SUNCOR ENERGY

Firebag Project

Low Pressure SAGD Artificial Lift Pilot

2005 Annual Report

Innovative Energy Technologies Program Application No. 01-018

June 2006

1. Project Summary

A. Schedule

Planning, engineering and execution of Suncor's Low Pressure SAGD Artificial Lift project was carried out by a multidisciplinary team that started working together in the second half of 2003. Contractor engineering and construction companies, dozens of vendors as well as Suncor's own resources were allocated to the project.

The planning stage of the pilot was carried out between late 2003 and Q2, 2004. It included all preliminary engineering and P&ID review and also the design and customization of new downhole tools to fit Firebag's well conditions and production requirements.

Appendix 1.1 details the proposed schedule for the pilot execution.

B. Activities and Operations

The facilities construction stage was executed in the second half of 2004. Service rig activity for well preparation and re-completion was also started during that period. The initial scope of the project involved the preparation and re-completion of wells P2P2 and P2P3, with planned installation of Can-K multiphase pumps in both of these wells. However, due to the difficulties encountered during the retrieval of production tubing and coil tubing in well P2P3, a decision was made on October 7, 2004 to remove this well from the scope of the pilot and to substitute well P2P1. The associated decision record is included in Appendix 1.2. It was further decided (November 16, 2004) to proceed with installation of the multiphase pump first in well pair 2P1. The associated decision record is included in Appendix 1.3.

Well P2P1 was re-completed in November 2004 and then started 2 months of pre-warming and steam circulation required prior to the pump installation. When this period was completed, the submersible pump system and downhole instrumentation tools were run in successfully in January 22, 2005. The pump was started two days later and it ran satisfactorily until March 17th, 2005 when it failed to bring fluids to surface. During the 54 days of operation, pump performance and downhnole wellbore conditions were monitored and optimized to fit pump manufacturer recommendations and reservoir and production requirements (see Section 3C).

The pump was pulled out on March 22nd, 2005 and brought to the vendor's shop for a full dismantle, inspection and failure analysis. Damage to the mechanical seals and check valve, both located at the base of the intake module, were determined to be the causes of the failure of the pump. All other mechanical and electrical components of the submersible system were in good condition. The inspection reports from the vendors are included in the separate documents "suncor tear down report pumpApril2805-final-May 0405.pdf" and "SLB 2723 Suncor.pdf", both provided in hard-copy accompanying this report.

A second multiphase twin screw pump was run in May 2nd, 2005. Again, the submersible system delivered good performance and allowed a flexible and continuous operation. Unfortunately, the pump failed 36 days after the install and needed to be pulled out. Once again the only component that failed was the pump itself. The failure cause this time was damage of the angular shaft module due to possible QC issues during the assembling process.

The other mechanical and electrical components of the system were not damaged. The pump failure report is included in the separate document "Tear down report pump 101.pdf".

The installation and run life history of the two pump installations is summarized in Table 1.1.

Table 1.1: Summary of 2P1 Multiphase Pump Installations

	FIRST INSTALL	**SECOND INSTALL**
PUMP SN	675UEFGHT100	675UEFGHT101
PUMP RATING	900 m3/d @60 HZ	900 m3/d @60 HZ
INSTALLATION DATE	January 22-05	May 2nd-05
FAIL DATE	March 17th-05	June 7th -05
PULL OUT DATE	March 22nd-05	June 18th -05
RUN LIFE - DAYS	54	36
FAILURE POINT	Main thrust module	Angular Shaft
FAILURE CAUSE	Check valve - Mechanical seals - Backflow	QC - Assembling Procedures

With the premature failure of the initial pump and also of its replacement, the scope of the pilot in well P2P1 came to an end sooner than anticipated. Consultation and failure causes review with the multiphase vendor and internal meetings convinced the project team to look for an alternative pump type for P2P1. A centrifugal type of pump was run in P2P1 to replace the twin screw positive displacement pump.

By end of 2005 there were no multiphase pumps installed at Firebag.

The other well included in the pilot, P2P2, was re-completed in Q1 of 2005 and started steam circulation and pre-warming in Q3 when steam became available. Pump installation was expected to happen in January 2006, depending upon further development of the technology.

2. Pilot Data

A. Data Submission

i. Geology and Geophysical Data

The geology of the pilot area (well pairs 2P1 and 2P2) is based on three coreholes, 1AA/13-01-095-06W4/00, 1AA/04-12-095-06W4/00 and 1AA/05-12-095-06W4/00, along well pair 2P1 for each of which core was collected and a suite of geophysical well logs run. The well log data for each of these coreholes, along with core photos, are included in separate computer files accompanying this report. The well logs are also included as hardcopy with this report. Gamma ray logs were also taken along the horizontal producers of each well pair and are provided as separate files "P2P1.las" and "P2P2MD.las". Petrophysical data were measured from the collected core and are included in the file "Core_analysis_data_3wells.xls".

ii. Laboratory studies

No laboratory studies specifically relating to the pilot area were carried out.

iii. Simulations

No simulations were carried out under the specific conditions of the pilot (ie a lengthy period of steam circulation followed by a brief period of low pressure operation under artificial lift). However, more generic simulations to predict the effects of lower pressure operation on SAGD operation for Firebag wells were carried out, and provided some of the incentive for this low pressure pilot. The predicted effect of operating pressure on steam-oil ratio (SOR) for Firebag wells is shown in Figure 2.1.

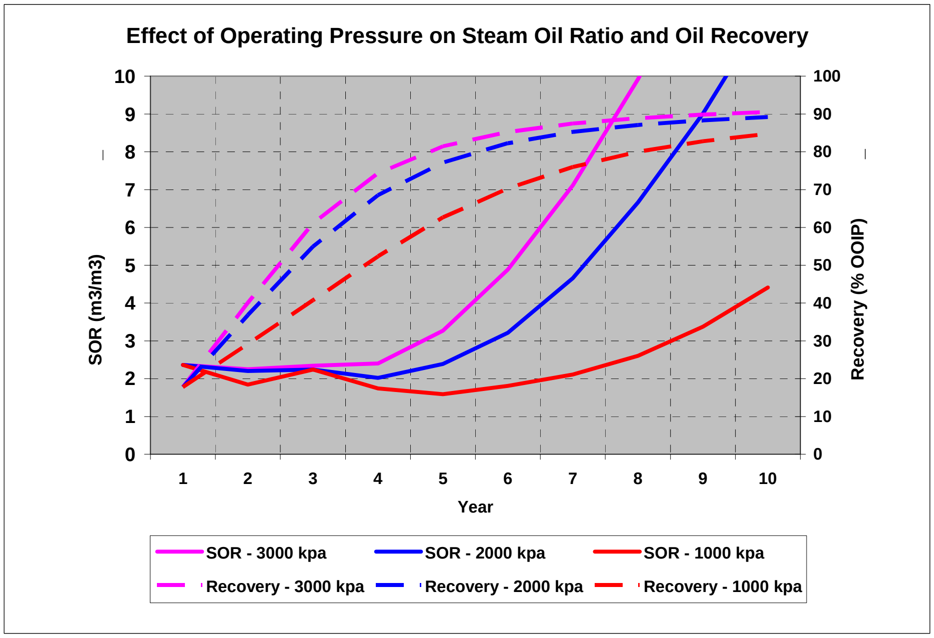


Figure 2.1: Effect of operating pressure on steam-oil ratio (SOR) for 30 m Athabasca reservoir

Reducing reservoir pressure has an effect both on cumulative SOR and cumulative recovery (at economic cutoff, instantaneous SOR=4.0), as shown in Table 2.1.

Table 2.1: Effect of operating pressure on SAGD performance for 30 m Athabasca reservoir

Operating Pressure (kPa)	Cumulative SOR (at instantaneous SOR=4.0)	Cumulative Oil Recovery (%ooip)
3000	2.42	81.84
2000	2.31	82.85
1000	2.08	83.35

iv. Pressure, temperature and other applicable reservoir data

No specific measurements of reservoir temperature and pressure were made in the pilot area. However, other such measurements in the Firebag Stage 1 area show that reservoir temperature is 8 to 9 ºC and pressure is typically 200-300 kPaa at the top of the McMurray channel sands and 800-900 kPaa at the bottom of the channel sands.

v. Other measurements, observations, tests or data pertinent to the pilot

N/A

B. Interpretation of Pilot Data

Figures 2.2 and 2.3 show interpreted cross-sections along well pairs 2P1 and 2P2.

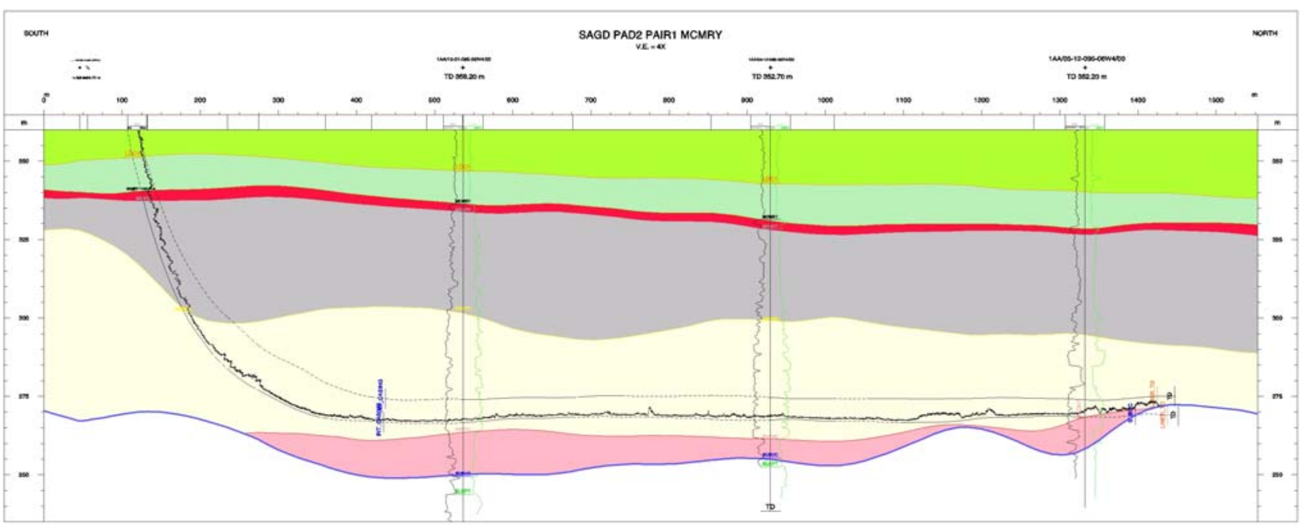


Figure 2.2: Cross-section along well-pair 2P1

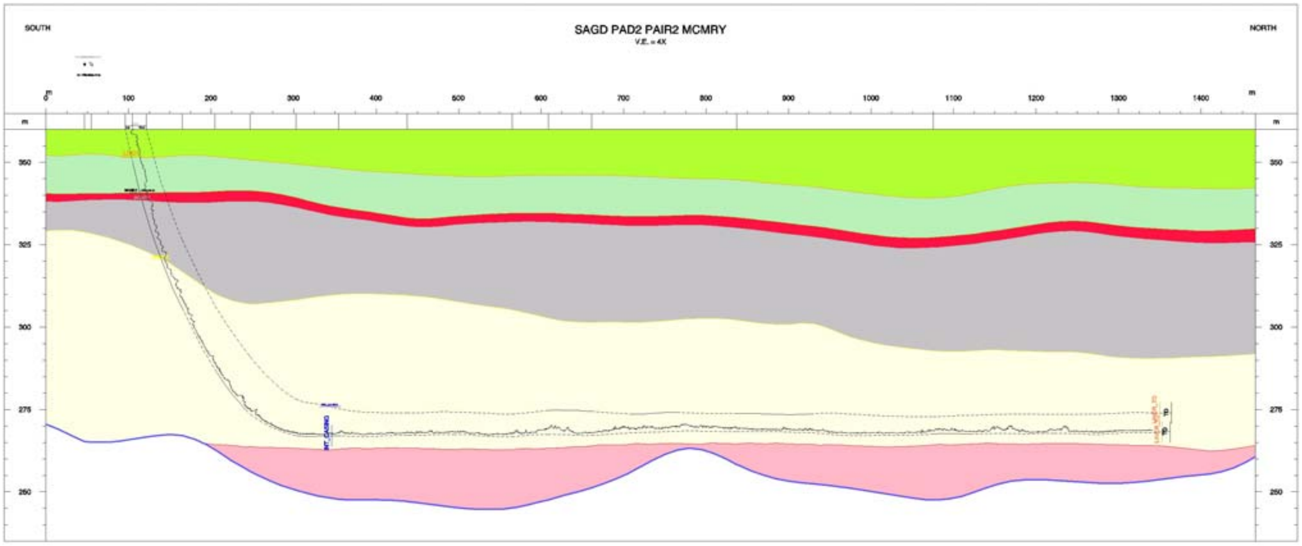


Figure 2.3: Cross-section along well pair 2P2

The geology of the McMurray is locally subdivided into four mappable units: continental, estuarine channel complex (which is the bitumen reservoir unit), estuarine tidal flat, and shoreface. The continental unit occurs at the base of the McMurray Formation and it is usually present in paleotopographic lows on the eroded Devonian surface. It is a heterogeneous unit and consists of narrow sandy fluvial channels, shaly overbank deposits, and thin argillaceous coal seams. The continental unit within well pairs 1 & 2 on Pad 2 (shown in pink in the above figures) ranges in thickness from nil to 12 metres. Above the continental unit is the estuarine channel complex (shown in yellow in the above figures) which varies in thickness from 40 metres (1AA/13-01-095-06W4/00) to 28 metres (1AA/05-12-095-06W4/00). This is the primary reservoir target and it is comprised of bitumen saturated stacked channel bar sands, abandoned channel-fill shales, and interbedded sand and shale sequences. Capping the estuarine channel complex is the shale dominated estuarine tidal flat complex (grey in the above figures) which is expected to form an internal seal within the McMurray Formation for the recovery of bitumen from the underlying estuarine channel complex. It is usually thinner over thick estuarine channel complex intervals and thicker over thin estuarine channel complex deposits. Within well pairs 1 & 2 on Pad 2, the estuarine tidal flat complex ranges in thickness from 20 metres near the heel of the wells and increases to about 30 metres near the toe of the wells. The uppermost unit within the McMurray Formation is the shoreface (red in the above figures). It consists of lower to upper shoreface sands. There is no economic bitumen potential in this unit because it is relatively thin with an average thickness of approximately 3 metres.

3. Well Information

A. Well Layout Map

Figure 3.1 shows the layout of Suncor's Firebag Stage 1 well pairs, and their conventional names (e.g. well pair "2P1" is the first well pair on Pad 2. It comprises an injector, "P2S1", and a producer, "P2P1"). Firebag Stage 1 comprises 20 well pairs. As discussed elsewhere in this report, it was initially planned to install a multiphase pump in well pair 2P3, but for operational reasons a decision was made in late 2004 to test the pump in well pairs 2P1 and 2P2 (indicated in red in Figure 3.1). During 2005, the pump test was carried out in 2P1, and preparations were made for further deployment in 2P2.

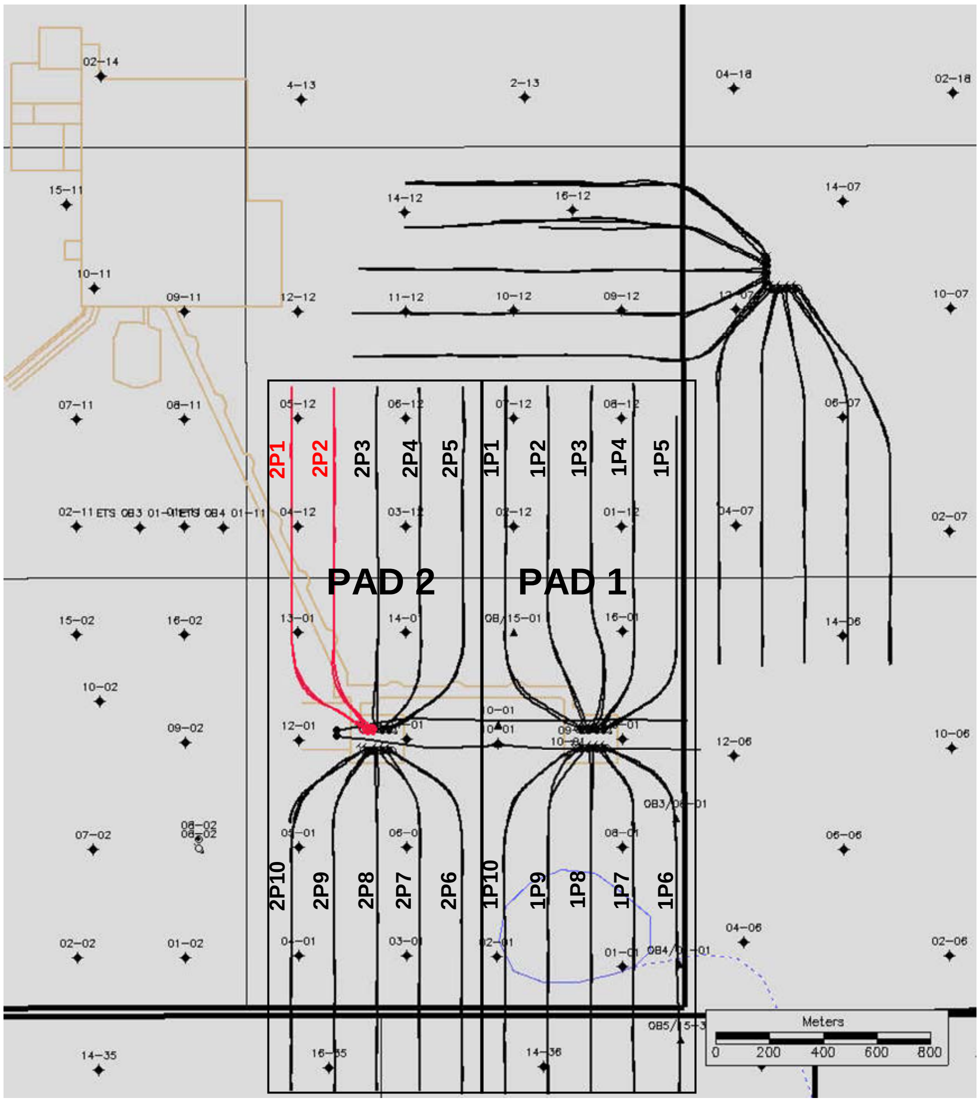


Figure 3.1: Layout of Suncor's Firebag Stage 1 well pairs with pilot test wells indicated in red.

B. Drilling, Completion and Workover Operations

The following is a chronological description of well re-completion activities and logistics executed in order to: prepare the well 2P1, install the first pump, pull out the first failed pump, run in and pull out the second pump. This summary covers the period from Q4-2004 to Q2-2005. At the beginning of this period, the well pair had already been drilled and completed for natural lift SAGD; this prior history will not be documented here.

1. WELL PREPARATION

This phase was executed from November 22nd to 25th, 2004. The goal was to pull out the 9-5/8" slave string and also the 1" coil tubing (see Section 3C). Neither of the two tubulars was required to stay in the well when the pump was installed. The service rig was moved onto the well on November 22nd and the program was completed without any major problem or delay. The learnings from previous wells, P2P2 and P2P3, and also the use of new tools and procedures, assured a successful well workover.

After pulling the slave string and coil tubing, the 5½" production string was run back in to allow steam circulation. As part of well conditioning prior to running the submersible pump, 6 weeks of steam circulation started on December 3rd at a rate of 60 m^3/day. The steam injection rate was gradually increased to 200 m^3/day and kept at this level until January 15th, 2005.

2. FIRST PUMP INSTALLATION

Prior to running the multiphase twin screw pump in the well, a bench test was completed satisfactorily at the pump vendor Can-K's shop. A decision was made to increase the number of stages from 5 to 6 in order to reduce slippage and improve pump performance. The pump testing is described in a separate document "A4 Suncor Test Bench ImagesR1jan0505.pdf". Also, a full equipment fit-up test was carried on to check coupling, bolting and alignment between the different components of the mechanical lifting string. This fit-up test was required due to the fact that submersible assembly contained equipment from two different vendors. The pump was supplied by Can-K and the motor-protector and all other electrical components were supplied by Schlumberger.

During the same period, the packer concept and strategy were reviewed and it was decided to use Schlumberger's SL-2 Thermal Liner Packer instead of the multi-port LP-SAGD Thermal Production Packer. The SL-2 packer hangs the 5½" tailpipe that goes to the toe of the well.

The bottomhole monitoring strategy was also reviewed and adjusted. A final decision was made to install fiber optics and a triplex configuration thermocouple wire for temperature monitoring (fiber supplied by Sensa Schlumberger, thermocouples by Petrospec and Wika) and to install a Pruett pressure chamber (from Haliburton) for downhole pressure. These three devices would allow the team to monitor temperature and pressure in the neighborhood of the pump landing depth and in this way determine and control local subcool. There was no instrumentation running below the pump assembly.

The actual pump installation was done from January 16th to 23rd, 2005. The steam circulation and pre-warming period had finished on January 16th, 2005, 12 hrs prior the initiation of rig activity. A twin screw positive displacement multiphase pump and a 150 HP submersible motor were successfully run in the well. The submersible assembly was landed between 510 mKB (pump discharge) and 540 mKB (Pressure chamber bottom), where inclination is 88 degrees and dogleg varies between 5.7 and 8.5 deg/100ft. Figure 3.2 shows the bottom-hole assembly; photos of the installation are included in Appendix 3.1. The total length of the assembly is 30 m and it goes from Halliburton's pressure chamber all the way up to the pump discharge adapter.

WELL COMPLETION. ESP PUMP INSTALLED IN JAN. 22-05

Prepared for	Date	Casing	Rig Name
DRILLING AND COMPLET.	DEC. 19-04	13-3/8" & 9-5/8"	
Field Name	**Well Name**	**Completion Type**	**Prepared by**
FIREBAG	SAGD P2P1	ARTIFICIAL LIFT	FERNANDO
District	**Telephone #**	**Work String**	**Drawing by**
FIREBAG SAGD	(403)920-8527		FERNANDO

No	Measur. Depth (mKB: 4.38 m)	Length (m)	Max OD (mm)	TVD m	Part #	Description
	(m, bottom)					
1	0.00					Wellhead
2	512.63	508.25	139.700	326.65		36 JTS 5.5" Tub. & 2m Pup jt.
3	523.64	11.01	171.450	326.74		Can-K Screw Pump & THA
4	527.24	3.60	136.525	326.90		LSMPMPM Protector
5	532.85	5.61	142.875	327.05		150 HP 562 ESP Motor
6	533.56	0.71	88.900	327.12		FiberSub 2-3/8" & Nipple
7	540.34	6.78	139.700	327.40		HB Press. Chamber & PUP JT
8	564.76	1.71	12.500	327.80		SLB SL-2 TL Packer/Hanger
9	1,579.87	1,015.11	139.700			72 JTS 5.5" Tailpipe, CX, Mule
10	603.30	598.80	339.725	328.20		13-3/8" Production Casing
11	1,610.00	1,026.50	244.475			9-5/8" Slotted Liner
12	577.15	1.85	244.500			IMPORT Liner Hanger
13	527.39	523.00	43.180			Flat ESP Cable.
14	540.34	535.96	4.763			Thermocouple Wire
15	533.55	529.17	6.35 x 2			Instrumentation Lines for Fiber
16	534.24	529.86	3.175			Instrumentation Line for Press.

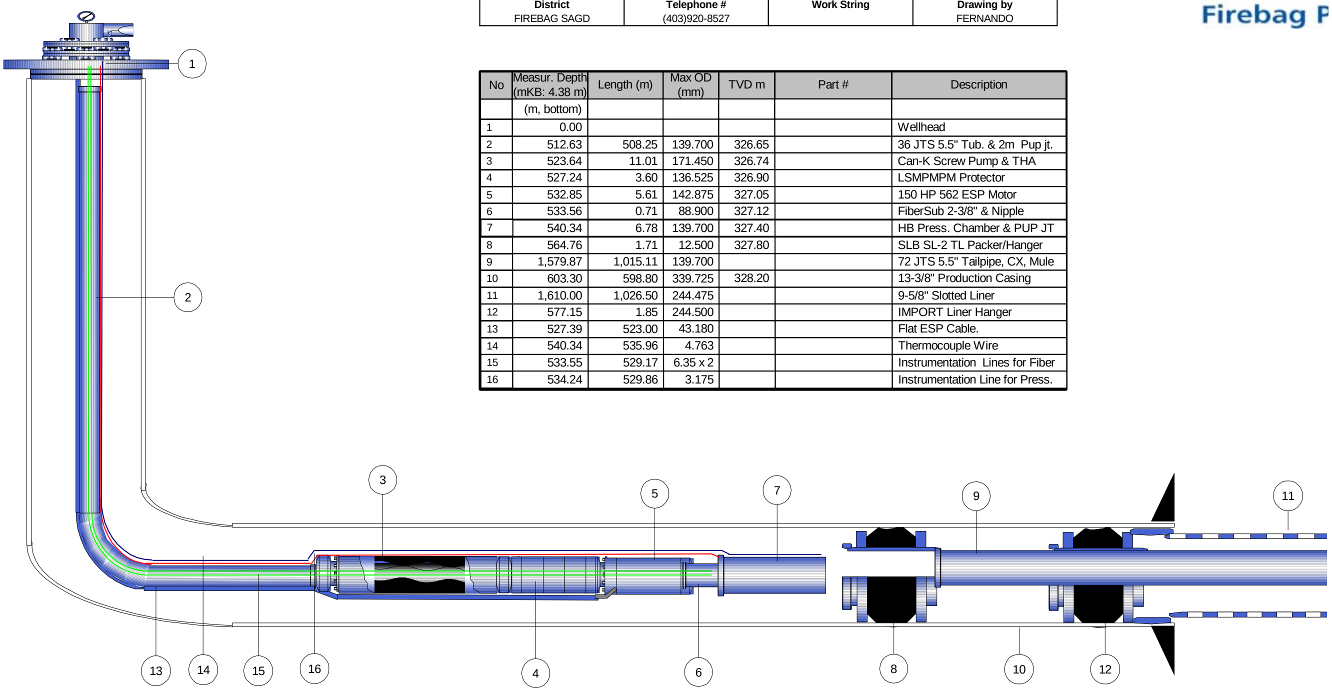


Figure 3.2: Bottom-hole assembly

As planned, the bottomhole instrumentation included a triplex thermocouple wire with three temperature sensors located at bottom end of the BHA, motor head and pump's intake. Fiber optics measured temperature every meter from below the motor to surface, and a Pruett chamber allowed continuous bottomhole pressure monitoring.

A 260 KVA surface electric gear that included a Variable Speed Drive (VSD), step-up transformer and harmonic line filter allowed the system to run between 40 and 65 HZ.

The pump was successfully started at 34 HZ on January 29th. Bottomhole temperature was in the range of 75C and bottomhole pressure 1945 kPa. Initial production rate was around 408 m^3/d. The system's running frequency was gradually increased to 40, 45 and 48 HZ where the production rate was around 500 m3/d, bottomhole flowing pressure 1460 kPa, and temperature 170ºC. The plan was to gradually increase the frequency up to 65 HZ, if bottomhole temperature and subcool permitted.

3. FAILURE AND PULL-OUT OF THE FIRST PUMP AND RUN-IN OF ITS REPLACEMENT

The pump ran smoothly until 9 AM of March 17^{th}, when a plant ESD at Firebag shut the pump down. The pump came back and stayed on production for about 6 hrs, at which time it went down on its own (March 17^{th} at 15:30). Several manual start-ups failed. All field tests and check outs indicated good electrical integrity of the system but it would not turn because most likely a stuck shaft induced the motor to shut down due to overload.

A service rig was moved on the well March 20th. The submersible system was pulled out of the ground on March 21st and brought to Edmonton for inspection. This inspection found the pump shaft broken due to overheat and damage of the main trust bearing module. It seems that the top mechanical seals failed and allowed entry of well fluid into the thrust bearing modules and all of the other modules of the pump below the intake. The replacement of the lubricant oil by well fluid caused the thrust bearing to burn and get stuck. Overall, the back flow when the pump was shut down is believed to be the cause of the failure of the mechanical seals.

The motor, protector and cable tested well.

The project team and vendors took some time to regroup, review failure causes improve the pump design and well completion configuration. The pump replacement installation started April 27th and finished May 3rd, 2005. A brand new, high metallurgy Can-K multiphase pump was built and bench tested. Significant engineering changes were implemented in the pump in order to address the suspected cause of the failure of the first pump. The bottomhole string was completed with a brand new protector and re-used motor. The submersible assembly was landed at same depth as before, 540 m MD. A 5½” check valve was installed to avoid back spin of the submersible system due to back flow.

The pump was started-up on May 4th. It started at 34 HZ, while bottomhole temperature was 47ºC. The initial production rate was 600 m^3/d and the motor was pulling 26 Amps. The equipment running speed was gradually increased to 50HZ. The near future plan included speeding up the unit up to a frequency where the maximum production rate could be reached. Pump performance would be closely monitored.

4. FAILURE AND PULL-OUT OF SECOND PUMP

As mentioned before, the pump had been running since May 4th and its performance was deemed to be within expected ranges. In ten days, pump speed was gradually increased from 45 up to 54 Hz where an average production rate of 750 m^3/d was achieved. At this point, bottomhole temperature was in the range of 150-160ºC.

The pump was down for almost one hour on May 13th due to a plant ESD. The unit was started-up without trouble after the ESD was cleared.

Later, wellbore temperature was gradually increased to almost 193ºC and local subcool was close to zero (0ºC). The higher volume of vapours and the fluid level fluctuations in the annulus were a good indication of the low subcool situation. However, the pump continued to lift significant amounts of fluids to surface without visible gas/vapour locking. As expected, pump efficiency and motor amps decreased substantially due to this situation. Unfortunately, the well could not be tested during this period of time because the test separator was not available.

Pump frequency was reduced to 40 Hz after June 2nd to keep subcool between 5 and 10ºC and adapt to a temporary lack of steam availability.

Overall, the pump's mechanical and electrical performance was satisfactory by the end of May 2005. This remained the case until June 3rd when an operational issue in the test separator triggered the unit to shut down. A high back pressure in the tubing created a high differential pressure through the pump which led into an overloaded motor situation. The pump came back on production once normal operation conditions were re-established. It then ran for three more days until June 7th at 11:30 when it definitely failed to bring fluids to surface. Electrical tests and check outs showed good electrical integrity of the motor, cable and other components of the electrical circuit. This was a good indication of a mechanical failure at the pump or the tubing string.

A service rig became available June 15th, 2005 and was moved to site. A tubing pressure test was conducted on June 16th. The tubing was pressured up to 2000 psi without any visible sign of leaking in the tubing or check valve. The submersible system was pulled out on June 18th and revealed a disengaged shaft at some point between the pump intake and the bottom end of the pump. The pump was taken to Edmonton for full dismantling and inspection.

The pump was dismantled June 23rd and 24th at Can-K's shop in Edmonton. A very evident failure was found at the CV joint located at the bottom end of the angular or centralization shaft. At this point, the splines of the shaft were completely worn out. This situation would prevent the power being transferred from the motor to the pump stages. No other failed points throughout the pump were found.

The shaft was sent to a lab for a hardness test. The angular shaft system will be redesigned for future applications.

A decision was made at this point to stop running multiphase positive displacement pumps in well P2P1 and also to further evaluate the feasibility of running them in the second well of the LP-SAGD Pilot, P2P2.

The separate documents "DIMS1.pdf" and "DIMS2.pdf" describe the day-by-day activities from the initial pump install to the 2nd pump pull out.

C. Well Operation

i. Well List and Status

As discussed above, the two wells that were planned for this low pressure artificial lift were 2P1 and 2P2, as illustrated in plan view in Figure 3.1. The Can-K pump test was carried out only in 2P1 up until the end of 2005, with testing being considered in 2P2 in 2006. At the end of 2005, 2P1 had been re-completed and was operating with an electric submersible pump, while 2P2 was operating on natural lift (no artificial lift installed).

ii. Wellbore Schematics

Schematics of the 2P1 and 2P2 wellbores are shown in Figures 3.3 and 3.4, respectively:

Firebag Project

SAGD Production Well

As drilled - completed Sep 30, 2002

Well: **P2P1**

Well name:	Suncor SAGD P2P1 Firebag 5-12-95-6
Toe location:	SW 12-095-06W4
Sfc location:	NW 01-095-06W4

Hole Size

Sfc	610	mm
Int	445	mm
Main	311	mm

Wellhead Data

Pressure rating	14000	Kpa
(Not temperature de-rated)		
Manufacturer	StreamFlo	
KB elevation	595.1	m
Ground elevation	590.6	m
GL to KB	4.5	m

Drilling Data

True vertical depth (TVD)	328.2	m
Total measured depth (TMD)	1620.0	m
Reservoir zone	McMurray	
License No.	261023	
Logs	Gamma Ray	
Drilling problems:	Problems running liner	

Downhole Equipment

	OD	ID	Weight	Grade	Jt type	Top	Depth	Length	Jts	Cement (Thermal 40M Thix-mix) Pumped	Returns
	mm	mm	kg/m			mKB	mKB	m		m3	m3
Sfc csg	473.1	451.0	130.2	K-55	Weld	1.5	79.8	78.3	7	13.0	3.0
Int csg	339.7	317.9	90.8	K-55	AMS-SI	4.5	603.3	598.8	43	51.1	15.0
Blank liner	244.5	224.4	59.5	K-55	AMS-XT/XC	580.9	609.9	29.0	2		
Slotted liner	244.5	224.4	59.5	K-55	AMS-XT/XC	612.5	1610.0	997.5	71		
Production tbg	244.5	224.4	59.5	J-55	BTC	4.0	554.8	550.8	42		
Production tbg	139.7	125.7	23.1	K-55	BTC	3.7	1583.9	1580.2	113		
Carrier line	25.4		1.7	QT-700		3.5	1575.8	1572.3			

Fibre-optic line installed and tested Sep 20. 2002

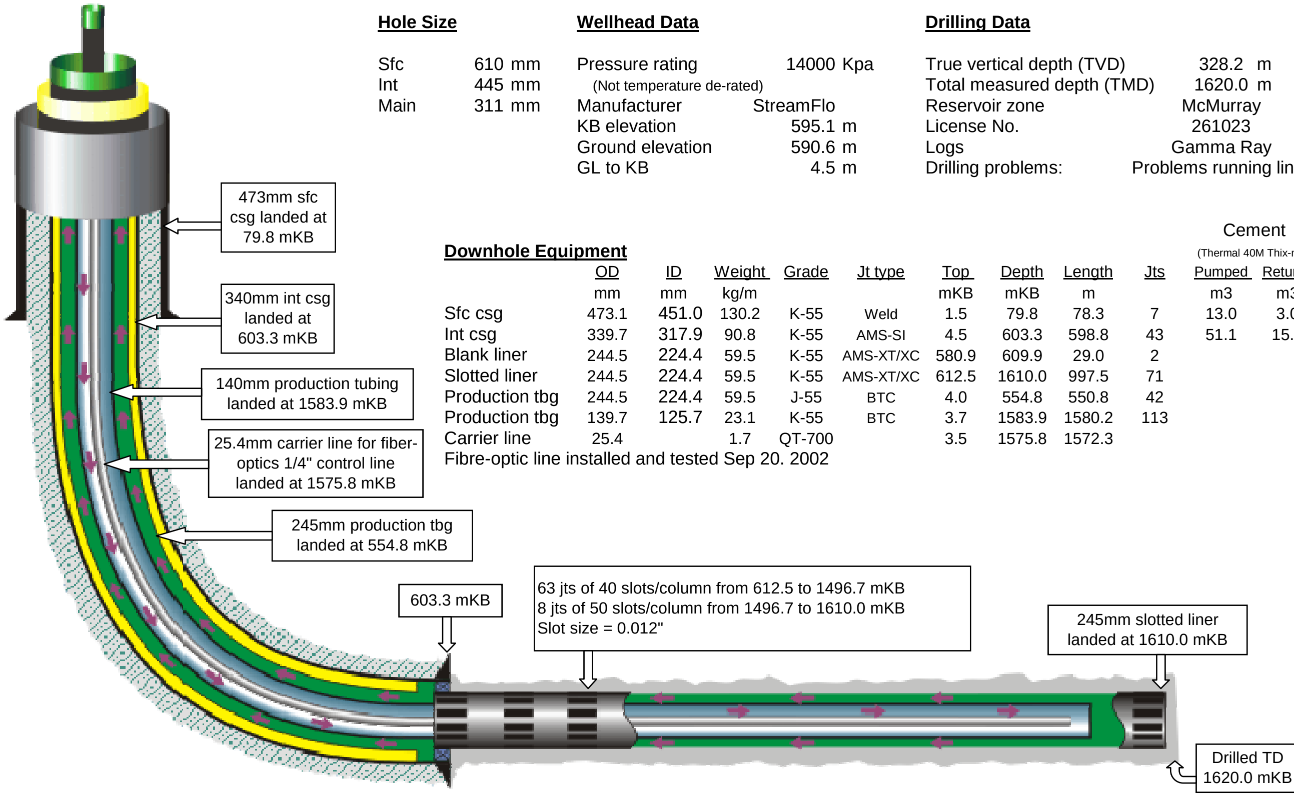


Figure 3.3: Wellbore schematic for P2P1 (2P1 producer)

Suncor Energy Firebag Project

SAGD Production Well

As drilled - completed Aug 13, 2002

Well: **P2P2**

Well name:	Suncor SAGD P2P2 Firebag 5-12-95-6
Toe location:	SW 12-095-06W4
Sfc location:	NW 01-095-06W4

Hole Size

Sfc	661	mm
Int	445	mm
Main	311	mm

Wellhead Data

Pressure rating (Not temperature de-rated)	14000	Kpa
Manufacturer	StreamFlo	
KB elevation	594.9	m
Ground elevation	590.6	m
GL to KB	4.3	m

Drilling Data

True vertical depth (TVD)	326.7 m
Total measured depth (TMD)	1539.0 m
Reservoir zone	McMurray
License No.	260991
Logs	Gamma Ray
Drilling problems:	Difficulty running liner

Downhole Equipment

	OD	ID	Weight	Grade	Jt type	Top	Depth	Length	Jts	Cement (Thermal 40M Thix-mix) Pumped	Returns
	mm	mm	kg/m			mKB	mKB	m		m3	m3
Sfc csg	473.1	451.0	130.2	K-55	Weld	1.5	79.7	78.2	10	16.2	2.0
Int csg	339.7	317.9	90.8	K-55	AMS-SI	4.3	521.3	517.0	37	41.0	10.0
Blank liner	244.5	224.4	59.5	K-55	AMS-XT/XC	503.2	517.3	14.1	2		
Slotted liner	244.5	224.4	59.5	K-55	AMS-XT/XC	532.5	1529.0	996.5	71		
Production tbg	244.5	224.4	59.5	J-55	BTC	0.0	562.7	562.7	36		
Production tbg	139.7	125.7	23.1	K-55	BTC	0.7	1517.5	1516.8	107		
Carrier line	25.4		1.7	QT-700		0.5	1505.0	1504.5			

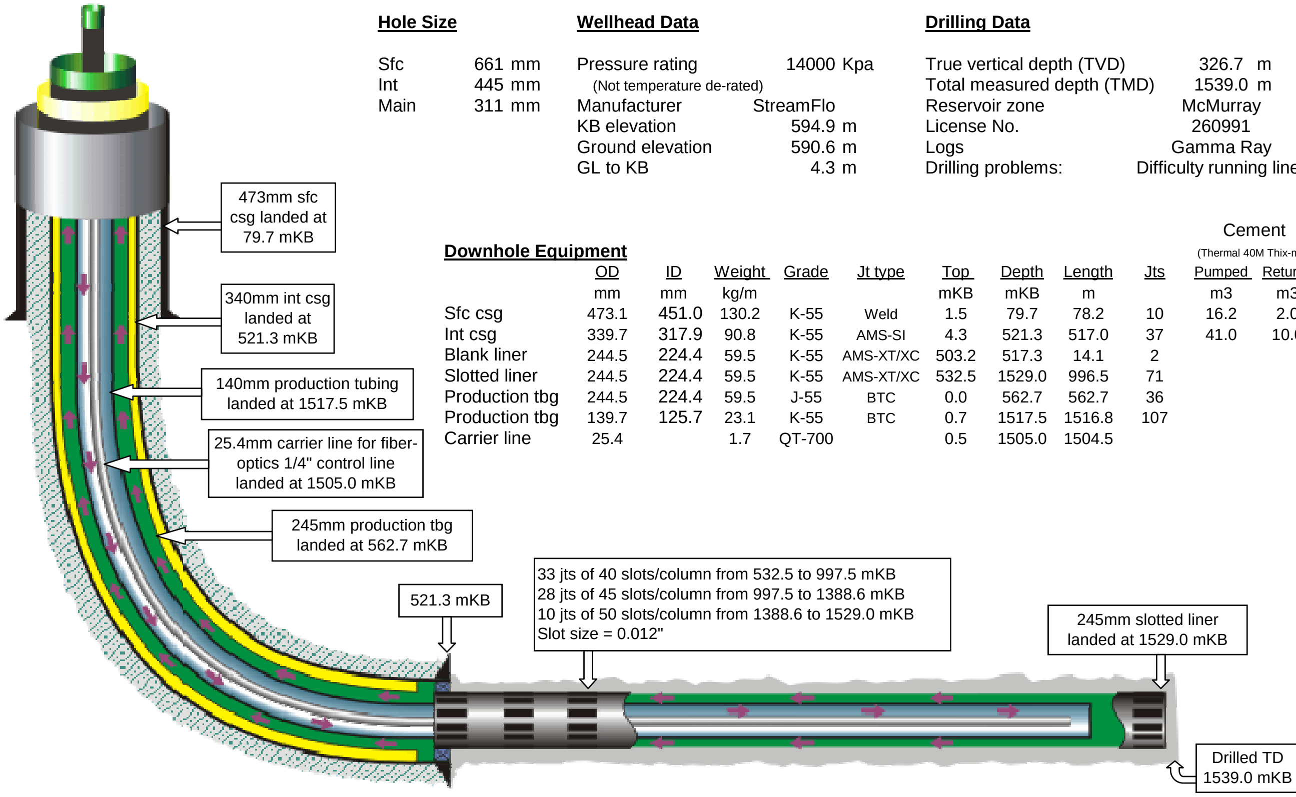


Figure 3.4: Wellbore schematic for P2P2 (2P2 producer)

iii. Spacing and Pattern

Well pairs 2P1 and 2P2 have 1000 m horizontal sections and are spaced laterally 160 m apart; the injector and producer of each pair are spaced approximately 6 m apart vertically.

iv. Operations

The operating philosophy and procedures for the pump test are described in detail in two separate documents, which are included as Appendices 3.2 and 3.3, respectively.

4. Production Performance and Data

All of the data discussed and graphed in this section may be found in the separate spreadsheet file "Pump data (combined).xls" included as part of this report package.

A. Injection and Production History

Neither 2P1 nor 2P2 was produced in SAGD mode prior to 2005. Rather they operated in "circulation" mode, a preparation for SAGD operation wherein steam is injected into the inner tubing of both injector and producer and fluids are produced up the annular space between inner and outer tubing (See Figures 3.3, 3.4) of both wells. Beginning with the first pump test, 2P1 operated in SAGD mode, characterized by steam being injected into either or both the tubing/casing of the injector and fluids being produced from the tubing of the producer. Following the 2nd pump failure, 2P1 was re-completed with an ESP and produced at somewhat higher pressure.

2P2 was not operated in SAGD mode until August 6, 2005 and for the remainder of 2005 was produced under natural lift (i.e. no pump), which for Firebag wells, requires an injection pressure of somewhat above 3000 kPa to lift fluids to surface. Fluids were produced up either or both the tubing and casing of the production well during this natural lift period.

Figures 4.1 and 4.2 show the monthly production data for well pairs 2P1 and 2P2, respectively, for the period from start-up of Firebag Stage 1 in September, 2003 until the end of 2005. These are data as reported to the EUB. Also included on the graphs is casing injection pressure on a daily basis.

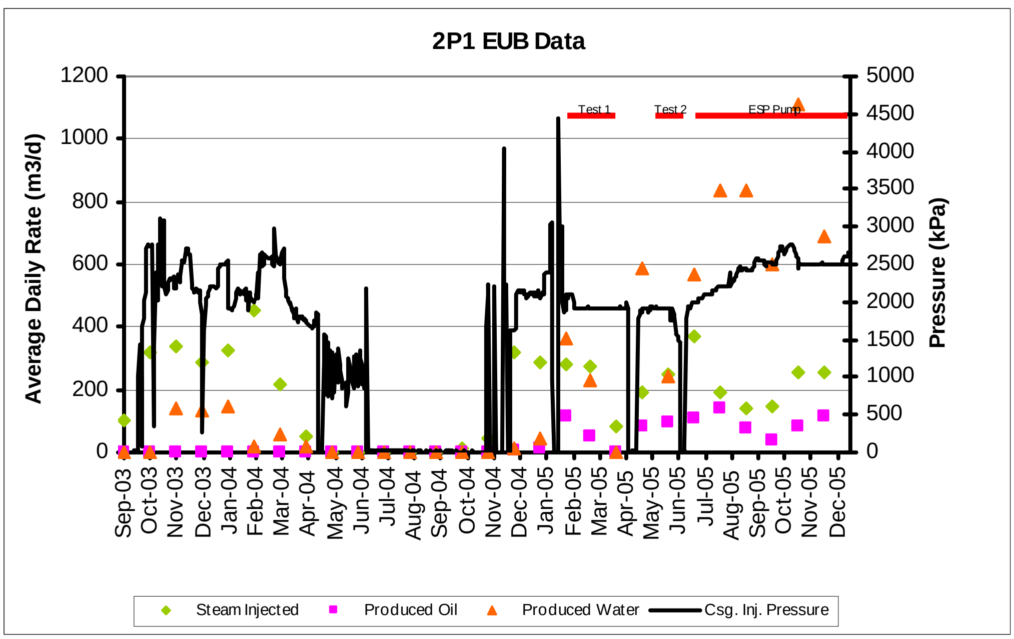


Figure 4.1: Performance data for well pair 2P1

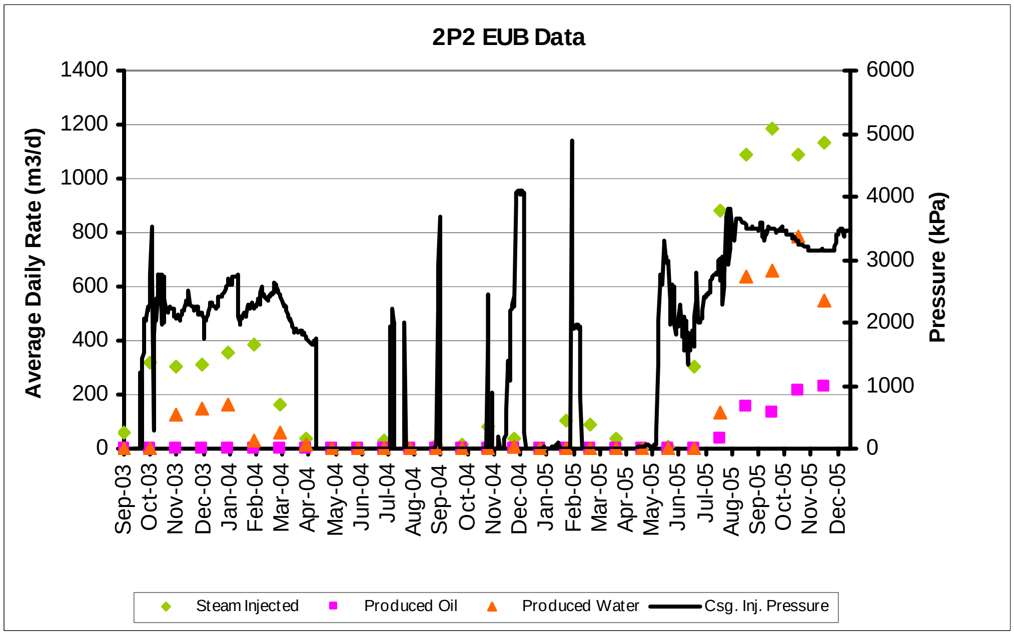


Figure 4.2: Performance data for well pair 2P2

Monthly Steam/oil ratios for the two well pairs are shown (for 2005 only, the only period for which there was oil production) in Figures 4.3 and 4.4.

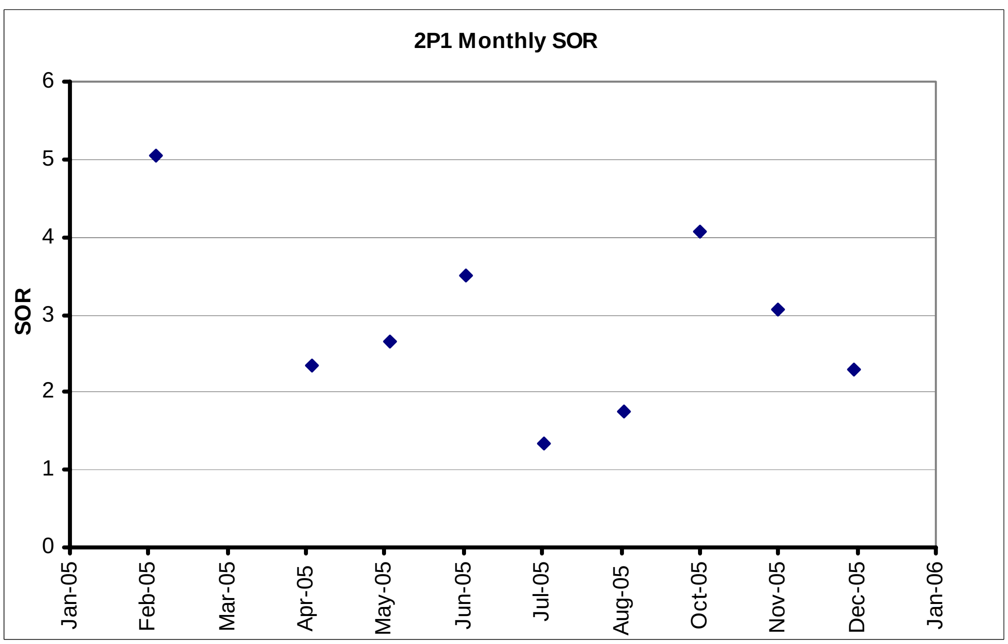


Figure 4.3: Monthly Steam-oil ratios for well pair 2P1

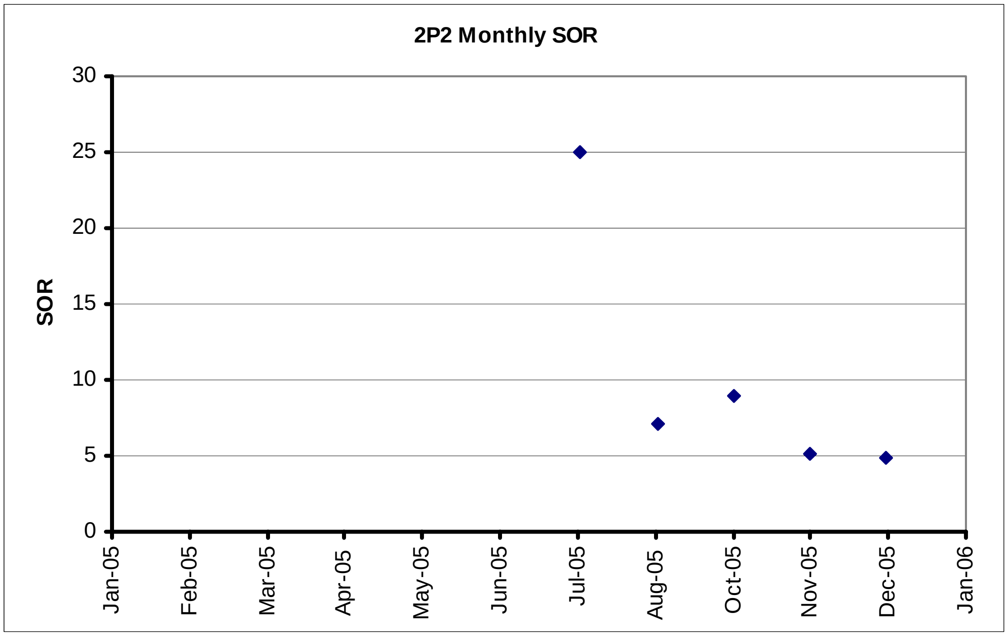


Figure 4.4: Monthly Steam-oil ratios for well pair 2P2

During the period of operation of the multiphase pumps in 2P1, the well was normally tested daily with the test separator. Data from these tests are shown in Figure 4.5 and 4.6, which show daily steam/oil/water and daily SOR, respectively.

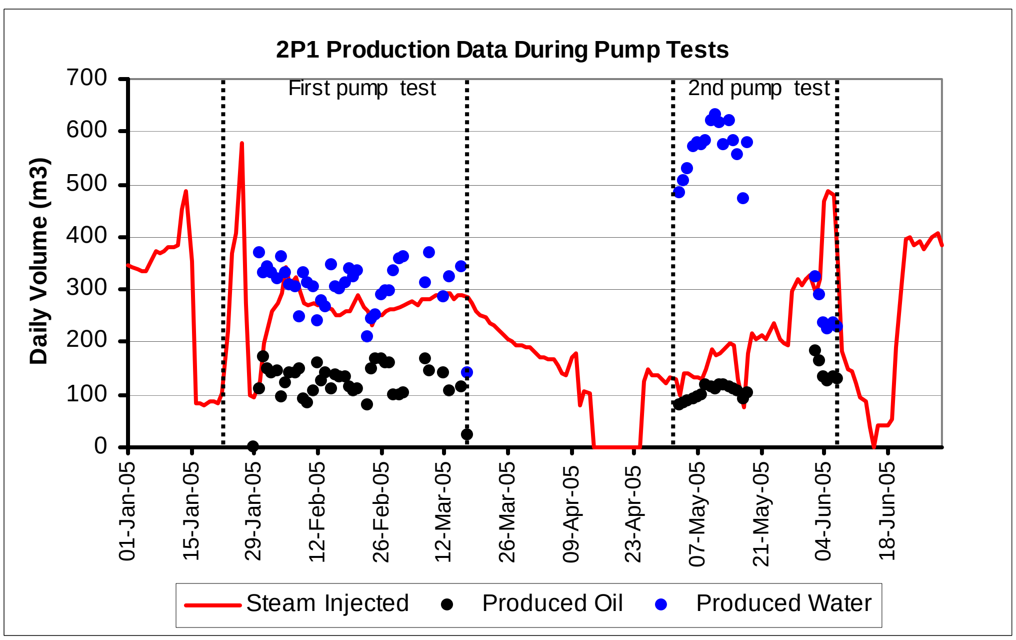


Figure 4.5: Production tests during pump operation in 2P1

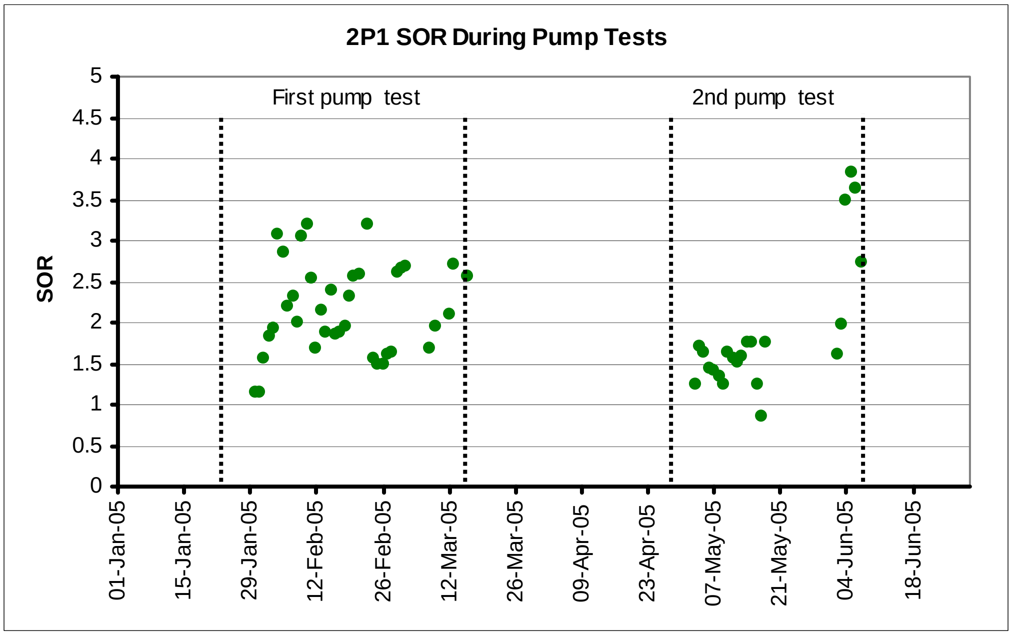


Figure 4.6: Steam-oil ratios based on daily production data during pump testing

B. Composition of Produced/Injected Fluids

Injected fluid was steam only. Only the total fluid and water cut of the produced fluids were measured. All of these data were shown in the figures in Section 4A.

C. Comparison of Predicted Versus Actual Pilot Performance

As noted earlier, Suncor did not conduct specific predictive simulations for well pair 2P1 prior to the pilot. Simulations were more generic during this period, and did not, for example, take into account the lengthy circulation period for well pair 2P1, and the fact that this well pair was isolated during the period of these pump tests since its neighbouring well pairs 2P2 and 2P10 were not operating.

One of the goals of the pilot was to test the benefits of low pressure operation. As shown earlier (Figure 2.1), a reduction of SOR is expected at lower operating pressures. Though the pilot did not operate long enough with artificial lift to reach steady-state SAGD operation and allow a complete test of such benefits, the early indications were encouraging. Casing injection pressure during the periods of pump testing in 2P1 were between 1900 and 2000 kPa, whereas, by comparison, the casing injection pressure during natural lift operation of 2P2 in the latter half of 2005 (using ESP) was greater than 3000 kPa (Figures 4.1 and 4.2). The SOR for 2P1 was significantly lower during this initial period of SAGD than that for the initial period of SAGD for 2P2 (compare Figure 4.3, 4.4).

D. History of Injection, Production and Observation Well Pressures

Injection and production pressures for the pilot wells pairs 2P1 and 2P2 were shown in figures in Section 4A. There were no pressure observation wells during this period.

E. Pump Performance

Several pump operating characteristics during the first pump test are shown in Figures 4.7 and 4.8. All pump operating characteristics were monitored very closely during the trial to stay within specified operating ranges. As mentioned earlier, the pump subcool reached 0 °C during part of this test. This confirmed the expectation that this type of multiphase pump was capable of operating with significant vapour present.

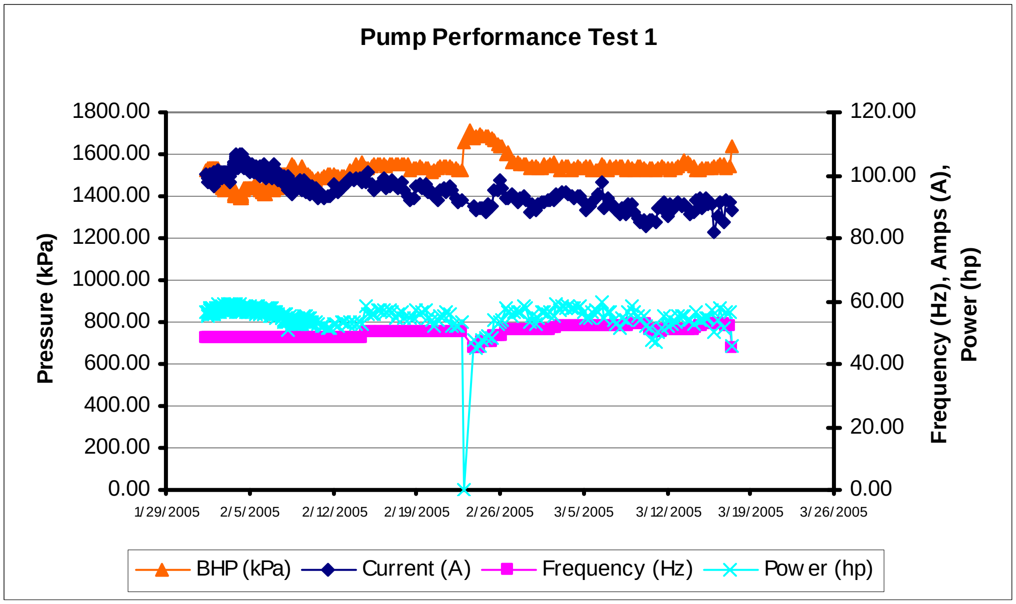


Figure 4.7: Operating history of pump during first trial in 2P1.

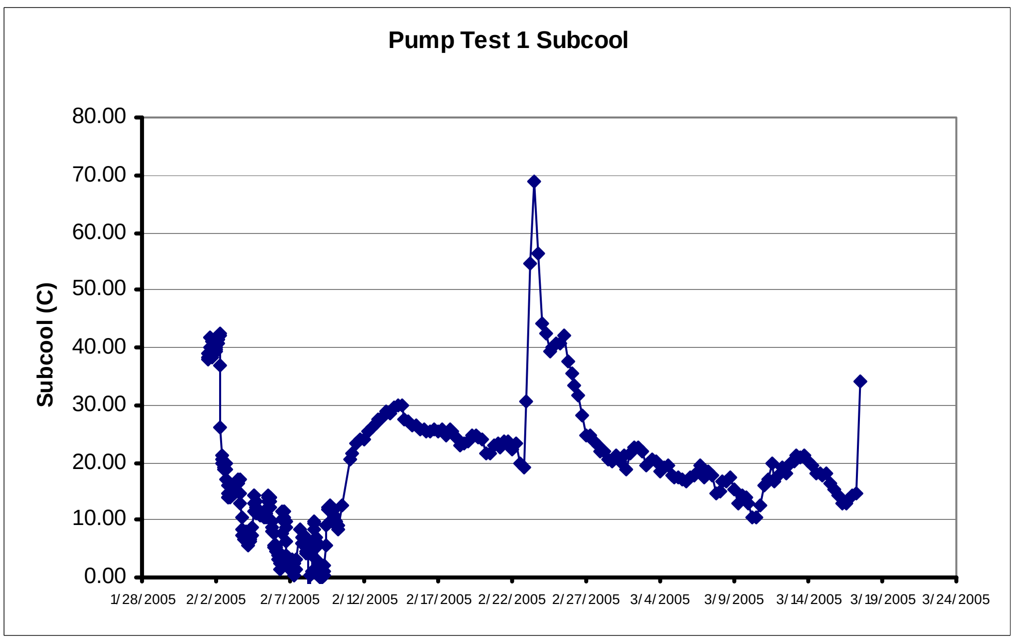


Figure 4.8: Pump subcool during test 1

Similar data for the second pump test are shown in Figures 4.9 and 4.10. Again, the pump was successfully operated at zero subcool for several periods during this test.

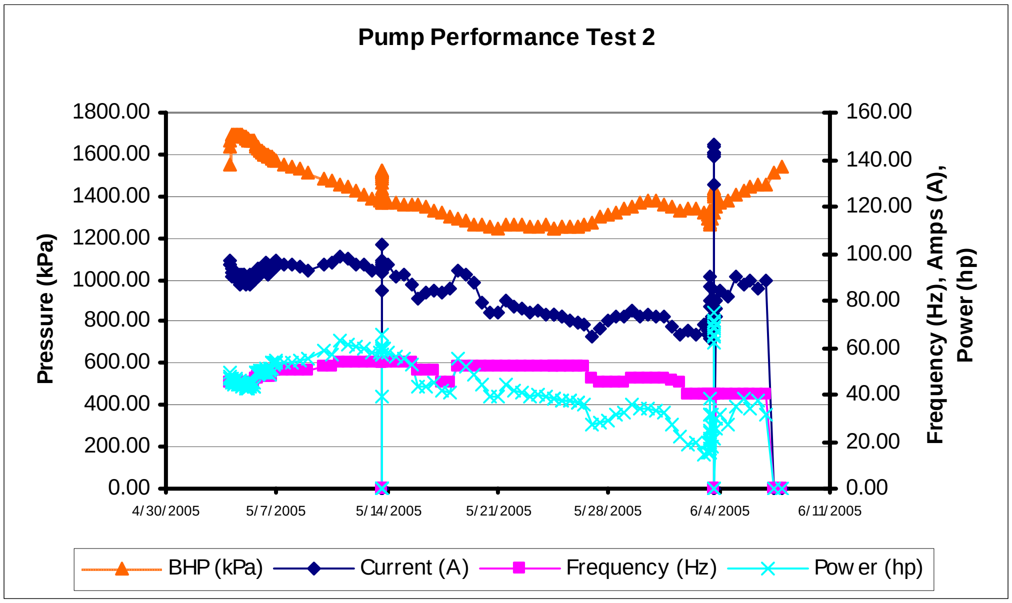


Figure 4.9: Operating history of pump during second trial in 2P1.

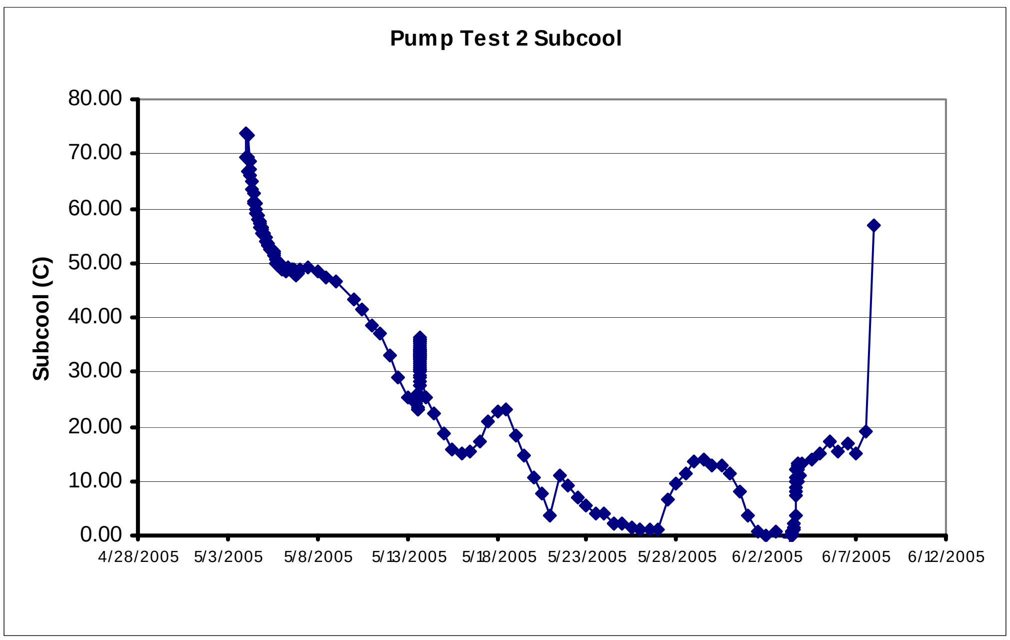


Figure 4.10: Pump subcool during test 2

5. Pilot Economics to Date

A. Sales volumes of natural gas and by-products

There have been no volumes of natural gas or by-products sold

B. Revenue

Revenue attributable to the pilot project totaled $1.6 million from June 2, 2004 to Dec 31, 2005

C. Capital costs (include a listing of items with installed cost greater than $10,000)

Please see Suncor's Mar 31, 2006 Low Pressure SAGD Artificial Lift (Project Number 01-018) filing, a copy of which is included as Appendix 5.1, that details capital costs of $745,447 to Dec 31, 2005

D. Direct and indirect operating costs by category (e.g. fuel, injectant costs, electricity)

Please see Suncor's filing (Appendix 5.1) that details operating costs (including drilling and completions) of $8,054,736 to Dec 31, 2005

E. Crown royalties, applicable freehold royalties, and taxes

Production from the Low Pressure SAGD Artificial Lift Pilot paid royalty under the terms of the *Oil Sands Royalty Regulation, 1997,* Project Approval No. OSR 050 and was calculated at 1% of gross revenues for the period
Royalty attributable to the pilot project totaled $16,000 from June 2, 2004 to Dec 31, 2005

F. Cash flow

See the table in the next section showing a cash flow for the pilot project of -$7.2 million.

G. Cumulative project costs and net revenue

See the table in the next section showing a net revenue of -$7.2 million on total costs of $8.8 million.

H. Explanation of material deviations from budgeted costs

Total costs to Dec 31, 2005 of $8,800,183 are $4,022,181 below the cumulative spending forecast in the original application

This difference is primarily due to the following trends:

- Commissioning and start-up costs were less than the budgeted amount mainly because portable metering equipment was not required and personnel requirements were less than expected.
- Operating costs charged to the pilot were reduced because the pilot operated only about half of 2005, where it was originally expected to operate until 2008
- The installation of the pumps into both wells was delayed by several months.
- The cost estimate included an initial CAN-K pump installation and a replacement installed after one year for both 2P1 and 2P2. The 2P2 installations of CAN-K pumps had not been completed by the end of 2005, although the surface facilities were constructed as per the original pilot project scope of work.
- Contingency funds were not fully utilized.

Suncor is still waiting for final invoices from the construction contractor for work carried out during 2005.

The cost break-down shown in the royalty filing is different due to drilling and completions costs being included with Operating Costs in the royalty filing rather than Capital as in the original application.

For an updated discussion of the economics presented in Appendix 13 of the original application, please see Appendix 5.2.

6. Facilities

A. Description of major capital items

The DBM document included as Appendix 6.1 of the present report describes the scope of the project in regards the facilities needed for the pilot. It includes new facilities addition and also modifications for piping, civil and structural, electrical as well as instrumentation and control.

B. Capacity limitations, operational issues, and equipment integrity

N/A

C. Process flow and site diagram

P&ID's for both demolition and construction of the pilot surface facilities are attached to this report.

7. Environment/Regulatory/Compliance

A. Summary of Project Regulatory Requirements and Compliance Status

Approval for the LP-SAGD pilot (including also other low pressure options) was sought in a letter to the Alberta Energy and Utilities Board (EUB) dated August 12, 2004, which is included with this report as hard-copy and as file "LPSAGD Letter to EUB final.pdf". The authorization for the pilot was received from the EUB in a letter dated September 9, 2004 and is included with this report as hard-copy and as file "LPSAGD Pilot Authorization.pdf".

B. Procedures to Address Environmental and Safety Issues

The possible need for flaring of annulus gas was identified and accepted in the EUB authorization letter.

C. Plan for Shut-down and Environmental Clean-up

N/A

8. Future Operating Plan

A. Project Schedule Update Including Deliverables and Milestones

As of early 2006, this pilot is on hold. Suncor is continuing to pursue low pressure SAGD options, but will probably use alternative technologies (than multiphase pumps) for artificial lift. This IETP project was based on testing a particular artificial lift technology; therefore, Suncor will seek official approval from the Minister to terminate the project.

B. Changes in Pilot Operation

The pilot is on hold, with little chance of being re-started.

C. Salvage update

This will be addressed when the project has been officially terminated.

9. Interpretations and Conclusions

A. Lessons learned

The Pilot allowed the project team to learn a variety of lessons while planning, executing and operating it. Since this was a “first time” project in Suncor’s SAGD operation, it has been at times a steep learning curve.

The initial challenges of the Pilot were related to two main concerns. The first was the fact that new hardware and downhole equipment needed to be run in the producer well. That is, a typical natural lift SAGD producer well had to be converted into an artificial lifted well. The second concern had to do with the need to demolish and rebuild parts of the existing wellhead, flowlines and fluid treatment and separation facilities to accommodate new flow paths and a new type of well operation. This second concern also included the need to build an electrical supply and power grid to feed the downhole motor and related surface electrical control system.

In regards concern number one, the electric submersible system and downhole instrumentation tools were chosen to fit wellbore conditions and production expectations and requirements. Joint work between the vendors and Suncor was done to get adequate and proper equipment. In some cases, the design of equipment started from scratch and was finally built and customized to fit Suncor’s well diameter, temperature and other well conditions. One example of this was the design, manufacturing and qualification of a downhole hanger packer completed with a circulation sleeve. This unique piece of equipment was designed by Schlumberger Canada for this pilot. In other cases, the pilot has given the chance to some vendors to run, prove and improve existing technology that had not been tried in Canada before. This was the case for the Can-K multiphase pump and for Haliburton’s Pruett pressure chamber, among others.

As a result of this interaction, we can also say the pilot has given the opportunity to local vendors to create new designs and to improve existing ones. All of this learning has increased their capability of offering more reliable technology for SAGD producers.

A significant part of the conversion from SAGD natural lift into artificial lift was the development of a strategy and field procedures to physically deploy and run the submersible system, packers and instrumentation tools. To do this, a team was formed with the service companies and Suncor people. Several planning meetings were held prior to attempting field activity. The result was a detailed step-by-step field procedure to assemble the equipment, run it in the hole, commission and start up the pump. A similar learning procedure was followed to develop the procedures of operation and control philosophy of the pilot. Such procedures have been revised and updated every time the pump was pulled out and re-run as part of the pilot and every time the operation has required doing so. This was probably the most significant learning process and training for field operators, contractors, service rig crews and engineers.

Minutes of one of the “lessons learned” sessions are included as Appendix 9.1

B. Difficulties encountered

Probably the biggest and most expensive difficulty encountered during the implementation of the Pilot had to do with the well preparation. Such well preparation involves the retrieval of existing production tubing, coil tubing and instrumentation lines from the well. These completions had been run in the well when it was initially completed as a natural lift SAGD well.

Inexperience in this kind of procedures and the complexity of the new well completion led to a very time-consuming and expensive fishing and well cleaning activity. This situation occured in both wells (P2P2 and P2P3) included in the initial scope of the pilot. Pipe and coil tubing recovery procedures were revised and new fishing tools and experts were brought on site to solve the situation. A chronological description of difficulties found in well P2P3 is included in Appendix 9.2.

Another big difficulty in the Pilot's implementation was the very short run life of the multiphase twin screw pump. The premature and frequent failure of this mechanical component of the submersible system led to the mobilization of the service rig and all other resources to replace it. This again, it was a very expensive activity.

A description and analysis of the failure mode of the pump was provided in Section 1 of this report.

C. Technical and economic viability

The LP-SAGD artificial lift pilot demonstrated its technical feasibility since it was executed and implemented according to the general plan. A new downhole pumping technology was tried in Suncor's wells and the overall technical results and learnings were satisfactory *while the pump was running*. From the technical point of view, the results of the Pilot project allowed the exploitation team to evaluate and to confirm the need for an artificial lift system to better produce Suncor's SAGD wells. The pilot also helped to understand the production potential and performance of such wells under artificial lift. In a broader sense, the Pilot allowed the production and exploitation team to recognize and understand the interaction between well behavior and pump performance and to think of both together as an interdependent system.

The economic evaluation of the Pilot showed many different things. On the positive side, it clearly concluded that the presence of an artificial lift system would allow the wells to be produced at lower downhole pressure and therefore, that the well could still be produced when steam injection rates and pressures were reduced and even in the absence of steam injection. Even more important, the presence of a flexible and wide-range artificial lift system would decrease the SOR (Steam-Oil Ratio) which is one the key performance indicators of the economics of SAGD projects.

On the other hand, the shorter-than-expected run life of the initial pump accelerated the installation of the second pump. This replacement was part of the initial scope of the project but was expected to happen 1 year after the initial install. It ended up happening just two months later. As mentioned before, the second pump failed just 36 days after the installation. The high cost associated with the pump replacement, and the fact that a second replacement was not part of the scope of the project, convinced the project team to stop running more multiphase positive displacement pumps in well pair 2P1. A plan was still in place to carry out the originally planned test of the Can-K technology in a second well pair, 2P2, likely in early 2006.

D. Overall effect on overall gas and bitumen recovery

As discussed in Section 4, the period of operation of the two pump tests in 2P1 met the general expectation of lower SOR associated with low pressure artificial lift. However, the very short duration of the pilot, during the initial period of "ramp-up" of 2P1, did not allow definitive conclusions to be drawn regarding long-term reservoir performance. Suncor has been sufficiently encouraged by the operation of the pilot that it will continue to pursue various low pressure options in its future development of the Firebag field.

Although it is not particularly an issue for Firebag, we believe that lowered operating pressure would also help to balance pressure between a bitumen-producing zone and any associated gas zone, allowing for higher recovery factors for bitumen in this situation.

E. Assessment of future expansion or commercial field application

The implementation of the Pilot and the findings from its execution and operation have been crucial for the expansion of the field application of artificial lift and downhole instrumentation in Firebag's SAGD wells. Even though operation of the Pilot in 2005 concluded that the multiphase twin screw pump technology still needs to be improved for SAGD application, it also showed that artificial lift systems allow these wells to be produced in a more flexible, safe and economic way. During the latter half of 2005, Suncor was also testing other lift technologies as alternatives to positive displacement pumps such as the twin screw pump. By the end of 2005, it seemed likely that electric centrifugal pumps would provide a more satisfactory option for artificial lift at Firebag, given the current state of technology. Both surface facilities and downhole components have been gradually engineered and improved as part of the learning and recommendations from the Pilot.

As for multiphase twin screw pumps, Suncor maintains its relationship with the vendor and remains interested in further developments and improvements of this technology.

Appendix 1.1: Original Schedule for Pilot Execution

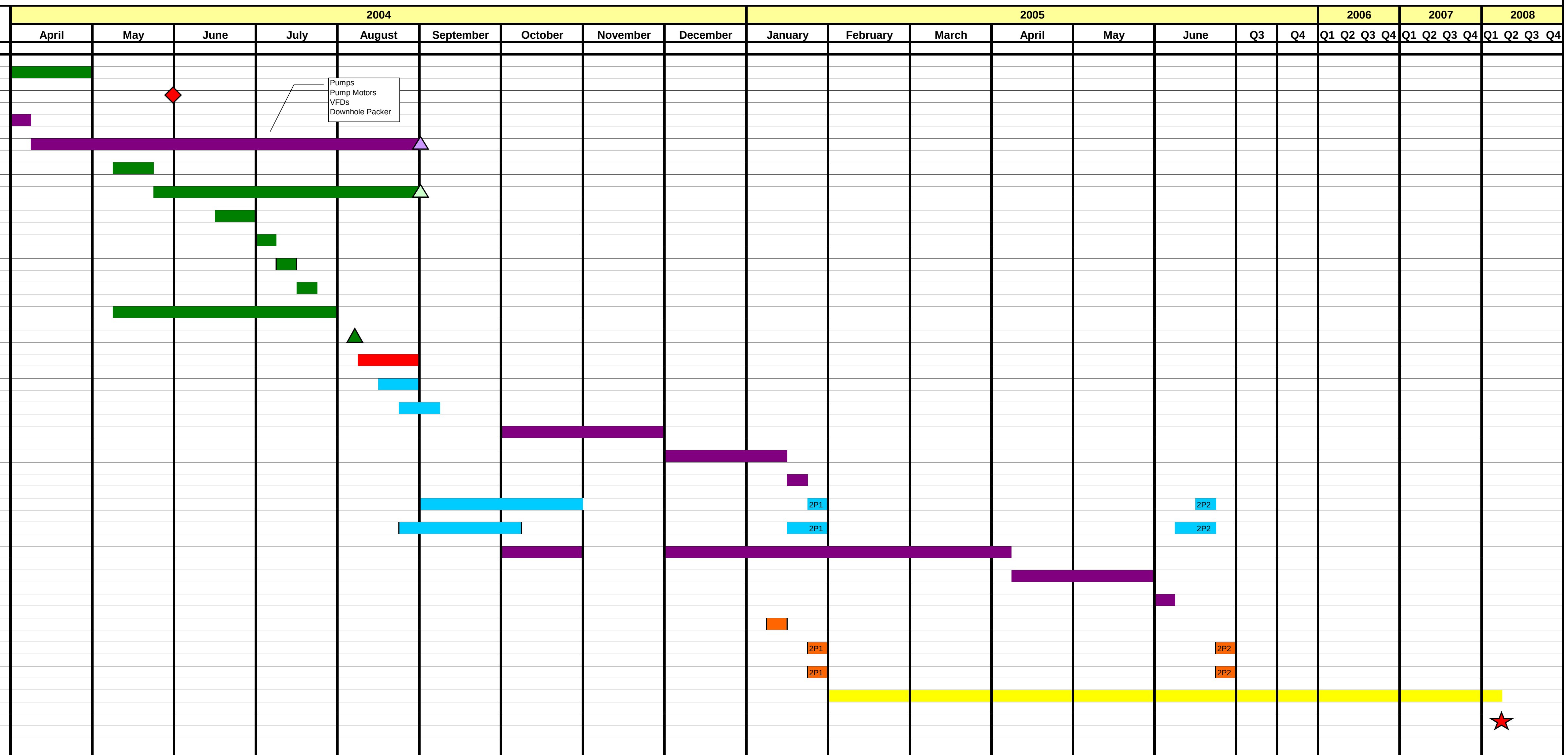
FIREBAG LP-SAGD PILOT - SCHEDULE

Overview Schedule

SUNCOR ENERGY

Updated: 30-March-2005

Project Phases & Key Activities Firebag - LP-SAGD Pilot	Responsibility
AFE Cost Estimate Preparation	Drilling/Jacobs
AFE Approval	Business Unit
Obtain Quotes for Long Lead Equipment - Drilling	Drilling
Drilling/Downhole Equipment - Procurement & Delivery	Drilling
Obtain Quotes for Long Lead Equipment - Surface	Jacobs
Surface (long lead) Equipment - Procurement & Delivery	Jacobs
Issue for Review (IFR) Drawings	Jacobs
Issued for HAZOP (IFH) Drawings	Jacobs
HAZOP	All
Issue for Approval (IFA) Drawings	Jacobs
Detailed Design, IFC Drawings	Jacobs
Issue Construction Work Package (CWP)	Jacobs
Unplanned Firebag Plant Shutdown	Operations
Shop Fabrication of VFD Skid	Flint/Jacobs
Shop Fabrication of Piping Spools	Flint/Jacobs
Recompletion (Part 1) Well 2P1 15d/well, pull/install prod tubing to toe with packer (c/w CV) at heel	Drilling
Pre-Steam Well 2P1	Drilling
Recompletion (Part 2) Well 2P1 5d/well, remove 51/2" tubing from packer & above,install d/h pump	Drilling
Site Construction - Electrical & Instrumentation Set MCC bldg, install 2.5MVAtransformer, run CT & cable, etc.	Flint/Jacobs
Site Construction - Mechanical Install pre-fab pipe spools, well tie-ins, etc.	Flint/Jacobs
Recompletion (Part 1) Well 2P2 15d/well, pull/install prod tubing to toe with packer (c/w CV) at heel	Drilling
Pre-Steam Well 2P2	Drilling
Recompletion (Part 2) Well 2P2 5d/well, remove 51/2" tubing from packer & above,install d/h pump	Drilling
Operations Training	C &S/U Team
Systems Turn-Over	
Commissioning & Start-Up	C &S/U Team
Ongoing Pilot Operation	
Project Complete	



Appendix 1.2: Decision Record – Replace 2P3 with 2P1

Firebag Project

Decision Record #002

Firebag Drilling

Subject: Evaluate alternative candidate well to replace P2P3 in the Low Pressure SAGD Pilot.

To: Brett Regier, Richard Sendall

From: Fernando Gaviria

CC: Swapan Das, Blaine Anderson, Fraser Hubbard, Toby Dinter

Date: October 7, 2004

Summary

A meeting was held on October 6 2004 to review LP-SAGD recompletion progress and performance on well P2P3. A brief of summary of events during drilling and original completion was described. Such summary also included a review of the extreme operational issues while trying to complete Part Two of the LP SAGD program. Running the 5½" tail pipe along with 1" CT and setting the Thermal packer are part of mentioned program.

Observations

- The recompletion for LP-SAGD in this well started in July 7, 2004 with the pull out of the 5½" tubing and 1" CT.
- Pulled to 707 m. All recovered tubing was spiraled. Operation was suspended in July 10 due to stuck pipe. All recovered CT was 'snaked" around tubing.
- From July 10 to 19th several backoffs and retrieval of 5½" tubing were completed until able to get grapple and jars to top of liner. String was freed in July 19. Pulled free after moving 5½" down and tension on Coil. Had problems trying to break connections due to twisted tubing and CT snaked around it.
- 9 5/8" Slave string was pulled out in 5 hours with no reported incidents.
- Both slave string and 5½" tubing strings were sent to Nisku (Tuboscope) inspection.
- Rig released in July 20.
- Rig activity re-starts on September 2, 2004. 2 3/8" tubing (well steaming string) was run in the hole without any reported problems.
- Rig came back on September the 12, 2004. Pulled 2 3/8" steam string and run 13 3/8" scrapper, drift sub with 3½" drill pipe. Debris founded at 430m. Worked trough it. Liner top tagged at 449.97m (Morning report said TOL @ 458m).
- Ran mule shoe and Petrospec DCS, CT and 5½" tub. Tagged top at 451.97m. (2m into the liner top). No rotation was possible. POOH. CT was broken above disconnect tool. Mule shoe showed markings from rotation (See Picture).
- Ran Impression block. Tagged top of liner at 449.97m. POOH. Different types and sizes of marks observed on block. (See picture).
- Ran tapered milling assembly. Tagged obstruction at 450m. Milled 1.35m. POOH. Mill with rotational marks.
- Ran magnet-drift sub combo. No obstruction at 450. Found restriction at 456m. Worked string. No movement down. Final depth 457.99m. POOH. Found CT wrapped around drift sub. (See pictures).
- Ran and pulled CT spear. Final depth 465.6m. More pieces of coil were retrieved.

- Ran 9 3/8" gage ring. Found very tight spot at 699-728m. Suspected bad dogleg and severe uphill turn. (See deviation survey). Tried 3 days unsuccessfully to pull out debris.

- Fishing tools, overshot and spear were lost while pulling out @ tight spot @ 720.25m. Fish was engaged several times but it would not come through tight spot.

- It was decided on September 28 2004, to push fish as deep as possible. Left it at 1406.29, fish top. Fish length 13.42m. Fish bottom 1419.71m. Slotted liner landed at 1486m. (See drawing).

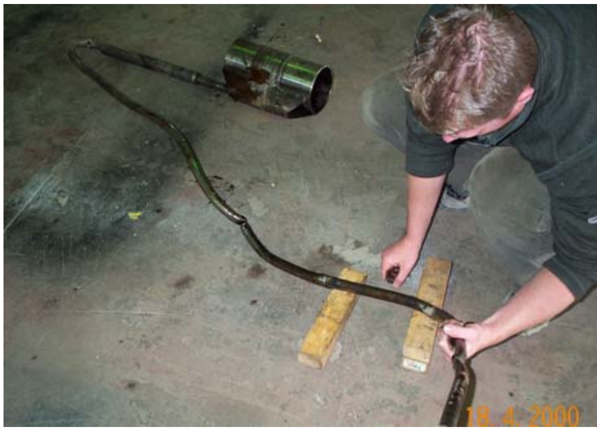
Accumulated cost for LP Recompletion (from September 2 to September 29): $501,318
Accumulated cost @ October 4 2004: $1,036,772
Total AFE: $1,300,000

Decision:

Discussion was in regards the course of action for P2P3 (either trying to pull fish out again, check casing liner integrity, put the well back on SAGD mode, and different completion configuration options) and also the option of having an alternative well to recomplete for LP SAGD.

It was proposed to evaluate P2P1 as a candidate instead of P2P3. The idea was agreed upon by all attendees at the meeting and action is being taken immediately to determine economical and technical feasibility of subject proposal.

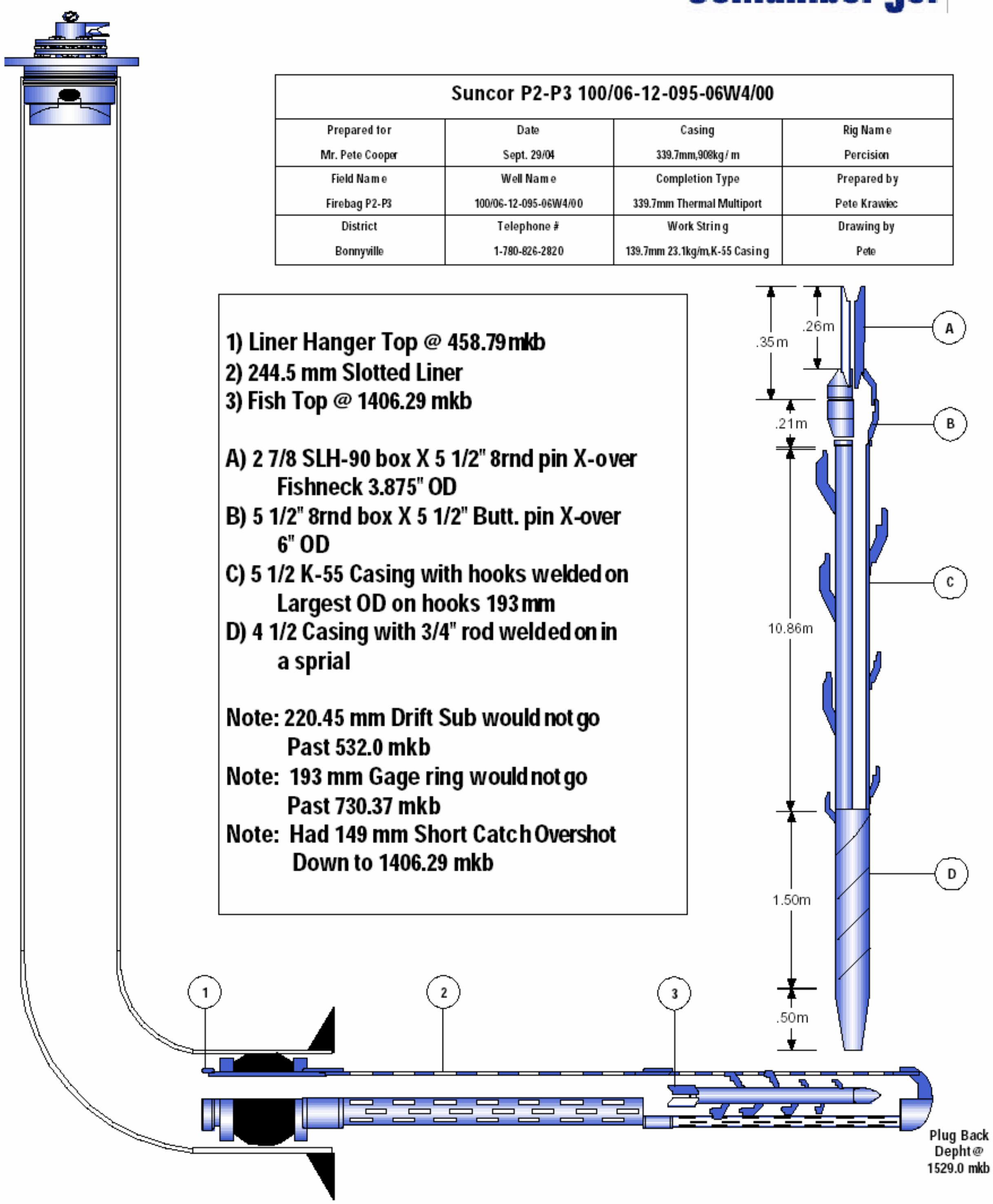
P2P3 will stay as inventory well and final recompletion will be decided in the near future.


18. 4. 2000


Liner Top

Schlumberger

Suncor P2-P3 100/06-12-095-06W4/00			
Prepared for Mr. Pete Cooper	Date Sept. 29/04	Casing 339.7mm,908kg/m	Rig Name Percision
Field Name Firebag P2-P3	Well Name 100/06-12-095-06W4/00	Completion Type 339.7mm Thermal Multiport	Prepared by Pete Krawiec
District Bonnyville	Telephone # 1-780-826-2820	Work String 139.7mm 23.1kg/m,K-55 Casing	Drawing by Pete



1) Liner Hanger Top @ 458.79mkb
2) 244.5 mm Slotted Liner
3) Fish Top @ 1406.29 mkb

A) 2 7/8 SLH-90 box X 5 1/2" 8rnd pin X-over
Fishneck 3.875" OD
B) 5 1/2" 8rnd box X 5 1/2" Butt. pin X-over
6" OD
C) 5 1/2 K-55 Casing with hooks welded on
Largest OD on hooks 193mm
D) 4 1/2 Casing with 3/4" rod welded on in
a sprial

Note: 220.45 mm Drift Sub would not go
Past 532.0 mkb
Note: 193 mm Gage ring would not go
Past 730.37 mkb
Note: Had 149 mm Short Catch Overshot
Down to 1406.29 mkb

Initiator:

_________________________ (print)

_________________________ (sign)

_________________________ (date)

Drilling Approval:

__________________________ (print)

__________________________ (sign)

__________________________ (date)

Geo Science Approval:

__________________________ (print)

__________________________ (sign)

__________________________ (date)

Meeting Attendees: Richard Sendall, Swapan Das, Blaine Anderson, Brett Regier, Fraser Hubbard, Fernando Gaviria, Frank O’Neill.

Appendix 1.3: Decision Record – First Multiphase Pump Install in 2P1

Firebag Project

Decision Record #003

Firebag Drilling

Subject: P2P2 Latest events and ML-SAGD project review.

To: Brett Regier, Richard Sendall,

From: Frank O'Neill, Fernando Gaviria

CC: Blaine Anderson, Mike Swirp

Date: November 16, 2004

Summary

A meeting was held on November 16, 2004 to evaluate recent complications in the execution of the ML-SAGD (formerly called LP-SAGD) program on well P2P2. The goal of the meeting was to explore other alternatives and come up with a plan to continue with the Project.

Observations

- **P2P1**: Intact. Nothing has been done in regards the implementation of ML-SAGD on this well.

- **P2P2**: Control line for sub-surface valve was found failed. Packer was found 0.7m deeper than original landing depth. 1" Coil tubing and ¼" control line founded in tension. Very tight while attempting to pull out thermal packer. String was pulled out 103m, locating packer top at 383m; it was at 486m before.

  Well is currently completed with 2 3/8'' string inside 5½" tubing for warm-up mode.

Decision:

- Move service rig to P2P1 well. Before this, wellbore warm-up is required. The plan is to pull original completion, steam circulation for 6-8 weeks and run pump string.

- Warm-up P2P2. 60 to 100 m3/day steam injection through 2 3/8" tubing will start as soon surface piping is finished. Steaming will also continue on P2S2 well at pre-established rates. Pullout of thermal packer string will be attempted once bottomhole warm-up conditions are reached. Packer and the rest of accessories will be sent to the shop for inspection and engineering review. Decision of running pump string will be revised then.

- Completion engineers will optimize well completion. The goal is to find a more reliable and simpler completion that allows us to field-test the multiphase pump as soon as possible. This would involve the review of the packer concept and strategy, circulation sleeve requirement, positive steam seal to avoid production from the heal and instrumentation alternatives.

Initiator:

_________________________ (print)

_________________________ (sign)

_________________________ (date)

Drilling Approval:

_________________________ (print)

_________________________ (sign)

_________________________ (date)

Geo Science Approval:

_________________________ (print)

_________________________ (sign)

_________________________ (date)

Meeting Attendees:

Richard Sendall, Brett Regier, Blaine Anderson,

Appendix 3.1: Photos of Pump Installation

CAN-K PUMP BEING LIFTED TO RIG FLOOR

MOTOR AND PROTECTOR

20' PRESSURE CHAMBER RUNNING IN HOLE

SHEAVES SET-UP ON SURFACE

CABLE POTHEAD SPLICE INTO MOTOR HEAD

13-3/8 INCH. TAIL PIPE HANGER

PUMP AND PROTECTOR BOLTING TOGETHER

Appendix 3.2: Process Description and Control Philosophy

This appendix is a copy of the document "LP-SAGD Pilot – Process Description and Control Philosophy Rev C.doc"

LP-SAGD PILOT - PROCESS DESCRIPTION AND CONTROL PHILOSOPHY
Revision C, January 21, 2005
Section 1.0 originally by S. Das
Section 2.0 originally by D. Pilgrim

1.0 WELL CONTROL – LP SAGD

1.1 Steps Prior to Pump Installation:

1. Both the injector and the producer wells will be circulated at 200 m3/d for 6-8 weeks depending on the shut down period.
2. After 4 weeks of circulation in the injector, the injector return will be shut in. Therefore, steam will be squeezed in the injector and the circulation will continue in the producer. This may enhance the development of communication between the injector and the producer.
3. Based on the temperature and pressure response, once it has been decided to convert the well to SAGD mode, stop circulation and get the well ready for packer and pump installation.

1.2 Pump Installation:

4. Spend as little time as possible in this step to avoid cooling the well bore.
5. Pull out the 5 ½" production tubing and the 9 $^{5}/_{8}$" slave string from the producer well. Run in the 5 ½" production tubing (as much as necessary), attach the packer at the top and run with the tail pipe such that the 5 ½" tubing extends to the toe (1 joint short of the toe for thermal expansion allowance). Set the packer and pull out the packer running tool.
6. Run the pump-motor assembly in the well and complete the well head.
7. Simultaneously remove the circulation spool and install the jumper line.
8. Must have the DTS and Thermo Couple connected to the DCS

1.3 Start Up:

9. Start injection into the injector well at the rate of 200 m3/d to the tubing and 500 m3/d to the casing as soon as the producer well is secured.
10. Once all of the surface line connection to the producer well head are completed, divert part of the injector casing steam to the producer well through the jumper line and inject into the casing of the producer. This steam will go through the production casing, warm up the well bore and will be squeezed to the toe of the well. Special care needs to be taken to avoid any temperature higher than 200 C at the Thermocouple and the Fiber at the motor. Therefore the injection pressure at the producer well head should not exceed 1900 kPag. Temperature at the motor should be monitored closely.
11. After 300-400 m3 (depending on the temperature and pressure response) of steam has been injected in the producer start full steam injection in the injector.

12. Slowly open the casing vent line to reduce the pressure in the casing and allow fluid influx in the producer. The temperature and pressure measurement at the pump will indicate liquid build up.

1.4 Pump Control Philosophy:

1. If the temperature at the pump suction is higher than 160 C the bitumen viscosity should be low enough to pump. Pump will be started at a lower RPM. At this point there should be plenty of fluid available to pump. Pump should be run below the full capacity for 24-48 hours. Then Speed should be ramped up slowly to the maximum pump capacity. CAN-K recommended that the pump be started at 40 Hz within 10 seconds and then slowly ramping up the speed from there.
2. High temperature (>200 C) at the motor (indicated by the DTS fiber) will trigger the primary shutdown mechanism.
3. From early response a level of current flow will be estimated for different pumping situation. Later, this amperage will be used as an indication of gas/steam breakthrough in the pump. As the amperage drops below this level for over 30 seconds at a stretch, the motor will be stopped. A chart recorder that will continuously measure amperes has been installed on the VSD panel.
4. Subcool at the heel of the producer well will be estimated on the basis of the measured temperature and the injector casing injection pressure. Trends of this subcool will be monitored manually and as the subcool shows decreasing trend, the motor will be slowed down and vice versa. We will also have a pressure from the Halliburton pressure chamber.
5. Initially the casing will be vented (100 m of the casing volume) to the vapour production line to get rid of any accumulated noncondensable gas from the area near the pump intake. On a normal operation, if low amperage is encountered very frequently (indicates vapor breakthrough/build up of noncondensible gases), the casing will be vented periodically. If this helps but does not solve the problem, venting may be continued at a set surface pressure.
6. If the gas/steam breakthrough is related to lower productivity, the pump may be run intermittently (eg. every 3-4 hrs for 3-4 hours) at the minimum of its capacity.
7. If the temperature at the pump suction drops below 150 C, it may be necessary to inject a slug of steam in the 13 $^3/_8$" casing of the producer, using the jumper line.

2.0 SURFACE FACILITIES

The description in this section is written for well 2P2 to match P&ID PD91D-A-8012-2, but the description is the same for well 2P1. Well 2P1 tag numbers are given only when required, but can be found in the P&ID tables.

2.1 Group and Test Production

The downhole pump will deliver the produced fluids to surface through the 5 $^1/_2$" tubing only, and the routing of the produced fluids to either the group or test headers is done the same way as the NL-SAGD wells. For 2P1 the well flowline backpressure control valve 91PV-82084 is left inplace and is to be operated as an automatic backpressure controller for the pilot. This control valve allows well 2P1 downhole pump to operate against a fixed flowing wellhead pressure that can be adjusted by Operations as required. Well 2P2 will have the well flowline backpressure control valve 91PV-82090 removed for the pilot. Without the control valve, the well 2P2 downhole pump will operate against a relatively fixed flowing wellhead pressure but it will be more variable than 2P1. The well 2P2 flowing wellhead pressure will vary slightly as the group separator pressure changes and/or the total flowrate through the group header changes. The comparison of pump operation between 2P1 and 2P2 because of the impact of fixed versus variable flowing wellhead pressure will be one important observation to be recorded during the pilot.

2.2 Well Annulus Venting (Refer to P&ID PD91D-A-8012-2)

Each pilot well has two (2) piping systems that can be used to vent the well annulus.

The first piping system that will be used is the same piping arrangement that allows steam to be injected down the well annulus from the disconnected production flowline. For well 2P2 this vent piping lineup at the wellhead is 91SG8014-2"-HBE (drawing grid D8) and 91SG8016-2"-HBE (drawing grid C6) being installed and connected to 91P8154-6"-HBD (drawing grid D5) which will route well annulus vapours to the group header. As previously mentioned in the description of pump operation, the well annulus will be vented to the group header through 91PV-82092 (well 2P2) to establish a liquid level above the downhole pump prior to starting pump. Once the pump is started the well annulus pressure at surface can be controlled by 91PC-82092, or 91PV-82092 can be closed. Venting through 91PC-82092 should allow the well annulus pressure at surface to be lowered to approximately 500 kPag. Any vapours that form in the production wellbore or flow into the production wellbore should pass through the downhole pump since the downhole pump is indicated to be able to handle some multiphase flow. It is a test of the downhole pump operation to confirm if annulus venting is required or not.

The second piping system will only be required if a lower well annulus surface pressure is required than what can be achieved venting to the group header. The second vent piping system will route well annulus vapours to the group separator outlet, and should allow the well annulus pressure at surface to be lowered to approximately 350 to 400 kPag depending on the produced vapour flowrate. If the second vent piping system is required the steam restart piping at the wellhead must be disconnected. As shown on the P&ID for well 2P2, the two spools of steam restart piping that will be disconnected from the wellhead are 91SG8014-2"-HBE (drawing grid D8) and 91SG8016-2"-HBE (drawing grid C6). It is very important that both of these spools be removed and not just 91SG8016-2"-HBE. The history of the pilot design is that this steam restart line was not originally included, so a reduced design temperature was used for parts of the second vent piping system. With the addition of the steam restart piping the pilot wells now require piping spools to be removed to ensure a physical separation between the steam restart supply piping and the new annulus vent piping.

If during normal operation annulus venting is required it should first be done using backpressure control and a high setpoint; initially as high as the steam chamber pressure and then reduced gradually. Operating with a lower annulus pressure will result in a higher liquid level above the downhole pump suction and will also result in flashing of the downhole produced fluids. If a significant amount of flashing occurs because of a low setpoint the volume of flashed water vapour may be enough to carry bitumen foam up the annulus. Operations should be aware that there could be operating problems caused by a low annulus pressure so if venting is required the reduction of the annulus pressure must be done gradually. This operating consideration applies to both vent piping systems although it is more of a concern if the second vent piping sytem is used.

2.3 Steam Injection for Well Restart (Refer to P&ID PD91D-A-8012-2)

The pilot wells 2P1 and 2P2 have piping added to route steam down the annulus if required to restart the well after an extended outage. This steam would flow around the downhole pump but not through the pump body. If the steam restart is required the two (2) spools 91SG8014-2"-HBE (drawing grid D8) and 91SG8016-2"-HBE (drawing grid C6) will be installed and a section of the annulus vent line 91SG8012-2"-HBE (drawing grid C6) must be removed. The section of the annulus vent line that must be removed is from the wellhead up to the flange set at the isolation valve upstream of 91PT-82142.

2.4 Downhole Pressure Monitoring

Downhole pressure monitoring is included with a Halliburton system that uses a static helium-filled tubing run to a downhole pressure chamber. Once the downhole pressure chamber is purged and filled with helium the downhole pressure is determined by measuring the surface pressure of the helium-filled tubing with a correction for the depth to the pressure chamber. The surface pressure is measured by two (2) instruments. A pressure transmitter (91PT-82081 for 2P1 and 91PT-82087 for 2P2) that is not part of the Halliburton system gives a BPCS indication and a Halliburton supplied pressure transducer gives an indication to a Halliburton supplied local display and datalogger. These two pressure readings may differ slightly because of the corrections for the depth of the pressure chamber. The correction required for the BPCS transmitters is to add 6 kPa to the measured pressure to determine the downhole pressure at the pressure chamber. This correction is essentially constant over the range of downhole operating conditions and is small compared to the total pressure reading.

2.5 Control Setpoint, Alarm and Shutdown Settings

The Alarm and Shutdown Settings have been summarized by Instrumentation and Controls. Please refer to Specification SC91-J-14-1, Specification for Alarms and Shutdowns.

The alarm and shutdown philosophy for the pilot wells is very similar to the existing wells with one exception. The pilot wells have a shutdown that has been added to protect the surface piping against possible overpressure by the downhole pump. For well 2P1 this shutdown is through a new transmitter 91PT-82144. The new transmitter was required because for 2P1 the existing transmitter 91PT-82084 is being kept for backpressure control service. For well 2P2 this shutdown is through 91PT-82090, which is an existing transmitter that is available for service since 91PV-82090 is being removed for the pilot.

Given the nature of a pilot operation, control setpoints will be changed frequently to suit different testing modes. Some considerations regarding possible ranges are noted below.

91PC-82084 (Well 2P1), Not applicable for well 2P2
The lowest setpoint used for testing should provide a stable flowing wellhead pressure for the downhole pump to deliver against, but should be as low as possible to minimize the pump power required; a setpoint which results in 91PV-82084 having an operating position of 60 to 70% open would meet these requirements. It is also acceptable however to have 91PV-82084 100% open during the testing if required. A test of the downhole pump against a high flowing wellhead pressure would be useful to determine if the option of directly pumping produced fluids to the plant (no group separator or transfer pumps) may be possible for future pads. This is not suggested as one of the first tests that would be done, but if this test was to be included the setpoint for 91PC-82084 would be gradually adjusted up to approximately 2000 kPag or until pump operating problems were encountered.

91PC-82143 (Well 2P1) and 91PC-82142 (Well 2P2)
If the second vent piping system is required it is because a low annulus pressure is needed for pump operation. If venting is required then a setpoint of 1000 to 350 kPag should be used. The venting should be started with the high setpoint of 1000 kPag and reduced as required until satisfactory pump operation is achieved. The lower setpoint limit of 350 kPag is approximately the lowest pressure that will be achievable routing the vented vapours into the group separator outlet.

91FC-82181 (Well 2P1) and 91FC-82180 (Well 2P2)
The control of the well annulus pressure at surface is rather directly related to the downhole pump operation since changing the pressure will result in a change in the liquid level above the pump for a

constant reservoir chamber pressure. The flowrate of vented annulus vapour is not as directly related to a downhole condition as annulus pressure, but for testing purposes the ability to vent vapours from the annulus at a controlled flowrate has been included for both 2P1 and 2P2. The operating difficulty in using the flow control will be that there is no direct measurement of the total amount of vapour formed downhole in the production wellbore, so there is no reference for what percentage of the total vapour needs to be vented. However, if venting of the annulus is determined to be required it is recommended that the initial operation be on pressure control only.

Appendix 3.3: Standard Operating Procedures

This appendix is a copy of the document "LP-SAGD Standard Operating Procedures June 16.doc". It describes operations of both Can-K pumps and alternative ESP's.

1. **PURPOSE:**
   1.1. Describe the surface and downhole equipment used in the LP-SAGD pilot project.
   1.2. Describe the start-up, operating procedures and normal operation conditions for the equipment. This will include information from the vendor and troubleshooting situations.

2. **PREREQUISITE:**
   2.1. Production tech must be competent in Firebag well pad operations.
   2.2. Personnel must be competent with the downhole equipment and additional surface equipment used on this pilot project.
   2.3. P&IDs.
   2.4. Vendor equipment information.

3. **PRECAUTIONS!**
   3.1. Equipment must be operated within the recommended ranges. Any deviation will result in equipment damage and severely disable the project.

4. **POTENTIAL HAZARDS:**
   4.1 A HAZOP was conducted for the LP-SAGD project on July 8, 2004. All resolution items from this meeting have been taken completed.
   4.2 Other potential hazards relate to the operation of the downhole equipment and their operational limitations. Operating outside of these conditions will result in damage to the equipment, high replacement costs, and lost production time.
   4.3 The same hazards are present as in the normal SAGD operation.
   4.4 High voltage electricity is present around the VSD and wellhead. Only qualified electricians are permitted to work on this equipment.

5. **PERSONAL PROTECTIVE and SAFETY EQUIPMENT:**
   5.1. Fire retardant coveralls, hard hat, safety glasses, steel-toed boots, and gloves.
   5.2. Personal gas monitor.

6. **BACKGROUND INFORMATION:**
   6.1. Project Objectives

   Design and implement an artificial lift pilot project that will be used to evaluate LP-SAGD. The objective is to gain enough quality data to recommend the optimal pump and motor selection for maximum LP-SAGD production. The design includes a downhole pump and submersible motor with variable speed drive. Modifications will be made to the surface facilities to accommodate the needs of the pilot project. This pilot project is planned for an 18-month period.

   6.2. Description of Downhole Equipment

6.2.1. CAN-K Twin Screw Pump

The CAN-K twin screw pump is a positive displacement pump where the medium moves axially in a continuous straight path. It is a multiphase pump that can handle from 100% liquid to 95 to 98% gas. Slugs of 100% gas can be handled with this pump.

The CAN-K twin-screw multiphase pump is operated in a manner similar to other electric submersible pumps. However, since it is a positive displacement pump, its performance characteristics differ from centrifugal pump.

Minimize the starting and stopping of the pump as much as possible. This will reduce the life of the thrust tilting pad bearings.

The CAN-K pump contains no field-serviceable components. If maintenance is required on the pump, it must be sent to a CAN-K facility.

Due to the pump engineering design and tight tolerances, this pump must not be run in a reverse direction.

6.2.2. Schlumberger REDA Centrifugal Pump

The REDA Hotline 550 pump is a multistage centrifugal pump. To achieve the design capacity of 900 m3/day, the pump requires 45 stages. Temperature limit (218 °C) and capacity are essentially the same as the CAN-K pump. The motor, protector and surface equipment are exactly the same.

This bottomhole assembly will be equipped with two pieces of additional equipment. A bottom feeder intake ensures that the fluids are taken into the pump from the low side of the casing. This equipment is commonly used on horizontal wells with centrifugal pumps in order to reduce the risk of getting gas or steam into the pump. An Advanced Gas Handler (AGH) allows the centrifugal pump to handle large percentages of free gas without affecting performance.
The operating limits of the centrifugal pump will be more stringent than with the CAN-K pump. A twin-screw, CAN-K pump is designed to continue pumping if steam or gas is present in the fluid. The centrifugal pump will cavitate and get damaged if steam or gas gets into the pump stages. Therefore, with a centrifugal pump there must always be a column of fluid above the intake. This means operating with a subcool above 15 °C. Temperatures and pressures must be closely monitored in order to avoid any problems.

6.2.3. Schlumberger Submersible Motor

Schlumberger is supplying a 150 hp motor to drive the CAN-K pump. There will also be a protector above the pump to prevent wellbore fluids from entering the motor as wells as protect the coupling to the pump.

6.2.4. Halliburton Pressure Chamber

The EZ-Gauge Pressure Transmission System will provide real-time, continuous bottomhole pressure data. The acquired information will allow for monitoring of downhole pressures at a single known point. The system uses the most reliable methods of monitoring bottomhole pressure with no moving parts or electronics downhole; all electronics are contained at the surface.

A pressure chamber provides a volumetric area in which the purge gas is compressed during increases in wellbore pressures, thus keeping wellbore fluids out of the capillary tubing. During decreases in wellbore pressures, exhaust ports compensate for purge gas expansion. Helium will be used as the purge gas. The chamber also acts as a sensing junction to transmit pressure signals to a pressure transmitter located at the surface via compressed gas contained in the chamber and in a small diameter capillary tube. Pressures recorded at the surface are corrected for the size of the chamber and the weight of the gas to calculate the downhole pressure.

6.2.5. Thermocouples

A thermocouple line will be deployed along with the pump and motor. This line will contain three thermocouples. One thermocouple will be at the bottom of the assembly, near the Halliburton pressure chamber. Another thermocouple will be located at the motor and the other will be at the pump. These temperature measurements will be used to calibrate the fibre optic line and protect the downhole equipment.

6.2.6. Fibre Optic Line for Temperature Measurement

A ¼” fibre optic line control line will also be deployed with the bottomhole assembly. There will be a turn-around sub just below the motor. After the equipment is set in the well, Sensa will pump the fibre optic line down the control line. The fibre optic line will provide temperature readings at 1-meter intervals along the entire well. These temperature readings will provide the shut-down control points for the motor. At the surface, the fibre optic line will be spliced into the surface fibre optice system. Once connected to the Promore DTS system, the temperatures will be available in the control room and on ProcessNet.

6.3. Description of Additional Surface Equipment

6.3.1. Schlumberger Variable Speed Drive (VSD) Panel

The Schlumberger Variable Speed Drive controls the downhole motor, which drives the pump. The panels are located next to the Pad 2 MCC building. A human-machine interface (HMI) is the primary tool on the panel. Through a series of screens and menus, the various VSD options are made available. There will also be a chart recorder attached to the VSD panel that will show real-time amperage readings. The amp readings provide very important information about the motor and pump performance. This will be a critical piece of information during the start up period.

6.3.2. Halliburton Pressure Monitoring Panel

Halliburton is supplying a Mini-Max data logger unit which gathers and stores information at selected intervals. This data can be retrieved with a portable computer and uploaded into a reporting program. A pressure transmitter will be within the same panel as the data logger. The transmitter will sense the pressure changes within the downhole pressure chamber and capillary tube. Data is then transmitted to the data logger for weight of gas correction and local pressure display.

The helium purge gas system will also be installed on surface, close to the wellhead. Helium is supplied with a pressurized bottle, regulator, and valve system.

6.3.3. Casing Vent Gas

Any vapours that form in the production wellbore or flow into the production wellbore should pass through the downhole pump since this pump is capable of handling multiphase flow. However, a system for venting the annulus is included in the pilot facilities and will be operated if required. The annulus vent line consists of a backpressure control valve and a flowmeter. Any vapours vented from the annulus can be routed downstream of the group separator in the vapour production pipeline. The flowrate of any vented vapour is metered and the flowmeter reading is compensated for pressure and temperature.

The same piping spools are used to inject steam down the production casing. In order to inject steam, this spool would be connected to the production casing flowline rather than the vent gas line. With this configuration, vapours from the casing can be vented directly to the group separator via the casing flowline.

6.3.4. Warming Production Well with Steam

If the temperature at the pump suction drops below 130 C, it may be necessary to inject steam into the 13 3/8" production casing for a period of time. This can be done using the jumper line and steam from the injector casing. The piping for the annulus vent line must be connected to the production casing flowline. Temperatures must be closely monitored with the thermocouples and fibre optic line in order to stay below the maximum temperature of the downhole equipment. The maximum temperature recommended at the pump is 200°C. This steam temperature translates into approximately 1500 kPa (198.3 °C).

7. PROCEDURE:

7.1. Steps Prior to Pump Installation.

7.1.1. Both the injector and the producer wells will be circulated with steam rates of 200 m3/d for 6-8 weeks.

7.1.2. After approximately 4 weeks of circulation in the injector, the injector returns will be shut in. Steam will be squeezed into the injector but continue circulation in the production well. This should enhance the development of communication between the injector and the producer.

7.1.3. Once the wells are ready for pump installation, stop the circulation on the production well and prepare the well for the completion work. Reduce the steam rate to the injector to 100 m3/d. This low steam rate will help keep the well warm and improve the initial well start up.

7.2. Pump Installation and Facilities Construction.

7.2.1. It is important to minimize the time spent on the well workover and surface facilities construction. The fluids in the well will cool and become more difficult to pump as there is no steam injection or fluid flow.

7.2.2. The Drilling and Completions Department will take care of the work needed to prepare and install the downhole equipment into the well. Preparation of the wellhead is also the responsibility of the Drilling group.

7.2.3. The Construction Department will ensure the surface facilities, including electrical and instrumentation, are completed. Circulation spools will have to be removed and replaced with the SAGD production spools.

7.2.4. Thermocouples and DTS (fibre optic temperatures) from the well must be connected to the DCS as soon as possible.

7.3. Re-completion after downhole equipment failure.

7.3.1. Upon failure of a downhole pump, continue injecting steam down the injection well at low rate to maintain temperature.

7.3.2. A service rig will be called to site to pull out the failed downhole equipment and install a different assembly.

7.3.3. Once the new assembly is ready for start-up continue with the appropriate procedures described below. The same procedures will be follow with either a CAN-K pump or a REDA pump.

7.4. Prepare surface facilities and well for the downhole pump start-up.

7.4.1. Increase steam rates to the injection well as soon as the production well has been secured by the Drilling group. Steam can be injected to the injection well while the surface construction is being completed. Inject 200 m3/d of steam down the tubing and approximately 500 m3/d of steam down the casing. Limit the casing steam injection pressure to 2500 kPa in order to prevent damage to the downhole equipment.

7.4.2. Remove locks from the valves on the production well flowlines once the well and facilities have been turned over to operations.

7.4.3. Once the pump is installed, steam must not be injected down the production tubing. To ensure this does not happen, lock out and tag the valve that connects the production tubing and the steam jumper line. We will use the jumper line to put steam down the production casing, but not the production tubing.

7.4.4. The casing piping for the production well should be connected to the normal casing flowline, not the vent line. The vent line will be used if a lower pressure is required to vent the annular gas.

7.4.5. Inject steam down the casing of the production well using the jumper line to warm up the wellbore and fluids. Please see the Standard Procedure for operating the steam jumper lines. Closely monitor the pressure and temperature of the downhole motor. The maximum temperature for the pump is 200ºC, which is approximately 1500 kPa at saturated steam conditions.

7.4.6. When satisfied that there is a column of warm fluids that can be pumped, stop injecting steam down the production well. Close the jumper line and direct all of the steam to the injector casing.

7.4.7. Open the casing vent line to the group separator. This will reduce the pressure in the casing and allow fluid influx to the producer. The temperature and pressure at the pump will indicate the liquid level in the annulus.

7.5. Start the downhole pump using the VSD (variable speed drive).

7.5.1. A Schlumberger representative will be at the site to connect the VSD to the motor. Only qualified persons are permitted to work on this equipment because of the high voltage electricity. A series of checks and procedures will be followed to ensure the safety of the on-site personnel and the equipment. The VSD will be programmed as per the Basis of Design requirements.

7.5.2. Verify that the well is connected to the test separator. Walk the production line and ensure that the manual and/or automatic valves are appropriately positioned.

7.5.3. Increase the speed from zero to 1800 rpm (0 to 40 Hz), with a minimum acceleration time of 10 seconds. Maintain this speed and note performance data at the end of 2 minutes.

7.5.4. Increase the speed to 2320 rpm, with a minimum acceleration time of 20 seconds. Maintain this speed and note performance data at the end of 2 minutes.

7.5.5. The recommended running speeds are between 2300 rpm and 3600 rpm. This translates into 40 to 60 Hz. The minimum speed recommended is 40 Hz or 2300 rpm.

7.5.6. Pump at the minimum speed for 24 to 48 hours. Amperage, voltage and speed data from the VSD will provide information about the pump and motor performance while flow rate, temperature and pressure sensors will indicate well performance.

7.5.7. A Schlumberger technician will monitor the VSD and associated equipment for proper voltage and amperage throughout the system.

7.5.8. While pumping the production well, continue to inject steam into the injection well. It is expected that the steam rate will be between 500 m3/d and 800 m3/d at a pressure of approximately 1500 kPa.

7.5.9. After the pump and motor have been running smoothly for 48 hours, slowly increase the pump speed by 50 to 100 rpm. Closely monitor the amperage, motor load, pressure, flowrate and temperature.

7.5.10. The LP-SAGD design calls for the liquid level in the wellbore to be slightly above the pump intake and operating at low subcool conditions. In order to reach this condition, the amperage and temperature will be recorded and trended over the initial start up period. The data gathered will be used to optimize the motor settings.

7.6. VSD Operation

7.6.1. Schlumberger personnel will be on site during the initial start-up and will provide training and operational support. They will be the primary operator of the VSD for the first few days of operation while training the Suncor operators.

7.6.2. A manual for the VSD has been provided by Schlumberger. This manual is a detailed guide to operating the VSD panel. Operators have participated in training for the VSD and have copies of the manual.

7.6.3. Schlumberger will have Firebag LP-SAGD specific operating guidelines before the equipment is started on site.

7.7. Changing the speed on the VSD.

7.7.1. Press the “SPEED” button on the VSD panel. This will display the page that allows the motor speed to be changed by adjusting the Hz setting. The current speed will be flashing.

7.7.2. Type the desired motor speed using the keypad. Make sure to account for the decimal places.

7.7.3. Press the “ENTER” button on the panel. This will change the speed of the motor.

7.7.4. If an error is made at any time, press the “ESC/MENU” button. This will return back to the main screen.

7.7.5. When looking at the main page, check that the VSD shows the newly changed speed.

7.8. Expectations and Troubleshooting.

7.8.1. While the downhole pump and motor are running, the amperage reading from the motor will be available on a chart recorder mounted on the VSD panel. The amperage will be a key indicator of the equipment and well performance. If there is a reduction in amperage, this indicates that the pump is not working as hard and there is less fluid above the pump.

7.8.2. It is possible during the initial start-up period that the well influx cannot keep up with the pump output. This will result in the column of fluid in the well getting pumped off. We would expect to see the amperage decrease, pressure decrease, and temperature increase as this happens. In this case, the motor speed would be reduced to the minimum rate. It is also possible to choke the well production using the flow control valve of the well, which will put more load on the pump. **Do not choke the well when using a CAN-K pump.** If the well is still not flowing enough, it would be necessary to shut down the pump and wait for the fluid column to build. Under no circumstances should the equipment be operated outside the recommended ranges.

7.8.3. If the temperature of the wellbore fluid gets below 130°C, it will become too viscous to pump and some steam should be injected down the production casing.

7.9. Testing and Sampling Requirements.

7.9.1. Once the downhole pump is lifting liquid to the surface, it will be important to understand the volume and composition of the fluids being pumped. The production flowline will be directed into the test separator during the start-up of the pump. This well should remain in the test separator for two days.

7.9.2. After the initial start-up period, switch this well into the test separator every two or three days. It will depend on the performance on the well and the testing requirements of the other wells on the pad, but frequent testing will be an advantage to the pilot project.

7.9.3. When switching the LP-SAGD well from group to test or test to group, there must always be an open path for the fluid to flow. Having one of the switching valves or choke valves closed will put additional pressure on the pump and risk over-working the equipment.

7.9.4. It may be necessary to close the casing manual block valve, upstream of the pressure control valve, when venting the annulus to the group separator. When the tubing is flowing to the group separator and the annulus does not have

enough pressure to flow, it is possible for tubing fluid to flow down the annulus. Closing the manual block valve will prevent this backflow, but does not allow the casing pressure to be monitored. The production engineers will analyze this risk and provide direction to the operators.
NOTE: This only applies when the annulus is connected to the group separator. There will not be an issue when the annulus is vented downstream of the group separator.

7.9.5. Production engineers will have to ensure that minimum testing requirements for the conventional SAGD wells continue to be met while testing the LP-SAGD well(s).

7.9.6. Sampling requirements will stay the same as for conventional SAGD wells. A sample will be collected every shift, or two samples per test. Follow the standard procedures for collecting the sample and getting a manual BS&W analysis.

7.9.7. There may be sand in the oil that is too small to see with the naked eye. But it is important for the life of the pump to know whether or not there is sand present in the samples. A good way to check is to rub some of the separated oil with a piece of glass. If there is sand in the oil, it will make small scratches on the glass.

7.9.8. One additional sample per test will be collected and sent to Maxxam labs for density, chlorides, and other more detailed analysis.

7.9.9. It is possible that more samples will be required as the LP-SAGD pilot project progresses.

8. IMPLEMENTATION:

9. INTERPRETATION & UPDATING:

10. VALIDATED BY:

____(mm/dd/yy)_________________________
Patrick Spargo
Production Area Foreman

12. APPROVED BY:

____(mm/dd/yy)_________________________
K.W. Hart
General Manager
Firebag

****NOTE: ORIGINAL SIGNED COPY RETAINED BY FIREBAG DMS SPECIALIST****

APPENDIX I

FORMAL REVIEW RECORD

FORWARD THIS COMPLETED FORM TO APPROPRIATE AREA SUPERVISOR

PROCEDURE WAS REVIEWED DURING:

- Safety Meeting [ ]
- Planned Personal Contact [ ]
- Task Assignment [ ]
- Employee Training [ ]
- Orientation [ ]
- Accident/Incident Investigation [ ]

Supervisor: ____ **(mm/dd/yy)**__________________________

Procedure Assessed By: ___________________________________ **(mm/dd/yy)**__________________________

Employee(s): ____

____

____

____

____

Forward to Administrator for entry into TRAQS **(mm/dd/yy)**____

Appendix 5.1: Copy of Suncor's IETP Claim for Project 01-018

ENERGY

Monthly IETP Claim

IETP-1

Business Associate:	Suncor Energy Inc.	**Business Assoc. ID:**	Suncor
Project Name:	Low Pressure SAGD Artificial Lift	**Project Number:**	01-018
Prepared By:	Ryan Armstrong	**Telephone:**	403-920-8568
Date Prepared:	3/23/2006	**Reporting Year:**	2005

Period: 2005 TOTAL ☑ Jan ☑ Feb ☑ Mar ☑ April ☑ May ☑ June ☑ July ☑ Aug ☑ Sept ☑ Oct ☑ Nov ☑ Dec

Part 1: Costs This Period

Capital Cost	$745,447.00
Operating Cost	$8,054,736.00
Injectant Cost	$0.00
Total Costs	$8,800,183.00

Part 2: Royalty Adjustment Earned/Carried Forward

Total Costs x Crown % x 30% (IETP)

$8,800,183.00 x 100.00% x 25% — $2,200,045.75

Prior month Royalty Adjustment Carry Forward	$0.00	
Royalty Adjustment Earned	$2,200,045.75	
Maximum Monthly Royalty Adjustment (Cannot exceed previous month Royalty Payable)	$1,575,000.00	maximum annual claim
Royalty Adjustment Carry Forward	$625,045.75	

Part 3: Allocation of Royalty Adjustment Earned or Maximum Adjustment

☐ Oil Royalty (Operator Only) — $0.00

☐ Apply to Gas Royalty Account (Working Interest Owners)

Account # G94 Name: — $0.00 *

(If more than one account, please use page 2)

☑ Oil Sands Royalty (Operator Only)

Project # OSR 047 Project Name: Suncor Oil Sands — $1,575,000.00 *

(If more than one project, please use page 2)

Total Monthly Adjustment — $1,575,000.00

*** Total for Commodity**

For Department Use Only			
Reviewed By:		Date:	
Verified By:		Date:	
Authorized By:		Date:	

Page 1 of 3

Alberta ENERGY

Monthly IETP Claim

IETP-1

DRAFT

Business Associate:		**Business Assoc. ID:**	
Project Name:		**Project Number:**	
Prepared By:		**Telephone:**	
Date Prepared:		**Reporting Year:**	

Part 3: Allocation of Royalty Adjustment Earned or Maximum Adjustment (cont'd)

☐ Gas Royalty Account (Working Interest Owners)

Total Royalty Adjustment $0.00

Account #	**Name:**	% split	
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
G94		0.00%	$0.00
(attach sheet for additional accounts)			
		0.0%	$0.00

☐ Oil Sands Royalty (Operator Only)

Total Royalty Adjustment $0.00

Project #	**Project Name:**	% split	
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.00%	$0.00
		0.0%	$0.00

Page 2 of ___

ENERGY

Annual Capital Costs

IETP-2

Business Associate:	Suncor Energy Inc	**Business Assoc. ID:**	Suncor
Project Name:	Low Pressure SAGD Artificial Lift	**Project Number:**	01-018
Prepared By:	Ryan Armstrong	**Telephone:**	403-920-8568
Date Prepared:	23-MAR-06	**Reporting Year:**	2005

Well/Facility Name & Legal Location	Description and Details of **Capital** Costs	AFE	Amount
11085-21A-0000019	Transformer Rock	44-6577	$522.00
11085-25B-1000019	Piping Material	44-6577	$2,260.00
11085-25D-0000019	Construction	44-6577	$639,622.00
11085-27A-1000019	Transfomer	44-6577	$30,380.00
11085-27A-3000019	Motor Control centre	44-6577	$13,660.00
11085-27A-7000019	Switch/interpreter	44-6577	$0.00
11085-27B-7000019	Electrical equipment	44-6577	$0.00
11085-28B-0000019	Instrumentation Material	44-6577	$59,003.00
Total Capital Costs			$745,447.00

(Attach additional schedules as required)

PAGE 2 OF 3

ENERGY

Annual Operating Costs

IETP-3

Business Associate:	Suncor Energy Inc.	**Business Assoc. ID:**	Suncor
Project Name:	Low Pressure SAGD Artificial Lift	**Project Number:**	01-018
Prepared By:	Ryan Armstrong	**Telephone:**	403-920-8568
Date Prepared:	23-MAR-06	**Reporting Year:**	2005

Description and Details of **Operating** Costs	Amount
Transportation-Grimshaw	
Camp operations	$ 67,660.00
Bussing	
Offsite Engineering	$ 521,952.00
Hazardous Operations	$ 877.00
Travel	$ 2,621.00
Ancillary Construction costs	$ 180,998.00
Commissioning	$ 28,236.00
Operating Costs	$ 173,800.00
Regulatory/permits/approvals	
Well Completion-drilling	$ 7,078,591.51
TOTAL Operating Costs	8,054,735.51

(Attach additional schedules as required) PAGE 3 OF 3

Supplementary Information

LP-SAGD Drilling Breakdown

Code	Description	Incurred To-date as of December/2005
011	Wellhead Equipment	58,585
012	Wellhead Service	70,418
031	Packers	223,902
034	On-Off Connectors	-
036	Miscellaneous Completion Equipment	-
041	Instrumentation Equipment	466,238
042	Instrumentation Service	444,996
051	Artificial Lift Equipment	1,186,217
052	Artificial Lift Service	480,053
063	Casing and Tubing 3	40,412
065	Tubular Coating	1,169
066	Miscellaneous Tangibles	-
111	Drilling Foreman	160,287
112	Office Consulting Engineering	-
122	Employee and Contractor Recognition	3,451
131	Suncor Employee Expense/Air Travel	2,971
132	Crew Travel	-
141	Technology Development	(13,245)
151	Interest	315
182	Drilling Salaries	137,941
241	Rental Equipment	6,250
314	Telephone	690
315	2 Way Radios	-
322	Wellsite Unit Sewage	540
331	Camp	276,494
341	Potable Water	320
351	Dyed Diesel	38,696
352	Clear Diesel	15,181
353	Gasoline	4,667
411	Drilling Rig Transportation	11,139
416	Miscellaneous Transportation	31
421	Tubular Transportation	50,681
422	Fuel Transportation	1,850
425	Solids Control Transportation	-
426	Rentals Transportation	30,182
428	Miscellaneous Transportation	16,859
511	Moving	5,135
512	Operating - Rig	1,044,490
513	Crew Travel	130,876
514	CAODC Travel	10,745
516	Miscellaneous	25,512
521	Boiler	167,086
522	Loader	130,421
525	BOP & Flare Tank Rental	45,847
526	Power Swivel Rental	41,556
527	Miscellaneous	2,219
623	Drill Pipe Rentals	30,910
641	Casing Scrapers	5,944
642	Packers, Plugs	13,400
652	Generators & Lighting	-
654	Shack Rental	-
658	Miscellaneous Surface Rentals	125
681	Water Trucks	1,036
691	Matting	-
692	Lighting	4,375
693	Miscellaneous Surface Equipment	6,264
713	Miscellaneous Pumping	7,160
731	Power Tongs	580,218
751	Vacuum Truck	66,265
752	Water Trucks	(1)
761	Tools & Supervision	705,785
762	Wireline & Explosives	42,249
771	Logging	61,982
774	Wellbore Monitoring	3,125
783	Steamer	7,200
784	Inspection & Repairs - Pipe	104,713
785	Miscellaneous Services	9,365
786	Lease Labour	165
851	Miscellaneous Lab	-
951	Lease/Road Maintenance	-
SM	Engineering of Packer & Pump	107,135
	Total	**$ 7,078,592**

Annual Injectant Costs and Volumes

I E T P-4

ENERGY

Business Associate: ____________________ **Business Assoc. ID:** __________

Project Name: ____________________ **Project Number:** __________

Prepared By: ____________________ **Telephone:** __________

Date Prepared: ____________________ **Reporting Year:** __________

Type of Injectant ___________

(For multiple injectants please report each type on a separate form)

Month	Total Injectant Volume	Total Injectant Cost $
January	0.0	$0.00
February	0.0	$0.00
March	0.0	$0.00
April	0.0	$0.00
May	0.0	$0.00
June	0.0	$0.00
July	0.0	$0.00
August	0.0	$0.00
September	0.0	$0.00
October	0.0	$0.00
November	0.0	$0.00
December	0.0	$0.00
Total	0.0	$0.00

PAGE ___ OF ___

Appendix 5.2: Updated Appendix 13 from Original Application for Project 01-018

I. Project Economic Evaluation
For Alberta Department of Energy: Innovative Energy Technology Program
Annual Report
Firebag Low Pressure SAGD Pilot Project
Suncor Energy Inc. Oil Sands

Introduction:

Suncor Energy conducted a pilot project for Low Pressure SAGD (LP-SAGD) at its Firebag project. The pilot was aimed at testing a Can-K twin screw multiphase pumping system, and the resulting reservoir performance. Although Suncor remains positive about the long-term outlook for LP-SAGD, the pilot project showed that the Can-K pump did not result in a reliable and economic method of pumping the bitumen from the reservoir under lower pressure operation.

Assumptions

Production and cost numbers are based on actual values to December 2005, and are included in the 2005 calendar year to allow for easy representation.

No forecast data is included due to the pilot project ceasing testing of the Can-K pump. A commercial-scale economic evaluation is not included for the same reason.

As a result, for the incremental (pilot) case, the economic data shown is only for the initial two wells located in TWP 95 RGE 6 W4M to December 31, 2005.

Risks

As discussed elsewhere in the report, downhole pump reliability and rework costs, initially identified as a high risk item for LP-SAGD, was a key factor in judging the reliability and economic performance of the pilot project.

Summary of findings: (for Pilot Project)

Pilot Operation
Table 4: CASH FLOW SUMMARY AND PROJECT ECONOMICS

Base Case: HP SAGD Natural Lift

	Costs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 yrs rem	Tot.
Revenue	**Revenue**												
	Oil Revenue [M $]	12.72	26.32	35.13	10.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	84.22
	Total Revenue [M $]	**12.72**	**26.32**	**35.13**	**10.04**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**84.22**
Costs	**Costs**												
	Total Capital [M $]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Operating [M $]	7.44	16.74	20.77	5.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.40
	Total Royalties [M $]	0.13	0.26	0.35	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84
	Total Costs [M $]	**7.56**	**17.00**	**21.13**	**5.55**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**51.24**
	BEFORE TAX CASH FLOW [M $]	**5.15**	**9.32**	**14.01**	**4.50**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**32.98**
Taxes	**Taxes**												
	Provincial Taxes [M $]	0.55	1.01	1.51	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.55
	Federal Taxes [M $]	1.29	2.35	3.52	1.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.29
	Total Taxes	1.85	3.35	5.03	1.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.84
	AFTER TAX CASH FLOW [M $]	**3.30**	**5.97**	**8.98**	**2.89**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**21.14**

Base Case: HP SAGD Natural Lift

Summary Economics	Before Roy.	Before Tax	After Tax & Roy.
NPV6 [M $]	30.1	29.3	18.8
NPV8 [M $]	29.0	28.3	18.1
NPV12 [M $]	27.0	26.3	16.9
NPV15 [M $]	25.6	25.0	16.0

Incremental

	Costs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 yrs rem	Tot.
Revenue	**Revenue**												
	Oil Revenue [M $]	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.60
	Total Revenue [M $]	**1.60**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1.60**
Costs	**Costs**												
	Total Capital [M $]	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.75
	Total Operating [M $]	8.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.06
	Total Royalties [M $]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
	Total Costs [M $]	**8.82**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**8.82**
	BEFORE TAX CASH FLOW [M $]	**-7.21**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**-7.21**
Taxes	**Taxes**												
	Provincial Taxes [M $]	-0.55	-0.15	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.73
	Federal Taxes [M $]	-1.29	-0.35	-0.03	-0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1.70
	Total Taxes	-1.85	-0.50	-0.04	-0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-2.42
	AFTER TAX CASH FLOW [M $]	**-5.36**	**0.50**	**0.04**	**0.03**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**-4.79**

Incremental

Summary Economics	Before Roy.	Before Tax	After Tax & Roy.
NPV6 [M $]	-7.0	-7.0	-4.7
NPV8 [M $]	-6.9	-6.9	-4.7
NPV12 [M $]	-6.8	-6.8	-4.6
NPV15 [M $]	-6.7	-6.7	-4.5

Total Case: LP SAGD Mechanical Lift

	Costs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 yrs rem	Tot.
Revenue	**Revenue**												
	Oil Revenue [M $]	14.32	26.32	35.13	10.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	85.82
	Total Revenue [M $]	**14.32**	**26.32**	**35.13**	**10.04**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**85.82**
Costs	**Costs**												
	Total Capital [M $]	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.75
	Total Operating [M $]	15.49	16.74	20.77	5.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.45
	Total Royalties [M $]	0.14	0.26	0.35	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.86
	Total Costs [M $]	**16.38**	**17.00**	**21.13**	**5.55**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**60.06**
	BEFORE TAX CASH FLOW [M $]	**-2.06**	**9.32**	**14.01**	**4.50**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**25.77**
Taxes	**Taxes**												
	Provincial Taxes [M $]	0.00	0.86	1.49	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.82
	Federal Taxes [M $]	0.00	2.00	3.49	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.59
	Total Taxes	0.00	2.86	4.98	1.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.41
	AFTER TAX CASH FLOW [M $]	**-2.06**	**6.47**	**9.03**	**2.92**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**16.35**

Total Case: LP SAGD Mechanical Lift

Summary Economics	Before Roy.	Before Tax	After Tax & Roy.
NPV6 [M $]	23.1	22.3	14.1
NPV8 [M $]	22.1	21.3	13.5
NPV12 [M $]	20.2	19.5	12.3
NPV15 [M $]	18.9	18.3	11.5

As the chart shows, and as discussed elsewhere in the report, the performance of the pilot project did not meet expectations. As can be seen from the Incremental case, the NPV of the project was negative for all cases.

Appendix 6.1: DBM LP-SAGD Pilot

1.0 PROJECT DESIGN BASIS

1.1 Piping

- Tie-in annulus gas line, c/w electric heat tracing, to existing produced vapor line #91SG8005-16”-EDB that flows to the Firebag Plant.
- Piping modifications required at each well head will require installation of new piping spools. Only the 6” interconnecting piping from the well head to the production header requires replacement. These spools shall be shop fabricated and installed during a shutdown.
- Modify piping at each well head to facilitate lifting of the well head by approximately 610mm.

1.2 Civil and Structural

- Civil work required is limited to the installation of a transformer foundation including fencing.

1.3 Electrical

- Install a 25 kV outdoor pole mounted interrupter switch to serve as the primary disconnect for a new transformer.
- Install a 25 kV / 480V liquid filled, 500KVA outdoor transformer, to be located in the adjacent to the existing 1000KVA transformer. The existing yard needs to be redesigned to accommodate the new 480V transformer. Some modifications to the existing yard fence will be required.
- Install a 480V, 800 Amp. MCC with 800A main breaker and two 400A feeder breakers. The new MCC to be installed in the existing electrical building in the permit area.
- The MCC will be equipped with metering facility for power consumption of the pumps.
- EHT modification required on the new piping spools for the well head modification.

1.4 Instrumentation and Controls

- New signals will be wired into existing BPCS.
- Install two new flow control loops that will have pressure and temperature compensation on the annulus gas lines from wells to the temporary test separator. One control loop per well is included. A vortex meter and control valves are installed as part of the control loop.
- Monitor temperature of each submersible pump.
- Modbus serial communications from pump VFD’s in the field are converted into a fiber optic signal shall be used for motor controls.

- The use of a local/remote switch and a start/stop switch in the field shall be used to comply to Firebag Stage 2 standards. A Stop command from the BPCS will be configured as well.

- The existing fire and gas detection system does not have to be upgraded.

Appendix 9.1: Minutes of LP-SAGD Lessons Learned Meeting May 26, 2005

Firebag LP SAGD Pilot Project
Lessons Learned Workshop - May 26, 2005

"Effective meetings require that participants be committed to achieving the objectives."

Participants:
Toby Dinter, Darcy Riva, Fernando Gaviria, Ken Hart, Allison Aherne, Joe Kitt, Larry Yano, and Susan Heming.
Conference call attendees: Sam Veltri, Dave Tullis, and Dave Pilgrim

Distribution: Attendees plus, Blaine Anderson, Bruce McCarty, Patrick Spargo, Ann Howe, Carlos Torres, Bob Moore, Mark Edelmann, Swapan Das, Melanie Weber, Richard Sendall, John Myer, Greg Lewis, Andrea von Schoening.

Issued by: Larry Yano

Meeting Objectives:

To capture lessons learned from the LP-SAGD Pilot Project (Stage 1 Retrofits).

Key Outcomes:

Understanding and applying lessons learned (LL) from the pilot project serves the following purposes:
1) LL help to improve knowledge about low pressure, mechanical lift, SAGD well systems to aid in future development; and, 2) projects being carried out elsewhere in the company can benefit from lessons learned identified during the pilot project implementation.

Meeting Notes

Safety:

A safety message regarding the dangers of lightening was discussed, as we move into lightening season. You can tell how close you are to a lightning strike by counting the seconds between the flash and the thunder. For every five seconds you count, the lightning is 1.6 km away. If you see a flash and instantly hear thunder, take shelter immediately. If you can't take shelter, then crouch on the ground to minimize the amount of contact you have with the ground. A ditch or low-lying area is the best place to seek refuge, as tall objects are more susceptible to being hit by lightening. Also avoid carrying metal or conductive objects.

Introduction:

With the mission to optimize reservoir operations, the Firebag Small Projects team has finished Stage 1 of its Firebag LP SAGD well pilot project in conjunction with the Drilling, Operations and the Reservoir groups. The technology being employed to maximize well production is new to Suncor. A combination of low pressure steam and a mechanical lift system, which utilizes pumps, is being used to enhance SAGD bitumen recovery. Retrofit construction of 10 wells is scheduled to begin in July, with start up of the first completed wells scheduled for October of this year.

Lessons Learned Process:

Prior to the meeting, some key topic areas were distributed to attendees to focus the discussion. The discussion topics included:

- Communication Interfaces
- Scheduling and Execution
- Technical/Design/Scope
- Construction

There were a few potential LL items submitted in advance of the meeting. During the session additional LL items were identified and added to the initial list (Table 1 attached). This meeting deviated slightly from the normal practice of brainstorming a list, identifying priority items by participant voting, and then working the priority items. In the course of discussion, the lessons learned developed details around each item including making commitments to action. The next step in the process is to develop specific LL records for the tabled items, which appear as bolded items in the table.

Follow Up Actions:

1. Various actions items are identified in Table 1 for follow-up.
   Complete Actions by Individuals identified in Table 1.
2. Meeting notes to be reviewed for omissions and corrections.
   Toby to do an initial review and then all participants in meeting and individuals on distribution list
3. Lessons Learned to be entered into portal.
   Larry Yano/Susan Heming

Table 1. LP-SAGD Pilot Project Lessons Learned and Follow up Action Items

LESSON	ROOT CAUSE	ACTIONS
Description of the lesson learned (can be things that worked well and things that could be improved).	What was the root cause of the learning? May need some form of causal analysis (focus on cause and not just the symptoms).	Develop a set of actions that will ensure that the benefit is gained.
The pilot had on/off Operations sponsorship. Some pre-Commissioning items got dropped. For the retrofit installation, a more regular contact would be a big benefit. **LL: Need more dedicated and consistent Operations / C&SU support during start up and project implementation.**	Operations staff is not always available due to other commitments. The level of information to aid operations understanding wasn't fully complete. All 4 shifts (process dept. general foremen, operators etc.) did not receive the same level of training.	Process description & control narrative philosophy needs to be packaged and presented as a complete installation to Operations. This can be rolled into training packages. Identify the C&SU contacts (Ann & Carlos) along with Darcy's defined role and availability (Richard to confirm). Establish a training plan for the pad operators along with Schlumberger involvement.

LESSON	ROOT CAUSE	ACTIONS
There were partial turnovers during C&SU which resulted in inefficiencies. - Partial turnovers and the lack of defined turnover procedures caused confusion in the construction and operations offices (e.g. owner requirements). - Poor communication around project scope led to partial turnovers being rushed (e.g. staged turnover of some systems due to equipment delivery schedules). - Spec blind was left in the annulus gas header. -Not enough clarity around the turnover of partial systems/lines. **LL: A process for doing partial or complete turnovers needs to be defined in the early stages of a project. This includes identifying possible risks associated with each turnover event.**	There was a schedule rush and equipment deliveries didn't allow a full turnover. Turnover packages were not well defined and reflected in the C&SU schedule. Some confusion when systems were required (operations expectations didn't match up with the construction plan). Partial turnover scope & execution was a known condition but wasn't clearly defined or well planned.	Darcy to meet with Randy Crossman to better understand the turnover procedures (especially for small projects). Finalize the design (after HAZOP review) and plan the construction sequencing and identify partial turnover of systems. Ensure that design drawings, documents, packages etc. are available to support the turnover plan. Reflect the C&SU and turnover strategy in the detailed project schedule.
The Drilling/Completions involvement in the surface facilities design is welcomed and encouraged, but they cannot dictate the flow of information or design detail (e.g. marked up P&ID's and piping drawings were used to jump to design solutions). Most difficult part of design is the well head. **LL: Roles, responsibilities and signing authorities need to be clearly defined and communicated throughout a project. However, active participation in design changes is encouraged, but only when channeled through the proper authorities.**	Multi discipline reviews did not pick up all the potential issues. The weekly reviews were started but all issues didn't surface. Well head completion and surface facilities discussions weren't well coordinated.	The CWP checklists need to ensure all documents and potential issues are identified. Follow Jacobs design review and CWP procedures. Changes when they occur need to be processed following change management procedures. Field level risk assessments need to be done prior to starting the construction field work.
LL: Work scope, scope changes and execution plans need to be communicated to all groups involved in a project. This includes assigning a defined lead to communicate the work scope and ensure that work plans are integrated	There wasn't a defined lead to coordinate the integrated work plans. There was some confusion over respective roles & responsibilities of the key players.	Daily coordination meeting to ensure coordination between contractors and include the interface between operations (e.g. permitting, well pad operators) This coordination meeting needs to be in place prior to construction activity.
Need to be able to sign out blocks of instrument or equipment tag numbers to improve efficiency.	Suncor procedure may not allow block issue of tag numbers.	Check if this is a Suncor standard.
Need a dedicated person in document control to coordinate document flow between vendors, operations, project team.	Lack of document control budget.	Consider releasing budget for this position.
Contractor dropped a wrench down the hole resulting in a I day delay. **LL: During well construction, ensure that there is a work instruction in place to protect/cover the well hole.**	Lack of adequate protection / cover / work procedures.	Build in a work instruction to ensure adequate hole protection.
Low temperature start went well	Good SAGD design	Ensure the design is carried forward to

LESSON	ROOT CAUSE	ACTIONS
		future work.
CanK improving procedure and tools to fill up their pumps with lube oil. The CanK pump was successful in this application.	Focus to continuous improvement Implementation of new technology.	Need more complete transfer of information on pump performance characteristics to the design office.
LL: The team added a tubing check valve to avoid a backflow thru the multi phase pump.	Good response to a potential problem.	Ensure the practice is carried forward to future work.

Appendix 9.2: Decision Record relating to Well P2P3 completions difficulties

Decision Record #001

Firebag Drilling

Subject: Alter Pad 103 completions to remove the initial running of 31.4mm inch coil tubing

To: Brett Regier, Richard Sendall

From: Mack Kay

CC: Micaela Pilieci, Dave Cuthiell, Shaun Zimmer, Fraser Hubbard, Swapan Das, Mike Swirp, Blaine Anderson

Date: September 23, 2004

Summary

A meeting was held on September 22nd 2004 to discuss the value added by having a inch coil tubing line run in parallel with the 5.5" production tubing on Stage 2 Pad #103 as has been done on previous completions. The issue arose due to complications seen during the LP-SAGD test at P2P3. The subject well was to have the initial completion string of the 5.5" production tubing and 1" CT pulled from the wellbore but encountered extreme operational issues. It was suggested that the 31.4mm coil be left out of the initial completion and run at a later date as it is highly anticipated that the stage 2 wells will be converted to a LP-SAGD system of some type in the future.

Observations

The conversion to LP-SAGD in wells P2P2 and P2P3 commenced in July 2004. The program was to pull the existing down hole configuration of the 5.5" production tubing and 1" coil tubing line from the well to be replaced with a down hole packer production system.

The first well that the service rig went on was P2P3. Upon pulling the parallel strings simultaneously, the configuration got stuck in either the liner or the slave string. In order to retrieve the tubings it was necessary to cut off partial pieces of the strings and fish them out and then repeat the process until the entire length was removed from the wellbore. After getting out the entire string there was an operational issue which caused the service rig to move to P2P2 to pull the production strings instead of running the final assembly.

The trip out with the parallel strings on P2P2 went smooth. Total cost to pull the strings was ~$120,000 with no operational issues. The rig then returned to P2P3 to run the final packer assembly.

Upon running the packer the rig was unable to get past the liner hanger at ~500m. An impression block was run to see what the obstruction was and the block showed that there were still pieces of coil tubing remaining in the wellbore. Fishing then commenced to retrieve all excess coil tubing from the wellbore. The pictures below are some of what was retrieved.

It is estimated as of September 23, 2004 that the cost to pull the original configuration and replace it with the LPSAGD string is going to

be ~$1M due to the complexities of the coil tubing being in the wellbore.
It is felt that the coil tubing will naturally rotate to the right when being deployed in the wellbore upon completions. Due to the length that is run it is very difficult to maintain tension to avoid the coil tubing getting wrapped up around the 5.5” production tubing. Once the coil is wrapped around the tubing it creates a large diameter that is extremely susceptible to getting stuck when tension is put in the strings.

Decision:

The meeting that was held was to inform all parties that operationally it was much easier and would provide less long term complexities if the coil tubing would be left out of the initial completions on Pad 103. It was proposed that the 5.5” tubing be ran alone in the wellbore with the thermocouple lines being pumped directly down the tubing as conducted in the Stage 1 wells. The idea was agreed upon by all attendees at the meeting and action is being taken immediately to modify the completion procedure on pad 3103 to reflect this.

Initiator:

__________________________ (print)

__________________________ (sign)

__________________________ (date)

Drilling Approval:

__________________________ (print)

__________________________ (sign)

__________________________ (date)

Geo Science Approval:

__________________________ (print)

__________________________ (sign)

__________________________ (date)

Meeting Attendees: Mack Kay, Micaela Pilieci, Dave Cuthiell, Shaun Zimmer, Fraser Hubbard, Swapan Das, Mike Swirp, Blaine Anderson, Richard Sendall