IETP Application No. 06-094

Imperial Oil Resources – Cyclic Solvent Process Pilot

2016 Annual Project Technical Report

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1 Abstract

Imperial Oil Resources (Imperial) is conducting a Cyclic Solvent Process (CSP) experimental pilot scheme at Cold Lake in the Clearwater formation and is being operated under Energy Resources Conservation Board (ERCB) Approval 11604, dated May 5, 2011.

CSP is a non-thermal, in-situ bitumen recovery process that utilizes injected solvent to reduce the viscosity of the bitumen, enabling its production from wells drilled for that purpose. The liquid-phase solvent is injected into a horizontal well cyclically and, because of the large mobility contrast between the solvent and the bitumen, it fingers into the bitumen. Following injection, the solvent-bitumen blend is produced from the same well. Cyclic injection and production operations continue for multiple cycles over several years until the bitumen produced no longer justifies the cost of the solvent or until the bitumen production rate is no longer economic. The cyclic operation is followed by a final blow-down period, when additional solvent is recovered by vaporization at low pressure.

Since CSP is a non-thermal process, the two key challenges facing traditional thermal processes (e.g. Cyclic Steam Stimulation and Steam Assisted Gravity Drainage) are avoided: (1) thermal inefficiencies which limit applicability to thinner and/or lower bitumen saturation reservoirs and (2) production of GHGs arising from burning natural gas to produce steam.

The pilot is located at K50 pad in Imperial's Cold Lake development and is being conducted in the Clearwater formation. Three horizontal wells are operated using CSP as a recovery process. This report summarizes progress that was made through year-end 2016.

The project has transitioned from a single-well to multi-well operation with HW1 and HW2 coming online in 2016. At year-end, HW1 and HW2 were in the late-stage of cycle 3 production. HW3, the leading well, was in cycle 5 early-stage production. The work has continued to focus on active surveillance of the pilot in an effort to achieve high quality data. Operationally, the pilot has moved to limit the use of flow assurance solvent. In particular, HW2 eliminated co-injection of the flow assurance solvent by testing pure propane injection for all cycles. In general, the well performance is similar and also aligned with the expectations. However, HW3 has shown higher water production and greater sub-surface pressure support than the other wells. The installation of a new gas compressor has enabled the testing of low pressure production. HW1 and HW2 have realized the benefits of low-pressure operation by improving the rates during late-stage production. Active surveillance and maintaining operational stability remain top priorities for 2017.

2 Summary and Project Status Report

2.1 Members of the Project Team

The following were key members of the CSP pilot team at the end of 2016.

C. (Cheryl) Trudell, PhD, P.Eng.	Research Manager
J. (Jianlin) Wang, PhD	CSP Team Lead
N. (Nafiseh) Dadgostar, PhD, P.Eng.	CSP Reservoir Engineer
G. (Gordon) MacIsaac, PhD	CSP Reservoir Engineer
M. (Mat) Suitor, P.Eng.	CSP Reservoir Engineer

2.2 Key Activities

Key activities during the reporting period are described below:

HW1

- HW1 cycle 1 injection from February 5 to 9, production from February 12 to March 31
- HW1 cycle 2 injection from April 10 to 15, production from April 17 to July 6
- HW1 cycle 3 injection from July 12 to 21, production from July 22 and continued through year-end
- Casing pressure control valve installation from October 5 to 13
- HW1 pump replacement from December 1 to December 5

HW2

- HW2 cycle 1 injection from May 5 to 9, production from May 11 to June 30
- HW2 cycle 2 injection from July 6 to 10, production from July 13 to Sept 18
- HW2 cycle 3 injection from September 25 to October 2, production from October 4 and continued through year-end
- Casing pressure control valve installation from September 20 to 22

HW3

- HW3 cycle 3 restarted on January 31 (after compressor skid installation), production continued to March 20
- HW3 cycle 4 injection from March 23 to April 4, production from April 6 to November 27
- HW3 cycle 5 injection from November 27 to December 17, production from December 19 and continued through year-end
- Casing pressure control valve installation from September 25 to October 3

4D seismic

- Monitor 1 shoot on December 18

Pad Facility Maintenance and Construction

- Compressor skid and wellhead flow assurance solvent manifold installation from January 1 to 29
- Test separator demulsifying chemical injection skid installation from March 20 to 24
- Test separator oil-leg extension pipe installation for improved separation efficiency from October 8 to October 27

2.3 Production, Material and Energy Balance

During 2016 HW1 and HW2 were brought online and completed cycles 1 and 2. By year-end HW1 and HW2 were continuing through production of cycle 3. HW3 completed cycles 3 and 4 and cycle 5 production started before year-end. The reported production volumes are engineering estimates based on a combination of pad test separator readings, density based calculations, and compositional analysis of physical samples collected during production. Since propane, flow assurance solvent and bitumen all exist in the liquid phase; the process for determining component volumes is much more challenging than for traditional steam based processes. The injection volumes for each well are shown in Table 1. Total production volumes are given in Table 2 and volumes per well are given in Tables 3 through 5.

2.4 Resource

Based on a Petrel-based geologic model, the estimate of bitumen-in-place in the pilot area is 879 [km^3]. The current reservoir simulation estimate of recovery is 12 [km^3] after the planned five cycles of the pilot with 23 [km^3] solvent injection. The ratio of these values is not indicative of the recovery factor of the process – the wells have been spaced farther apart than would be anticipated during a commercial project, and the process may not run to an economic limit. Recovery factor and reserves will be determined by history-matched reservoir simulation model at the completion of the pilot.

3 Well Layout and Geology

3.1 Well and pad layout

The pilot consists of six observation (OB) wells and three horizontal wells:

IMP 08 OV COLD LK 14-18-65-4	– UWI 1AA/14-18-065-04W4/00
IMP 10 CSP OB-1 LEMING 14-18-65-4	– UWI 105/14-18-065-04W4/00
IMP 10 CSP OB-2 LEMING 14-18-65-4	– UWI 100/14-18-065-04W4/00
IMP 10 CSP OB-3 LEMING 14-18-65-4	– UWI 102/14-18-065-04W4/00
IMP 10 CSP OB-4 LEMING 14-18-65-4	– UWI 103/14-18-065-04W4/00
IMP 10 CSP OB-5 LEMING 14-18-65-4	– UWI 104/14-18-065-04W4/00
IMP 11 CSP H-01 LEMING 3-19-65-4	– UWI 100/03-19-065-04W4/00
IMP 11 CSP H-02 LEMING 14-18-65-4	– UWI 110/04-18-065-04W4/00
IMP 11 CSP H-03 LEMING 14-18-65-4	– UWI 111/04-18-065-04W4/00

The layout of the wells is shown in Figure 1. The six OB wells are drilled from three pads and the three horizontal wells are drilled from a fourth pad. Surface facility and pad locations are shown in Figure 2.

Well 14-18 was drilled in 2009; the remaining five OB wells were drilled in 2011. The horizontal wells were drilled in March 2012. All wells were completed from late 2012 to early 2013.

3.2 Geology

The pilot is being conducted in the Clearwater formation. A cross-section of the reservoir, through the observation wells, is shown in Figure 3. The reservoir consists of two sequences: the lower sequence, between the lower sequence boundary (bright green line in three wells in Figure 3) and the upper sequence boundary (purple line in Figure 3); and, the upper sequence between the upper sequence boundary and the top of the Clearwater formation (red line in Figure 3). The primary target is the lower sequence, with an average thickness of 21 [m]. The depth of the horizontal wells is shown approximately by the dashed dark green line in Figure 3.

The sands are generally clean, although one noticeable feature on the logs is the calcite cemented zones (colored blue in Figure 3). From core, we believe these features to be limited in areal extent. Observation of similar features elsewhere in the development would suggest their impact on conformance should be limited. Should the calcite zones be more extensive and have zero permeability, they may change the conformance of the solvent-invaded zone, but should not impact our ability to interpret the pilot results. Heterogeneity is higher in OB1 through OB5 than in the first well 14-18, upon which the site was picked. Again, this increase in heterogeneity is not expected to adversely impact the pilot results.

Also noticeable from Figure 3 is that three of the OB wells were drilled shallower than the other three. This was to avoid a higher water saturation zone below the Clearwater formation. Although the wells are cemented, it was decided not to penetrate that sand in the last three wells.

4 Well Information

4.1 Drilling, completion, and work-over operations

The 2012 annual report provided a detailed summary of the drilling activities and a brief description of the OB well completions. Figure 4 shows the OB wells surface and bottom-hole locations relative to the horizontal wells (HW1 through HW3) and provides an overview of the OB wells instrumentation for surveillance. The 2013 annual report discussed the work for the first phase of horizontal well completion work. The 2014 annual report discussed the work for the second phase of horizontal well completion work. The OB well completions are summarized in Table 7 and HW completions are summarized in Table 8.

4.2 Wellbore schematics

A general schematic of the three horizontal wells, to be completed similarly, is shown in Figure 5. Schematics of the six observation wells were provided in the 2012 annual report.

4.3 Spacing and pattern

The horizontal wells are spaced approximately 200 [m] apart, with approximately 100 [m] of drainage length per well, as shown in Figures 1 to 4. Adding 50 [m] to the potential drainage area on each end of each HW, the pilot encompasses 120,000 [m^2] (600 [m] x 200 [m]), which is roughly 32.5 acres per well.

4.4 Well operation

The pilot was shut-in during January of 2016 for facility modifications, which included the installation of a compressor skid. Details of the modifications are given in Section 5.3. In 2016, multi-well operation was initiated with HW1 and HW2 coming online. HW3 continued with normal operation. Minor differences in the well operation strategy are discussed below.

HW3 cycle 3 was restarted in January 31. Lower pressure operation was attempted by venting the casing gas through the newly installed compressor package. The gradual reduction of BHP led to a significant increase in the water production, with limited benefit to the hydrocarbon production. In general, HW3 water production through cycles 1 and 2 was higher than the nominal pre-pilot expectations and therefore the observed increase in water production at lower pressures was anticipated. Consequently, the lower pressure operation for HW3 was generally avoided other than a planned test of sustained lower pressure during the late-stage of cycle 4.

HW1 was brought online to test the repeatability of the CSP process. The operational plan for injection and production of HW1 was the same as HW3. However, observed changes in the production performance led to changes in the late cycle operation. Specifically, the water production of HW1 was lower compared to HW3, thereby permitting low pressure late cycle operation.

HW2 was brought online to test two changes to the operational strategy. The injected solvent was changed to 100% propane to test the effects of removing the flow assurance solvent as a co-injectant. Furthermore, HW2 is not equipped with functioning downhole heaters, thus operating HW2 would naturally test the robustness of the process without downhole heating. For reference, HW1 and HW3 have active wellbore heaters set at 18 and 30°C, respectively.

5 Surface Facilities

5.1 Detailed Design

Engineering design of the surface facilities was completed by August 2012. The process flow diagrams (PFDs) in Appendix A provide a high-level overview of the surface facilities and are representative of the pilot facilities as of December 31, 2016.

5.2 Progress

The current reporting period featured key facility modifications in January 2016:

1) A new vent gas compressor with a discharge pressure equal to the re-rated MOP of the pipeline.
2) A utility solvent manifold for the independent downhole distribution of flow assurance solvent to multiple wells
3) A demulsifying chemical injection system for the test separator to improve the water separation efficiency

Multi-well operation began in February 2016. Simultaneous and continuous venting of multiple wells was not possible due to a common venting manifold shared between the HWs. An intermittent venting strategy was applied until casing pressure control valves were installed for each well from September 20 to October 13. Thereafter, continuous venting was achieved for all wells.

The installation of the demulsifying chemical injection system improved the separation of the oil and water phases. However, the separated free-water was not completely dumped from the water leg, causing by-pass into the oil-leg. Installation of a weir was recommended but not logistically possible for the current design. As an alternative, the oil-leg piping was extended into the test separator and set at a pre-determined height above the floor. The free-water by-pass has been reduced and the reliability of test measurements improved with the oil-leg extension.

5.3 Surface equipment

Table 9 provides a list of major equipment and their design basis. Below is a description of the major equipment and how they are used in the injection and production system. Please refer to the Process Flow Diagrams (PFDs) in Attachment A.

<u>Solvent Preparation & Blending (Injection)</u>
Propane supplied via truck is stored in two storage vessels, V-0061/62. Propane transfer pumps, P-0061/62, supply liquid propane to the primary injection pumps P-0051/52. Flow assurance solvent is also supplied via truck and is stored in two atmospheric storage tanks, T-0071/72. Transfer pumps, P-0071/72 will boost the pressure for blending with the propane upstream of the static mixer, filters and primary injection pumps. The basket strainer, FIL-0071 is installed on the filling line of diluent tanks removes debris suspended in the diluent supply. The tanks are blanketed by low pressure nitrogen supplied by a LP nitrogen skid.

The blended injection fluid is mixed in an in-line static mixer and then filtered via fine mesh filters (FIL-0051/52) to remove basic sediment. Filtered solvent is routed to the primary injection pumps, P-0051/52 and electric solvent heaters, H-0051/52 before injecting into the wells.

<u>Production System</u>
After each injection cycle is completed, the injected well then starts producing. Production flows through ROV-401 where it is directed either to the electric production fluid heater (H-0054) and

subsequently the group production line or to the electric test fluid heater (H-0053) and subsequently the test separator (V-0011). In January of 2016, a demusifying chemical injection skid was installed. The demulsifying agent is injected through a static mixer upstream of the test-separator.

Any gas which may pressure up the casing is vented through the compressor (PK-0031) and re-routed back to the group line. PK-0031 was installed in January 2016 and replaced the MPP system that was originally in place. As described in Section 5.2, the common vent gas manifold prevented simultaneous and continuous venting of multiple wells. Casing pressure control valves were installed on the vent line of each well, thereby allowing the wells to operate at independent casing pressures.

Methanol injection into the pipeline is required for hydrate mitigation. The methanol injection system consists of a metering methanol pump (P-0022) and a chemical methanol tank (T-0022).

With the exception of the propane storage and transfer pump area, all site PSVs will discharge to an atmospherically vented pop tank (T-0001). PSV releases from the propane vessels, V-0061/62, and the propane transfer pumps will be discharged to atmosphere through a vent stack located at southwest corner of K-50 pad.

5.4 Capacity limitation, operational issues, and equipment integrity

The facility related operational issues encountered through 2014 and 2015 were largely mitigated with either facility modifications or operational improvements. Refer to the 2014 and 2015 IETP annual reports for further details. Operational issues encountered during 2016 are grouped as either injection or production system related.

Injection

- No major limitations or issues were identified

Production

- An intermittent venting strategy was applied during low-pressure operation of HW1 and HW2. Intermittent venting affects the liquid density, liquid rates and the water-cut – ultimately complicating the production allocation process. Continuous steady operation is desirable and therefore casing pressure control valves were installed on each well in September and October of 2016.
- The installation of the demulsifying chemical injection skid improved the test separator efficiency. However, free water by-pass to the oil leg was still observed. Installation of weir was not possible for the current test separator design, so as an alternative the oil-leg piping was extended vertically within the test separator. The vertical pipe has reduced the by-pass of free water into oil-leg; however, the issue has not been fully mitigated.
- HW1 experienced a pump failure on December 1, which was characterized by low wellhead pressure and no liquid delivery. The pump was replaced and the operation resumed on December 5.
- Pipeline pressure was managed with utility flow assurance solvent. During multi-well operation the co-mingled flow may lead to undesirable phase behavior and heavy liquid buildup. Treating with pipeline with flow assurance solvent can mitigate the heavy liquid buildup and restore the pipeline pressure to a normal operating level.

6 Production Performance

6.1 Injection and Production History

Multi-well operation was achieved during 2016 with HW1 and HW2 coming online in February and May, respectively. By year-end, HW1 and HW2 had completed cycles 1 and 2 and were continuing to produce cycle 3. HW3 completed cycles 3 and 4 and production of cycle 5 started before year-end. The total injection volumes for the pilot and the individual volumes for each well are shown in Table 1. Total production volumes are given in Table 2 and volumes per well are given in Tables 3 through 5.

Table 6 shows the updated production volumes from 2015. The updated volumes reflect changes arising from the sample analysis results and are therefore different than those in the 2015 report. Section 6.2 describes the two-stage process required to estimate the production volumes. The meter readings provide the initial estimates which are later corrected with the sample analysis data.

For each cycle in 2016, the narrative of injection and production events is described in the following sub-sections.

6.1.1 HW1 (Cycle 1 to Cycle 3)

Two full cycles of injection and production were completed for HW1 during the current reporting period. Cycle 3 production continued through year-end.

HW1 Cycle 1 Injection

Injection started on February 5 with a target injection volume of 502 [m³] containing 12.5% (by volume) flow assurance solvent. The maximum injection rate of 125 [m³/D] was achieved early in the injection cycle and sustained through the completion of injection on February 9. The maximum sustained bottom-hole pressure was 10.8 [MPa] and the corresponding bottom-hole pressure of the nearest observation well (OB1, ~18 m lateral distance from HW1) was 10.1 [MPa].

HW1 Cycle 1 Production

Production began with flowback on February 12 with rates as high as 25 [m³/D] during the early stage of the production. The bottom-hole pressure of HW1 and OB1 were 6.6 and 7.0 [MPa], respectively. The rate gradually decreased with the natural decline of the bottom-hole pressure, as expected for a typical CSP production cycle. To improve production rates at lower downhole pressures, venting through the gas compressor was started on February 27. The late-stage bottom-hole pressures of HW1 and OB1 were 375 [kPa] and 2.1 [Mpa], respectively. Cycle 1 was completed on March 31 with minimal downtime.

HW1 Cycle 2 Injection

Solvent injection started on April 10 and finished April 15 with a total solvent volume of 678 [m³] with 11.5% (by volume) flow assurance solvent. The target rate of 150 [m³/D] was achieved during a ramp-up period and sustained for the duration of the injection cycle. The maximum sustained bottom-hole pressure was 9.2 [MPa] and the corresponding bottom-hole pressure of OB1 was 8.7 [MPa].

HW1 Cycle 2 Production

Production started on April 17 and a peak production rate of 35 [m³/D] was achieved shortly thereafter. The bottom-hole pressures of HW1 and OB1 were initially 6.0 and 7.1 [MPa] and then declined naturally as the cycle progressed. Similar to the strategy used for HW1 Cycle 1 production, venting was used to improve production rates at lower downhole pressures during the late stage of the production cycle. An intermittent venting strategy, where HW1 and HW2 would alternate venting on a daily basis, was applied during the late-stage production due to the short-coming of the common vent-gas manifold, as described in Section 5.3. The late-stage bottom-hole pressures of HW1 and OB1 were 350 [kPa] and 2.0 [MPa], respectively. Production was completed on July 6.

HW1 Cycle 3 Injection

Injection started on July 12 with a target injection rate of 150 [m^3/D] achieved on the first day of injection and sustained throughout the injection cycle. A total of 1260 [m^3] of solvent with 12% (by volume) flow assurance solvent was injected with minimal downtime. HW1 Cycle 3 injection was completed on July 21. The maximum sustained bottom-hole pressure was 8.7 [MPa] and the corresponding bottom-hole pressure of OB1 was 8.4 [MPa].

HW1 Cycle 3 Production

Production started on July 22 and the production rate peaked at 38 [m^3/D] during the early stage of production. The bottom-hole pressures of HW1 and OB1 were initially about 6.7 and 8.0 [MPa], respectively. As expected, the rate then decreased along with the natural decline of the bottom-hole pressure. Intermittent venting was applied during the mid-stage production to increase the pump fillage and improve the production rates. The venting system was later improved with the installation of individual casing pressure control valves, as described in Section 5.3. For HW1 the installation was completed from October 5 to 13. Thereafter, production continued with continuous venting. On November 29, HW1 experience a pump failure which was characterized by a loss of tubing pressure and no liquid production to the wellhead. The pump replacement began on December 1 and production was restarted successfully on December 5. A previously scheduled mini-blowdown was then accelerated through December. Aggressive venting was applied to bring the bottom-hole pressure from approximately 1000 [kPa] to less than 300 [kPa]. Higher than normal gas rates were achieved during this period and production continued through the year-end.

6.1.2 HW2 (Cycle 1 to Cycle 3)

Two full cycles of injection and production were completed for HW2 during the current reporting period. Cycle 3 production continued through year-end.

HW2 Cycle 1 Injection

Injection started on May 5 and after going through the initial ramp-up period, the target injection rate of 150 [m^3/D] was achieved and sustained until the end of the cycle on May 9. A total of 507 [m^3] of 100% propane was injected. The maximum sustained bottom-hole pressure was 10.6 [MPa] and the corresponding bottom-hole pressure of the nearest observation well (OB3, ~13m lateral distance from HW2) was 9.2 [MPa].

HW2 Cycle 1 Production

Production started on May 11 with early production rates were as high as 35 [m^3/D] during the flow back period. The bottom-hole pressures of HW2 and OB3 were about 5.2 and 6.3 [MPa], respectively. The expected decline of the downhole pressure during the early stage of production resulted in a gradual drop in production rates. Venting was utilized to increase the pump fillage at lower downhole pressures and consequently to improve production rates at the late stage of the production cycle. The bottom-hole pressure was maintained at about 400 [kPa] during this period and the OB3 pressure was about 2.1 [MPa]. HW2 Cycle 1 was completed on June 30.

HW2 Cycle 2 Injection

Injection began on July 6 with a target injection rate of 150 [m^3/D] achieved after an initial ramp-up period and was sustained throughout the injection cycle. A total of 599 [m^3] of 100% propane was injected with minimal downtime. The bottom-hole pressure stabilized at 8.2 [MPa] and the corresponding OB3 pressure was about 7.6 [MPa]. HW2 Cycle 2 injection was completed on July 10.

HW2 Cycle 2 Production

Production started on July 13 with early stage rates that peaked at about 30 [m^3/D]. The bottom-hole pressures of HW2 and OB3 were about 4.3 and 4.8 [MPa], respectively. The rate naturally declined along with the bottom-hole pressure until continuous venting began on July 25. Venting continued to the end of the production cycle to enhance the production rates at lower downhole pressures. The venting was intermittently shut-in to accommodate the required venting of the other wells. Late stage bottom-hole pressures were as low as 550 [kPa] with corresponding OB3 pressures as low as 2.0 [MPa]. HW2 Cycle 2 was completed on September 18.

HW2 Cycle 3 Injection

The venting system of HW2 was upgraded with a casing pressure control valve installation following the completion of Cycle 2. Injection then started on September 25 with a target injection rate of 150 [m^3/D] achieved during the first day of injection and sustained through the injection period. A total of 1100 [m^3] of 100% propane was injected with minimal down time. The bottom-hole pressure stabilized at 7.8 [MPa] and the corresponding OB3 pressure was about 7.4 [MPa]. HW2 Cycle 3 injection was completed on October 2.

HW2 Cycle 3 Production

Production started on October 4 with peak rates of about 35 [m^3/D] during the early production period. The initial bottom-hole pressures of HW2 and OB3 were about 5.1 and 5.2 [MPa], respectively. Natural decline continued and the rates followed as expected. Continuous venting began on October 19 to improve the pump fillage during the mid-stage production thereby improving the liquid rates during low-pressure operation. By year-end the bottom-hole pressure was about 900 [kPa] with a corresponding OB3 pressure of about 1.8 [MPa]. Cycle 3 continued through the year-end.

6.1.3 HW3 (Cycle 3 Restart to Cycle 5)

Production of Cycle 3 was restarted in Q1 after a planned pad shut-in for facility upgrades. Cycle 4 was completed thereafter and Cycle 5 production continued through the year-end.

HW3 Cycle 3 Production Restart

Production was restarted on January 31 after facility modifications were completed during a planned pad shut-in beginning on December 27, 2015. Cycle 3 resumed during the late-stage production with initial rates as high as 14 [m^3/D].

Up to the current point in the pilot history low-pressure operation had not been achieved, largely due to the incompatibly of the MPP system with the re-rated pipeline. Details are given in the 2015 IETP annual report. With the newly installed compressor package venting trials began on February 9. The venting system preformed as designed; however, a short-coming was identified with the vent-gas recycle loop (a different issue than the common manifold mentioned in the previous sections) and continuous venting could not be maintained. Prior to rectifying the gas recycle loop, low pressure operation was tested by intermittently drawing down the pressure with the venting system. HW3 Cycle 3 production competed on March 20.

HW3 Cycle 4 Injection

Injection started on March 23. A total solvent volume of 1800 [m^3] with 12% (by volume) of flow assurance solvent was injected with minimal stoppage. The injection rate ramped up smoothly to the target value of 150 [m^3/D] and remained at this level until the end of injection on April 4. The bottom-hole pressure stabilized at 7.7 [MPa] and the corresponding pressure of the nearest observation well (OB5, ~16m lateral distance from HW3) was about 7.2 [MPa].

HW3 Cycle 4 Production

Production started on April 6 with early stage rates that peaked at about 37 [m^3/D]. The bottom-hole pressures of HW3 and OB5 were both about 5.5 [MPa], respectively. An intermittent venting strategy was applied to the majority of the cycle to maintain pump fillage as the bottom-hole pressure declined. Continuous venting was trialed starting on October 6 following the installation of the casing pressure control valve. The bottom-hole pressure was lowered from 2.0 [MPa] to 800 [kPa] by October 24 and then held constant for the duration of the cycle, which was competed on November 27. The corresponding late-stage OB5 pressure was 2.0 [MPa].

HW3 Cycle 5 Injection

Injection started on November 27. A total solvent volume of 2941 [m^3] with 6% (by volume) of flow assurance solvent was injected. The injection rate ramped up smoothly to about 162 [m^3/D]. Despite the brief shut-ins due to winter operational challenges, the cycle injection was ultimately completed on schedule by December 17 and the target volumes were achieved. The bottom-hole pressure stabilized at 7.0 [MPa] and the corresponding OB5 pressure was about 6.6 [MPa].

HW3 Cycle 5 Production

Production started on December 19 with early-stage rates that peaked at about 37 [m^3/D]. The bottom-hole pressure of HW3 was initially about 5.5 [MPa]. Cycle 5 continued production through the year-end.

6.2 Composition of Injected and Produced Fluids

In 2016, different solvent compositions were tested. For HW1 cycles 1 through 3, the injected solvent was approximately 88 vol% propane and 12 vol% flow assurance solvent. For HW2 Cycles 1 through 3 the injected solvent was nearly 100 vol% propane, with flow assurance used only for pre-injection wellbore treatments. HW3 cycle 4 applied the original ratio with 88 vol% propane and 12 vol% flow assurance solvent. HW3 cycle 5 aimed to reduce the amount of flow assurance solvent by lowering the injecting concentration to 6 vol%.

The propane is industrial grade propane with an average of 98 mass% of C3. The composition of the flow assurance solvent is proprietary.

Produced fluids can be comprised of methane, propane, flow assurance solvent, bitumen, and water. Over the course of the production cycle the composition of the produced fluid changes. The determination of composition happens in two parts. The first part is an initial estimate derived from pad measurements of masses, densities, and water-cuts. The estimate requires several assumptions to make a density-based split of propane, flow assurance solvent and bitumen. The second step happens several months afterwards once the compositional analysis of physical samples is completed and results are incorporated into the overall analysis. The compositional analysis itself includes gas chromatographs (GC) up to C6 for the volatile gas portion and up to C30+ for the remainder. Individual substances can then be identified from the mixture by their characteristic shapes on the GC outputs. Figure 7 shows examples of the characteristic shapes for each liquid phase substance.

A total of six production cycles were completed during 2016. The production characteristics of each well were similar. The water production of the three HWs is different. Tables 3 through 5 show the 2016 production volumes for HW1 through HW3, respectively. Although the cycles of each well are not synchronized in time, HW3 is an outlier in terms of water production. The cumulative water-cut for HW3 for 2016 production is about 43%, whereas HW1 and HW2 were both approximately 17%.

6.3 Simulation and Prediction of the Pilot Performance

In general, the performance expectations for all of the HWs are generated through preliminary simulations in combination with the learnings from laboratory experiments and previous CSP field trials. The unique nature of the CSP process requires significant simulation model development. In 2016, the simulation development largely focused on history matching of cycles 1 through 3 for all of the HWs. Performance predictions are then generated for each subsequent cycle using the latest history matched model. Currently, the history matched models for each well show good agreement with the pilot results from cycles 1, 2 and 3.

Future work will continue testing the predictive ability of the history matched model.

7 Pilot Data

7.1 Additional data and Interpretation

CSP surveillance uses an array instrumented OB wells to monitor solvent conformance. The well-layout at the CSP pad is shown in Figure 1. The measurement devices include ERD pressure and temperature sensors, distributed temperature sensing (DTS) thermal fibers, and passive seismic (PS) geophones. The design intent of each system is different. The ERD devices are installed in perforated wells and are used to sense the 1D lateral extent of the solvent during injection. Solvent arrival is generally characterized by a sharp increase in pressure at the bottom-hole location. The DTS thermal fibers were designed to sense temperature changes within the reservoir caused by solvent arrival, thereby yielding a vertical distribution of the solvent chamber at the OB well position. For OB wells without PS geophones, heaters were installed to increase the temperature difference relative to background to improve the sensitivity of the DTS system. The PS system was designed to monitor seismic activity during injection. Locatable events then provide a 3D distribution of the fluid movement within the sub-surface.

Not all of the wells are equally instrumented. Each HW has a nearest OB well that is perforated. Each HW also has a local PS OB well. All OB wells have DTS fibers but only three wells have heaters to improve the DTS sensitivity. The observed responses from the different OB measurements are discussed below:

In 2016, a total of eight injection cycles were completed. In general, PS events were temporally correlated with the injection pressure, but were not locatable due to their low energy relative to the background noise. As a result, reliable maps of the solvent conformance could not be determined from the sensed PS events.

The perforated wells with ERD sensors detect solvent arrival as a rapid change in bottom-hole pressure. During injection the HW bottom-hole pressure rises gradually. When solvent arrives at the OB well a mixture of reservoir fluid flows into the OB well causing the fluid column to rise and compress any gas in the headspace. The OB bottom-hole pressure increases accordingly and is nearly equal to HW bottom-hole pressure – the difference representing the pressure loss from the HW to the OB well. During all injection cycles for all wells, the corresponding perforated OB wells show this rapid pressure rise, thereby indicating connectivity to the solvent zone.

The DTS thermal fiber system has only detected solvent arrival on OB3, which is the only perforated OB well with a heater installed. However, the solvent arrival was not detected along the OB casing, as intended, and does not give the vertical distribution of the solvent. Instead, the DTS system responded to temperature changes of fluid moving within the tubing. Only OB3 has shown a DTS response to solvent injection. Wells without perforations, regardless of whether a heater is installed, have not shown a DTS response.

The minimum lateral extent of the solvent zone can be inferred from the relative OB well position if a response (pressure or temperature) is observed during injection. For HW1 through HW3 responses were observed at their respective perforated OB wells. Therefore, solvent has travelled laterally at a minimum of 18, 13 and 16 [m], respectively. The CSP pilot has additional sub-surface surveillance plans to further define the sub-surface conformance. The first 4D seismic shoot (M1) was completed on December 18. By comparing to the baseline pre-pilot seismic data, changes to the sub-surface can be further interpreted. The M1 shoot analysis began following the shoot and continued into 2017. The M2 shoot is scheduled for Q1 2017 and will provide a snapshot of the wells at different operating conditions.

8 Pilot Economics

Price data used in this section is a combination of:

- Bitumen/natural gas pricing based on actual prices from Imperial Oil's 2016 10-K filing
- The propane and flow assurance solvent price is estimated based on the average price paid by the CSP pilot in 2016 for each product respectively

The price information can be found in Table 10.

8.1 Sales volumes of natural gas and by-products

In 2016, the pilot produced 36,580 [Sm^3] of natural gas. No natural gas was consumed. Also, the pilot produced 3544 [m^3] of propane and 354 [m^3] of flow assurance solvent from the reservoir. Other than the flow assurance solvent produced from reservoir, the pilot has also recovered all the utility fluid used within the wellbore and surface facilities, totalled 447 [m^3].

8.2 Revenue

As the CSP pilot is part of Imperial Oil's Cold Lake Production Project, injection and production volumes are blended with Mahihkan plant volumes, and thus revenue is not calculated separately. This section provides the methodology of the estimated revenue calculation.

Revenue is derived from five sources: sale of the produced bitumen, the theoretical sale of produced solution gas, the theoretical sale of recovered propane and the theoretical sale of recovered flow assurance solvent.

Gross revenue for the pilot in 2016 is estimated to be 1,392 k$. This is based on 3544 [m^3] of propane, 801 [m^3] of flow assurance solvent (including 354 [m^3] recovered from reservoir and 447 [m^3] from surface facilities), 3556 [m^3] of bitumen and 36,580 [Sm^3] of natural gas produced at 22.58 $/bbl, 58.14 $/bbl, 26.52 $/bbl and 2.41 $/mcf, respectively.

A summary of the annual revenues over the project life is given in Table 11.

8.3 Costs

8.4 Drilling, completions, and facilities costs

Table 12 summarizes drilling, completions, facilities, and related costs by category, incurred in 2016. Often these costs are referred to as capital costs, but because of the uniqueness and short life of the facilities and the research nature of the pilot, they have not been capitalized. Under the category "HW drilling" a credit of 7 k$ was received due to account clearance, thus the total drilling, completions, and facilities costs in 2016 were was -7 k$.

8.5 Direct and indirect operating costs

Table 13 summarizes direct and indirect operating costs incurred in 2016, totalling 3,385 k$.

8.6 Injectant costs

Table 14 summarizes injectant costs by category incurred in 2016. Trucking costs associated with transporting each product to site are included.

8.7 Total Costs

A summary of the annual costs incurred over the project life is given in Table 15. Annual credits, such as those received from Emissions Reduction Alberta (formerly known as CCEMC), are deducted from the total costs for cash flow calculations.

8.8 Crown royalties

This pilot is part of Imperial Oil's Cold Lake Production Project, with revenue and costs impacting the total Cold Lake payable royalty. An estimation of the impact on the payable royalty is shown in Table 16.

8.9 Cash flow

As revenue is only estimated for the pilot, cash flow can only be estimated. Using the data from Tables 13 through 11, it is estimated as follows:

Revenue	= Bitumen + Solution Gas + Propane + Flow Assurance Solvent = 593 + 3 + 503 + 293 = 1,392 k$
Credits	= ERA Credit = 1,680 k$
Costs	= Drilling & Facilities Costs + Operating Costs + Injectant Costs - ERA Credit = (-7) + 3,385 + 2,027 – 1,680 = 3,725 k$
Before Royalty Cash Flow	= Revenue – Costs = 1,392 – 3,725 = -2,333 k$
Royalties	= -587 k$
Cash Flow	= Revenue – Costs – Royalties = 1,392 – 3,725 – (-587) = -1,746 k$

This estimation of cash flow does not include taxes.

8.10 Deviations from budgeted costs

Changes to individual cost components are expected. To date, there is no change to the total cost of the pilot.

9 Environmental/Regulatory/Compliance

A copy of any approvals mentioned in the following sections, as well as amendments made, can be supplied upon request.

9.1 Regulatory Compliance

The project is operating under ERCB scheme approval 11604. To date, the pilot has been in full compliance, and no regulatory issues have arisen.

9.2 Environmental Considerations

The CSP pilot (construction, operation and reclamation) has been planned to align with the environmental objectives as outlined in the Cold Lake Expansion Project (CLEP) Environmental Impact Assessment (EIA) (Imperial Oil Resources, 1997) as well as with the requirements outlined in operating approval No. 73534-01-00 (as amended) issued by Alberta Environment and Sustainable Resources Development (ESRD) under the Alberta Environmental Protection and Enhancement Act (AEPEA). Numerous other directives and codes of practice have also been reviewed during the planning phase to ensure full compliance. Imperial has an internal database system populated with commitments, requirements and responsibilities as outlined in applicable regulations.

9.3 Air Quality

The CSP pilot has not resulted in any change to air emissions as considered in the EIA discussed previously. Imperial presently conducts air quality monitoring in the Cold Lake Operations (CLO) area outside of regulatory mandates and as a measure of due diligence, Imperial actively monitors the air quality of the CLO area air shed through placement of eleven passive air quality monitoring stations targeting H_2S and SO_2 gas emissions associated with operating CLO facilities. CSP is a sweet oil process and therefore H_2S and SO_2 are not emitted from the current pilot.

9.4 Aquatic Resources

Imperial regularly conducts monitoring programs involving aquatic resources located within the CLO area including surface water, wetlands and groundwater. These programs are regularly expanded and modified as a consequence of field expansion. Imperial presently reports its water diversion volumes in response to corresponding regulations and is in full compliance with water diversion reporting requirements. The addition of the CSP pilot did not generate an increase in water demand.

A Wetland Monitoring Program (Imperial Oil Resources 2005) was implemented in 2006 in which wetland vegetation, water quality and flow dynamics are evaluated on a regular basis. Groundwater monitoring instrumentation is utilized proximal to wetland areas to monitor water flow and drainage performance as well as to monitor water quality/chemistry. Setback requirements associated with environmentally sensitive areas have been maintained in proposed pad and facilities designs.

9.5 Wildlife

Imperial develops its project schedules in a manner consistent with applicable regulations. Environmental aspects are considered and evaluated during the pre-construction planning phase of all Cold Lake projects with special attention paid to wildlife habitat and movement issues. The

CSP development was conducted with the objective of minimizing disturbance to wildlife habitat and movement.

During production, Imperial personnel adhere to the Wildlife Mitigation and Monitoring Plan which outlines specific actions and responsibilities designed to reduce operations-related risks to wildlife and wildlife habitat in the CLO area.

Reclamation plans are developed and implemented with particular attention paid to returning the land to an equivalent land capability. Wildlife use of reclaimed sites is a key aspect of reclamation success and will be monitored through the Cold Lake Reclamation Monitoring Program.

9.6 Noise

Through direct consultation with regulators and other stakeholders, Imperial has developed a noise prediction model to meet the requirements of ERCB Directive 038 (ERCB 2007). The entire Cold Lake Expansion Project has shown to be significantly below the allowable p sound level (PSL).

9.7 Reclamation

The CSP pilot decommissioning and reclamation activities will be addressed in accordance with EPEA Approval 73534-0-00, as amended.

10 Future Operating Plan

10.1 Project schedule

In 2016, the CSP pilot transitioned from single-well to multi-well operation with HW1 and HW2 coming online. A total of eight injection cycles and six production cycles were completed. HW1 and HW2 were in late-stage cycle 3 by the year-end while HW3 was in early-stage of cycle 5. It is the nature of the CSP process for the injection volumes of subsequent cycles to increase. As the pilot progresses the length of the cycles also increases accordingly. It is expected that HW1 and HW2 will begin Cycle 4 in Q1 of 2017 and continue through to Q4 of 2017. HW3 cycle 5 will continue through to Q1 2018. The key activities for 2017 are listed below:

- Complete the second 4D seismic shoot (M2) in Q1 2017
- Complete HW1 Cycle 3 and begin cycle 4 in Q1 2017
- Complete HW2 Cycle 3 and begin cycle 4 in Q1 2017
- Complete HW1 Cycle 4 in Q4 2017
- Perform a mini-blow down of HW2 prior to completing HW2 Cycle 4 in Q4 2017
- Continue with stable multi-well pilot operation. Pilot surveillance and data interpretation, simulation history matching, and operation sensitivity studies are part of the work plan
- M1 and M2 4D seismic analysis and interpretation

10.2 Changes in pilot operation

The pilot progress during 2016 has not resulted in significant changes to the pilot operation schedule.

10.3 Optimization strategies

In 2016, the CSP pilot focussed on operational stability as the pilot transitioned to a multi-well operation. Initially, a conservative approach was applied to the use of flow assurance solvent, methanol and downhole heating to ensure operational stability. As the pilot progressed through the first cycles of HW1 and HW2 the focus shifted to limiting the use of downhole flow assurance solvent. Selective use of downhole flow assurance resulted in improvements to production allocation and sample analysis program. Continuous delivery of flow assurance solvent to the pipeline was only required during specific periods when the co-mingled flow of multiple wells led to undesirable heavy liquid build up in the pipeline.

HW2 was brought online and tested two different operational variables. The solvent composition was changed to 100% propane injection, thereby eliminating downhole co-injection of the flow assurance solvent. Also, HW2 does not have active downhole heaters, so the operation of HW2 had to proceed without additional downhole heating. To date, the performance of HW2 is similar to HW1 and HW3 suggesting that HW2 strategy is a more optimized approach to operate CSP. The performance of HW2 was one factor that led to a change of the injectant composition for HW3 cycle 5. Eliminating flow assurance solvent from HW1 is a possibility for cycle 4 in Q1 2017.

Lastly, the installation of the new vent gas compression system allowed the wells to be operated at lower bottom-hole pressures. HW1 and HW2 realized the benefits of low pressure operation which aimed to extend the cycle life and improve the hydrocarbon recovery. As described previously, the pressure support experienced on HW3 limited the low-pressure operation range of HW3. Further testing of low-pressure operation is planned for 2017. In particular, a mini-blowdown is planned for HW2 in Q4 of 2017.

10.4 Salvage update

Currently, no plans to salvage any of the equipment on site have been developed.

11 Interpretations and Conclusions

11.1 Overall Performance Assessment

To summarize the overall 2016 performance:

- HW1 and HW2 were successfully operated into the late-stage of cycle 3
- HW3 completed cycles 3 and 4 and was operated into the early-stage of cycle 5
- The overall performance of the pilot was aligned with expectations
- The installation of the vent gas compressor enable testing of the CSP process at low pressures
- The flow assurance solvent was effective in mitigating heavy liquid plugging in the wellbore, the surface facilities and pipeline

11.2 Difficulties Encountered

The facility issues of 2014 were largely mitigated with the re-rating of the trunkline from the pilot site to the Mahihkan plant. The introduction of a new flow assurance solvent in 2015 has reduced the difficulties caused by heavy liquid deposition, both within the wellbore and on the surface facilities.

The primary difficulty encountered in 2016 was the balancing of the venting requirements for multiple wells without individual casing pressure control. With the installation of the casing pressure control valves in Q3-Q4 2016 the difficulty was mitigated.

Additionally, the test separator efficiency has been improved with the installation of the demulsifying chemical injection system and the oil-leg extension pipe. However, inconsistent levels of water are still by-passed to the oil-leg. Further testing of the required concentration of the demulsifying agent is planned for 2017.

11.3 Technical and Economic Viability

The current pilot represents one study that will be used in combination with others to evaluate the overall technical viability of the CSP process. Judgements regarding the technical and economic viability of the CSP process have not yet been made.

11.4 Overall Effect on Gas/Bitumen Recovery

This has yet to be determined.

11.5 Future expansion or commercial field application

Decisions regarding the future expansion of the CSP pilot or commercial field application have not been made at this time.

Tables

Table 1: Material Balance Data – Injection

	HW1		HW2		HW3		Total	
Injected Volumes[1] (m^3)	**Propane**	**FAS²**	**Propane**	**FAS²**	**Propane**	**FAS²**	**Propane**	**FAS²**
January	-	-	-	-	-	-	0	0
February	439.5	62.2	-	-	-	-	440	62
March	-	-	-	-	1178.0	158.5	1178	158
April	599.9	78.1			406.9	55.9	1007	134
May	-	-	507.2	8.0	-	-	507	8
June	-	-	-	-	-	-	0	0
July	1109.2	152.7	598.6	6.9	-	-	1708	160
August	-	-	-	-	-	-	0	0
September	-	-	827.4	8.7	-	-	827	9
October	-	-	272.4	-	-	-	272	0
November	-	-	-	-	356.7	90.9	357	91
December	-	-	-	-	2401.9	90.9	2402	91
Total 2016	**2148.6**	**293.0**	**2205.6**	**23.6**	**4343.5**	**396.2**	**8698**	**713**

[1]Injectant volumes indicate delivered to the reservoir and do not include 447 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore
[2]Flow assurance solvent (FAS)

Table 2: Material Balance Data – Total Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	0	2	0	0	0
February	220	279	1355	134	16
March	124	193	847	55	5
April	244	35	182	672	113
May	548	245	2772	373	48
June	307	328	3293	144	15
July	338	201	909	531	41
August	611	357	10405	362	39
September	266	299	6598	128	9
October	397	395	3190	532	13
November	285	411	3752	145	6
December	216	218	3277	468	49
Total 2016	**3556**	**2963**	**36580**	**3544**	**354**

[1]Produced volumes indicate recovered from the reservoir and do not include 447 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 3: Material Balance Data – HW1 Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0
February	107.6	17.5	114.4	87.2	10.3
March	86.9	49.2	673.1	39.8	3.5
April	133.3	3.3	181.7	180.6	26.8
May	234.3	46.9	2454.4	106.0	15.8
June	87.0	77.9	1667.5	36.1	5.6
July	41.0	14.9	277.6	232.5	31.7
August	347.6	42.7	8654.2	261.8	33.6
September	166.5	55.3	5543.9	86.8	6.4
October	89.7	63.2	683.8	38.3	4.5
November	64.2	83.7	665.8	31.1	3.5
December	89.3	113.5	2568.7	40.4	2.9
Total 2016	**1447.4**	**568.1**	**23485.1**	**1140.6**	**144.6**

[1]Produced volumes indicate recovered from the reservoir and do not include 447 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 4: Material Balance Data – HW2 Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0
April	0.0	0.0	0.0	0.0	0.0
May	125.6	17.2	78.0	91.7	3.6
June	71.8	71.1	1559.2	33.9	0.0
July	177.1	11.2	503.5	250.8	2.9
August	153.6	80.0	1602.6	59.7	0.6
September	37.8	71.3	1021.4	19.1	0.1
October	228.0	16.1	1307.1	461.9	5.2
November	158.9	67.3	1537.3	87.9	0.9
December	121.3	104.8	708.6	57.1	0.6
Total 2016	**1074.1**	**439.0**	**8317.7**	**1062.1**	**13.9**

[1]Produced volumes indicate recovered from the reservoir and do not include 447 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 5: Material Balance Data – HW3 Production

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Flow Assurance Solvent
January	0.1	2.2	0.0	0.0	0.0
February	112.5	261.1	1241.1	46.8	5.3
March	37.3	143.6	173.6	14.9	1.4
April	110.6	31.3	0.0	491.4	86.2
May	187.6	180.4	239.8	175.8	28.1
June	148.4	178.6	66.2	73.4	9.7
July	120.2	175.2	128.0	47.6	6.2
August	109.9	234.2	148.6	40.7	5.3
September	61.7	172.4	32.3	22.4	2.9
October	78.6	316.0	1198.8	31.8	3.0
November	61.7	260.7	1548.9	26.3	1.9
December	5.7	0.0	0.0	370.5	46.0
Total 2016	**1034.3**	**1955.7**	**4777.3**	**1341.6**	**196.0**

[1]Produced volumes indicate recovered from the reservoir and do not include 447 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 6: 2015 Material Balance Data – HW3 Production Corrected with Sample Analysis Data

Produced Volumes[1] (m^3)	Bitumen	Water	Sol'n Gas	Propane	Diluent	Flow Assurance Solvent
January	0.0	0.0	0.0	0.0	0.0	0.0
February	0.0	0.0	0.0	0.0	0.0	0.0
March	0.0	0.0	0.0	0.0	0.0	0.0
April	52.0	11.6	0.0	32.4	23.5	0.0
May	75.3	77.5	92.0	37.2	18.3	0.0
June	12.6	25.9	99.9	5.9	2.5	0.0
July	221.6	53.8	0.0	205.4	10.5	23.4
August	115.0	98.9	0.0	45.4	4.3	3.7
September	21.2	15.4	0.0	107.6	0.3	23.2
October	215.2	71.0	0.0	266.0	0.0	49.5
November	134.5	85.1	0.0	60.9	0.0	8.0
December	80.3	78.0	0.0	33.8	0.0	4.5
Total 2015	**927.7**	**517.2**	**191.9**	**794.6**	**59.4**	**112.3**

[1]Produced volumes indicate recovered from the reservoir and do not include 545.8 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 7: Observation Well Completions

	OB1	OB2	OB3	OB4	OB5	14-18
Tubing OD (mm); Grade	73, J-55	73, J-55	73, J-55	73, J-55	73, J-55	60.3, L-80
Casing OD (mm); Grade	177.8, L-80	177.8, L-80	177.8, L-80	177.8, L-80	177.8, L-80	139.7, J-55
Well PBTD Deepened	N	N	N	N	Y	Y
Wellbore Fluids Upon Completion	Annular Cemented	Annular Cemented	Water Filled	Water Filled	Annular Cemented	Water Filled
Fiber Optics Depth (mKB)	459.9	475.2	462.0	483.0	464.2	484.4
Installation Hardware:	Geophones	Geophones	Heater	Heater	Geophones	Heater
Bottom Geophone or Heater Set Depth (mKB)	459.4	474.4	463.0	484.0	459.2	484.1
Well Perforated	Y	N	Y	N	Y	N
Packer Set Downhole (Y/N)	N	N	Y	N	N	N

Table 8: Horizontal Well Completions

Well	Liner	Dual Casing	Instrumentation	Pump
CSP HW-01	Installed	Installed	Installed	Installed
CSP HW-02	Installed	Installed	Installed[1]	Installed
CSP HW-03	Installed	Installed	Installed	Installed

[1]HW-02 well downhole heater not functioning

Table 9: Major Equipment and Design Basis

	Tag number	Equipment Description	Quantity	Size
1	V-0061/62	Propane vessel	2	4420 mm ID X 24282 mm S/S (working capacity 250 m^3 each)
2	T-0071/72	Diluent tank	2	4648 mm OD X 7315 mm H (750 BBL)
3	P-0071/72	Diluent transfer pumps	2 (2 x 100%)	67 m^3/day each
4	P-0061/62	Propane transfer pumps	2 (2x100%)	175 m^3/day each
5	P-0051/52	Injection pumps	2 (2x100%)	7.5 m^3/hr
6	H-0051/52	Electric solvent heater	2 (2x50%)	200 KW each
7	FIL-0071	Diluent filter	1	100 Microns
8	FIL-0051/52	Solvent filter	2	5 Microns
9	P-0030/40	Multiphase vent gas pumps	2 (2x100%)	153 m^3/h
10	V-0003	Liquid separator	1	736 mm ID X 2550 mm S/S
11	E-0005	Recycle liquid cooler	1	203 KW
12	P-0023	Make up water pumps	1 (1x100%)	100 LPH per pump
13	T-0023	Make up water tank	1	1830 mm OD X 3518 mm H (capacity 8 m^3)
14	H-0053	Electric test fluid heater	1	13 KW
15	H-0054	Electric production heater	1	40 KW
16	V-0011	Test separator	1	1219 mm ID X 3600 mm S /S, Boot 508 mm ID X 1200 mm L
17	P-0024	Purge Liquid Pump	1 (1X100%)	0-1000 LPH
18	PK-001	Instrument air package	1	110 sm^3/hr
19	T-0022	Methanol tank	1	2413 mm ID X 3048 mm H (90 BBL)
20	P-0022	Methanol injection pump	1 (1X100%)	5000 LPD
21	P-0073	Utility diluent pump	1 (1X100%)	8000 LPD
22	T-0001	Pop tank	1	2896 mm ID X 3658 mm High (150 BBL)
23	T-0002/0003	Closed Drain Tank	2	1256 mm OD X 3517 mm OAL
24	K50-1/ K50-2/ K50-3	Pump Jack	3	22.2 KW
25	PK-0031	Portable Compressor	1	1007-3029 Sm3/D

Table 10: Price Assumptions for Revenue Calculations

	Bitumen $/bbl	Natural Gas $/mcf	Propane[1] $/bbl	Pilot Flow Assurance Solvent[1] $/bbl
2016	$26.52	$2.41	$22.58	$58.14

[1]Average price paid for the CSP pilot for 2016

Table 11: Cumulative Project Revenue

Cumulative Revenue (k$)	2009	2010	2011	2012	2013	2014	2015	2016	Total
Bitumen	0	0	0	0	0	18	194	593	805
Solution Gas	0	0	0	0	0	0	0	3	3
Recovered Propane	0	0	0	0	0	22	105	503	630
Recovered Diluent	0	0	0	0	0	294	26	0	320
Recovered Flow Assurance Solvent	0	0	0	0	0	0	410	293	703
Total Revenue	**0**	**0**	**0**	**0**	**0**	**334**	**735**	**1392**	**2461**

[1] Estimated, see section 8.2 for assumptions

Table 12: Drilling and Facilities Costs

Drilling and Facilities Costs (k$)	2016
Preliminary Engineering	0
Surface Facilities	0
OB Well Drilling	0
HW Drilling	-7
Completions	0
Geo Surveillance	0
Total Drilling and Facilities Costs	-7

Table 13: Operating Costs

Direct and Indirect Operating Costs (k$)	2016
Operating Costs	3,385
Total	**3,385**

Table 14: Injectant Costs

Injectant Costs (k$)	2016
Propane	1,500
Flow assurance solvent	527
Total	**2,027**

Table 15: Cumulative Project Costs

Cumulative Costs (k$)	2009	2010	2011	2012	2013	2014	2015	2016	Total
Drilling & Facilities Costs	563	1,631	8,991	33,257	22,776	4,591	77	-7	71,879
Operating Costs	0	0	0	0	0	1,649	2,103	3,385	7,137
Injectant Costs	0	0	0	0	0	776	846	2027	3649
Total Costs	**563**	**1,631**	**8,991**	**33,257**	**22,776**	**7,016**	**3,026**	**5,405**	**82,665**

Table 16: Estimated Crown Royalty Calculation

Crown Royalties (k$)	2009	2010	2011	2012	2013	2014	2015	2016	Total
Pilot Revenue[1]	0	0	0	0	0	334	735	1,392	2,461
Pilot Costs[2]	563	1,631	8,991	33,257	22,776	7,016	3,026	5,405	82,665
ERA (Formerly CCEMC) Credit[3]				2,400	2,480	480	960	1,680	8,000
Before Royalty Cash Flow	-563	-1,631	-8,991	-30,857	-20,296	-6,202	-1,331	-2,333	-72,204
Cold Lake Royalty Rate[4]	27.8%	30.9%	33.8%	34.2%	35.4%	36.8%	27.2%	25.2%	-
Cold Lake Royalty Impact	-156	-504	-3,039	-10,553	-7,185	-2,282	-362	-587	-24,668
Total Cold Lake Royalties[4]	438,240[5]	628,605[5]	935,665[5]	678,964[5]	599,433	772,086	228,198	247,787	-

[1] Estimated, see Section 8.2 for assumptions

[2] Based on IETP claim form submissions, see Sections 8.3, 8.4 and 8.5

[3] Grant received from Climate Change and Emissions Management Corporation (CCEMC), now ERA, offsetting pilot costs. Credit is shown in year earned, independent of when it was received.

[4] Total Cold Lake rate and royalties paid, which include CSP Pilot costs and revenue. Values may change from previous submissions due to revisions.

[5] Amendments to prior years were processed therefore the royalties for these years have been revised

Figures

Figure 1: Well Layout

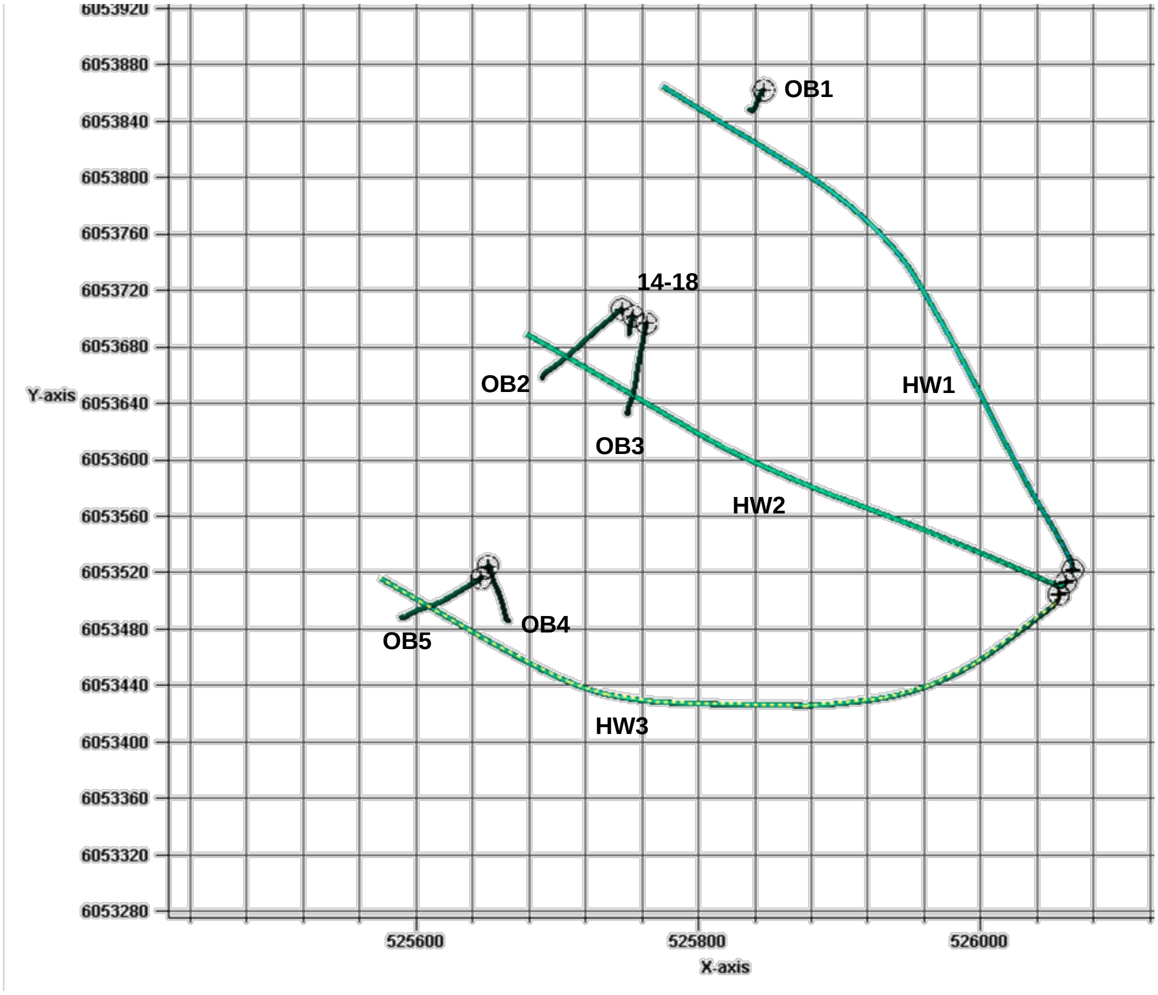


Figure 2: Surface Facility and Pad Locations

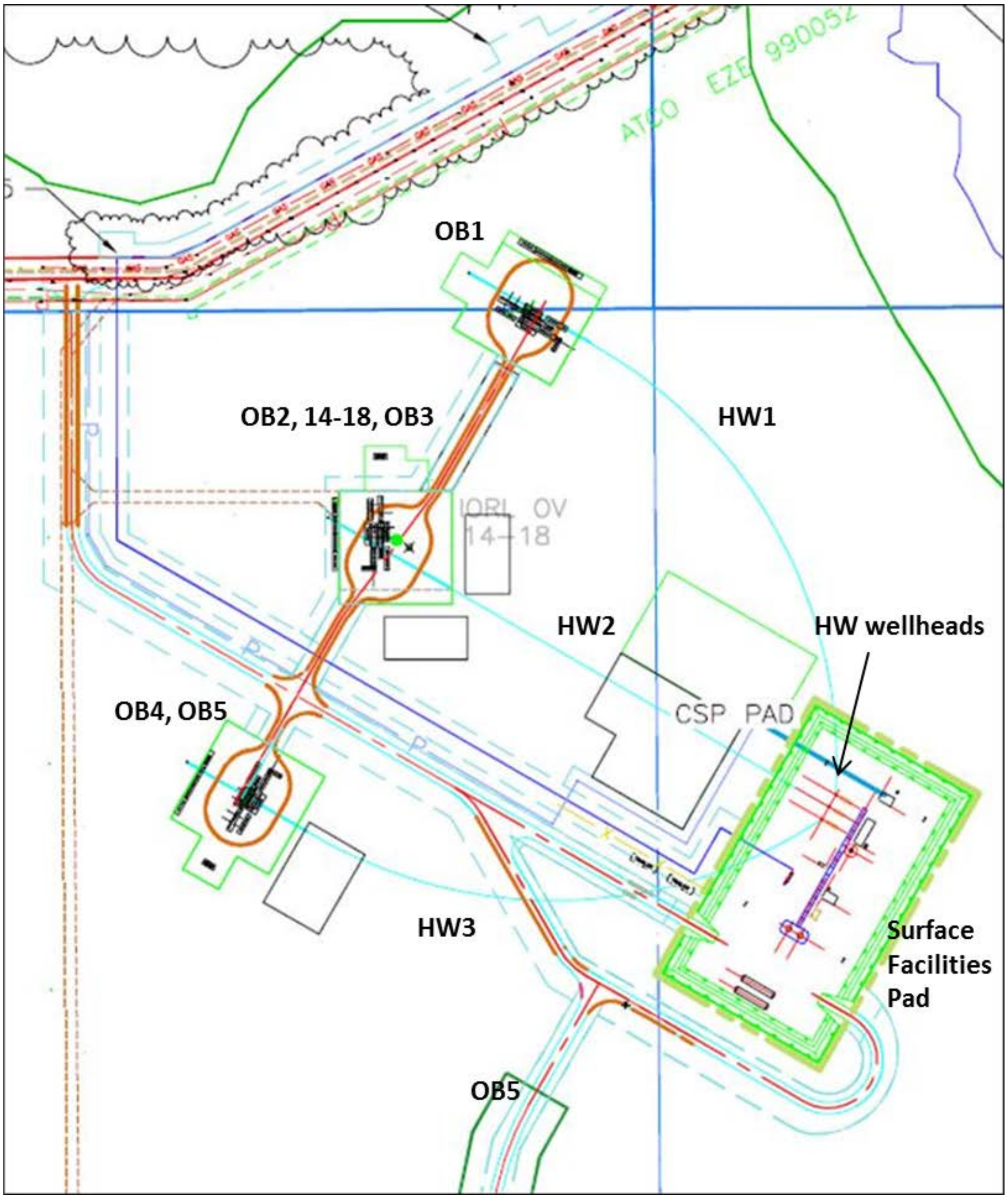


Figure 3: Log Cross Section of Pilot Area through OB Wells

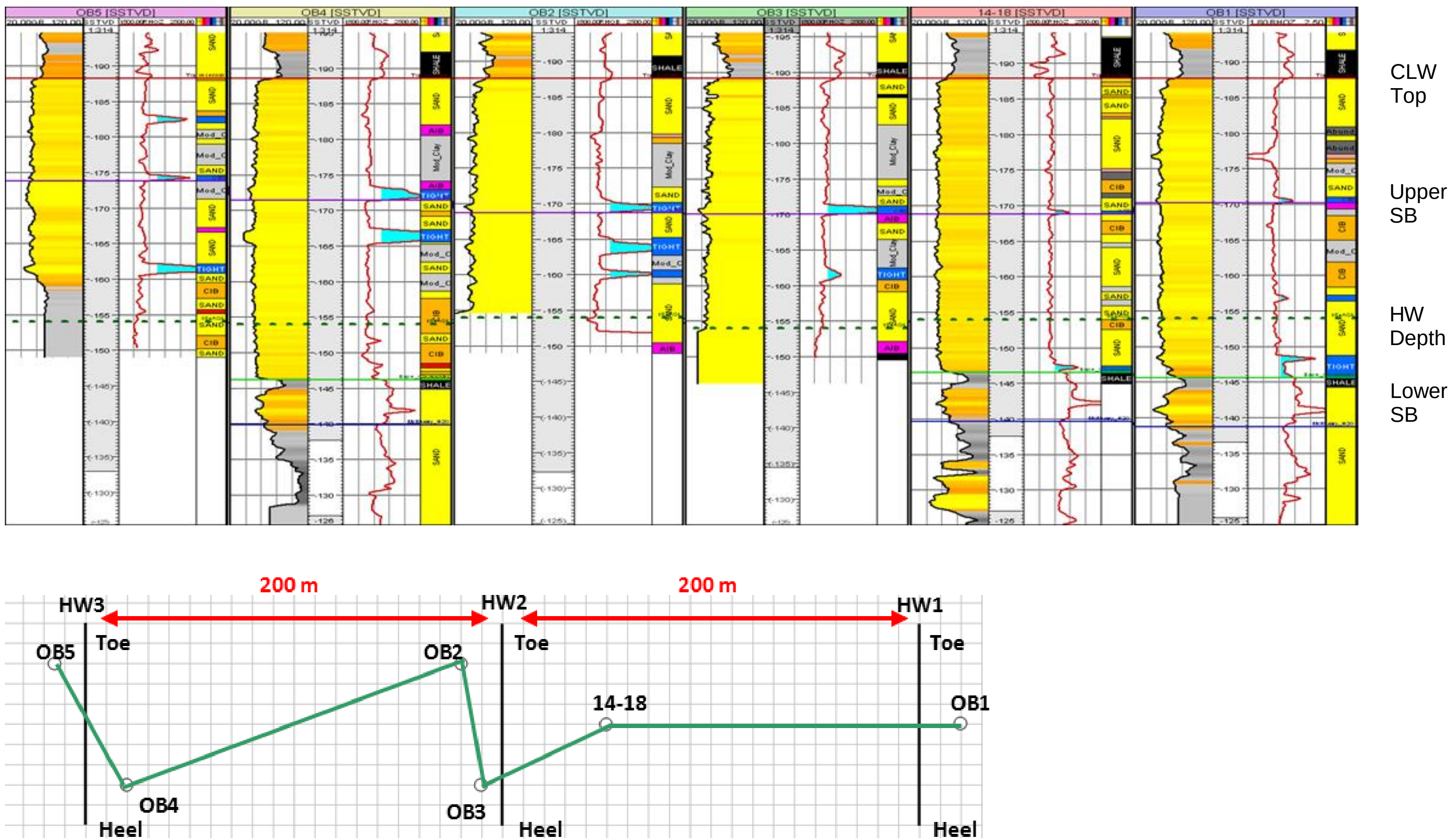
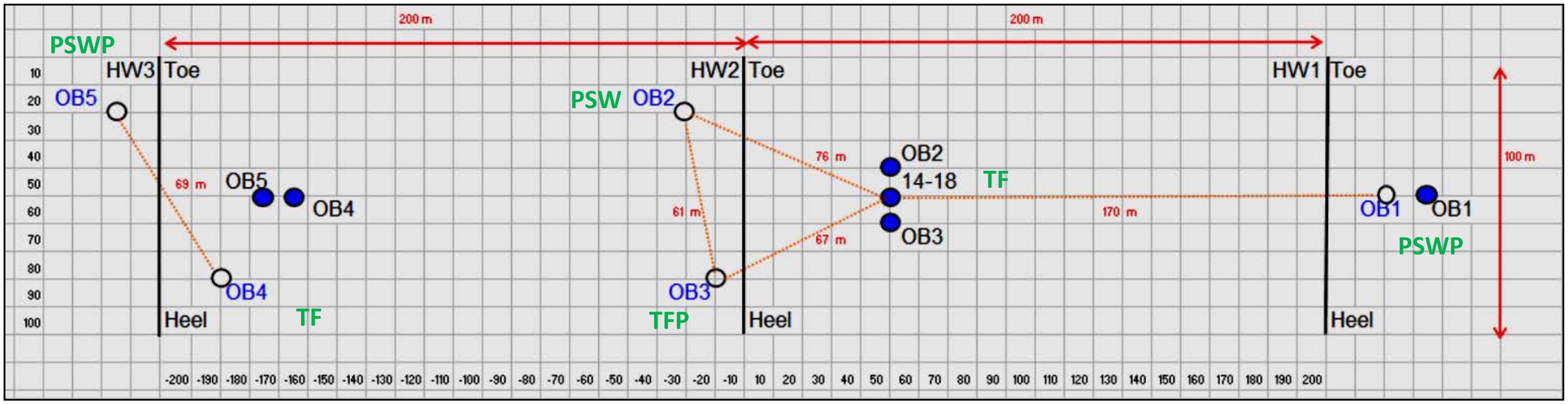


Figure 4: OB Wells Location and Surveillance Instrumentation



● Surface Location ○ Bottom Hole

PSW – Passive Seismic Well (with evacuated tubing)

PSWP – Hybrid PSW (Passive Seismic Well with BHP measurement)

TF – Thermo Fiber Well with Heater

TFP – Thermo Fiber Well with Heater and BHP measurement

Figure 5: CSP Horizontal Well Schematic

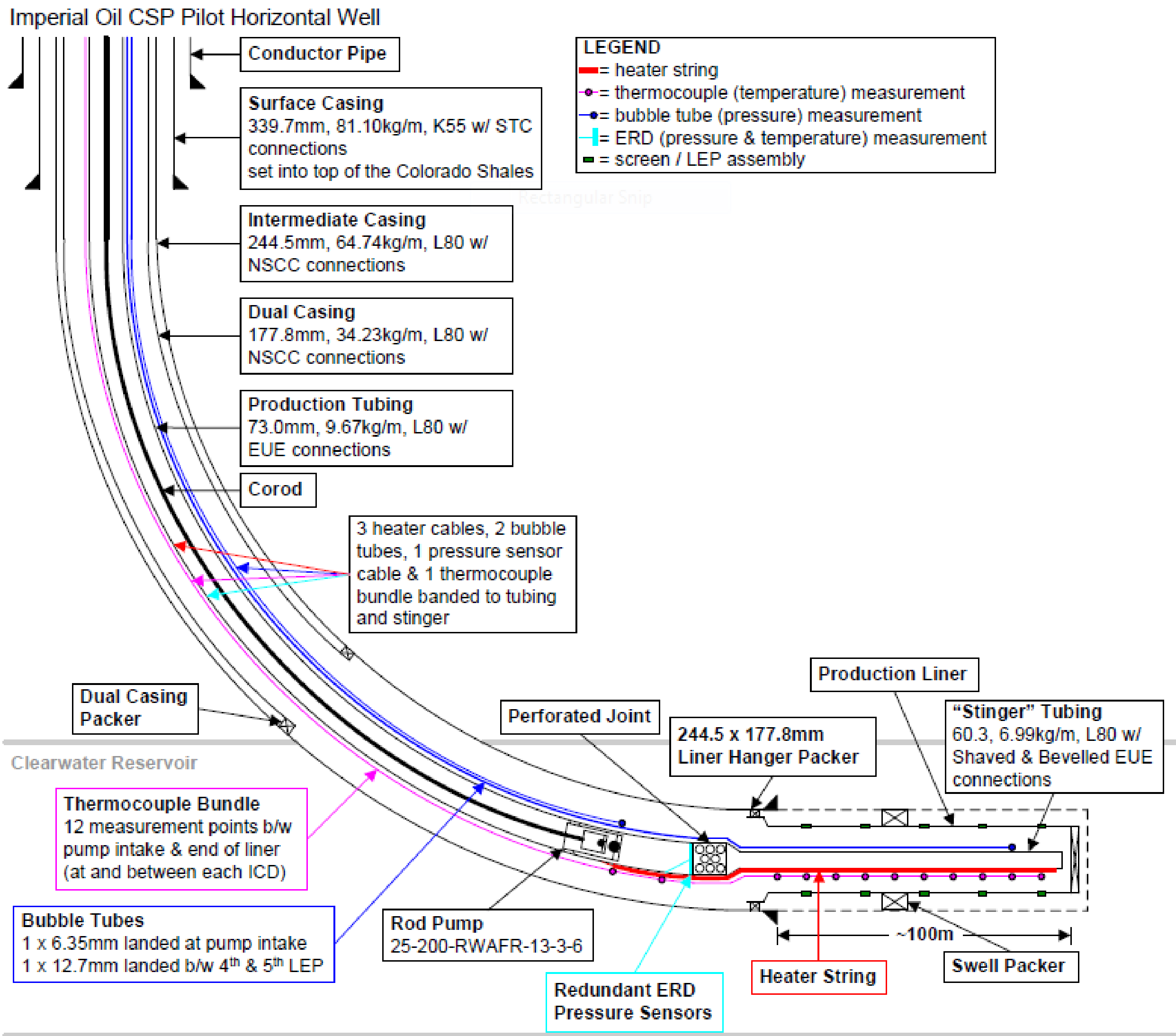


Figure 6: CSP Pilot Site View

Figure 7: Characteristic Curve Shapes of CSP Components in C30+

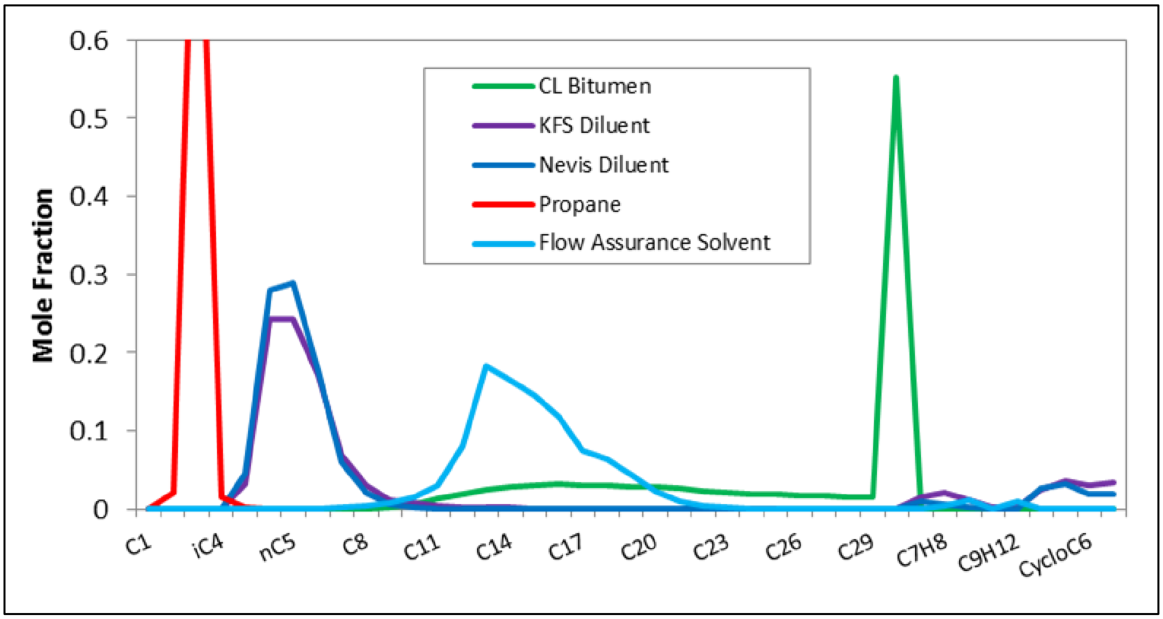
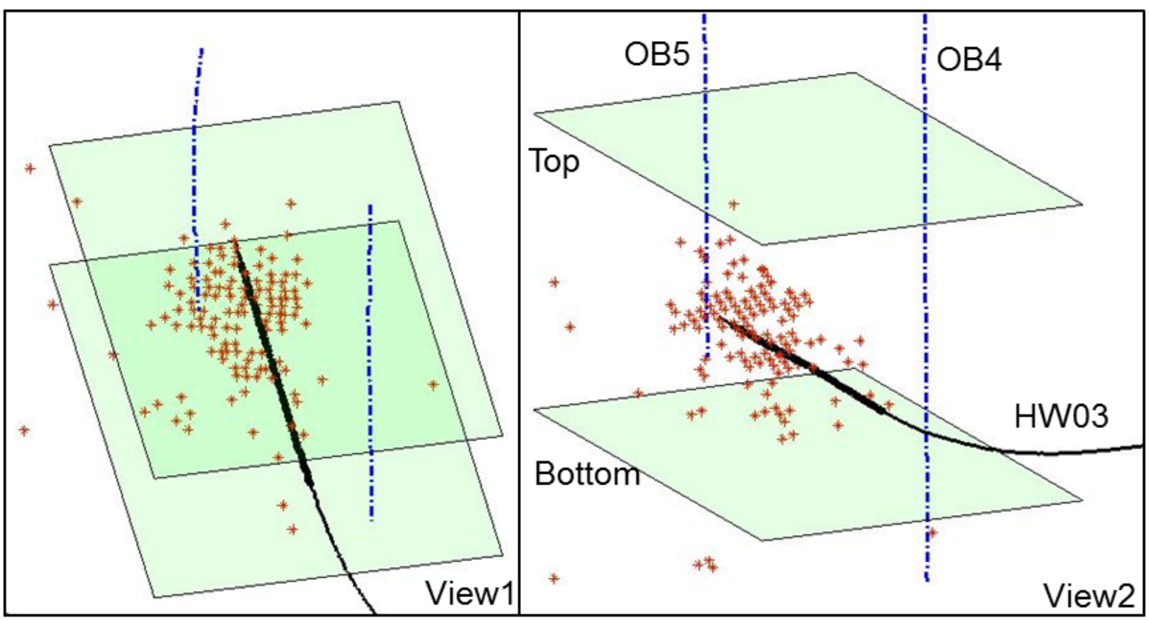
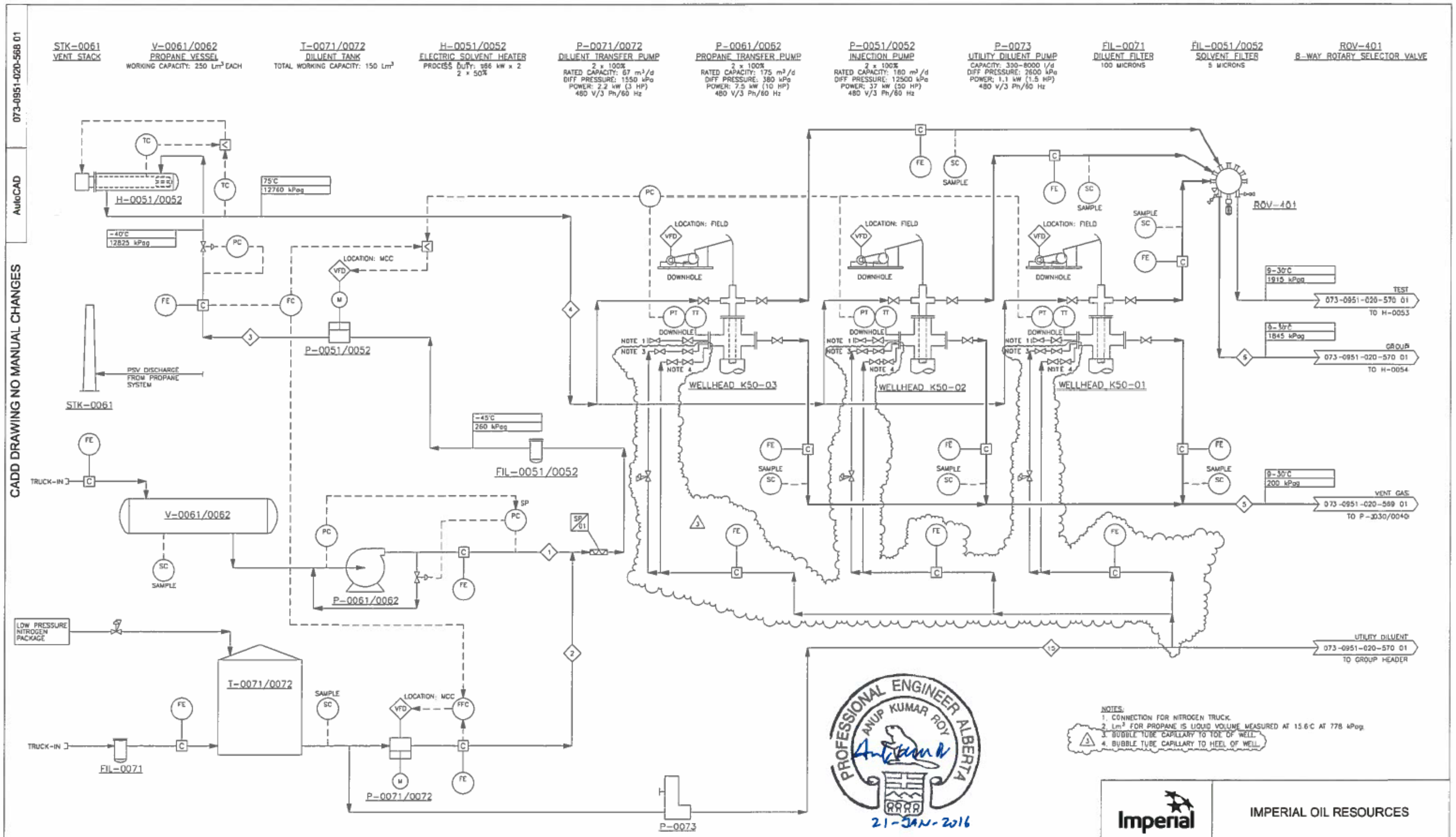


Figure 8: Passive Seismic Event Locations for HW3 Cycle 1



Appendix A: Process Flow Diagrams (PFDs)



NOTES:
1. CONNECTION FOR NITROGEN TRUCK.
2. Lm³ FOR PROPANE IS LIQUID VOLUME MEASURED AT 15.6°C AT 778 kPag.
3. BUBBLE TUBE CAPILLARY TO TOE OF WELL.
4. BUBBLE TUBE CAPILLARY TO HEEL OF WELL.

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
3	16 01 21	ISSUED FOR CONSTRUCTION AS PER EMOC 476 (700000021085)	JH			
2	14 07 15	AS BUILT - NO CHANGE (XO.2010.48016)	SW	HAK		AR
1	13 05 07	RE-ISSUED FOR CONSTRUCTION AS PER MOC 0-4765 (XO.2010.48016)	PNP	DM	AR	SS
0	12 03 06	ISSUED FOR CONSTRUCTION (XO.2010.48016)	BM	MG	AR	WK

DRAFTING / ENGINEERING

IOR DWG NO.	TITLE
073-0951-020-500 01	PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM

REFERENCE DRAWINGS

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Imperial

IMPERIAL OIL RESOURCES

CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
WORLEYPARSONS CANADA SERVICES LTD	NONE	073-0951-020-568 01	3
CONTRACTOR DWG NUMBER: XO.2010.48016			

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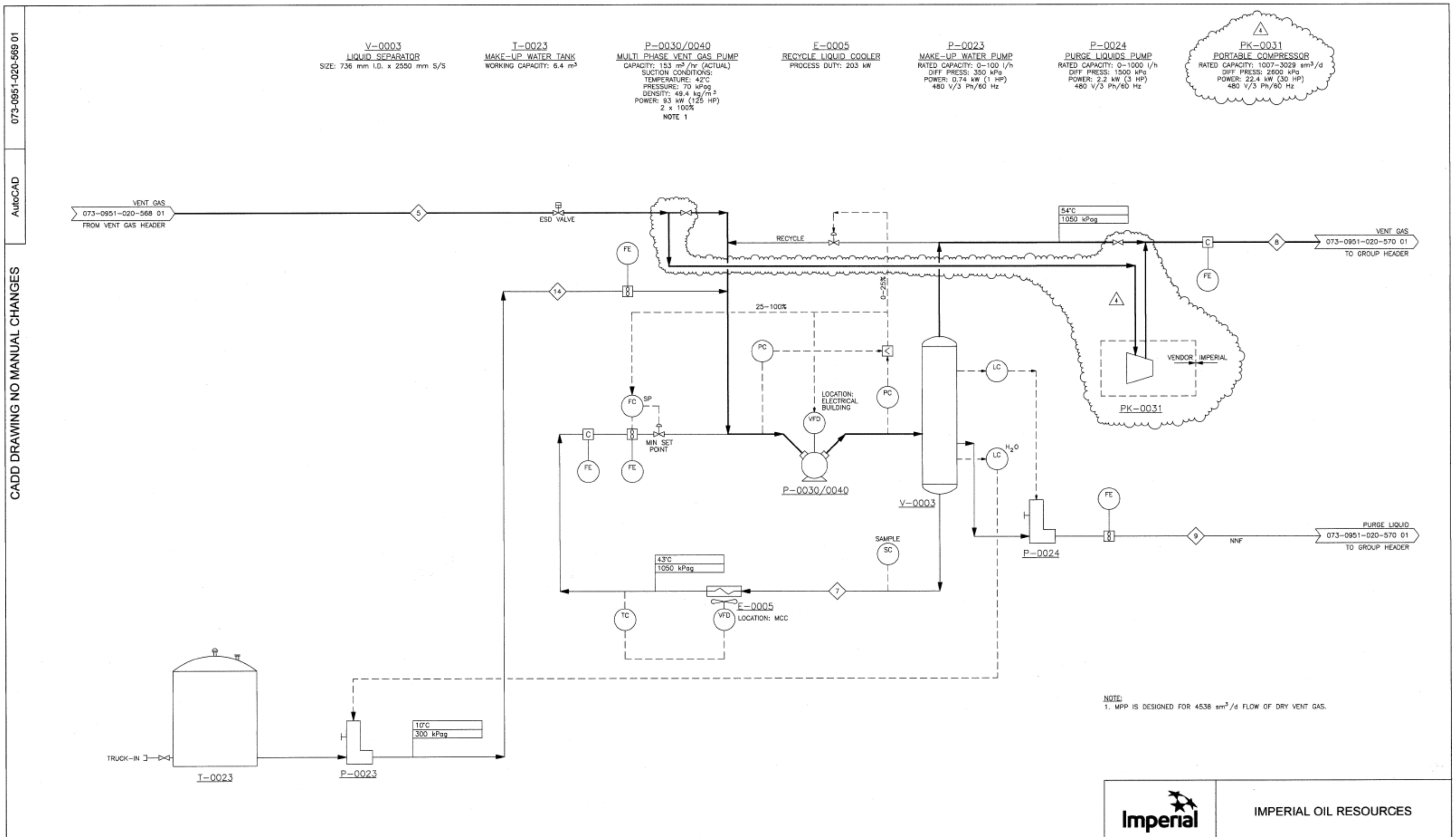

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3	14 07 15	AS BUILT - NO CHANGE (XO.2010.48016)	SW	HAK		AR		
2	12 10 31	RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7333 (XO.2010.48016)	BM	RG	AR	SS		
1	12 08 22	RE-ISSUED FOR CONSTRUCTION AS PER MOC O-7185 (XO.2010.48016)	BM	MG	AR	SS		
0	12 03 06	ISSUED FOR CONSTRUCTION (XO.2010.48016)	BM	MG	AR	WK	073-0951-020-600 01	PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM
			DRAFTING		ENGINEERING		REFERENCE DRAWINGS	

Version: 5 D-STD

Filename: Y:\FILENET\073-0951-020-569-01.DWG User ID: ENIKO.JOO Plot date/time: September 28, 2015 - 1:09pm XREF drawings: IMAGE attachments:

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28-Sept-2015
Rev 4 only

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CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM

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CONTRACTOR DWG NUMBER XO.2010.48016			

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