IETP Application No. 06-094

Imperial Oil Resources – Cyclic Solvent Process Pilot

2015 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 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 2015.

The project has completed cycle 1 and cycle 2 of the leading well. At year-end, cycle 3 production was in progress. Production has overcome many of the challenges faced in 2014. The re-rating of the production pipeline has allowed for a larger pipeline pressure differential between the pilot site and the Mahihkan plant. Hydrate formation in the pipeline was successfully mitigated with methanol treating. The plugging issues caused by heavy liquid have also been avoided with the application of a flow assurance solvent. The work has focused on the active surveillance of the pilot in an effort to achieve the highest quality data. In 2016, multi-well operation is planned with the start-up of HW1 and HW2. Active surveillance remains a top priority for 2016 while also working towards gaining more operational experiences and establishing pilot operational baseline.

2 Summary Project Status Report

2.1 Members of the project team

The following were key members of the CSP pilot team to the end of 2015.

J.F. (John) Elliott, P.Eng.	Oil Sands Recovery Research Manager
T.J. (Tom) Boone, PhD, P.Eng.	ExxonMobil Senior Technical Professional
J. (Jianlin) Wang, PhD	CSP Team Lead
L. (Lu) Dong, M.S.	CSP Reservoir Engineer
N. (Nafiseh) Dadgostar, PhD	CSP Reservoir Engineer
G. (Gordon) MacIsaac, PhD	CSP Reservoir Engineer

2.2 Key activities

Key activities during the reporting period are described below:

- Preparatory work for the restart of HW3 cycle 1 completed Q1 of 2015
- HW3 cycle 1 restarted on April 9
- HW3 cycle 1 production completed on June 8
- Trunkline hydro-test on June 14 to increase the Maximum Operating Pressure (MOP) to 3675 [kPa]
- HW3 cycle 2 injection started on June 18 and completed on June 24.
- HW3 cycle 2 production progressed smoothly and completed September 4
- HW3 cycle 3 injection started on September 15 and completed on September 23.
- HW3 cycle 3 production began on September 25
- Cycle 3 shut-in on November 25 for wellhead heat-tracing installation and pilot site access bridge scheduled maintenance
- Cycle 3 production resumed on December 11 and shut-in on December 27 in preparation for facility upgrades in January of 2016

2.3 Production, material and energy balance flow sheets

As of year-end 2015 there has been injection and production from HW3 only. The 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, diluent, 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 are shown in Table 1. Production volumes are shown in Table 2.

2.4 Reserves

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 17 [km^3] after the planned five cycles of the pilot with 42 [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 to 3) 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 4 and HW completions are summarized in Table 5.

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 1-4. 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 from September 2014 until April 2015 due to the surface facility challenges encountered in 2014.

HW03 cycle 1 production was restarted on April 8 following a wellbore treatment with the flow assurance solvent. Production continued until June 8, 2015. The introduction of the flow assurance solvent resulted in a step change in facility performance. However, the pipeline differential was still a significant bottleneck for future operations. Gas production through the pipeline was limited to impractically low flow rates and future multi-well operation would not be possible. The pipeline was re-rated from an MOP of 1850 to 3675 [kPa] and was successfully hydro-tested prior to cycle 2 injection on June 18, 2015.

Cycle 2 injection achieved the target volume; however, the rate was limited by partial plugging of the ICDs. Production of cycle 2 was smooth with no reservoir issues encountered and continued until September 4, 2015.

Prior to cycle 3 injection the wellbore was treated with the flow assurance solvent to prevent the ICD plugging observed during cycle 2 injection. The treatment was successful. Cycle 3 injection was smooth with minimum pressure drop observed across the completions. The target injection rate and total injection volume was achieved. Production commenced on September 25, 2015 and continued uninterrupted until October 18, 2015 at which point production was shut-in for a two-day planned pressure build-up test. Thereafter, production continued until November 25, 2015. The pilot was shut-in to accommodate repairs to an access bridge. Wellhead heat-tracing was also installed during this shut-in. Production resumed on December 11, 2015 and continued until December 26, 2015. The pilot was shut-in at this point for the facility upgrades in January of 2016.

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, 2015. The diagrams do not reflect the facility modification made in Q1 of 2016 which will be included in the 2016 annual report.

5.2 Progress

Surface facility construction was completed by the year-end of 2013. Figure 6 shows two site views after the completion of the facility construction. The facility was turned over to Cold Lake Operations at the end of April 2014 with final commissioning completed by end of May 2014.

In 2014 the operation of the HW3 cycle 1 was limited by a number of facility constraints. The MOP of the underground pipeline was too low for the conditions encountered during pilot operation. After the completion of HW3 cycle 1 in June 2015 the pipeline MOP was re-rated from 1850 to 3675 kPa. Effectively, the operating differential pressure, between the pilot site and plant, was increased from approximately 650kPa to 2100kpa. In addition to the pipeline re-rating, the methanol pump was replaced with a higher capacity pump capable of operating at the increased MOP.

Another facility upgrade completed in 2015 was the installation of wellhead heat tracing for HW3. In late November 2015 freezing was experienced at the well-head. The freezing was caused by the lower ambient temperatures and a small section of unheated line near the wellhead. Heat tracing was installed during the planned shut-in beginning November 25, 2015. Heat tracing for HW1 and HW2 was installed during Q1 of 2016.

In anticipation of multi-well operation, three additional facility upgrades were planned for installation during Q1 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 distribution of flow assurance solvent to multiple wells downhole
3) A demulsifying chemical injection system for the test separator to improve the test separator efficiency

5.3 Surface equipment

Table 6 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 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).

Any gas which may pressure up the casing is vented to multiphase pumps which compresses the vent gas and sends the compressed gas into the group header. Note that the vent gas system in place for 2015 will be replaced in 2016 as described in Section 5.2. For reference the 2015 system is described here:

The system uses common vent piping at the wellhead manifolds to gather the vent gas from individual flow lines. A dedicated multiphase pump (MPP) suction header then conveys the fluid from the manifolds to the MPPs (P-0030/40). In order to achieve sealing requirements, water will be used as seal liquid stored in on-site tankage (T-0023) and supplied by a small pump (P-0023). The recycled water is cooled by means of an aerial cooler (E-0005) and utilized to minimize make up water requirements. The cooled recycled liquid is mixed into the vent gas stream. The mixed stream enters the multi-phase pump (MPP), and is compressed. The discharge from the MPP flows into the liquid separator, V-0003. The liquid in the pump discharge stream is separated in this vessel, which is recycled to the aerial cooler while maintaining a minimum liquid inventory in the vessel. Excess water from the liquid separator is purged to the group header. In case of accumulation of any propane in the liquid separator, the excess propane will be purged to the group header by the purge liquid pump, P-0024.

For methanol injection into production fluids at the inlet of the pipeline to avoid hydrate, a chemical methanol injection system is provided. Chemical Methanol injection consists of a metering methanol pump (P-0022) and a chemical methanol tank (T-0022). In June of 2015, the methanol pump was replaced with a higher capacity pump capable of discharging at the increased trunkline MOP.

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

Operational issues encountered during 2015 are grouped as either injection system related or production system related. The primary facility limitation of 2014 was the MOP of the trunkline to Mahihkan plant. By re-rating the pipeline in 2015 and using a flow assurance solvent this limitation has largely been mitigated. Below is a list of issues that impacted injection and production during 2015:

Injection

- Plugging of the wellbore ICDs during injection (HW03 cycle 2)
  - No wellbore treatment prior to injection which allowed late-stage reservoir fluid within the wellbore to contact propane rich solvent during injection
  - For future cycles the wellbore is treated prior to injection

Production

- Production rate limited due to pressure differential of the trunkline to Mahihkan plant (HW1 cycle 1 restart)
  - Pipeline re-rated to a higher MOP

- Minor plugging of test-separator (V-0011) water leg
  - Resolved by flushing with flow assurance solvent

- Degradation of the separation efficiency of the test separator (V-0011)
  - Oil leg density fluctuating in response to water dumping
  - Low water leg density indicating oil is present
  - Installation of demulsifier chemical injection skid planned for Q1 2016

- Wellhead high pressure shutdown due to freezing during low ambient temperatures (November 2015)
  - Heat tracing installed on HW3 in December 2015. HW1 and HW2 heat tracing installation planned for Q1 2016

- Low pressure production limited by vent gas system
  - Casing gas could not be vented using the MPP system (P-0030/40) after the pipeline was re-rated as the discharge pressure was insufficient
  - New gas compressor installation planned for Q1 2016

6 Production Performance

6.1 Injection and production history

As of the end of 2015 only HW3 was operated. Cycle 1 and 2 were completed and cycle 3 was still producing by year end. The summary of injection and production volumes can be found in Table 1 and 2, respectively. Note that diluent was not injected down hole during the 2015 year. The produced diluent in 2015 is the remnants of the diluent injection from cycle 1 in 2014.

Table 3 shows the production volumes from 2014. The volumes have been updated to reflect the sample analysis results and are therefore different than those in the 2014 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. By the end of cycle 2, the total recovered diluent was approximately 109 [m^3], or about 93% of the total diluent injected in 2014. The total recovered diluent is approaching the ultimate recovery levels that can be expected for the CSP process. For subsequent cycles, the diluent content was only detectable within the levels of uncertainty of the sample analysis program. Therefore, diluent is not totalled beyond the end of cycle 2 (September 2015), as shown in Table 2.

For each cycle in 2015, the narrative of injection and production events for each cycle is given below:

HW3 Cycle 1

Production (Restart)

Production restart began on April 8, 2015 and continued to June 8, 2015. Flow assurance solvent was injected to the wellbore toe during production to mitigate any potential flow assurance issues downhole, on the surface facility and within the pipeline. The ratio of the load to produced fluid decreased as the cycle progressed. No flow assurance issues were encountered. At times during the production restart, the water-cut of the production reached nearly 50%. With limited water handling capacity the water production was closely monitored in order to mitigate hydrate formation. No hydrate incidents were encountered.

During this cycle the gas venting system was tested. The pipeline differential pressure increased rapidly with small amounts of gas production. For example, 1 [m^3] of gas (at the pipeline condition) resulted in about 250 kPa additional pressure differential. Additional pipeline pressure differential would be required for improved gas venting handling. As mentioned in Section 5.2, the pipeline MOP was increased to accommodate gas venting in future cycles.

HW3 Cycle 2

Injection

Following the completion of cycle 1 the facility upgrades described in Section 5.2 were completed with the pilot shut-in. Cycle 2 injection then started on June 18 and continued to June 24. The initial injection rate was throttled below the 150 [m^3/D] target rate to maintain bottom-hole pressures less than 12MPa. With maximum reservoir pressure observed in the nearest observation well (OB5) less than 8 MPa, higher than normal bottom-hole pressures were due to plugging of the ICDs. Pauses during injection indicated near-well pressure drop of about 3MPa, much higher than the anticipated pressure drop of 0.5-1MPa.

The wellbore was not treated prior to the cycle 2 injection. The formation of heavy phase within the wellbore during injection was the suspected cause of the plugging. Subsequent injections, performed after a wellbore treatment, were not restricted by the bottom-hole pressure thereby confirming the suspected cause of the plugging for cycle 2.

Production

Production began on July 1 after a pressure-fall period. Production was smooth and continued to September 4, 2015 with no periods of downtime in excess of 8hrs. The total production rates exceeded 30 [m^3/D] and declined with the reservoir pressure over the course of the cycle. Instantaneous water-cut exceeded 50% at times during this cycle. Flow assurance solvent was used at the surface and within the wellbore. Compared to cycle 1 the total flow assurance solvent used was significantly reduced. With the higher trunkline MOP the production was not limited by the pipeline pressure differential, as in cycle 1.

During this cycle metering issues were also resolved. The wellhead Coriolis meters were re-calibrated to fix inconsistencies between the mass and volume readings. The group and test-separator meters were thus used for the production volume allocation. The AGAR meter was re-calibrated to improve the water cut-estimation.

HW3 Cycle 3

Injection

Prior to cycle 3 injection the wellbore was treated with flow assurance solvent. Cycle 3 injection began on September 15, 2015 and continued until September 23, 2015. After an initial ramp up period the target injection rate of 150 [m^3/D] was achieved. A planned mid-injection pressure fall-off test was conducted on September 19, 2015. The results showed a small pressure drop (<300 [kPa]) between the well-bore and reservoir, indicating no plugging and positive flow through all of the ICDs. The pre-cycle wellbore treatment was successful in mitigating the plugging issues experienced during the cycle 2 injection.

Production

Cycle 3 production began on September 25, 2015 following a pressure fall-off period. The total liquid production rate peaked at about 30 [m^3/D] and declined with the reservoir pressure over the course of the cycle. Operation was generally smooth and the pipeline differential pressure was managed with timely use of the flow assurance solvent. An unplanned shut-in occurred on November 25, 2015. An unheated line near the wellhead experienced freezing due to the colder ambient temperatures. Having not previously operated the pilot facilities in the winter months it was evident that the heat content of the fluid leaving the wellhead was not sufficient to prevent freezing over this small section of line. An unrelated and planned shut-in for repairs to the pilot site access bridge was schedule for November 29, 2015. The HW03 heat tracing was installed during this downtime. Production resumed on December 11, 2015 and continued until December 26, 2015. The pilot was shut-in for the planned facility upgrades of Q1 2016. Refer to Section 5.2 for further details.

6.2 Composition of injected and produced fluids

In 2014, HW3 cycle 1, the solvent injected was 88 vol% propane and 12 vol% diluent. During production in September 2014, a mini-injection with 86 vol% diluent and 14 vol% propane was used to stimulate production and alleviate heavy liquid phase issues.

In 2015, the solvent injected for cycles 2 and 3 was 88 vol% propane and 12 vol% flow assurance solvent.

The propane is industrial grade propane with an average of 98 mass% of C3. The diluent composition can vary depending on the source plant however for this pilot the diluent selected is primarily C5 with only a small fraction being above C8. Diluent density is in the range of 650 to 690 [kg/m^3]. The composition of the flow assurance solvent is proprietary.

Produced fluids can be composed of methane, propane, diluent, 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, diluent, 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 is comprised of 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 that indicate each liquid phase substance.

6.3 Simulation and Prediction of the Pilot Performance

In general, the performance expectations for HW3 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. Thus, the simulation model development and pilot are progressing concurrently. Performance predictions are then generated prior to each cycle using the latest history matched model. Learnings from the previous cycle are adopted into the model as necessary. Currently, the history matched models for cycles 1, 2 and 3 are in relatively good agreement with the pilot results.

Work continues on the fine-tuning of the simulation model phase behaviour. The pilot sample analysis program is an integral part to understanding the composition of the produced fluids and the effects on the reservoir performance.

6.4 Pressures

The pressure history for each cycle during 2015 is described below:

HW3 Cycle 1

Production (Restart)

The bottom-hole pressure (BHP) was approximately 3.2 [MPa] prior to production restart. The long shut-in period and frequent interventions during 2014 significantly influenced the bottom hole pressure history for cycle 1. After restart the BHP declined smoothly with the production rate, as expected. Generally, in order to operate at BHPs below the vaporization pressure of methane and/or propane, the casing gas must be vented. As previously described, the venting system was tested during this cycle. The pipeline response was undesirable and venting activities were postponed for future cycles. As such, the lowest BHP pressure during the cycle was about 750 [kPa].

The nearest OB well, OB5, showed a gradual decline that trended asymptotically towards 2.5 [MPa] by the end of the cycle.

HW3 Cycle 2

Injection

During cycle 2 injection the change in BHP was rapid and also unstable. The injection rate was increased in stepwise increments of 50 [m^3/D]. When switching from 100 to 150 [m^3/D] rapid fluctuations of the BHP were followed by a drop of about 1MPa. The observed BHP response is indicative of plugging within the wellbore followed the partial release of the plugging at the higher flow rates. Further into the injection period the BHP increased up to a maximum of 12 [MPa] at which point the injection rate was reduced to 100 [m^3/D]. The BHP pressure responded to the rate adjustment and leveled off at about 11 [MPa].

The response of the nearest OB well, OB5, was also monitored. The pressure response of OB5 was smooth and gradual. At the peak BHP pressure the corresponding OB5 pressure was about 7 [MPa]. As mentioned previously, during the planned flow tests, the differential pressure between the OB and horizontal well was about 3 [MPa]. Partial plugging of the ICDs was the suspected cause of the relatively high differential pressure between the wellbore and reservoir.

Production

The BHP and OB pressure declined with the production rate and asymptotically approached 1.5 and 2.8 [MPa], respectively, by the end of the cycle. Gas venting was not possible during this cycle. As mentioned previously, the MOP of the pipeline was increased prior to the cycle, but the vent gas system was not upgraded to match the required discharge pressure. As such, low pressure production for this cycle was not achieved. During the pressure buildup test the BHP increased as expected. The OB5 pressure did not respond significantly during the build-up tests.

HW3 Cycle 3

Injection

The BHP responded smoothly and gradually during the cycle 3 injection. The plugging issues of cycle 2 were largely mitigated by the pre-injection wellbore treatment with the flow assurance solvent. At the sustained target rate of 150 [m^3/D] the BHP reached about 8 [MPa]. The corresponding OB5 pressure reached about 7.5 [MPa]. A mid-injection pressure test revealed a wellbore-to-reservoir differential pressure of about 300 [kPa]. The injected flow was unobstructed across all ICDs.

Production

The BHP and OB5 pressure declined with the production rate and asymptotically approached 1.8 and 2.5 [MPa], respectively, prior to the November shut-in period (PAD access bridge repair and heat-trace installation). During the shut-in period the BHP pressure recovered from 1.8 [MPa] to 2.5 [MPa]. The corresponding OB5 pressure response was small (<100 [kPa]). The subsequent production in December saw a gradual decline in the BHP pressure back to the 1.8 [MPa] level observed prior to the shut-in while the OB5 pressure declined slightly (about 100 [kPa]).

7 Pilot Data

7.1 Additional data

CSP surveillance uses three passive seismic (PS) OB wells (one located close to each horizontal well) with geophones in the Clearwater to detect the small micro-seismic events caused by solvent movement and to gain a quantitative understanding of the solvent conformance. This is a novel application of PS geophone typically employed to detect events of much larger magnitude such as casing failures. Two factors that make the CSP micro-seismic events particularly difficult to detect are their extremely low energy level and the tendency of the Clearwater formation to dampen the signal.

In 2014, cycle 1 injection recorded several moderate energy locatable events during injection. Figure 8 shows two views of the detected events plotted in three dimensions relative to HW3, OB4 and OB5. The majority of detected events are clustered around the toe of HW3 and reach towards OB5.

In 2015, cycle 2 injection did not yield moderate energy locatable events as observed during cycle 1 injection. However, lower energy reservoir events were observed within the vicinity of OB5. The low energy events are similar in magnitude to the background noise and are not locatable. Thus, for the purpose of determining the solvent conformance the observed events were not helpful. Comparing to cycle 1, the lower energy level and number of reservoir events is attributed to the lower reservoir pressures achieved during injection. Also, the solvent would likely travel through channels created during cycle 1, thereby leading to a lower number of detectable events.

Secondary events, termed Stoneley waves, are formed when a wave generated from a reservoir event hits the perforations of OB5. The Stoneley waves then "ring" (travel) up the tubing and casing. Stoneley waves and the corresponding reservoir events were observed near the end of the injection cycle and for two days after. A few of these reservoir events were locatable to OB5 at 460mTVD, suggesting the solvent had reached OB5 and was continuing to move within the reservoir after the injection had stopped.

The PS results for cycle 3 injection are similar to those of cycle 2. Moderate energy locatable events were not detected. Again, similar to cycle 1, the lower reservoir pressures led to lower energy events which are masked by the background noise. Stoneley waves were also observed and are again evidence of the solvent finger reaching OB5.

7.2 Interpretation of pilot data

The combined pressure, temperature, and passive seismic data from HW3 and OB5 (approximately 16 [m] from HW3) are used to assess the solvent conformance for cycle 2 and 3.

During the cycle 2 injection a small but detectable temperature change at OB5 was observed during the first two days of injection suggesting the solvent had arrived at the OB5. The temperature change corresponds to a pressure increase of about 2.5 [MPa] at OB5. Only later during the injection cycle, at OB5 pressures greater than 7 [MPa], were the Stoneley waves observed – suggesting there is a disconnect between the solvent arrival and PS events. A likely explanation is that the temperature and pressure response correspond to the solvent arriving to OB5 through channels created during cycle 1. The PS events observed later in the injection cycle are likely caused by additional fingering of the solvent in the vicinity of OB5.

Cycle 3 injection was similar to cycle 2. A small temperature response was detected during the first two days and a corresponding pressure rise at OB5 of about 2.5MPa was observed. Moderate energy detectable events were not observed and low energy events and Stoneley waves were observed at OB pressures higher than 7 [MPa]. The results are consistent with cycle 2, which suggests the solvent is moving through existing channels created during the previous cycles. The low energy events observed later in the cycle occur at higher pressures and likely represent new finger growth in the vicinity of OB5.

The production volumes from HW3 for 2015 are shown in Table 2. The cumulative water-cut of HW3 for 2015 is about 20%, which represents data from part of cycle 1, all of cycle 2 and a portion of cycle 3. The water production is higher than the nominal expectations which were derived from previous field trials. However, the produced volumes are within expected range of uncertainty given the present understanding of the pilot site geology. Methanol is added to the produced water for hydrate prevention through the trunkline. In 2015, the capacity of the methanol pump was increased, as described in Section 5.3, to increase the water treatment capacity.

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 2015 10-K filing
- The propane and flow assurance solvent price is estimated based on the average price paid by the CSP pilot in 2015 for each product respectively
- Diluent pricing is based on the average Diluent sales price used in the Imperial CL Royalty Calculation, form PST-7a

The price information can be found in Table 7.

8.1 Sales volumes of natural gas and by-products

In 2015, the pilot produced 192 [Sm³] of natural gas. No natural gas was consumed. Also, the pilot produced 787.4[m³] of propane, 61.9 [m³] of diluent and 86.2 [m³] of flow assurance solvent from the reservoir. Other than the diluent and flow assurance solvent produced from reservoir, the pilot has also recovered all the utility fluid used in the surface facilities, totalled 531.7 [m³].

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 (offsets natural gas purchases elsewhere in the operation), the theoretical sale of recovered propane (offsets natural gas purchases elsewhere in the operation), the theoretical sale of recovered diluent (offsets diluent purchases for shipping the bitumen) and the theoretical sale of recovered flow assurance solvent.

Gross revenue for the pilot in 2015 is estimated to be 728 k$. This is based on 787.4[m³] of propane, 61.9 [m³] of diluent, 617.8 [m³] of flow assurance solvent (including 86.4 [m³] recovered from reservoir and 531.7 [m³] from surface facilities) and 948.8 [m³] of bitumen produced at 21.21 $/bbl, 65.72 $/bbl, 105.59 $/bbl, and 32.48 $/bbl respectively.

A summary of the annual revenues over the project life is given in Table 8.

8.3 Costs

8.3.1 Drilling, completions, and facilities costs

Table 9 summarizes drilling, completions, facilities, and related costs by category, incurred in 2015. 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 126 k$ was received due to account clearance. Total drilling, completions, and facilities costs in 2015 were thus 77 k$.

8.3.2 Direct and indirect operating costs

Table 10 summarizes direct and indirect operating costs incurred in 2015, totalling 2,103 k$.

8.3.3 Injectant costs

Table 11 summarizes injectant costs by category incurred in 2015. Trucking costs associated with transporting each product to site are included.

8.3.4 Total Costs

A summary of the annual costs incurred over the project life is given in Table 12. Annual credits, such as those received from CCEMC, are deducted from the total costs for cash flow calculations.

8.4 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 13.

8.5 Cash flow

As revenue is only estimated for the pilot, cash flow can only be estimated. Using the data from Tables 10 through 11, it is estimated as follows:

Revenue	= Bitumen + Solution Gas + Propane + Diluent + Flow Assurance Solvent = 194 + 0 + 105 + 26 + 410 = 735 k$
Credits	= CCEMC Credit = 960 k$
Costs	= Drilling & Facilities Costs + Operating Costs + Injectant Costs - CCEMC Credit = 77 + 2,103 + 846 -960 = 2,066 k$
Before Royalty Cash Flow	= Revenue – Costs = 735 – 2,066 = -1,331 k$
Royalties	= -362 k$
Cash Flow	= Revenue – Costs – Royalties = 735 – 2,066 + 362 = -968 k$

This estimation of cash flow does not include taxes.

8.6 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

The facility flow assurance issues of 2014 have been largely mitigated with the re-rating of the underground pipeline in 2015. A step change in facility performance was achieved with HW3 operating with limited unplanned down time. The major focus for 2016 is then to successfully bring HW1 and HW2 online and sustain stable operation with multiple wells. Below is a list of major goals for 2016.

- Complete the planned facility upgrades in Q1 2016
    - Vent gas compressor
    - Diluent injection manifold
    - Chemical injection system for the test separator
- Complete HW1 cycle 1 in Q1 2016, cycle 3 by Q4 2016
- Complete HW2 cycle 1 in Q2 2016, cycle 3 in progress by Q4 2016
- Complete HW3 cycle 4 in Q4 2016
- 4D seismic to start in Q4 2016

10.2 Changes in pilot operation

The overall CSP pilot timeline has been pushed back 10-12 months due to the surface flow issues in 2014. The pilot progress of 2015 had not resulted in significant changes to the pilot operation schedule.

10.3 Optimization strategies

In 2015, production on HW3 was restarted. Initially, a conservative approach was taken with regards to the use of flow assurance solvent in order to maintain stable operation of the pilot. As the year progressed and operational experience developed the conservative approach transitioned to a more optimized approach. Once the facility modifications planned for Q1 2016 are complete the facility will better equipped to further test the operational boundaries of the CSP process. In particular, limiting the use of flow assurance solvent, methanol and downhole heating are planned for 2016. In fact, there is a unique opportunity to test the effects of downhole heating with HW2. Unlike HW1 and HW3, HW2 is not equipped with active downhole heaters. Also, the requirement for co-injected flow assurance solvent could be tested with HW1 or HW2. Selectively using flow assurance solvent to address symptoms of heavy liquids, opposed to continuously flowing, would be a more optimized mode of operation. Eliminating the use of flow assurance solvent downhole would significantly streamline the sample analysis process and further optimize the pilot surveillance. Lastly, with the installation of the new vent gas compression system in Q1 of 2016, the pilot will be able to operate wells at lower bottom-hole pressures. Testing the well performance with low pressure production is an optimization goal of 2016.

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 2015 performance:

- Facility upgrades, specifically the re-rating of the trunkline MOP, has led to a step change in facility performance
- The new flow assurance solvent was effective in mitigating heavy liquid plugging in the wellbore and on the surface facilities
- HW3 was successfully operated through the cycle 1 restart and cycle 2
- Cycle 3 production continued up to a planned shut-in at year-end
- The overall performance of the pilot was in line with expectations
- Facility upgrades are planned for Q1 of 2016 in preparation for multi-well operation

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 2015 was the inability to vent the well casing gas. The consequence was higher bottom-hole pressures during the production of cycles 1 through 3 for HW3.

11.3 Technical and Economic Viability

The current pilot represents one study that will be used in combination 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

Injected Volumes[1] (m^3)	Propane	Flow Assurance Solvent
January	0.0	0.0
February	0.0	0.0
March	0.0	0.0
April	0.0	0.0
May	0.0	0.0
June	526.8	75.0
July	0.0	0.0
August	0.0	0.0
September	895.3	118.8
October	0.0	0.0
November	0.0	0.0
December	0.0	0.0
Total 2015	**1422.1**	**193.8**

[1]Injectant volumes indicate delivered to the reservoir and do not include 531.7 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 2 – Material Balance Data – Production

Produced Volumes[1] (m³)	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	91.9	37.2	18.3	0.0
June	12.6	25.9	100.0	5.9	2.5	0.0
July	218.8	53.8	0.0	205.4	10.4	23.4
August	113.9	98.9	0.0	45.4	4.3	3.7
September	29.3	15.0	0.0	108.9	2.9	12.3
October	238.1	50.4	0.0	266.7	0.0	35.4
November	142.6	57.7	0.0	56.1	0.0	7.4
December	66.0	96.4	0.0	29.4	0.0	3.9
Total 2015	**948.8**	**487.2**	**192.0**	**787.4**	**61.9**	**86.2**

[1]Produced volumes indicate recovered from the reservoir and do not include 531.7 [m^3] of flow assurance solvent used for the surface facilities or the within the wellbore

Table 3 – 2014 Material Balance Data – Production Correction 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	0.0	0.0	0.0	0.0	0.0	0.0
May	0.0	0.0	0.0	0.0	0.0	0.0
June	5.7	0.0	0.0	24.0	3.6	0.0
July	0.0	0.0	0.0	0.0	0.0	0.0
August	16.5	0.0	0.0	28.9	12.9	0.0
September	5.7	0.0	0.0	8.2	31.0	0.0
October	0.0	0.0	0.0	0.0	0.0	0.0
November	0.0	0.0	0.0	0.0	0.0	0.0
December	0.0	0.0	0.0	0.0	0.0	0.0
Total 2014	**27.9**	**0.0**	**0.0**	**61.0**	**47.4**	**0.0**

Table 4: 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 5: 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 6: 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

Table 7: Price Assumptions for Revenue Calculations

	Bitumen $/bbl	Natural Gas $/mcf	Diluent $/bbl	Propane[1] $/bbl	Pilot Flow Assurance Solvent[1] $/bbl
2015	$32.48	$2.78	$65.72	$21.21	$105.59

[1]Average price paid for the CSP pilot for 2015

Table 8: Cumulative Project Revenue

Cumulative Revenue (k$)	2009	2010	2011	2012	2013	2014	2015	Total
Bitumen	0	0	0	0	0	18	194	212
Solution Gas	0	0	0	0	0	0	0	0
Recovered Propane	0	0	0	0	0	22	105	127
Recovered Diluent	0	0	0	0	0	294	26	320
Recovered Flow Assurance Solvent	0	0	0	0	0	0	410	410
Total Revenue	**0**	**0**	**0**	**0**	**0**	**334**	**735**	**1,069**

[1] Estimated, see section 8.2 for assumptions

Table 9: Drilling and Facilities Costs

Drilling and Facilities Costs (k$)	**2015**
Preliminary Engineering	0
Surface Facilities	191
OB Well Drilling	0
HW Drilling	-126
Completions	11
Geo Surveillance	0
Total Drilling and Facilities Costs	77

Table 10: Operating Costs

Direct and Indirect Operating Costs (k$)	**2015**
Operating Costs	2,103
Total	**2,103**

Table 11: Injectant Costs

Injectant Costs (k$)	**2015**
Propane	241
Flow assurance solvent	605
Total	**846**

Table 12: Cumulative Project Costs

Cumulative Costs (k$)	2009	2010	2011	2012	2013	2014	2015	Total
Drilling & Facilities Costs	563	1,631	8,991	33,257	22,776	4,591	77	71,886
Operating Costs	0	0	0	0	0	1,649	2,103	3,752
Injectant Costs	0	0	0	0	0	776	846	1622
Total Costs	**1,375**	**829**	**8,980**	**33,257**	**22,776**	**7,016**	**3,026**	**77,259**

Table 13: Estimated Crown Royalty Calculation

Crown Royalties (k$)	2009	2010	2011	2012	2013	2014	2015	Total
Pilot Revenue[1]	0	0	0	0	0	334	735	1,069
Pilot Costs[2]	563	1,631	8,991	33,257	22,776	7,016	3,026	77,260
CCEMC Credit[3]				2,400	2,480	480	960	6,320
Before Royalty Cash Flow	-563	-1,631	-8,991	-30,857	-20,296	-6,202	-1,331	-69,871
Cold Lake Royalty Rate[4]	27.8%	30.9%	33.8%	34.2%	35.4%	36.8%	27.2%	-
Cold Lake Royalty Impact	-156	-504	-3,039	-10,553	-7,185	-2,282	-362	-24,081
Total Cold Lake Royalties[4]	438,240[5]	628,605[5]	935,665[5]	678,964[5]	599,433	772,086	228,198	-

[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 (CCEMC) Corporation 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

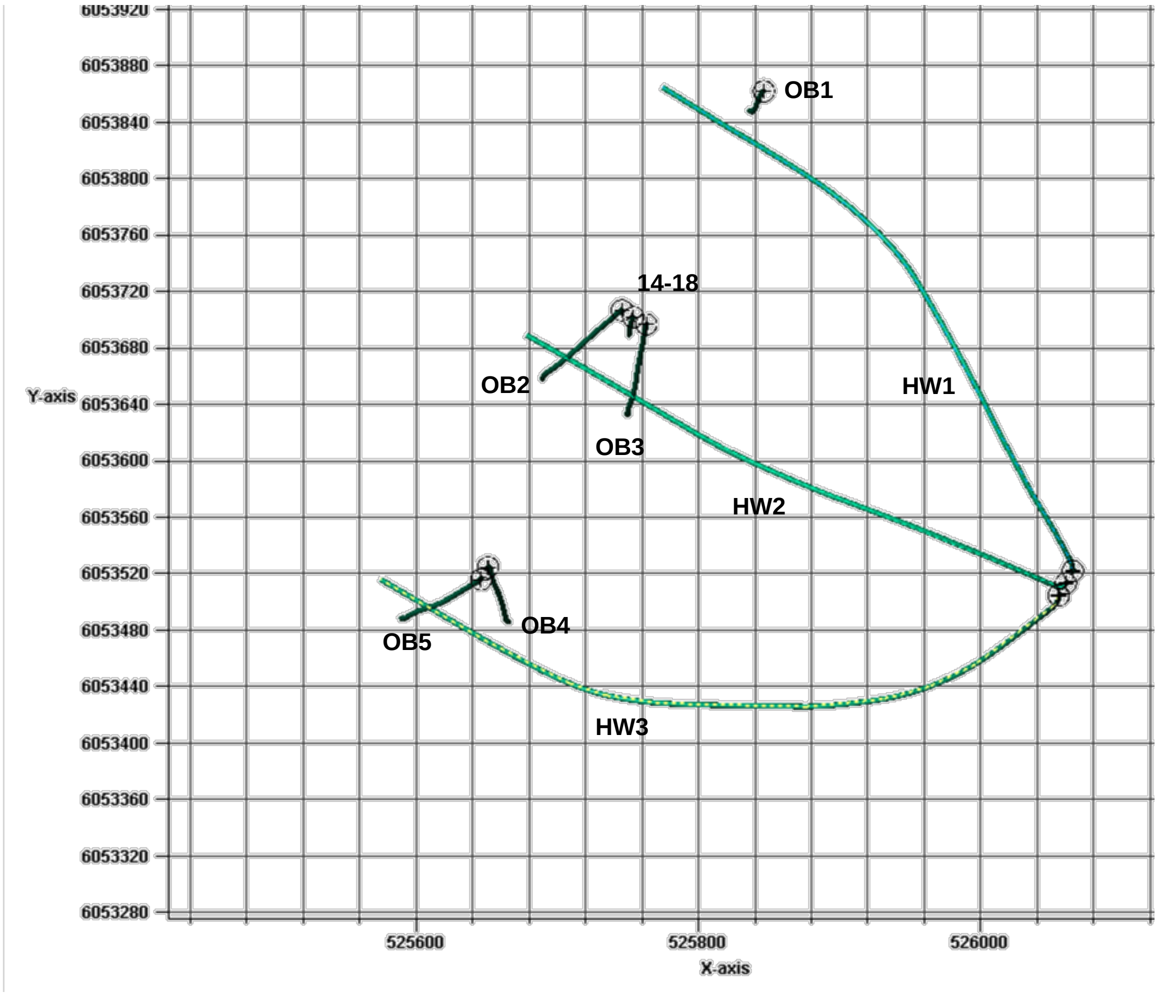


Figure 2: Surface Facility and Pad Locations

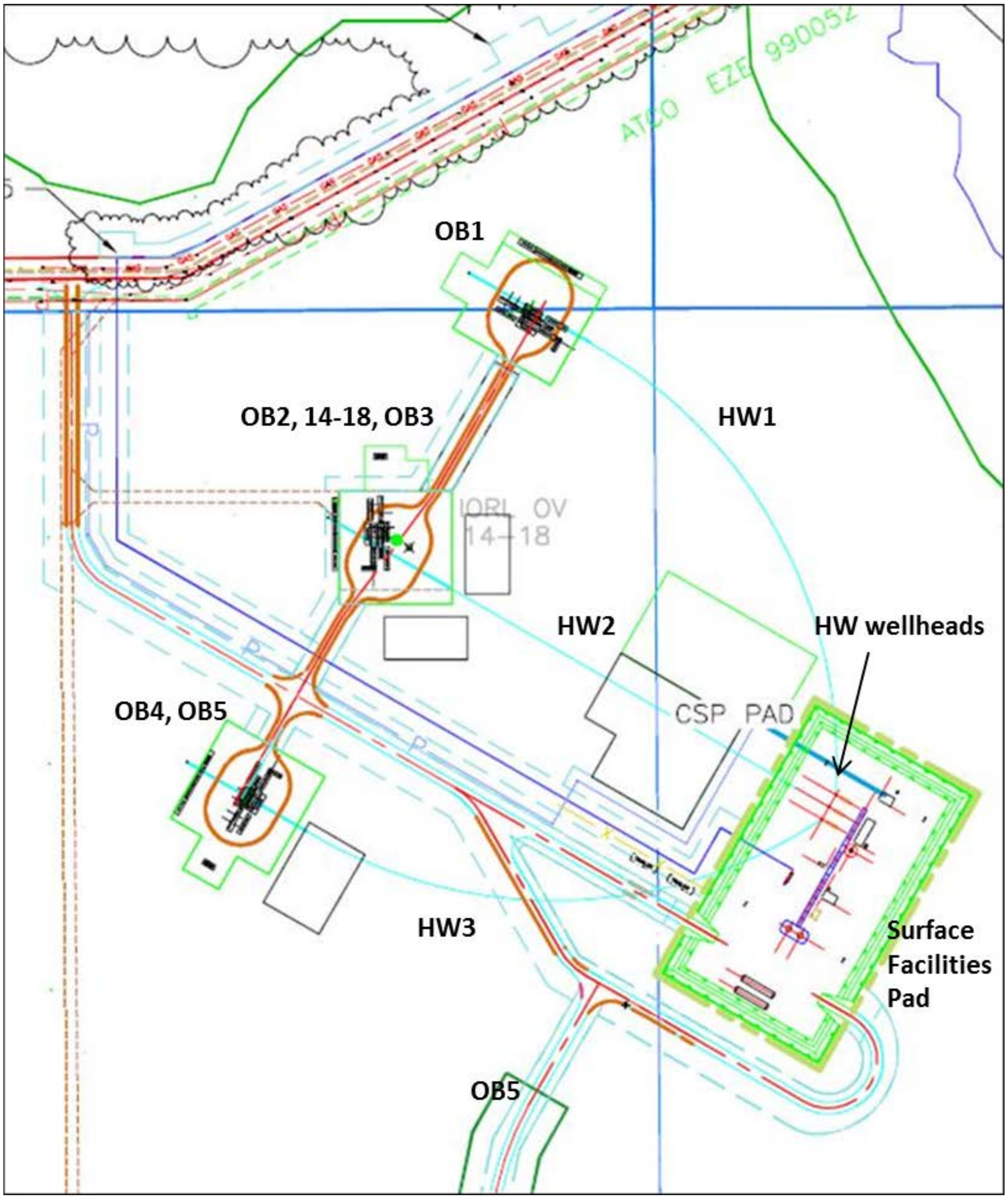


Figure 3: Log Cross Section of Pilot Area through OB Wells

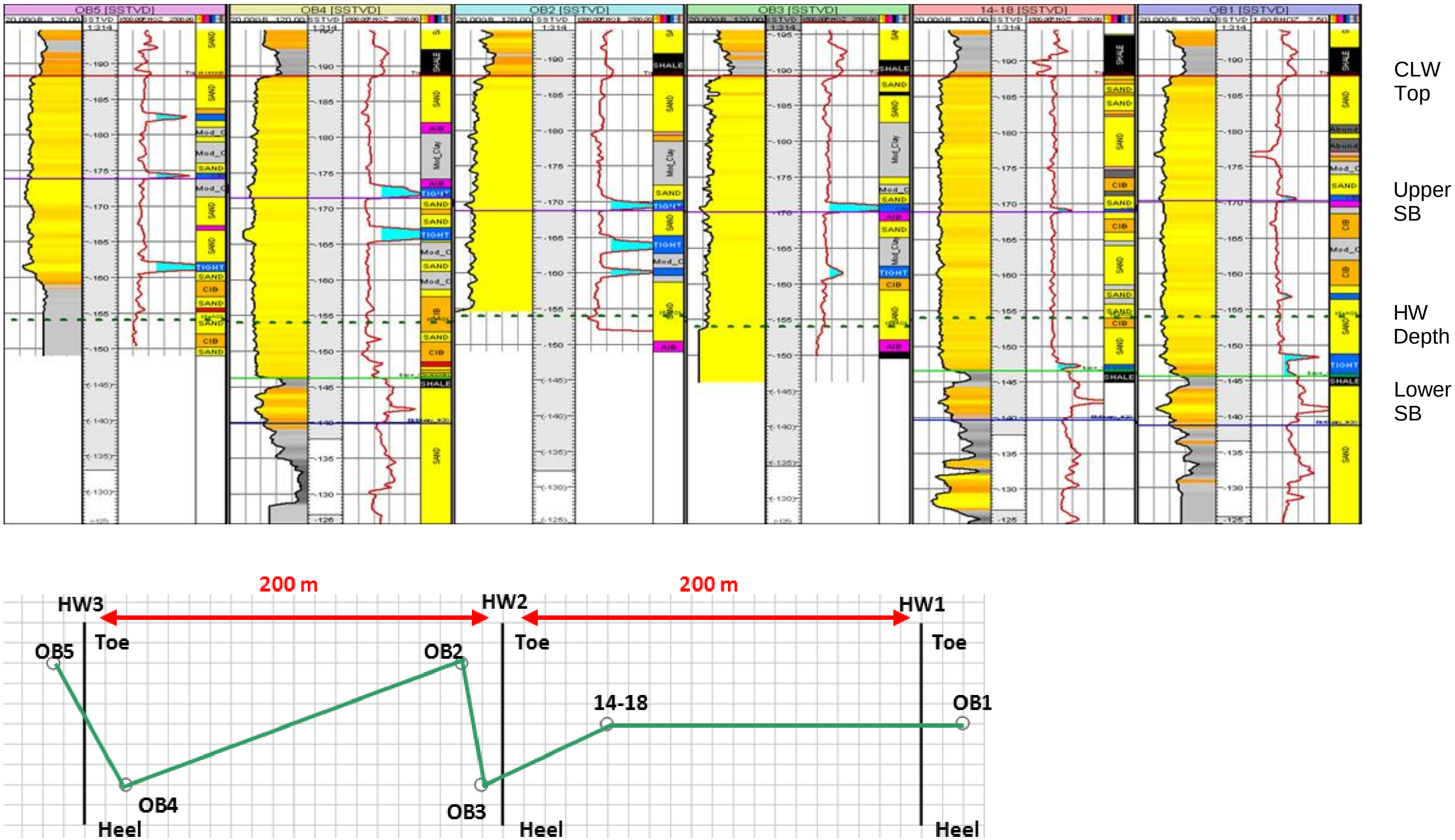
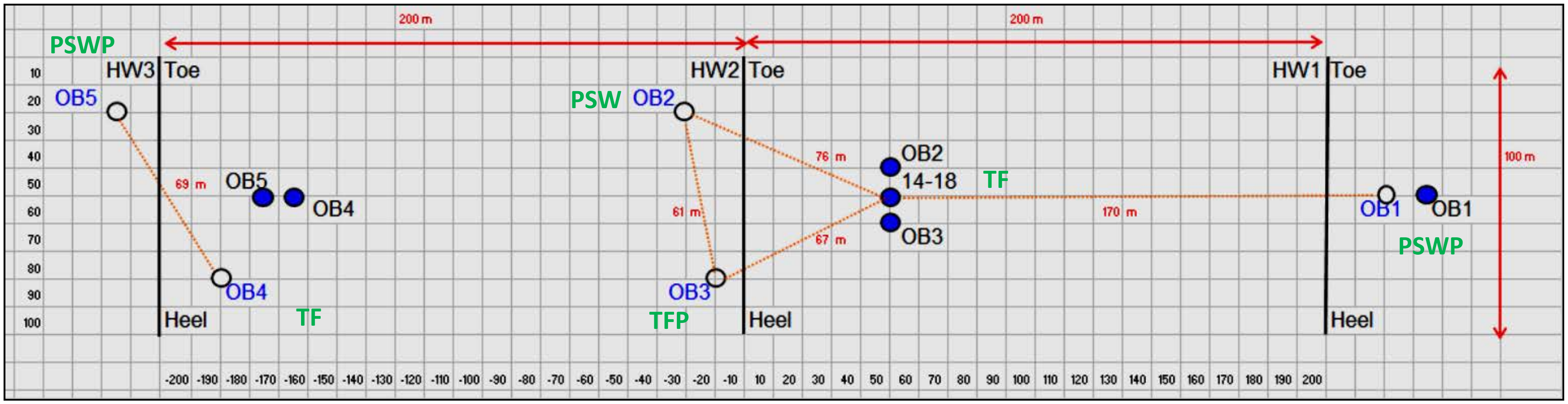


Figure 4: OB Wells Location and Surveillance Instrumentation



● 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

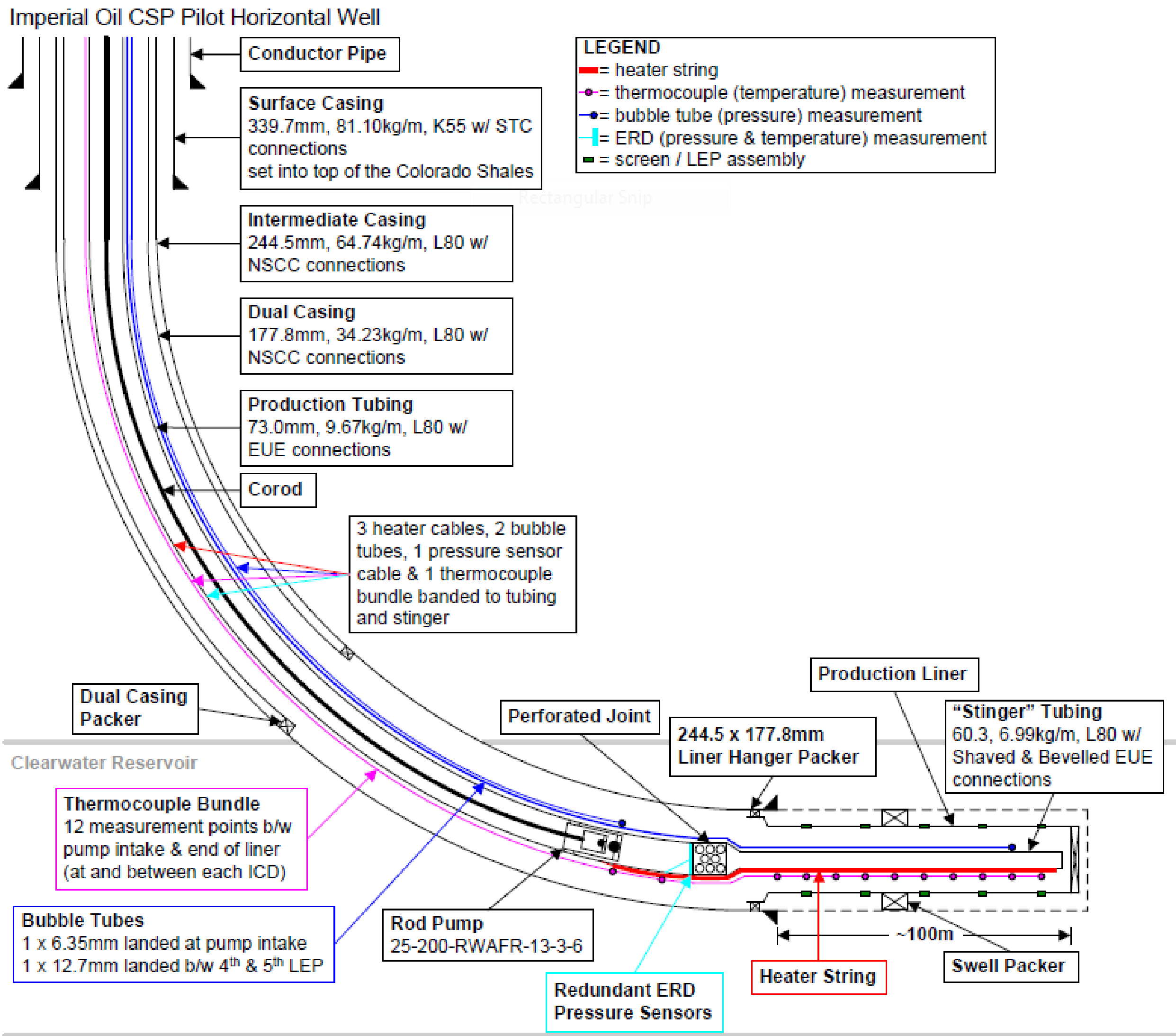


Figure 6: CSP Pilot Site View

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

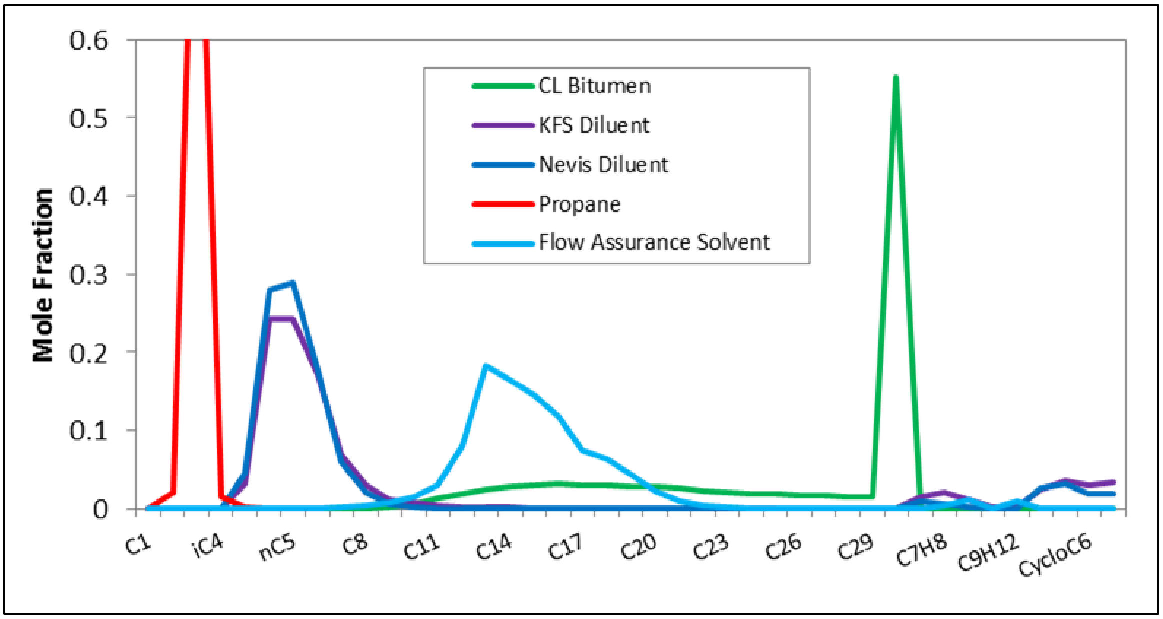
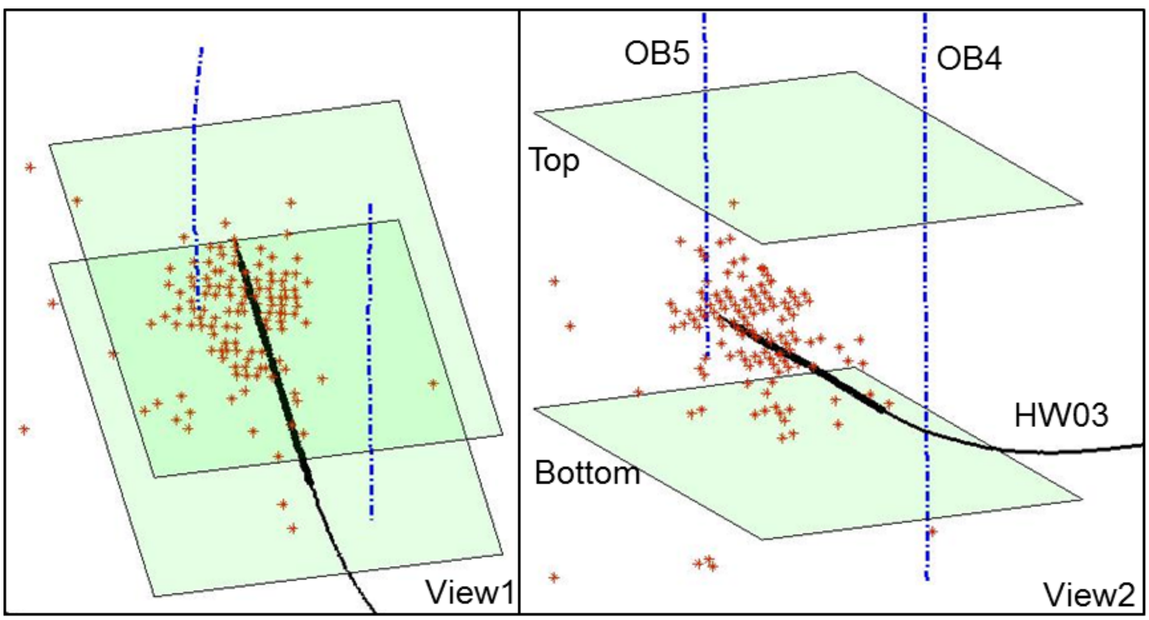
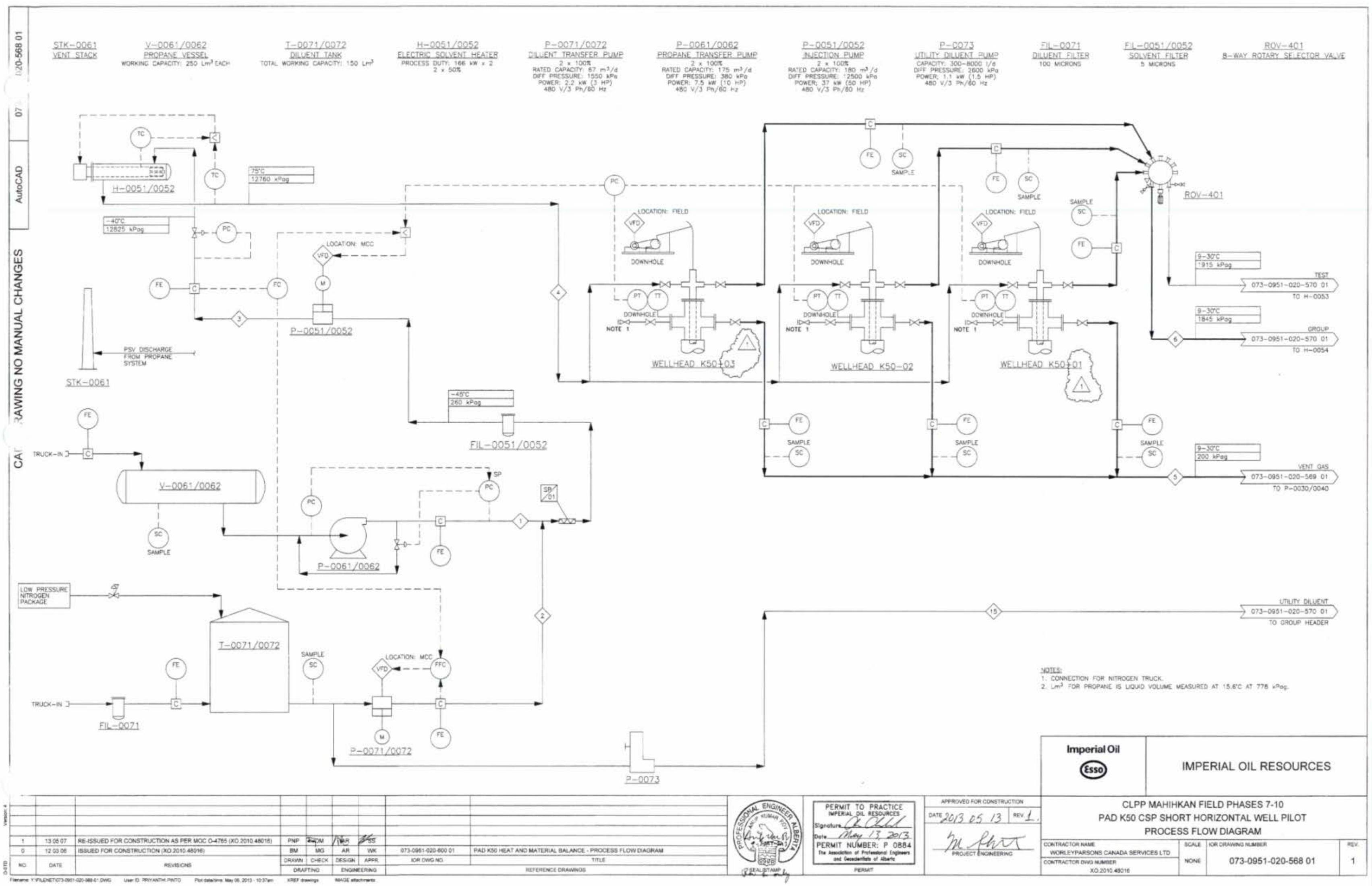


Figure 8: Passive Seismic Event Locations for HW3 Cycle 1



Appendix A:

Process Flow Diagrams (PFDs)


STK-0061
VENT STACK
V-0061/0062
PROPANE VESSEL
WORKING CAPACITY: 250 Lm³ EACH
T-0071/0072
DILUENT TANK
TOTAL WORKING CAPACITY: 150 Lm³
H-0051/0052
ELECTRIC SOLVENT HEATER
P-0071/0072
DILUENT TRANSFER PUMP
P-0061/0062
PROPANE TRANSFER PUMP
P-0051/0052
INJECTION PUMP
P-0073
UTILITY DILUENT PUMP
FIL-0071
DILUENT FILTER
100 MICRONS
FIL-0051/0052
SOLVENT FILTER
5 MICRONS
ROV-401
8-WAY ROTARY SELECTOR VALVE
WELLHEAD K50-03
WELLHEAD K50-02
WELLHEAD K50-01
LOW PRESSURE NITROGEN PACKAGE
TRUCK-IN
PSV DISCHARGE FROM PROPANE SYSTEM
TEST
073-0951-020-570 01
TO H-0053
GROUP
073-0951-020-570 01
TO H-0054
VENT GAS
073-0951-020-569 01
TO P-0030/0040
UTILITY DILUENT
073-0951-020-570 01
TO GROUP HEADER
NOTES:
1. CONNECTION FOR NITROGEN TRUCK.
2. Lm³ FOR PROPANE IS LIQUID VOLUME MEASURED AT 15.6°C AT 778 kPag.
Imperial Oil
IMPERIAL OIL RESOURCES
CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM
CONTRACTOR NAME
WORLEYPARSONS CANADA SERVICES LTD
CONTRACTOR DWG NUMBER
XO.2010.48016
SCALE
NONE
IOR DRAWING NUMBER
073-0951-020-568 01
REV.
1
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
APPROVED FOR CONSTRUCTION
DATE 2013 05 13
REV. 1
PROJECT ENGINEERING
1 13 05 07 RE-ISSUED FOR CONSTRUCTION AS PER MOC O-4785 (XO.2010.48016)
0 12 03 06 ISSUED FOR CONSTRUCTION (XO.2010.48016)
073-0951-020-600 01 PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM

073-0951-020-569 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES

V-0003
LIQUID SEPARATOR
SIZE: 736 mm I.D. x 2550 mm S/S

T-0023
MAKE-UP WATER TANK
WORKING CAPACITY: 6.4 m^3

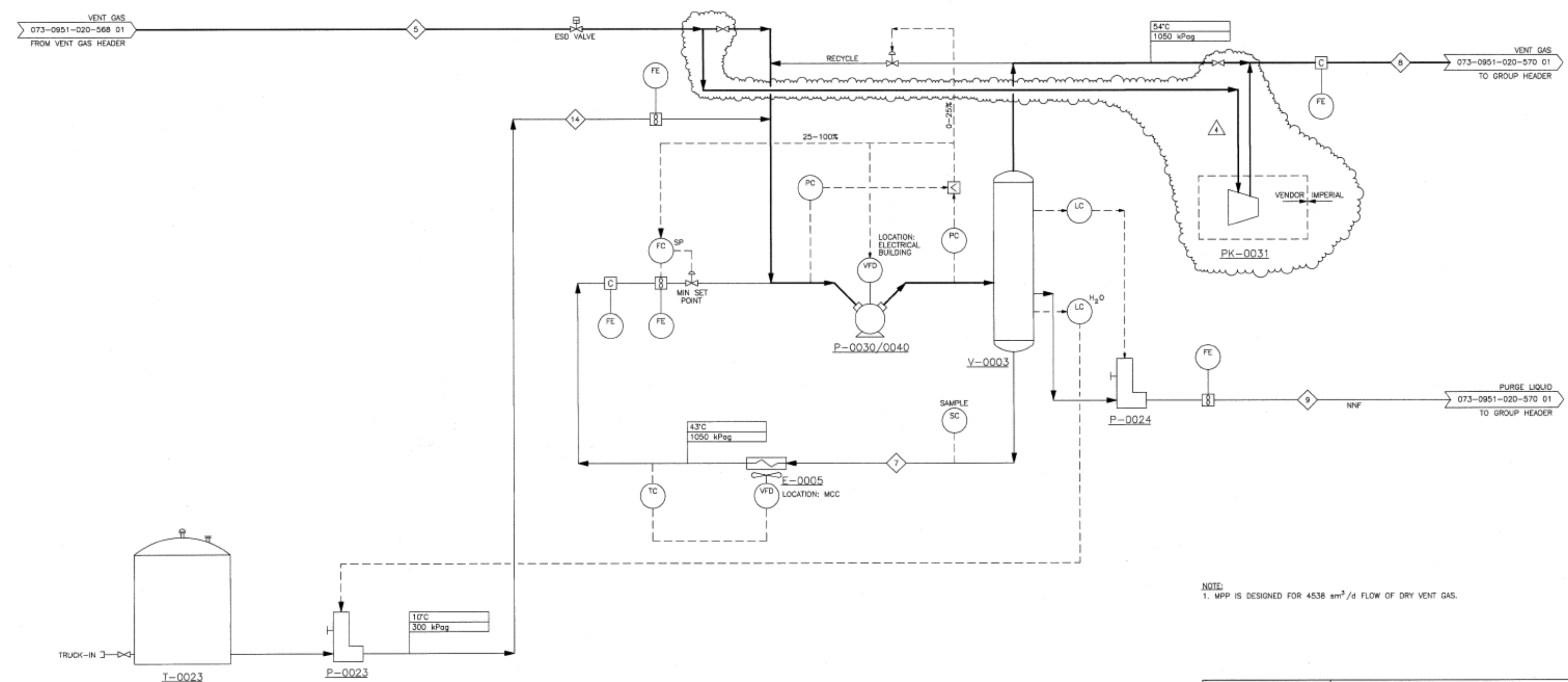
P-0030/0040
MULTI PHASE VENT GAS PUMP
CAPACITY: 153 m^3/hr (ACTUAL)
SUCTION CONDITIONS:
TEMPERATURE: 42°C
PRESSURE: 70 kPag
DENSITY: 49.4 kg/m^3
POWER: 93 kW (125 HP)
2 x 100%
NOTE 1

E-0005
RECYCLE LIQUID COOLER
PROCESS DUTY: 203 kW

P-0023
MAKE-UP WATER PUMP
RATED CAPACITY: 0-100 l/h
DIFF PRESS: 350 kPa
POWER: 0.74 kW (1 HP)
480 V/3 Ph/60 Hz

P-0024
PURGE LIQUIDS PUMP
RATED CAPACITY: 0-1000 l/h
DIFF PRESS: 1500 kPa
POWER: 2.2 kW (3 HP)
480 V/3 Ph/60 Hz

4
PK-0031
PORTABLE COMPRESSOR
RATED CAPACITY: 1007-3029 sm^3/d
DIFF PRESS: 2600 kPa
POWER: 22.4 kW (30 HP)
480 V/3 Ph/60 Hz



NOTE:
1. MPP IS DESIGNED FOR 4538 sm^3/d FLOW OF DRY VENT GAS.

IMPERIAL OIL RESOURCES

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.	IOR DWG NO.	TITLE
4	15 09 24	ISSUED FOR CONSTRUCTION AS PER EMOC-386 (700000021085)	EJ	HJB		SYJ		
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: ENBKO.JOO Plot date/time: September 28, 2015 - 1:09pm XREF drawings: IMAGE attachments:

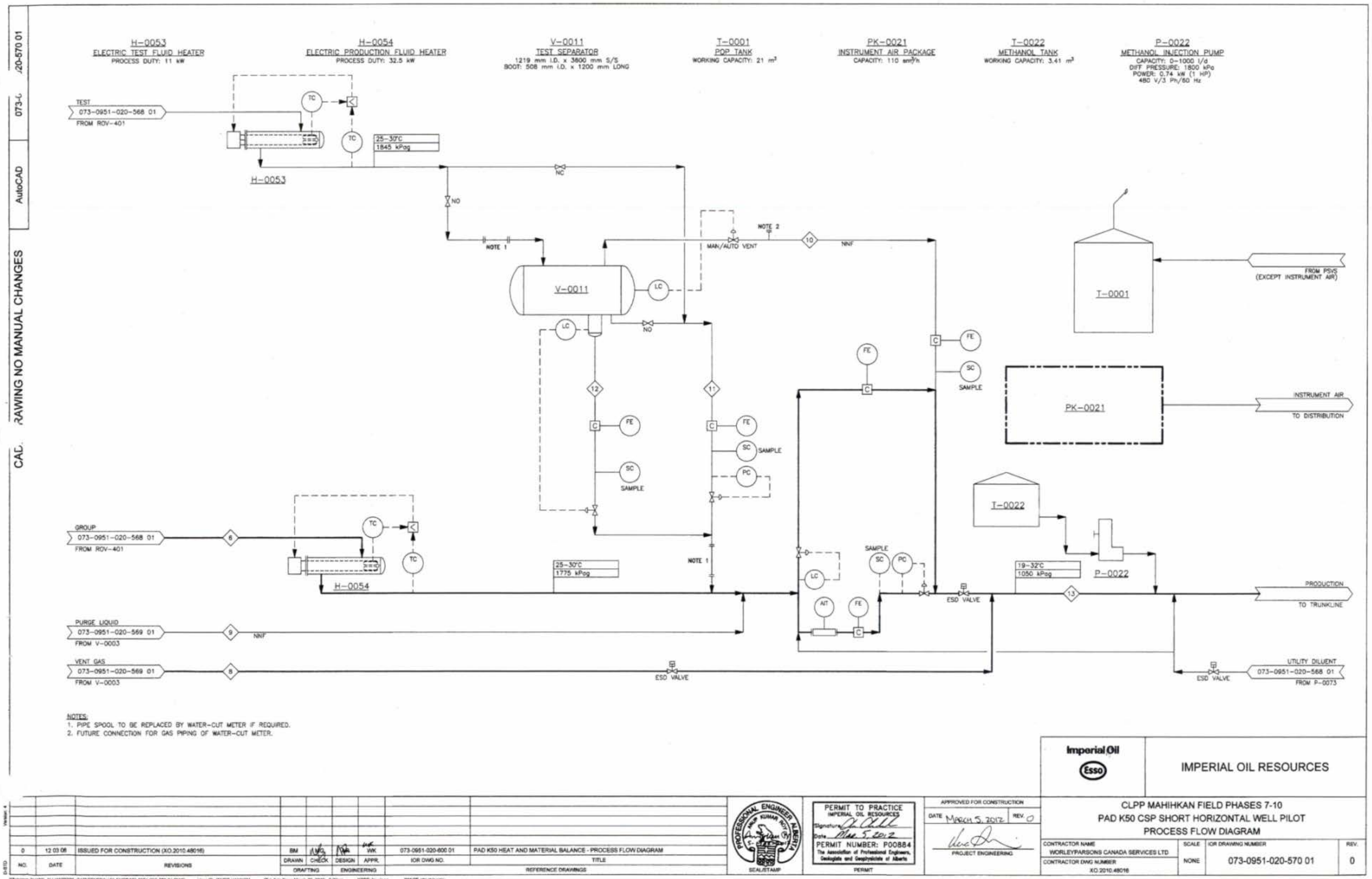
PROFESSIONAL ENGINEER ANUP KUMAR ROY ALBERTA
SEAL/STAMP
28-Sept-2015
Rev 4 only

PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date Sept. 28, 2015
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
PERMIT

APPROVED FOR CONSTRUCTION
DATE 2015 09 28 REV. 4
PROJECT ENGINEERING

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	073-0951-020-569 01	4
CONTRACTOR DWG NUMBER XO.2010.48016			



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