# IETP Application No. 06-094

# Imperial Oil Resources – Cyclic Solvent Process Pilot

# 2014 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 to be 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 abandonment 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) production of GHGs arising from burning natural gas to produce steam and (2) thermal inefficiencies which limit applicability to thinner and/or lower bitumen saturation reservoirs.

The pilot is located at K50 pad in Imperial's Cold Lake development and is being conducted in the Clearwater formation. Three horizontal wells will be operated using CSP as a recovery process. The project has completed the first cycle of injection on the leading well. Production has been challenging due to plugging or flow restriction in the surface facilities caused by gas, hydrates, or heavy liquid phases. The surveillance to date has exceeded original expectations and has been effective in identifying solvent reach and conformance in the reservoir during injection. Current work is focused on alleviating surface flow issues and resuming production from the well for cycle one.

This report summarizes progress that was made through year-end 2014.

# 2 Summary Project Status Report

## 2.1 Members of the project team

The following were key members of the CSP project team to the end of 2014.

| | |
|---|---|
| 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 |
| M. (Mike) Sheptycki, P.Eng. | CSP Project Manager |

## 2.2 Key activities

Key activities during the reporting period are described below:

- Remainder of completion work on HW2 and HW3 completed in early February
- Facility pre-commissioning from February to end of April
- Facility was turned over to Cold Lake Operations with final commissioning completed by the end of May
- Cycle 1 injection into HW3 took place from May 29 to June 8 with stoppages to deal with injection system controls and diluent quality issues
- Initial production lasted from June 10 to 12 but was halted due to hydrate formation in the trunkline to Mahihkan plant
- From mid-June to mid-August, the pipeline hydrates were removed, additional hydrate and phase behavior studies were conducted, and new operational guidelines were adopted to prevent future occurrences
- Production of HW3 cycle 1 resumed intermittently from mid-August to mid-September but was ultimately discontinued so that surface facility flow issues could be addressed
- During the August to September production, diluent was injected at times into the wellbore and near wellbore reservoir to clear it of blockage and stimulate production
- The CSP pad was shut-in for the remainder of the year while the team has been working on resolutions to the various flow issues encountered

## 2.3 Production, material and energy balance flow sheets

As of year-end 2014, 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 the new Petrel-based geologic model (Section 3.2), 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 (HW1-3) 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 first phase of horizontal well completions work occurred during September 2012-July 2013, including installation of annular packers in HW1-3 and installation of the tubing string with attached thermocouples, heater, ERD sensor, and bubble tubes in HW1 (See Figure 5 for the horizontal well completions design schematic). Tubing string installation in HW2 had some complications with heater function test unsuccessful and the equipment was retrieved to surface. As Completions ran out its allocated time in 2013, installation of instrumented tubing strings in HW2 and HW3 was rescheduled to Q1 2014 to avoid interfering with the Surface Facilities work.

The second phase of the horizontal well completions commenced from January to early February 2014. The objectives were to complete the tubing and instrumentation installation activities at HW2 and HW3 in finalizing the wellbores for pilot operations.

Primary activities at HW2 occurred during January 10-21. Initial steps included a mobilization and setup stage of all unique services to the CSP operation, drifting and scraping the well, and circulating the well clean with fresh water. The instrument lines (downhole heater, thermocouple bundle, bubble tubes, ERC sensor, as shown in Figure 5) were strapped and clamped to the tubing string exterior in order to land the equipment inside the well at precise pre-determined positions as has been the process consistently throughout the project; and the heater was checked every 50 [m] into the well as the recommended procedure. All the tests were reading maximum response in resistivity and conductivity prior to reaching the position, where the bottom of the tubing / heater string was situated just above the top of the 5.5 ["] LEP liner string (depth ~630 [mKB]). The resistivity test failure and continued conductivity test passes indicate that the source of the problem is likely seepage/fluid damage wetting the magnesium powder insulation. This implies that the heater lines are physically not broken. All other lines (bubble tubes, ERD sensor, and thermocouple) are functioning as normal on their latest tests, further indicating this is likely not cracking / pinch / scrape damage. The collective decision was made to complete the installation with the functionality loss in the heater unit to preserve all other well instrumentation. The tubing was landed on position and the wellhead installed on January 20.

Operations moved immediately to HW3 for mobilization efficiency. The overall scope of the operations plan was the same as HW2, including the scraper, drift, and fresh water circulation. Instrumentation clamping and installation proceeded as planned. Near the bottom of the well, a hang-up point was observed where the tubing string took weight indicating the pipe may potentially be dragging or shouldering slightly. After a team technical review, carefully lowering the tubing allowed passage past the tight point without any complications. All instruments were installed on target depth with full functionality.

Downhole rod insert pumps had been installed on all three horizontal wells by early February after all surface facilities and pump jack installations were complete, putting the final equipment in place for upcoming production pumping operations. Pumps were left in bypass position to allow flow down the tubing strings for the first propane injection cycle. The final status of the OB well completions is summarized in Table 3 and HW completions status is summarized in Table 4.

## 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 1-3. 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

HW3 was injected into from May 29 to June 8. Injection was initially intermittent while injection facility control loop and diluent quality issues were resolved. Production from HW3 occurred from June 10 to 12 and from mid-August to mid-September intermittently due to hydrate, gas, and heavy hydrocarbon liquid phase formation issues in the surface facilities.

# 5 Surface Facilities

## *5.1 Detailed Design*

Engineering design of surface facilities had been completed by August 2012. The process flow diagrams (PFDs) in Appendix A provide a high-level overview of the surface facilities.

## *5.2 Progress*

Surface facilities construction was complete by year end of 2013, with only some minor activities such as cleanup, insulation, and hydro-testing completed in 1Q 2014. Figure 6 includes a couple of site views after completion of facilities construction. Facility pre-commissioning started in the third week of February 2014 following the completion of well work and continued until the end of April. Facility was turned over to Cold Lake Operations at the end of April 2014 with final commissioning complete by end of May 2014.

## *5.3 Surface equipment*

Table 5 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 will be stored in two storage vessels, V-0061/62. Propane transfer pumps, P-0061/62, will supply liquid propane to the primary injection pumps P-0051/52. Diluent will also be supplied via truck and will be stored in two atmospheric storage tanks, T-0071/72. Diluent 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 will remove debris suspended in the diluent supply. The tanks will be 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 has been 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. 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).
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 to date are grouped as either injection system related or production system related. The major facility limitation that could not be sufficiently mitigated and ultimately caused the decision to shut in production was excessive pressure difference in the underground buried trunkline to Mahihkan plant. The factors contributing to this limitation are the relatively low pressure operating ceiling of the pipeline, low temperature leading to increased liquid phase splitting and viscosity, low velocity of flow in the line, and differential velocity between the two hydrocarbon liquid phases which leads to continuous accumulation of the heavier phase. These conditions and subsequent impacts were previously untested and present a challenge unique to CSP. Below is a list of issues that impacted injection and production.

Injection

- Plugging of solvent injection filters (FIL-0051/52) by black colored solids caused intermittent shutdown of injection
  - Due off-spec batch of diluent and possibly residual solids from tank construction
  - Resolved by switching diluent and cleaning the tank interior

Production

- Wellhead high pressure shutdown due to extreme viscosity heavy liquid phase formation
  - Temporary resolution through flushing with diluent

- Test separator (V-0011) oil and water legs plugged with heavy liquid phase on several occasions
  - Smaller valves make the separator particularly susceptible to plugging
  - Separator design is such that high density heavy liquid phase or asphaltene tends to settle into the water leg and cause frequent flow impairment or plugging
  - Flushing with diluent was generally sufficient to unplug flows, however in an extreme case, xylene was needed to first dissolve the heavy hydrocarbon before flushing

- Pad pressure control valve (XV-410) unable to properly actuate or becoming plugged due to heavy liquid phase formation – diluent flush used to remove blockage

- Trunkline to Mahihkan plant shut down due to high pressure differential
  - Commissioning water released into pipeline during initial production formed hydrates with propane – resolved through depressurization
  - High viscosity heavy liquid phase, insolvent in diluent, caused excessive pressure difference

- Nitrogen gas released into pipeline becomes trapped in pipeline and causes sufficient increase to pressure difference that production is shut in until gas can be flushed out

# 6 Production Performance

## *6.1 Injection and production history*

As of the end of 2014, only HW3 has seen injection or production. The summary of injection and production volumes can be found in Table 1 and 2 respectively. The injection rate is nominally 150 [$m^3$/day] of total solvent once stable operation is achieved. The main injection for HW3 cycle occurred from May 29 to June 10. The narrative of events is given below.

- May 29 to June 2, intermittent injection at times reaching 150 [$m^3$/day] due to injection system controls tuning and solvent injection filter fouling
- June 3 to June 6, no injection while off-spec diluent removed from CSP tanks and replaced with new product
- June 7 to June 9, steady injection at 150 [$m^3$/day] for nearly 60 hours until first injection volume target reached

As noted previously, production suffered frequent stoppages due to flow related issues on surface. Nominally, the maximum production rate from a well is 30 [$m^3$/day] of total fluids based on the pumpjack capacity. Actual fluid production rate at any time depends on reservoir pressure, fluid viscosity, and presence of free gas at wellbore conditions. Conceptually, CSP is expected to show high initial production rate with a long tail of gradually slowing production rates similar to CSS. Production thus far has encountered surface facility limitations to flow and does not accurately reflect the reservoir's production limits. During production in September, a small mini-injection was tried in hopes of stimulating the well. The mini-injection totalled 65.6 [$m^3$] of solvent.

## *6.2 Composition of injected and produced fluids*

The solvent injected for cycle 1 of HW3 is 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. 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 [$kg/m^3$].

Produced fluids can be composed of methane, propane, diluent, bitumen, and water. Table 2 shows composition of produced fluids. 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, 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 gives examples of the characteristic shapes that indicate each liquid phase substance.

## *6.3 Predicted vs. actual comparisons*

Performance expectations for the first cycle of HW3 have been generated through simulation and tempered with experience from previous CSP field trials. Comparisons that can be made are limited due to the relatively small produced volume and surface facility related interventions. From a qualitative standpoint, the early production follows the expected trend of density and component concentration variation with time. Despite issues on surface, reservoir inflow showed no indicators of plugging.

## 6.4 Pressures

Injection into HW3 reached a peak bottomhole pressure of 10.5 [MPa] initially with a subsequent peak of 10 [MPa] during the long continuous injection. Accounting for the pressure loss of 1 to 1.5 [MPa] through the inflow control devices in the horizontal wellbore, the reservoir injection pressures achieved (maximum of 9 [MPa]) align with previous experience during the CSP single cycle test where similar compositions were injected. As expected, OB5 was the only other well to see any pressure effect. OB5 bottomhole reached a peak pressure of 7 [MPa] just as injection for the cycle ended.

Production bottomhole pressures have been significantly influenced by frequent pauses and interventions. As of end of 2014, the pressure from cycle one injection has fully dissipated and the bottomhole pressure of HW3 has settled back to initial reservoir pressure of approximately 3.2 [MPa].

# 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 event cause by solvent movement and gain a quantitative understanding of 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. 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. This is generally in line with reservoir simulations to date.

During injection, there were several instances of pressure fall off once flow was halted. The data will be used in the future for pressure transient analysis to get a qualitative measure of solvent reach. Similarly, production pressure buildup data when pumping stops can help indirectly assess pressure communication distance. The analysis will be based on methodologies of traditional pressure transient analysis with modifications to compensate for the special nature of CSP.

## *7.2 Interpretation of pilot data*

The combined pressure, temperature, and passive seismic data from HW3 and OB5 (approximately 16 [m] from HW3) present strong evidence a solvent finger passed by OB5. Near the end of HW3 injection, there was a step change in the previously slow pressure response at OB5. Several hours later, the PS events detected by OB5 transitioned from primarily reservoir type events to Stoneley wave type evens (vibrations along the wellbore) indicating fluid reaching the well. Finally, there was also a small but notable change in the OB5 bottomhole temperature. The corroboration between these three observations helps to both establish solvent conformance as well as successfully demonstrate the use of PS to detect CSP fluid movement.

During the Q4 of 2014, there have also been significant efforts to better understand, quantify, and ultimately resolve the heavy liquid phase issue in the CSP pilot. Several solvents were assessed through bench tests, EOS modeling, and PVT experiments. Based on effectiveness, availability, and cost, a catalytic distillate with high aromatics content was selected as the best solvent for CSP facility flow assurance. As of the end of 2014, work was underway to secure a sizable shipment of the solvent for testing at the CSP pilot.

# 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 2014 10-K filing
- Average price paid by the CSP pilot in 2014 for propane and diluent

The price information can be found in Table 6.

## *8.1 Sales volumes of natural gas and by-products*

To date, the pilot has both zero production and zero usage of natural gas. The pilot has produced 66.4[$m^3$] of propane and 27.8[$m^3$] of diluent from the reservoir to date. Other than the diluent produced from reservoir, the pilot has also recovered all the utility diluent used in the surface facilities, totalled 434.6 [$m^3$].

## *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 four sources: sale of 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), and the theoretical sale of recovered diluent (offsets diluent purchases for shipping the bitumen).

Gross revenue for the pilot in 2014 is estimated to be 334 k$. This is based on 66.4[$m^3$] of propane, 462.4[$m^3$] of diluent (including 27.8[$m^3$] recovered from reservoir and 434.6[$m^3$] from surface facilities) , and 42.9[$m^3$] of bitumen produced at 53.42 $/bbl, 101.08 $/bbl, and 67.20 $/bbl respectively.

## *8.3 Drilling, completions, and facilities costs*

Table 7 summarizes drilling, completions, facilities, and related costs by category, incurred in 2014. 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. Total drilling, completions, and facilities costs in 2014 were 4,591 k$.

## *8.4 Direct and indirect operating costs*

Table 8 summarizes direct and indirect operating costs by category, incurred in 2014.

## *8.5 Injectant costs*

Table 9 summarizes injectant costs by category, including trucking costs associated with transporting these volumes to site, incurred in 2014.

## 8.6 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 royalty payable is shown in Table 10.

## 8.7 Cash flow

As revenue is only estimated for the pilot, cash flow can only be estimated. Using the data from Tables 8 through 11, it is estimated as follows:

| | |
|---|---|
| Revenue | = Bitumen + Solution Gas + Recovered Propane + Recovered Diluent<br>= 18+ 0 + 22+ 294<br>= 334 k$ |
| Costs | = Drilling & Facilities Costs + Operating Costs + Injectant Costs – CCEMC Credit<br>= 4,591 + 1,649 + 766 – 480<br>= 6,536 k$ |
| Before Royalty Cash Flow | = Revenue - Costs<br>= 334 – 6,536<br>= -6,202 k$ |
| Royalties | = -2,282 k$ |
| Cash Flow | = Revenue – Costs – Royalties<br>= 334 – 6,536 + 2,282<br>= -3,902 k$ |

This estimation of cash flow does not include taxes.

## 8.8 Cumulative project costs and net revenue

Cumulative project costs to date are shown in Table 11. Cumulative project revenue is shown in Table 12.

## 8.9 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.

## *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*

Facility flow issues, particularly in the underground trunkline to Mahihkan, are the primary focus for the coming year. Below is a list of major goals for 2015.

- Address difficult multiphase flow behavior in the facilities
  - Near term (Q1): Secure supply of new flow assurance solvent to assess in the CSP pilot for effectiveness in mitigate 2$^{nd}$ liquid phase
  - Long term (Q1-Q4): Examine potential facility modifications and upgrades to further increase pilot tolerance to high pressure flow, high viscosity liquids, and gas production
- Resume HW03 Cycle 1 operations to finish production and move to injection/production of Cycle 2 (Q2)
- Apply learnings from HW03 and begin injection/production from HW01 and HW02 (Q4)

## *10.2 Changes in pilot operation*

The overall CSP pilot timeline has been pushed back 10-12 months due to the surface flow issues.

## *10.3 Optimization strategies*

The pilot will test the high-aromatics catalytic distillate as the primary flow assurance solvent to replace diluent. If successful, it will replace diluent both for surface flow assurance and subsurface injection with propane.

## *10.4 Salvage update*

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

# 11 Interpretations and Conclusions

Injection and production data to date has been limited by the surface facility flow issues. Information up to this point shows the pilot to be well aligned with previous experience and forecasts. Experience with the pilot facilities demonstrate gas-liquid, liquid-liquid, and hydrate phase equilibrium control can be critical in the operability of the CSP process. Significant work is underway to understand and manage these phenomena which are not present in typical in-situ oil sands processes.

**Table 1 – Material Balance Data – Injection**

| Injected Volumes[1] ($m^3$) | Propane | Diluent |
|---|---|---|
| January | 0.0 | 0.0 |
| February | 0.0 | 0.0 |
| March | 0.0 | 0.0 |
| April | 0.0 | 0.0 |
| May | 149.6 | 8.6 |
| June | 315.1 | 52.9 |
| July | 0.0 | 0.0 |
| August | 0.0 | 0.0 |
| September | 9.2 | 56.4 |
| October | 0.0 | 0.0 |
| November | 0.0 | 0.0 |
| December | 0.0 | 0.0 |
| **Total 2014** | **473.9** | **117.9** |

[1]Injectant volumes indicate delivered to the reservoir and do not include 434.6 [$m^3$] of diluent used in the surface facilities

**Table 2 – Material Balance Data – Production**

| **Produced Volumes[1] ($m^3$)** | **Bitumen** | **Water** | **Sol'n Gas** | **Propane** | **Diluent** |
|---|---|---|---|---|---|
| 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| June | 6.5 | 0.0 | 0.0 | 22.7 | 3.1 |
| July | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| August | 21.9 | 0.1 | 0.0 | 26.6 | 9.7 |
| September | 14.5 | 0.0 | 0.0 | 17.0 | 15.0 |
| October | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| November | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| December | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total 2014** | **42.9** | **0.1** | **0.0** | **66.4** | **27.8** |

[1]Produced volumes indicate recovered from the reservoir and do not include 434.6 [$m^3$] of diluent used in the surface facilities

**Table 3: 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 4: 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 5: 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%) | 1000 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 6: Price Assumptions for Revenue Calculations**

| | Bitumen $/bbl | Natural Gas $/mcf | Pilot Diluent[1] $/bbl | Propane[1] $/bbl |
|---|---|---|---|---|
| 2014 | 67.20 | 4.54 | 101.08 | 53.42 |

[1]Average cost to CSP pilot for 2014

**Table 7: Drilling and Facilities Costs**

| Drilling and Facilities Costs (k$) | 2014 |
|---|---|
| Preliminary Engineering | 0 |
| Surface Facilities | 3,278 |
| OB Well Drilling | 0 |
| HW Drilling | -4 |
| Completions | 1,316 |
| Geo Surveillance | 0 |
| **Total Drilling and Facilities Costs** | **4,591** |

**Table 8: Operating Costs**

| Direct and Indirect Operating Costs (k$) | 2014 |
|---|---|
| Operating Costs | 1,649 |
| **Total** | **1,649** |

**Table 9: Injectant Costs**

| Injectant Costs (k$) | 2014 |
|---|---|
| Propane | 343 |
| Diluent | 433 |
| **Total** | **776** |

**Table 10: Estimated Crown Royalty Calculation**

| Crown Royalties (k$) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|---|---|
| Pilot Revenue[1] | 0 | 0 | 0 | 0 | 0 | 334 | 334 |
| Pilot Costs[2] | 563 | 1,631 | 8,991 | 33,257 | 22,776 | 7,016 | 74,233 |
| CCEMC Credit[3] | | | | 2,400 | 2,480 | 480 | 5,360 |
| Before Royalty Cash Flow | -563 | -1,631 | -8,991 | -30,857 | -20,296 | -6,202 | -68,539 |
| Cold Lake Royalty Rate[4] | 27.8% | 30.9% | 33.8% | 34.2% | 35.4% | 36.8% | - |
| Cold Lake Royalty Impact | -156 | -504 | -3,039 | -10,553 | -7,185 | -2,282 | -24,019 |
| Total Cold Lake Royalties[4] | 438,240[5] | 628,605[5] | 935,665[5] | 678,964[5] | 599,433 | 772,086 | - |

[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

**Table 11: Cumulative Project Costs**

| Cumulative Costs (k$) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|---|---|
| Drilling & Facilities Costs | 563 | 1,631 | 8,991 | 33,257 | 22,776 | 4,591 | 71,808 |
| Operating Costs | 0 | 0 | 0 | 0 | 0 | 1,649 | 1,649 |
| Injectant Costs | 0 | 0 | 0 | 0 | 0 | 776 | 776 |
| **Total Costs** | **1,375** | **829** | **8,980** | **33,257** | **22,776** | **7,016** | **74,233** |

**Table 12: Cumulative Project Revenue**

| Cumulative Revenue (k$) | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|---|---|---|
| Bitumen | 0 | 0 | 0 | 0 | 0 | 18 | 18 |
| Solution Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Recovered Propane | 0 | 0 | 0 | 0 | 0 | 22 | 22 |
| Recovered Diluent | 0 | 0 | 0 | 0 | 0 | 294 | 294 |
| **Total Revenue** | **0** | **0** | **0** | **0** | **0** | **334** | **334** |

[1] Estimated, see section 8.2 for assumptions

**Figure 1: Well Layout**

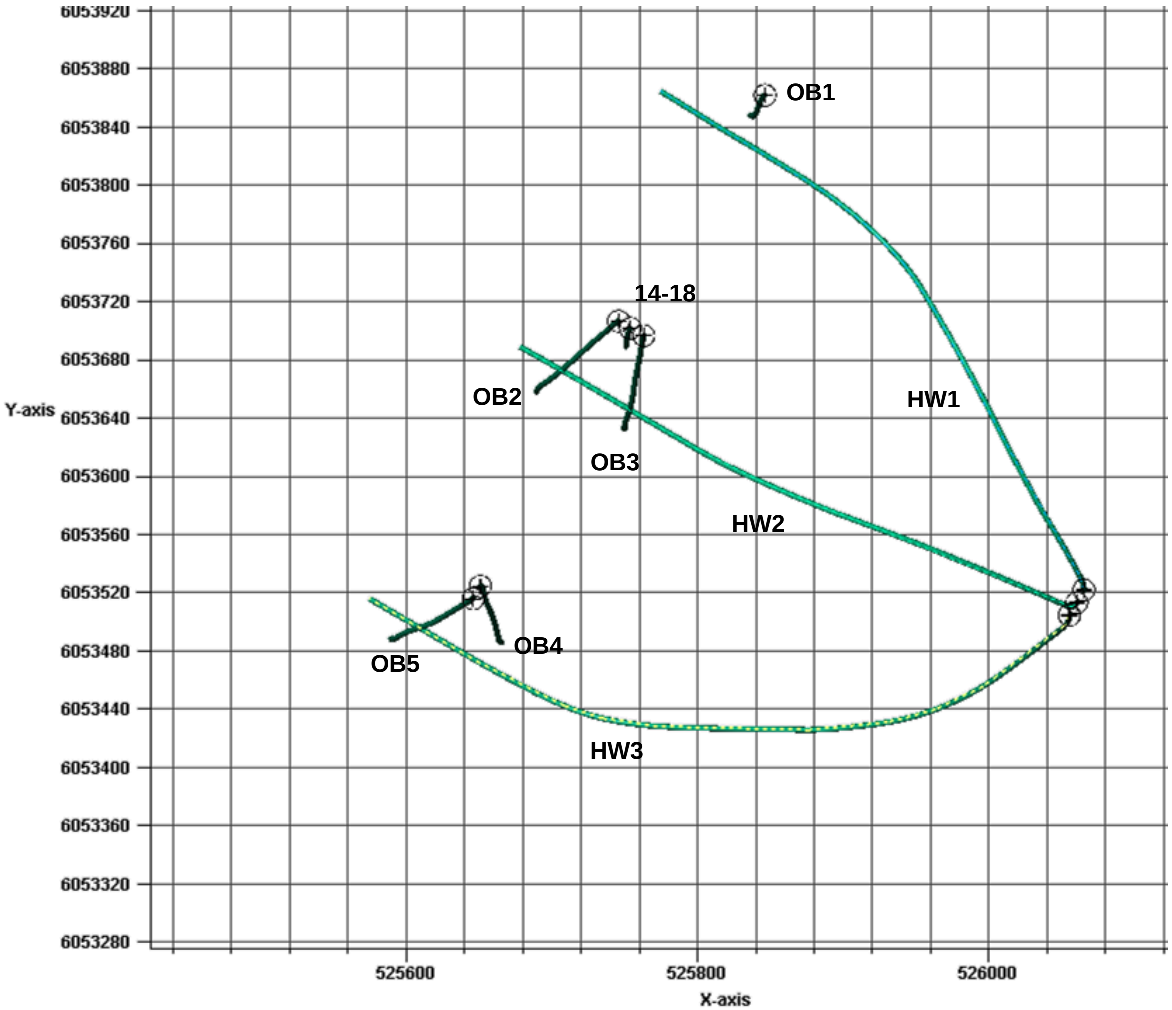


**Figure 2: Surface Facility and Pad Locations**

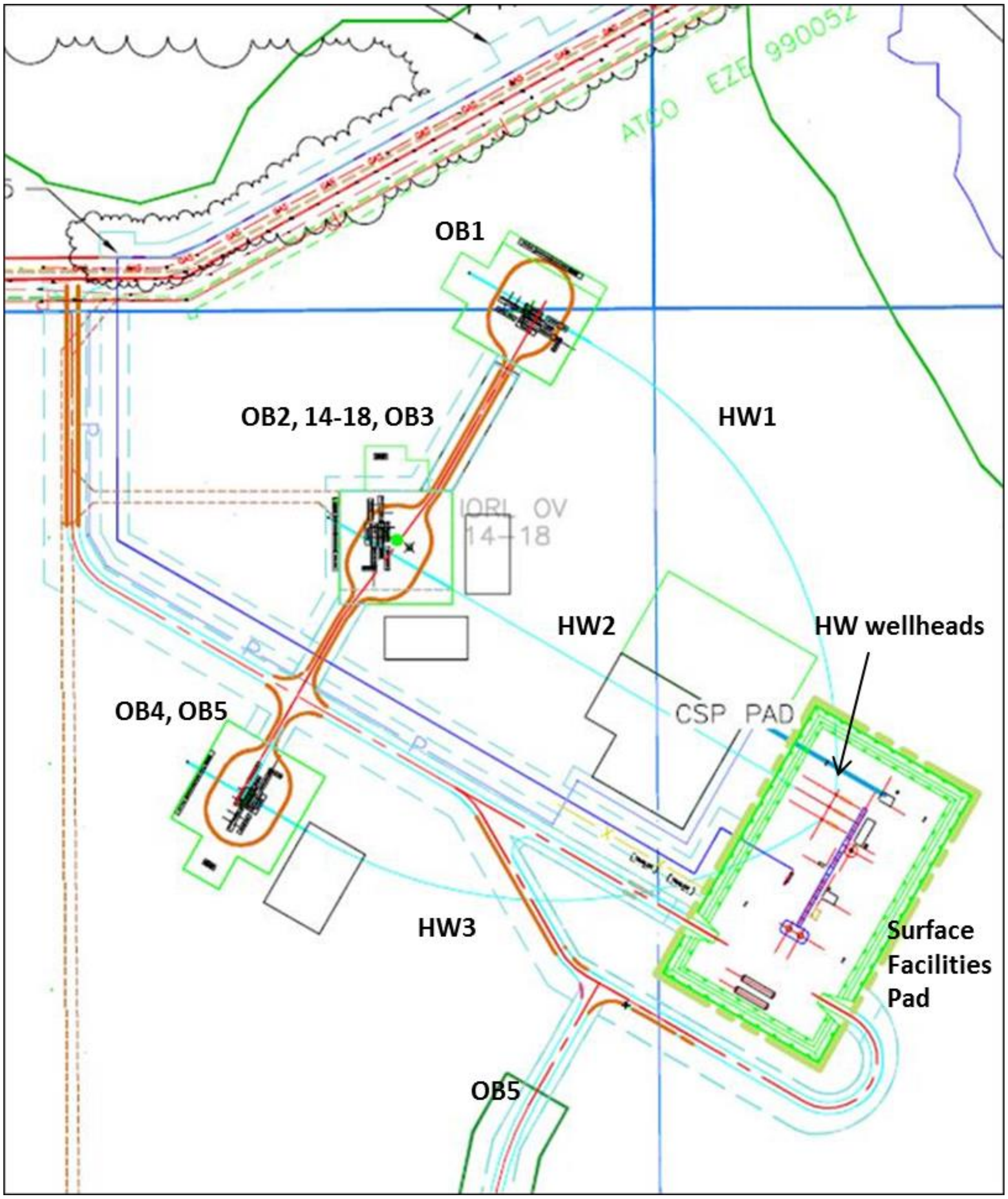
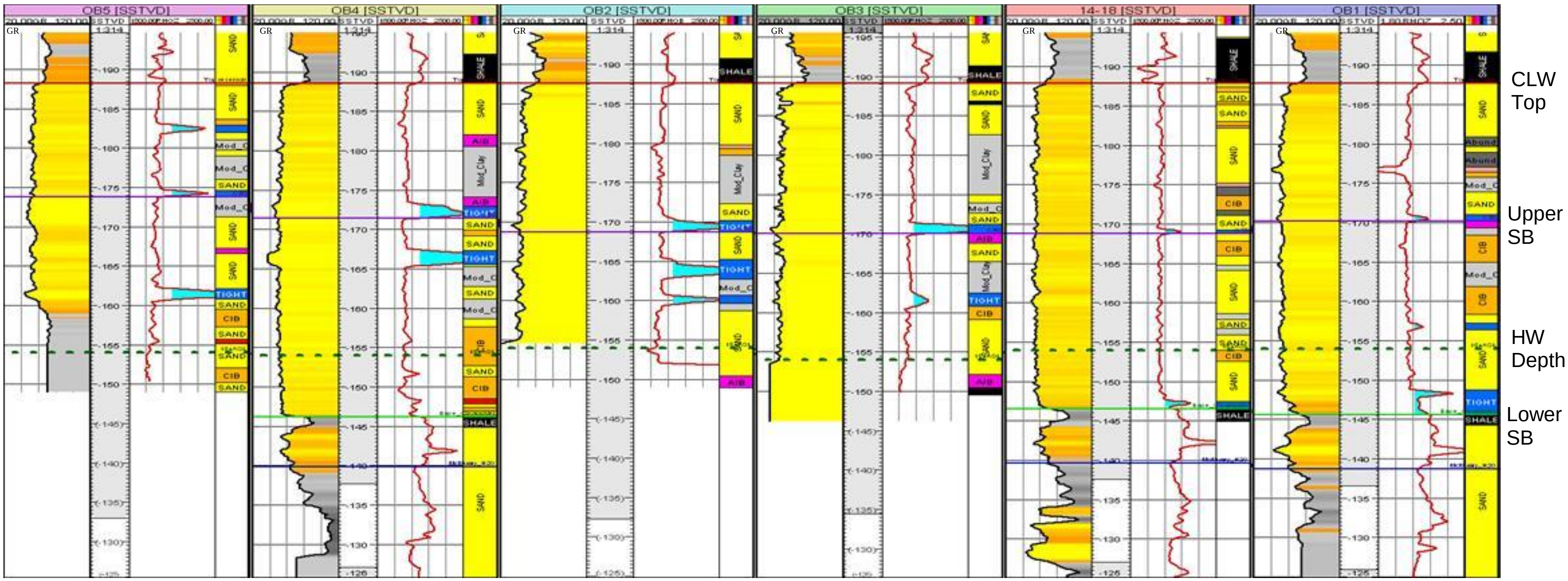
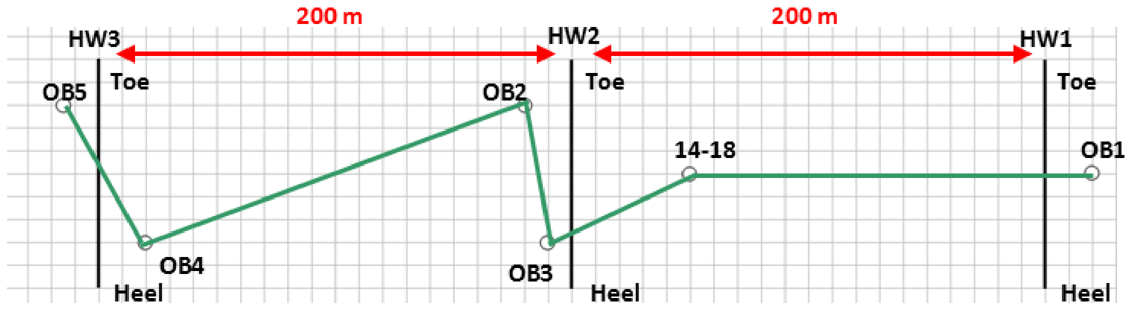


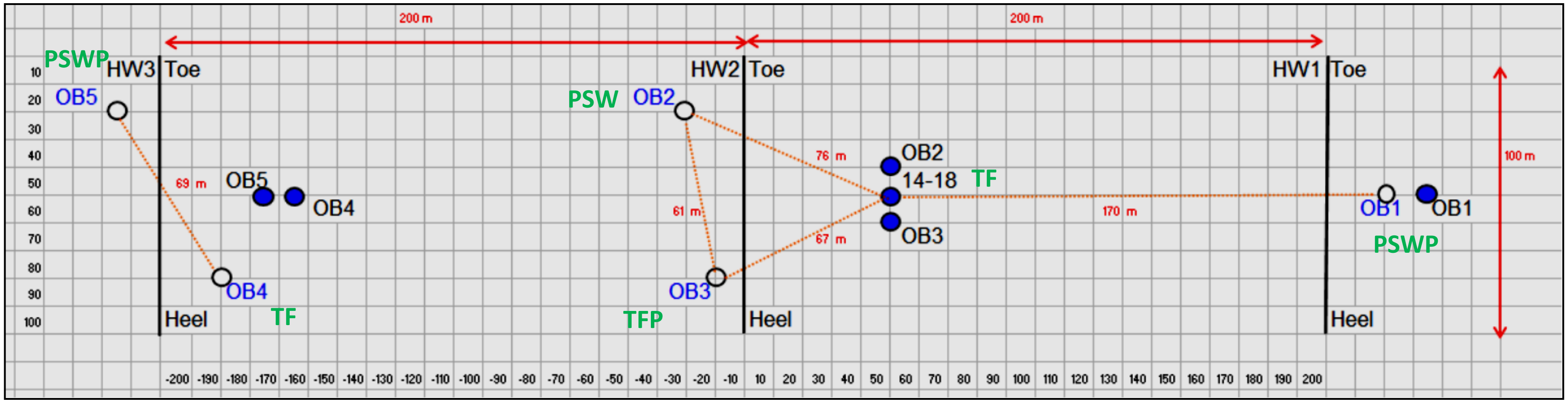
**Figure 3: Log Cross Section of Pilot Area through OB Wells**




-

**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**

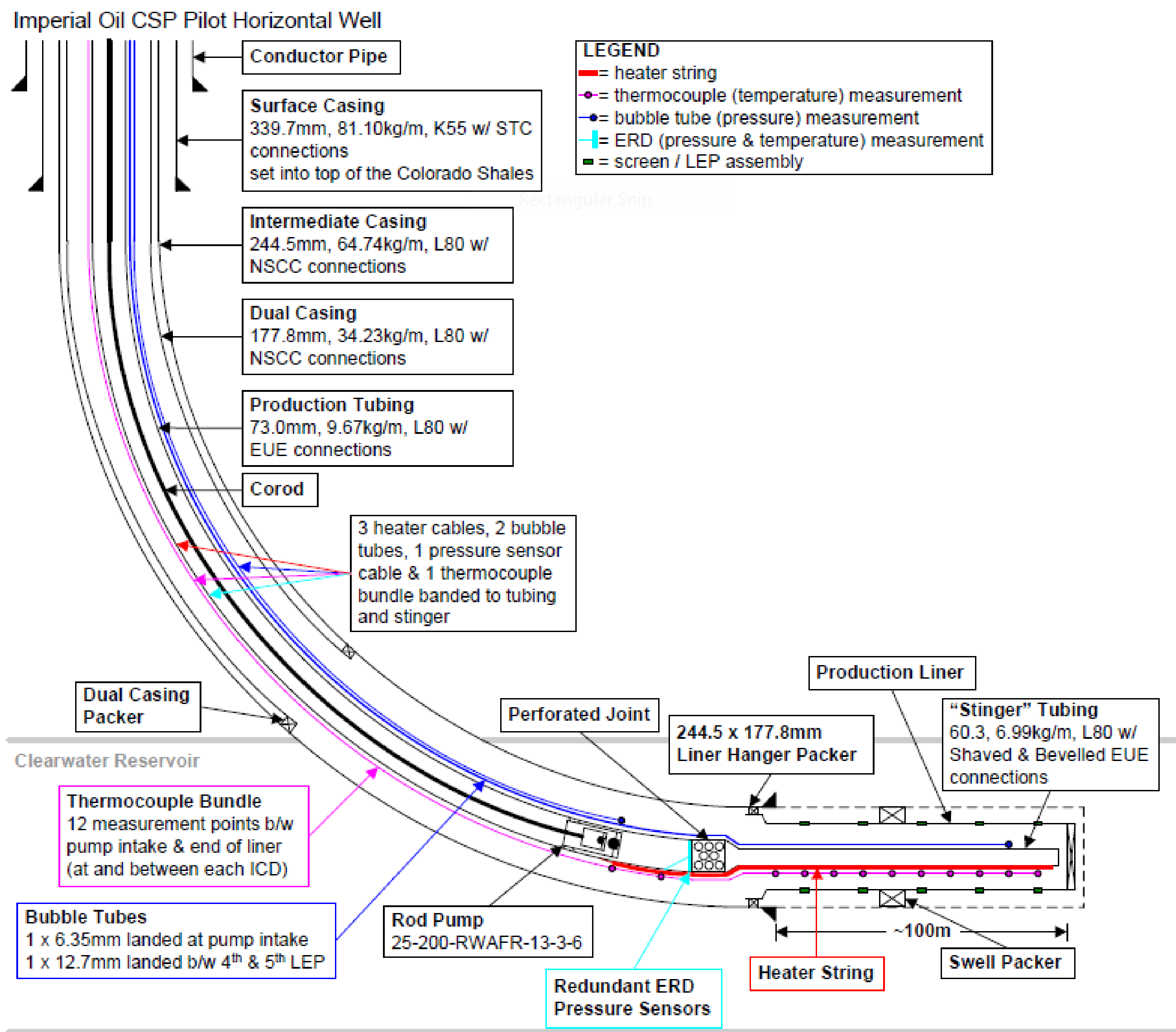


**Figure 6: CSP Pilot Site View**

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

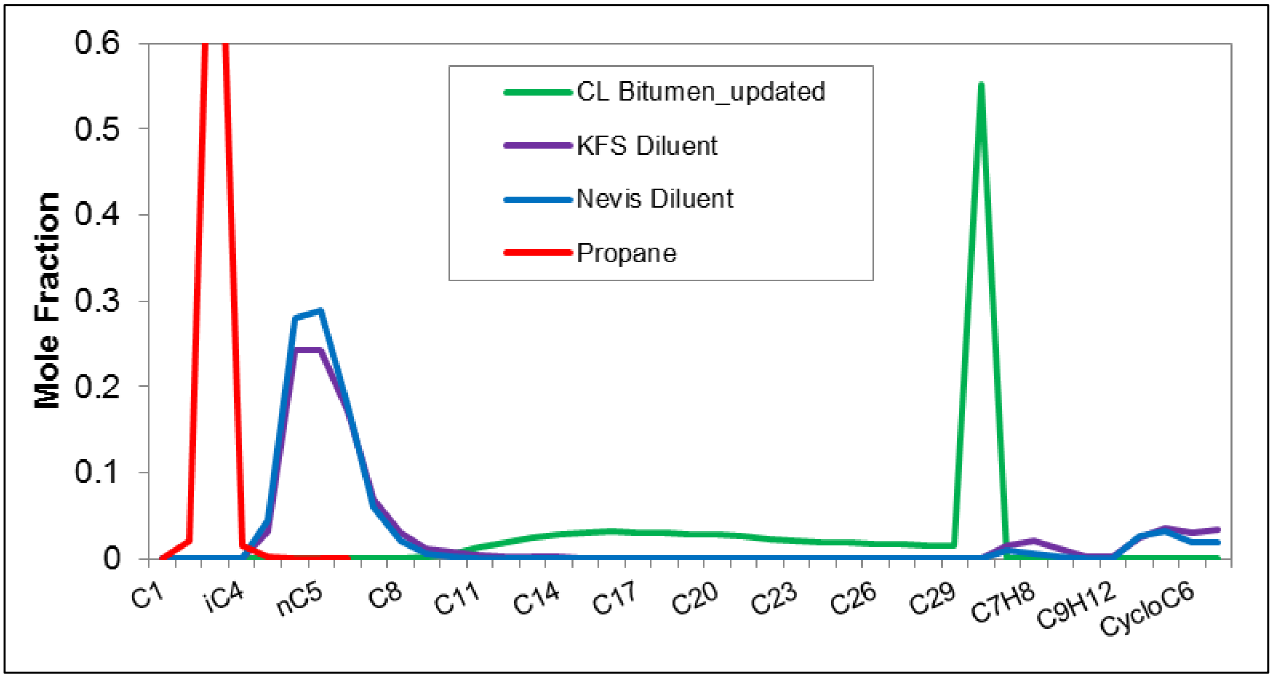
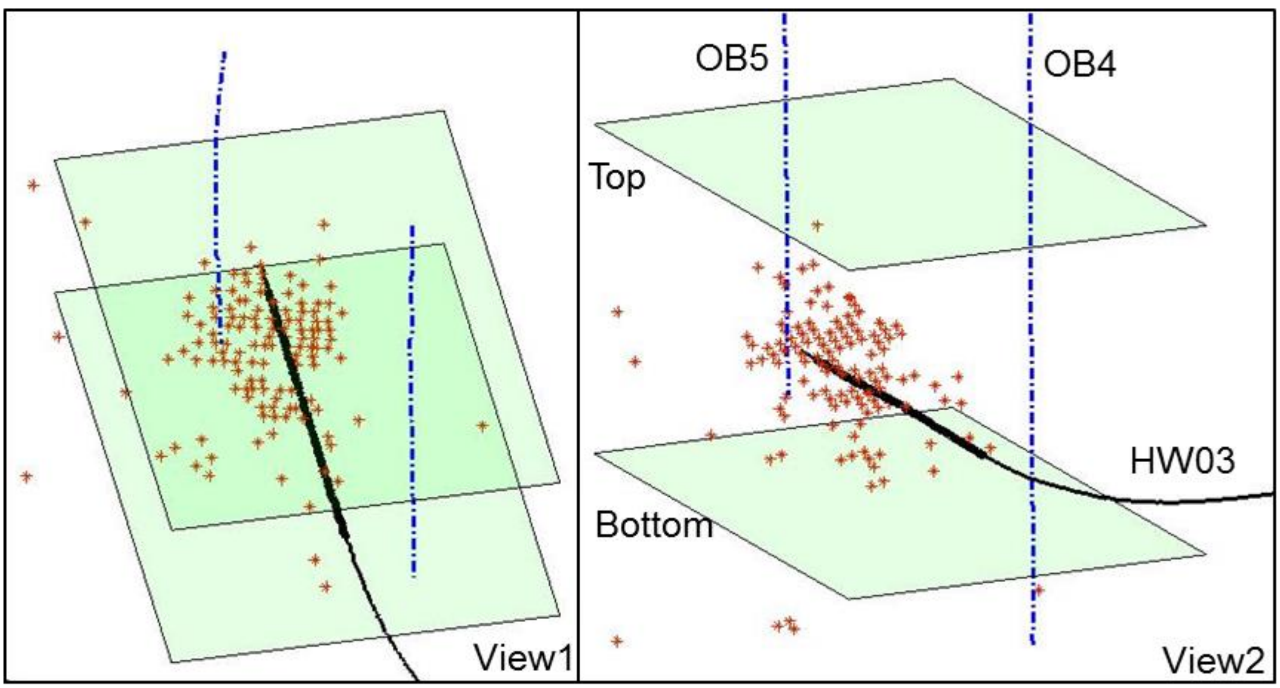
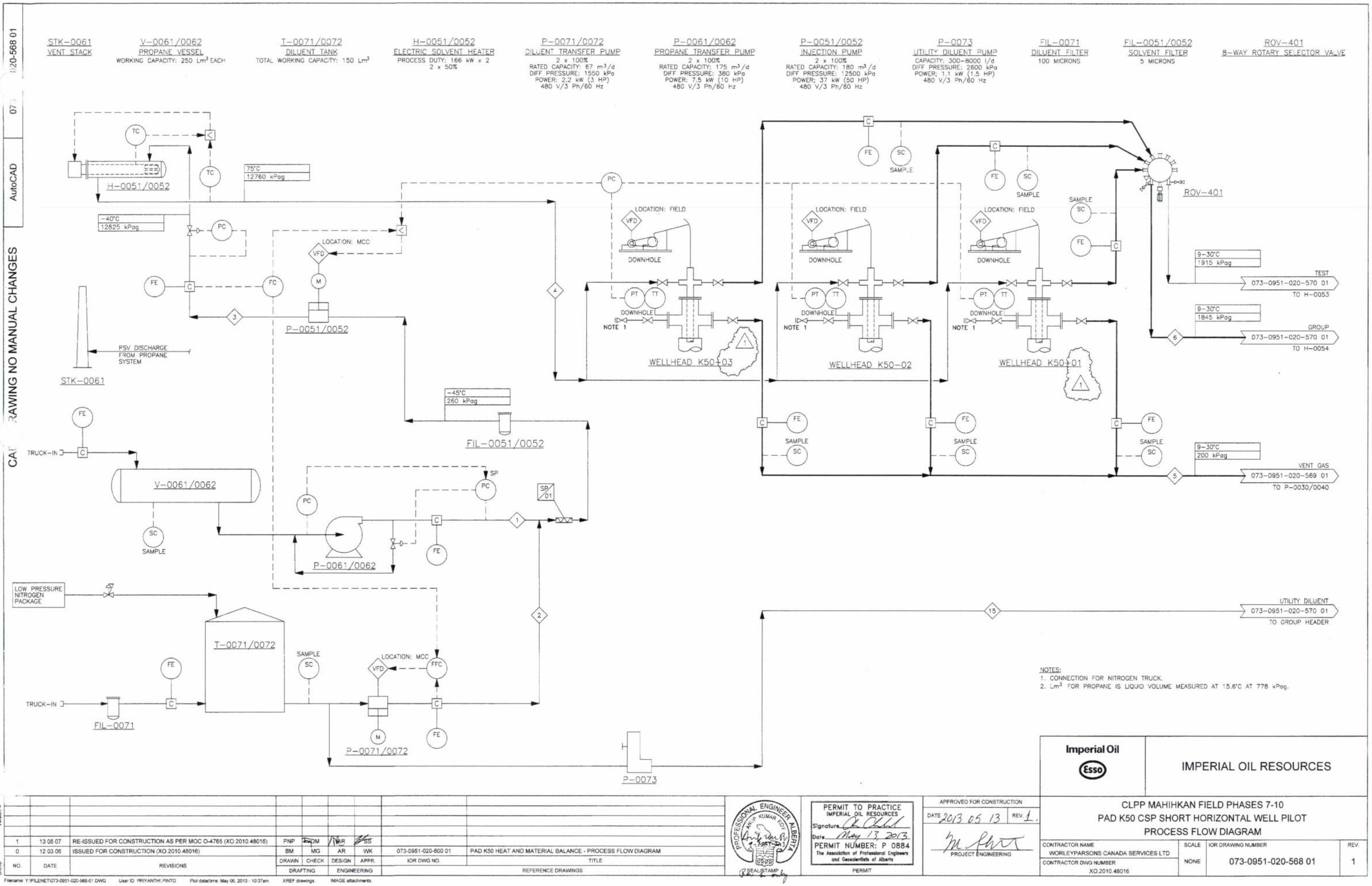



**Figure 8: Passive Seismic Event Locations for HW3 Cycle 1**



# 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
PROCESS DUTY: 166 kW x 2
2 x 50%
P-0071/0072
DILUENT TRANSFER PUMP
2 x 100%
RATED CAPACITY: 67 m³/d
DIFF PRESSURE: 1550 kPa
POWER: 2.2 kW (3 HP)
480 V/3 Ph/60 Hz
P-0061/0062
PROPANE TRANSFER PUMP
2 x 100%
RATED CAPACITY: 175 m³/d
DIFF PRESSURE: 380 kPa
POWER: 7.5 kW (10 HP)
480 V/3 Ph/60 Hz
P-0051/0052
INJECTION PUMP
2 x 100%
RATED CAPACITY: 180 m³/d
DIFF PRESSURE: 12500 kPa
POWER: 37 kW (50 HP)
480 V/3 Ph/60 Hz
P-0073
UTILITY DILUENT PUMP
CAPACITY: 300-8000 l/d
DIFF PRESSURE: 2600 kPa
POWER: 1.1 kW (1.5 HP)
480 V/3 Ph/60 Hz
FIL-0071
DILUENT FILTER
100 MICRONS
FIL-0051/0052
SOLVENT FILTER
5 MICRONS
ROV-401
8-WAY ROTARY SELECTOR VALVE
75°C
12760 kPag
-40°C
12825 kPag
-45°C
260 kPag
LOCATION: MCC
LOCATION: FIELD
DOWNHOLE
NOTE 1
WELLHEAD K50-03
WELLHEAD K50-02
WELLHEAD K50-01
PSV DISCHARGE FROM PROPANE SYSTEM
TRUCK-IN
SAMPLE
LOW PRESSURE NITROGEN PACKAGE
9-30°C
1915 kPag
TEST
073-0951-020-570 01
TO H-0053
9-30°C
1845 kPag
GROUP
073-0951-020-570 01
TO H-0054
9-30°C
200 kPag
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
Esso
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
APPROVED FOR CONSTRUCTION
DATE 2013 05 13 REV. 1
PROJECT ENGINEERING
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date May 13, 2013
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
PERMIT
PROFESSIONAL ENGINEER ALBERTA
ANUP KUMAR ROY
SEAL/STAMP
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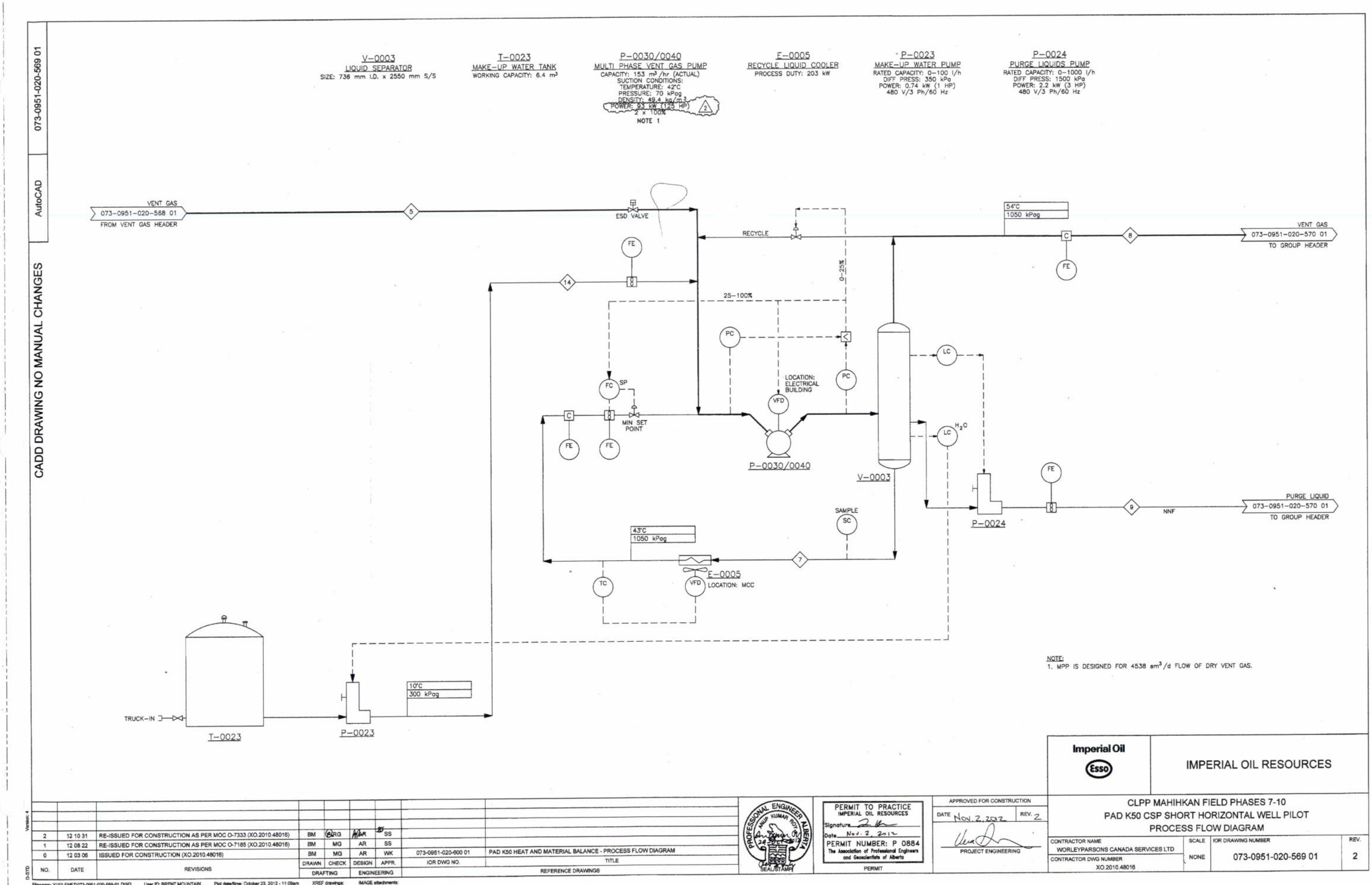

V-0003
LIQUID SEPARATOR
SIZE: 736 mm I.D. x 2550 mm S/S
T-0023
MAKE-UP WATER TANK
WORKING CAPACITY: 6.4 m³
P-0030/0040
MULTI PHASE VENT GAS PUMP
CAPACITY: 153 m³/hr (ACTUAL)
SUCTION CONDITIONS:
TEMPERATURE: 42°C
PRESSURE: 70 kPag
DENSITY: 48.4 kg/m3
POWER: 93 kW (125 HP)
2 x 100%
NOTE 1
E-0005
RECYCLE 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
VENT GAS
073-0951-020-568 01
FROM VENT GAS HEADER
ESD VALVE
RECYCLE
54°C
1050 kPag
VENT GAS
073-0951-020-570 01
TO GROUP HEADER
0-25%
25-100%
LOCATION: ELECTRICAL BUILDING
MIN SET POINT
P-0030/0040
V-0003
PURGE LIQUID
073-0951-020-570 01
TO GROUP HEADER
NNF
P-0024
SAMPLE
43°C
1050 kPag
E-0005
LOCATION: MCC
10°C
300 kPag
TRUCK-IN
T-0023
P-0023
NOTE:
1. MPP IS DESIGNED FOR 4538 sm³/d FLOW OF DRY VENT GAS.
CADD DRAWING NO MANUAL CHANGES
AutoCAD
073-0951-020-569 01
Imperial Oil
Esso
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 073-0951-020-569 01
REV. 2
APPROVED FOR CONSTRUCTION
DATE Nov. 2, 2012 REV. 2
PROJECT ENGINEERING
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date Nov. 2, 2012
PERMIT NUMBER: P 0884
The Association of Professional Engineers and Geoscientists of Alberta
PERMIT
PROFESSIONAL ENGINEER ALBERTA
ANUP KUMAR ROY
SEAL/STAMP
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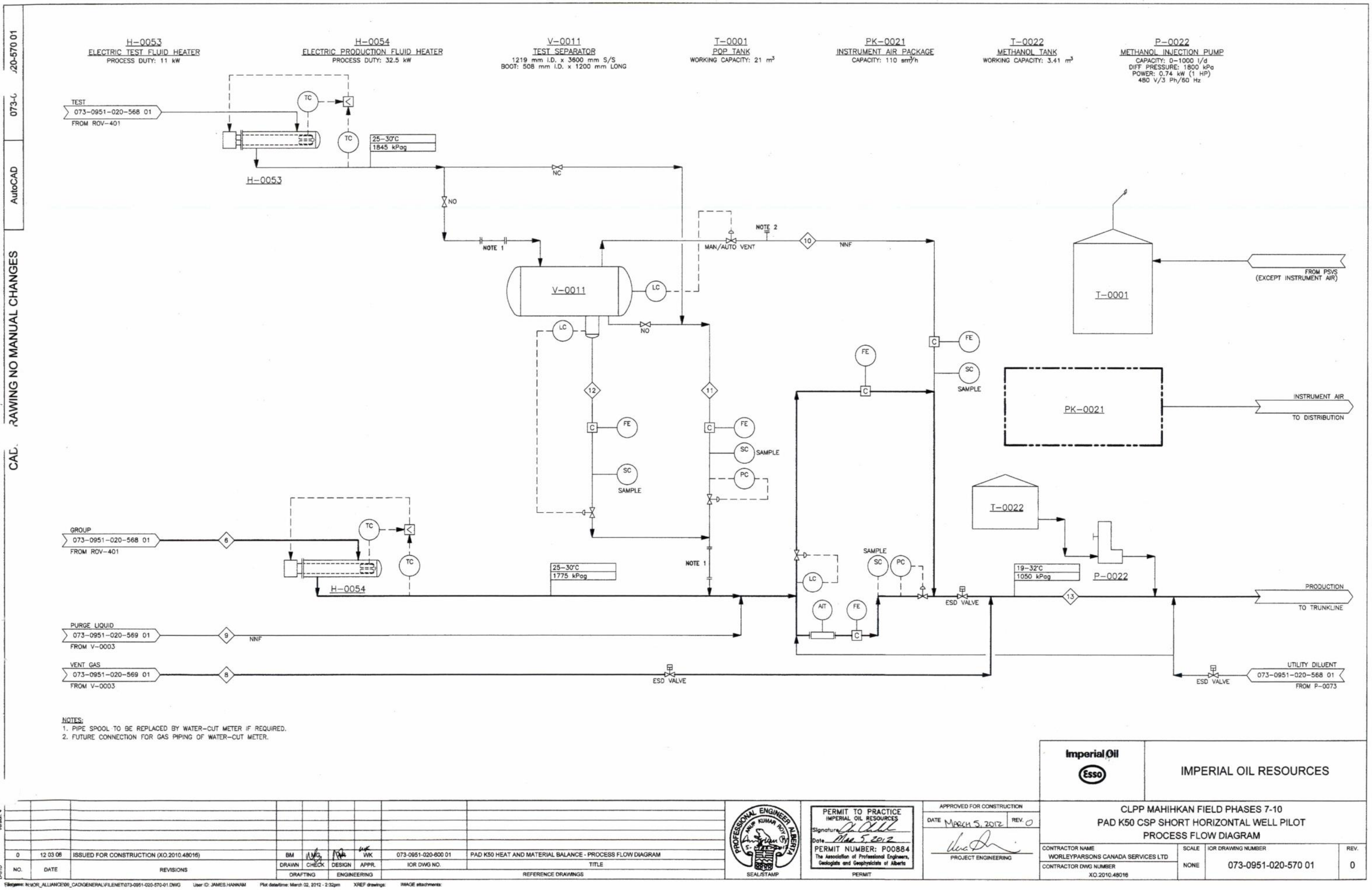
H-0053
ELECTRIC TEST FLUID HEATER
PROCESS DUTY: 11 kW
H-0054
ELECTRIC PRODUCTION FLUID HEATER
PROCESS DUTY: 32.5 kW
V-0011
TEST SEPARATOR
1219 mm I.D. x 3600 mm S/S
BOOT: 508 mm I.D. x 1200 mm LONG
T-0001
POP TANK
WORKING CAPACITY: 21 m³
PK-0021
INSTRUMENT AIR PACKAGE
CAPACITY: 110 sm³/h
T-0022
METHANOL TANK
WORKING CAPACITY: 3.41 m³
P-0022
METHANOL INJECTION PUMP
CAPACITY: 0-1000 l/d
DIFF PRESSURE: 1800 kPa
POWER: 0.74 kW (1 HP)
480 V/3 Ph/60 Hz
TEST
073-0951-020-568 01
FROM ROV-401
25-30°C
1845 kPag
NC
NO
NOTE 1
NOTE 2
MAN/AUTO VENT
NNF
FROM PSVS
(EXCEPT INSTRUMENT AIR)
INSTRUMENT AIR
TO DISTRIBUTION
SAMPLE
GROUP
073-0951-020-568 01
FROM ROV-401
25-30°C
1775 kPag
19-32°C
1050 kPag
ESD VALVE
PRODUCTION
TO TRUNKLINE
PURGE LIQUID
073-0951-020-569 01
FROM V-0003
VENT GAS
073-0951-020-569 01
FROM V-0003
UTILITY DILUENT
073-0951-020-568 01
FROM P-0073
NOTES:
1. PIPE SPOOL TO BE REPLACED BY WATER-CUT METER IF REQUIRED.
2. FUTURE CONNECTION FOR GAS PIPING OF WATER-CUT METER.
Imperial Oil
Esso
IMPERIAL OIL RESOURCES
CLPP MAHIHKAN FIELD PHASES 7-10
PAD K50 CSP SHORT HORIZONTAL WELL PILOT
PROCESS FLOW DIAGRAM
0 12 03 06 ISSUED FOR CONSTRUCTION (XO.2010.48016) BM WK
073-0951-020-600 01 PAD K50 HEAT AND MATERIAL BALANCE - PROCESS FLOW DIAGRAM
PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
APPROVED FOR CONSTRUCTION
DATE March 5, 2012 REV. 0
PROJECT ENGINEERING
CONTRACTOR NAME
WORLEYPARSONS CANADA SERVICES LTD
CONTRACTOR DWG NUMBER
XO.2010.48016
SCALE NONE
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CAD DRAWING NO MANUAL CHANGES
AutoCAD
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