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ATTACHMENTS:

Signed Copy of Statutory Declaration Disclosure Form

Intellectual Property Agreement Form

Electronic copy of the complete Final report (DVD)

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1. REPORT ABSTRACT

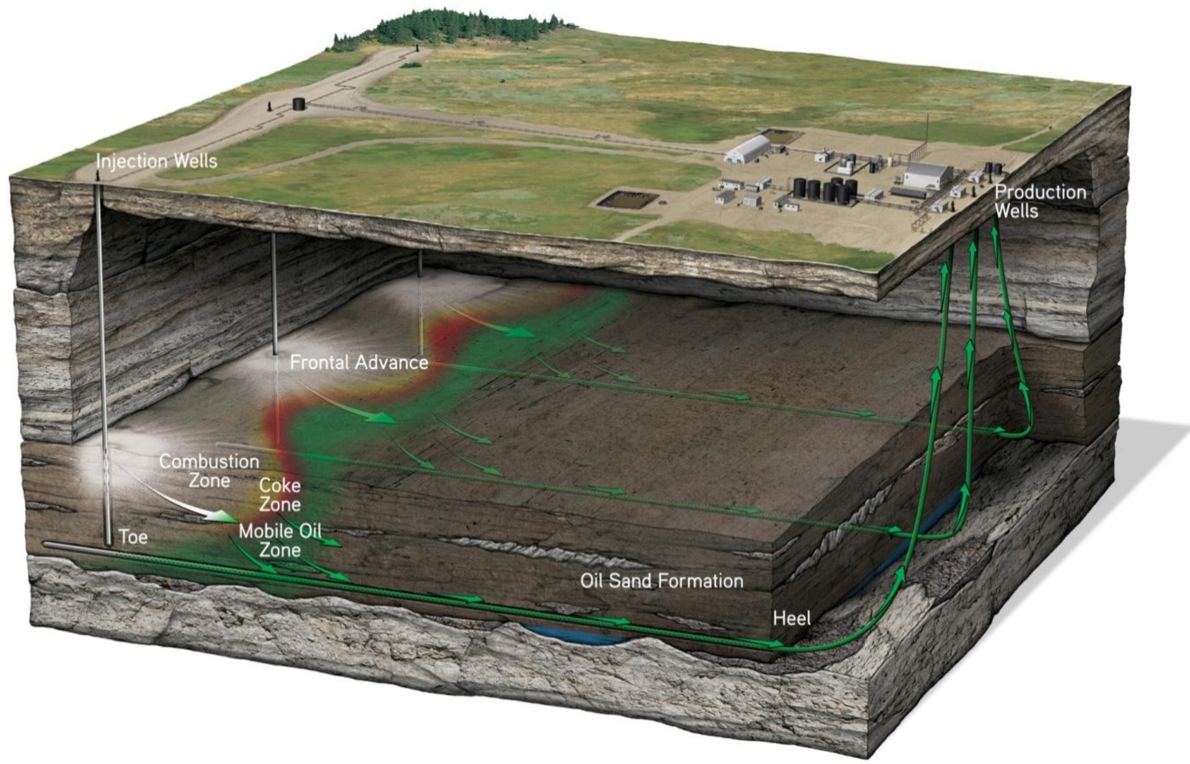
This Final/Annual 2009 progress Report is submitted as per IETP Project Report Requirements (IETP grant # 01-019) for Whitesands Experimental Pilot Project. The report covers all major aspects of the progress and observations made at pilot project since the last reporting period. The report lists all the main events during the reporting period for both the field operations and R&D in a chronological form. Key data collected, operations performance, challenges encountered along with remedial steps taken are also reported up to the shut in of the original wells P1, P2 and P3 project in mid 2009. For reporting purposes, we request IETP to regard mid 2009 as the completion of the approved project 01-019.

THAI™ process has, as predicted, shown remarkable stability and promise as a sustainable technology. Since the start of the combustion, continuous high temperature oxidation and partial in-situ upgrading has been observed. Some of the problems experienced were higher than expected sand and sour gas production. Innovations and modifications made in the project have proven effective in managing the sand control and sour gas scrubbing. The process has also proven to be robust by restarting after pauses in operations for routine maintenance. The project has yielded a very useful database and knowhow for the commercialisation of THAI(TM) process.

2. SUMMARY PROJECT STATUS REPORT:

THAI™ Description

The THAI™ process uses a vertical air injection well at the "toe" of a horizontal production well. Following a steam preheat period, air is injected to initiate combustion. The heat generated reduces the viscosity of the bitumen in the mobilized oil zone (MOZ) ahead of the combustion front and enables it to flow by pressure gradient and gravity drainage into the horizontal production well. Based on laboratory and numerical modeling, the combustion front sweeps the bitumen from the toe to the heel of the horizontal producing well, recovering an estimated 70-80% of the bitumen from the target zone and partially upgrading the crude bitumen in-situ. The process has the potential to significantly lower bitumen production costs and operate in a broader range of bitumen and heavy oil reservoirs than Steam Assisted Gravity Drainage (SAGD) technology.



The Whitesands Experimental Pilot Project used three well pairs of vertical injector and horizontal producer to produce partially upgraded bitumen (THAI™ OIL). The project started three initial well pairs A1-P1, A2-P2 and A3-P3 as approved by IETP. The well P3 was later shut in due to excessive sand production and a new well P3B well was drilled at about 15 metres from the original well P3 instead. This well used a concentric liner system to encase an upgrading Catalyst. P3B has been deemed outside the scope of the IETP approved project. This report contains all data with a complete list of various activities on the lease pertaining to A1-P1, A2-P2 and A3-P3 up to the year end 2009 is provided in the report in chronological order as per IETP requirements. Activities related to P1B, P2B and P3B (replacement wells for P1, P2 and P3 respectively have been excluded from the report as they are deemed outside the scope of initial project application.

2.1 MEMBERS OF THE PROJECT TEAM

2008/2009

Chris Bloomer	Senior Vice President, Heavy Oil
Greg Deuchar	Senior Facilities Engineer
Shaohua Li	Oil Sands Geologist
Audra Papp	EH&S Coordinator
Ron Sinkinson	VP Project Development
Dave Reddecliff	Operations Manager
John Szuszkiewicz	Production Technologist
Ravinder Sierra	Manager Heavy Oil Technology
B. K. Sekar	Sr. Reservoir Specialist
Emery Spronken	Sr. Facilities Engineer
Krista Norum	Health & Safety Coordinator
Susan Johnson	Sr. Staff Reservoir Engineer
Garnet Turcotte	Senior Geologist, Heavy Oil
Kejia Xi	Senior Staff Reservoir Engineer
Craig Budris	Whitesands Plant Operations Manager
Dr. Conrad Ayasse	VP Technology
Dr. John Donnelly	Thermal Recovery Consultant
Barry Noble*	Development Consultant

*** The project team remains unchanged from 2008 with the exception of Barry Noble**

2.2 CHRONOLOGICAL REPORT OF ACTIVITIES

A chronological list of main events, activities and operations for the pilot project is as below:

2003: Application submitted in November

2004: Approval received in February

2005: Project financing in April

Project construction commenced in May

2006: All 'A' wells refer to injector wells while 'P' wells refer to producer wells.

Steam injection (Pre-heat phase) started in

A2 on Mar 9, 2006 / P2 on Apr 21, 2006

A1 on Oct 17, 2006 / P1 on Sep 21, 2006

A3 on Dec 31, 2006 / P3 on Dec 31, 2006

Air Injection (combustion phase) started in

A2 on July 20, 2006

2007: Air Injection (combustion phase) started in:

A1 on January 10, 2007

A3 on May 11, 2007

Equipment and field related tasks during the year:

In early 2007, three sand knockout vessels, one for each well were installed to handle the higher than expected sand production from the wells.

To counter Sand erosion problems new wellhead chokes were developed.

The H2S scrubber was upgraded and a new gas incinerator to handle noxious components of the produced gas was designed.

A new water disposal well was drilled and completed to improve water disposal capacity. The well was completed in the McMurray zone.

H2S monitoring was integrated with the incinerator to determine S02 emissions.

Tilt meters were installed at the pilot plant as a method to monitor the development of the combustion process in the reservoir. However the method was proven ineffective and was abandoned.

The option of recovering sulphur at the pilot plant was proposed and initial studies were carried out.

Archon Laboratory and R&D work for 2007

A fully operational Archon analytical and R&D laboratory was established in the facility of Canada Chemical Corporation in Calgary.

Design, construct and commission new 3-D cells (test apparatus, high pressure and high temperature) to study and evaluate operational variables physically.

In parallel to the 3-D cell program, Archon undertook a large number of numerical simulations (over 30) using STARS software leased from the Computer Modelling Group to study ways to control wellbore temperature and pressure in order to inhibit air entry into the wellbore. Patents have been filed.

2008: Main events completed on the Wells:

A3/P3 well pair shut in April 2008 due to excessive sand production

Another well parallel to P3 was drilled. This new well, P3-B which incorporated a down-hole catalyst, has been deemed out of scope for the approved project. Accordingly, associated air injection at A3 has been excluded from this report. P3

Other equipment and field related tasks completed for 2008

In the desand vessels the sand pan system, the flush water pumps and the desand vessels were further modified to improve sand removal capabilities.

The H2S removal and control system was further improved by installing and commissioning a permanent flooded gas scrubbing system.

The handling of the vented gas was improved by installing and commissioning a new incinerator.

Heating system was added in the tanks to improve treating of recycled emulsions. At the same time, additional experiments were carried out with different chemicals to enhance emulsion treatment.

An improved method to measure and evaluate produced light hydrocarbon condensates was also installed. A 2000 bbl tank and new liquid header was installed in order to collect the fluids from the secondary separators.

A 25 mmbtu/hr steam generator was added in order to provide additional steam capacity.

Additional screw and reciprocating compressors were installed in order to bring the plant air injection capacity up to 340×10^3 m^3/d.

Archon Laboratory and R&D work for 2008

Numerous analyses on pilot samples were completed during the reporting period. The tests comprised of SARA analysis, Total acid number, Bromine number, Hydrocarbon Distribution, Conradson Carbon, Cloud point, Pour point, Total organic chlorides, Water hardness, Water TDS and Water alkalinity.

Archon's analytical and R&D laboratory continued to assist the pilot project and further technology developments related to THAI™.

Extensive numerical simulation runs were continued in 2009 to study and conduct sensitivity analyses to different parameters.

2009: Archon Laboratory and R&D work for 2009

Archon's analytical and R&D laboratory continued to assist the pilot project and further technology developments related to THAI™. Numerous analyses on pilot samples were completed during the reporting period. The tests comprised of SARA analysis, Total acid number, Bromine number, Hydrocarbon Distribution, Conradson Carbon, Cloud point, Pour point, Total organic chlorides, Water hardness, Water TDS and Water alkalinity.

Extensive numerical simulation runs were to study and advance the flexibility of the THAI™ process.

2.3 PRODUCTION, MATERIAL AND ENERGY BALANCE FOR 2009

Table 1 shows a summary of actual production compared to simulated production up to mid 2009.

Table 1 Actual and Simulated Production

Month	Actual Produced Oil (m^3)	Actual Produced Gas (10^3 m^3)	Actual Produced Water (m3)	Actual Produced Sand (m3)	Simulated Produced Oil (m3)	Simulated Produced Gas (10^3 m^3)	Simulated Produced Water (m^3)
Mar-06	0.0	0.0	0.0	0.0	0.0	309.9	0.0
Apr-06	0.0	0.0	0.0	0.0	0.0	280.0	0.0
May-06	0.0	0.0	0.0	0.0	0.0	310.0	0.0
Jun-06	20.5	9.4	1,118.3	0.0	444.2	1,154.7	1,574.0
Jul-06	20.1	0.0	1,840.3	0.0	570.8	580.5	2,573.9
Aug-06	18.8	105.7	1,053.0	54.2	814.9	570.2	2,483.5
Sep-06	113.9	40.9	246.2	109.2	896.3	501.6	2,564.5
Oct-06	146.4	93.4	1,613.3	315.1	897.8	516.3	2,580.6
Nov-06	162.7	502.0	475.6	75.2	931.5	769.8	2,489.0
Dec-06	295.8	139.0	0.0	55.1	1,044.3	759.8	2,545.2
2006 Total	**778.2**	**890.4**	**6,346.7**	**608.1**	**5,599.8**	**5,753.0**	**16,810.7**
Jan-07	512.2	97.9	0.0	205.3	931.4	802.8	2,524.3
Feb-07	514.2	363.1	0.0	31.9	1,542.5	1,653.0	4,152.8
Mar-07	178.6	91.8	0.0	134.5	1,623.5	1,091.6	5,096.4
Apr-07	598.3	386.8	12.1	60.9	1,862.0	1,355.2	4,860.6
May-07	620.7	674.3	998.5	19.0	2,149.2	1,273.1	5,014.4
Jun-07	694.7	961.9	982.0	116.9	2,102.1	1,360.1	5,174.0
Jul-07	406.2	1,156.5	1,728.3	167.4	2,788.2	2,119.8	6,534.5
Aug-07	626.5	961.2	815.3	108.2	2,925.0	1,589.6	7,667.8
Sep-07	797.6	688.4	1,919.3	94.0	3,219.3	1,569.5	7,510.8
Oct-07	524.0	1,436.5	1,815.5	183.0	3,523.7	1,538.8	7,736.9
Nov-07	663.5	1,566.6	1,323.2	336.1	3,465.2	1,520.1	7,512.3
Dec-07	720.1	1,856.5	3,671.1	129.0	3,598.1	1,476.1	7,466.7
2007 Total	**6,856.6**	**10,241.5**	**13,265.3**	**1,586.2**	**29,730.3**	**17,349.7**	**71,251.4**
Jan-08	616.1	4,639.5	3,413.6	224.3	3,885.9	1,469.6	7,399.9
Feb-08	364.7	2,587.7	2,218.5	1,340.4	3,836.1	1,571.1	7,738.0

Month	Actual Produced Oil (m^3)	Actual Produced Gas (10^3 m^3)	Actual Produced Water (m3)	Actual Produced Sand (m3)	Simulated Produced Oil (m3)	Simulated Produced Gas (10^3 m^3)	Simulated Produced Water (m^3)
Mar-08	679.3	3,202.3	3,444.8	1,168.1	4,241.0	1,516.3	7,486.4
Apr-08	470.4	2,895.0	3,669.3	1,058.0	4,004.8	1,545.2	7,487.5
May-08	471.1	2,320.3	4,794.7	431.1	4,408.4	1,498.0	7,317.9
Jun-08	951.9	2,222.0	3,539.0	592.3	4,591.3	1,570.9	7,614.9
Jul-08	450.1	1,725.2	1,129.9	202.2	4,728.4	1,544.9	7,445.0
Aug-08	966.9	2,391.7	2,005.8	380.4	4,947.5	1,587.3	7,642.3
Sep-08	688.7	2,740.1	2,552.9	239.0	4,944.6	1,555.4	7,449.4
Oct-08	342.0	3,059.3	2,866.5	216.6	5,232.4	1,597.4	7,694.8
Nov-08	368.8	3,400.1	1,535.1	268.3	5,359.8	1,559.1	7,411.3
Dec-08	542.3	3,437.1	1,809.6	227.9	5,540.8	1,531.6	7,342.4
2008 Total	**6,296.2**	**29,980.8**	**29,566.1**	**6,348.6**	**55,720.9**	**18,546.7**	**90,029.8**
Jan-09	553.6	3,791.8	4091.8	17.8	3380.5	3823.5	1247.5
Feb-09	618.3	3,674.8	6825.1	457.0	3249.5	3766.2	1223.1
Mar-09	300.2	3,822.0	2336.4	358.2	3350.5	3784.6	1251.7
Apr-09	304.1	1,952.9	921.5	13.46	3375.3	3852.0	1255.9
May-09	221.3	2,136.5	1238	88.3	3254.7	3596.5	1162.9
Jun-09	224.6	2,105.2	1020.3	29.51	3486.1	3841.7	1251.7
Jul-09	197.2	1,647.9	852.3	64.31	3401.7	3777.9	1216.0
2009 Total	**2,419.3**	**19,131.1**	**17,285.4**	**1,028.58**	**23,498.3**	**26,442.3**	**8,605.8**
Cum to 2009	**16,350.3**	**60,243.8**	**66,463.5**	**9,571.48**	**114,549.4**	**68,091.6**	**186,700.7**

The basis for the simulation is the half-well model used in the scheme approval. Production has been delayed by sand production issues. Also, the simulation assumed a uniform, thicker zone and did not include bottom water. This is discussed in section 4.3.1.

The following material balance and energy balance flow sheets are modeled on the ERCB requirements for scheme applications. Material balances for the first 7 months of 2009 and cumulative to July 2009 are in Figure 1 and Figure 2 respectively. For comparison Figure 3 has a material balance flow sheet based on simulation to July 2009.

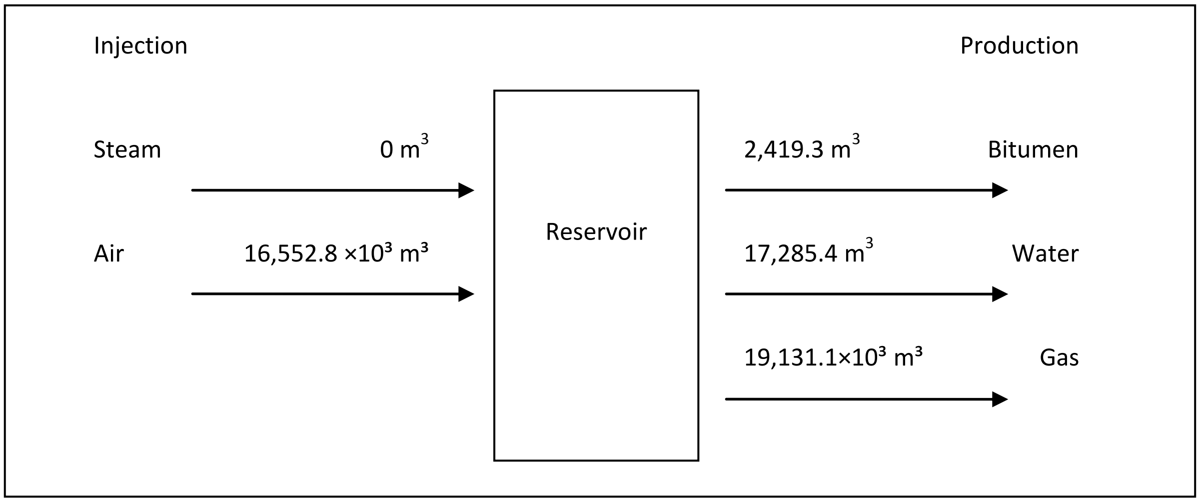


Figure 1: Material Balance Flow Sheet, 2009

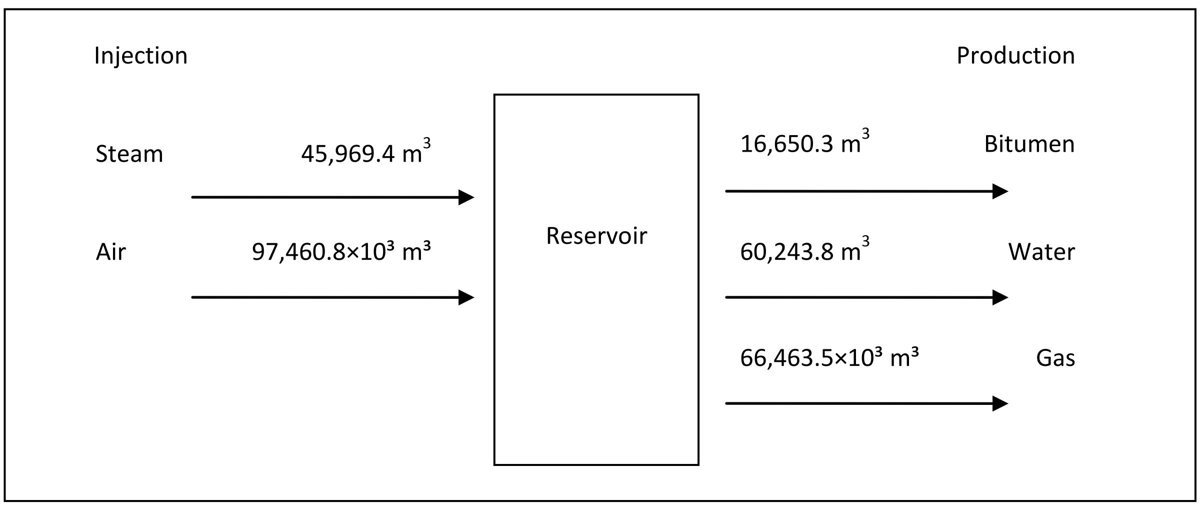


Figure 2: Material Balance Flow Sheet, Cumulative to July 2009

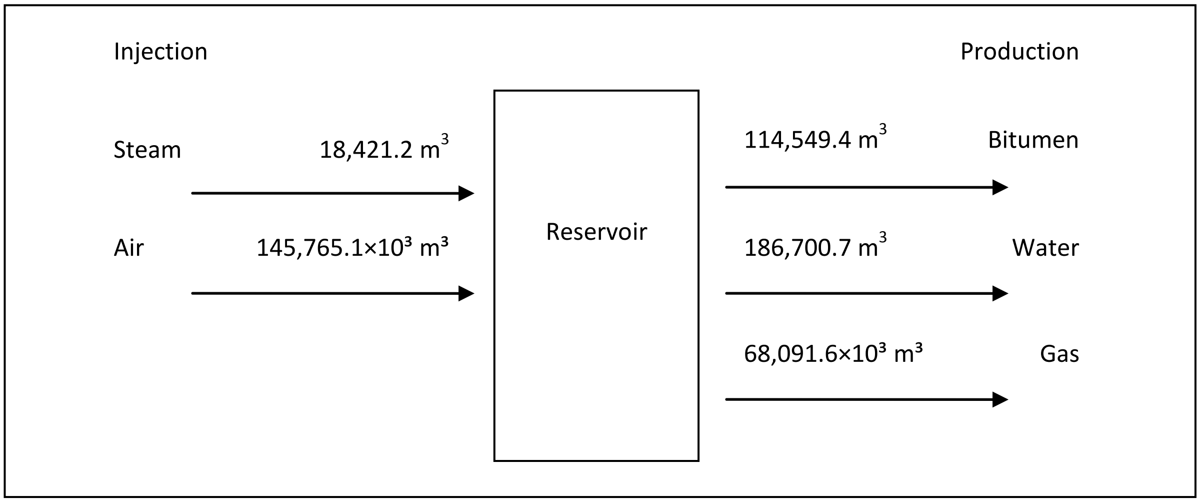


Figure 3: Material Balance Flow Sheet, Simulation to End of 2009

Energy balances for 2009 and cumulative to end of July 2009 are in Figure 4, Figure 1 and Figure 5 respectively.

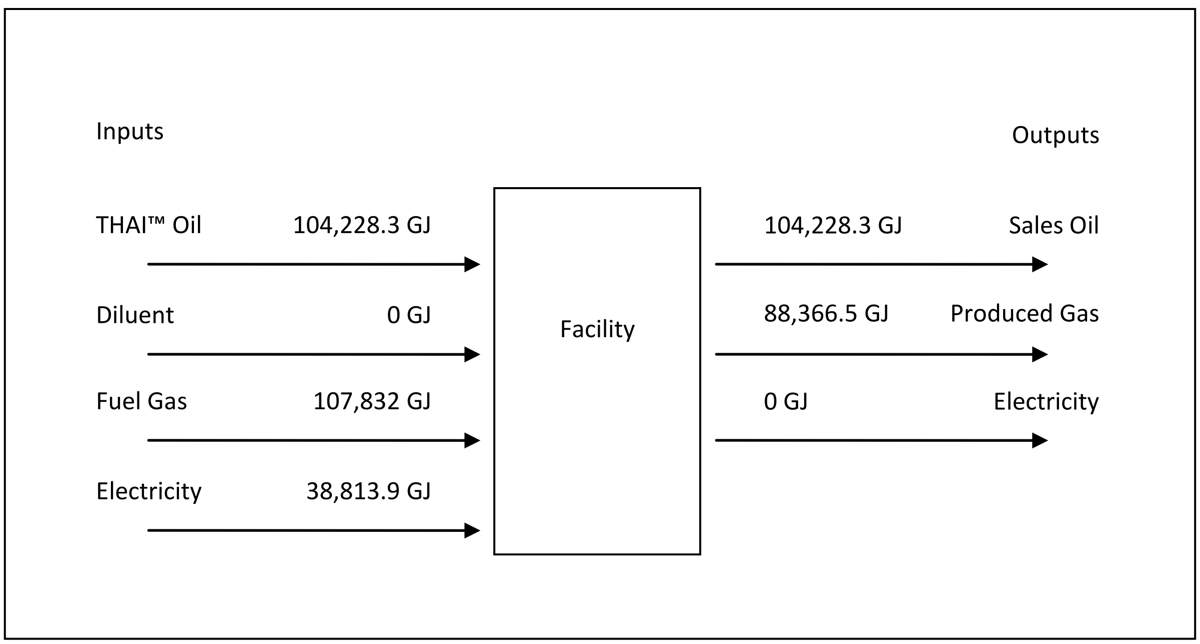


Figure 4: Energy Balance Flow Sheet, 2009

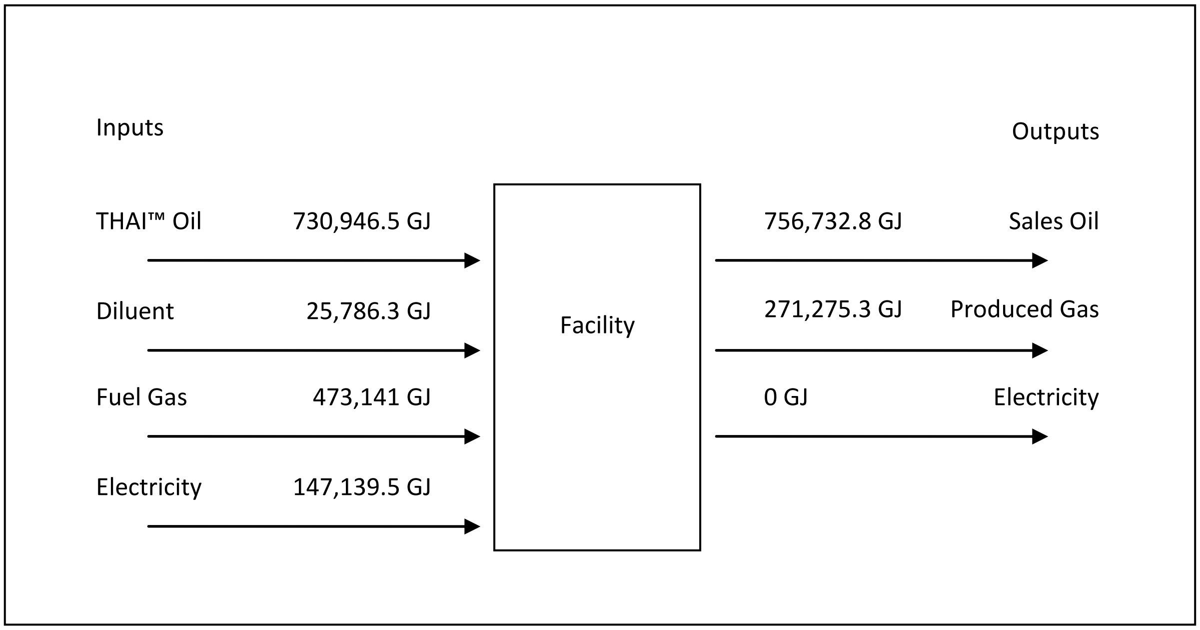


Figure 5: Energy Balance Flow Sheet, Cumulative to July 2009

These energy balances are based on metered electricity and purchased GJs of fuel gas. The heating value of the THAI™ oil was determined to be typically about 43,082 MJ/m^3 and that of the diluents that have been used at the pilot to be about 38,287 MJ/m^3.

An energy balance had not been done on the simulation data. To provide an equivalent based on the assumptions made before the start of the project, the following assumptions were applied to the simulation data:

- 17% diluent added to the produced oil
- Energy for steam generation at 75% efficiency, 6,000 kPa a header pressure , 80% quality would be about 3.2 MJ/m3
- Energy for air compression to 6,000 kPa a header pressure would be about 380 kJ/m3
- Utility gas requirements would be about 50,000 m3/month or 1,695 GJ/month
- Utility electrical requirements would be about 950 kVA at 0.9 load factor or 2,270 GJ/mo

The resulting energy balance is shown in Figure 6.

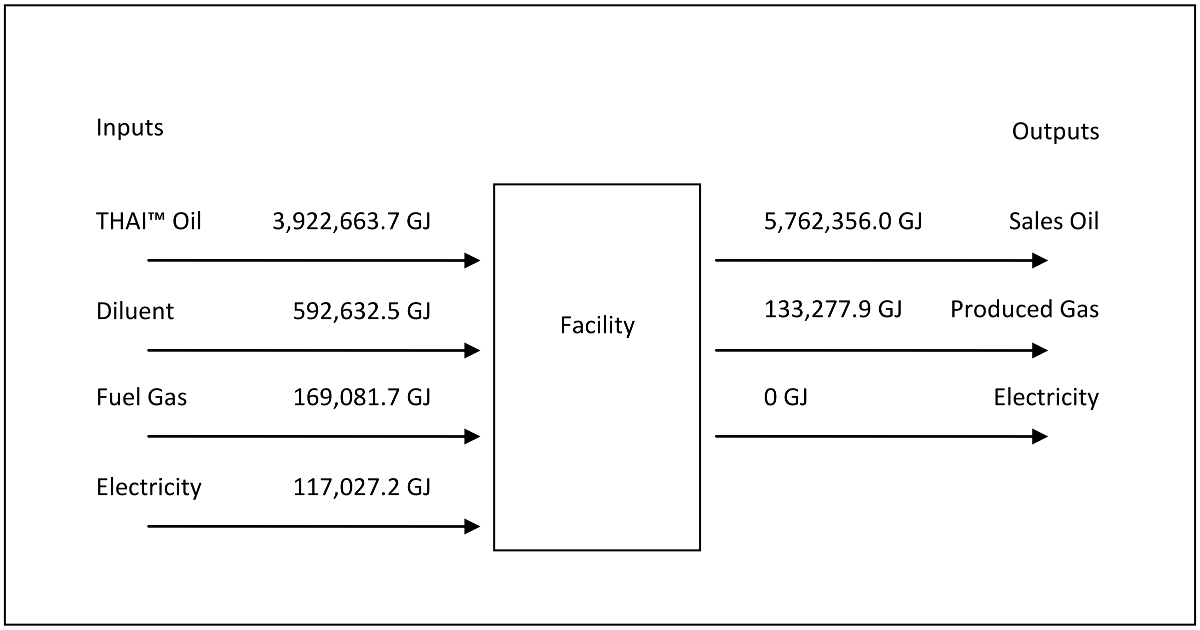


Figure 6: Energy Balance Flow Sheet, Simulation to End of 2009

The energy in the produced gas is not captured in the pilot but would be in a commercial application.

2.4 RESERVES ESTIMATE

2.4.1 Reserve Estimate 2009 Year-End

Based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society), McDaniel & Associates Consultants Ltd. has assigned 70 mmbbls of Total Proved Plus Probable reserves (2P) to the section 12-077-09W4M and 79 mmbbls of Total Proved Plus Probable Plus Possible reserves (3P) to the sections 12-077-09W4M and 07-077-08W4M. In this estimate, 27% porosity and 8% mass bitumen content cut-offs are used. The average porosity is 34% and average bitumen saturation is 80%.

Compared with the estimates at the time of project approval, 2P reserves have increased by 45 mmbbls and 3P reserves by 8 mmbbls.

3. WELL INFORMATION

3.1 WELL LAYOUT MAP

The current well layout is shown in Figure 7. In 2008 operation of P3 was suspended and P3-B was drilled as a CAPRI™ well. P3-B is now operated in place of P3.

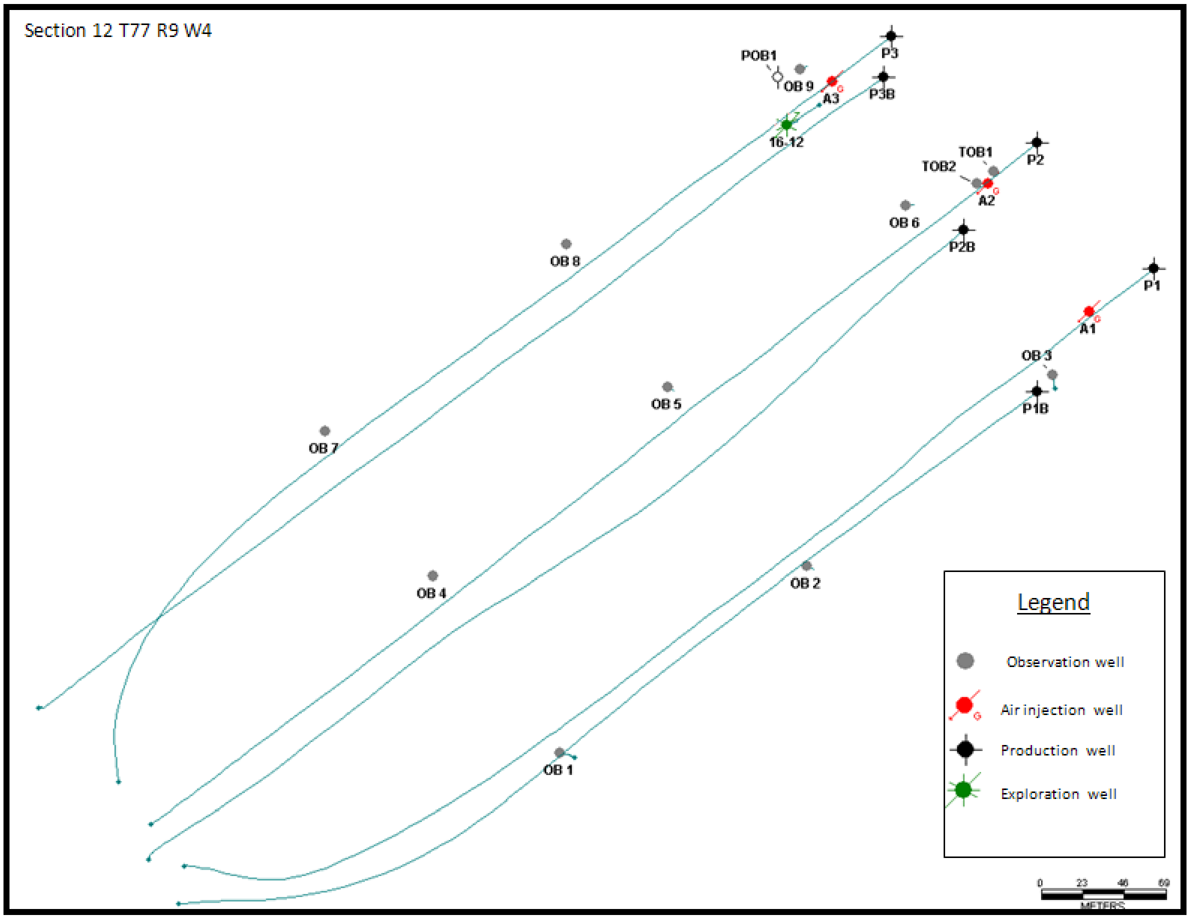


Figure 7: Well Layout Map

3.2 2008 DRILLING, COMPLETION AND WORK-OVER OPERATIONS

P3 was suspended due to unmanageable sand production. Another well parallel to P3 was drilled. This new well, P3-B which incorporated a down-hole catalyst, has been deemed out of scope for the approved project. Accordingly, associated air injection at A3 has been excluded from this report. P3 remains suspended and is currently being used for temperature monitoring.

In all, there were 13 routine sand cleanouts carried out for P1, P2 and P3.

A2 & A3 air injectors had 2 packer work-over repairs on each well. The completions were changed from concentric strings connecting to separate injection intervals to single string completions. These changes are discussed in detail in section 3.5.2. Otherwise, all the wells were operated as before.

Injection and production histories for all wells are covered in part 4.1.

3.3 WELL OPERATIONS

Well operations as defined in Schedule B of Project Approval No. 01-019 are covered by items 3.4, and 3.5

3.4 WELL LIST AND STATUS

In 2008 operations on P3 were discontinued due to the excessive sand production.

A new water disposal well 00/15-12-077-09W4/3 was put into use and is now the main disposal well for the project.

The wells which make up the project are listed in Table 2.

Table 2: Well List

Well	UWI	Status at End of 2009
Injection wells		
A1	AR/16-12-077-09W4/0	On injection
A2	AP/16-12-077-09W4/0	On injection
A3	AQ/16-12-077-09W4/0	On injection
Production Wells		
P1	AH/16-12-077-09W4/0	Suspended
P2	AJ/16-12-077-09W4/0	Suspended
P3	AK/16-12-077-09W4/0	Suspended
Water Disposal		
WD1	00/08-12-077-09W4/0	On disposal
WD2	00/15-12-077-09W4/3	On disposal
Water Source		
Source	F2/10-12-077-09W4/0	On production
Monitor	F3/10-12-077-09W4/0	Standing
Observation		
OB1	AA/09-12-077-09W4/0	Cemented full length - operational
OB2	AD/16-12-077-09W4/0	Cemented full length- operational
OB3	AE/16-12-077-09W4/0	Cemented full length- operational
OB4	AA/15-12-077-09W4/0	Cemented full length- operational
OB5	AB/16-12-077-09W4/0	Cemented full length- operational
OB6	AC/16-12-077-09W4/0	Cemented full length- operational
OB7	AB/15-12-077-09W4/0	Cemented full length- operational
OB8	AF/16-12-077-09W4/0	Cemented full length- operational
OB9	AG/16-12-077-09W4/0	Cemented full length- operational
TOB1	AN/16-12-077-09W4/0	Cemented full length- operational
TOB2	AT/16-12-077-09W4/0	Cemented full length- operational

3.5 WELLBORE SCHEMATICS

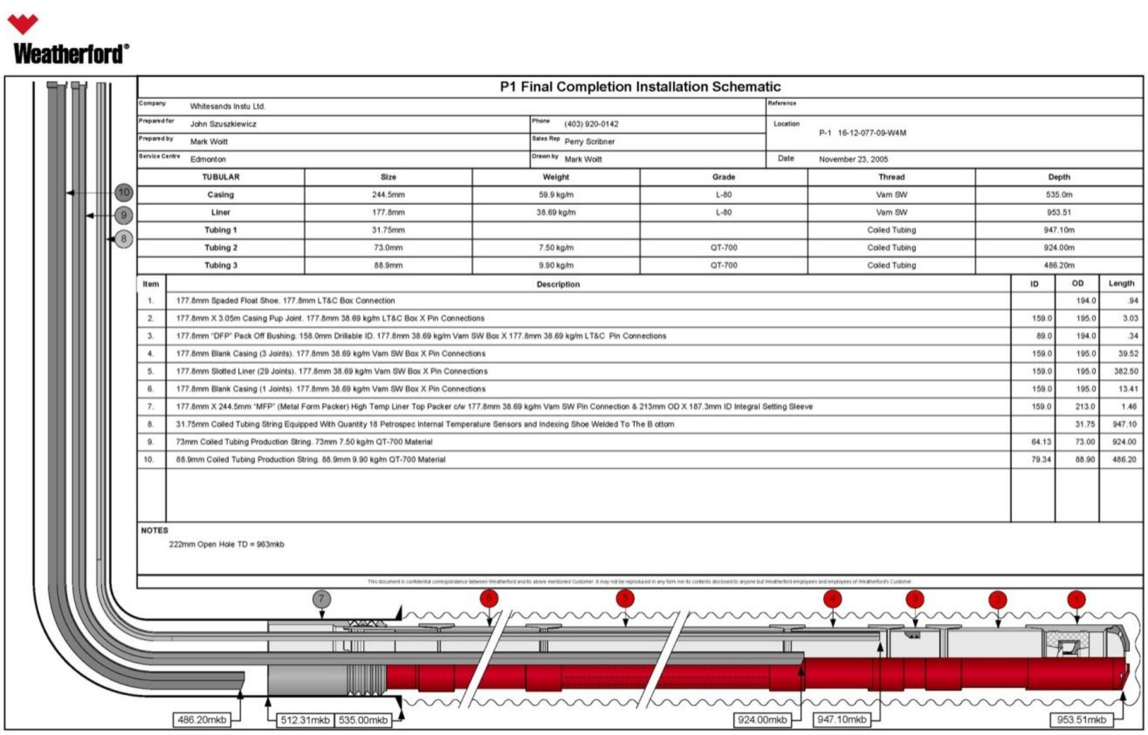
3.5.1 Production Wells

The original Production wells P1, P2 and P3 were all designed as shown in Figure 8. Features of the production wells are:

- 244.5 mm intermediate casing from surface to horizontal at bottom of zone.
- 144.5 mm slotted liner from heal to about 30 metres from the toe of the well.
- 144.5 mm blank liner for the last 30 metres at the toe of the well.
- 88.9 mm production tubing landed at the heel just above the liner top.
- 73.0 mm injection tubing to the toe of the well.
- 31.8 mm coiled tubing string to the toe of the well with 18 thermocouples spanning the horizontal interval.

The three tubing strings were run side by side. The injection string was used to heat the formation around the well prior to air injection. Also, until there was sufficient heat in the surrounding formation steam injection was necessary to keep the bitumen hot and flowing. It was also a means of introducing heat to maintain lift on steam.

The main operating problem with the horizontal wells has been sand production which has created erosion and handling problems at surface. The slots in the P wells were formed by cutting 0.559 mm slots and rolling them to create a surface lip of only 0.457 mm. We plan to use a smaller opening size on future wells.



P1 Final Completion Installation Schematic

Company	Whitesands Instu Ltd.	Reference	
Prepared for	John Szuszkiewicz	Phone	(403) 920-0142
Prepared by	Mark Woitt	Sales Rep	Perry Scribner
Service Centre	Edmonton	Drawn by	Mark Woitt
Location	P-1 16-12-077-09-W4M	Date	November 23, 2005

TUBULAR	Size	Weight	Grade	Thread	Depth
Casing	244.5mm	59.9 kg/m	L-80	Vam SW	535.0m
Liner	177.8mm	38.69 kg/m	L-80	Vam SW	953.51
Tubing 1	31.75mm			Coiled Tubing	947.10m
Tubing 2	73.0mm	7.50 kg/m	QT-700	Coiled Tubing	924.00m
Tubing 3	88.9mm	9.90 kg/m	QT-700	Coiled Tubing	486.20m

Item	Description	ID	OD	Length
1.	177.8mm Spaded Float Shoe. 177.8mm LT&C Box Connection		194.0	.94
2.	177.8mm X 3.05m Casing Pup Joint. 177.8mm 38.69 kg/m LT&C Box X Pin Connections	159.0	195.0	3.03
3.	177.8mm "DFP" Pack Off Bushing. 158.0mm Drillable ID. 177.8mm 38.69 kg/m Vam SW Box X 177.8mm 38.69 kg/m LT&C Pin Connections	89.0	194.0	.34
4.	177.8mm Blank Casing (3 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	39.52
5.	177.8mm Slotted Liner (29 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	382.50
6.	177.8mm Blank Casing (1 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	13.41
7.	177.8mm X 244.5mm "MFP" (Metal Form Packer) High Temp Liner Top Packer c/w 177.8mm 38.69 kg/m Vam SW Pin Connection & 213mm OD X 187.3mm ID Integral Setting Sleeve	159.0	213.0	1.46
8.	31.75mm Coiled Tubing String Equipped With Quantity 18 Petrospec Internal Temperature Sensors and Indexing Shoe Welded To The B ottom		31.75	947.10
9.	73mm Coiled Tubing Production String. 73mm 7.50 kg/m QT-700 Material	64.13	73.00	924.00
10.	88.9mm Coiled Tubing Production String. 88.9mm 9.90 kg/m QT-700 Material	79.34	88.90	486.20

NOTES

222mm Open Hole TD = 963mkb

Figure 8: Production Well Diagram – Typical

3.5.2 Injection Wells

Injection wells A1, A2 and A3 are all designed as shown in Figure 9. Features of the injection wells are:

- 177.8 mm casing into the top of the McMurray formation.
- 114.3 mm liner with a wire wrap screen straddling the top of the basal McMurray and the IHS and another at the base of the McMurray on depth with the horizontal production well.
- 60.3 mm inner tubing from surface to a pack-off at the top of the lower screen.
- 114.3 mm tubing to the top of the liner and packed off from the casing.

This arrangement allowed steam to be injected at the base of the well to develop communication through the cold bitumen to the horizontal well and allowed steam or air to be injected to the upper screen.

We have experienced loss of isolation between the outer tubing string and the casing annulus on A2 and A3. A workover on A-3 found a collapsed tubing. The well has been recompleted with only the upper string. We no longer have to steam the lower part to establish bitumen mobility and air injectivity is not impaired, so the tubing string to the lower screen is no longer required. The annulus has been fully displaced to nitrogen so that if we ever do use steam again pressure build-up in the annulus will be minimal.

At this time we do not intend to change the injector well design but would ensure that the casing annulus has been displaced to nitrogen and not left with a column of water.

3.5.3 Temperature Observation Wells

Prior to drilling the three well-pairs observation wells labeled OB-1 to OB-9 were drilled and cased. Each of these wells had a sensor suspended in place to aide with steering the horizontal well as it was drilled past. Then thermocouple strings consisting of 16 thermocouples spanning the McMurray and two above the McMurray were placed and the wells were filled with cement. The typical completion is shown in Figure 10.

Two additional wells were drilled at the toe of producer P2 on alternate sides of injector A2 after P2 and A2 were drilled. These wells were not cased. They were just cemented with the thermocouples in place.

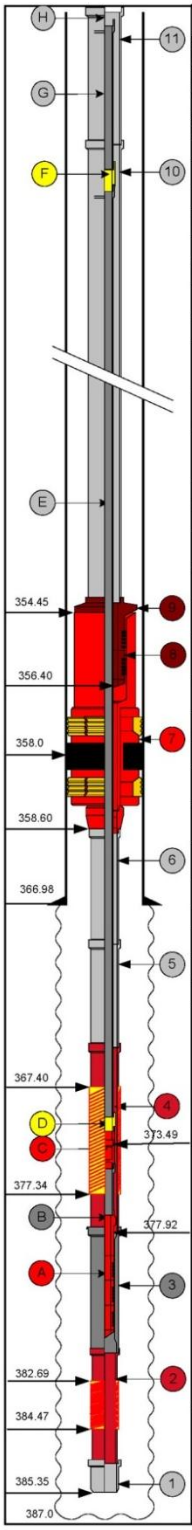
The thermocouples are read by a solar powered converter and transmitted by an RTU to the data acquisition system.

A typical observation well is shown in Figure 10.

3.5.4 Pressure Observation Well

The pressure observation well was drilled through the Wabasca and cased. However, it is open to the Clearwater and Wabasca, zones above the pilot zone, and does not monitor THAI™ pressures.

Weatherford®



Whitesands THAI A1 Injector Final Installation Report

Company	Whitesands Instu LTD	Reference	69766
Prepared for	John Szuszkiewicz	Phone	(403) 920-0142
Prepared by	Mark Woitt	Sales Rep	Perry Scribner
Service Centre	Edmonton	Drawn by	Laren Cruise
Location	Petrobank A1 Liesmer 16-12-77-9-W4	Date	Sept 19, 2006

TUBULAR	Size	Weight	Grade	Thread	Depth
Casing	177.8mm	38.68kg/m	L-80	Premium	366.98mKb
Liner	114.3mm	17.26kg/m	L-80	Vam Top	385.3mKb
Tubing 1	114.3mm	18.75kg/m	NKAC-80M	New NK3SB	
Tubing 2	60.3mm	6.84kg/m	L-80	Old NK3SB	

ITEM	DESCRIPTION	I.D.	O.D.	Length
	114.3mm Liner & Liner Packer			
1.	114.3mm Guide Shoe. 114.3mm 17.26 kg/m Vam Top Box		124.5	.25
2.	114.3mm X 2.0m DuraGrip Wire Wrap Screen With .006" Gauge. 114.3mm 17.26kg/m Vam Top Box X Pin, c/w Bottom .63m Blank Section and 1.42m Top Blank Section, L-80 Base Pipe Material, 825 Rib and Guage Wire	101.6	127.0	3.83
3.	68.27mm X 3.0m Polish Bore Receptacle. 114.3mm 17.26 kg/m Vam Top Pin X Pin c/w Coupling Connection, L-80 Material	68.27	124.5	3.35
4.	114.3mm X 10.0m DuraGrip Wire Wrap Screen With .006" Gauge. 114.3mm 17.26kg/m Vam Top Box X Pin, Bottom .58m Blank Section and 1.42m Top Blank Section, L-80 Base Pipe Material, 825 Rib and Guage Wire	101.6	127.0	11.94
5.	114.3 x 6.17m Pup Joint. 114.3mm 17.26 kg/m Vam Top Box X Pin	101.6	124.5	6.17
6.	114.3 x 1.21m Pup Joint. 114.3mm 17.26 kg/m Vam Top Box X Pin	101.6	124.5	1.21
7.	177.8mm UltraPak Permanent Packer c/w 120.6mm X 3.0m Upper Seal Bore & 101.6mm Lower Bore, PiPacker Thermal Element, 114.3mm 17.26kg/m Vam Top Pin Down, L-80 Material	101.6	148.7	4.15
	114.3mm Injection Tubing			
8.	120.6mm Single Piece (Integral) Seal Assembly w/ 3 Sets Thermal Optivee Seals, **2.71m Effective Stroke**, 114.3mm 17.26 kg/m Vam Top Pin Up Connection, L-80 Material	95.25	120.6	3.59
9.	120.6mm Seal Assembly Locator Sub. 114.3mm 17.26 kg/m Vam Top Box X 114.3mm 18.75kg/m New NK3SB Box, L-80 Material	100.3	143.5	.33
10.	36 Joints of 114.3 Tubing To Surface. 114.3mm 18.75 kg/m New NK3SB Box X Pin NKAC-80M Material	100.53	132.0	346.72
11.	114.3 X .51m Pup Joint. 114.3mm 18.75 kg/m New NK3SB Box X Pin L-80 Material	100.53	132.0	.51
	60.3mm Injection Tubing			
A.	68.27mm X 3.0m Single Piece Locator Seal Assembly c/w 3 Sets Thermal Optivee Seals & 60.3mm 6.84kg/m Old NK3SB Box Up X Half Mule Shoe Down. **2.68m Effective Stroke**, L-80 Material	47.63	79.50	3.30
B.	60.3mm X 2.46m Pup Joint, 60.3mm 6.84 kg/m Old NK3SB Box X Pin Connections. L-80 Material	49.40	73	2.46
C.	60.3mm "NCN" Landing Nipple c/w 47.63mm "XN" Profile & 45.49mm No-Go. 60.3mm 6.84 kg/m Old NK3SB Box X Pin. L-80 Material	45.49	77.70	.35
D.	60.3mm 6.84kg/m NK3SB Pin x 60.3mm 6.84kg/m NS-CT Box Crossover Sub, L-80 Material	49.00	73.0	.61
E.	39 Joints of 60.3mm 6.84kg/m NS-CT Tubing, L-80 Material	49.00	73.0	364.44
F.	60.3mm 6.84kg/m NS-CT Pin to 60.3mm 6.84kg/m Old NK3SB Box Crossover, L-80 Material	49.00	73.0	.44
G.	60.3mm X 2.48m Pup Joint, 60.3mm 6.84kg/m Old NK3SB Box X Pin Connections, L-80 Material	49.00	73.0	2.48
H.	60.3mm X 114.3mm Old NK3SB Tubing Hanger	49.00	120.0	.27

NOTES

The 114.3mm tubing string was landed with the seal assembly 1.60m from shouldering out on the packer to accommodate tubing length change associated to Delta T

The 60.3mm tubing string was landed with the seal assembly 1.86m from shouldering out on the packer to accommodate tubing length change associated to Delta T

Figure 9: Injection Well Diagram – Typical

Consultant: Kim Bazant   Tel1: (403) 969-3637   Tel2:

UWI: 100/15-12-077-09W4/00					DATE:	2005.11.03
WELL: PETROBANK OB4 LEISMER					AFE #:	9058027C
ELEVATIONS (m)		CASING / TUBING	Size (mm)	Weight(kg/m)	Grade	Depth(mKB)
KB:	615.53	Surface Casing	177.80	25.30		98.24
Ground:	611.30	Intermediate Casing				
TD:		Production Casing	114.30	14.14		433.56
KB to GL:	4.23	Production Liner				
KB to CBF:	3.80	Tie Back Casing				
KB to THF:	3.80	Tubing	38.10	2.41		415.30
PBTD:	433.56	Open Hole				

TUBING Type/Class: Coiled 38.1mm   Make: Quality /Varco   Zone: Mcmurry

TUBING String Description: Tubing Number 1 Tally

No	Qty	Name	Comment	Length	TopOf(mKB)
1	1	Coil Tubing Centralizer	w/ 8 fins and 38.1mm Lenze Loc	3.14	415.96
2	1	HS 80 Coiled Tubing String	W/ 18 Thermocoupler & lines banded to side	411.86	4.10
3	1	Casing bowel & bonnet	179.4mm 21 Mpa (7 1/16" 2K) R45 x 60.3mm	0.30	3.80

Weight or Tension on String	Packer	daN	Total String Weight	daN	String Length	415.30	m
	Tubing	daN	Str or Slackoff -/+	daN	Correction +/-	.00	m
	Hanger	daN	Landed String Wt.	daN	Adjusted Length	415.30	m

From C.F. - K.B. to C.F. 3.80 m   Wireline +/- .00 m   Depth from KB 419.10 mKB

Directions to Site:

Remarks:
38.1mm OD CT string landed w/ 9 type K duplex MI insulated wires w/ 18 sensor points banded to exterior of 38.1mm CT
First sensor landed @ 412 mkb
CT / instrument string cemented off to surface w/ thermal 40 cement w/ .5% of CFR

Figure 10: Temperature Observation Well Diagram – Typical

3.6 SPACING AND PATTERN

The original pattern consisted of 3 horizontal production wells that were spaced 100 metres apart with vertical injection wells at the toes. Producers P1 and P2 and injectors A1, A2 and A3 all remained in use. The overall current well layout is shown in Figure 7. The project consisted of three well pairs, each consisting of a vertical injection well and a horizontal production well. However, P3 has been suspended. The project has a water source well, water disposal wells, and several temperature observation wells.

The wells which make up the project are listed in Table 2.

4. PRODUCTION PERFORMANCE AND DATA FOR 2009

4.1 INJECTION AND PRODUCTION HISTORY ON AN INDIVIDUAL WELL AND COMPOSITE BASIS

The following tables show the injection and production histories of the wells for 2009.

Table 3: Well and Composite Air Injection

	A1 (10^3m^3)	**A2** (10^3m^3)	**A3** (10^3m^3)	**Composite** (10^3m^3)
Jan-09	1,660.65	1,494.02	N/A	3,154.67
Feb-09	1,598.14	1,435.49	N/A	3,033.63
Mar-09	1,989.40	1,687.68	N/A	3,677.08
Apr-09	364.29	1,511.03	N/A	1,875.32
May-09	N/A	1,699.14	N/A	1,699.14
Jun-09	N/A	1,738.99	N/A	1,738.99
Jul-09	N/A	1,373.93	N/A	1,373.93
Aug-09	N/A	N/A	N/A	N/A
Sep-09	N/A	N/A	N/A	N/A
Oct-09	N/A	N/A	N/A	N/A
Nov-09	N/A	N/A	N/A	N/A
Dec-09	N/A	N/A	N/A	N/A
2008 Total	5,612.48	10,940.19	N/A	16,552.76

In 2008 the producer, P3, was suspended and a parallel well that includes another technology was drilled. Air injection following suspension of P3 has been excluded and so is marked N/A in the table. There was no steam injection to the A wells there after.

Table 4: P1 Production and Injection History - 2009

	Produced Oil (m^3)	**Produced Gas** (10^3m^3)	**Produced Water** (m^3)	**Injected Steam** (m^3)
Jan-09	282.5	2,011.7	1,839.5	0.0
Feb-09	219.0	2,049.3	4,334.6	0.0
Mar-09	73.7	1,926.2	1,374.8	0.0
Apr-09	2.0	0.0	0.0	0.0
May-09	N/A	N/A	N/A	0.0
Jun-09	N/A	N/A	N/A	0.0
Jul-09	N/A	N/A	N/A	0.0
Aug-09	N/A	N/A	N/A	0.0
Sep-09	N/A	N/A	N/A	0.0
Oct-09	N/A	N/A	N/A	0.0
Nov-09	N/A	N/A	N/A	0.0
Dec-09	N/A	N/A	N/A	0.0
2009 Total	**577.2**	**5,987.2**	**7,548.9**	**0.0**

Table 5: P2 Production and Injection History - 2009

	Produced Oil (m^3)	Produced Gas (10^3m^3)	Produced Water (m^3)	Injected Steam (m^3)
Jan-09	271.1	1,780.1	2,252.3	0.0
Feb-09	399.3	1,625.5	2,490.4	0.0
Mar-09	226.4	1,895.9	961.7	0.0
Apr-09	302.1	1,952.9	921.5	0.0
May-09	221.3	2,136.5	1238	0.0
Jun-09	224.6	2,105.2	1,020.3	0.0
Jul-09	197.2	852.3	1,647.9	0.0
Aug-09	N/A	N/A	N/A	0.0
Sep-09	N/A	N/A	N/A	0.0
Oct-09	N/A	N/A	N/A	0.0
Nov-09	N/A	N/A	N/A	0.0
Dec-09	N/A	N/A	N/A	0.0
2009 Total	**1,842.0**	**12,348.4**	**10,532.1**	0.0

Operations on P3 were suspended in April 2008.

Table 6: Composite Production and Injection - 2009

	Produced Oil (m^3)	Produced Gas (10^3m^3)	Produced Water (m^3)	Injected Steam (m^3)	Injected Air (10^3m^3)
Jan-09	553.6	3,791.8	4,091.8	0.0	3,154.67
Feb-09	618.3	3,674.8	6,825.0	0.0	3,033.63
Mar-09	300.1	3,822.0	2,336.5	0.0	3,677.08
Apr-09	304.1	1,952.9	921.5	0.0	1,875.32
May-09	221.3	2,136.5	1,238.0	0.0	1,699.14
Jun-09	224.6	2,105.2	1,020.3	0.0	1,738.99
Jul-09	197.2	852.3	1,647.9	0.0	1,373.93
Aug-09	N/A	N/A	N/A	0.0	N/A
Sep-09	N/A	N/A	N/A	0.0	N/A
Oct-09	N/A	N/A	N/A	0.0	N/A
Nov-09	N/A	N/A	N/A	0.0	N/A
Dec-09	N/A	N/A	N/A	0.0	N/A
2009 Total	**2,419.2**	**18,335.6**	**18,081.0**	**0.0**	**16,552.76**

4.2 COMPOSITION OF PRODUCED / INJECTED FLUIDS

This information is provided in Appendix 1.

4.3 COMPARISON OF PREDICTED VS. ACTUAL WELL / PILOT PERFORMANCE AND A DISCUSSION REGARDING THE DIFFERENCE

Initial pilot performance predictions were based on numerical simulation modeling and physical 3-D tests conducted at the lab. However as more project data becomes available more simulation work related to history matching will be undertaken

The following describes the main features of the predictive numerical modeling work done prior to the Pilot design and start up:

4.3.1 Numerical Simulation Input Data

Since at the time, reservoir parameters from Whitesands were not available, the reservoir parameters of the nearby Kirby Lake (KL) McMurray sands, provided by Rio Alto in their public EUB SAGD pilot application, were chosen for the model (Table 7).

Project site indicated the absence of bottom water, so bottom water was not included in the numerical simulations.

Table 7: Parameters Used in Simulation

Simulator	STARS 2003.1
Components (9)	Water, bitumen, upgrade, methane, CO_2, CO, N_2, O_2 and Coke
Grid size (m)	2.5 x 2.5 x 1.0
Number of grids	40,000 in element of symmetry (Design Model)
Wells	1-vertical steam injector for communication pre-heating and air injection, 1-discretized horizontal well with tubing for well pre-heating
Heterogeneity	Homogeneous
Permeability	6.4 D (h), 3.4 D (v) (KL)
Porosity	33% (KL)
Oil viscosity (bitumen)	340,900 cP @ 10 °C (KL)
Temperature	20 °C (Whitesand's log)
Reservoir pressure	2,600 kPa (KL)

'KL' denotes the values were obtained from the nearby Kirby Lake Project.

As more project data becomes available simulation work related to history matching and further fine tuning of the model will be undertaken

4.3.2 Simulation Model Description

The model used a 500 m horizontal well (with 50-percent perforated liner of diameter 177.8 mm) spaced 100 m apart. The start-up procedure in the model entailed steam injection over a 3-month period. Steam needed for pre-heating, was injected into the 4- central grid blocks of the vertical well (left edge of Figure 11) and into the horizontal well under partial recycle. Upon switching to air injection into the top 4-grid blocks, ignition occurred and the process was underway. The toe of the horizontal well was offset from the vertical injector well by 15 m.

In Figure 11, a 2-dimensional vertical slice is shown that cuts through the horizontal well. The 'quasi-vertical' displacement front is clearly shown and the peak temperature is 755 °C, indicating high temperature oxidation reactions. The light green area, where there remains only air, is at an average temperature of 267 °C and the dark blue area ranges from 33 °C to 67 °C.

Figure 12 shows the phase distribution (oil, water, gas) and the oil flux above the horizontal well. The red area is 100 percent gas and behind the front the gas is air. The green area on the lower left contains some coke and the remainder is 95–100 percent oil.

The green area on the right, ahead of the combustion front is 70 percent oil, 18 percent water and 12 percent combustion gas: the missing 10 percent oil having already drained into the horizontal well. Dark blue represents a water rich region 29 percent oil, 45 percent water and 26 percent combustion gas. The high water saturation derives from connate water that flashed in the combustion zone and condensed in the cooler oil ahead. Light blue represents a phase composition: 58 percent oil, 31 percent water and 11 percent combustion gas. The oil flux vectors indicate that substantial oil production comes from oil draining from the inter-well region. There are three regions of oil drainage: from the sides behind the combustion front, from just ahead of the front and from the warmed region ahead of the front. The process is highly productive because some oil drainage occurs all along the horizontal well. With a 100 m well spacing, the reservoir sweep is 45 percent and with a 50 m well spacing it is 62 percent. However, because most of the remaining oil will be substantially recovered in the next phase of field development, a recovery factor over 80 percent is expected.

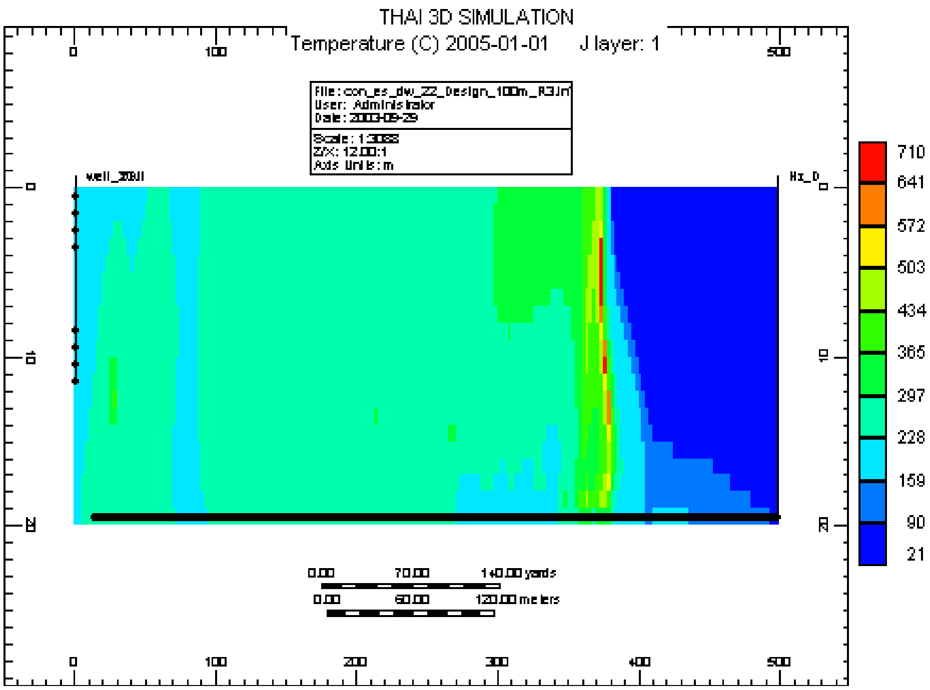


Figure 11: Design Model Numerical Simulation, Temperature

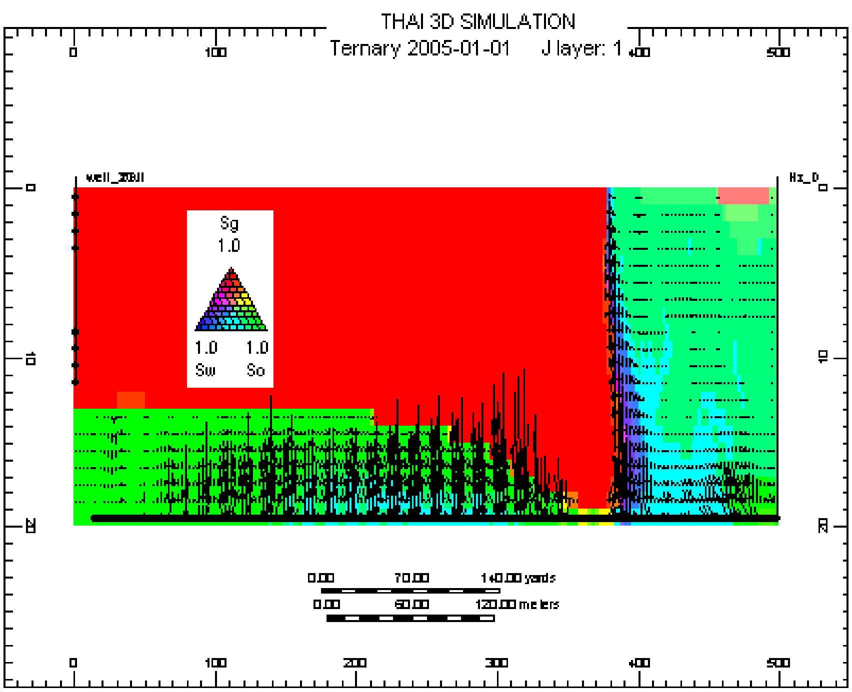


Figure 12: Design Model Numerical Simulation, Ternary Phase Distribution

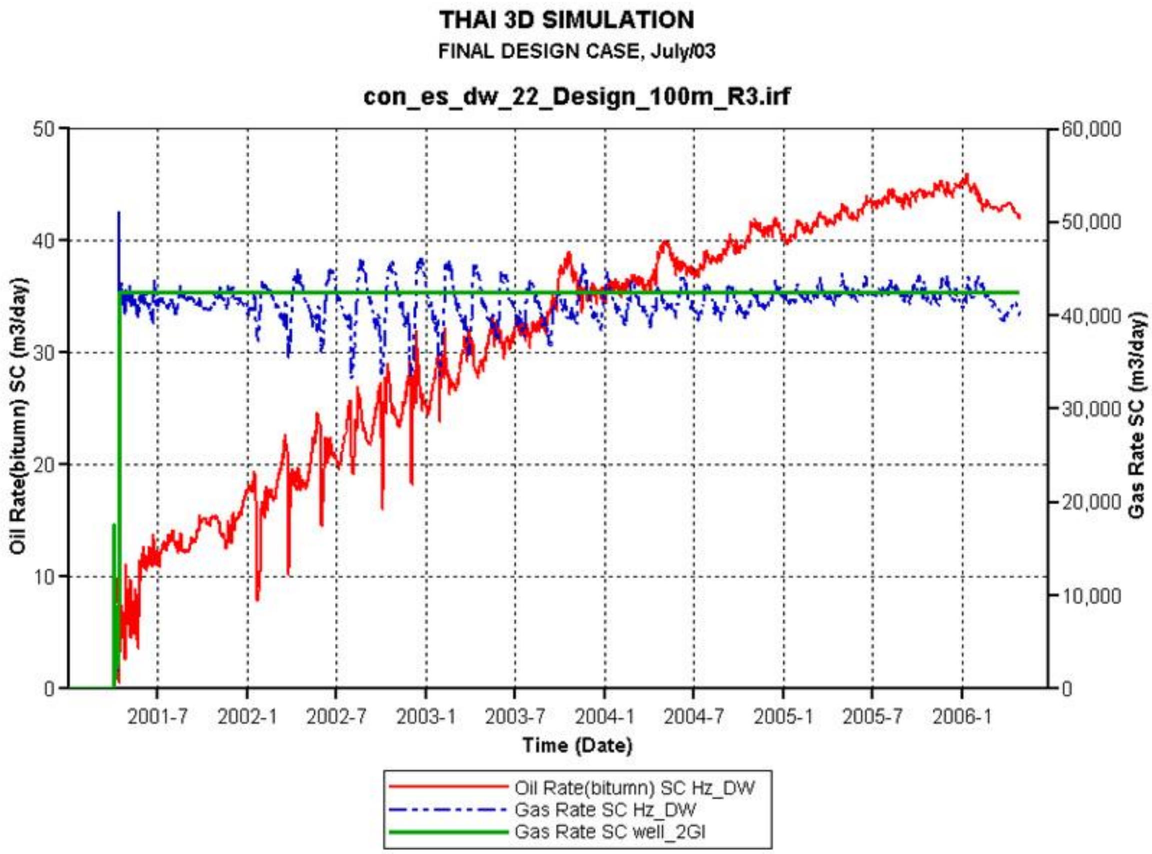


Figure 13: Design Model Oil and Gas Rates

Note: The oil and gas production rates shown must be doubled to represent a full –well production.

4.3.3 Discussion of Actual vs Predicted Well Performance.

The STARS numerical field-scale simulations replicated the THAI™ performance in the 3-D cell model with respect to thermal contours and a stable vertical displacement front. As shown in Figure 13, oil production started at 20 m³/d/well and increased monotonically to 90 m³/d/well over the 5-year period required for the combustion front to arrive at the well heel. Frontal advance rate averaged 0.28 m/d. Figure 2-6 also shows the gas production and air injection rate to be approximately equal. Note that all production values in Figure 2-6 must be doubled to represent a full-well section because the “element of symmetry” feature was used in the simulation to save computation time.

A comparison of actual and simulated production of oil, gas and water is listed in a table form in section 2.3 of this report while the actual temperatures measured in the pilot are listed in sections 5.1. The variations in the actual and observed values in can primarily be attributed to the following main factors:

- Due to the lack of detailed reservoir information at the time of initial simulation runs (only 3 stratigraphic wells were drilled prior to the Pilot), the simulation model used a homogenous pay thickness of 20 m without bottom water whereas the actual drilling revealed that the pay zone comprised of 10 m of interbedded sand/shale over 10m oil overlying 1.5 m of bottom water. The reduction in the net good pay available for oil production in combination with higher than expected in situ bitumen viscosities resulted in variation in the expected and actual field production rates. Use of more representative reservoir data now available, can result in predicting a more reliable well performance. An updated report on the geology including core logs and stratigraphic logs available as the year end 2009 is included under the geology section 5.1.1

- The other factor that resulted in actual vs predicted is because of reduced on-stream time for the production wells due to unexpectedly higher sand production experienced in the earlier phases of the pilot.
- Presence of high temperature combustion along with in situ upgrading of bitumen was predicted both in the simulation modeling and the physical reactor testing in the lab. The gas analyses as well the temperature monitoring from the pilot confirms this.

4.4 HISTORY OF INJECTION, PRODUCTION AND OBSERVATION WELL PRESSURES, AND AVERAGE RESERVOIR PRESSURE

The monthly average injection well pressures for 2009 are given in Table 8. The long string is associated with the lower screen in the well and the short string is associated with the upper string (Figure 9). The casings were isolated from the reservoir by packers.

In June 2008 A2 was converted to a single string completion so the long string pressures no longer applied. Similarly, A3 was converted to a single string in November. The separate string to the lower interval was only desirable for selectively steaming that interval during start-up. It was expected that the well would be damaged by combustion temperatures after the well was put on air injection but that this would not matter as long as injectivity to the upper interval was maintained and isolation at the base of the cap rock remained competent.

Table 8: Monthly Injection Well Pressures (kPa)

	A1		A2		A3	
Month	**Long**	**Short**	**Long**	**Short**	**Long**	**Short**
Jan-09	2,934	3,266	3,285	3,326	N/A	N/A
Feb-09	2,761	2,845	3,023	3,096	N/A	N/A
Mar-09	3,092	3,324	3,318	3,384	N/A	N/A
Apr-09	N/A	N/A	3,210	3,124	N/A	N/A
May-09	N/A	N/A	3,358	3,384	N/A	N/A
Jun-09	N/A	N/A	3,073	3,088	N/A	N/A
Jul-09	N/A	N/A	2,673	2,781	N/A	N/A
Aug-09	N/A	N/A	N/A	N/A	N/A	N/A
Sep-09	N/A	N/A	N/A	N/A	N/A	N/A
Oct-09	N/A	N/A	N/A	N/A	N/A	N/A
Nov-09	N/A	N/A	N/A	N/A	N/A	N/A
Dec-09	N/A	N/A	N/A	N/A	N/A	N/A

The monthly average production well pressures for 2008 are given in Table 9. The long string is an injection string that goes to the toe of the well and the short string is the production string landed at the heel of the well (Figure 8). These strings normally show flowing pressure. However, when no steam is injected into the long string there can be a column of condensed water in that string.

The casings were not isolated in the production wells. When the well is shut in the casing can have a small column of condensed fluid. During a workover it would have a high column of kill fluid. However, while the well is flowing the casing is a static column that displaces to produced gas. Consequently the casing pressure gives a good indication of flowing bottom-hole pressure since the gas column head would be a small value on the order of 50 to 100 kPa.

In April P3 was shut in and the tubing strings were pulled for inspection and for an effort to log the liner. The well was filled with kill fluid for the workover and, afterward, the casing was left displaced to nitrogen.

Table 9: Production Well Pressures (kPa)

	P1			P2			P3		
Month	**Long**	**Short**	**Casing**	**Long**	**Short**	**Casing**	**Long**	**Short**	**Casing**
Jan-09	1,384	1,615	2,205	1,903	1,492	1,805	N/A	N/A	N/A
Feb-09	689	1,393	2,129	1,784	1,348	1,843	N/A	N/A	N/A
Mar-09	827	1,747	2,303	1,945	1,400	2,189	N/A	N/A	N/A
Apr-09	N/A	N/A	N/A	1,938	1,235	2,140	N/A	N/A	N/A
May-09	N/A	N/A	N/A	2,003	1,152	2,173	N/A	N/A	N/A
Jun-09	N/A	N/A	N/A	1,962	1,107	2,110	N/A	N/A	N/A
Jul-09	N/A	N/A	N/A	1,443	1,156	2,078	N/A	N/A	N/A
Aug-09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sep-09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Oct-09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nov-09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Dec-09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

There is no observation well that is perforated in the reservoir so there is no direct observation of reservoir pressures.

5. PILOT DATA

5.1 ACTIVITIES IN ADDITION TO THE PRODUCTION AND PERFORMANCE DATA

In addition to the production and performance data (Section 4) the following activities in different categories were conducted.

5.1.1 Geology and Geophysics

During December 2008 to January 2009, we shot 4-D seismic in the pilot project area to monitor the THAI™ process. The seismic interpretation is very consistent with the expected reservoir change in petrophysical characteristics due to temperature, pressure and fluids changes. The seismic interpretation is also supported by the temperature observation wells. This is addressed in section 5.1.1.3.4. The basic geological information provided along with last year's report remains unchanged inside the Pilot project as the only well drilled is the horizontal well P3B replacing P3. On the lease outside of the Pilot project, six oil sands evaluation wells were drilled in 2008 to confirm resources for the commercial May River Phase 1 project. The results generally meet geological expectations in terms of oil sands distribution and quality.

1n 2009, P1B and P2B horizontal wells were drilled to replace P1 well and P2 well, respectively. These two wells indicate similar geological characteristics to the P1 and P2 wells. No other geologic data were acquired in 2009. Therefore, the geological interpretation and mapping remain unchanged.

5.1.1.1 Resource Description

Whitesands currently holds 73 sections of land under oil sands lease agreements in the Conklin area of north eastern Alberta. The site of the planned Project in Section 12, Twp 77, Rge 9, and Section 7, Twp 77, Rge 8, W4M is held under Oil Sands Agreement 7400010012 (Lease 012), which expires in 2015-01-13. The P&NG rights in Section 7 are held by BP Canada. In Section 12, where the Project's producing zone in the McMurray Formation is located, BP Canada holds the natural gas rights in the Clearwater Formation.

In 2008, six evaluation wells were drilled more than 1 mile away northward from the Pilot project. On average, the oil sands sections are about 5m thicker than that in the Pilot project area.

In 2003 and 2006 Whitesands conducted 2 3-D seismic programs of an approximate 39 km^2 area on the Whitesands Lease. One 3-D survey encompassed the Project site (see Figure 14 and Figure 25). The objectives of the 3D programs were to evaluate bitumen resource to identify a Project location with acceptable reservoir characteristics that was a suitable development site within reasonable proximity to existing infrastructure.

5.1.1.2 Regional Geology

The bitumen resource target for the Project is the McMurray Formation, the basal unit of the Lower Cretaceous Mannville Group. The McMurray Formation contains significant bitumen reserves which constitute the Athabasca oil sands deposit of north eastern Alberta.

The Mannville Group is composed of very weakly consolidated to unconsolidated clastic sedimentary rocks that rest unconformably on the carbonates of the Devonian Beaverhill Lake Group (see Figure 15). In northeastern Alberta, the Mannville Group is divided into three formations (from oldest to youngest): the McMurray, the Clearwater, and the Grand Rapids. The Mannville Group is overlain by Cretaceous Colorado Shale that is truncated by Quaternary glacial deposits. (see Figure 15).

5.1.1.2.1 Geology of the McMurray Formation – Production Zone

The Whitesands Lease is situated in the south-eastern corner of the Athabasca Oil Sands Area. On the lease, bitumen accumulations are found within clastic sediments of the McMurray Formation of the Lower Cretaceous Mannville Group. The Whitesands Lease is located directly west of the main channel system of the Lower-Middle McMurray. Two main channels within the McMurray succession are present on the lease and it is within these channels that THAI™ reservoir is confined. Outside of these two channels, much of the lease hosts non-reservoir estuarine embayment sediments. Future delineation drilling and interpretation may reveal further local channel development with THAI™ potential. Throughout the lease and surrounding area, the McMurray has been subdivided into lower, middle and upper units, consistent with McMurray interpretation elsewhere in north-eastern Alberta.

There are very few preserved occurrences of the Lower McMurray in the lease area. Where present, the Lower McMurray consists of thin and often wet, fine- to coarse-grained subarkosic sands, typically with interbedded shales. These sediments were deposited unconformably on eroded argillaceous carbonates and calcareous shales of the Waterways Formation of the Devonian Beaverhill Lake Group. Limited exploitable reservoir is noted within this unit. During Lower McMurray time, base level in the lease area was mostly above that of the main channelling taking place to the east. The result of this was a paucity of Lower McMurray fluvial channel development or Lower McMurray deposition in the area.

The Middle McMurray hosts the richest accumulations of bitumen within the McMurray succession on the Whitesands lease. Middle McMurray time was marked by development of two main estuarine channels that cut across the lease, with one directed southwest-northeast and the other southeast-northwest. These channels are of variable width, but generally average more than 1.6 km in cross-sectional area. Within these channels, the Middle McMurray is dominated by estuarine channel deposits consisting of highly permeable subarkosic sands with good vertical, and more limited lateral continuity, interbedded with sandy and muddy lateral accretion beds, mudstone clast material and cross-bedded tidal flat deposits. Good sediment supply and a lower base level during Middle McMurray time permitted multiple channelling events, channel stacking, and reworking of older deposits, resulting in reservoir units tens of metres in thickness.

Often within the upper portion of the Middle McMurray, and within the regional sequences outside of the channel areas, estuarine bayfill deposits, generally sourced from migrating distributary channels within a prograding delta are found. These deposits consist of very fine- to medium-grained sands, with both muddy and silty drapes and interbeds, demonstrating a strong tidal influence. On well logs, these deposits have a coarsening-upwards character. Clean sand intervals within these embayment sediments are generally thin, limiting development potential to instances where they are in direct communication with estuarine channel deposits of the Middle McMurray unit.

The upper McMurray is typically separated from the Middle McMurray by a thin regional shale horizon—McMurray A Shale. The Upper McMurray is dominated by estuarine bayfill deposits. These are characterized by very fine- to medium-grained, often cross-bedded sands, with both muddy and silty drapes and interbeds. On well logs, these sequences have a coursing-upwards character and closely resemble similar sequences within the Middle McMurray, previously described.

5.1.1.2.2 Clearwater Formation

The Clearwater Formation is made up of two sand-shale sequences in the Project area, described below:

5.1.1.2.2.1 Wabiskaw C Sand

The lowermost part of the Clearwater Formation is made up of the Wabiskaw C Sand, which directly and sharply overlies the McMurray Formation. This interval, typically around 3m thick, consists of marine silty sands. The contact between Wabiskaw C Sand and upper McMurray is usually sharp due to the lithology and fluid difference within these units.

5.1.1.2.2.2 Lower Clearwater Shale

Overlying the Wabiskaw C Sand is a shale sequence that is about 20 m thick forming the major cap rock between the Clearwater Sandstone Member above and the Wabiskaw–McMurray below. It includes the five-metre thick Wabiskaw Marker, a regionally correlatable bentonite bed. Over a five-metre interval, this shale sequence quickly grades into the overlying Clearwater Sandstone.

5.1.1.2.2.3 Clearwater Sandstone

The Clearwater Sandstone is a very uniform, 30 to 40 m thick marine shoreface complex that hosts a significant, structurally-controlled gas but now essentially depleted accumulation, which extends into the northeastern-most part of the Whitesands lease holdings.

5.1.1.2.2.4 Upper Clearwater Shale

The Clearwater Sandstone is sharply overlain by a series of interbedded shales and cleaning-upward sandy siltstone packages that total 22 to 36 m in thicknesses. This is the seal for the Clearwater Sandstone gas pool.

The top of the Clearwater Formation has a short, transitional contact with the base of the Grand Rapids Formation.

5.1.1.2.3 Grand Rapids Formation

The Grand Rapids Formation can be divided into an upper and lower member:

The Lower Grand Rapids Member is a 30 to 40 m thick upward-coarsening sandstone, which is water wet throughout the area.

The Upper Grand Rapids member consists of 38 to 60 m of up to four stacked coarsening-upwards sand cycles separated by impermeable, thin marine shales. Minor gas is sometimes trapped in combined structural-stratigraphic traps in the upper cycles in the regional study area.

5.1.1.2.4 Colorado Group

Tight marine shales of the Cretaceous Colorado Group overlie the Grand Rapids Formation. The Colorado Group is truncated at the unconformable contact with the unconsolidated Quaternary glacial drift. Preserved Colorado Group thickness varies from as little as 3 m to more than 80 m in the study area. In the vicinity of the proposed Project, 40 to 60 m of Colorado section is expected. The Colorado Group Shale forms an effective seal between the brackish water- and hydrocarbon-charged Cretaceous sediments below and the freshwater-bearing glacial sediments above.

5.1.1.2.5 Quaternary – Water Source Horizon

The surficial glacial drift is made up of gravel, sand, silt and mud. It is the freshwater aquifers of the Quaternary glacial drift that are used as fresh water source for the Project.

5.1.1.3 Project Site Geology

The Project site is in Section 12 Twp 77 Rge 9W4M (see Figure 14). In this section, there are 3 horizontal wells and 19 vertical wells which have penetrated the McMurray Formation. Among them, 9 wells were cored. All the 19 vertical wells are accompanied by standard open hole logs, 7 of which with HMI (High Resolution Micro Imager) logs.

5.1.1.3.1 Typical Composite Well Log and Cross Section

The OB7 well logs show the common stratigraphic units in the project site area (see Figure 16 and Figure 17). From the bottom to the top, these units are Devonian limestone, McMurray C (Lower McMurray), McMurray B (Middle McMurray), McMurray A (Upper McMurray), Wabiskaw C Sand, and Lower Clearwater Shale including the Wabiskaw Marker. The contacts between each unit are distinctive. The top of the Devonian limestone shows a significant increase on the density porosity log. The contact between McMurray C and McMurray B can be identified from the Gamma Ray log or Density Porosity log due to the sudden lithological change from McMurray C Shale to McMurray B basal sand. A 2~3 meter water zone at the bottom of McMurray B can be identified from the resistivity logs with the help of the Gamma Ray log. The top of McMurray B is identified by the regional correlation marker—McMurray A Shale, which shows a distinctive high Gamma API value. A thin gas zone (<1 m) is interpreted from the Neutron-Density log crossover. The boundary between McMurray A and Wabiskaw C sand is picked at the step shown on both Gamma Ray and

Resistivity logs. The top of Wabiskaw C Sand is identified from both Gamma Ray and Resistivity logs due to the sudden lithological change from Wabiskaw C Sand to the Lower Clearwater Shale. The Lower Clearwater Shale is a regional stratigraphic marker due to its significant thickness, distinctive log characteristics, and widely areal distribution.

Figure 18 shows the correlation for the stratigraphic units between wire line logs and cores. Although generally speaking, lithology and fluids saturation can be well interpreted from logs, cores are very useful to confirm the log interpretation and especially for identifying mud clast breccias.

The stratigraphic units shown on the OB7 well logs are generally correlatable in the project site area Figure 19 and Figure 16). The McMurray C varies in thickness depending on the topography of the Devonian unconformity and the McMurray B channel scouring. Where the McMurray B channel cuts deeper (See OB3 in Figure 19), the McMurray C is relatively thinner. Correspondingly, the McMurray B is thicker with relatively thicker bottom water zone. Internally, the McMurray B shows a typical channel characteristic becoming shalier upwards. It's characterized by a sand-dominated interval at the base, a sand-shale interbedded interval in the middle, and a shale-dominated interval at the top. The McMurray A is uniform in thickness and lithology with a total thickness of about 8m including the 2 meters McMurray A Shale at the bottom and 6 meters sand on the top. A very thin gas zone is present locally. Overlying the McMurray A, the Wabiskaw C Sand is about 3m in thickness uniformly. The Lower Clearwater Shale, which is a regional cap rock for the Wabiskaw C and McMurray Formation, is about 20m in thickness in the entire project area.

5.1.1.3.2 Isopach Maps of the Zones of Interest

For the THAI™ process, the zones of interest include the McMurray B, McMurray A, Wabiskaw C Sand, and the Lower Clearwater Shale as the cap rock. As the thicknesses and lithology of McMurray A, Wabiskaw C Sand, and the Lower Clearwater Shale are very uniform in this area, it's unnecessary to generate isopach maps for them. As a result, only the following isopach maps are generated: McMurray B total thickness, McMurray B total net bitumen sand, McMurray B basal bitumen sand, McMurray B bottom water sand, and gas pay in the McMurray A or Wabiskaw C Sand.

McMurray B thickness ranges between 32m and 39m in the project area (See Figure 20). The general NW-SE contour trend is interpreted to be consistent with the regional main channel direction. Areas with relatively thick McMurray B correspond to the channel thalweg. For example, on the cross section in Figure 19, the OB3 well is interpreted to intersect the channel thalweg while the OB1 well is relatively closer to the south western channel edge.

McMurray B net bitumen is defined by using a 27% porosity cut off and 20 Ωm. resistivity cut off in the McMurray B succession without requiring the continuity of the bitumen. Therefore, the bitumen in both the interbedded sand-shale interval and basal sand interval is included. The net pay ranges between 13m and 20m in the area (See Figure 21).

As recovery of bitumen in the interbedded sand-shale interval will be strongly affected by the shale layers, distribution of the bitumen in the basal clean sand is considered to be a key factor to determine the horizontal well locations. From the Isopach map (See Figure 22), the good quality bitumen pay zone is about 10m, much less than the initial number used in the simulation model (20m).

Bottom water is another factor which has effect on the THAI™ process. In this area, bottom water zone is up to 4m in thickness (See Figure 23).

A very thin gas zone is locally present in the McMurray A or Wabiskaw C Sand. The gas zone is usually less than 1 meter in thickness (See Figure 24).

5.1.1.3.3 Water Disposal Zones

Whitesands proposes to dispose of water produced from the Project into the bottom water sandstone of the McMurray Formation.

The water sand of the McMurray Formation is up to 4m intersected by the well AA/12-07-077-08W4 in this area. The permeability of the sand is 6,610 mD. The porosity is 34% and water saturation is 93.4%.

5.1.1.3.4 Seismic

2003 and 2005 surveys were prestack merged, reprocessed and interpolated from 20X15m bins down to 5X5m bins.

New high resolution 3D-3C seismic at 5X5m bins is to be used for reservoir monitoring (4D) and reservoir characterization. Surveys acquired in the winters of 2008 and 2009.

So far we have the baseline (2003) and two monitor surveys (2008 and 2009).

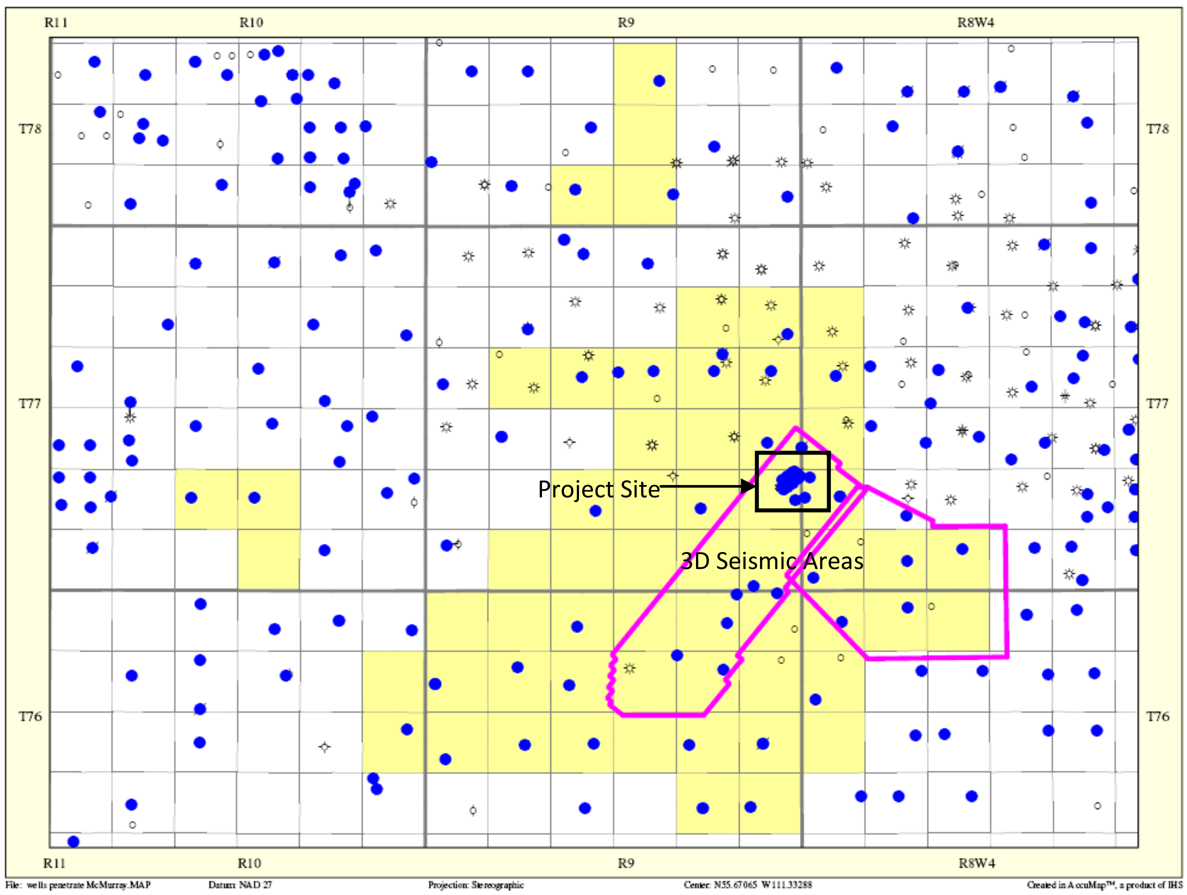


Figure 14: Well Control and 3D Seismic Areas

Note:
1. Whitesands lease in yellow
2. Wells in solid blue penetrated McMurrayFormation

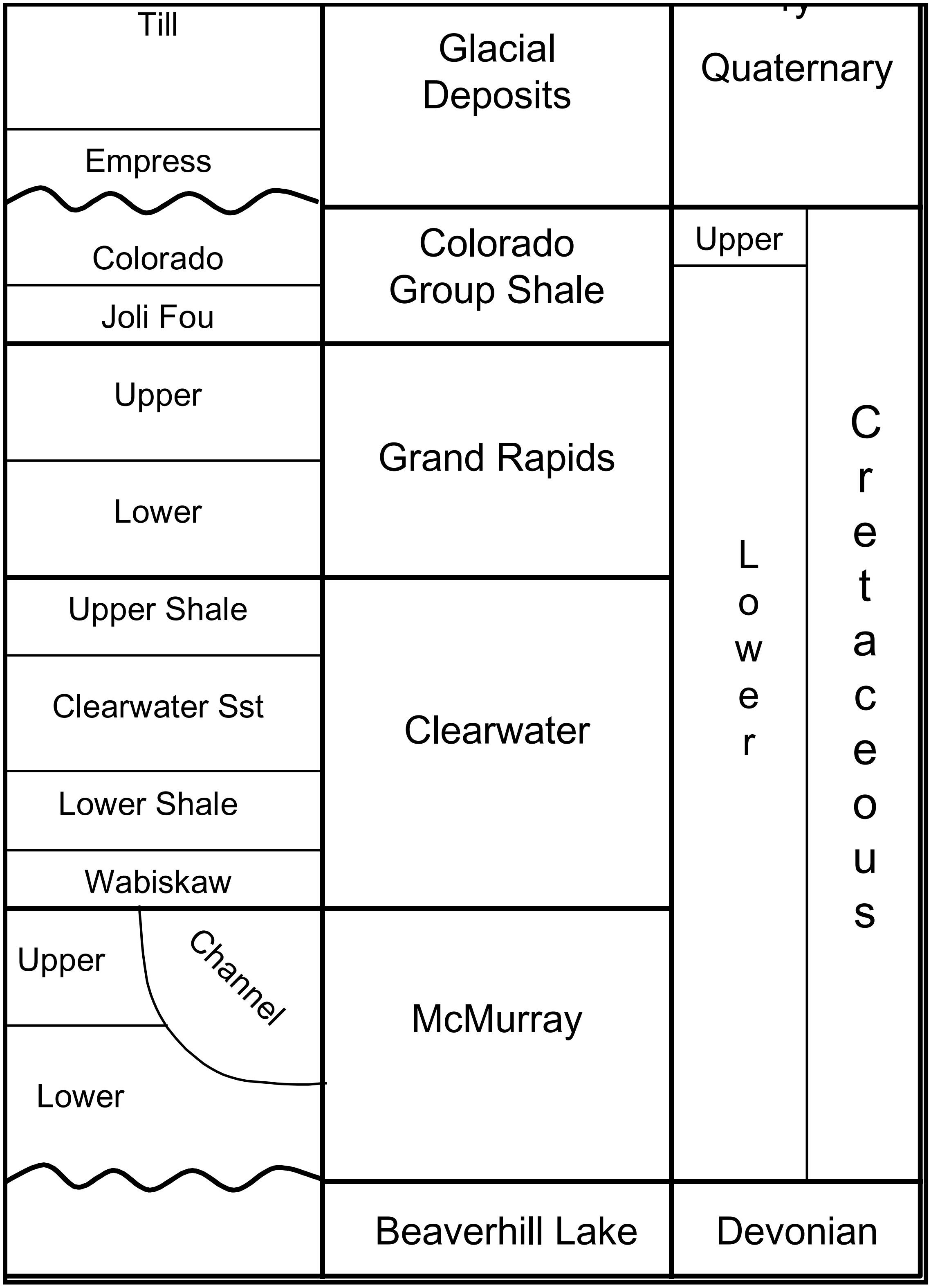


Figure 15: Generalized Stratigraphic Chart of the Project Area

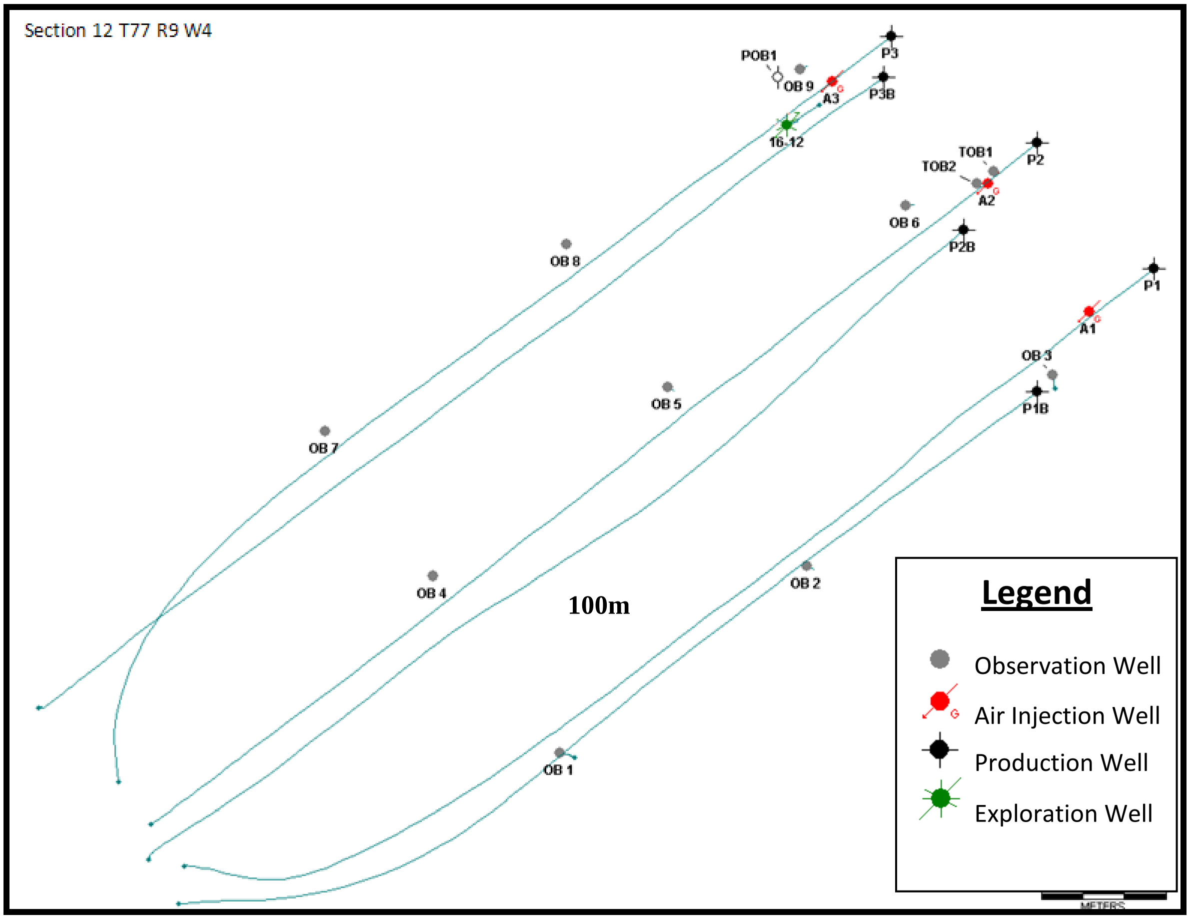


Figure 16: Project Well Layout

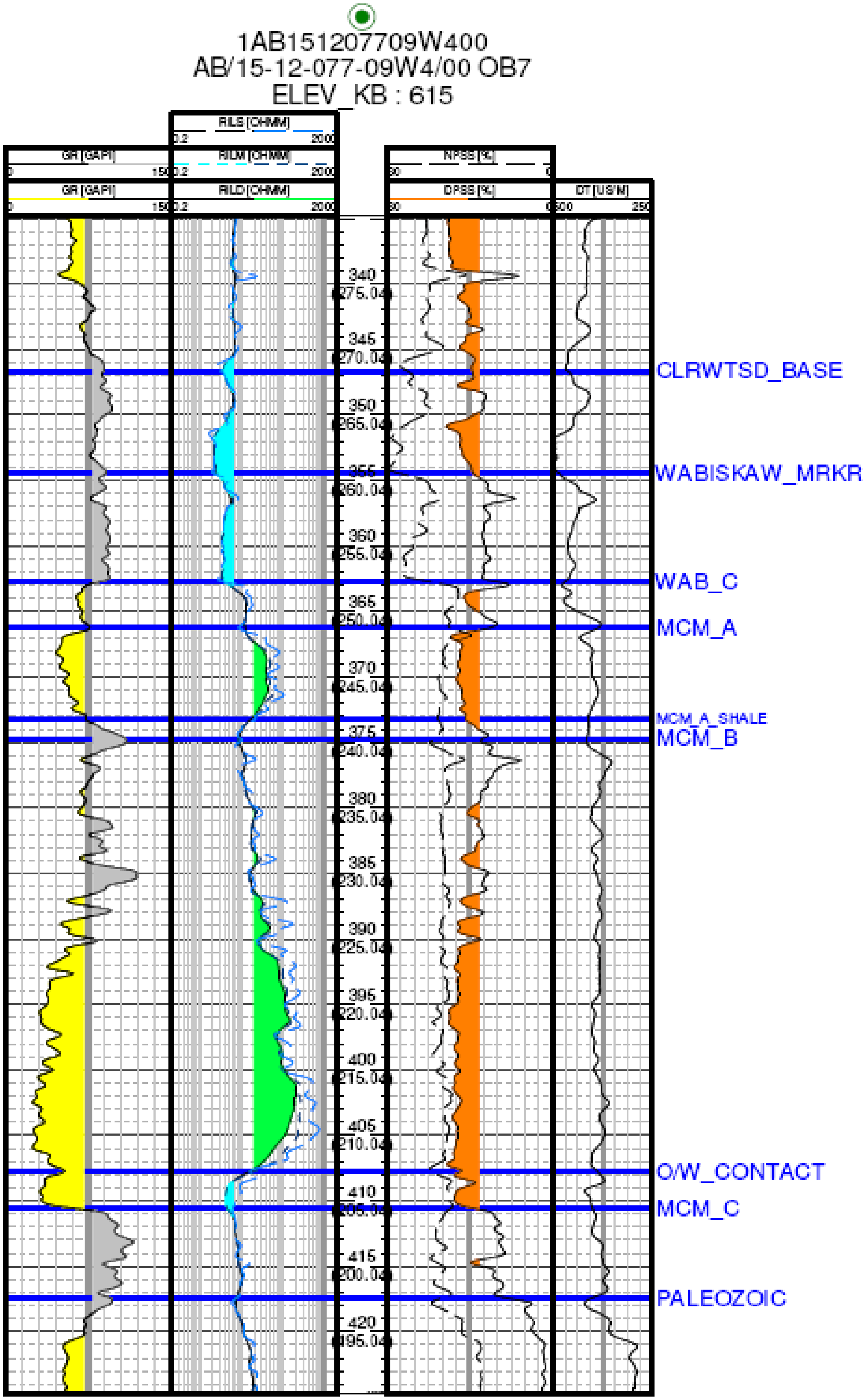


Figure 17: Typical Composite Log at the Project Site

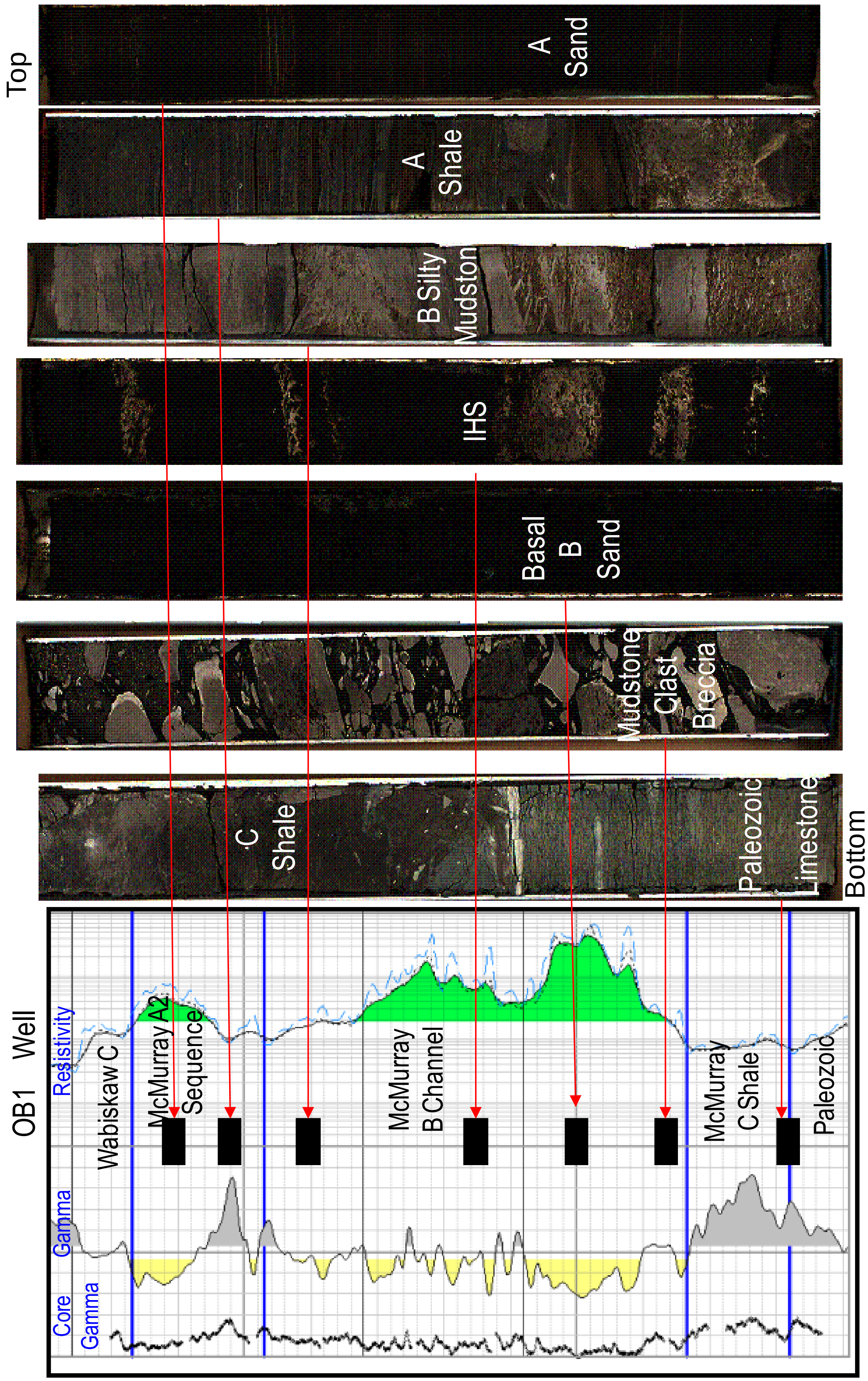


Figure 18: Core – Log Correlation

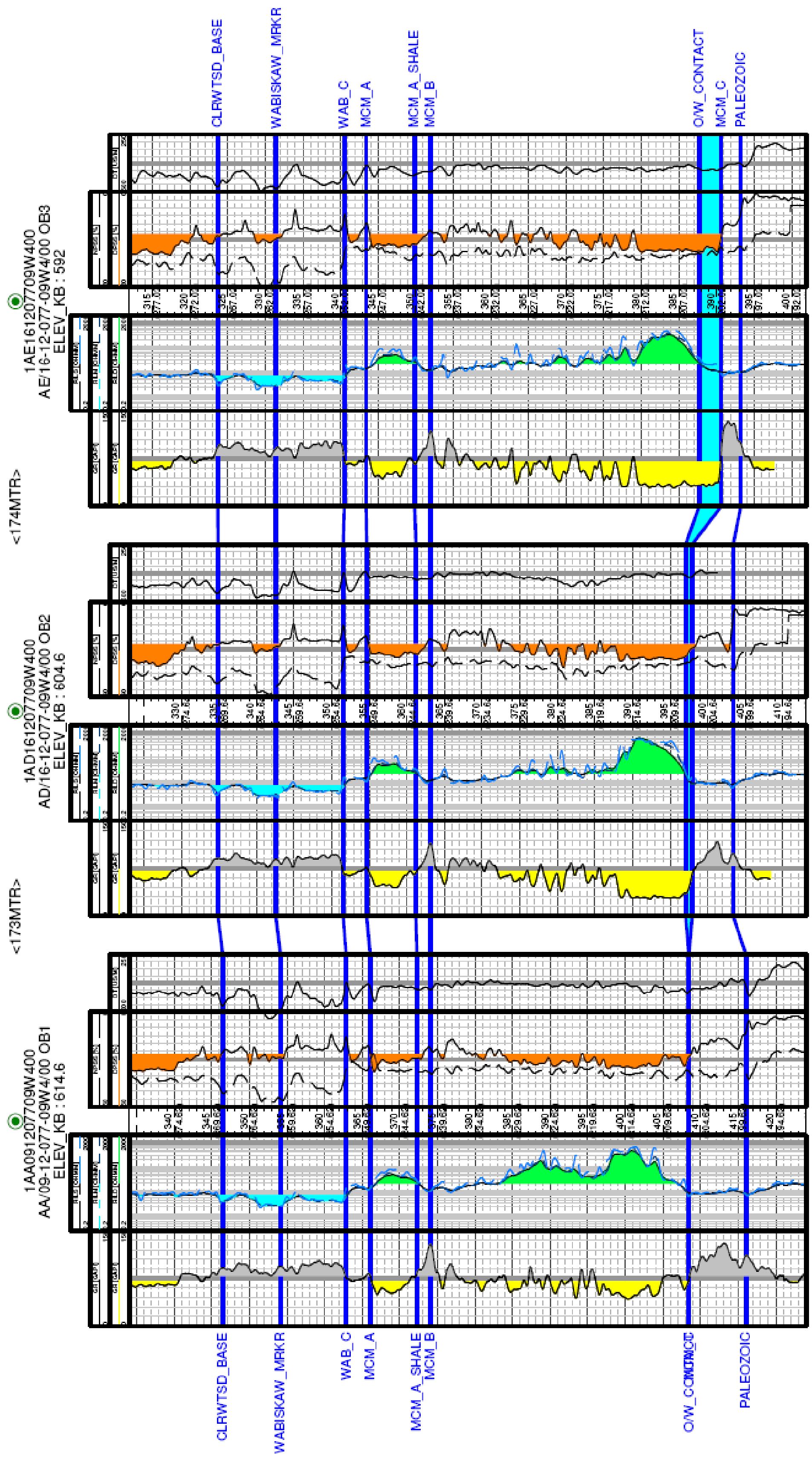


Figure 19: Representative Stratigraphic Cross Section at the Project Site

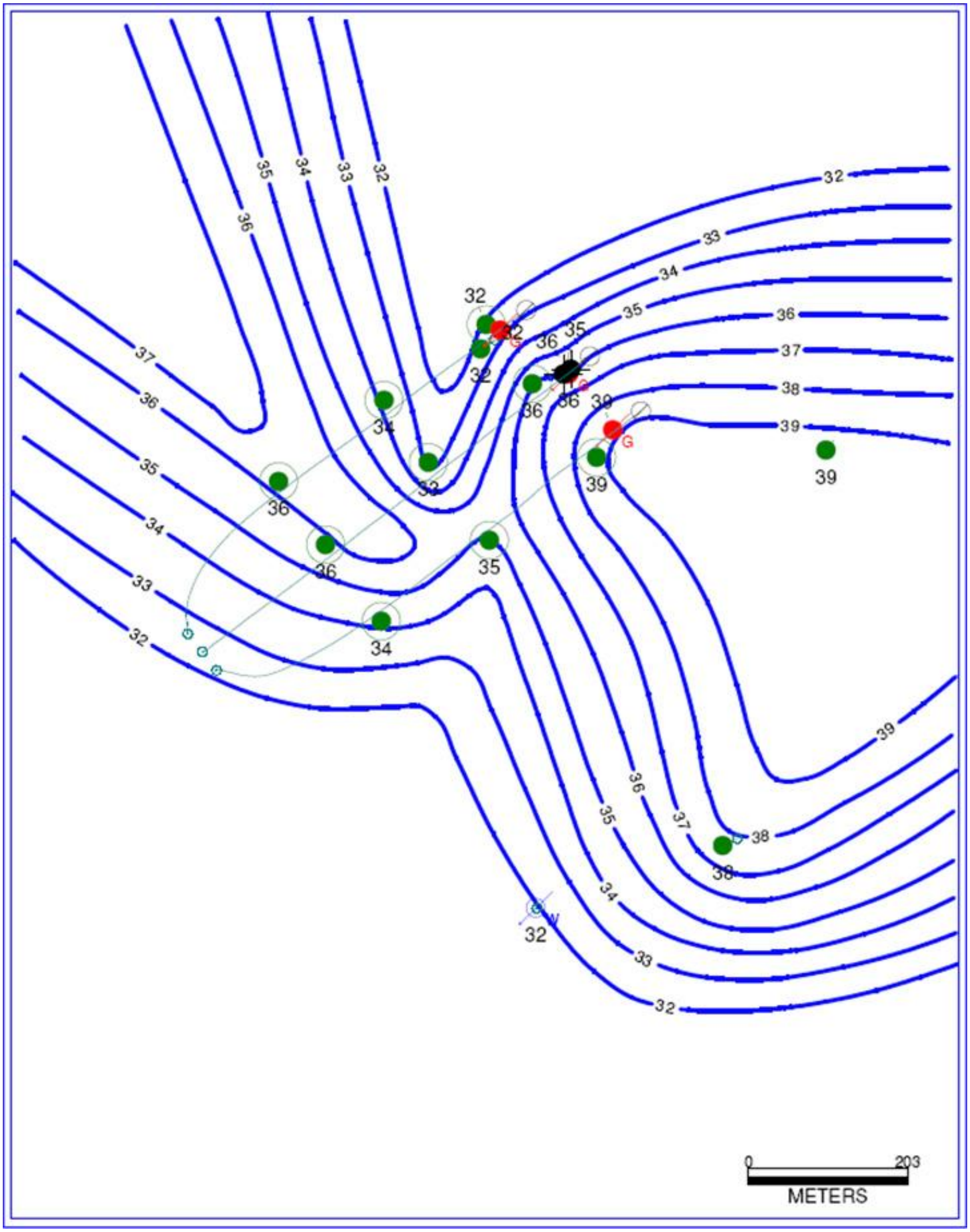


Figure 20: McMurray B Isopach Map

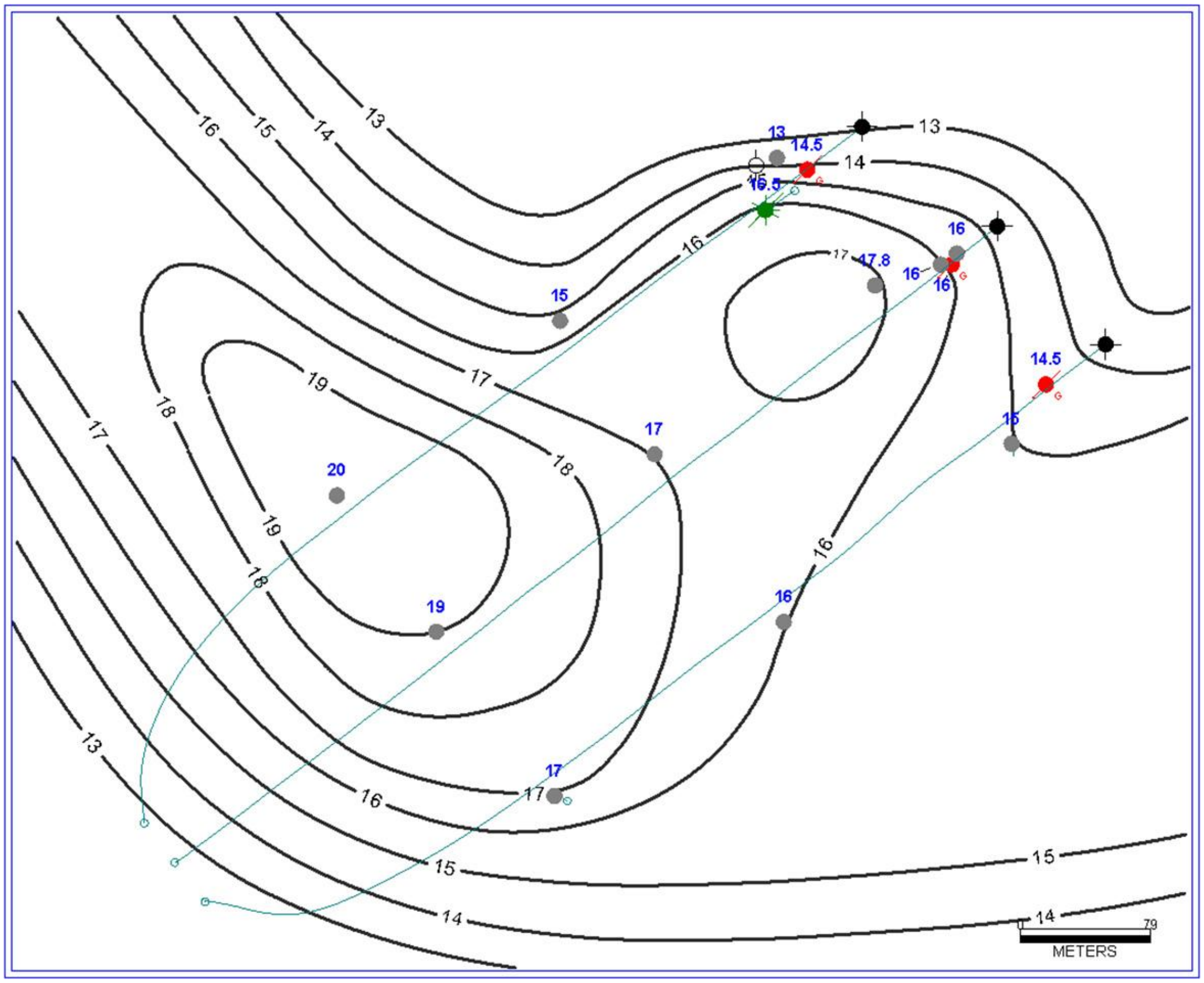


Figure 21: McMurray B Net Bitumen Isopach Map

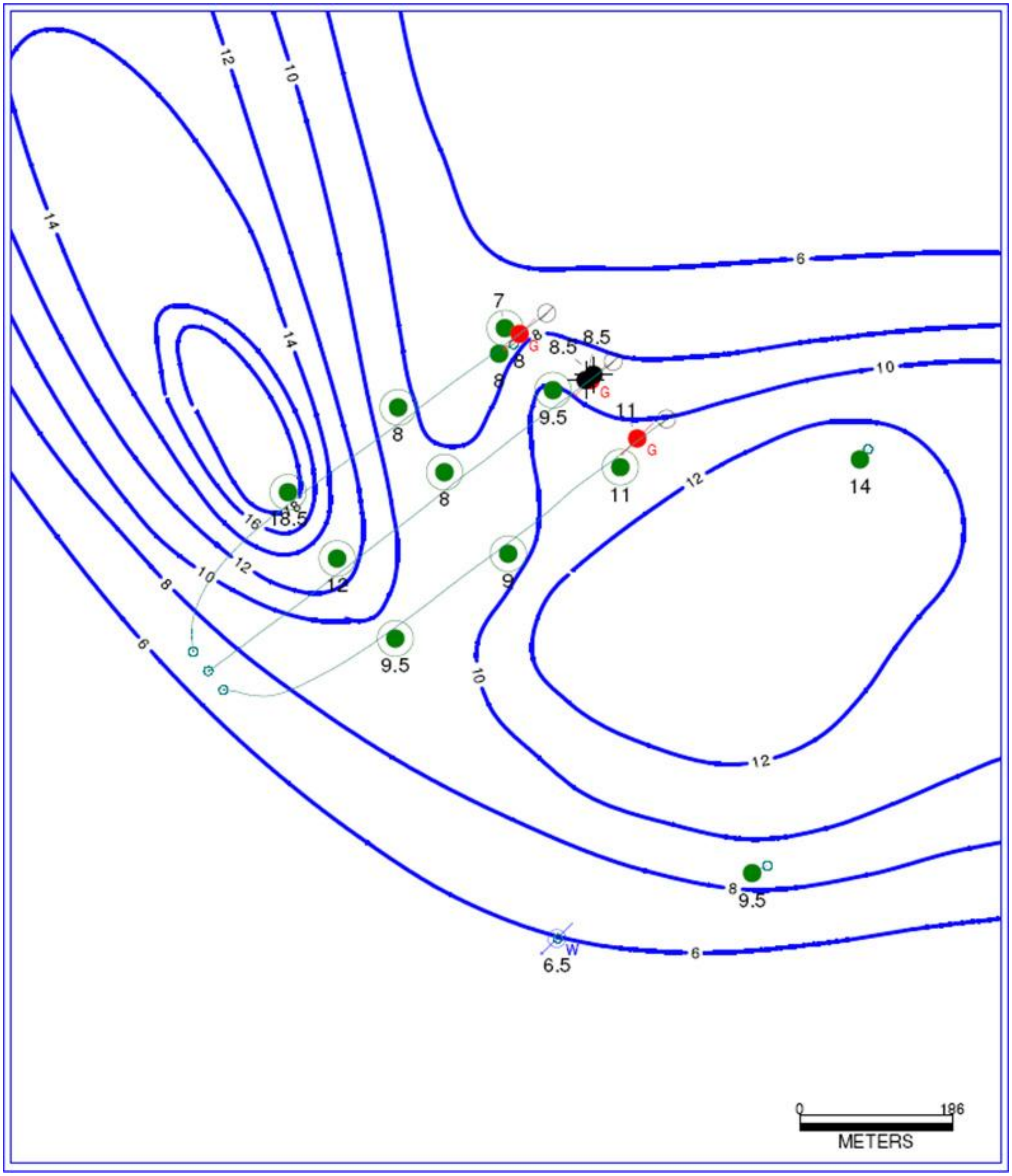


Figure 22: McMurray B Basal Sand Net Pay Isopach Map

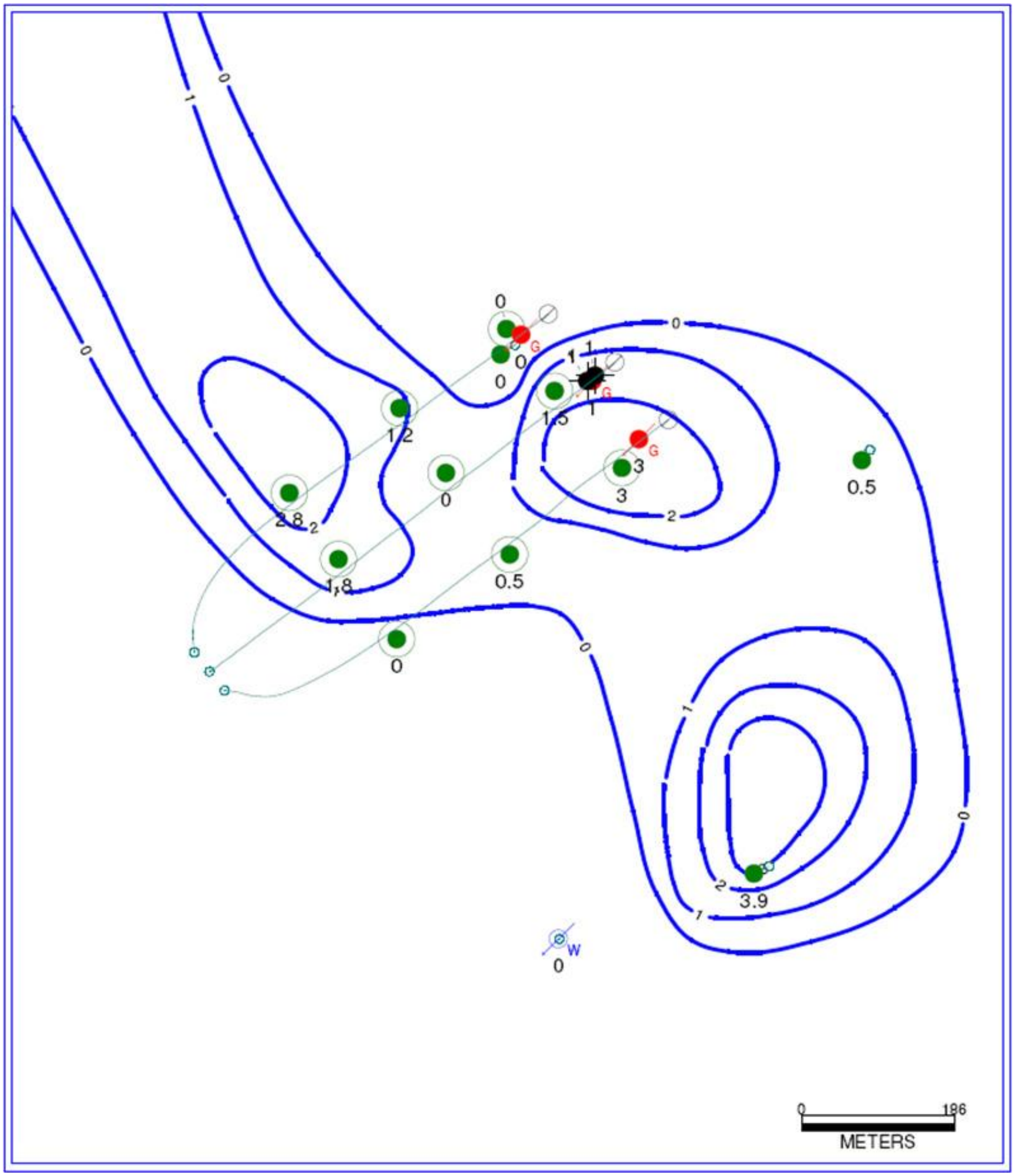


Figure 23: McMurray B Bottom Water Isopach Map

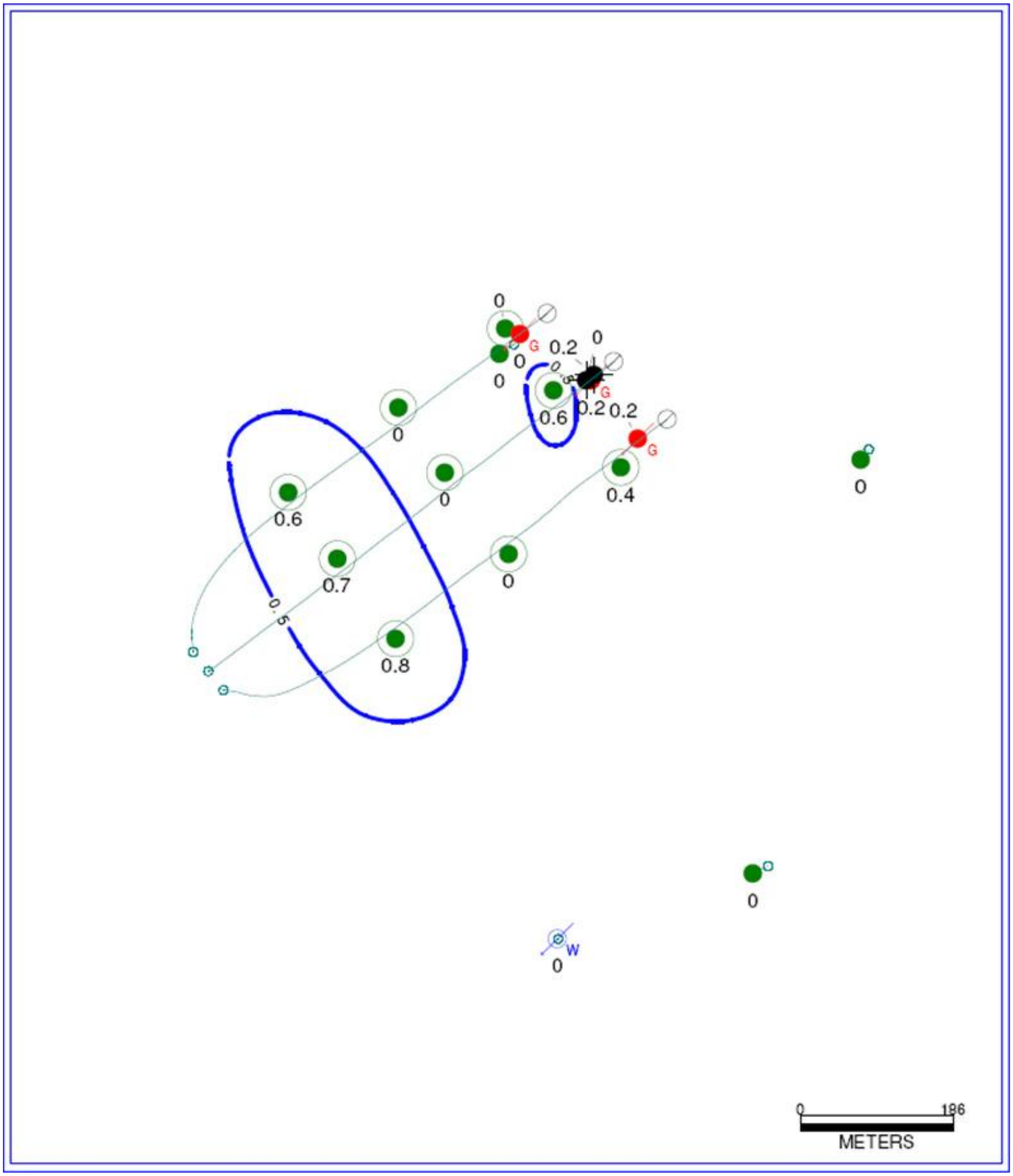


Figure 24: Top Gas Isopach Map

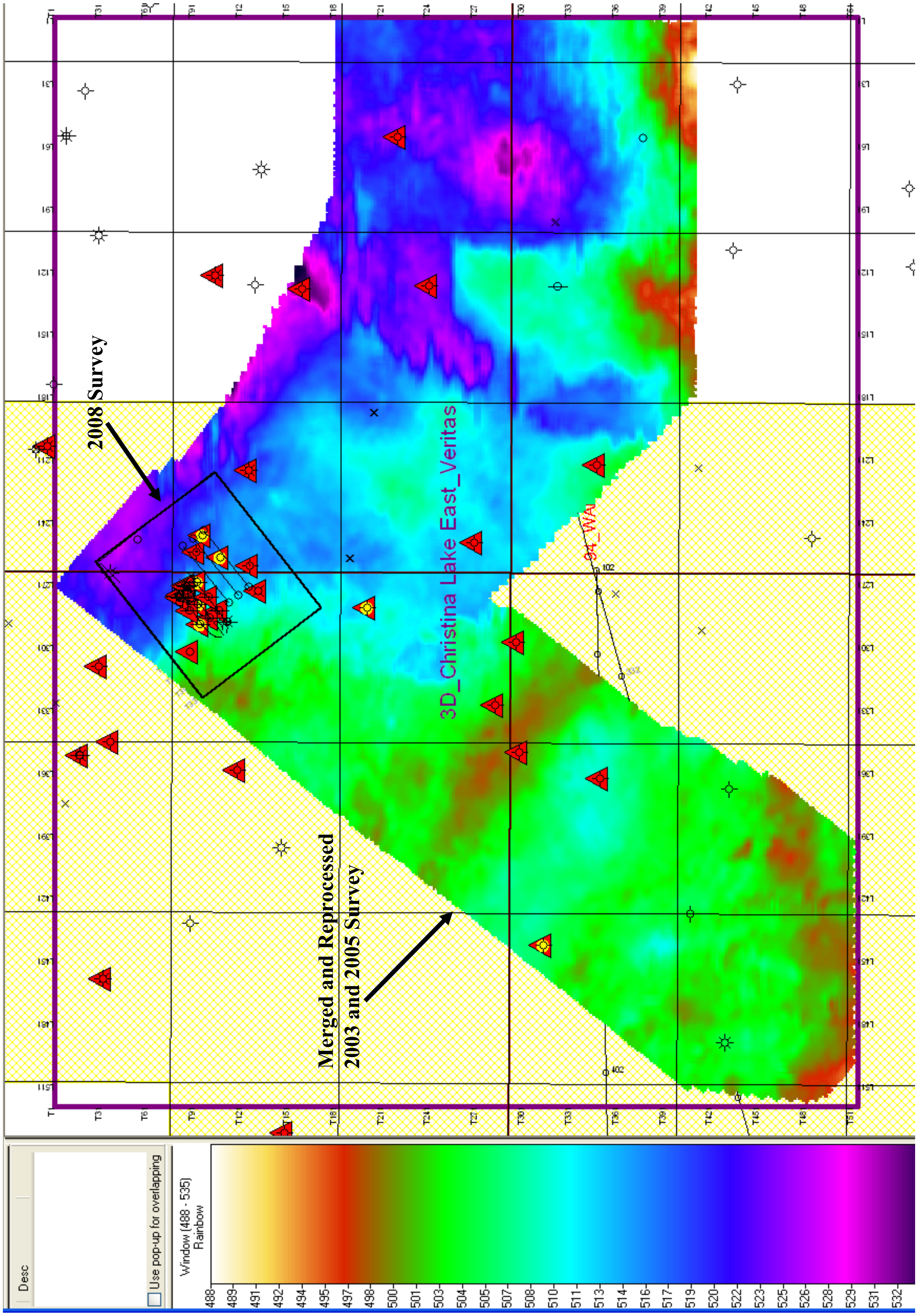


Figure 25: Seismic Surveys

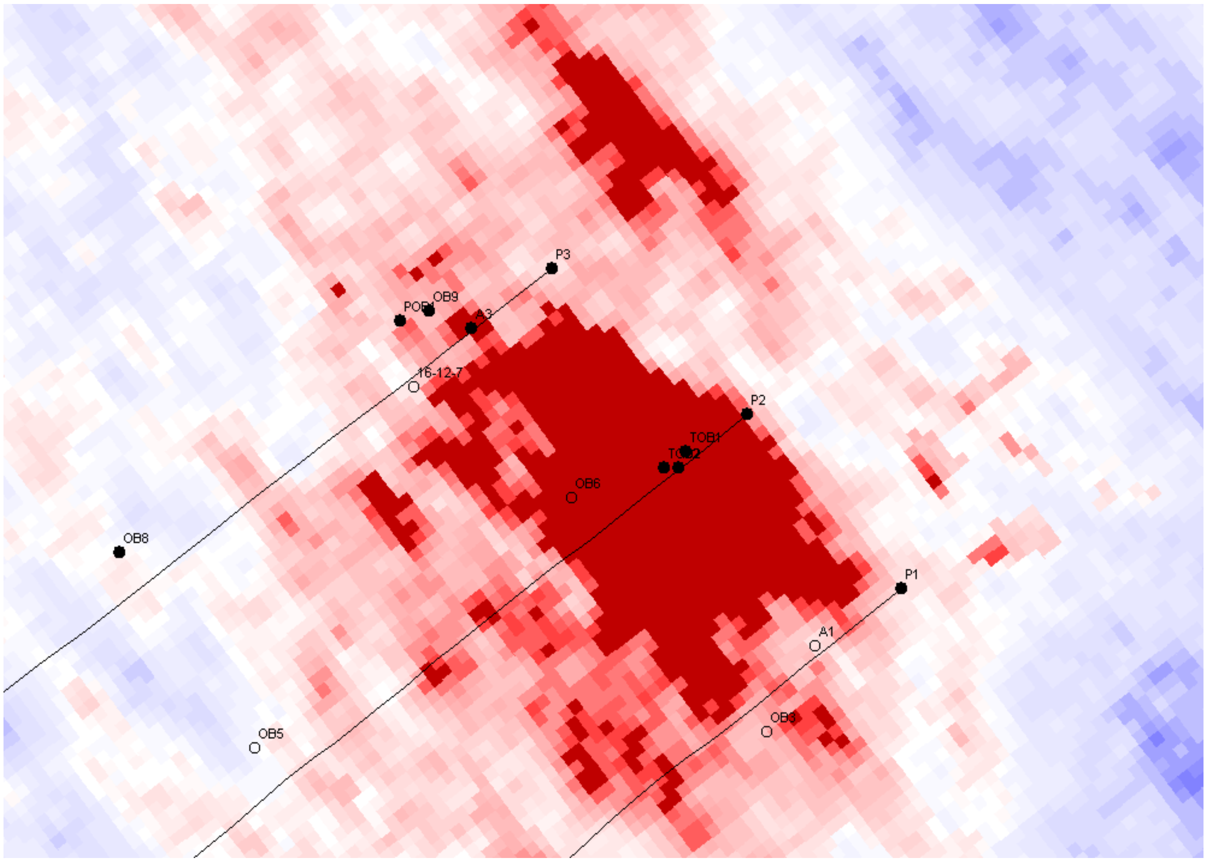


Figure 26: 4D Seismic Surveys (2008) Interpretation

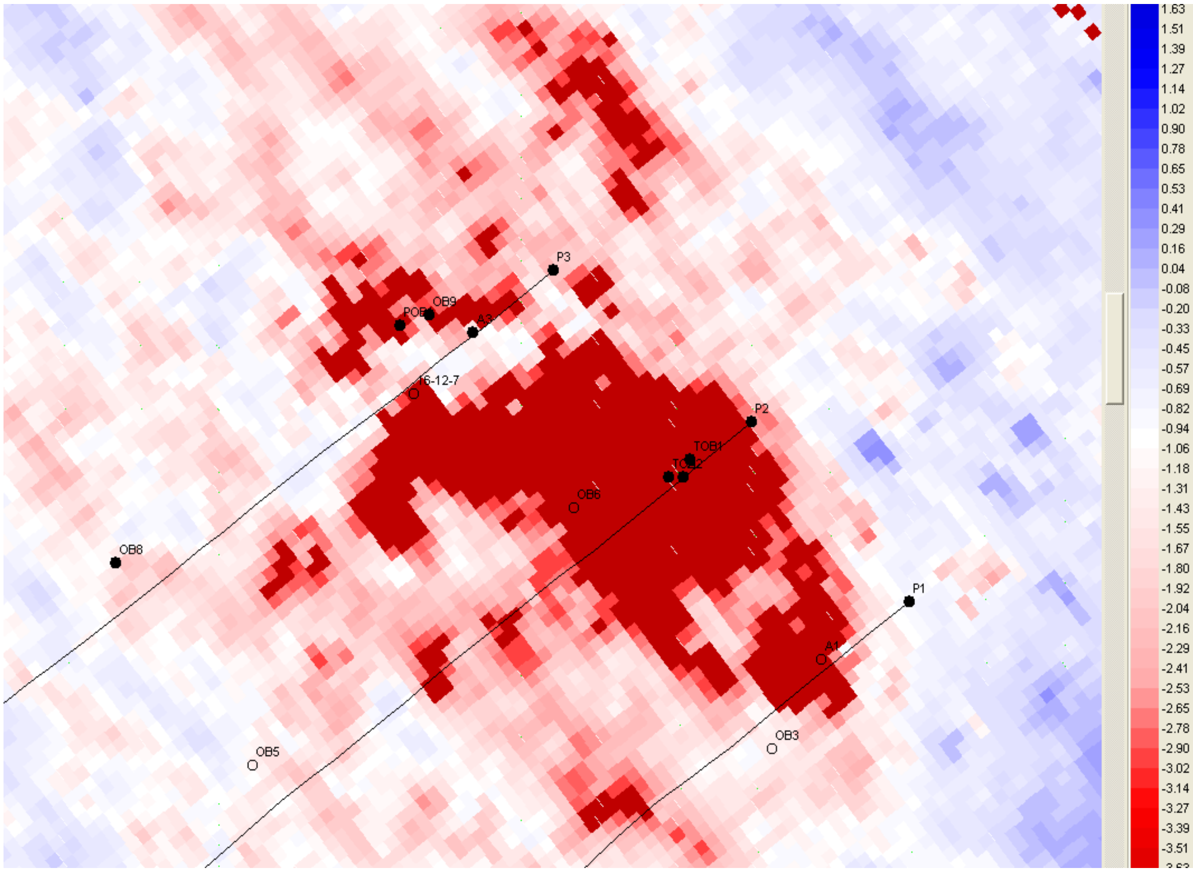


Figure 27: 4D Seismic Surveys (2009) Interpretation

5.1.2 Laboratory Studies:

Numerous routine laboratory tests were carried out to support and optimize the field project. This lab test data is presented in Appendix 1 along with a detailed report of the physical lab simulation of THAI™ process 3-D reactor run using Whitesands crude which is attached in Appendix 2.

5.1.3 Simulations

A number of numerical simulation studies were conducted in 2008. These studies examined the effect of the following four (4) parameters on the THAI™ process: well spacing, cap rock integrity, enriched air injection and wet combustion (the co-injection of steam with air). Homogeneous, half-well element of symmetry models were constructed using STARS, the Computer Modelling Group's Steam, Thermal and Advanced Processes Reservoir Simulator, to study the effect of each of these parameters.

5.1.3.1 Well Spacing Models

To determine the optimum well spacing, models were constructed with inter well spacing of 50, 75, 100 and 125 m.

This study to investigate the effect of different well spacing (Aug. 2008) used 500m horizontal well length going 50 m past the vertical injector with 15 m offset to first perfs. These sensitivities were for a homogeneous bitumen pay thickness of 20 m and used 750 kPa as BHP and 2600 kPa as the reservoir pressure. A brief summary is as follows:

The 50 m and 75 m well spacing simulation cases terminated early because of air in the producer, giving high coke level and temperatures greater than 600 ºC. For the 100 m case this occurred when the front reached the heel and for the 125 m case the run was stable for more than 3 years after the front reached the heel. The protective oil head over the producer, or "gas trap", is not maintained when the spacing is small because an early gas bank is formed (gas bank is the term for the situation when the air zone is continuous between the injection wells). For the 100 m case, the gas bank between wells is not formed until the front has reached the heel so that oil always flows into and over the producer from the sides of the 'prow'. For the 125 m case, even when the gas bank is very well established, there is still no entry of air into the producer, and the oil head is maintained. There appears to be a greater need for tubing steam to increase wellbore pressure when the well spacing is small. The 50 m case needs to be re-run with more steam in the tubing.

Table 10: Effect of Well Spacing in the THAI™ Process

Well spacing, m	50	75	100	125
Tubing water, m^3/d	5	7.5	10	10
Air rate, $10^3 m^3/d$	30	75	100	100
Maximum oil rate, m^3/d	33	36	76.8	84.3
Recovery factor, %	23.5	28.8	53.2	63.1
Time to develop gas bank between wells (yrs)	1.50	2.83	4.83	7.00

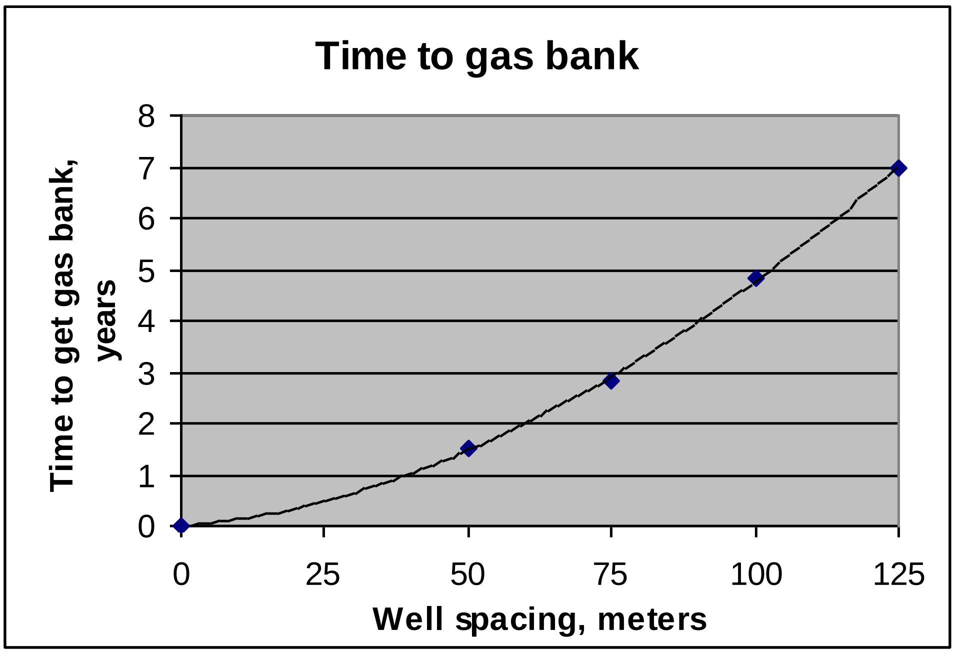


Figure 28: Gas Bank Development vs Well Spacing

5.1.3.2 Cap Rock Integrity

The effect of a limited seal on the THAI™ process was investigated by varying the seal permeability. Vertical seal permeabilities of 0.2 mD, 1 mD, 5 mD and 50 mD were studied. It was determined that the THAI™ process is feasible with a minimum seal permeability of 0.2 mD. Careful control of injection pressures is required to contain injection gases within the producing zone. As the process becomes less effective with time (distance), a poor seal quality may require shorter horizontal well production lengths.

5.1.3.3 Enriched Air Injection

To determine the effect on the THAI™ process of enriching the air injection stream with oxygen a number of simulations were done with 42% oxygen and 58% nitrogen injection stream. Enriching the air stream with a higher concentration of oxygen promotes higher burn temperatures increasing the efficiency of the process. Compared with normal air at 21% oxygen, the enriched run showed significant benefits, including faster oil recovery, peaking at 188 m3/d versus 100 m3/d and cumulative Gas-Oil-Ratio of 707 compared with 1100 with air (in the Figure, the fluid rates need to be doubled for a full well).

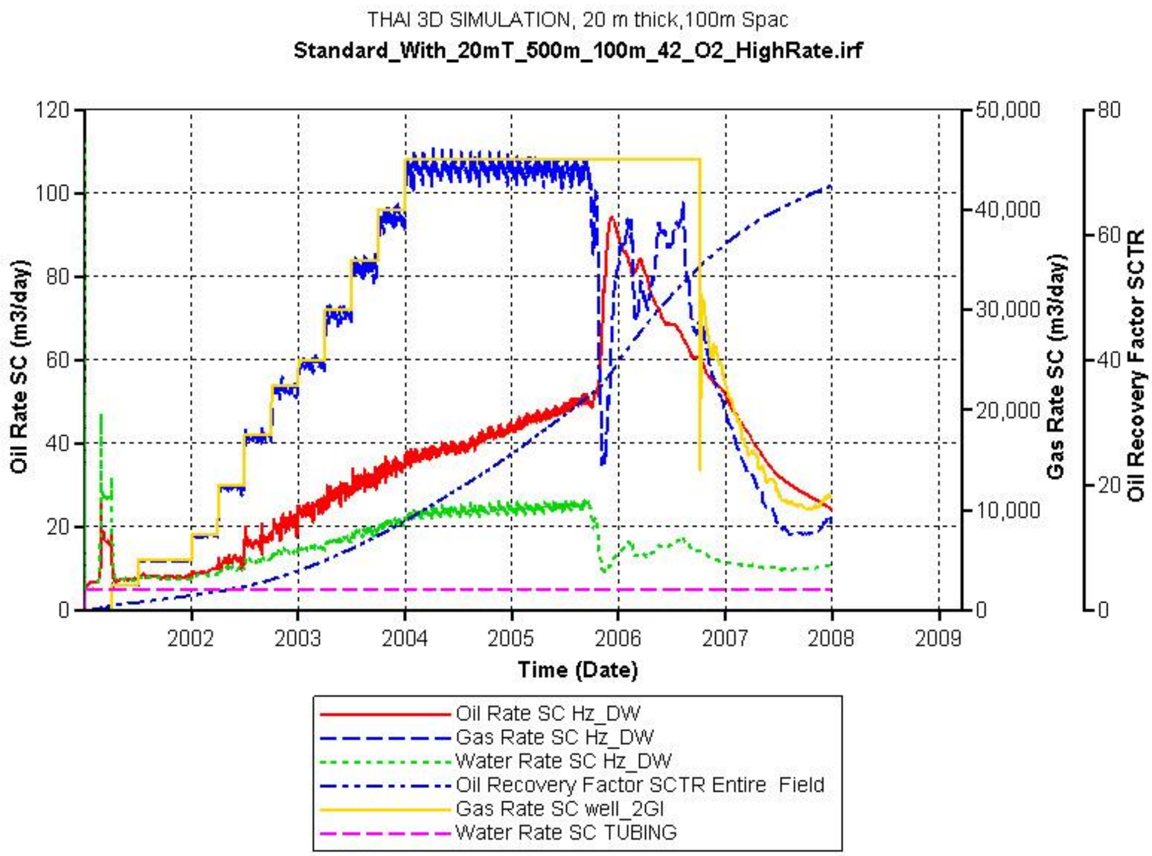


Figure 29: Simulation with Enriched Air

5.1.3.4 Wet Combustion

Simulations were also performed to determine if co-injection of steam with air would improve flood performance. Varying steam quantities have been tested. Preliminary results indicate that the injection of steam along with air can improve oil rates but excessive steam injection is detrimental. Also, the location of steam injection is important. The injection of steam below the air point promotes air breakthrough by depleting the oil gas trap. Work is ongoing to determine optimum levels of co-injection and the appropriate point of stream injection.

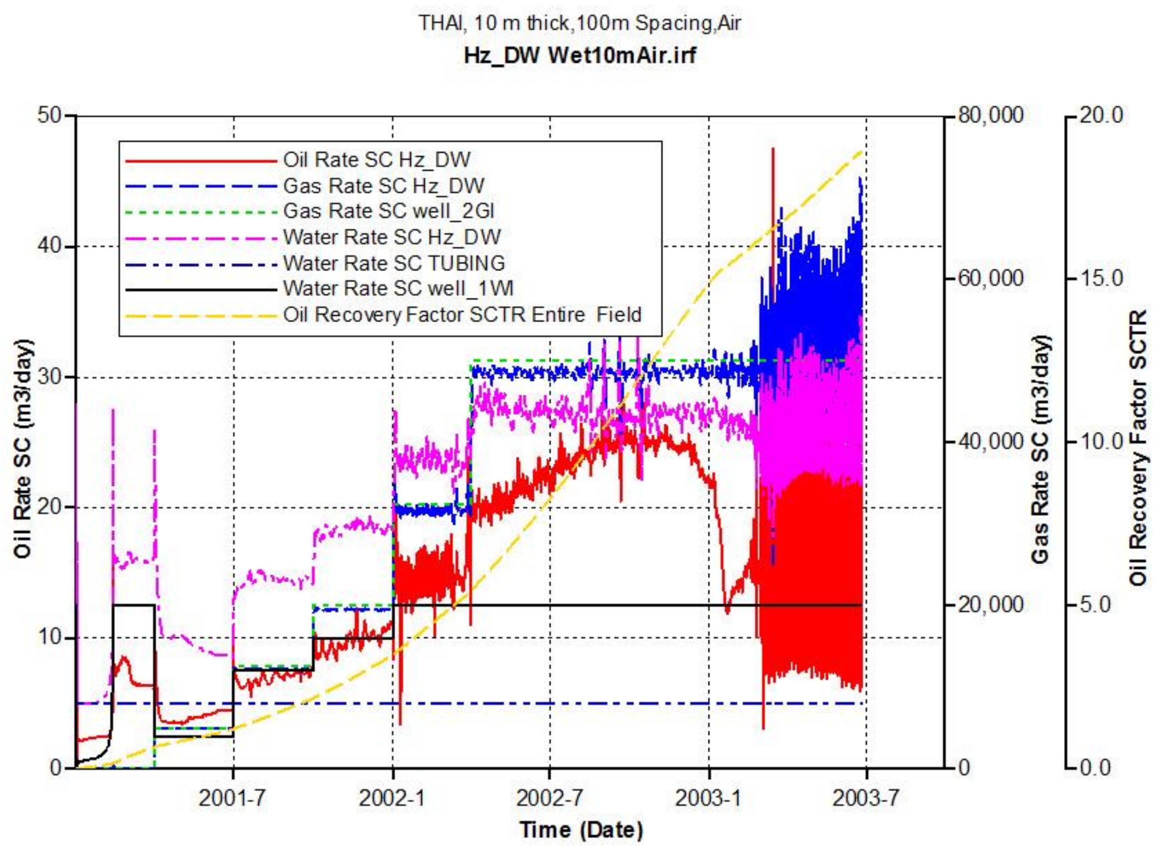


Figure 30: Wet Combustion Simulation

5.1.3.5 Pressure, Temperature and Other Applicable Reservoir Data

The only pressures monitored in the pilot reservoir are those of the injection and production wells which are discussed in section 4.4.

The following figures show the temperature data at wells where temperature variations have been observed. Where temperature curves are discontinuous the thermocouples have failed and there is no data.

The well locations are shown in Figure 7.

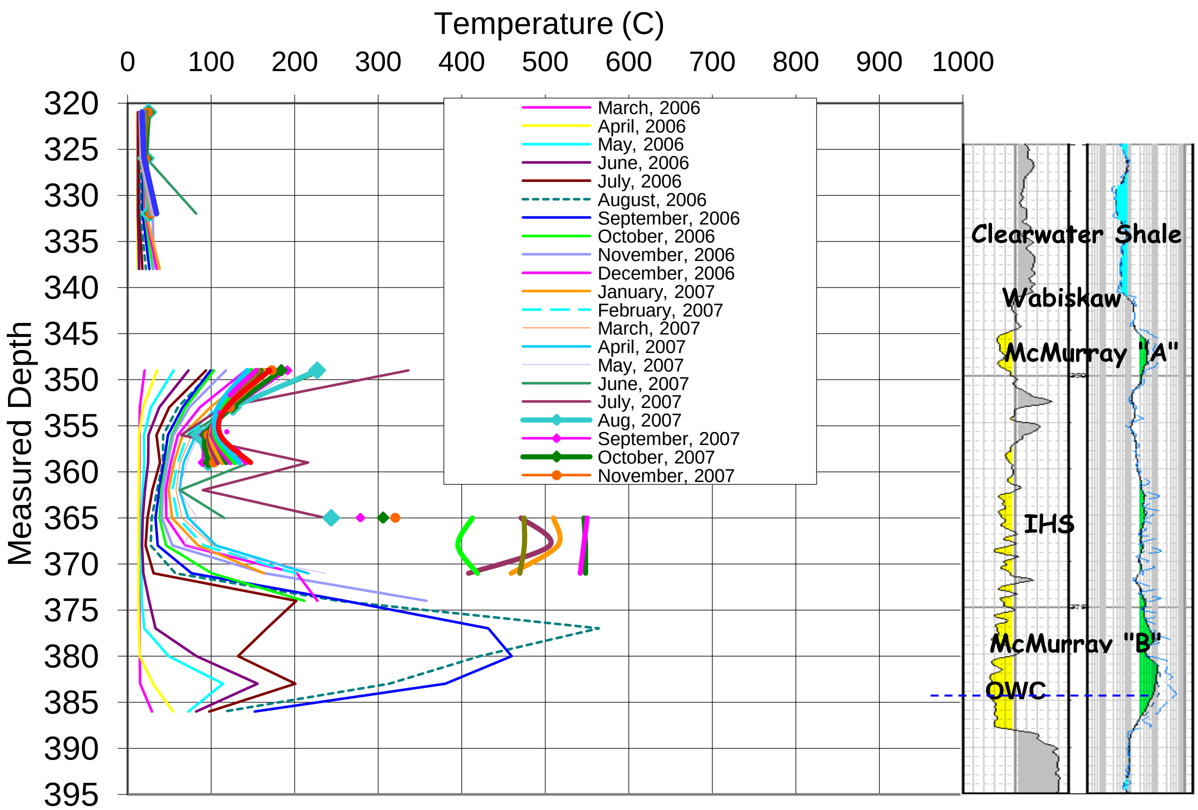


Figure 31: TOB1 Temperatures

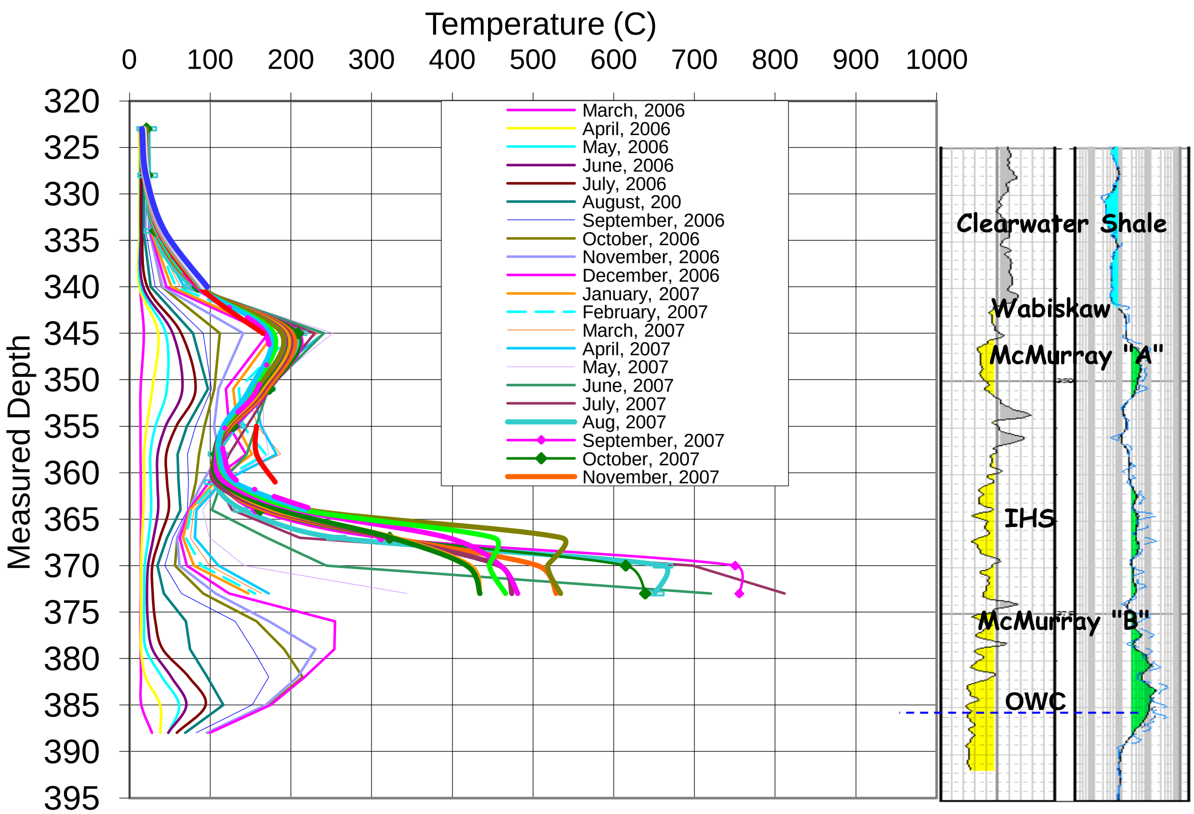


Figure 32: TOB2 Temperatures

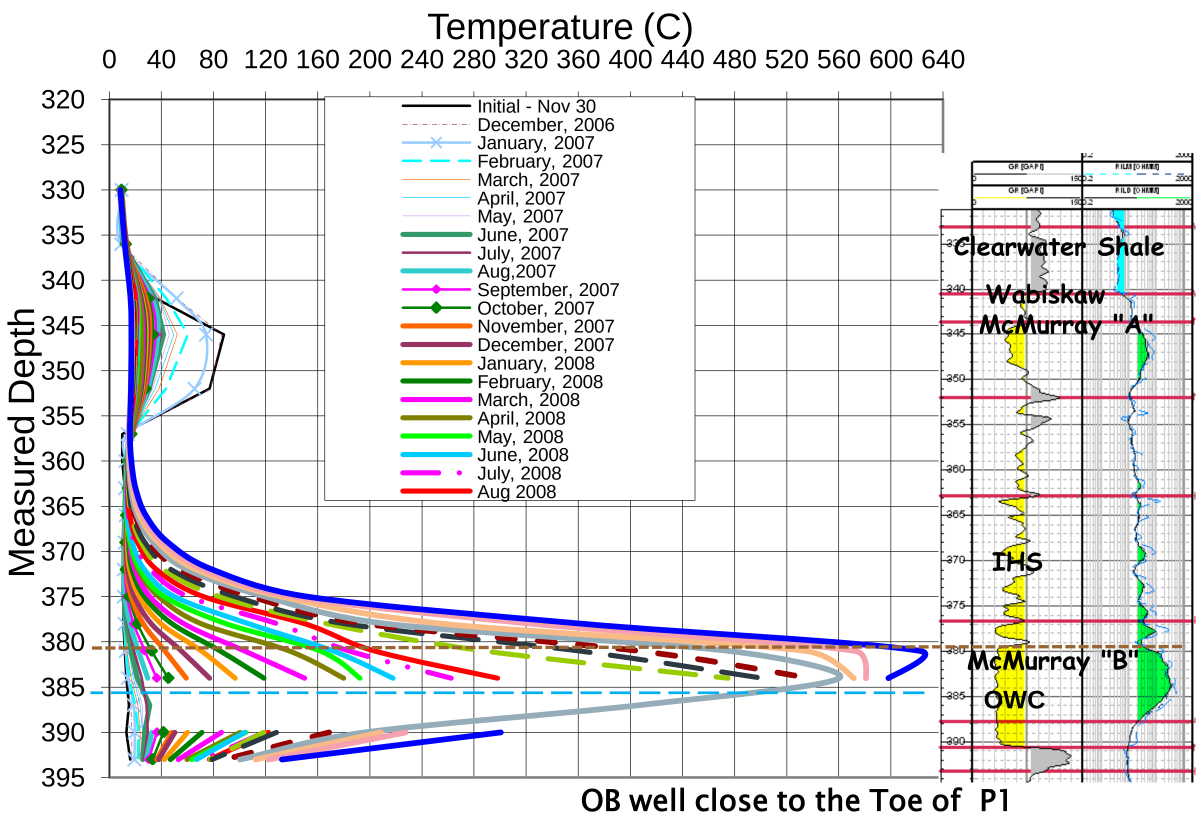


Figure 33: OB3 Well Temperatures (close to P1 toe)

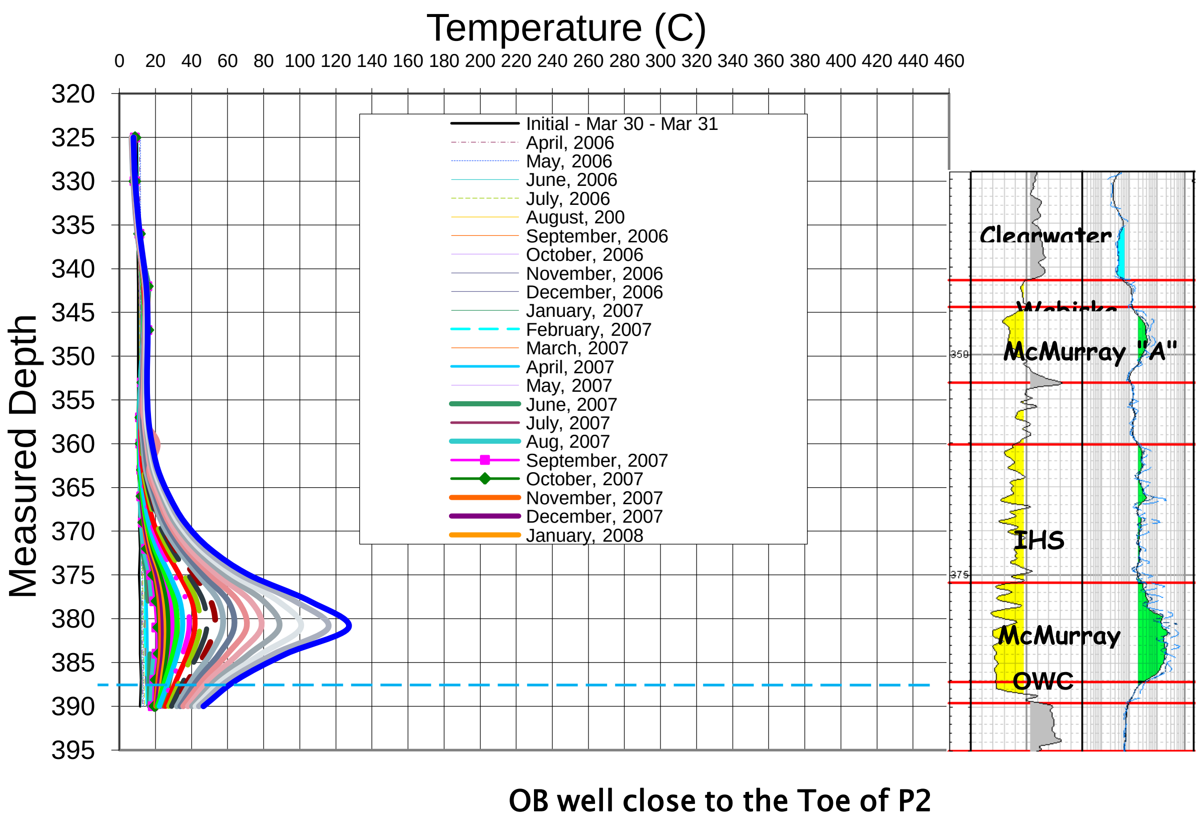


Figure 34: OB6 Well Temperatures (close to P2 toe)

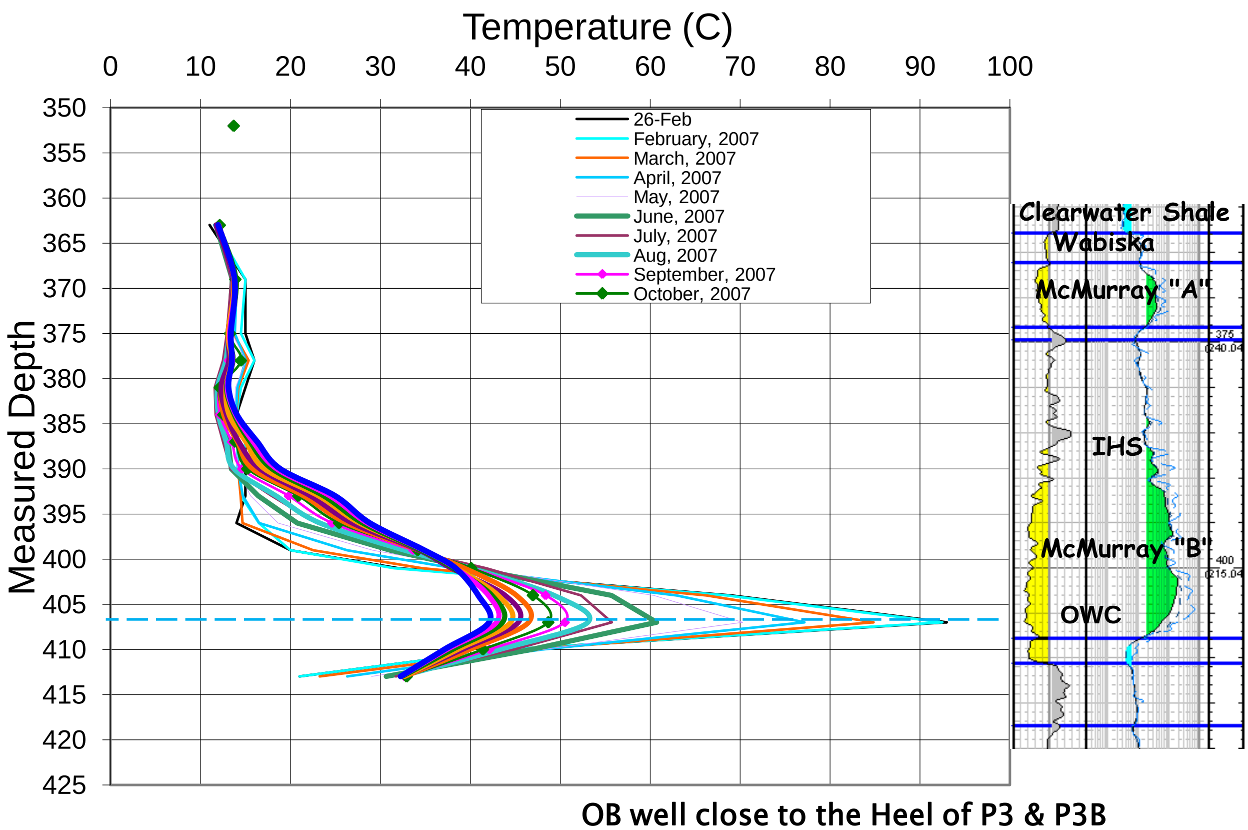


Figure 35: OB7 Wellbore Temperatures (near P3 heel)

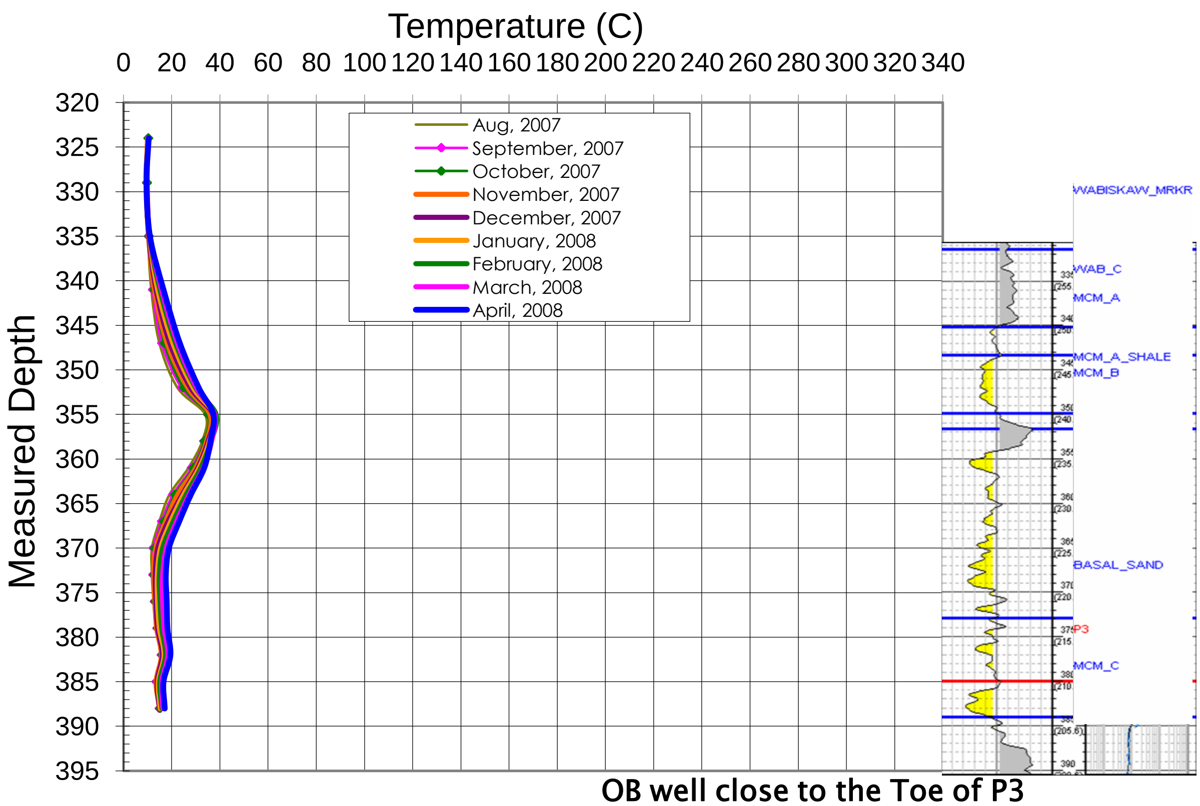


Figure 36: OB9 Wellbore Temperatures (near P3 toe)

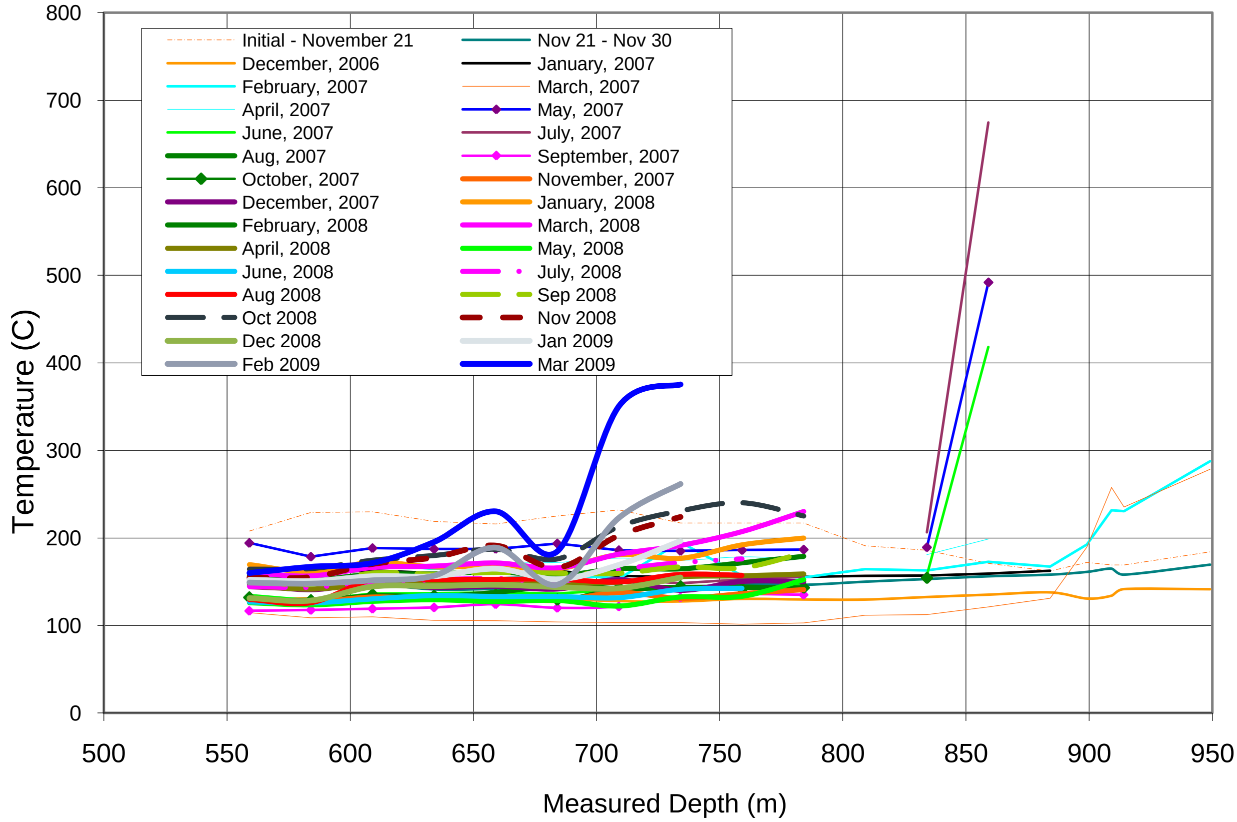


Figure 37: P1 Wellbore Temperatures

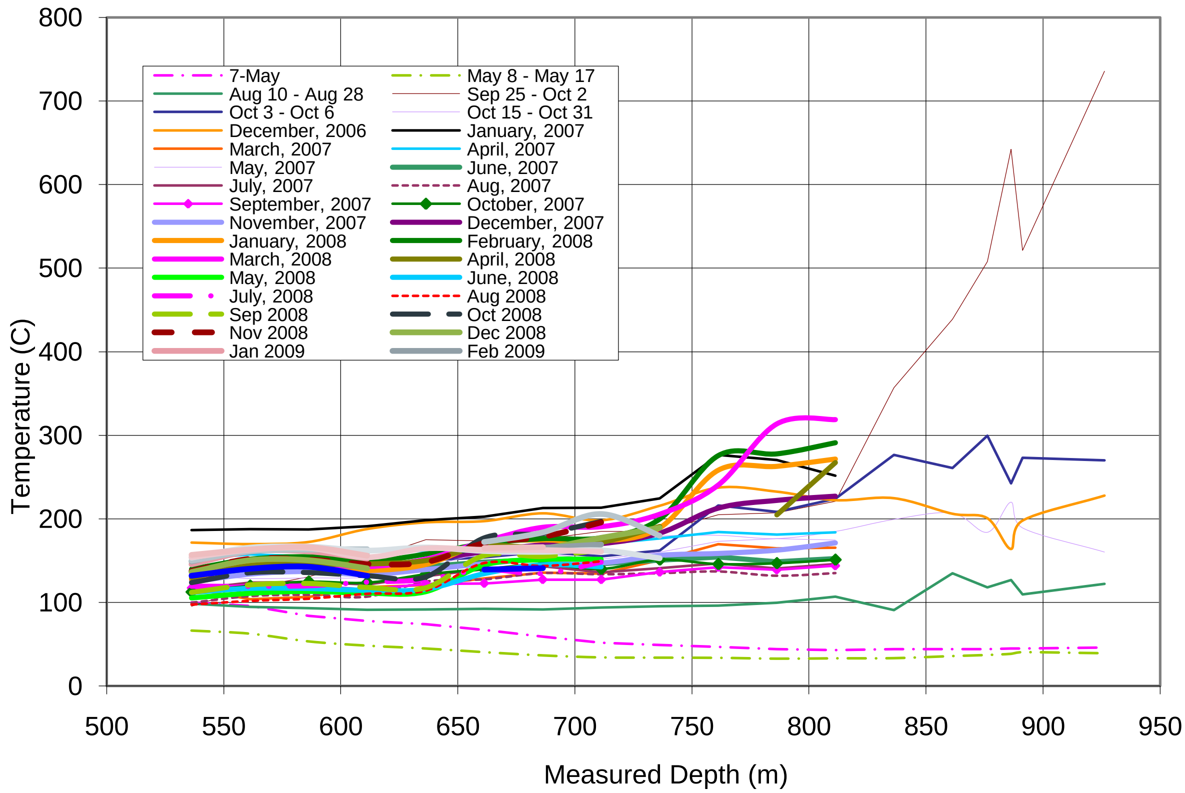


Figure 38: P2 Wellbore Temperatures

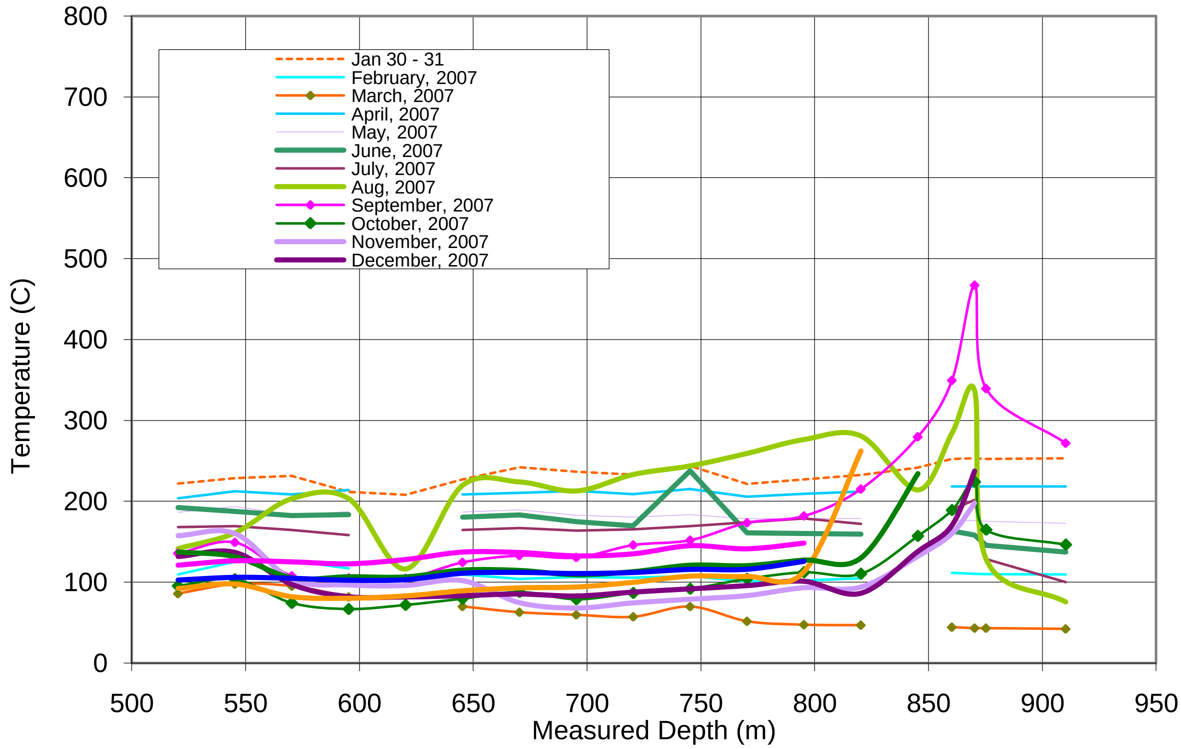


Figure 39: P3 Wellbore Temperatures

5.2 INTERPRETATION OF PILOT DATA

The following is interpreted from the above data:

- The gas analyses as well as the temperature monitoring from the pilot confirms that continuous HTO reactions were maintained under a wide range of operating conditions
- Additionally, temperature profiles monitored also indicate that the heat generated during combustion process also migrates to IHS above the main pay zone with time.
- No changes in cap rock temperatures have been seen.
- Bitumen upgrading is consistently shown by the lab analyses done on a routine basis.
- It appears that up to 8% hydrogen is also produced due to water-gas shift reactions. This contributes to further in-situ upgrading of the bitumen in addition to the thermal cracking due to high temperatures due to combustion.
- Significant lighter end production is also observed. This could provide for a potential new product stream from THAI™.
- API upgrade and viscosity reduction has been consistently observed.
- Up to 5% of hydrocarbons (C1–C5) with a gas heating value 85-120 Btu/scf, is seen in the produced gas and is suitable for use in Low-Btu steam generators.
- Significant increases in volatiles and saturates are observed.
- Notable reductions of resins, asphaltenes and aromatics are observed.
- No issues with O2 in produced gas have been observed.
- Levels of CO2 and CO production were as expected.
- H2S levels in produced gas are consistent with reduction of sulphur in the produced oil .
- Produced water was of industrial use quality and can be used as source water for nearby SAGD operations if needed.
- The THAI™ process is robust as combustion can be easily re-started (A-3 injection resumed after 100 days of suspension & A-2 resumed after 30 days of shut-in)
- The process is influenced by bottom water.
- Optimum air flux in the range of 26 - 30 m3/day-m2 was observed.
- The modeled and actual production rates differed due to down time on the producer wells.

6. PILOT ECONOMICS TO DATE

(Thousands of dollars, unless otherwise noted)

6.1 SALES VOLUMES OF NATURAL GAS AND BY-PRODUCTS

	2009	Cumulative
Natural gas and by-products	0	0
Bitumen (bbls)	48,441	85,671

6.2 REVENUE

	2009	Cumulative
Bitumen sales	**$ 2,309.9**	**$ 6,949.1**

6.3 CAPITAL COSTS

	2009	Cumulative
Environmental		
Surface Hydrology & Groundwater Environmental	$ -	$ 136.0
Utilities, Communications & Data Acquisition		
Electricity Consumer Distribution Contribution	-	208.0
Natural Gas Supply	-	524.0
SCADA & Wireless Equipment at Plant Site	-	536.8
	-	**1,268.8**
Engineering and Detailed Design	-	5,346.0
Drilling & Completion		
Stratigraphic/Observation Wells	-	3,207.0
Observation Wells	-	1,384.0
Water Source Wells	-	220.0
Disposal Wells	-	2,409.5
Air Injectors	-	2,591.0
Horizontal Producers	-	7,863.2
	-	**17,674.7**
Plant & Civil	-	21,150.0
	$ -	**$ 45,575.5**

6.4 DIRECT AND INDIRECT OPERATING COSTS

	2009	Cumulative
Electricity Expense	1,232.5	4,380.7
Labour, including R&D Monitoring	3,889.3	14,604.6
Services and Site Maintenance	12,050.1	52,364.0
Steam Rental	181.5	1,015.5
	17,353.4	72,365.2
Labour Benefits	547.9	1,641.8
	$ 17,901.3	**$ 74,007.0**

6.5 CROWN ROYALTIES, APPLICABLE FREEHOLD ROYALTIES, AND TAXES

	2009	Cumulative
Crown royalties	$ 45.8	$ 98.8

6.6 CASH FLOW

	2009
Revenue	$ 2,309.9
Royalties	(45.8)
Operating costs	(17,901.3)
Cash flow from operations	$ (15,637.2)
Capital expenditures	-
Total cash flow for project	**$ (15,637.2)**

6.7 CUMULATIVE PROJECT COSTS AND NET REVENUE

Cumulative capital costs	$ 45,575.5
Cumulative operating costs	$ 74,007.0
Cumulative net revenue	$ 6,850.3

6.8 EXPLANATION OF MATERIAL DEVIATIONS FROM BUDGET

Costs relating to solving production and operational issues post start-up were incurred which were not originally budgeted. Higher than anticipated operating costs are due to increased costs of services and materials in the energy sector overall as well as costs associated with H_2S management, sand control and well maintenance.

Listing of items with installed cost greater than $10,000:

Plant & Civil

Project#	Project Name	GL Acct#	GL Account Name	2009	Cumulative
1037000	WHITESANDS CORPORATE G&A	28040008	COMPUTER HARDWARE		67,802.0
9040276F	WHITESANDS 9-12-77-09W4 FACILITY	23020104	LOCATION PREPARATION/RESTORATION		5,125.0
		23020189	CONSULTING ENGINEERING SERVICES		8,782.5
		25620102	SITE PREPARATION		13,684.8
		25620104	SERVICE RIG		16,317.0
		25620180	SUPERVISION & TRAVEL		6,625.4
		25620189	CONSULTING ENGINEERING		2,586.8
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		10,329.5
9058011E	COMPUTER MODELING GROUP(CMG) STARS MODEL	22520006	CONSULTING (R&D/Process Modeling Software)		95,030.0

Project#	Project Name	GL Acct#	GL Account Name	2009	Cumulative
9058013F	CHRISTINA LK/LEISMER WHITESANDS PILOT-S1	23020189	CONSULTING ENGINEERING SERVICES		3,110.0
		25620102	SITE PREPARATION		351,279.0
		25620103	LICENCES, PERMITS, SURVEY		15,783.6
		25620182	TRANSPORTATION		522.5
		25620186	SITE AND R/W RESTORATION		26,464.6
		25620189	CONSULTING ENGINEERING		91,328.2
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		536,787.8
		25630502	PUMPS AND ACCESSORIES		27,678.7
9058014F	CHRISTINA LK 16-12-077-09W4 FACILTY	22520006	CONSULTING (R&D/Process Modeling Software)		39,833.9
		25620102	SITE PREPARATION		729,684.9
		25620103	LICENCES, PERMITS, SURVEY		134,880.0
		25620180	SUPERVISION & TRAVEL		75,842.9
		25620181	EQUIPMENT RENTAL		1,151,617.7
		25620182	TRANSPORTATION		1,183,253.1
		25620185	MISCELLANEOUS		21,857.1
		25620186	SITE AND R/W RESTORATION		889.0
		25620189	CONSULTING ENGINEERING		35,949.1
		25620191	CHEMICALS		6,380.7
		25620192	LINEPIPE INSTALLATION		3,953.6
		25620193	XRAY INSPECTION & TESTING		309,198.1
		25620194	COATING & INSULATION		570,256.7
		25620303	CONTRACT LABOUR/WELDING		1,217,398.8
		25620305	INSTRUMENTATION AND AUTOMATION		174,847.3
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		1,332.5
		25620325	ELECTRICAL EQUIPMENT INSTALLATION		3,382,218.3
		25620326	CONCRETE WORK, PILES		88,839.5
		25620500	BUILDINGS		10,141.3
		25620502	PUMPS AND DRIVERS		9,080.1
		25620503	PRESSURE VESSELS		147,810.0
		25620505	TANKS		26,500.0
		25620507	PIPE, VALVES AND FITTINGS		68,092.6
		25620604	FOUNDATIONS		2,140.0
		25630401	TUBING AND PACKERS		2,607.0
		25630404	ELECTRICAL EQUIPMENT		1,149,352.2
		25630500	BUILDINGS		1,044,922.2
		25630502	PUMPS AND ACCESSORIES		201,141.5
		25630503	SEPARATORS, TREATERS		1,261,959.7

Project#	Project Name	GL Acct#	GL Account Name	2009	Cumulative
		25630505	TANKS		996,614.5
		25630506	FLARE AND VENT SYSTEMS		70,937.5
		25630507	PIPE, VALVES AND FITTINGS		2,533,963.6
		25630560	STRUCTURAL STEEL		1,581,580.4
		25630600	H2S REMOVAL EQUIPMENT		160,141.0
		25630601	INTRUMENTATION, METERS		925,614.0
		25630603	STEAM GENERATOR PACKAGE		24,730.3
		25630607	HEATERS, HEAT EXCHANGERS		302,734.4
9058046F	OPERATIONS EQUIPMENT 16-12-077-09W4	25620180	SUPERVISION & TRAVEL		7,148.9
		25620191	CHEMICALS		166,266.7
		25630403	OTHER TANGIBLE COSTS		36,636.0
		25630507	PIPE, VALVES AND FITTINGS		6,762.5
		25630510	START-UP FLUIDS		5,931.5
				-	**21,150,278.1**

SCADA

Project#	Project Name	GL Acct#	GL Account Name	2009	Cumulative
9058014F	CHRISTINA LK 16-12-077-09W4 FACILTY	25620304	COMMUNICATION AND INSTALLATIONS		15,661.0
		25630601	INTRUMENTATION, METERS		365,558.0
				-	381,219.0

Wireless Equipment at Plant Site

Project#	Project Name	GL Acct#	GL Account Name	2009	Cumulative
9058046F	OPERATIONS EQUIPMENT 16-12-077-09W4	25620304	COMMUNICATION AND INSTALLATIONS		13,525.9
		25630304	TELECOMMUNICATIONS EQUIPMENT (satellite comm)		12,925.0
0916001	CHRISTINA LK 16-12-077-09W4 GAS PLANT	60010019	COMMUNICATION (portable radio)		12,000.0
9078023F	INSTALLATION OF WIRELESS RADIOS AND COMM.	25620609	AUTOMATED RADIO CONTROL EQUIPMENT		116,795.0
					155,245.9

7. FACILITIES

7.1 MAJOR CAPITAL ITEMS

INSTALL BYPASS STATION AROUND V-170

P1B WELLHEAD TIE-IN

REPLACE TORE'S WITH SAND PANS IN V160

REPLACE TORE'S WITH SAND PANS IN V170

INSTALL WELLHEAD PIPING ON P2B

TIE-IN AND WINTERIZE CONDENSATE SYSTEM

INSTALLATION OF A NEW HIGH EFFICIENCY INCINERATOR

7.2 MAJOR CAPITAL ITEMS

This appears to be a redundant section requested by IETP Committee in the listing of the 2008 Annual Project Report Requirements. It is included here to maintain numbering consistent with the 2008 Annual Project Report Requirements document.

7.3 CAPACITY LIMITATION, OPERATING ISSUES AND EQUIPMENT INTEGRITY

It was decided in 2009 to replace the existing P1 and P2 wells due to low production rates and ongoing issues with solids. New wells, P1B and P2B, were drilled close to the combustion zone and the work at the pilot plant in 2009 involved tying in these new wells, as well as making modifications to the inlet vessels to improve their sand handling capabilities. A new high efficiency incinerator was installed to replace the existing incinerator which utilized substantially less fuel gas, and burned hotter allowing complete combustion of produced gas components.

7.4 PROCESS FLOW

Same process flow drawing applies except change color and wording on incinerator to “new high efficiency incinerator”.

Figure 40 shows a simplified flow diagram with the changes under construction or completed at the end of 2008 highlighted in blue.

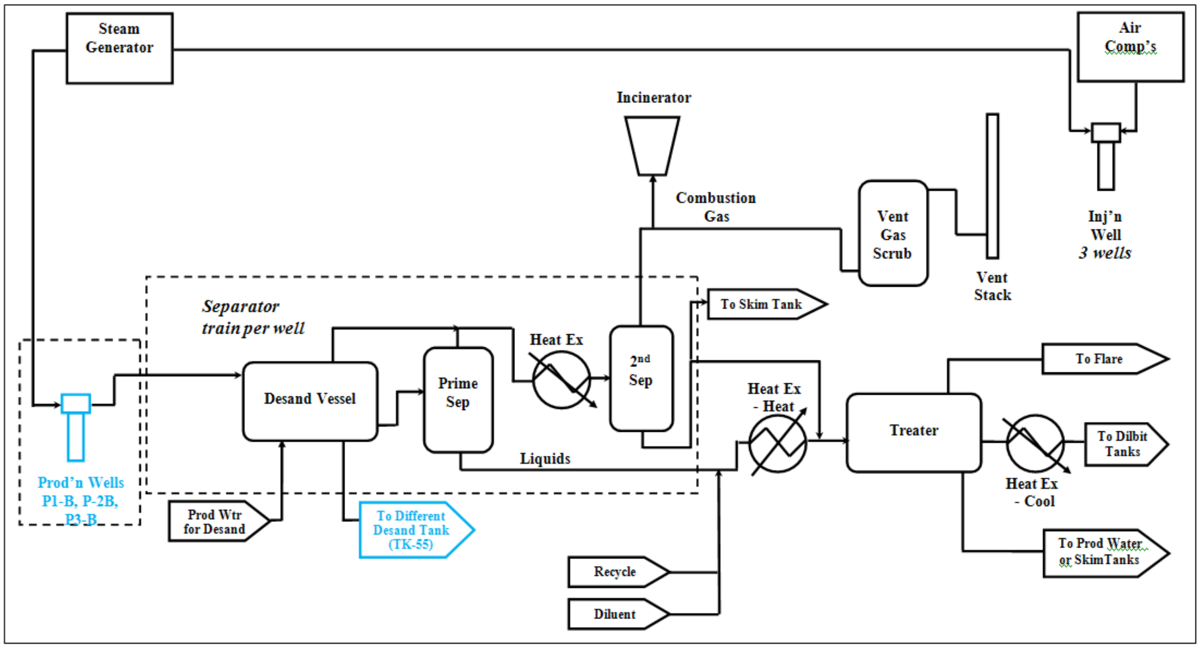


Figure 40: Process Flow Diagram

7.5 SITE DIAGRAM

A site diagram to November 7, 2008 is attached but changes noted in section 7.1 occurred afterward during a winter construction period. Figure 41 shows a picture of the pilot site in June 2008. Changes to the facility are highlighted.

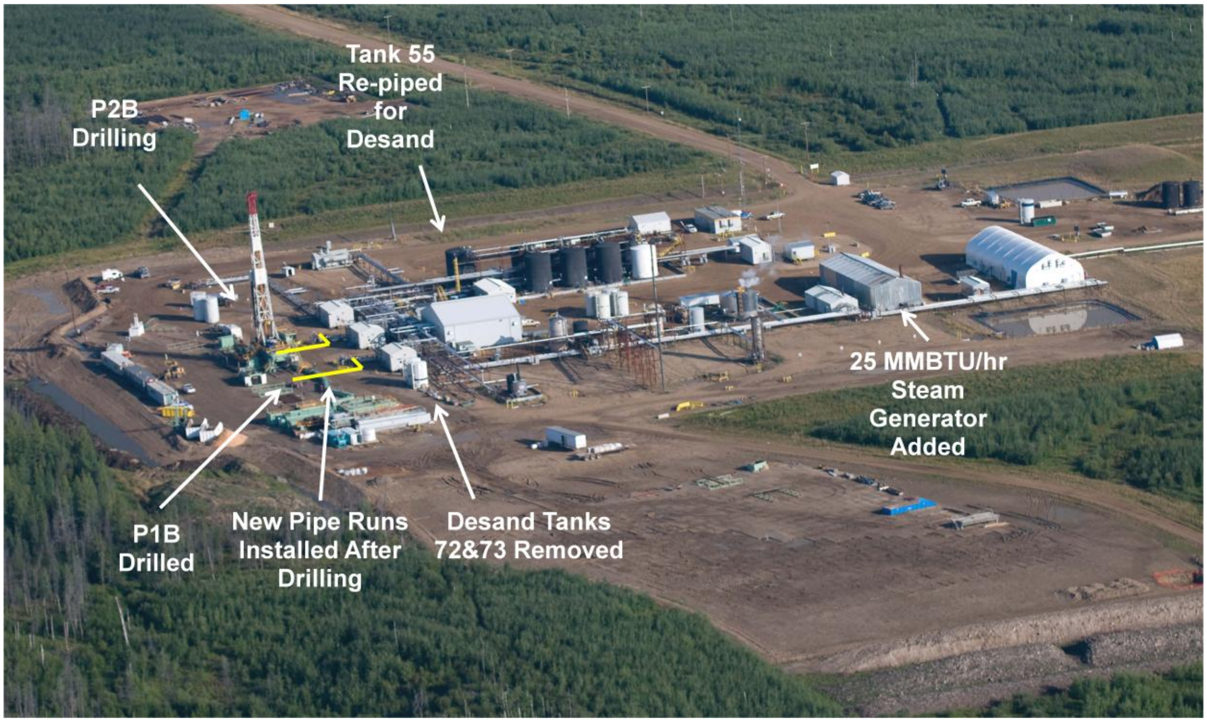


Figure 41: Facility Site Showing 2009 Additions

8. ENVIRONMENT / REGULATORY / COMPLIANCE

8.1 SUMMARY OF PROJECT REGULATORY REQUIREMENTS AND COMPLIANCE STATUS FOR 2009

The following is a list of compliance issues flagged by the ERCB in 2009.

Date	Non-Compliance Notice Issued
April 2009	One high risk enforcement due to pipeline strike during installation. Ground disturbance practice has been enhanced as per ERCB requirements and conditions of the non-compliance order have been satisfied.

Besides direct action and responses to the ERCB for the above items, the following initiatives were undertaken to avoid further issues:

- Evaluated various compliance software alternatives
- Implemented a regulatory communication log to track all regulatory conversations on a project by project basis
- A staff member was designated to coordinate all regulatory activities for the heavy oil business unit

8.1.1 Procedures to Address Environmental and Safety Issues

The following are environmental regulatory requirements and the procedures to address them:

- A 4 station passive sulphur monitoring program surrounding the plant site
- Daily monitoring of vent gas SO2 and H2S concentrations
- Annual plant surveys for fugitive emissions
- Plant site surface water runoff and containment system
- 18 shallow groundwater monitoring wells (early detection of subsurface contamination)
- Dedicated Empress aquifer groundwater temperature, quality and level monitoring
- Ongoing site re-vegetation, weed control and erosion control program
- Surface disturbance reclamation and reforestation program
- Disposal of all oil field and domestic waste at approved sites; for example, CCS Janvier and Newalta Elkpoint

The following are health and safety issues and the procedures to address them:

- Enhanced our Facility, Drilling and Corporate Emergency Response Plan
- Conducted a baseline Health and Safety Program Audit
- Improved our existing health and Safety program including our manual
- Implemented comprehensive incident reporting program for all Whitesands worksites to improve data reliability
- Recognized 1000 days Lost Time Free on December 31st, 2008.

There were no environmental or safety compliance issues during 2008.

8.1.2 Plan for Shut-Down and Environmental Clean-up

When the decision is made to discontinue operation and abandon the pilot a decommissioning plan will be developed as required by Section 5.2 of EPEA Approval 201967-00-01. At that time all equipment will be removed, any contamination issues remediated and the site reclaimed using the stored topsoil and subsoil.

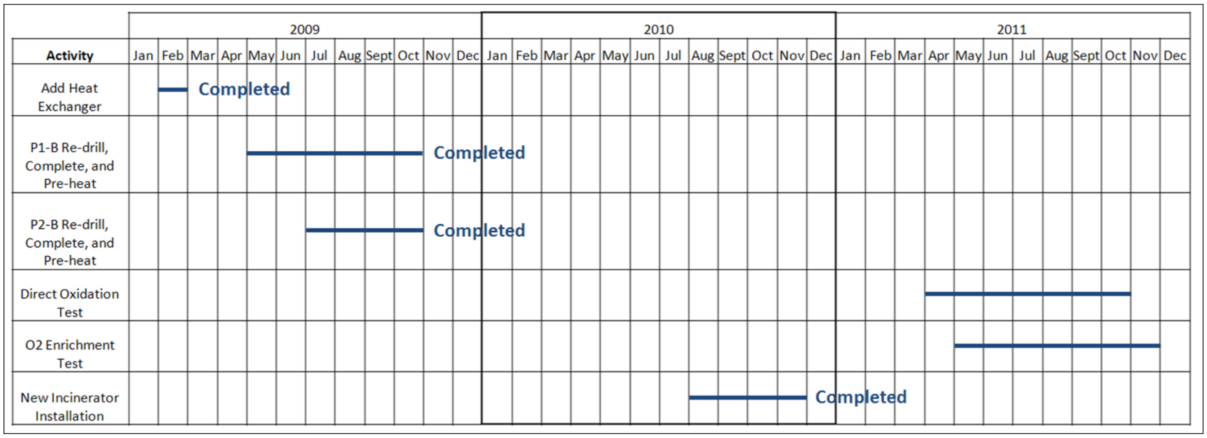
Environment, Health & safety issues:

-No environment or safety compliance issues were reported for 2009

9. FUTURE OPERATING PLAN

9.1 PROJECT SCHEDULE

The following diagram shows anticipated changes completed since the last report and anticipated changes up to year 2011. P1 & P2 were redrilled as P1B and P2B in 2009 to test new liners for reducing excessive sand production as seen in earlier due to bigger liner slots of the initial liners in P1 and P2. The facility was upgraded with an oil cooler after the treater and a new incinerator was installed. A field test of direct oxidation for recovering sulphur from produced THAI™ gas is planned for mid 2011 . A test using O_2 enrichment is also under consideration For 2011.



9.2 CHANGES TO PILOT OPERATIONS

Replacement wells for P1 and P2 to reduce sand production to manageable levels have been successfully drilled, completed and put on production. The proposed modifications to the facilities will not alter the operating strategy for the reservoir but should further improve facility operations.

9.3 OPTIMIZATION STRATEGIES

- The replacement of P1 and P2 with liners having smaller slot sizes as in P1B & P2B has significantly reduced sand production and associated sand handling costs. Direct oxidation as a means of recovering sulphur at a reduced cost for a commercial project will be tested in a slipstream unit (uses a side-stream of produced gas for testing).
- A possible test using O_2 enrichment at one of the injectors is being considered but is in early stages of scoping as a test project.

9.4 SALVAGE UPDATE

No reclamation or salvage has been conducted to date.

10. INTERPRETATIONS AND CONCLUSIONS

Fluid quality Summary:

- Oil
    - Consistent API upgrade and viscosity reduction
    - Significant increase in Volatiles and Saturates
    - Notable reduction of Resins and Asphaltenes
    - Increased carryover of lighter ends to the secondary separators due to higher surface temperatures
    - Early production from new wells is not upgraded
- Gas
    - No issues with O_2 in produced gas
    - Free H_2 production up to 8%
    - Up to 5% of hydrocarbons (C_1–C_5) with a gas heating value 85-120 Btu/scf, suitable for use in Low-Btu steam generators
    - Expected levels of CO_2 and CO production
    - H_2S levels consistent in produced gas, off-set by reduction of sulphur in produced oil

Sub surface

- Impact of existing water disposal scheme on project performance had not been observed
- Increased lighter end production due to higher wellbore temperatures
- Temperature monitoring has indicated that greater part of the reservoir can be affected by heat potentially increasing recoverable reserves

General conclusions:

- THAI™ is a robust process. Combustion can easily be re-started (A-3 injection resumed after 100 days of suspension & A-2 resumed after 30 days of shut-in)
- Observed temperatures and gas and fluid analyses indicate that THAI™ recovery process and upgrade are occurring consistently.
- Observed temperatures and gas analyses demonstrate that continuous high temperature oxidation reactions are occurring under a wide range of operating conditions.
- The process is influenced by bottom water. Observation well data indicated initial combustion expansion appears to have first occurred at the oil/water interface in the toe region of P1 and P2. This was not evident at the toe of P3 since the bottom water was not present there.
- Improved sand control has been achieved by installing a new type of well liner (FacsRite) –
- Higher back pressure as helped with on-steam factor.
- Increased production of lighter end products from the secondary separators could potentially provide for a new product stream(10 to 14% of the oil produced)

Difficulties encountered:

- Higher than expected temperatures were seen within the wellbore.
- Higher than expected sand production was experienced. Desand vessels were installed to manage the high sand production.
- Higher than expected production of H_2S was experienced. The vent gas system was modified to handle it. However, for a larger recovery scheme a sulphur recovery scheme compatible with produced combustion gas will need to be incorporated.
- Water disposal at the plant proved inadequate and another disposal well was required.

Technical and economic viability

- First wells have demonstrated the feasibility of the toe-to-heel air injection process. Observation of the temperatures indicates that the combustion front indeed moves from toe to heel and that the produced oil is upgraded.
- Surface facility changes to handle produced sand have been helpful. However, the original liner design for the P wells is now considered inadequate.
- H_2S has been successfully and economically handled for the pilot using an incinerator. A sulphur recovery system for commercial scale THAI™ operations still needs to be designed.
- Comprehensive operational data has enabled the development of new technology, effective problem solving, and future integrated process design.

Overall effect on bitumen recovery:

- Since the project is still in the early stages, the oil production data gathered so far is not sufficient to provide a basis to revise the estimate of ultimate recovery.

P1 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	5.14	0.23	71.23	1.90	4.83	14.71	0.82	0.42	0.11	0.06	0.56	100.01	7.85	0.74
Feb-09	5.25	0.28	69.85	2.38	6.36	13.74	0.90	0.47	0.11	0.06	0.59	100.00	5.92	0.85
Mar-09	3.56	0.20	73.06	1.62	5.59	13.95	0.86	0.49	0.12	0.06	0.49	100.01	10.31	1.16
Shut-in														

P2 Monthly Gas Analysis

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	2.38	0.24	74.25	0.64	5.39	14.99	0.99	0.52	0.13	0.06	0.40	100.00	23.58	1.08
Feb-09	2.28	0.24	75.66	0.65	4.68	14.54	0.84	0.54	0.12	0.07	0.39	100.00	22.80	1.33
Mar-09	1.66	0.22	77.29	0.65	3.73	15.10	0.58	0.37	0.09	0.04	0.26	100.00	23.67	1.25
Apr-09	2.44	0.26	73.60	0.79	5.87	15.58	0.62	0.35	0.08	0.04	0.35	100.00	20.35	0.82
May-09	1.64	0.35	75.52	0.50	5.21	15.47	0.60	0.32	0.07	0.04	0.29	100.00	31.96	1.01
Jun-09	1.71	0.58	76.29	0.70	3.51	16.01	0.52	0.28	0.07	0.03	0.31	100.00	24.70	0.82
Jul-09	1.89	0.48	73.99	0.64	4.56	17.30	0.47	0.28	0.06	0.03	0.31	100.00	27.52	0.39
Shut-in														

P3 Monthly Gas Analysis

Shut-in

Composite Monthly Gas Analysis - Sampler after the Sweetener

Month	H2	O_2	N_2	CO	CH_4	CO_2	C_2H_6	C_3H_8	C_4	C_5	H_2S	Total	CO_2/CO RATIO	AAHCR
Jan-09	4.00	0.07	73.05	1.40	5.24	14.61	0.92	0.51	0.13	0.06	0.00	100.00	10.54	1.04
Feb-09	3.93	0.15	73.84	1.65	5.71	13.15	0.86	0.55	0.11	0.06	0.00	100.00	8.30	1.53
Mar-09	2.91	0.03	74.20	1.28	5.38	14.78	0.79	0.47	0.10	0.05	0.00	100.00	12.42	1.09
Apr-09	2.74	0.08	74.81	1.39	5.37	14.38	0.66	0.43	0.09	0.05	0.00	100.00	10.81	1.26
May-09	2.37	0.10	73.88	1.54	4.94	15.96	0.63	0.43	0.09	0.04	0.01	100.00	13.02	0.67
Jun-09	2.91	0.16	73.28	1.48	4.16	16.75	0.65	0.46	0.09	0.05	0.00	100.00	12.29	0.42
Jul-09	4.00	0.13	70.83	1.50	5.27	17.08	0.62	0.45	0.08	0.04	0.00	100.00	12.35	0.24
P2 Shut-in														

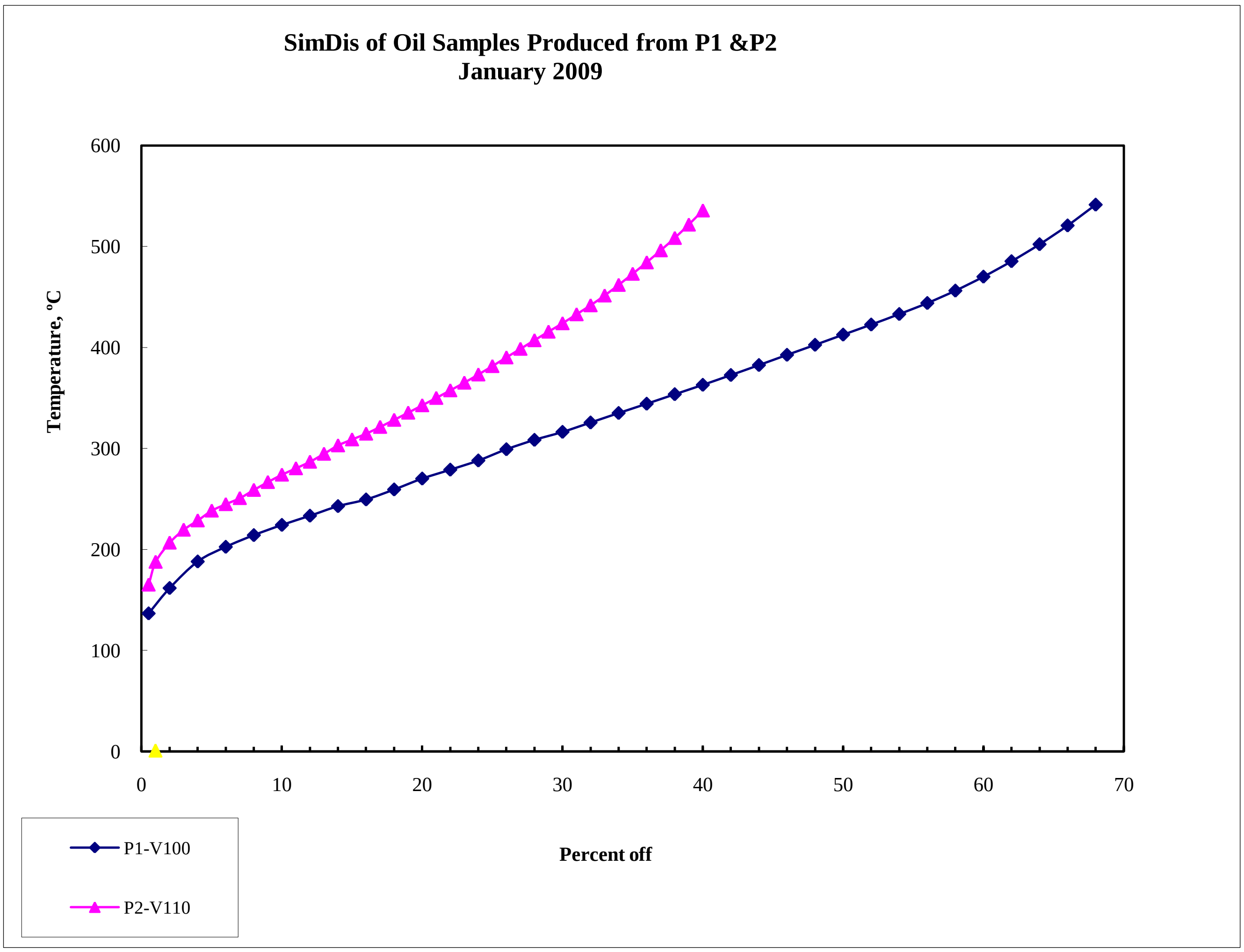
P1 & P2 Monthly Oil Analysis: January 2009

CCC Sample ID	P1-13-09	P2-13-09
Sampling Date	5-Jan-09	5-Jan-09
Sampling Point	V-100	V-110
Viscosity, cP @ 20°C	1158.59	12204
Density @ 15.5ºC	0.9921	1.0051
API Gravity @ 15.6ºC	11.12	9.28
Total Sulphur, Wt%	2.31	1.66
Total acid number, mg KOH/g	2.26	3.57
Bromine number, g/100g	10.92	6.17
Pour Point, °C	-24	-21
SARA analysis, %		
Asphaltene	13.72	17.57
Resin	17.76	20.91
Aromatics	33.65	28.49
Saturates	15.98	13.84
Volatiles	18.89	19.18
Water content, wt%	41	50

Analysis	P1-V100	P2-V110
Metal content, mg/kg		
Tin	0	1
Lead	1	1
Copper	0.2	0.3
Aluminum	6	9
Silicon	21	38
Iron	15	32
Chromium	0.4	0.6
Silver	0	0
Zinc	0.3	0.9
Magnesium	1	5
Nickel	46	37
Barium	0	0
Sodium	15	198
Calcium	0.7	9
Vanadium	115	90
Phosphorous	2	4
Molybdenum	5	6
Boron	3	11
Manganese	0	0

Simulated Distillation

P1-V100		P2-V110	
% off	Temp. ºC	% off	Temp. ºC
0.5	136.6	0.5	165.1
2	161.7	1	187.7
4	188.0	2	206.7
6	202.5	3	219.5
8	214.1	4	228.7
10	224.2	5	238.4
12	233.3	6	244.8
14	242.8	7	250.8
16	249.4	8	258.9
18	259.3	9	266.7
20	270.1	10	274
22	278.9	11	280.3
24	288	12	286.8
26	299.1	13	294.7
28	308.4	14	303
30	316.3	15	308.9
32	325.6	16	314.6
34	335	17	321.3
36	344.2	18	328.3
38	353.6	19	335.4
40	362.9	20	342.7
42	372.6	21	350
44	382.5	22	357.5
46	392.6	23	365.1
48	402.5	24	373.2
50	412.6	25	381.5
52	422.6	26	390.1
54	433	27	398.6
56	443.9	28	407.1
58	456.2	29	415.6
60	470	30	423.9
62	485.3	31	432.8
64	502.1	32	441.7
66	520.7	33	451.4
68	541.3	34	461.9
		35	472.9
		36	484.2
		37	496.1
		38	508.4
		39	521.6
		40	535.6
% Residue	31.7	% Residue	59.4



SimDis of Oil Samples Produced from P1 &P2
January 2009
Temperature, °C
Percent off
0
100
200
300
400
500
600
0
10
20
30
40
50
60
70
P1-V100
P2-V110

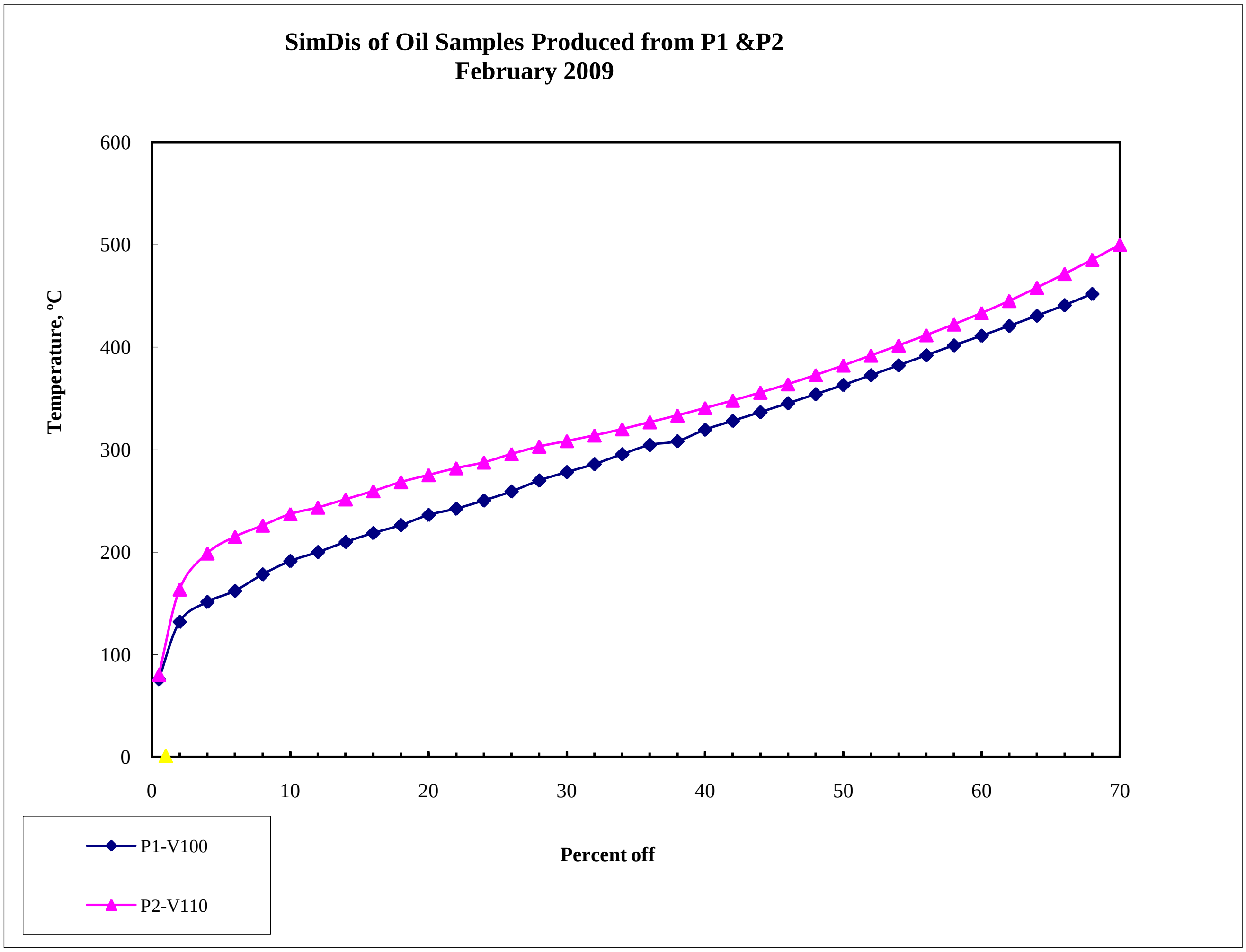
P1 & P2 Monthly Oil Analysis: February 2009

CCC Sample ID	P1-33-09	P2-45-09
Sampling Date	2-Feb-09	9-Feb-09
Sampling Point	V-100	V-110
Viscosity, cP @ 20°C	1,310	1,513
Density @ 15.5ºC	0.9940	0.9968
API Gravity @ 15.6ºC	10.85	10.45
Total Sulphur, Wt%	2.24	3.29
Total acid number, mg KOH/g	2.37	1.78
Bromine number, g/100g	11.18	11.61
SARA analysis, %		
Asphaltene	16.65	12
Resin	18.17	18.79
Aromatics	33.81	39.55
Saturates	17.39	19.77
Volatiles	13.98	9.89

Analysis	P1-V100	P2-V110
Metal content, mg/kg		
Tin	0	0
Lead	3.6	2
Copper	0	0
Aluminum	2	4
Silicon	11.4	15.5
Iron	36.2	12
Chromium	0.1	0.1
Silver	0	0
Zinc	0	0
Magnesium	5.3	1
Nickel	40	52
Barium	0	0
Sodium	224.1	44.7
Calcium	15.8	7.1
Vanadium	100.3	132.3
Phosphorous	3.4	2.2
Molybdenum	4.2	7
Boron	27.8	8.8
Manganese	0	0

Simulated Distillation

P1-V100		P2-V110	
% off	**Temp. ºC**	**% off**	**Temp. ºC**
0.5	75.9	0.5	80.2
2	132	2	163.6
4	151.4	4	198.8
6	162.2	6	215
8	178.3	8	226
10	191.3	10	237.2
12	200	12	243.6
14	209.9	14	251.6
16	218.6	16	259.6
18	226.3	18	268.4
20	236.3	20	275.3
22	242.4	22	282
24	250.4	24	287.6
26	259.2	26	295.8
28	269.9	28	303.1
30	278.1	30	308.5
32	285.9	32	314
34	295.5	34	320.1
36	304.6	36	326.9
38	308.3	38	333.5
40	319.5	40	340.7
42	328.1	42	348
44	336.6	44	355.8
46	345.3	46	364
48	354.1	48	372.9
50	363.1	50	382.3
52	372.6	52	392
54	382.3	54	401.9
56	392.1	56	411.9
58	401.8	58	422.4
60	411.2	60	433.5
62	420.8	62	445.3
64	430.7	64	458.2
66	441	66	471.7
68	452	68	485.5
70	463.8	70	500.2
72	475.9	72	515.5
74	488.4	74	534.4
76	501.4	75	539.4
78	514.9		
80	528.9		
82	543.2		
% Residu	**18**	**% Residu**	**25**


SimDis of Oil Samples Produced from P1 &P2
February 2009
Temperature, °C
0
100
200
300
400
500
600
0
10
20
30
40
50
60
70
Percent off
P1-V100
P2-V110

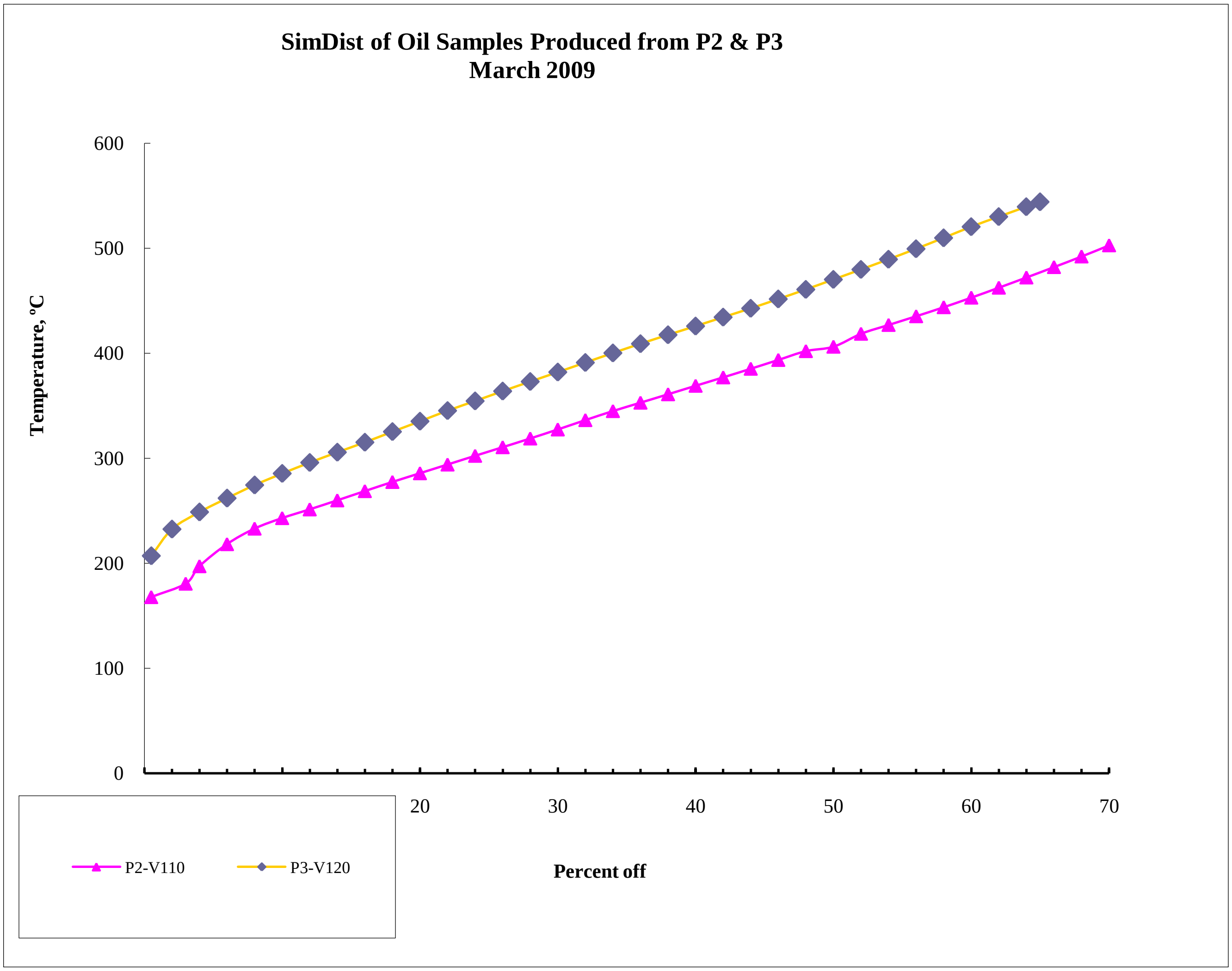
P2 & P3 Monthly Oil Analysis: March 2009

CCC Sample ID	P2-62-09	P3-125-09
Sampling Date	2-Mar-09	12-Mar-09
Sampling Point	V-110	V-120
Viscosity, cP @ 20°C	1,083	75,609
Density @ 15.5ºC	0.9928	1.01
API Gravity @ 15.6ºC	11.03	8.94
Total Sulphur, wt%	1.76	2
Total acid number, mg KOH/g	2.42	2.83
Bromine number, g/100g	7.67	7.00
SARA analysis, %		
Asphaltene	16.39	16.96
Resin	25.14	25.57
Aromatics	31.43	32.89
Saturates	16.72	17.91
Volatiles	10.31	6.68
Pour Point, °C	-18	-9
Conradson-Carbon Residue, wt%	9.2	10.06

Analysis	P2-V110	P2-V110
Metal content, mg/kg		
Tin	0	0
Lead	1	1
Copper	0.3	0.4
Aluminum	2	2
Silicon	4	14
Iron	5	17
Chromium	0.5	0.7
Silver	0	0
Zinc	0.7	0.5
Magnesium	0.2	0.7
Nickel	44	0
Barium	0	0
Sodium	11	28
Calcium	1	1
Vanadium	102	115
Phosphorous	2	3
Molybdenum	5	7
Boron	2	3
Manganese	0	0

Simulated distillation

P2-V110		P3-V120	
% off	Temp. ºC	% off	Temp. ºC
0.5	167.8	0.5	207.0
3	180.6	2	232.4
4	197.2	4	248.7
6	218.2	6	261.9
8	233	8	274.4
10	243	10	285.4
12	251.3	12	295.8
14	259.9	14	305.6
16	268.7	16	315.1
18	277.4	18	325.2
20	285.7	20	335.1
22	294	22	345.2
24	302.3	24	354.4
26	310.5	26	363.8
28	318.8	28	372.9
30	327.4	30	381.9
32	336.3	32	391
34	344.9	34	400.1
36	352.9	36	408.9
38	360.9	38	417.4
40	369	40	425.7
42	377	42	434.2
44	385.2	44	442.6
46	393.6	46	451.5
48	402	48	460.6
50	406.2	50	470.1
52	418.5	52	479.6
54	426.9	54	489.3
56	435.2	56	499.3
58	443.8	58	509.7
60	452.9	60	520.3
62	462.4	62	529.9
64	472.1	64	539.3
66	482	65	544
68	492.1		
70	502.7		
72	513.6		
74	524.4		
76	534.1		
78	543.9		
% Residue	22	% Residue	35


SimDist of Oil Samples Produced from P2 & P3
March 2009
Temperature, °C
600
500
400
300
200
100
0
20
30
40
50
60
70
Percent off
P2-V110
P3-V120

P2 & P3 Monthly Oil Analysis: April 2009

CCC Sample ID	**P2-99-09**	**P3-157-09**
Sampling Date	13-Apr-09	14-Apr-09
Sampling Point	V-110	P3B well
Viscosity, cP @ 20°C	46,424	16,282
Density @ 15.5ºC	1.0110	1.002
API Gravity @ 15.6ºC	8.47	9.7
Total Sulphur, wt%	2.75	3.12
Total acid number, mg KOH/g	2.90	3.47
Bromine number, g/100g		
SARA analysis, %		
Asphaltene	17.54	15.61
Resin	26.99	21.49
Aromatics	32.16	35.19
Saturates	17	16.14
Volatiles	6.31	11.57
Pour Point, °C	-9	-15

Analysis	**P2-V110**	**P3-V120**
Metal content, mg/kg		
Tin	0	0
Lead	0.7	0.5
Copper	0	0.3
Aluminum	5.6	5.8
Silicon	15.4	14.7
Iron	10	88.1
Chromium	0	0.6
Silver	0	0
Zinc	0.8	0.3
Magnesium	0.6	0
Nickel	47.2	53.9
Barium	0	0
Sodium	272	59.9
Calcium	18.7	53
Vanadium	122.9	147.8
Phosphorous	0.3	0
Molybdenum	4.6	6.7
Boron	32.2	15.2
Manganese	0	0.7

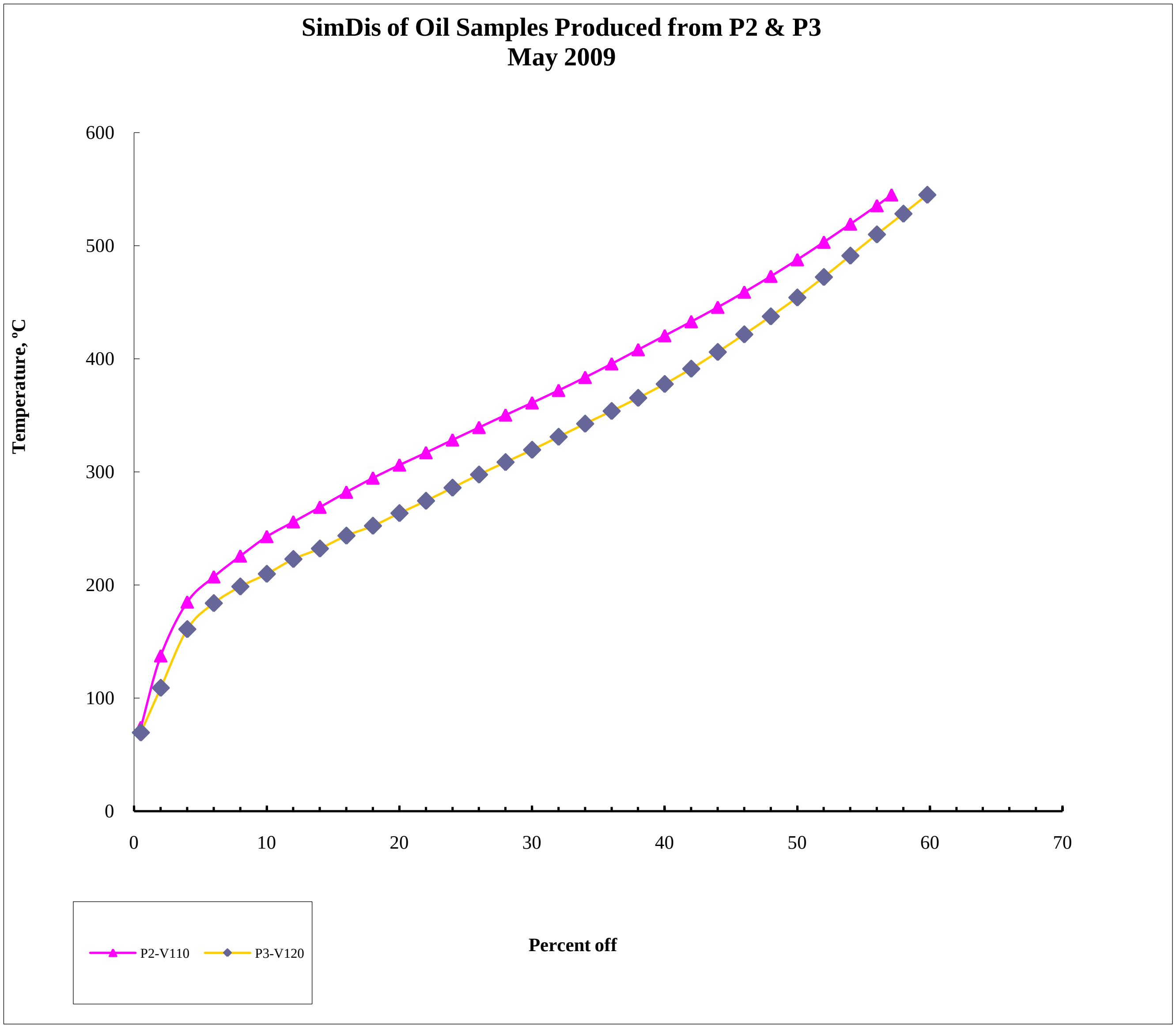
P2 & P3 Oil Monthly Analysis: May 2009

CCC Sample ID	P2-136-09	P3-183-09
Sampling Date	18-May-09	9-May-09
Sampling Point	P2-V110-Treate	P3B-V120
Viscosity, cP @ 20°C	7,051	2,064
Density @ 15.5ºC	0.9988	0.9865
API Gravity @ 15.6ºC	10.18	11.93
Total Sulphur, wt%	3.67	4.16
Molecular mass, g/mol	428	372
Total acid number, mg KOH/	2.09	1.93
Bromine number, g/100g	13.01	10.99
SARA analysis, %		
Asphaltene	16.23	12.73
Resin	22.72	20.13
Aromatics	30.95	34.45
Saturates	13.38	16.59
Volatiles	16.73	16.1
Pour Point, °C	-9	-18

Analysis	P2-V110	P3B-V120
Metal content, mg/kg		
Tin	4	2
Lead	5	1
Copper	0.3	0.3
Aluminum	21	54
Silicon	35	84
Iron	47	73
Chromium	0.2	0.2
Silver	0	0
Zinc	2	1
Magnesium	0.3	0.6
Nickel	61	57
Barium	0	0
Sodium	120	46
Calcium	43	14
Vanadium	168	157
Phosphorous	0	0
Molybdenum	6	6
Boron	23	4
Manganese	0	1

SimDist Analysis results:
% weight versus boiling point

P2-V110		P3-V120	
% off	Temp. ºC	% off	Temp. ºC
0.5	74	0.5	69.5
2	137.3	2	109
4	184.9	4	160.9
6	207.2	6	183.9
8	225.6	8	198.6
10	242.8	10	209.8
12	255.8	12	222.9
14	268.8	14	232.2
16	282.1	16	243.6
18	294.6	18	252.3
20	306.1	20	263.5
22	317	22	274.4
24	328.3	24	286
26	339.3	26	297.6
28	350.3	28	308.6
30	361.1	30	319.5
32	372.1	32	331
34	383.6	34	342.6
36	395.6	36	353.8
38	408.1	38	365.4
40	420.5	40	377.7
42	432.9	42	391.2
44	445.6	44	406
46	459	46	421.6
48	473	48	437.5
50	487.7	50	454.2
52	503.2	52	472.3
54	519.2	54	491.2
56	535.5	56	510
57.1	545	58	528.3
		59.8	545
% Residue	42.9	% Residue	40.2



SimDis of Oil Samples Produced from P2 & P3
May 2009
Temperature, °C
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
Percent off
P2-V110
P3-V120

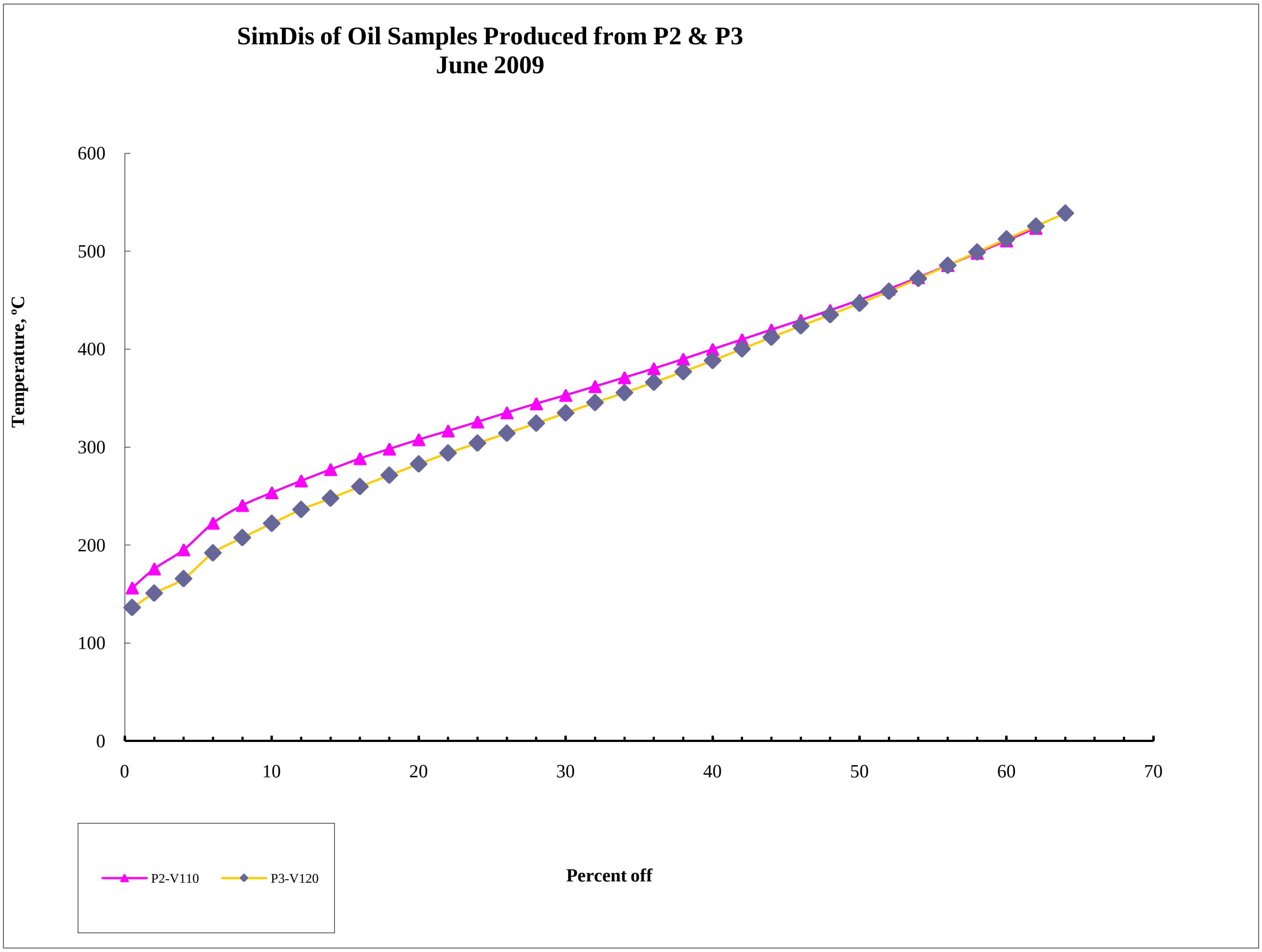
P2 & P3 Oil Monthly Analysis: June 2009

CCC Sample ID	**P2-158-09**	**P3-220-09**
Sampling Date	7-Jun-09	9-Jun-09
Sampling Point	P2-V110	P3B-V120
Viscosity, cP @ 20°C	14,443	6,369
Density @ 15.5ºC	1.0026	0.9936
API Gravity @ 15.6ºC	9.63	10.90
Total Sulphur, wt%	3.84	4.13
Molecular mass, g/mol	429	387
Total acid number, mg KOH/g	1.78	1.69
Bromine number, g/100g	3.06	3.33
% distillate under 327°C	25.4	26.41
Bromine number of distillate, g/100g	12.05	12.62
SARA analysis, %		
Asphaltene	16.52	13.94
Resin	19.67	21.38
Aromatics	37.02	35.68
Saturates	17.25	15.83
Volatiles	9.53	13.17
Pour Point, °C	-9	-12

Analysis	**P2-V110**	**P3B-V120**
Metal content, mg/kg		
Tin	0	0
Lead	2	4
Copper	0	0.1
Aluminum	11	111
Silicon	20	217
Iron	52	175
Chromium	0	0.4
Silver	0	0
Zinc	1	0.2
Magnesium	3	10
Nickel	68	63
Barium	0	0
Sodium	108	50
Calcium	57	17
Vanadium	171	158
Phosphorous	3	6
Molybdenum	7	9
Boron	22	24
Manganese	0	6

SimDist Analysis results:
% weight versus boiling point

P2-V110		**P3-V120**	
% off	**Temp. ºC**	**% off**	**Temp. ºC**
0.5	156.5	0.5	136.2
2	175.92	2	150.9
4	195.4	4	165.7
6	222.6	6	192
8	240.7	8	207.6
10	253.6	10	222.1
12	265.7	12	236.3
14	277.3	14	247.8
16	288.5	16	259.7
18	298.2	18	271.3
20	307.8	20	282.8
22	316.7	22	294
24	325.9	24	304.1
26	335.3	26	314.2
28	344.5	28	324.4
30	353.1	30	334.9
32	362.1	32	345.5
34	371.1	34	355.6
36	380.3	36	366.2
38	390	38	377
40	400	40	388.4
42	409.9	42	400.3
44	419.9	44	412.2
46	429.7	46	423.8
48	439.8	48	435.2
50	450.2	50	446.8
52	461.4	52	459.1
54	473.2	54	472.2
56	485.6	56	485.6
58	498.2	58	499.2
60	510.8	60	512.5
62	523.6	62	525.6
64	536.7	64	538.9
65.2	545	64.9	545
% Residue	**34.8**	**% Residue**	**35.1**


SimDis of Oil Samples Produced from P2 & P3
June 2009
Temperature, ºC
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
Percent off
P2-V110
P3-V120

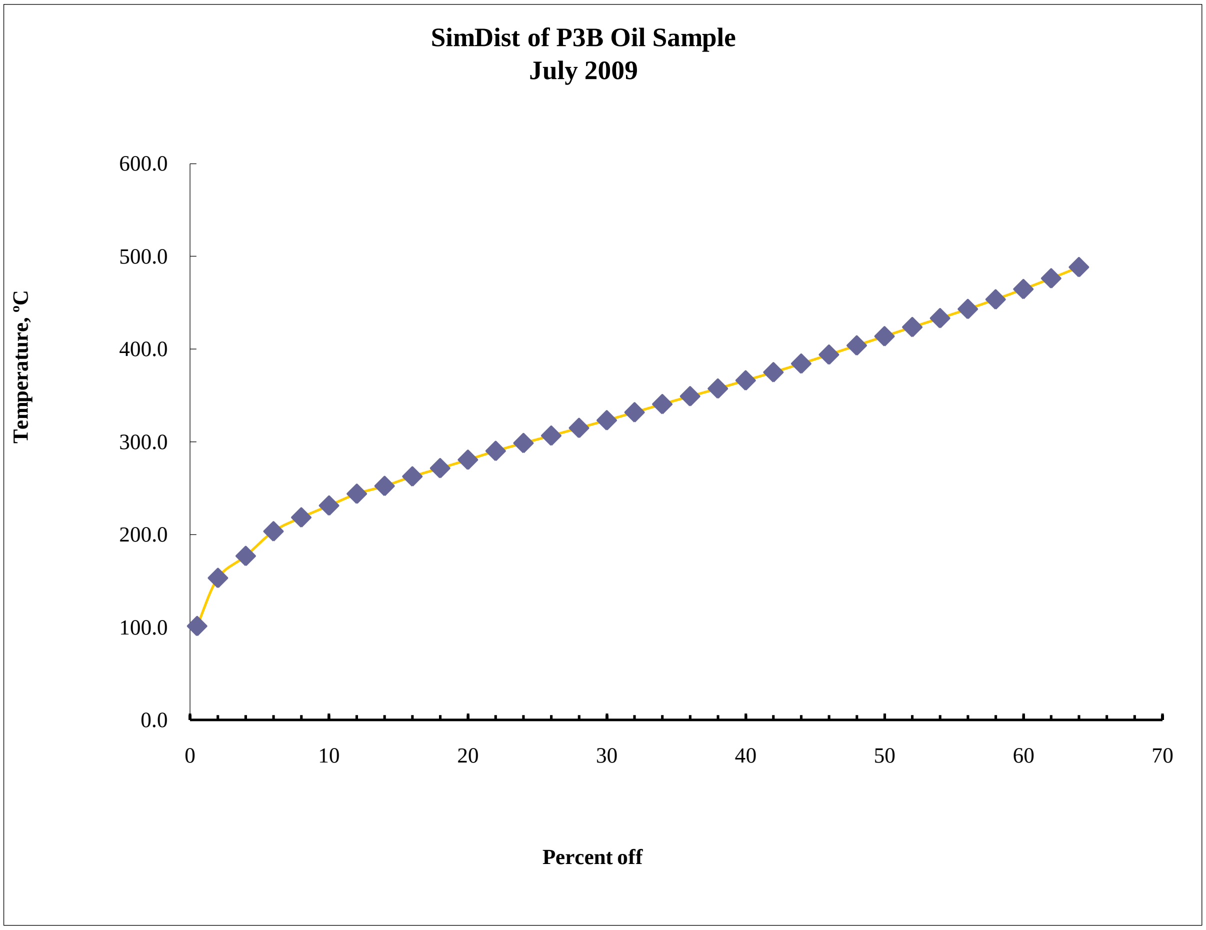
P2 & P3B Oil Monthly Analysis: July 2009

CCC Sample ID	P2-184-09	P3-247-09
Sampling Date	2-Jul-09	8-Jul-09
Sampling Point	P2-V110	P3B
Viscosity, cP @ 20°C	35,016	2,245
Density @ 15ºC, g/cm^3	1.0108	0.9904
API Gravity @ 15.6ºC	8.49	11.4
Total Sulphur, wt%	4.49	4.3
Molecular mass, g/mol	493	377
Total acid number, mg KOH/g	2.39	1.89
Bromine number, g/100g	3.87	3.68
% distillate under 327°C	35.26	25.02
Bromine number of distillate, g/100g	10.99	14.7
SARA analysis, wt%		
Asphaltene	17.5	13.91
Resin	20.82	19.36
Aromatics	35.33	35.8
Saturates	15.54	16.44
Volatiles	10.81	14.49
Pour Point, °C	-3	-18

Analysis	P2-V110	P3B
Metal content, mg/kg		
Tin	0	0
Lead	1	0
Copper	0	0
Aluminum	7	28
Silicon	18	44
Iron	22	78
Chromium	0.3	0.7
Silver	0	0
Zinc	1	0.6
Magnesium	6	0
Nickel	85	68
Barium	0	0
Sodium	394	17
Calcium	97	292
Vanadium	233	187
Phosphorous	0	0.7
Molybdenum	7	7
Boron	15	4
Manganese	2	1

SimDist Analysis results

P3B	
% off	**Temp. ºC**
0.5	101.1
2	153
4	176.7
6	203.3
8	218.3
10	231.1
12	243.8
14	252.2
16	262.5
18	271.4
20	280.5
22	290
24	298.5
26	306.5
28	314.8
30	323.1
32	331.7
34	340.5
36	349
38	357.3
40	366.1
42	374.9
44	384.2
46	393.9
48	403.8
50	413.7
52	423.6
54	433.2
56	443.1
58	453.5
60	464.6
62	476.2
64	488.3
66	500.9
68	513.7
70	526.7
72	540.2
% Residue	**27.1**


SimDist of P3B Oil Sample
July 2009
Temperature, °C
600.0
500.0
400.0
300.0
200.0
100.0
0.0
0
10
20
30
40
50
60
70
Percent off

THAI™ Process
3-D Combustion Cell Test
of Whitesands Bitumen

Conducted by

Archon Technologies Ltd.,

a wholly-owned subsidiary of

Petrobank Energy and Resources Ltd.

June 2009
Calgary, Alberta

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Lead Scientific Staff

Ahmed Shahin, Ph.D., Laboratory Manager
Conrad Ayasse, Ph.D., V.P. Technology

Abstract

Two THAI™ process laboratory combustion tests were conducted in Archon Technology's Calgary Research Center using a bitumen sample provided by Whitesands Insitu Ltd., Canada, to evaluate the ease of combustion ignition, combustion stability, shape of the combustion front, composition of combustion gases, oil recovery factor and degree of oil upgrading. The tests were entirely successful, with ignition at 300 ºC, a high combustion temperature maximum of 600 ºC, a stable combustion front movement with a quasi-vertical burning front, normal combustion gas composition with CO_2/CO ratio ~ 4 for Test **I (Single air injection port)** and **II (Two air injection ports)** and about 60 % oil recovery. The viscosity and API gravity of THAI™ oil composite produced from Test **I** were 52 cP at 20ºC and 18.5 °API, respectively. For Test **II** the values were 115 cP and 17 °API. The increase in saturates and decrease in asphaltenes, sulphur and heavy metals indicated an increase in the bitumen upgrading and added substantially to the value of the bitumen.

1. Introduction

Until 2005, the only THAI™ 3-D combustion test cell was housed at the University of Bath in the U.K. Over 70 runs were conducted with that equipment by Dr. Malcolm Greaves and his IOR Research Group. A number of papers resulting from the research are listed in the Bibliography.[1-4] Following Dr. Greaves' retirement the equipment was dismantled. In 2007, Archon Technologies set up its own research facilities in Calgary to continue the THAI™ research and to test a variety of heavy oils and bitumen for applicability to the THAI™ process.

2. Purpose

The purpose of the tests was to assess the suitability of a bitumen sample provided by Whitesands Insitu Ltd., Canada for use in the THAI™ in situ combustion process based on:

- the ease of ignition,
- stability of the burning front and front shape,
- sand temperatures,
- composition of produced gases, and
- produced-oil properties including
    - viscosity,
    - API gravity,
    - SARA composition,
    - Molecular weight
    - sulphur content,
    - metals content

3. Procedures

a) Materials used

Artificial oil sand was prepared by making the homogeneous mixtures given in Table 1.

The sand and clay were placed in a cement mixer, the water added and then the oil. Homogeneity was assured by manually breaking up any lumps that formed while churning the mixture.

b) Cells completion and packing

Two thick-walled 316 stainless steel 3-D cells were fitted with a 5mm inner lining of high-temperature ceramic insulation. The two 3-D cells were brought to similar dimensions (Table 1) with high-temperature ceramic insulation sheets of 50mm thickness. Each cell had 72 thermocouple ports on the top surface. In the first experiment, a production well consisting of 6.4mm internal diameter perforated tubing having an 80-mesh screen wrapped around it to keep out sand, was placed at the center base of the cell. However, a production well of 9.5mm internal diameter perforated tubing was used in the second experiment. The last 40mm of the production wells were not perforated to provide an offset of the first perforations from the points of air injection. In Test **I**, 5 mm perforated air injection tubing penetrated the cell at the upper center zone of the cell, while in Test **II** two 5 mm perforated air injection tubes penetrated the cell at the upper corners. The cells were packed with oil sand by slow additions followed by tamping with a heavy steel rod with a plate at the end. The production tubing was passed through the gasketed end plate and the bolts were secured. Using a lab crane, the packed cell was placed inside a large steel box under a fume shroud. Thermocouples were inserted in 9-rows of 8 thermocouples set at 3 different levels within the oil sand. A picture of the cell is shown in Figure 1.

c) Experimental set-up

Figure 2 shows the experimental set-up. An air compressor provided air to the 3-D cell at up to 689 kPa (100 psia). Nitrogen was available for cell pre-heating at up to 700 kPa pressure. Typically, the injection pressure was 276 kPa (40 psia) at start-up. Both the air and nitrogen were flow-controlled. The oil sand in the vicinity of the air injectors was pre-heated with hot nitrogen by heating the 3.2 mm (1/8 inch) feed line with DC current from a DC inverted-arc welder. Cell surface temperatures were measured with thermocouples and controlled with band heaters. The produced fluids entered a hot separator, where high-boiling oil was recovered. The gas and low-boiling materials were cooled to separate water and oil from the gas phase and these liquids were combined with product from the hot separator. The cooled gas was passed through Drierite (anhydrous calcium sulfate), though CO_2 and O_2 continuous analyzers and finally through a gas chromatograph equipped with a thermal conductivity detector. A back-pressure control valve was placed on the gas stream after the cold separator to maintain cell back-pressure at 204-239 kPa (15-20 psig).

4. Results and Observations

Hot nitrogen was introduced at the air inlets until the first thermocouples reached 300 ºC, and then the feed gas was switched to air. The experimental parameters are provided in Table 1. A stable combustion was achieved after 4.0 hours. The air injection rate varied between 8 and 10 liters per minute (Test **I**), which provided an air flux between 5 and 6 m^3/m^2 hr. However throughout Test **II,** the air injection rate varied between 10 to 13 liters per minute providing an air flux between 6 and 8 m^3/m^2 hr. Liquid products of oil and water were collected every hour from the high-temperature and low-temperature separators and re-combined. The temperature profile was recorded every 10-seconds, Figure 3. The products of every three hours were combined together as one sample for analysis. The dried gas stream passed through a dual O_2/CO_2 continuous analyzer to monitor O_2 for safe operation and CO_2 to assess the efficiency of combustion. Calculated gas phase parameters measuring the efficiency of the burn are given in

Table 2. The overall oil recovery calculated for Test **I** (58.85 % OOIP) was in a good agreement with that calculated for Test **II** (58.05 % OOIP), Table 2. Gas samples were analyzed hourly by gas chromatography and the average is shown in Table 3. The high CO_2/CO ratio (3.94 and 3.91 for Test **I** and **II**, respectively) is indicative of high-temperature oxidation. Figure 4 shows the water and oil production rates. In both Test **I** and **II** most of the water was produced in the first half of the test, indicating that mobile water was flowing ahead of the combustion front. Figure 5 shows the cumulative liquid production from Test **I** and **II**. The end effect was apparent in the decline in liquid production over the last 10 hours of the tests. Figure 6 shows the variation in API gravity of THAI™ oil produced from Test **I** and **II**. The API gravity of THAI^{TM} oil produced from Test **I** varied between 9.5 and 22, with an average of 18.5 degrees, while API gravity of THAI^{TM} oil produced from Test **II** varied between 10 and 20, with an average of 17 degrees. Table 4 shows physical and chemical properties of the THAI™ oil composite from Test **I** and **II**. Very substantial oil upgrading was indicated by 10 and 7-degree increase in API gravity for THAI^{TM} oil composites produced from Test **I** and **II**, respectively. Figure 7 shows the variation in density of THAI™ oil produced from Test **I** and **II**, and Figure 8 shows the variation of water pH for the produced water samples. The pH ranged approximately between 1.5 and 4; however the large buffering effect in bitumen reservoirs is expected to moderate pH to close to neutral.

The viscosity of each heavy oil sample was measured at 3-temperatures and the result extrapolated to 20 ºC: results are shown in Figure 9. The reduction in viscosity from 1340906 cP to 52 cP (Test **I**) and 115 cP (Test **II**), as well as, the decrease of asphaltenes from 18.34 mass% to 3.61 mass% (Test **I**) and to 4.13 mass% (Test **II**) offers additional insight into the enhancement of the downhole thermal bitumen upgrading. The significant increase of saturates (Table 4) increases the potential volume of motor fuels obtained from THAI^{TM} oil. The increase in Bromine number is indicative of extensive cracking reactions and is close to the pipeline specification limit. Furthermore, vanadium content was significantly reduced 73.1% (Test **I**) and 72.4 % (Test **II**), while nickel was reduced 69.8 % (Test **I**) and 76.2 % (Test **II**). Sulphur content was slightly reduced from 4% to 3.52% (Test **I**) and 3.3% (Test **II**). It was also observed that simulated distillation residue reduced from 66% to 22% (Test **I**) and 15.5% (Test **II**), Table 6.

5. Conclusions

The 3-D cell THAI™ tests of Whitesands bitumen indicated that it is an excellent candidate oil for the THAI™ process. Coke deposition supplied ample fuel to achieve a stable high-temperature burn. The oil was substantially upgraded with regard to API Gravity, viscosity, SARA composition and metals content. The oil production rate in Test **II** was higher than that obtained for Test **I** because of the higher air injection rate in Test **II**. Consequently, more un-upgraded oil was produced in Test **II** than in Test **I**, resulting in decreasing the overall degree of upgrading in Test **II** than in Test **I**. Using a single injection port resulted in slightly increase in the API gravity of the produced oil; however the oil recovery factor calculated in Test **I** and **II** was almost the same.

6. Bibliography

1. M. Greaves, T. X. Xia, A. T. Turta, C. Ayasse **“Recent Laboratory Results of THAI™ and Its Comparison With Other IOR Processes.”** SPE/DOE Improved Oil Recovery Symposium, 3-5 April 2000, Tulsa, OK
2. M. Greaves, T. X. Xia, C. Ayasse **“Underground Upgrading of Heavy Oil Using THAI-Toe-To-Heel Air Injection.”** SPE/PS-CIM/CHOA International Thermal Operations and Heavy Oil Symposium, 1-3 November 2005, Calgary, AB, Canada
3. M. Greaves, C. Ayasse, A. T. Turta **“In Situ Upgrading Potential of the Capri™ Process.”**. World Heavy Oil Congress. March, 2008, Edmonton, Alberta
4. .M. Greaves, T. X. Xia, T. A. Turta **“Stability of the THAI™ Process- Theoretical and Experimental Observations”**. Canadian International Petroleum Conference, June, 2007, Calgary, Alberta

TABLES

Table 1: Experimental parameters of THAI™ 3-D cell

	Test I	Test II
Cell Size	0.69m x 0.49m x 0.19m	0.69m x 0.49m x 0.19m
Clean Sand	97% Sand + 3% Kaolin	97% Sand + 3% Kaolin
Sand Porosity	36%	36%
Combustion Mode	Dry	Dry
Pre-ignition		
Pre-ignition gas	Hot nitrogen	Hot nitrogen
Rate of hot nitrogen gas, l/min	10	15
Maximum pre-ignition temp.	300ºC	300ºC
Ignition		
Air injection rate, l/min	8 - 10	10 – 13
Air flux, m^3/m^2 hr	5 - 6	6 – 8
Back pressure, psig	15 – 20	15 – 20
Oil sand composition, kg		
Sand	74	76
Oil	19.7	19
Water	8.9	8.2

Table 2: Calculated gas phase parameters

	Test I	Test II
H/C ratio (Based on injection flux)	2.12	1.48
$CO/(CO+CO_2)$	0.20	0.20
O_2 Utilization, %	90.05	78.44
O_2/fuel ratio, m^3(ST)/kg	2.66	2.86
Air/fuel ratio, (m^3(ST)/kg	12.67	13.62
Air/oil ratio, m^3 /m^3	3150	4675
Oil recovery, (%OOIP)	58.85	58.05

Table 3: Produced gas composition

	Test I	Test II
Components,	**mole% (average)**	
Hydrogen	1.48	0.66
Oxygen	2.06	4.59
Nitrogen	78.06	80.21
Carbon monoxide	2.66	2.75
Methane	1.24	0.50
Carbon dioxide	10.49	10.75
Ethylene	0.16	0.12
Ethane	0.29	0.13
Propylene	0.14	0.04
Propane	0.18	0.09
i-butane	0.10	0.04
n-butane	0.10	0.06
H_2S, ppm	6828	2533

Table 4: Physical properties of Whitesands Oil partly upgraded by the THAI™ process

Analysis	Crude Oil	THAI™ Oil (Composite)	
		Test I	Test II
API gravity @ 15.6ºC	8.3	18.52	16.96
True density @ 15ºC	1.012	0.9429	0.9529
Viscosity @ 20Cº	1,340,906	52.21	114.92
Pour Point, ºC	6	< -30	< -30
Acid number, mg KOH/gm	1.93	1.77	2.88
Bromine number, g/100g	5.15	24.7	16.43
Molecular weight, g/mol	732.3	277	303
Conradson Carbon, wt%	8.15	3.72	4.74
SARA analysis:			
Asphaltene, %	18.34	3.61	4.13
Resin, %	27.21	11.07	13.75
Aromatic, %	34.45	41.37	41.47
Saturates, %	17.1	23.66	24.23
Volatile, %<260 ºC	2.89	20.29	16.42

Table 5: Metal and sulphur analyses

Analysis	Crude Oil	THAI^{TM} Oil (Composite)	
		Test I	Test II
Metal content, mg/kg			
Tin	0	0	0
Lead	5	0	2
Copper	0.3	0	0.4
Aluminum	10	8	53
Silicon	39	12	87
Iron	25	3	8
Chromium	0.6	0.1	0
Silver	0	0	0
Zinc	8	2	4
Magnesium	2	0.1	3
Nickel	63	19	15
Barium	0	0	0
Sodium	31	0	1
Calcium	12	2	15
Vanadium	156	42	43
Phosphorous	12	0.1	5
Molybdenum	14	3	3
Boron	51	2	20
Manganese	0	0	0
Sulphur (Wt. %)	4.0	3.52	3.3

Table 6: Simulated distillation data

% off	Temperature, °C			
	Crude Oil	% off	THAI™ Oil (Composite)	
			Test I	Test II
IBP	198	IBP	75	113
2	253	2	111	148
4	290	4	136	177
6	315	6	157	202
8	335	8	176	220
10	354	10	188	235
16	404	16	222	270
20	432	20	243	290
26	475	26	272	315
30	507	30	290	331
34	540	40	331	368
		50	366	404
		60	402	441
		70	441	487
		74	459	514
		80	497	
		84	538	
Percent Residue	**66%**		**15.5%**	**22%**

FIGURES

LAB SCALE TESTING FOR THAI™

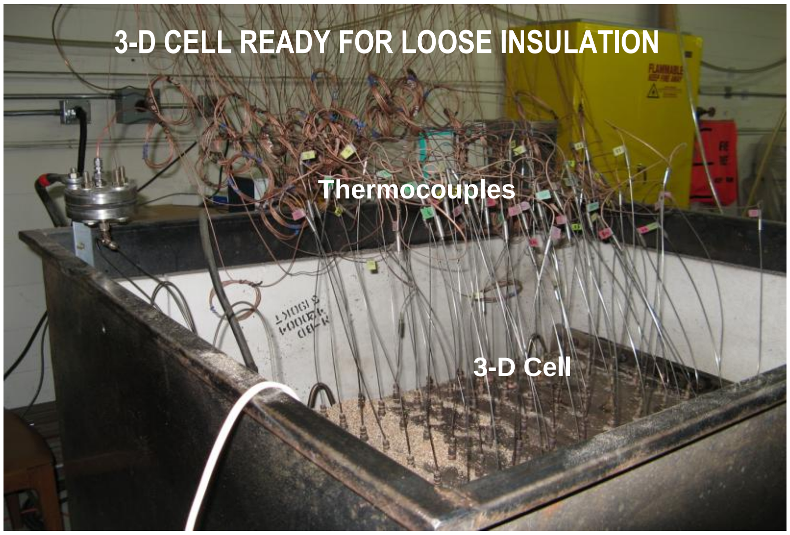

Figure 1: Picture of THAI™ 3-D Cell

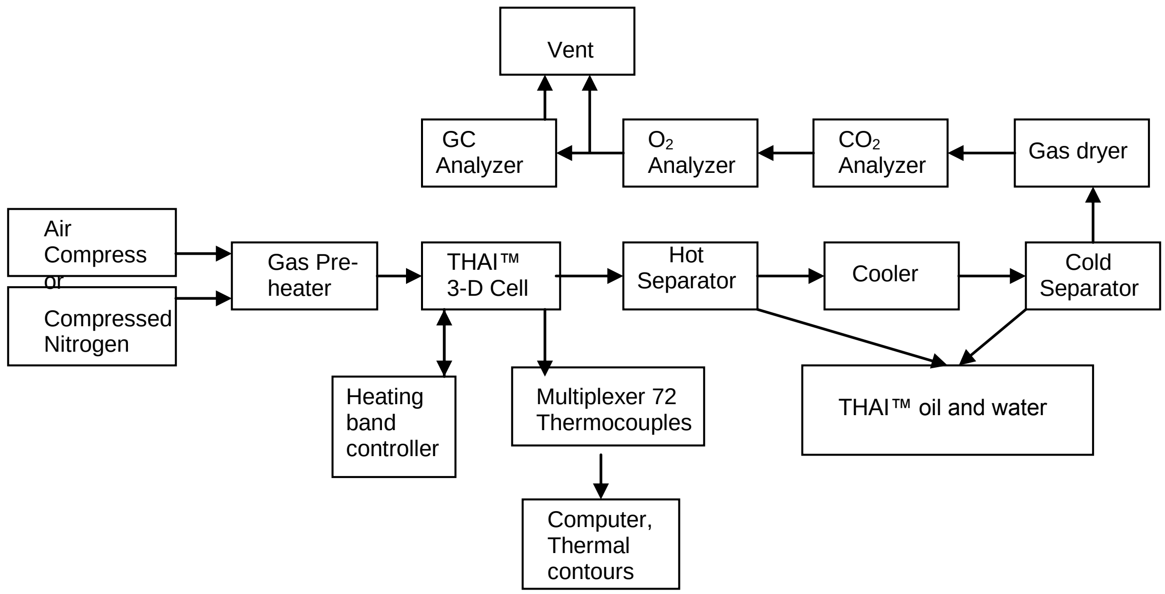

Figure 2: THAI™ 3-D Test process schematic

Figure 3: Temperature profiles at the top view and side view of mid-plans of the 3D-Cell_ Test II

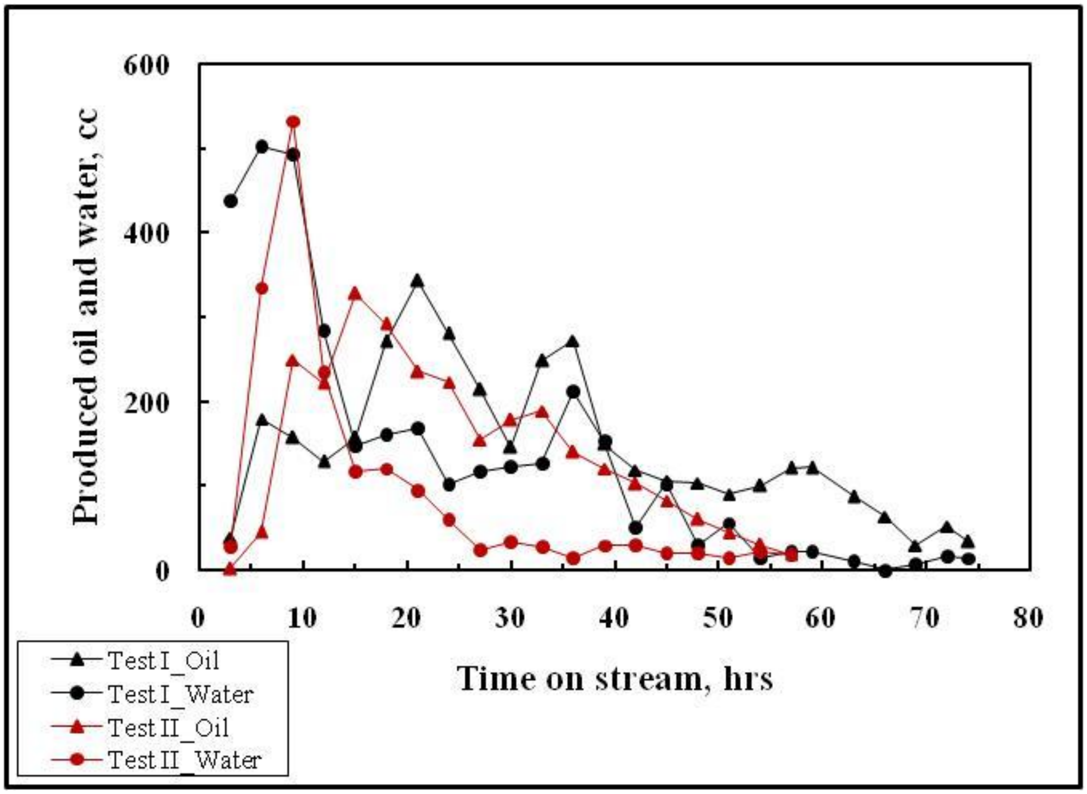

Figure 4: Whitesands THAI^{TM} water and oil production rate

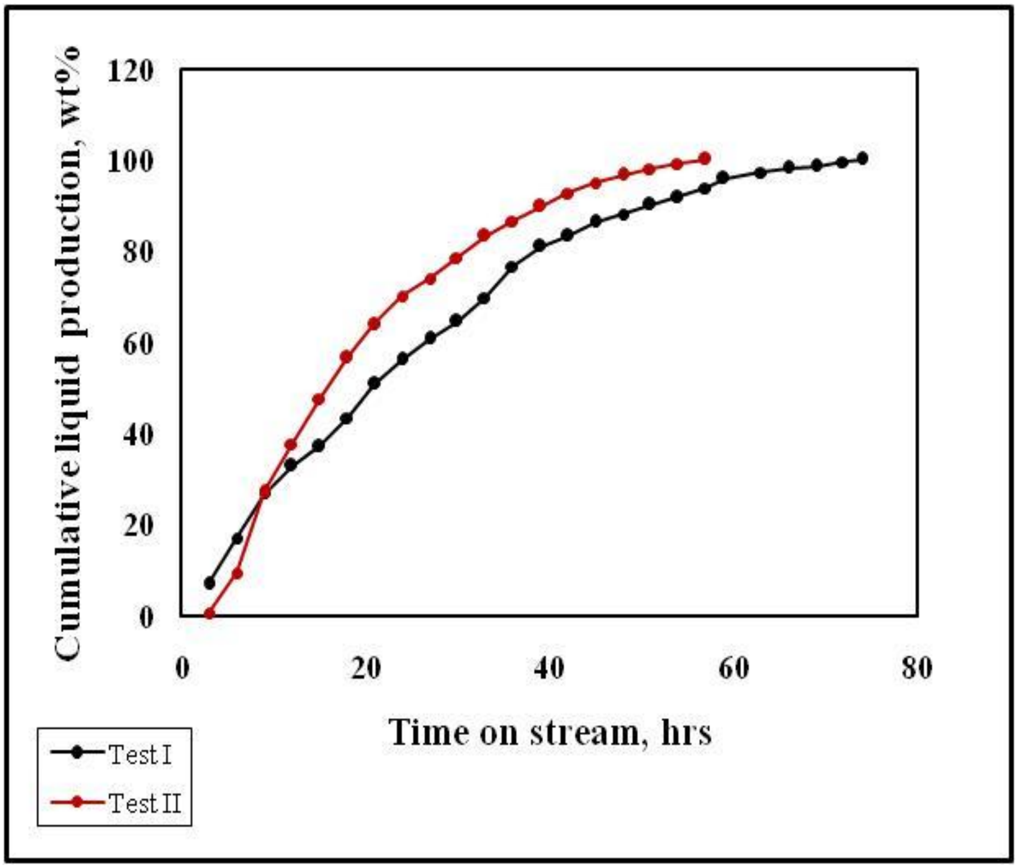

Figure 5: Cumulative Whitesands THAI™ liquid production

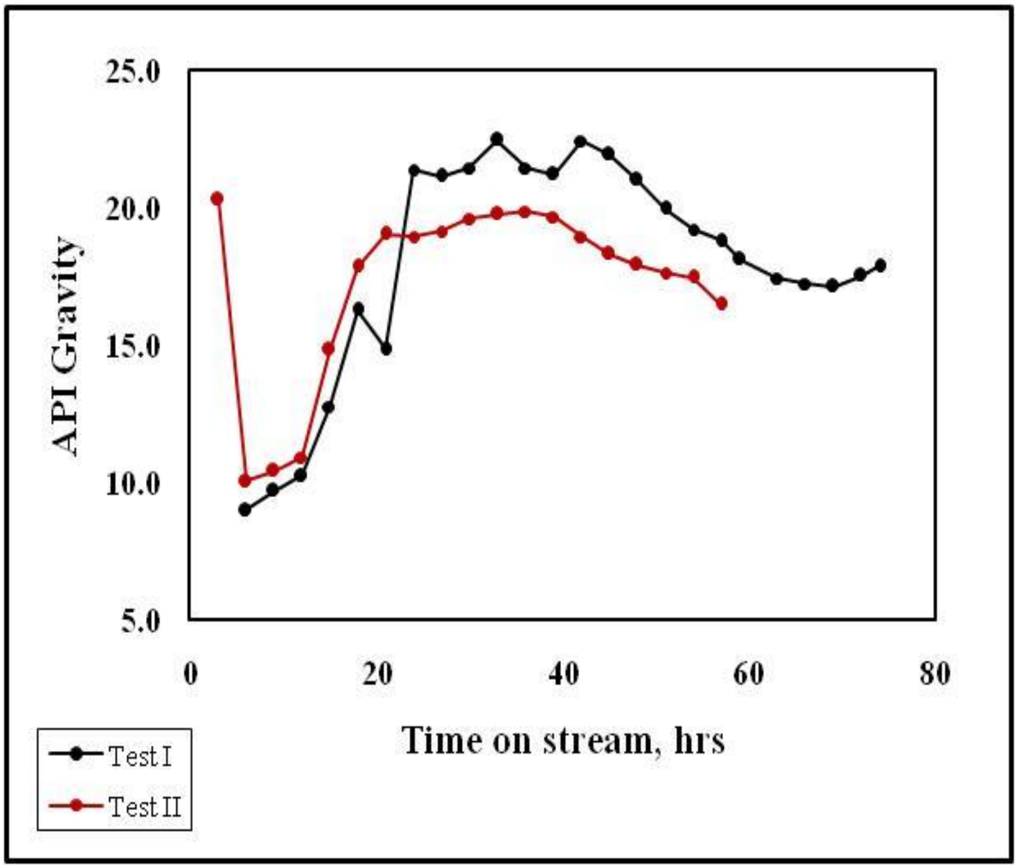

Figure 6: API Gravity of Whitesands THAI™ oil at 15.5 ºC

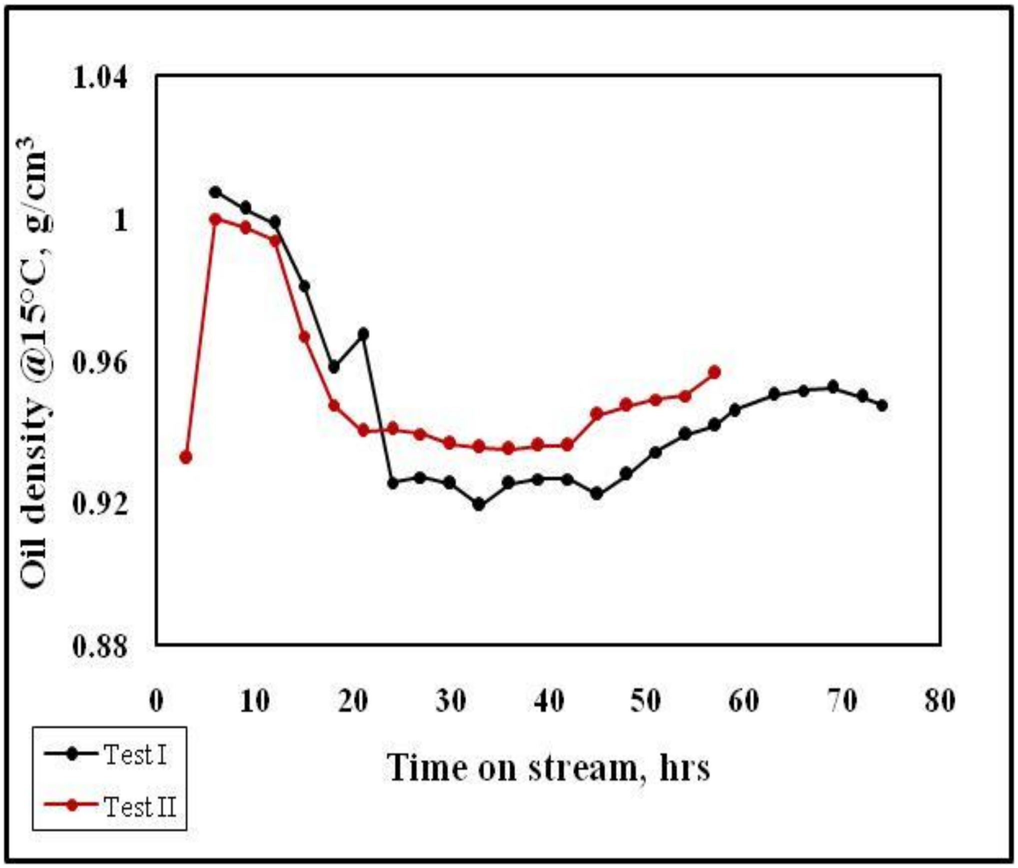

Figure 7: Density of Whitesands THAI™ oil (g/cc) @ 15 ºC

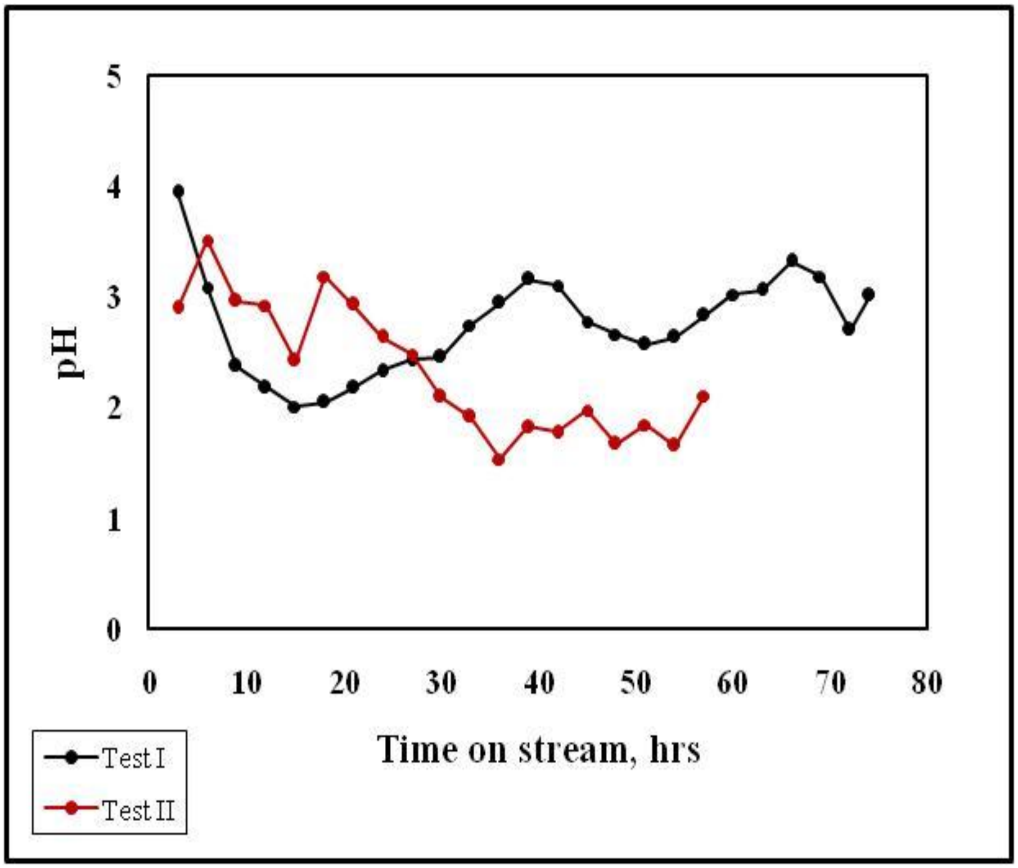

Figure 8: pH of Whitesands THAI™ produced water

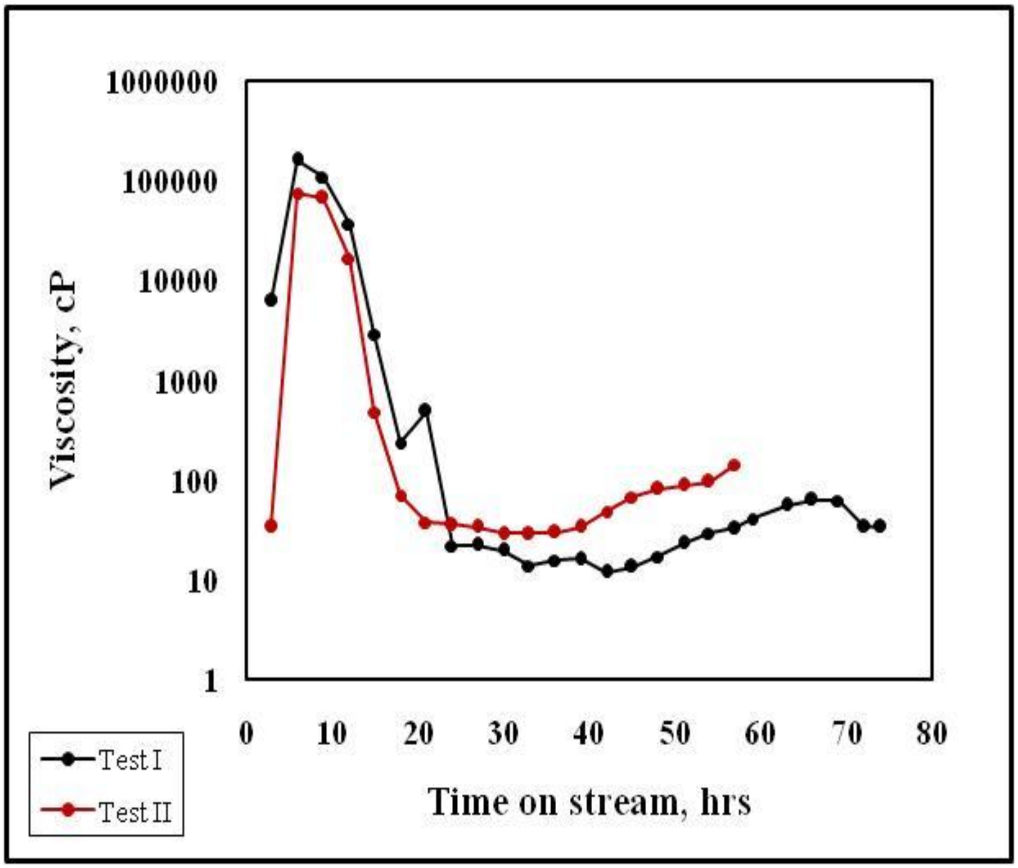

Figure 9: Viscosity of Whitesands THAI™ oil samples