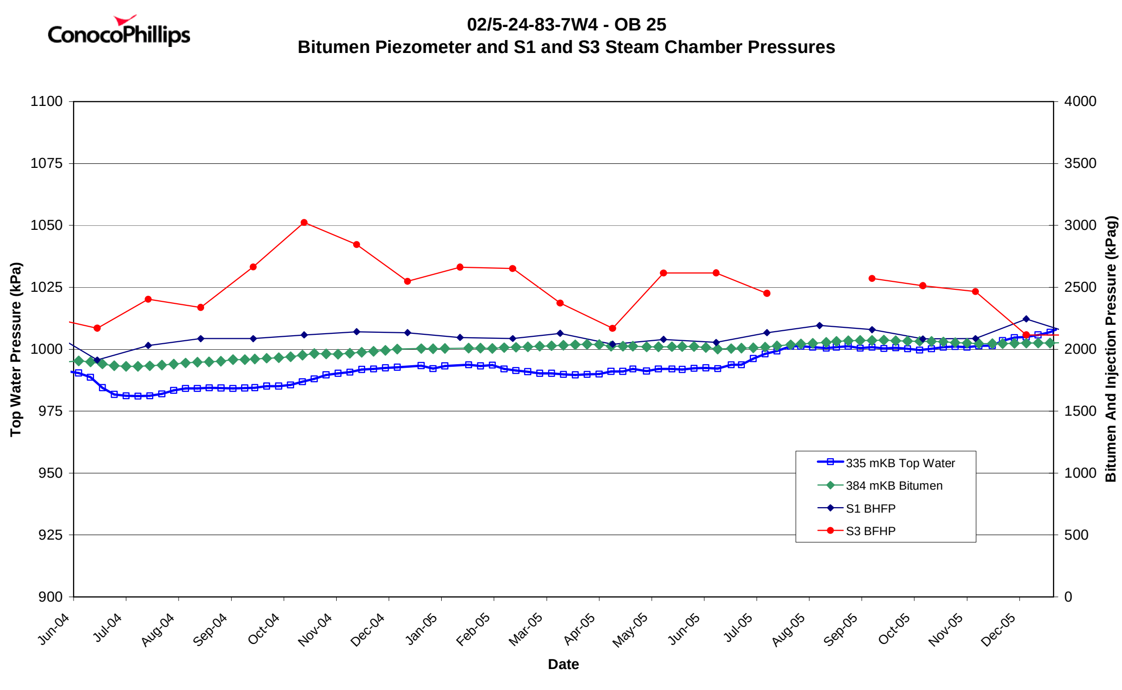


There are four piezometers installed at the OB 39 well, one in the top water zone and three in the bitumen zone. The three in the bitumen zone are installed at 347.0 m KB, 359.0 m KB and 373.5 m KB. The lower most piezometer, at 7 m above the injector showed the most pronounced pressure response while the middle bitumen piezometer exhibited a small response.



4.4.13 OB 25 (102/5-24-83-07 W4M)

OB 25 is located between the S1 and S3 horizontal injectors. The piezometer in the bitumen zone of the OB 25 well indicates that the pressures in the bitumen zone were as high as 2000kPa during the reporting period. These pressures indicate the pressure wave from the steam chamber. The pressure exhibited by top water piezometer at 335 m KB over the last year appears to be following the S1 steam injection pressure.



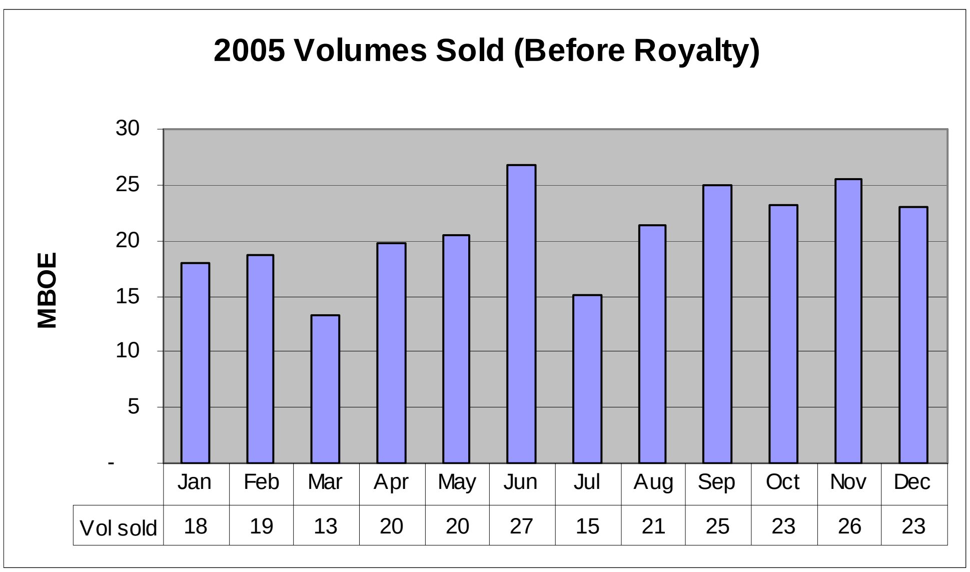
5 Pilot economics to date

The following table summarises the Surmont Pilot Plant financial data for the year 2005.

Surmont Pilot
Financial Summary for 2005
($000)

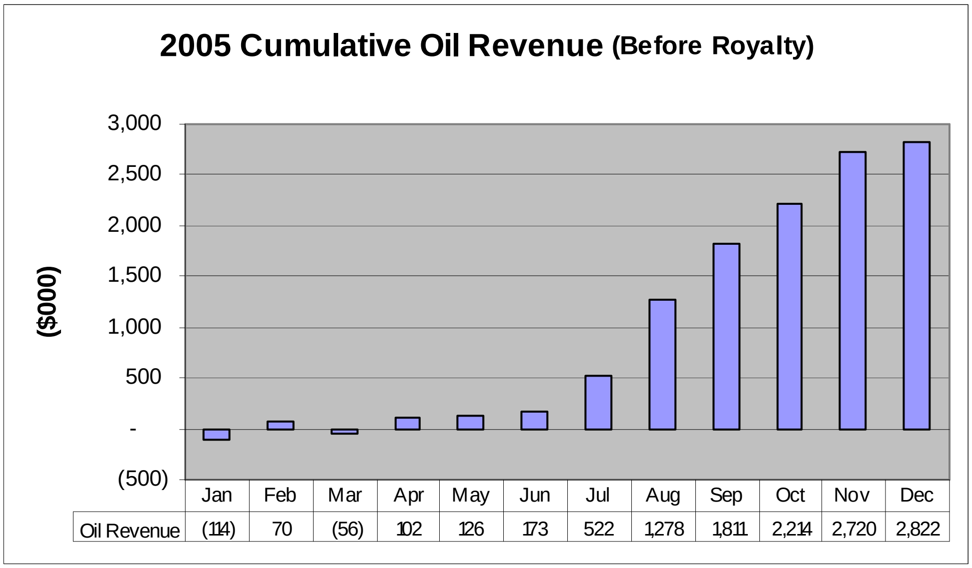
	2005
Sales Volumes (mboe)	250
Revenue Before Royalty	2,822
Crown Royalties	22
Revenue After Royalty	2,800
Operating Costs	13,186
Capital Costs	2,509
Cash Flow	(12,895)

5.1 Sales Volumes



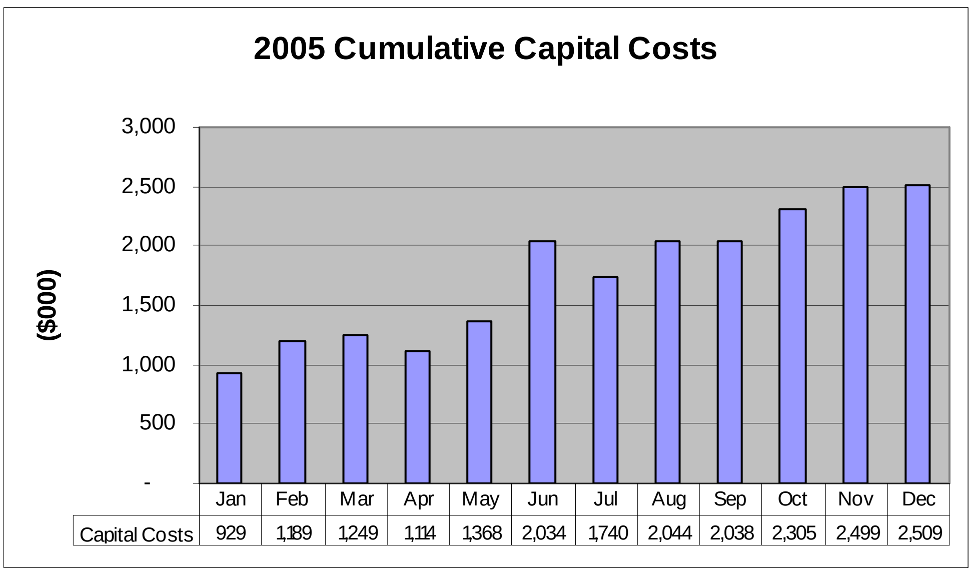
This graph illustrates the sales volumes resulting from 2005 production at the Surmont Pilot Plant.

5.2 Revenue



This graph represents the cumulative before royalty revenue the Surmont Pilot Plant generated in 2005.

5.3 Capital Costs



These are the 2005 cumulative capital costs incurred at the Surmont Pilot Plant. The two months where costs are negative results from accrual reversals; Cumulative capital costs for 2005 are correct.

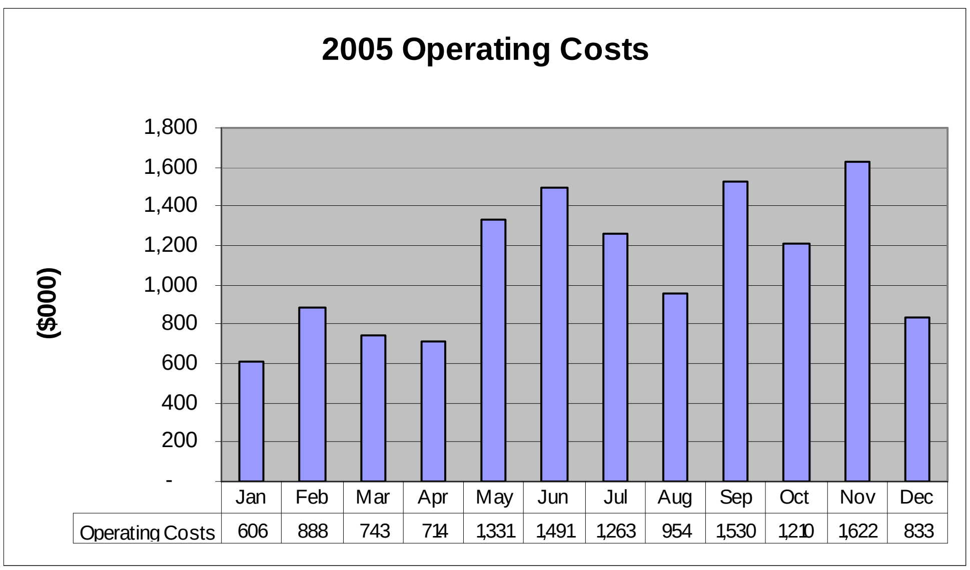
Below is a listing of the types of capital expenditures that compromise the 2005 capital costs.

Description of capital cost items:

- Surmont RST Logging
- Surmont Regional Initiatives
- Surmont Environmental Management
- FMC Multi-Phase Meter Test

- Jiskoot Multi-Phase Meter Test
- Surmont Pressure Study
- Gas Bitumen AGR-Facilitator
- Surmont Geomechanical Testing
- Surmont 4-24 SPT Pump Test
- Gas Bitumen Transcripts
- Surmont GOB
- Surmont GRIPE
- Surmont Geostatical Modeling
- Surmont Facimage & Geomage License
- Surmont Arc Study on Bitumen
- 2005 Geophysical Workshop
- 2004 Modelling & Acoustic
- Surmont Palynology Study
- Surmont Subsidence Study
- Surmont HGP Pump Test
- Surmont P1 Can-K Test
- Surmont P1 Upgrade

5.4 Operating Costs

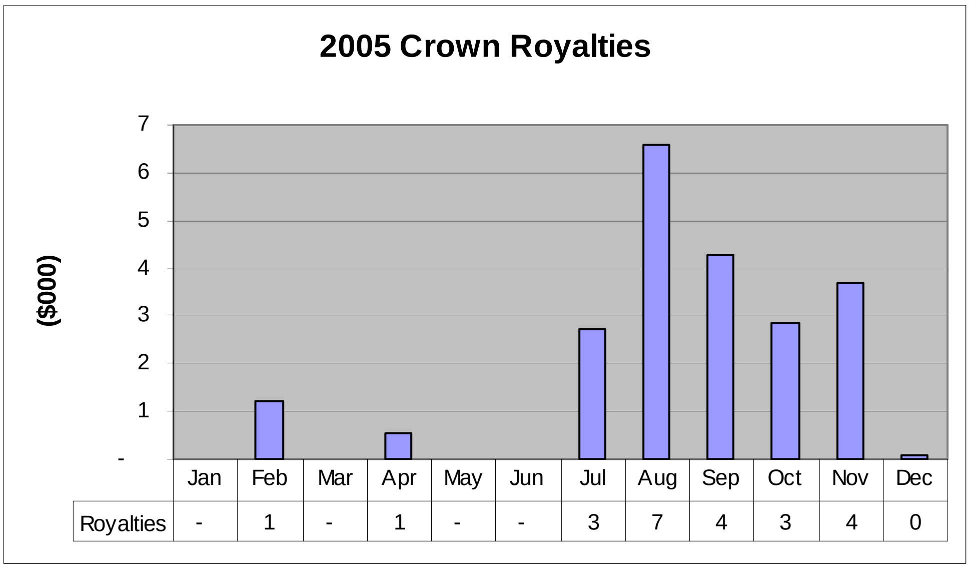


The 2005 operating costs incurred at the Surmont Pilot Plant depicted in the above graph includes fuel gas. The table below splits out the operating costs by category.

Surmont Pilot
Operating Costs
($000)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Salaries & Benefits	1	176	224	243	177	251	175	234	429	248	294	283
Travel, Meals & Entertainment	13	12	13	11	21	23	22	12	18	11	16	18
Other Personnel	5	4	(2)	11	19	40	148	6	5	39	21	19
Consulting & Contracting	149	286	178	123	349	495	350	278	224	184	169	87
Utilities & Rent	415	350	299	316	364	330	304	400	460	477	596	557
General Expense, and Transport.	-	2	2	1	331	107	38	112	101	55	48	(37)
Software & Communications	19	33	1	0	2	2	2	3	1	3	1	5
Workover	3	5	(7)									
Seismic	-	22	35	8	68	244	225	(91)	293	193	478	(99)
Total	606	888	743	714	1,331	1,491	1,263	954	1,530	1,210	1,622	833

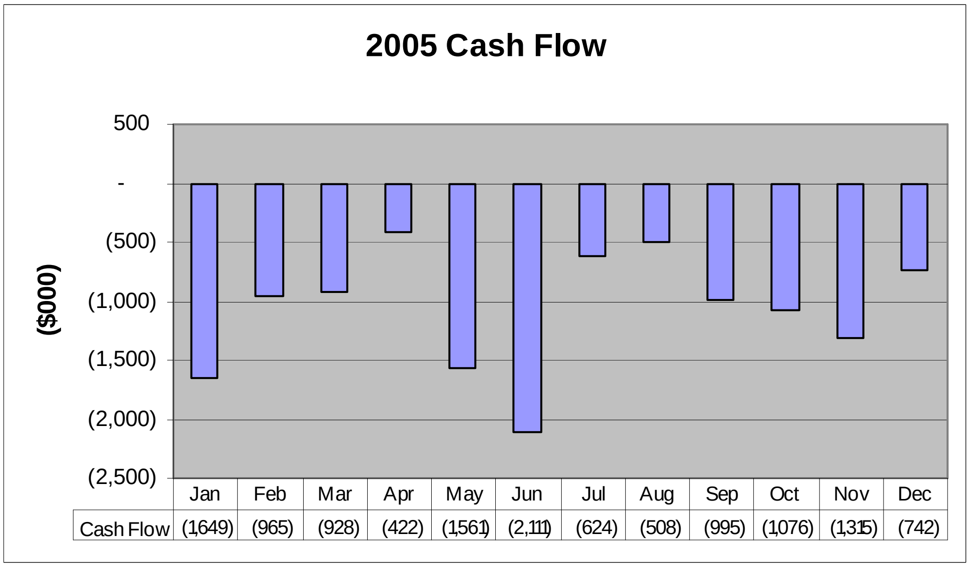
5.5 Crown Royalties and Taxes



The 2005 crown royalties related to the Surmont Pilot Plant, illustrated in the above graph, are net of clean oil transportation fees.

The Surmont Pilot Plant is operated as an R&D facility, with net financial losses, thus no taxes are incurred.

5.6 Cash Flow



Cash flow for the Surmont Pilot Plant does not include taxes.

5.7 Cumulative project cost and net revenue

See items 5.2 and 5.3.

5.8 Material Deviations from Budgeted Costs

There are no material deviations from our 2005 Surmont Pilot Plant budget.

6 Facilities

6.1 Major capital items

There were no major facilities modifications at the Surmont Pilot in 2004-2005.

An extensive HazOp was completed on the Surmont Pilot facilities in February 2004. This study identified a number of minor risks, operability issues and deviations from the as-built P&IDs. Operations have since successfully mitigated all of the major outstanding items and a major P&ID drawing update is complete.

The June 2005 turnaround was routine in nature. All PSVs in the facility were serviced, the steam generator was cleaned (pigged) and some minor header piping was added to facilitate meter testing.

Please see Appendix B for P&IDs and other supporting facilities documentation.

6.2 Capacity limitation, operational issues, and equipment integrity

With respect to water handling and processing, there continued to be fouling problems and resulting high differential pressures on the produced water exchangers. The belief is that a recent switch of chemical providers, while providing good quality separation, caused solids to carry over with the water and drop out downstream of the treater. Mitigating actions include blowdown washes, physical cleanings with pressure trucks and a solvent to aid the solid suspension qualities of the water. In addition, the rental steam generator installed in 2003 operated to capacity, but experienced longer down times during the year due to parts sourcing problems and lack of qualified service technicians.

6.2.1 P1 (107/05-24-83-07W4)

The tubing pump failed from normal wear in May after a long run life since November 2002. A tubing pump was put in as a replacement but subsequently failed in June. The pump teardown failed to discern the cause, though it was agreed that the pump had not been torqued properly resulting in the cage coming loose from the rest of the pump. A replacement 4.75” tubing barrel pump was installed.

In August, there was a minor workover to replace the polish rod, which was slightly bent and causing some problems with leakage around the stuffing box. At this time, the downhole pressure measurement device (Promore ERD) malfunctioned and left only temperature measurements until the next workover was completed in October. Reservoir subcools remained in the range of 25-35^{o}C.

The surface drive Ecoquip unit was changed out for a few weeks in September with a smaller version with limited capacity to enable servicing and was returned to the original design when the service rig was on site for other work.

The pump installed in June failed in October 2004 likely due to a quick over pressuring of the flow line and suspected blowing of bottom hole drain. Given that there was no longer the steam requirement at this well, the high cost for a tubing pump and recent difficulties with these pumps, a 3.25” insert pump was installed.

6.2.2 P2 (108/12-24-83-07W4)

Dynamometer cards indicated a problem with the P2 well and the pump subsequently failed in May. The pump teardown determined the cause of failure to be wear, particularly on the traveling valve. The pump had been running since May 2003 and was using a 3.25” insert type pump. In September, the Lufkin pump jack had to be re-aligned by Weatherford so that the polish rod was stroking straight

Reservoir subcools were also quite constant after turnaround in the 20-25^{o}C range.

An ESP was installed in May 2005. The pump has been performing flawlessly.

6.2.3 P3 (AA/04-24-83-07W4)

In 2003, sufficient steam chamber pressure was lost in C well pair such that gas lift was no longer able to function. P3 did not produce until a SRP was installed in October 2004. The surface drive for the P3 SRP is a Weatherford VSH2 hydraulic pumping unit that uses nitrogen to push down on the accumulator to help drive the rods. A 4.75” tubing pump was installed downhole. Later in October, a minor workover was needed to change out the polish rod since it was leaking too much from the stuffing box. The workover revealed the previous polish rod was not fully spray coated and was upside down. The downhole spacing was also adjusted during this time.

To assist in analysis and troubleshooting, a pump-off controller was installed with radio communication back to a laptop at the Pilot Plant. Due to some electrical difficulties this had only moderate success and was not used to the best of its capabilities.

Reservoir subcools were quite high upon initial start up, 50°C and above. After a change in heel/toe steam distribution, reservoir subcools dropped into the 10-15° C range.

The pump failed in January, and a March work over revealed a significant sand problem. Investigations revealed that a zero subcool event had occurred, resulting in steam flashing across the slots in the production line. This the downhole pump with sand, causing almost immediate failure. The complete extent of any damage is still unknown, but production continued from the P3 well pair.

6.2.4 Water Disposal Well

The 9-25 disposal well experienced some plugging at the wellhead meter. The plugging material was found to be pieces of mastic (pipeline joint compound). It is likely the mastic was over applied, and future applications in the commercial phase will have to be more closely observed.

6.3 Process flow and site diagram

Please see Appendix B for applicable diagrams.

7 Environment/Regulatory/Compliance

7.1 Project regulatory requirements and compliance status

The Surmont Pilot surface facilities are operating in accordance with the original and amended operating license. The current operating license is valid until June 2009

7.1.1 AEUB

The major regulatory monitoring and reporting requirements for the EUB are:

- Monthly Reporting of fluid injection and withdrawal
- Annual Performance Presentation
- Annual Resource Management Report (as per EUB Decision 2005-122 Addendum dated December 21, 2005 section 3.5.4 this report can be combined with the annual Performance Presentations)
- Bi-Annual Water Disposal Report

7.1.2 Alberta Environment

As outlined in Surmont's Approval to operate the following is reported to Alberta Environment on a monthly basis:

- Sulphur Dioxide emissions from the flare and steam generator
- Total Sulphation levels
- Hydrogen Sulphide levels
- Produced Gas which includes Total Hydrocarbons
- Lower Heating Value

7.1.3 AERI

CPC is obligated to provide a report and presentation to AERI on an annual basis similar to the Resource Management Report. CPC is also obligated to provide AERI a final report on the Surmont Pilot Project after 5 years of operation, however since the pilot has not yet met its primary objective of communication with the thief zone at 5 years the report has been delayed to 2006.

7.1.4 ADOE

CPC is obligated to provide an annual report on the progress of the Surmont SAGD Pilot project as a condition of the IETP funding. It is envisioned that a report similar to the Resource management report will suffice.

7.2 Procedures to address environmental and safety issues

The Surmont Pilot Plant has been operating since 1997 with stringent corporate guidelines designed to prevent and address any environmental and safety issues.

7.3 Plan for shut-down and environmental clean-up

The Surmont Pilot plant is licensed to continue operations until July 2009. When the plant ceases operations, all required steps will be taken to ensure corporate, provincial and federal compliance.

There is a possibility to extend the Pilot Operations to investigate SAGD alternatives, like e.g. XSAGD or ES-SAGD.

8 Future operating plan

8.1 Project schedule update including deliverables and milestones

The Surmont Pilot Plant has received an extension to the operating permit until June 2009. The current operating strategy is to continue stable operations to properly monitor TZ interactions and steam chamber coalescence effects.

8.2 Changes in pilot operation, including production operations, injection process, and cost optimization strategies

Prior to the June 2005 Technical Committee Meeting, the plan had been to incorporate the Surmont Pilot Plant in the commercial phase. Due to the economic environment this is no longer an financially viable option, and the Pilot plant will continue to operate as a standalone facility.

ConocoPhillips' operating plan remains aligned with pilot objectives as stated in Application No. 960817.

Both the A and B well pairs will remain the primary wells to determine the effect of a top water thief zone on the SAGD recovery process. As discussed in the previous report, the operating strategy for A and B wellpair was to increase pressures to 2000 kPag. Now that pressure of approximately 2000 kPag is reached at A and B wellpairs, C well will get any remaining steam. However the C wellpair will be closely monitored as the chamber approaches the top water at the heel.

Although the main focus will be on the A and B well pairs, the operations through out 2005 will be adjusted accordingly to provide maximum reservoir data as well as optimizing the production from all the well pairs.

From a plant optimization perspective, a “Six Sigma” process was initiated. The goal of the program is to maximize plant efficiency through greater steam output and less fuel usage. It is hoped that this process will not only improve Pilot efficiency, but also be applied to the Phase I Commercial Plant once it is in a steady state operation.

8.3 Salvage update

No changes have been made to the salvage strategy relative to the Surmont Pilot plant and wells.

9 Interpretations and Conclusions

9.1 Lessons learned

9.1.1 Heterogeneities

The pilot showed that heterogeneities act as baffles not barriers but this depends on the thickness and we currently use a threshold of 3m for the lease evaluation which is not field “proven” as such. The ones encountered by the steam at the pilot were thinner.

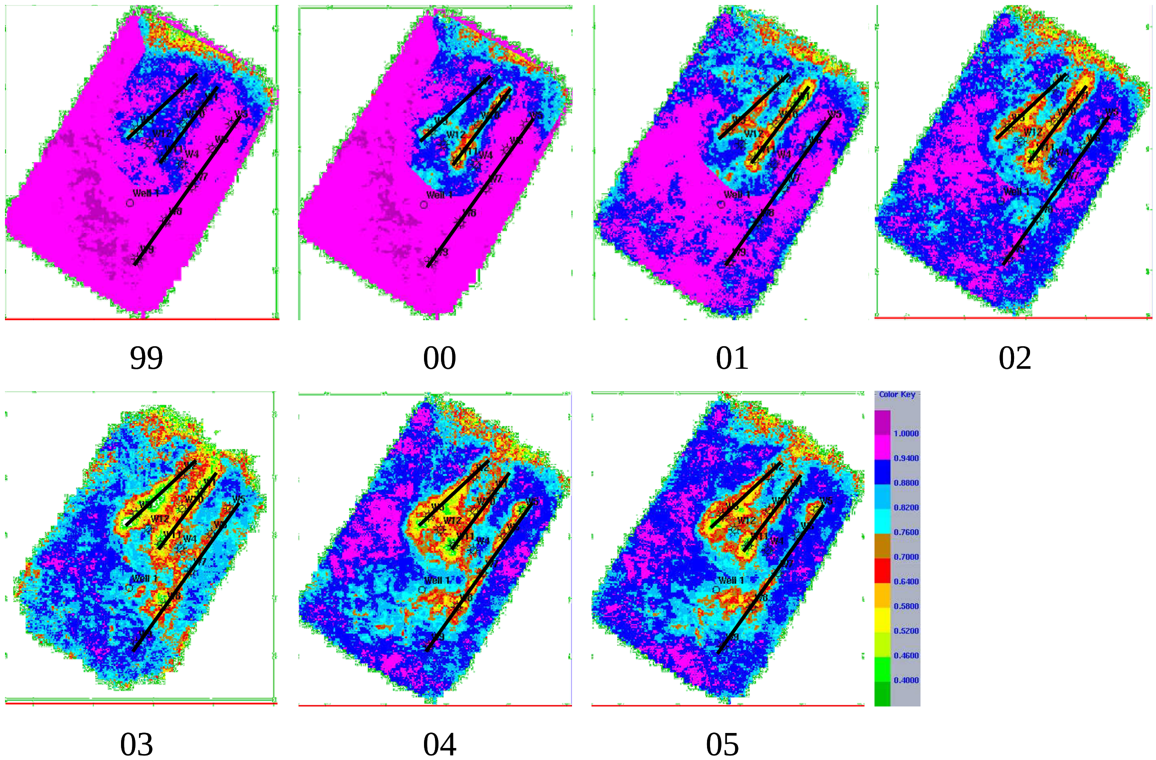
On C pair today the steam is stopped by a “shale” of ~0.8m. We are observing to see if the steam will go around / through or not. To achieve this, the chamber pressure might need increasing.

9.1.2 Pilot Area Time Lapse Seismic

The 4D seismic is used to monitor development of the steam chamber around the injection wells. The seismic data responds to the development of the steam chambers and should be useful for predicting breakthrough into overlying thief zones, as well as interaction between adjacent steam chambers.

For the current reporting period the June 2005 seismic data has been incorporated with the previous 7 years of seismic data and the map view of the steam chambers has been updated. The images that follow illustrate in map view the effects related to steam. Note that the difference baseline is extended for the 2003 analysis, using 1998 for the northern area and 2000 for the southern portion of the “C” well pair.

The 2004 data indicate that the shorter well pairs’ (A & B) steam chambers are connected seismically and the longer (C) well pair’s chamber is growing.



The 4D seismic continues to show affected areas at all three well pairs. Additional well data is continually acquired to better calibrate the seismic analysis and to assist with 4D visualization of steam chamber development.

9.1.3 Thief Zone Breakthrough

Interaction between the SAGD wellpairs and the thief zone at Surmont have contributed learnings in the a related to:

- Higher current recovery factors in areas where thief zones are present. Ultimate recovery is still being assessed through ongoing operations.
- Current reservoir descriptions generally show degradation in reservoir properties at the Pilot as you move up into the thief zones, increasing the likelihood of SAGD operation management post breakthrough.
- Current models with more representative shale distributions decrease the drainage of top water into the steam chamber
- Shown the ability to control steam rise rates with pressure.
- Significant temperature levels can exist at the top reservoir without any currently observed negative effects. The Thief Zone also shows direct pressure communication with the underlying reservoir.

An active steam chamber has not yet reached the Thief Zone, thus not allowing for a firm conclusion relative to the complete Thief Zone Breakthrough issue. We are now entering the second stage which consists in operating under a moderate pressure to mitigate the potential interaction. This stage is critical for the commercial phases as 70% of the well pair life will occur under those conditions. We are in an ideal learning situation with B almost breaking into the TZ, and A far from the TZ. Operating merged chambers in a TZ environment will be a large issue in the commercial operation with 9 well pairs per half-pad.

9.1.4 RST C/O logging

A Reservoir Saturation Tool (RST) was run in 2003, 2004, and again in 2005 in select observation wells to attempt to qualify the steam chamber evolution. Findings were relatively optimistic, but due to the absence of a baseline reading a consistent conclusion is not possible.

- The through-tubing RST tool uses dual detector spectrometry to record both carbon-oxygen and thermal decay time measurements during the same trip in the well
- The carbon-oxygen information is used to determine formation oil saturation independent of the formation water salinity
- A combination of both measurements can be used to detect and quantify the presence of injection water(steam) where the injected water(steam) is of different salinity than the connate water
- Reduced accuracy when baseline log has not been captured

The tool does have some temperature limitations and the OB well environment definitely tests those limits. Results from the previous RST logs were encouraging.

9.1.5 Tracer Study

Tracers were injected in the reservoir April 2004. Tracers were recovered from the producers, indicating that in the future this type of technique might have valuable applications. However the study was inconclusive due to problems believed to be linked to sampling procedures.

9.1.6 Steam Chamber Development

Observation well data and production volumes demonstrate continued steam development. This is part of a continuous evaluation of the SAGD process in the Surmont Pilot Plant. Of specific learnings we can mention the P2 – S2 well pair, which demonstrated that a steam chamber which has been receding due to lowering operating pressures/rates can be reestablished and increased at higher levels relatively quickly when the operating conditions are reestablished to the previously higher levels.

9.1.7 Artificial Lift

Several artificial lift systems have been tested and the learnings implemented into the commercial SAGD operations. As of December 2005 the artificial lift options, post gas-lift (i.e. reservoir pressures not allowing to lift without DH pumps) were optimistic, but continued investigations were underway.

9.1.8 Reservoir Surveillance

The Surmont Pilot Plant provides invaluable support in testing and analyzing various reservoir surveillance options. To date 4D seismic, horizontal observation wells (pressure and temperature), Seismovie, tracers, etc have been tested. Several tested technologies have been implemented in the commercial operations.

Knowledge of the operating history is critical in understanding pilot reservoir performance.

9.1.9 Meter Testing

A Quadrant edge orifice meter was successfully tested for commercial use for measuring emulsion flow. An Agar OW-201 series water cut meter was also tested successfully and will be included in the commercial facilities. Later in the year, a FMC multi-phase meter was tested however the test was inconclusive due to problems with flow ranges. Potential future tests involve Jiskoot and Schlumberger for water cut metering. Photon Controls is also being looked at for Steam Quality metering.

9.2 Difficulties encountered

Reservoir issues have not directly impacted the operation of the Surmont Pilot Plant. The main challenges have been related to ensuring consistent plant and artificial lift performance.

The C well pair ceased production due to a sand event linked to low subcool conditions in the well. Continued production of the C well pair after sand inflow event is very encouraging for the commercial operations. Previously it was thought a sand event would be catastrophic for a well pair, and no further production would be possible.

9.3 Technical and economic viability

The Surmont Pilot Plant has, and continues to, contribute greatly to the learning process of operating a SAGD steam chamber under LP conditions.

9.4 Overall effect on overall gas and bitumen recovery

The Surmont Pilot plant performance for the period June 2004 to December 2005 show that increased bitumen and gas recovery while being constrained by LP operating conditions is feasible. At this point it is too early to come with a general statement relative to the overall effect on resource recovery.

9.5 Assessment of future expansion or commercial field application

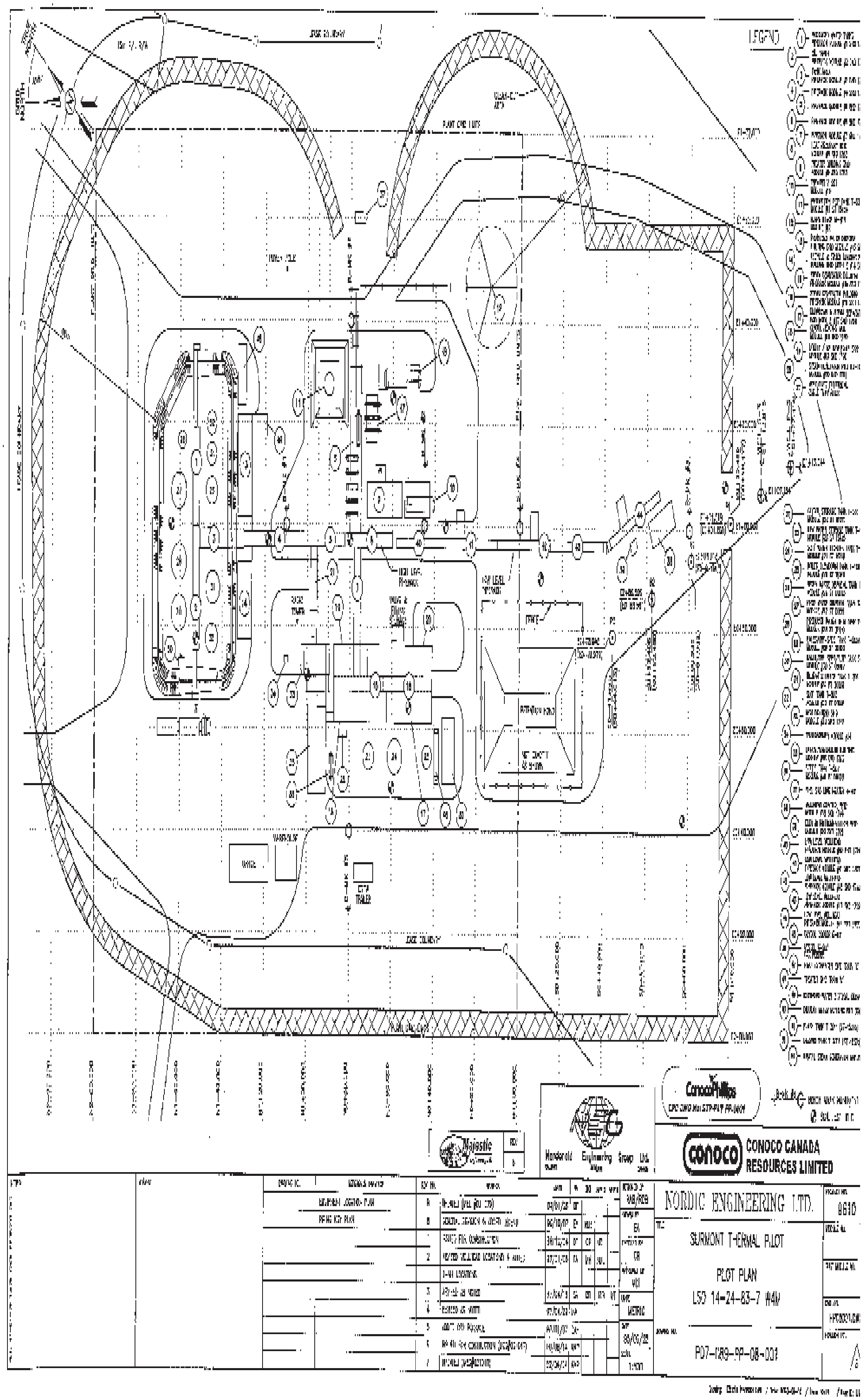
The Surmont Pilot Plant provides continuous input into the optimization of the Surmont full field development. This optimization is relative to a multitude of points, among others:

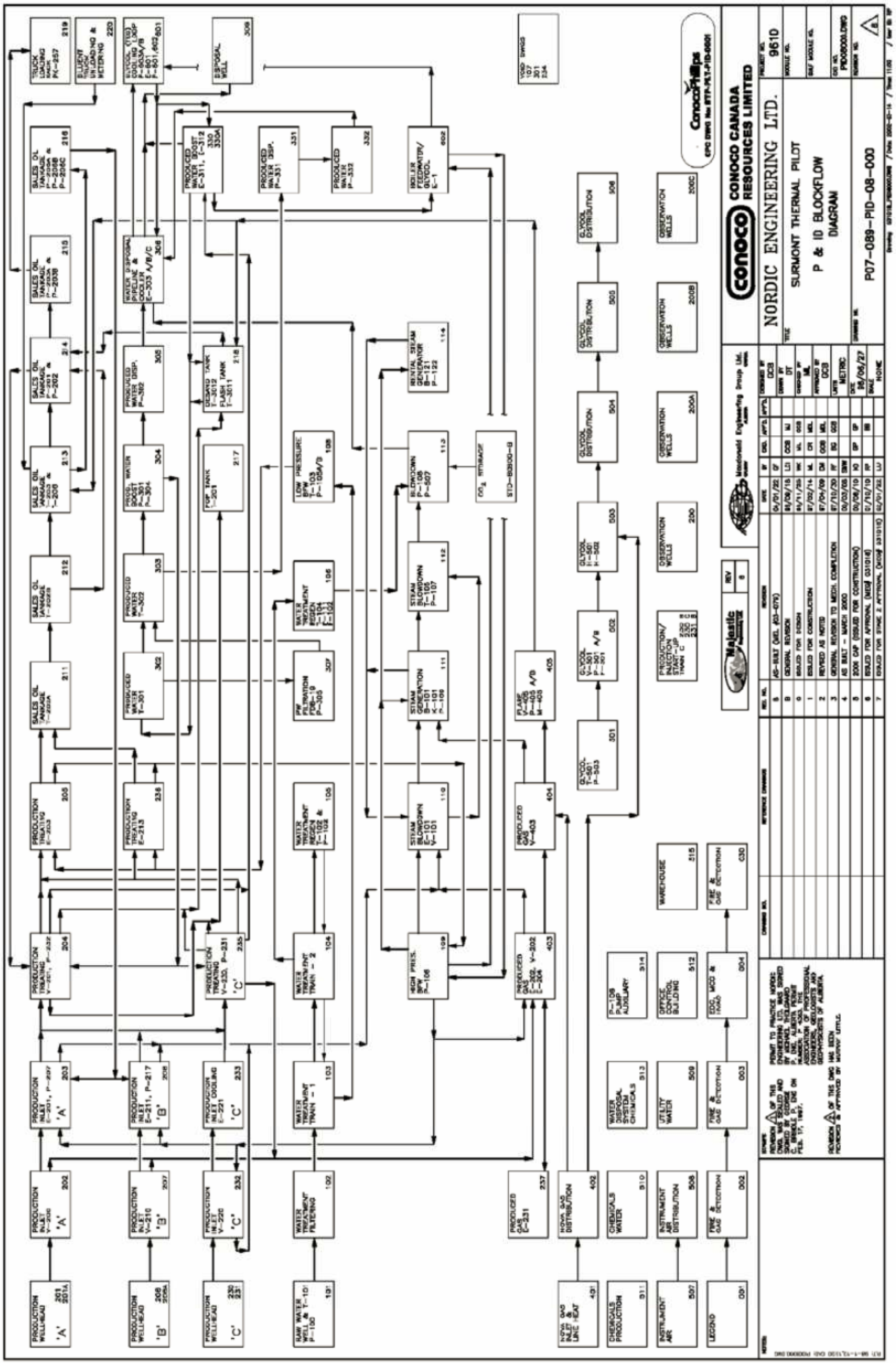
- Well placement
- Optimizing of the well operating strategy
- Reservoir prediction process developed at the Surmont Pilot plant will help to optimize commercial operations
- Monitoring strategies
- Etc

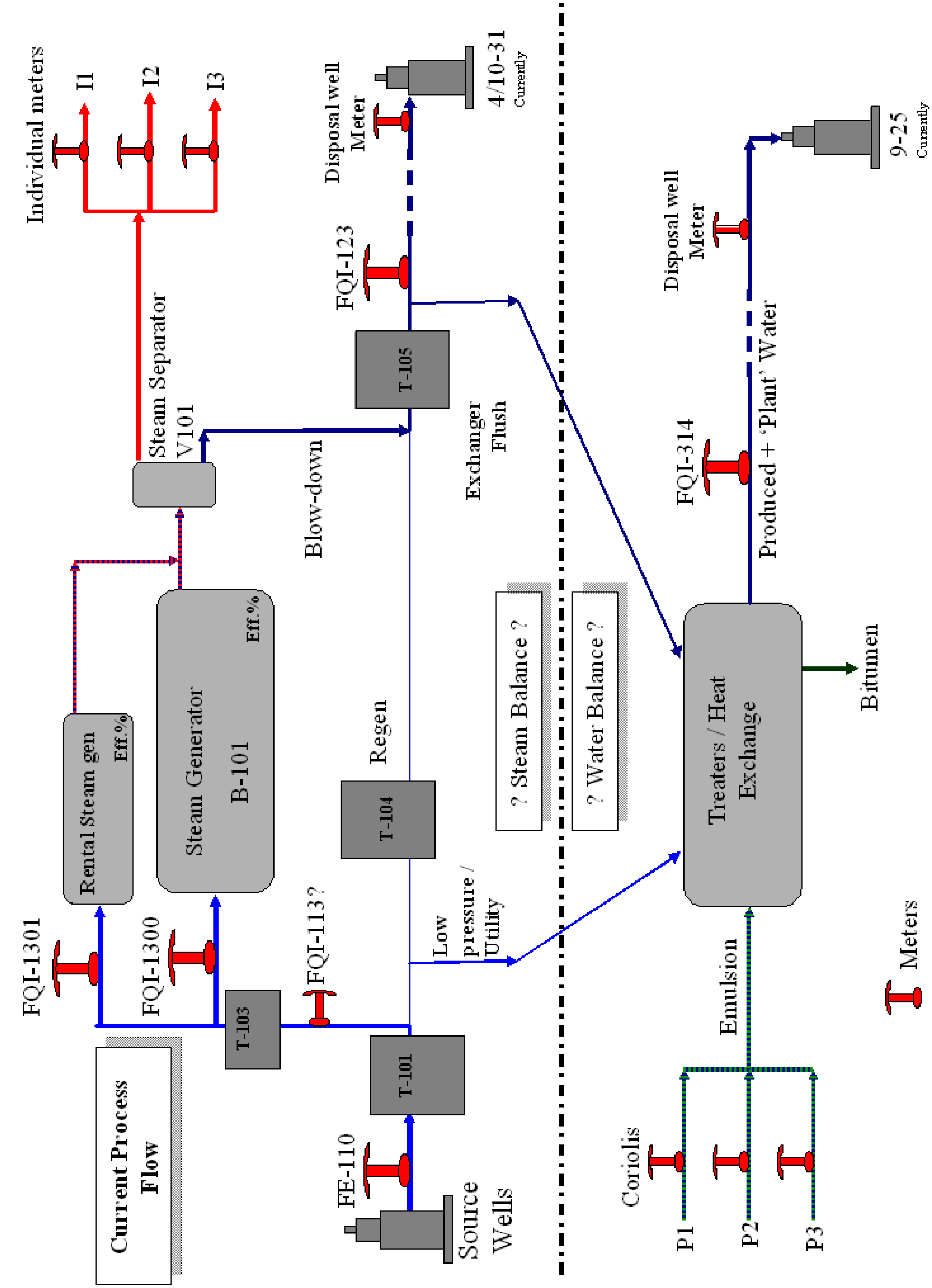
The list is non-exhaustive; These items are covered in more detail other places in the report.

Appendix A : Fluid Analysis

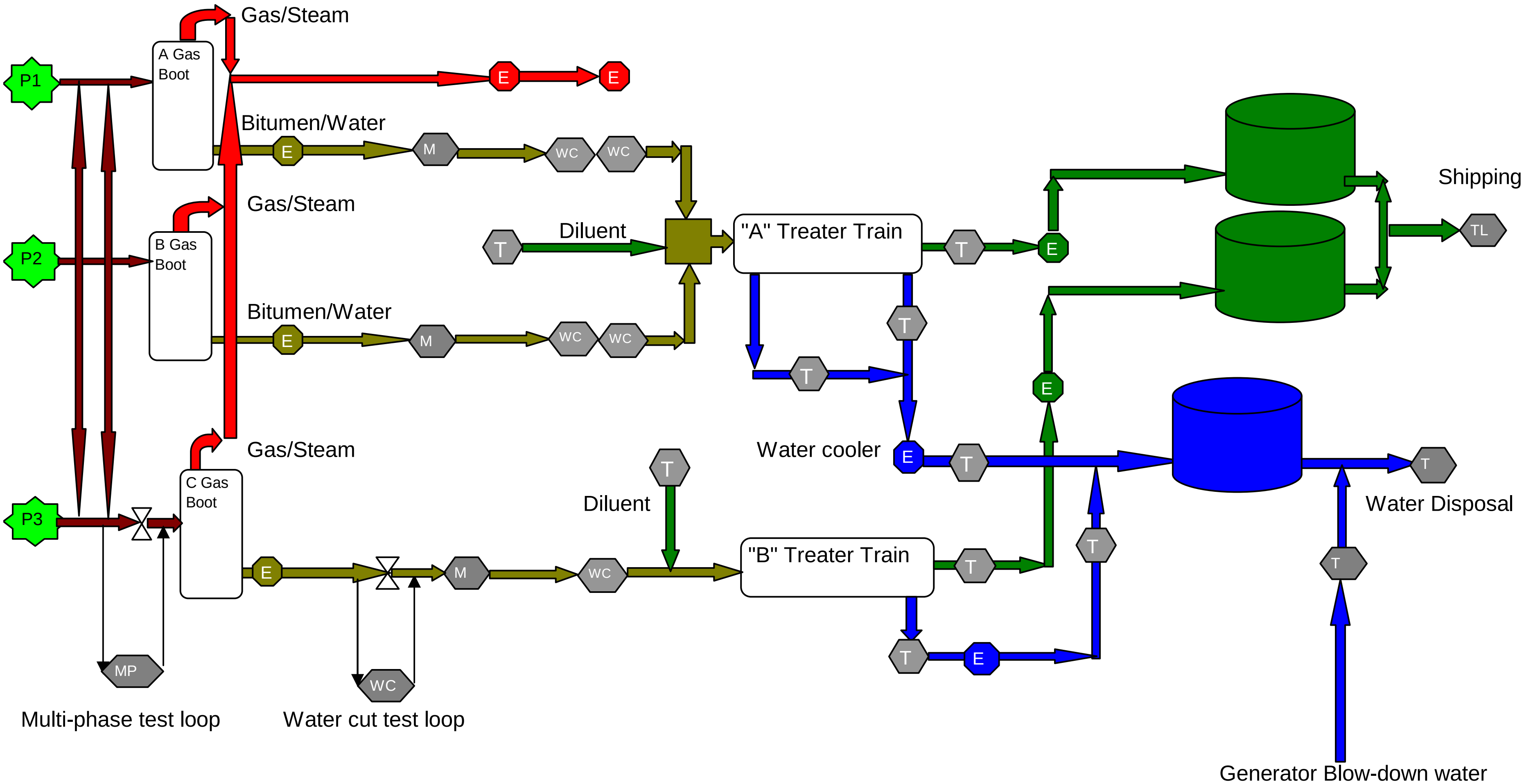
Appendix B : Facilities Diagrams







Current Process Flow
Individual meters
I1
I2
I3
Steam Separator V101
Rental Steam gen
Eff.%
Steam Generator
B-101
Eff.%
FQI-1301
FQI-1300
T-103
FQI-113?
T-101
FE-110
Source Wells
T-104
Regen
Blow-down
T-105
FQI-123
Disposal well Meter
4/10-31
Currently
Exchanger Flush
Low pressure / Utility
? Steam Balance ?
? Water Balance ?
Treaters / Heat Exchange
Bitumen
Emulsion
Coriolis
P1
P2
P3
Meters
FQI-314
Produced + 'Plant' Water
Disposal well Meter
9-25
Currently



E = shell/tube heat exchanger
WC = water ctu meter

P = Prosonic sonic meter
MP = multi-phase meter

H = Halliburton turbine meter
TL = truck loading meter

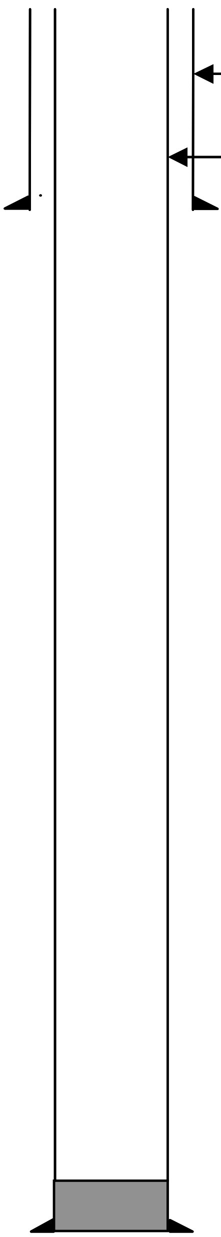
Appendix C : Observation Well Schematics

<u>Pilot OBS 17</u>

Well Bore Schematic

GULF RESDELN
12-24-83-7 W4M
Observation Well
104/12-24-083-07/W4
OBS 17

KB: 587.7 m
GL: 585.1 m
TD: 395.0 mKB
PBTD: 394.5 mKB



Surface Casing: 9 jts.of 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 59.0 mKB. Cemented with 1.9 m3 0:1:0 Class A cement.

Intermediate Casing: 47 jts. of 73.0 mm, 9.67 kg/m, J-55, EUE tubing landed at 394.5 mKB. Cemented with 9.0 m3 Thermal 40 + 0.25% CFL + 2.0% $CaCl_2$. 1.0 m3 cement returns.

Internal Traversing Bundle

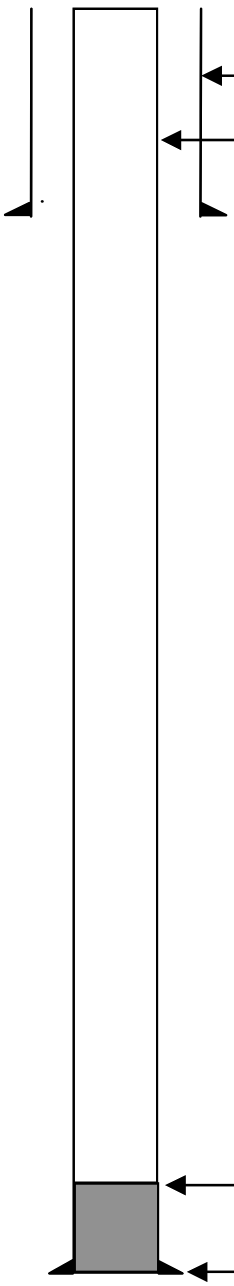
T1 @ 340.5 mKB
T2 @ 342.0
T3 @ 343.5
T4 @ 345.0
T5 @ 346.5
T6 @ 348.0
T7 @ 349.5
T8 @ 351.0
T9 @ 352.5
T10 @ 354.0
T11 @ 355.5
T12 @ 357.0
T13 @ 358.5
T14 @ 360.0
Horizontal Injection Well @ 361.2
T15 @ 361.5
T16 @ 363.0
T17 @ 364.5
T18 @ 366.0
Horizontal Production Well @ 366.6
T19 @ 367.5
T20 @ 369.0

Pilot OBS 20

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB20 Resdeln 100/11-24-83-07 W4
Spud: January 20, 2000 Rig Released: January 25, 2000

KB: 598.01 m
GL: 594.16 m
KB-GL: 3.85 m



Surface Casing: Set at 97.5m - 14 joints of 177.8mm 25.3 kg/m H40 ST &C
Cemented with 0:1:00 Class "G" Cement

Production Casing: 43 joints of 73mm 9.67 kg/m CS L80 Hydril tubing
Cemented with 9.5 tonnes Thermolite 1550 + 3% CACL2 and CFL-2

Cores: 14 cores cut: 314 to 360m

Piezometers: 331.5m, 360m, 385.8m

331.5 Piezometer

T20 @ 347.5
T19 @ 349.0
T18 @ 350.5
T17 @ 352.0
T16 @ 353.5
T15 @ 355.0
T14 @ 356.5
T13 @ 358.0
T12 @ 359.5
360.0 Piezometer
T11 @ 361.0
T10 @ 362.5
T9 @ 364.0
T8 @ 365.5
366.2 Horizontal section of Injection well
T7 @ 367.0
T6 @ 368.5
T5 @ 370.0
371.2 Horizontal section of Production well
T4 @ 371.5
T3 @
T2 @ 374.5
T1 @ 376.0
385.8 Piezometer

Plug back Depth: 395.6m

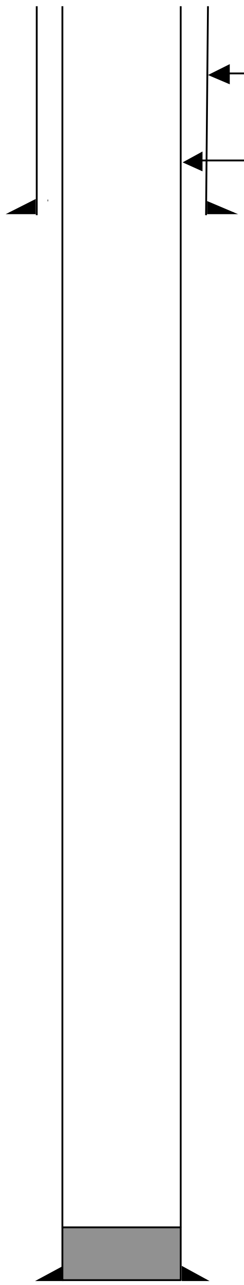
Total Depth: 400m

Pilot OBS 22

Well Bore Schematic

GULF RESDELN
12-24-83-7 W4M
Observation Well
105/12-24-083-07/W4
OBS 22

KB: 601.64 m
GL: 599.04 m
TD: 409.50 mKB
PBTD: 408.70 mKB



Surface Casing: 10 jts.of 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 66.0 mKB. Cemented with 2.4 m3 0:1:0 Class A cement. 0.5 m3 cement returns.

Intermediate Casing: 43 jts. of 73.0 mm, 9.67 kg/m, J-55, EUE tubing landed at 409.0 mKB. Cemented with 16.0 tonnes Thermal 40 + 0.25% CFR + 2.0% $CaCl_2$ to surface.

Internal Traversing Bundle

T1 @ 355.5 mKB
T2 @ 357.0
T3 @ 358.5
T4 @ 360.0
T5 @ 361.5
T6 @ 363.0
T7 @ 364.5
T8 @ 366.0
T9 @ 367.5
T10 @ 369.0
T11 @ 370.5
T12 @ 372.0
T13 @ 373.5
T14 @ 375.0
Horizontal Inj. Well @ 376.4
T15 @ 376.5
T16 @ 378.0
T17 @ 379.5
T18 @ 381.0
Horizontal Prod. Well @ 381.6
T19 @ 382.5
T20 @ 384.0

Internal Traversing Bundle

Moved up 20m
April 2, 2000

T1 @ 335.5 mKB
T2 @ 337.0
T3 @ 338.5
T4 @ 340.0
T5 @ 341.5
T6 @ 343.0
T7 @ 344.5
T8 @ 346.0
T9 @ 347.5
T10 @ 349.0
T11 @ 350.5
T12 @ 352.0
T13 @ 353.5
T14 @ 355.0
T15 @ 356.5
T16 @ 358.0
T17 @ 359.5
T18 @ 361.0
T19 @ 362.5
T20 @ 364.0

Horizontal Inj. Well @ 376.4

Horizontal Prod. Well @ 381.6

Internal Traversing Bundle

Moved up 4.5m
July 30, 2004

T1 @ 331.5 mKB
T2 @ 333.0
T3 @ 334.5
T4 @ 336.0
T5 @ 337.5
T6 @ 339.0
T7 @ 340.5
T8 @ 342.0
T9 @ 343.5
T10 @ 345.0
T11 @ 346.5
T12 @ 348.0
T13 @ 349.5
T14 @ 351.0
T15 @ 352.5
T16 @ 354.0
T17 @ 355.5
T18 @ 357.0
T19 @ 358.5
T20 @ 360.0

Horizontal Inj. Well @ 376.4

Horizontal Prod. Well @ 381.6

Data Acquisition

1997 - Initial Log Suite:

June 2003 - RST Logging

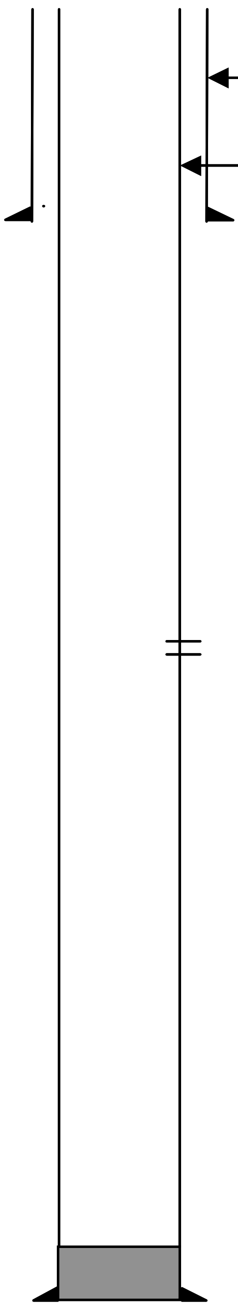
June 2004 - RST Logging

Pilot OBS 23

Well Bore Schematic

GULF RESDELN
12-24-83-7 W4M
Observation Well
103/12-24-083-07/W4
OBS 23

KB: 608.4 m
GL: 605.3 m
TD: 414 mKB
PBTD: 385.3 mKB



Surface Casing: 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 21.0 mKB.

Intermediate Casing: 73.0 mm, 9.67 kg/m, J-55, EUE tubing landed at 389.9 mKB. Displaced during cementing, returns to surface

H2S monitor well

Perforated in McMurray gas cap @ 324-326 mKB

Significant drilling problems, fishing core barrel

Standard OH log suite

Cored from314 – 414 mKB

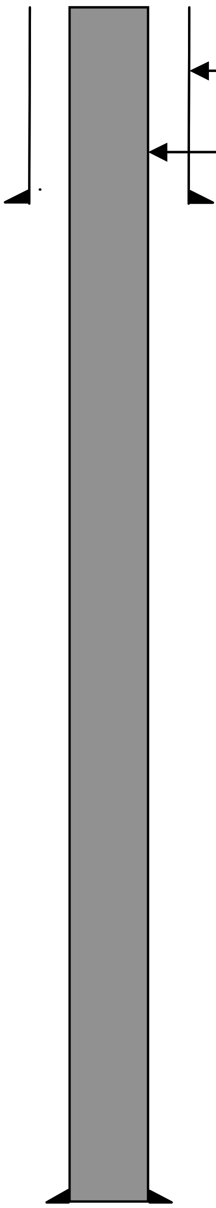
Temperature log to 385 mKB Dec 01, normal temp gradient indicated

Pilot OBS 24

Well Bore Schematic

GULF RESDELN
12-24-83-7 W4M
Observation Well
102/12-24-083-07/W4
OBS 24

KB: 611.86 m
GL: 608.76 m
TD: 413.70 mKB
PBTD: Surface



Surface Casing: 8 jts.of 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 50.0 mKB.

Intermediate Casing: 41 jts. of 48.3 mm, 4.32 kg/m, J-55, EUE tubing landed at 410.0 mKB. Cemented with 20.0 tonnes Thermal 40 + 0.25% CFR + 2.0% $CaCl_2$ to surface. Entire string left full of cement.

External Bundle Cemented in Place

T1 @ 326.5 mKB
T2 @ 328.0
Piezometer #1 @ 328.5
T3 @ 329.5
T4 @ 331.0
T5 @ 332.5
T6 @ 334.0
T7 @ 335.5
T8 @ 337.0
T9 @ 338.5
T10 @ 340.0
T11 @ 341.5
T12 @ 343.0
T13 @ 344.5
T14 @ 346.0
T15 @ 347.5
T16 @ 349.0
T17 @ 350.5
T18 @ 352.0
T19 @ 353.5
T20 @ 355.0

Horizontal Injection Well @ 389.8

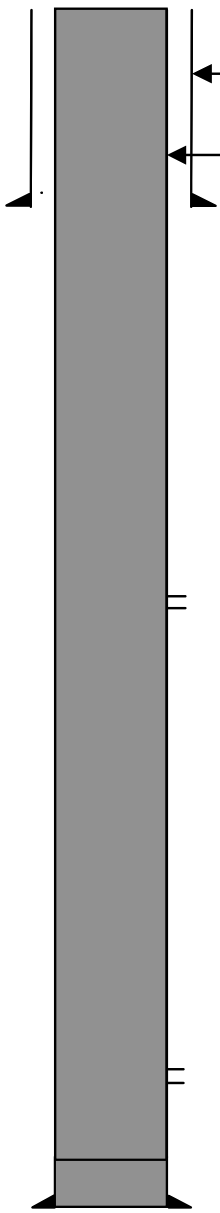
Horizontal Production Well @ 394.3

Pilot OBS 25

Well Bore Schematic

GULF RESDELN
5-24-83-7 W4M
Observation Well
102/05-24-083-07/W4
OBS 25

KB: 612.7 m
GL: 609.6 m
TD: 423 mKB
PBTD: surface



Surface Casing: 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 52.0 mKB.

Intermediate Casing: 48.3 mm, 3.57 kg/m, J-55, tubing landed at 390 mKB. Not displaced, cement to surface inside and outside

Piezo in McMurray top water zone @ 335 mKB

Standard OH log suite plus dipmeter plus directional

Cored from 319 – 423 mKB

Piezo in McMurray bottom bitumen zone @ 384 mKB

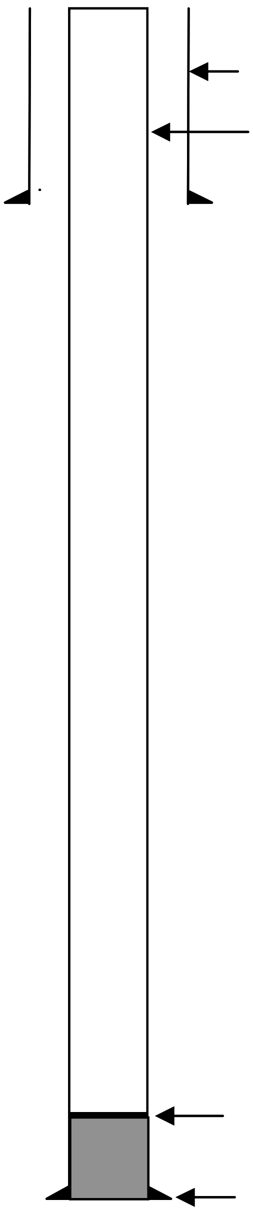
Pilot OBS 26A

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB26A Resdeln 108/05-24-83-07 W4

Spud: January 20, 2000 Rig Released: January 22, 2000

KB: 607.67 m
GL: 602.93 m (GL + Fill = 604.27)
KB-GL: 3.40 m



Surface Casing: Set at 96 m - 14 joints of 177.8mm 25.3 kg/m H40 ST &C
Cemented with 0:1:00 Class "G" Cement

Production Casing: 41 joints of 73mm 9.67 kg/m CS L80 Hydril tubing
Cemented with 8.3 tonnes Thermolite 1550 + 3% CACL2 and CFL-2

Cores: 4 cores cut: 313m to 402m

Piezometers: 342m, 356m, 370m

342.0 Piezometer
356.0 Piezometer
T20 @ 357.5
T19 @ 359.0
T18 @ 360.5
T17 @ 362.0
T16 @ 363.5
T15 @ 365.0
T14 @ 366.5
T13 @ 368.0
T12 @ 369.5
370.0 Piezometer
T11 @ 371.0
T10 @ 372.5
T9 @ 374.0
T8 @ 375.5
375.7 Horizontal section of Injection well
T7 @ 377.0
T6 @ 378.5
T5 @ 380.0
380.7 Horizontal section of Production well
T4 @ 381.5
T3 @ 383.0
T2 @ 384.5
T1 @ 386.0

Plug back Depth: 402m

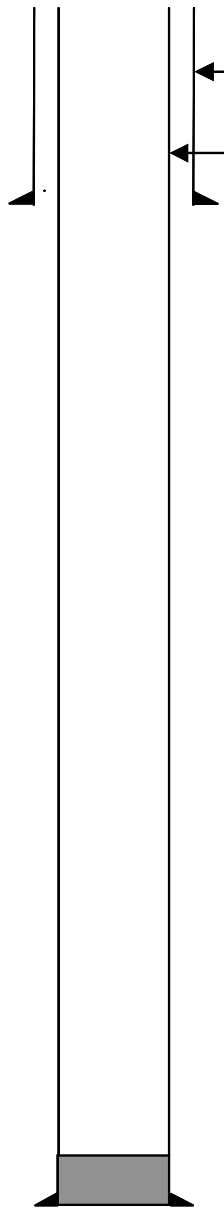
Total Depth: 408m

Pilot OBS 28

Well Bore Schematic

GULF RESDELN
5-24-83-7 W4M
Observation Well
100/05-24-083-07/W4
OBS 28

KB: 614.3 m
GL: 611.2 m
TD: 422 mKB
PBTD: 420 mKB



Surface Casing: 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 53.0 mKB.

Intermediate Casing: 73.0 mm, 9.67 kg/m, J-55, EUE tubing landed at 420 mKB. Displaced during cementing, returns to surface

Well loggable, int casing blown dry to TD

Standard OH log suite plus dipmeter plus directional plus VSP

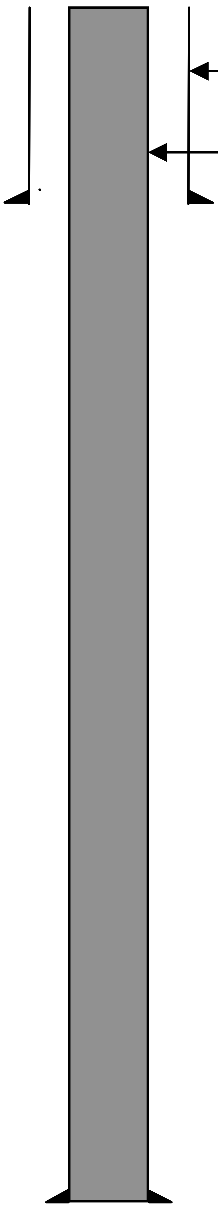
Cored from 319 – 411 mKB

Pilot OBS 36

Well Bore Schematic

GULF RESDELN
12-24-83-7 W4M
Observation Well
106/12-24-083-07/W4
OBS 36

KB: 605.35 m
GL: 602.75 m
TD: 413.00 mKB
PBTD: Surface



Surface Casing: 11 jts.of 219.1 mm, 35.72 kg/m, J-55, ST&C casing landed at 69.0 mKB.

Intermediate Casing: 40 jts. of 48.3 mm, 4.32 kg/m, J-55, EUE tubing landed at 413.0 mKB. Cemented with 17.0 tonnes Thermal 40 + 0.25% CFR + 2.0% $CaCl_2$. 0.5 m^3 cement returns. Entire string left full of cement.

External Bundle Cemented in Place

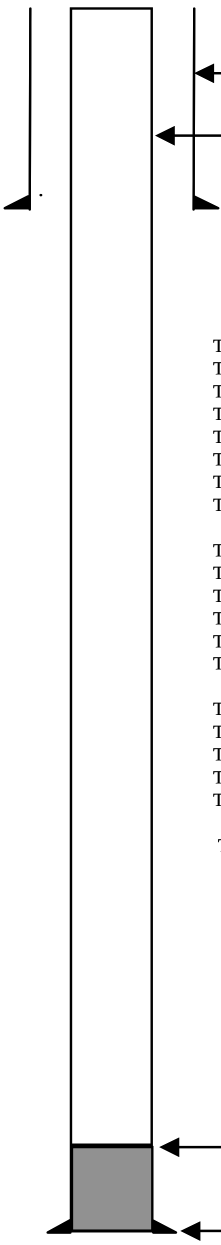
Experimental Piezometer #1 @ 318.0 mKB
T1 @ 329.5
T2 @ 331.0
T3 @ 332.5
T4 @ 334.0
T5 @ 335.5
T6 @ 337.0
T7 @ 338.5
Piezometer #2 @ 340.0 w/bubble tube
T8 @ 340.0
T9 @ 341.5
T10 @ 343.0
T11 @ 344.5
T12 @ 346.0
T13 @ 347.5
T14 @ 349.0
T15 @ 350.5
T16 @ 352.0
T17 @ 353.5
T18 @ 355.0
T19 @ 356.5
Piezometer #3 @ 358.0 w/bubble tube
T20 @ 358.0
T21 @ 362.5
T22 @ 364.0
T23 @ 365.5
T24 @ 367.0
T25 @ 368.5
T26 @ 370.0
T27 @ 371.5
T28 @ 373.0
T29 @ 374.5
T30 @ 376.0
T31 @ 377.5
Piezometer #4 @ 378.0 w/bubble tube
T32 @ 379.0
T33 @ 380.5
T34 @ 382.0
Horizontal Injection Well @ 383.3
T35 @ 383.5
T36 @ 385.0
T37 @ 386.5
T38 @ 388.0
Horizontal Production Well @ 388.6
T39 @ 389.5
T40 @ 391.0

Pilot OBS 37

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB37 Resdeln 102/11-24-83-07 W4
Spud: January 27, 2000 Rig Released: January 31, 2000

KB: 613.83 m
GL: 608.95 m (GL + Fill = 609.98)
KB-GL: 3.85 m



Surface Casing: Set at 86.5m - 13 joints of 177.8mm 25.3 kg/m H40 ST &C
Cemented with 0:1:00 Class "G" Cement

Production Casing: 43 joints of 73mm 9.67 kg/m CS L80 Hydril tubing
Cemented with 8.5 tonnes Thermolite 1550 + 3% CACL2 and CFL-2

Cores: 15 cores cut: 322.4m to 412.6m

Piezometers: 353m, 365m, 376m

Cased hole TDT in 2000

353.0 Piezometer

T20 @ 354.9
T19 @ 356.4
T18 @ 357.9
T17 @ 359.4
T16 @ 360.9
T15 @ 362.4
T14 @ 363.9
T13 @ 365.4
365.0 Piezometer
T12 @ 366.9
T11 @ 368.4
T10 @ 369.9
T9 @ 371.4
T8 @372.9
T7 @ 374.4
376.0 Piezometer
T6 @ 375.9
T5 @ 377.4
T4 @ 378.9
T3 @ 380.4
T2 @ 381.9
382.0 Horizontal section of Injection well
T1 @ 383.4

Thermocouple string re-set on March 8, 2001

353.0 Piezometer

T20 @ 363.5
T19 @ 365.0 Piezometer
T18 @ 366.5
T17 @ 368.0
T16 @ 369.5
T15 @ 371.0
T14 @ 372.5
T13 @ 374.0
T12 @ 375.5
376.0 Piezometer
T11 @ 377.0
T10 @ 378.5
T9 @ 380.0
T8 @ 381.5
382.0 Horizontal section of Injection well
T7 @ 383.0
T6 @ 384.5
T5 @ 386.0
387.0 Horizontal section of Production well
T4 @ 387.5
T3 @ 389.0
T2 @ 390.5
T1 @ 392.0

Plug back Depth: 414m

Total Depth: 418m

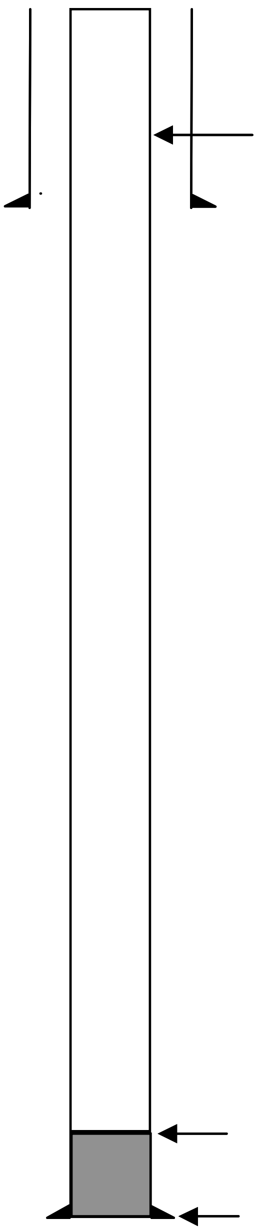
Pilot OBS 38

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB38 Resdeln 109/05-24-83-07 W4

Spud: January 14, 2000 Rig Released: January 18, 2000

KB: 606.39 m
GL: 601.97 m
KB-GL: 3.40 m



Surface Casing: Set at 96m - 14 joints of 177.8mm 25.3 kg/m H40 ST &C
Cemented with 0:1:00 Class "G" Cement

Production Casing: 41 joints of 73mm 9.67 kg/m CS L80 Hydril tubing
Cemented with 8 tonnes Thermolite 1550 + 3% CACL2 and CFL-2

Cores: 24 cores cut: 314m to 360m

Piezometers: 363m, 347m

Cased hole TDT in 2000

347.0 Piezometer

T20 @ 355.5
T19 @ 357.0
T18 @ 358.5
T17 @ 360.0
T16 @ 361.5
T15 @ 363.0 Piezometer
T14 @ 364.5
T13 @ 366.0
T12 @ 367.5
T11 @ 369.0
T10 @ 370.5
T9 @ 372.0
T8 @ 373.5
374.5 Horizontal section of Injection well
T7 @ 375.0
T6 @ 376.5
T5 @ 378.0
T4 @ 379.5 Horizontal section of Production well
T3 @ 381.0
T2 @ 382.5
T1 @ 384.5

Plug back Depth: 390m

Total Depth: 400m

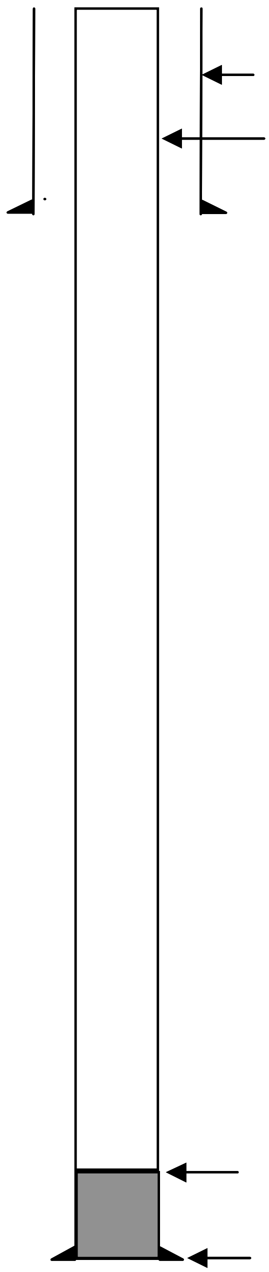
Pilot OBS 39

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB39 Resdeln 100/04-24-83-07 W4

Spud: January 9, 2000 Rig Released: January 13, 2000

KB: 611.6 m
GL: 608.2 m
KB-GL: 3.40 m



Surface Casing: Set at 83 m - 12 joints of 177.8mm 25.3 kg/m H40 ST &C
Cemented with 0:1:00 Class "G" Cement

Production Casing: 43 joints of 73mm 9.67 kg/m CS L80 Hydril tubing
Cemented with 10 tonnes Thermolite 1550 + 3% CACL2 and CFL-2

Cores: 4 cores cut: 317m to 400m

Piezometers: 333.5m, 347m, 359m, 373.5m

333.5 Piezometer
347.0 Piezometer
359.0 Piezometer
T20 @ 361.5
T19 @ 363.0
T18 @ 364.5
T17 @ 366.0
T16 @ 367.5
T15 @ 369.0
T14 @ 370.5
T13 @ 372.0
T12 @ 373.5 Piezometer
T11 @ 375.0
T10 @ 376.5
T9 @ 378.0
T8 @ 379.5
380.2 Horizontal section of Injection well
T7 @ 381.0
T6 @ 382.5
T5 @ 384.0
385.2 Horizontal section of Production well
T4 @ 385.5
T3 @ 387.0
T2 @ 388.5
T1 @ 390.0

Thermocouple string re-set on March 8, 2001

333.5 Piezometer
347.0 Piezometer
359.0 Piezometer
T20 @ 360.0
T19 @ 361.5
T18 @ 363.0
T17 @ 364.5
T16 @ 366.0
T15 @ 367.5
T14 @ 369.0
T13 @ 370.5
T12 @372.0
T11 @ 373.5 Piezometer
T10 @ 375.0
T9 @ 376.5
T8 @ 378.0
T7 @ 379.5
380.2 Horizontal section of Injection well
T6 @ 381.0
T5 @ 382.5
T4 @ 384.0
385.2 Horizontal section of Production well
T3 @ 385.5
T2 @ 387.0
T1 @ 388.5

Plug back Depth: 403m

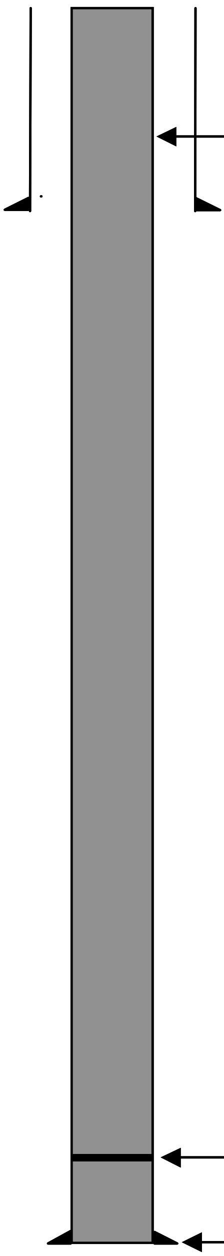
Total Depth: 406m

Pilot OBS 41

CONOCO CANADA
Oil Sands Division
Well Bore Schematic

Well Name: Gulf OB41Resdeln 103/11-24-83-07 W4
Spud: September 22, 2001 Rig Released: September 25, 2001

KB: 587.56 m
GL: 583.96 m
KB-GL: 3.60 m



Surface Casing: Set at 83 m - 20 joints of 177.8mm 25.3 kg/m H40 ST &C; 6 joints of 177.8mm 34.23 L80 QB2
Cemented with 0:1:00 Class "G" Cement

Production Casing: 31 joints of 114.3 mm 9.67 kg/m CS L80 Hydril &
J55 tubing
Cemented with 9 tonnes of Gastight 1800 TS cement + .6% TDF-HT,
1% TA-1; .2% TR-1

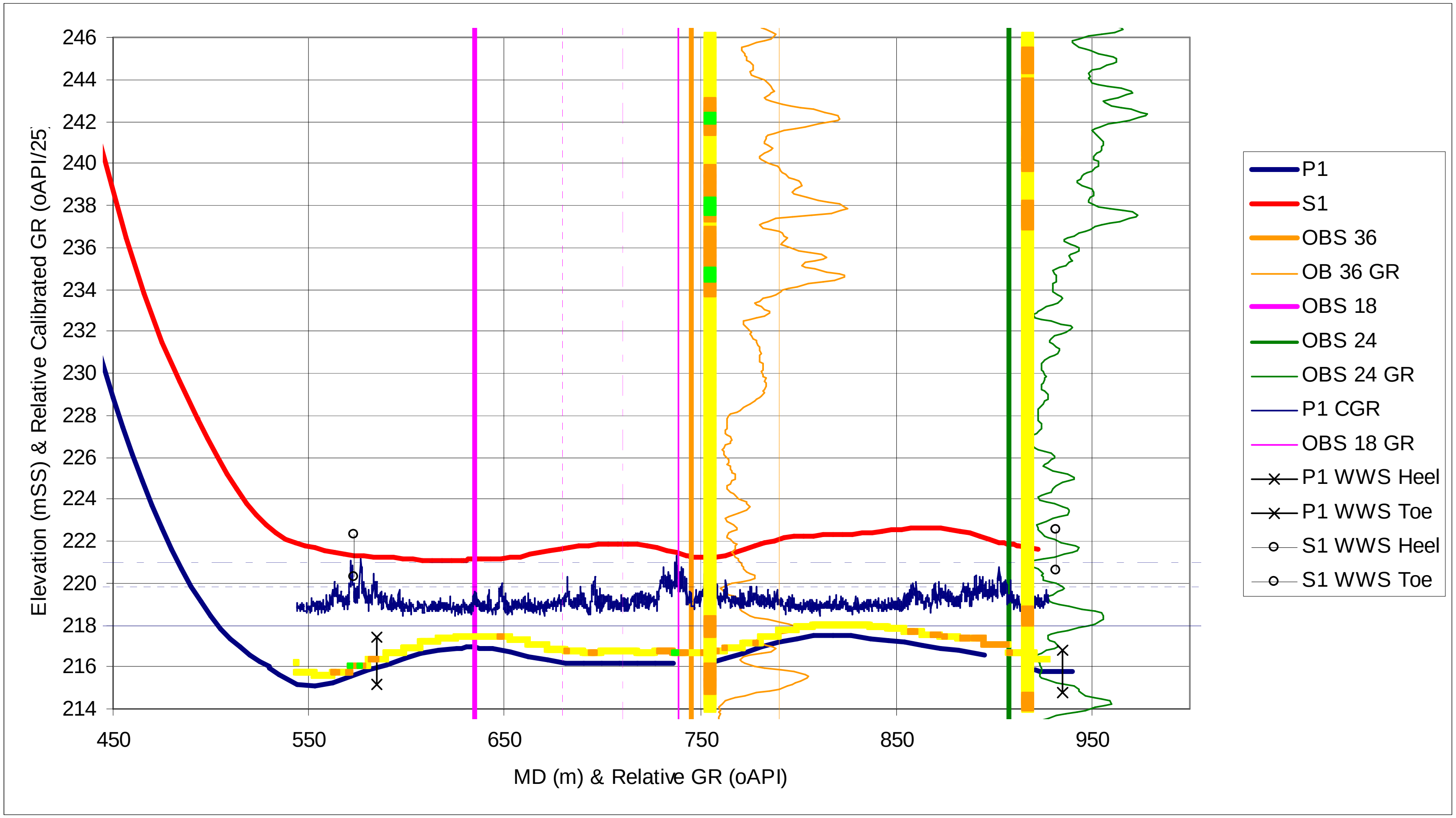
Piezometers: 312m, 321.5m,

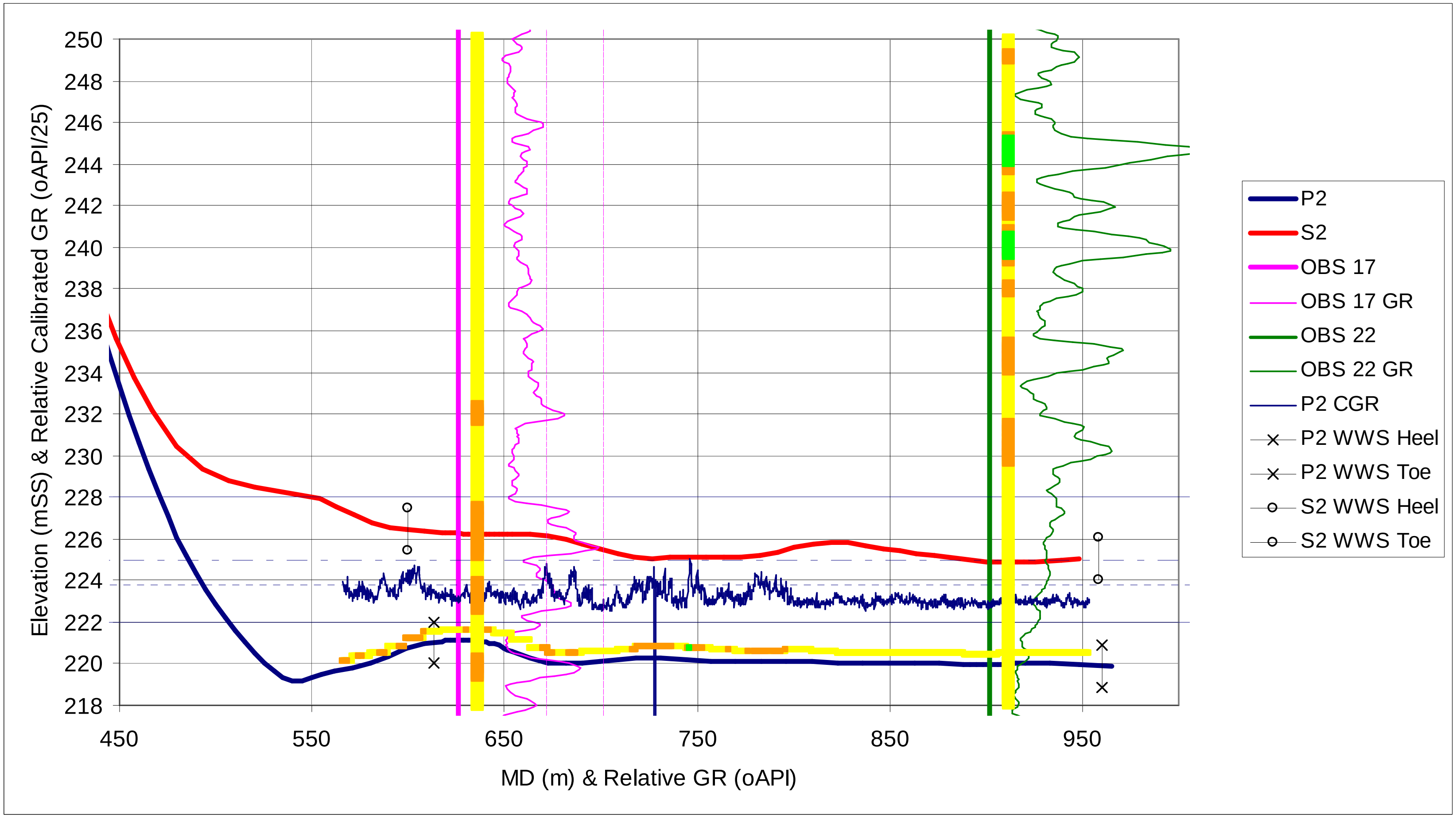
312.0 Piezometer - malfunctioned
321.5 Piezometer - malfunctioned
T20 @ 343.5
T19 @ 345.0
T18 @ 346.5
T17 @ 348.0
T16 @ 349.5
T15 @ 351.0
T14 @ 352.5
T13 @ 354.0
T12 @ 355.5
T11 @ 357.0
T10 @ 358.5
T9 @ 360.0
T8 @ 361.5
T7 @ 363.0
T6 @ 364.5
T5 @ 366.0
T4 @ 367.5
T3 @ 369.0
T2 @ 370.5
T1 @ 372.0

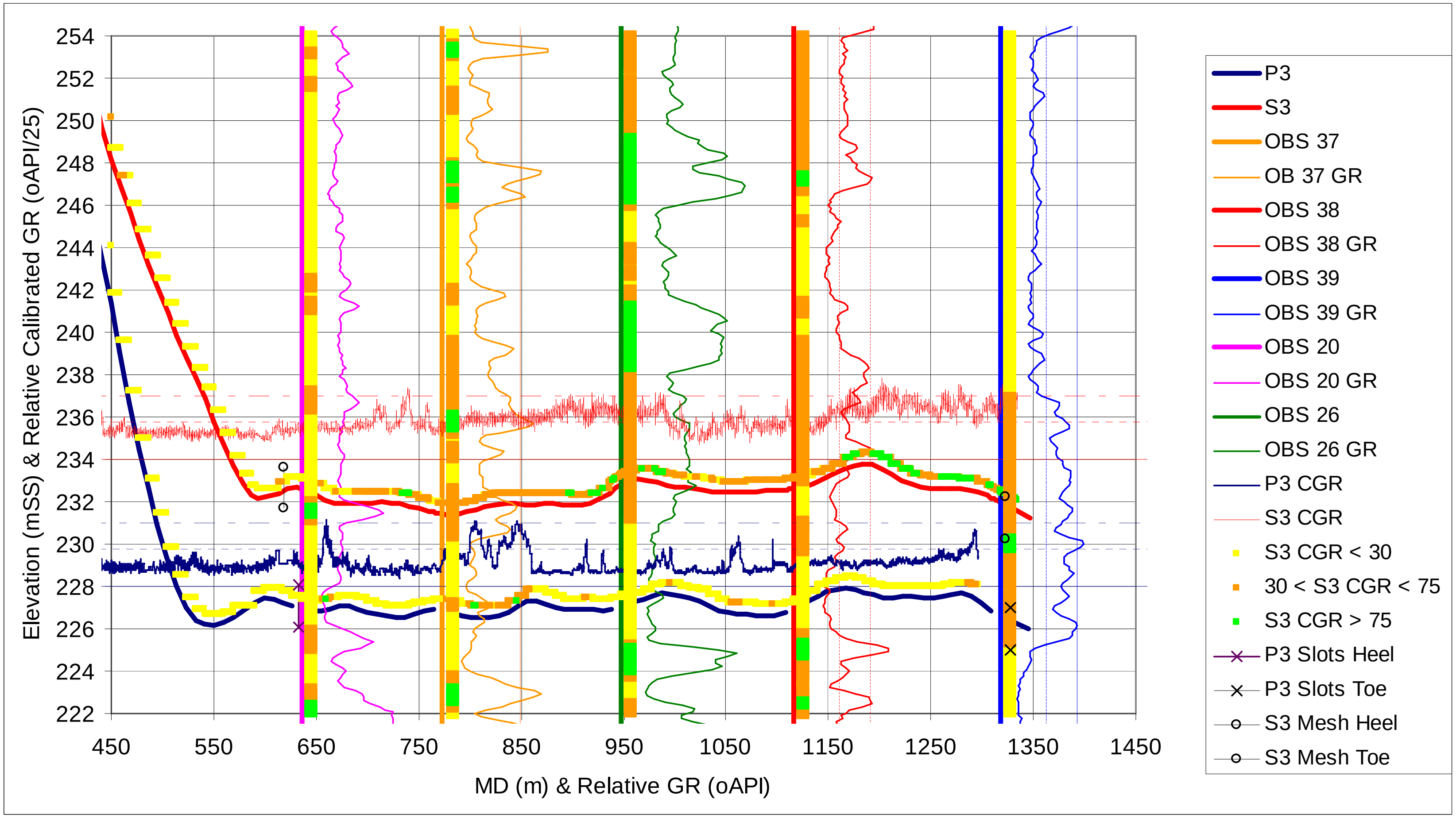
Plug back Depth: 383.6

Total Depth: 397m

Appendix D : Well Pair Logs



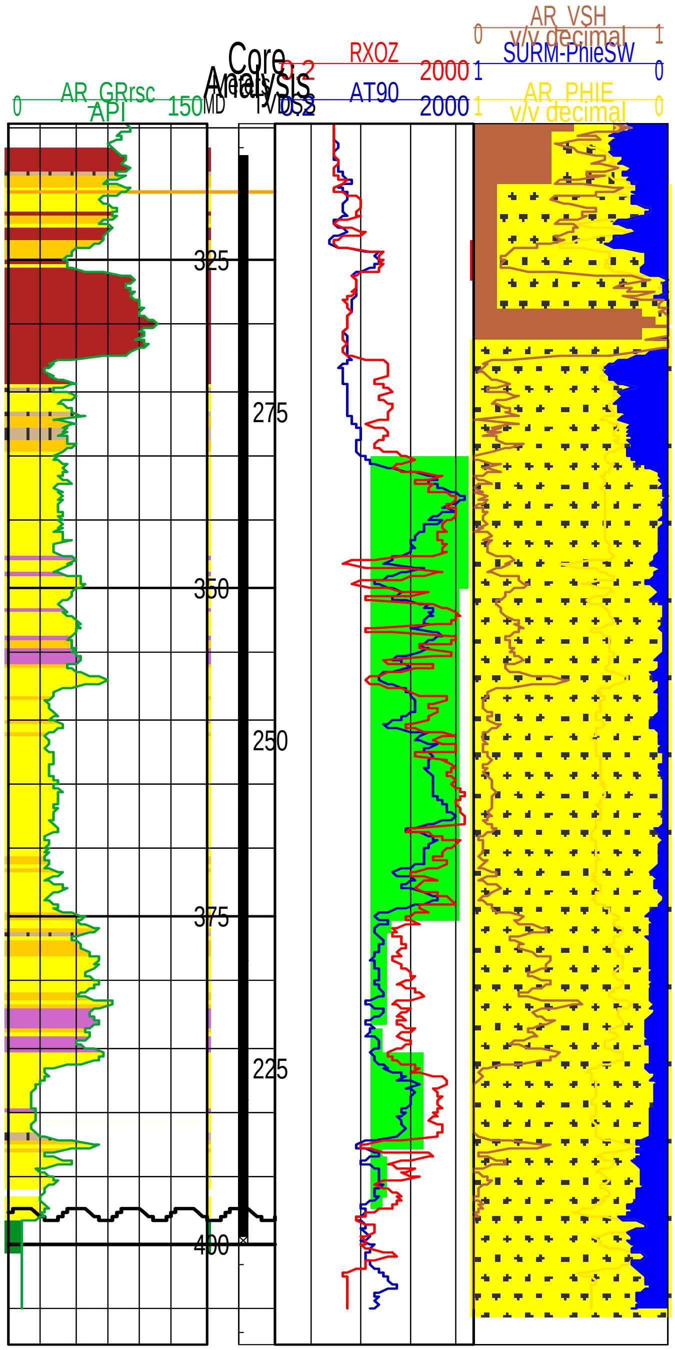

Elevation (mSS) & Relative Calibrated GR (oAPI/25)
MD (m) & Relative GR (oAPI)
250
248
246
244
242
240
238
236
234
232
230
228
226
224
222
220
218
450
550
650
750
850
950
P2
S2
OBS 17
OBS 17 GR
OBS 22
OBS 22 GR
P2 CGR
P2 WWS Heel
P2 WWS Toe
S2 WWS Heel
S2 WWS Toe


Elevation (mSS) & Relative Calibrated GR (oAPI/25)
MD (m) & Relative GR (oAPI)
254
252
250
248
246
244
242
240
238
236
234
232
230
228
226
224
222
450
550
650
750
850
950
1050
1150
1250
1350
1450
P3
S3
OBS 37
OB 37 GR
OBS 38
OBS 38 GR
OBS 39
OBS 39 GR
OBS 20
OBS 20 GR
OBS 26
OBS 26 GR
P3 CGR
S3 CGR
S3 CGR < 30
30 < S3 CGR < 75
S3 CGR > 75
P3 Slots Heel
P3 Slots Toe
S3 Mesh Heel
S3 Mesh Toe

Appendix E : Observation Well Logs

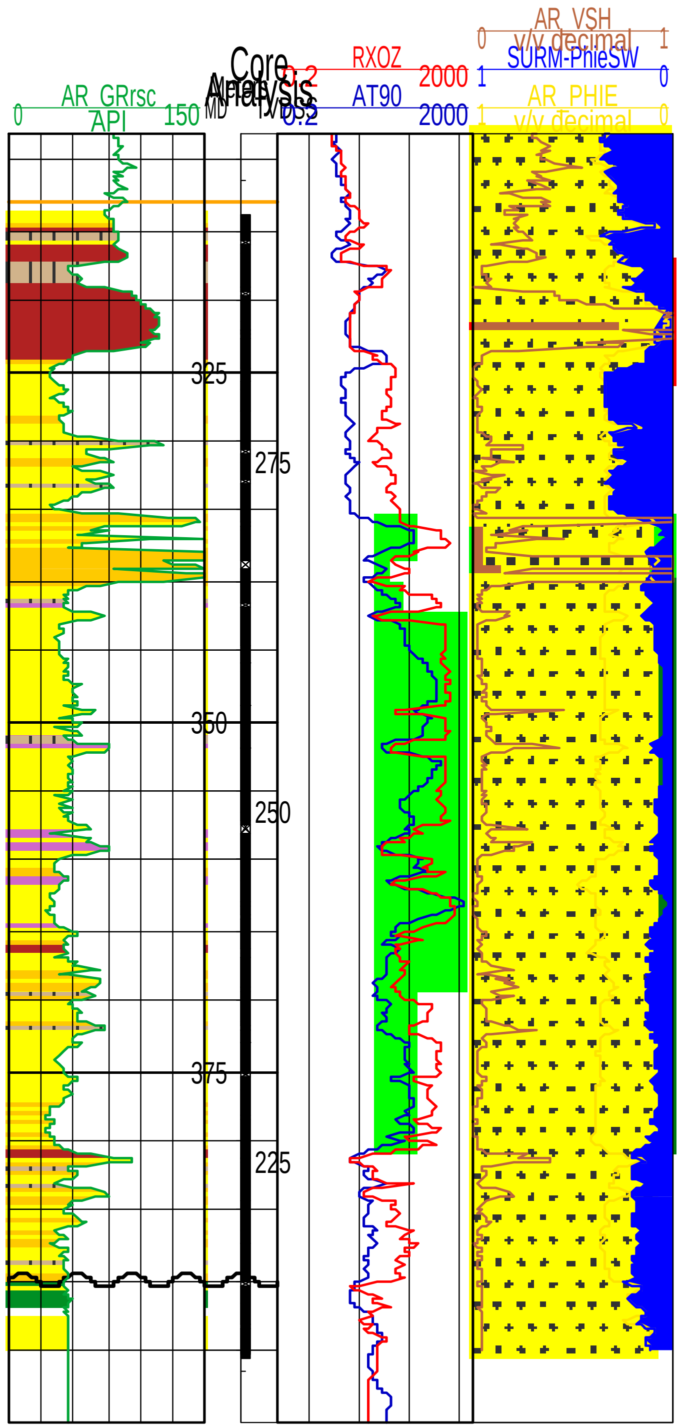
OB39

100042408307W400



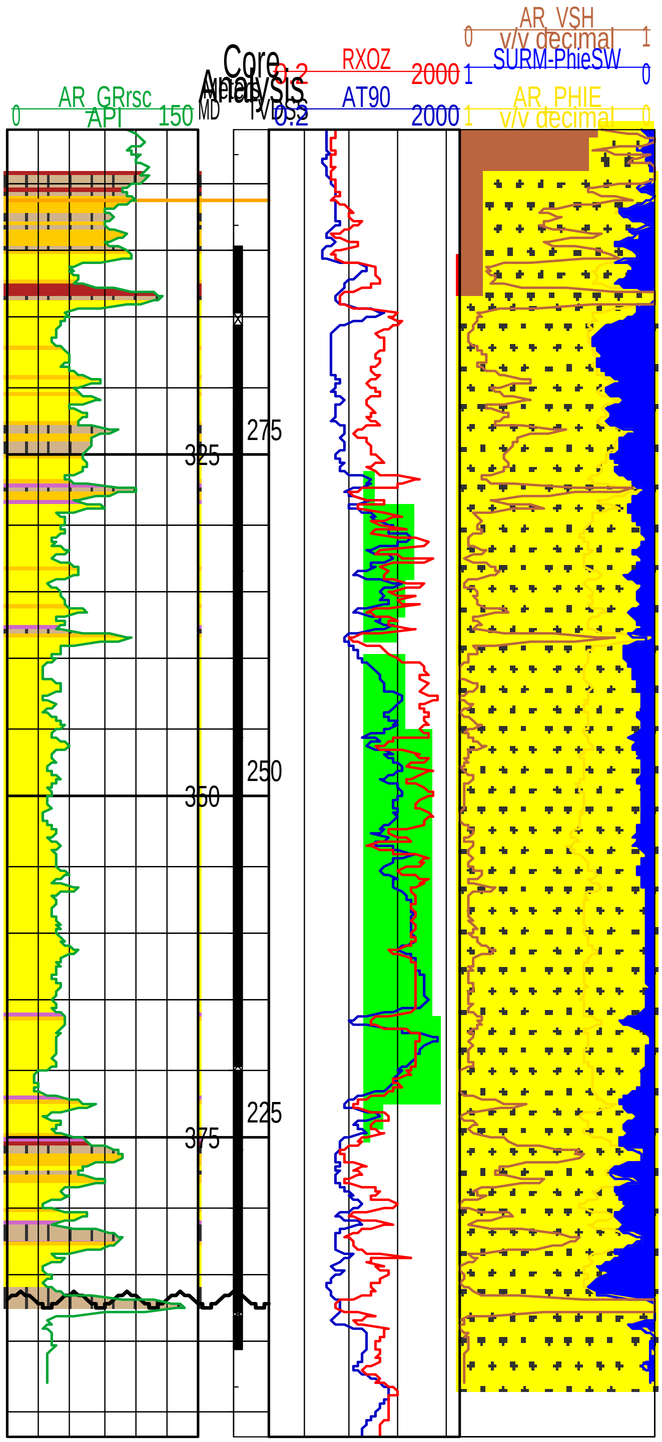
OB38

109052408307W400



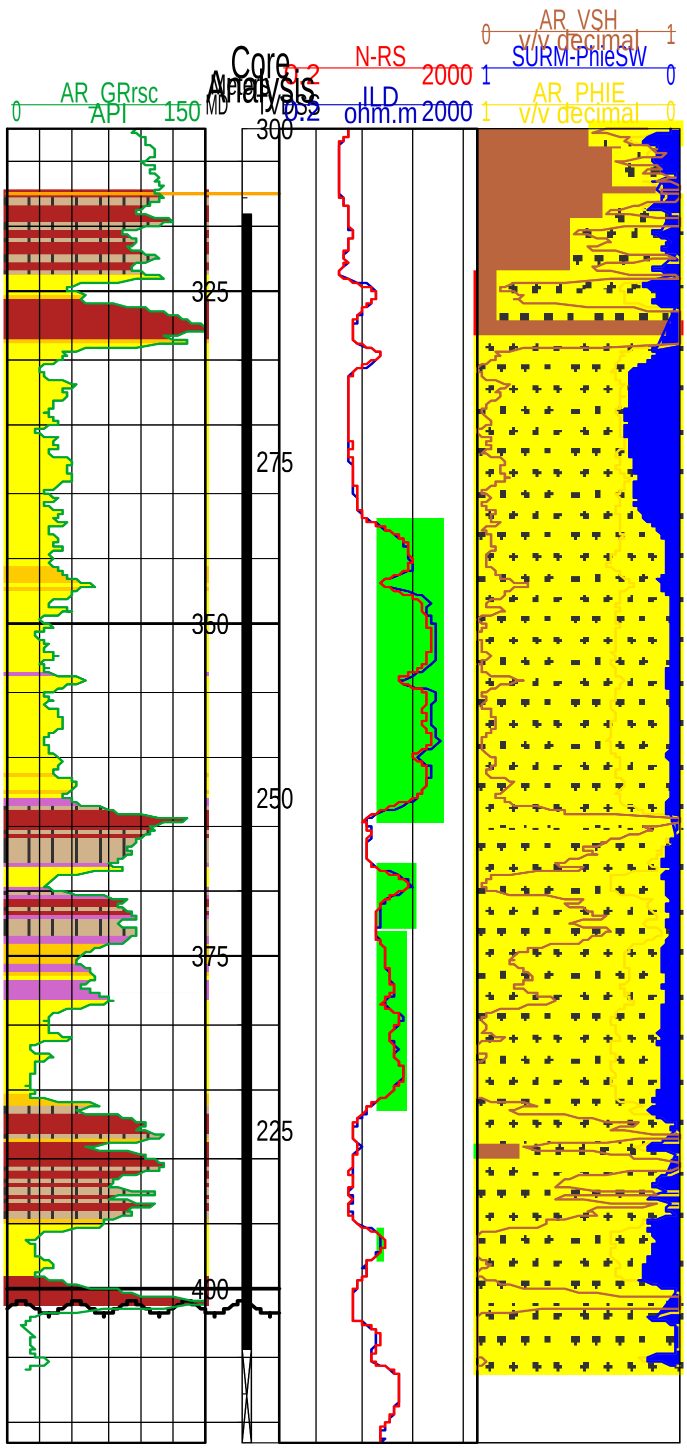
OB20

100112408307W400



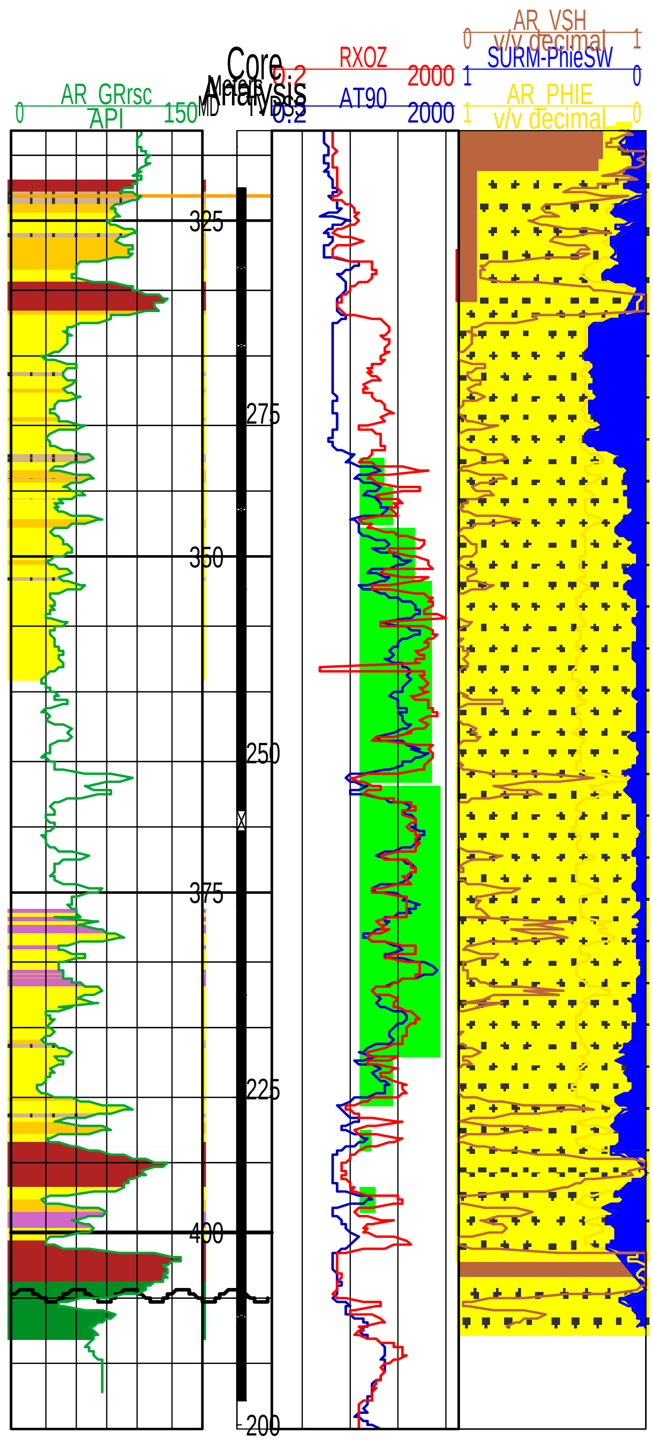
OB25

102052408307W400



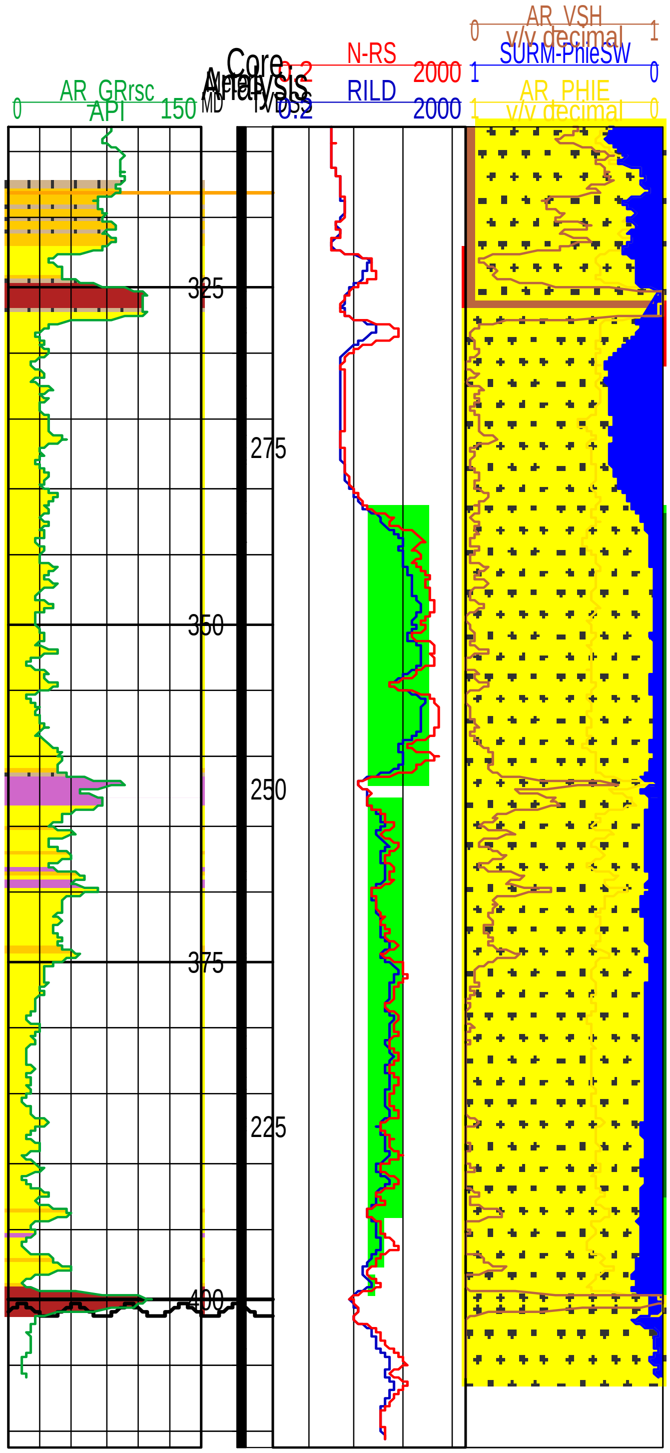
OB37

102112408307W400



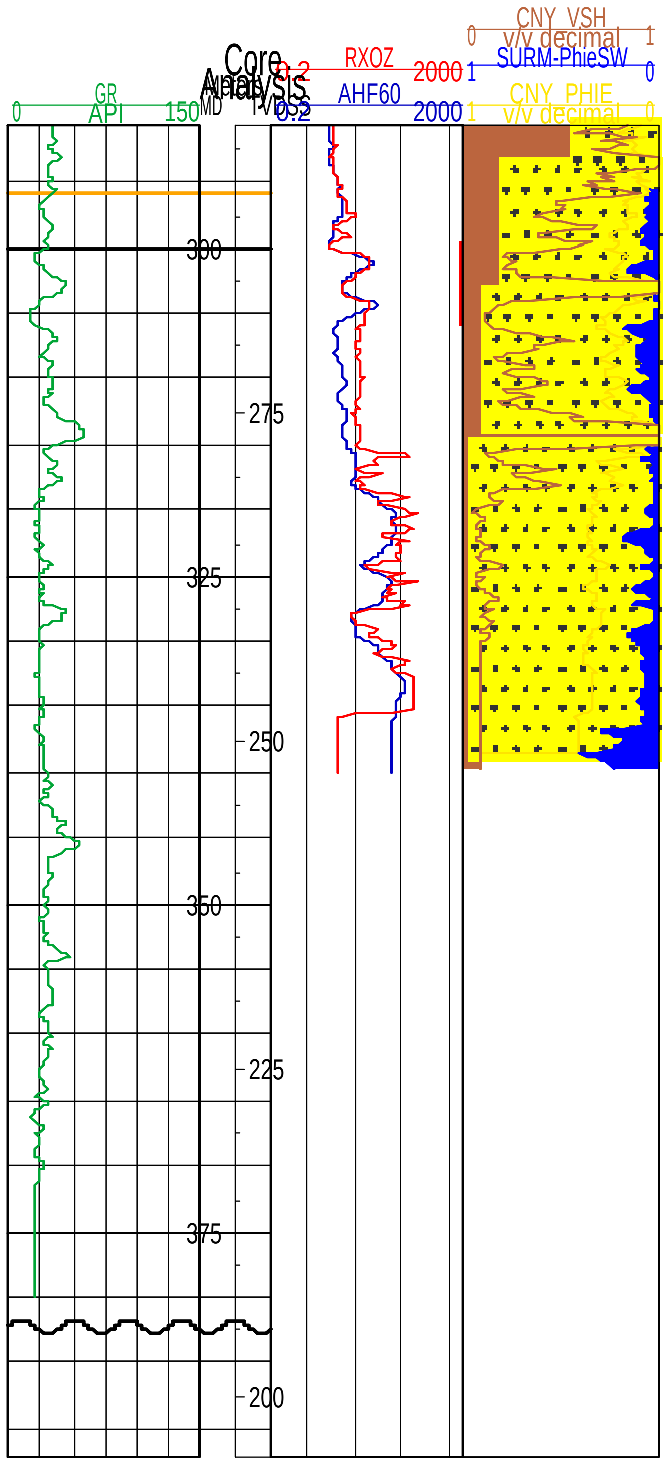
OB24

102122408307W400



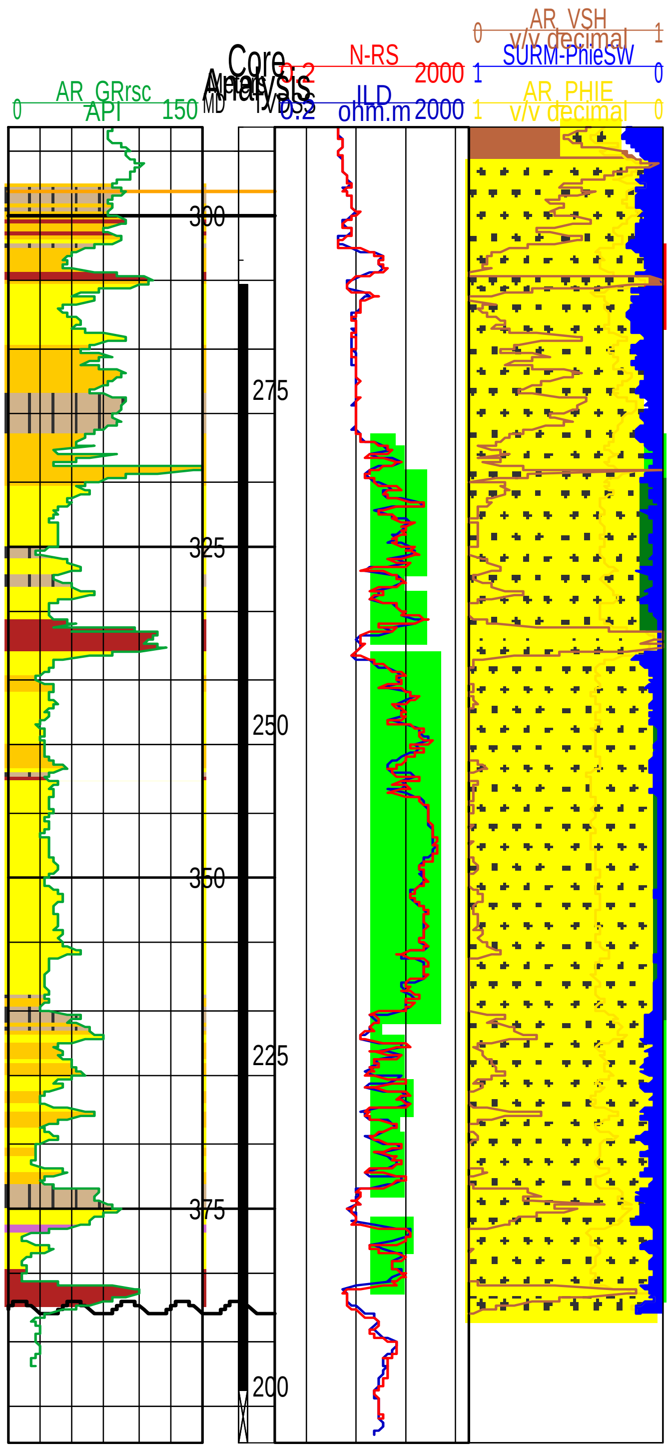
OB41

103112408307W400



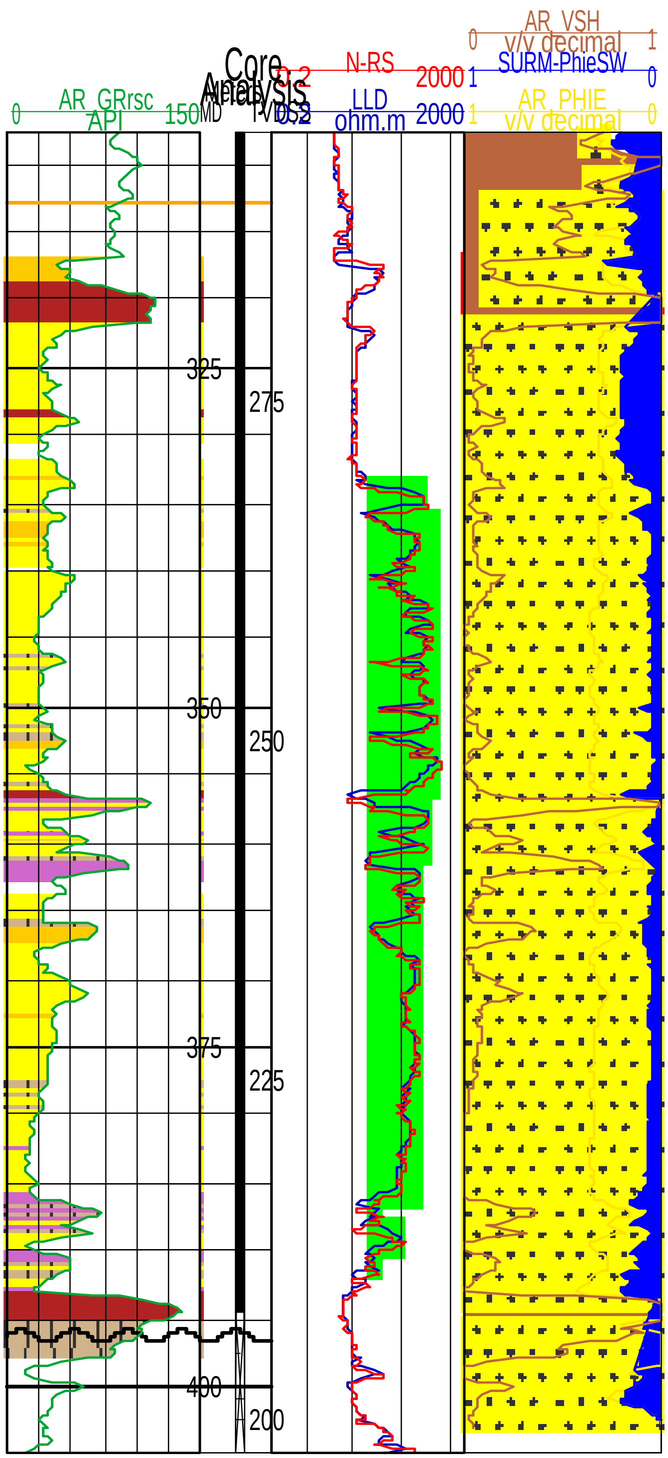
OB17

104122408307W400



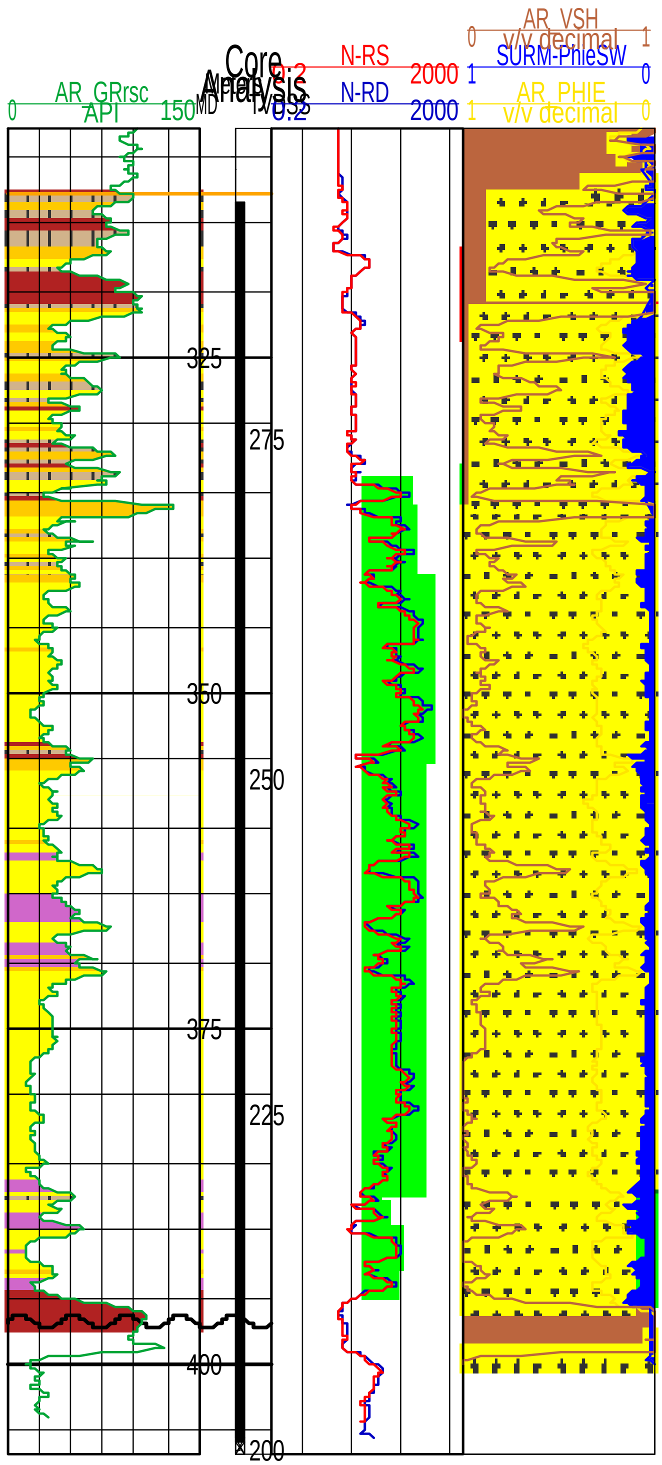
OB22

105122408307W400



OB36

106122408307W400



OB26A

108052408307W400