IETP Application No. 03-047

Imperial Oil Resources - Cold Lake Solvent Assisted - SAGD Pilot

2009 Annual Project Technical Report

Confidential under IETP Agreement

Table of Contents

List of Appendices

Appendix A: Process Flow Diagrams (PFDs) and Site Maps

1 Abstract

Imperial Oil Resources (Imperial) is conducting a Solvent Assisted - Steam Assisted Gravity Drainage (SA -SAGD) experimental pilot scheme at Cold Lake in the Clearwater formation to be operated under Alberta Energy and Utilities Board (AEUB) Approval 10689, dated October 30, 2006.

The experimental process design for the pilot involves the addition of 5 – 20% by volume of hydrocarbon solvent (diluent) along with the injected dry steam in a dual horizontal well SAGD configuration. Work performed by the Alberta Research Council (ARC)[1] and by Imperial indicates that the addition of solvent to the steam results in increased bitumen rates and decreased steam oil ratios relative to the conventional SAGD process. The ES-SAGD process has been patented by ARC and Imperial has use rights to the technology through partial funding of the development work.

The pilot includes two horizontal well pairs (four wells), six observation wells, associated steam and diluent injection facilities, artificial lift, as well as, production measurement and testing facilities. The SA-SAGD pilot will use existing steam generation, water treatment, bitumen separation and processing facilities at Imperial's Mahkeses plant, as well as, the existing steam distribution and production gathering system.

The pilot operation is expected to last up to five years.

This report summarizes progress that was made in 2009. Facility construction that began in previous years continued into the majority of 2009. Pilot operation commenced in mid November which consisted of steam injection into all wells to begin the warm-up phase. As a result of the late year start-up, operational data in this report is limited.

[1] Nasr, T.N., Beaulieu, G., Golbeck, H., and Heck, G.: "Novel Expanding Solvent – SAGD Process "ES-SAGD"", JCPT January 2003, Volume 42, and No.1.

2 Summary Project Status Report

2.1 Members of the project team

The following are key members of the SA-SAGD team, with changes from the original application identified:

Tom Boone, PhD, P.Eng – Manager, Oil Sands Recovery Research
Ali Jaafar, P.Eng (replacing Lynn McIntyre) – SA-SAGD Pilot Engineer
Jeff Yerian, PhD (new addition) – SA-SAGD Pilot Engineer
Darrel Perlau, P.Eng – Thermal Solvent Research Lead
George Scott, P.Eng – Senior Reservoir Advisor
Brian Speirs, P.Eng – Research Advisor
Andrew Hodgetts, P.Eng – Project Manager

2.2 Key activities

Key activities undertaken in 2009 include:

January – November, 2009: Continuation of surface facility construction
November 5, 2009: Pad turned over to operations
November 17, 2009: First steam-in, SAGD circulation phase begun into both well-pairs
December 4 - 5, 2009: OV 08-30 abandonment – direction from ERCB to maintain lower (4.5 MPa) bottom-hole pressures while abandonment work was being carried out
December 5, 2009: T13-03 shut-in, failure to achieve required bottom-hole pressure
December 7, 2009: Pad shut in due to facility issues
December 19, 2009: Re-started steam injection
December 20, 2009: Pad shut in due to facility issues

2.3 Production, and material and energy balance flow sheets

Gross balances

Electricity consumed:

- Electricity consumption at the pad was not measured in 2009. Imperial will begin measuring monthly pad electricity consumption in the future. Electricity is generated at Imperial's Mahkeses plant.

Steam:

- Steam for the SA-SAGD pilot was generated at the Mahkeses plant in Cold Lake, which falls outside of the IETP project scope.

Produced Materials

Produced water (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Nov-09	36.8	54.1	55.2	65.1
Dec-09	319.5	460.5	493.8	616.5

Volume disposed:

- There are no disposal wells included in this IETP project

Produced oil (by well, in m^3):

- No oil was produced in any well in 2009. The standard API of Cold Lake oil is 9.

Diluent (purchased, in m^3):

- No diluent was purchased in 2009.

Sales Oil (by well, in m^3):

- No oil was produced in 2009.

Produced Sand (m^3):

- Sand production is not measured at the pilot, and any sand production is assumed to be negligible.

Produced gas (m^3):

- No gas was produced in 2009.

2.4 Reserves

Industry data and simulation of Petrel-based geologic models supported an ultimate reserves recovery of 445 km^3 (before royalty) from both well pairs. Reserves for T13 will be reviewed after the pilot life.

3 Well Information

3.1 Well Layout Map

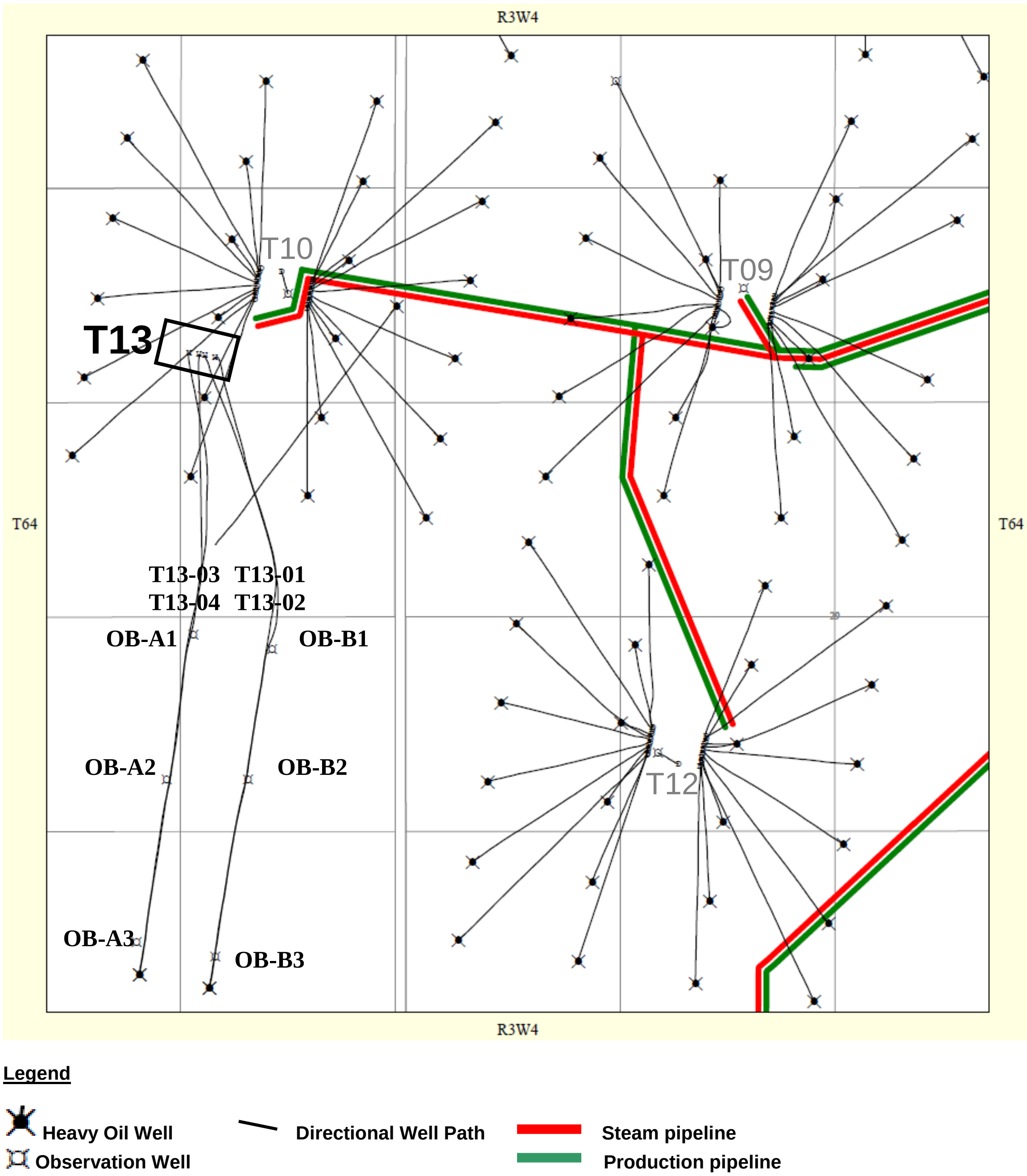


Figure 1: Location of SA-SAGD surface facilities and well trajectories

3.2 2009 drilling, completion, and work-over operations

No drilling or completion work to report for 2009. Drilling and completion work on the four horizontal wells was completed in 2008, and all six observation wells were drilled in the 2006-2007 timeframe.

Remediation activities were conducted in July, 2009 on observation wells OB-A3 and OB-B3 to address hydraulic isolation issues across the aquifers, as per ERCB guidance. Imperial ran casing patches across the perforated (and cement squeezed) intervals, pressure tested the wellbores to 10 MPa, and re-ran the monitoring equipment in both wells. Post remediation bond logs showed significant improvement in cement bond quality and were submitted to the ERCB on July 23, 2009, with the ERCB approving the remediation efforts on the same day.

3.3 Well operation

All four horizontal wells (T13-01, 02, 03, 04) first injected steam on November 17, 2009. For the reminder of the year, the wells were operating under warm-up mode.

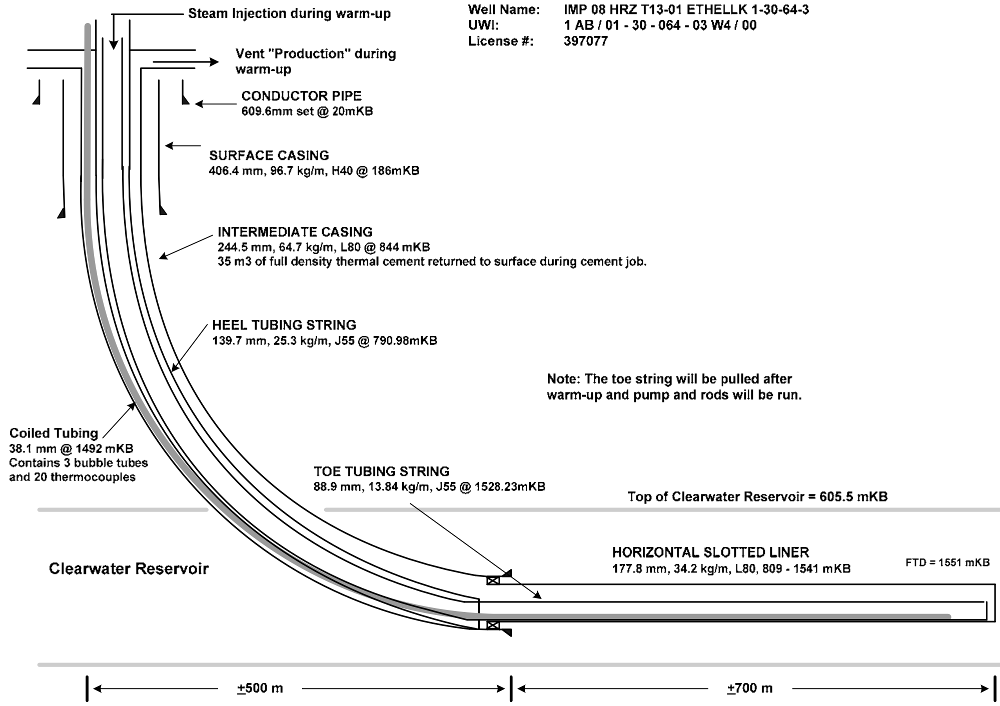
3.4 Well list and status

All wells are currently active. List as follows:

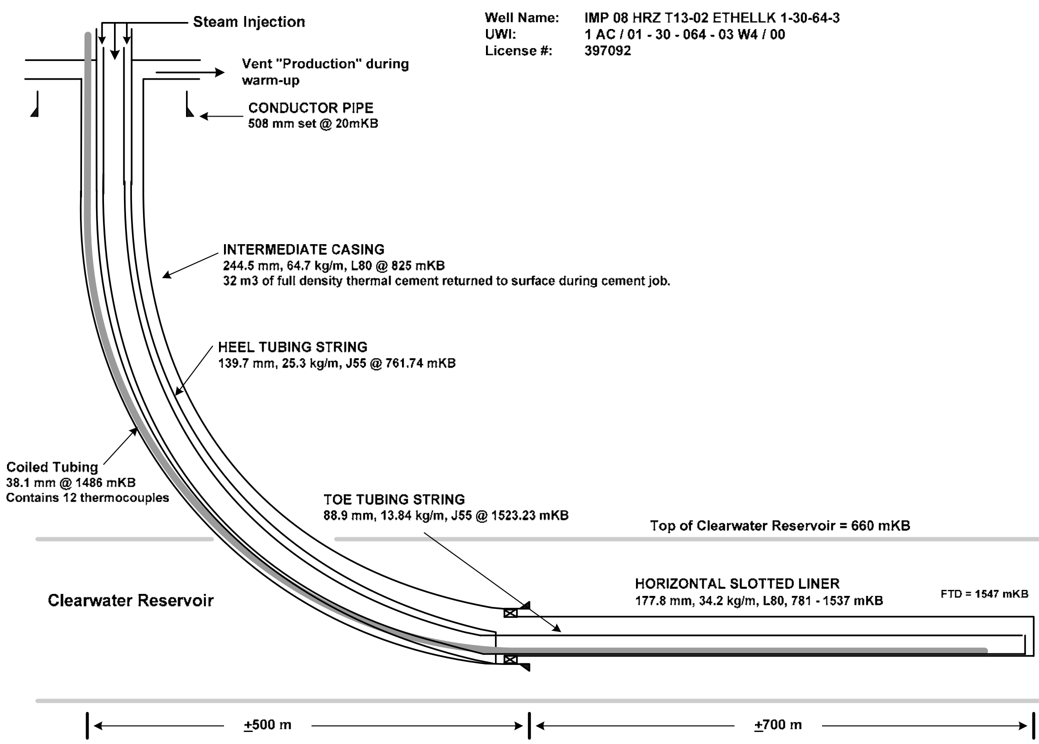
East well pair	1AB/01-30-064-03W4/0 (**T13-01**) producer
	1AC/01-30-064-03W4/0 (**T13-02**) injector
	1AA/08-30-064-03W4/0 (**OB-B1**) observation well
	1AD/08-30-064-03W4/0 (**OB-B2**) observation well
	1AA/01-30-064-03W4/0 (**OB-B3**) observation well
West well pair	1AB/02-30-064-03W4/0 (**T13-03**) producer
	1AC/02-30-064-03W4/0 (**T13-04**) injector
	1AB/08-30-064-03W4/0 (**OB-A1**) observation well
	1AA/07-30-064-03W4/0 (**OB-A2**) observation well
	1AA/02-30-064-03W4/0 (**OB-A3**) observation well

3.5 Wellbore schematics

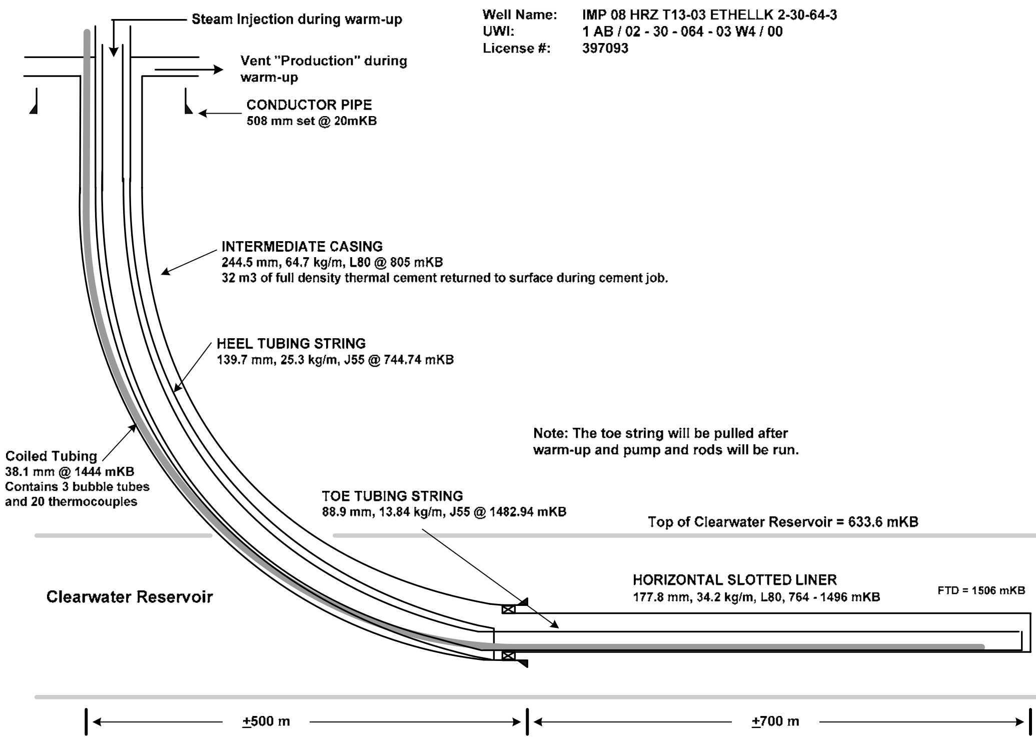
T13-01 (east producer):



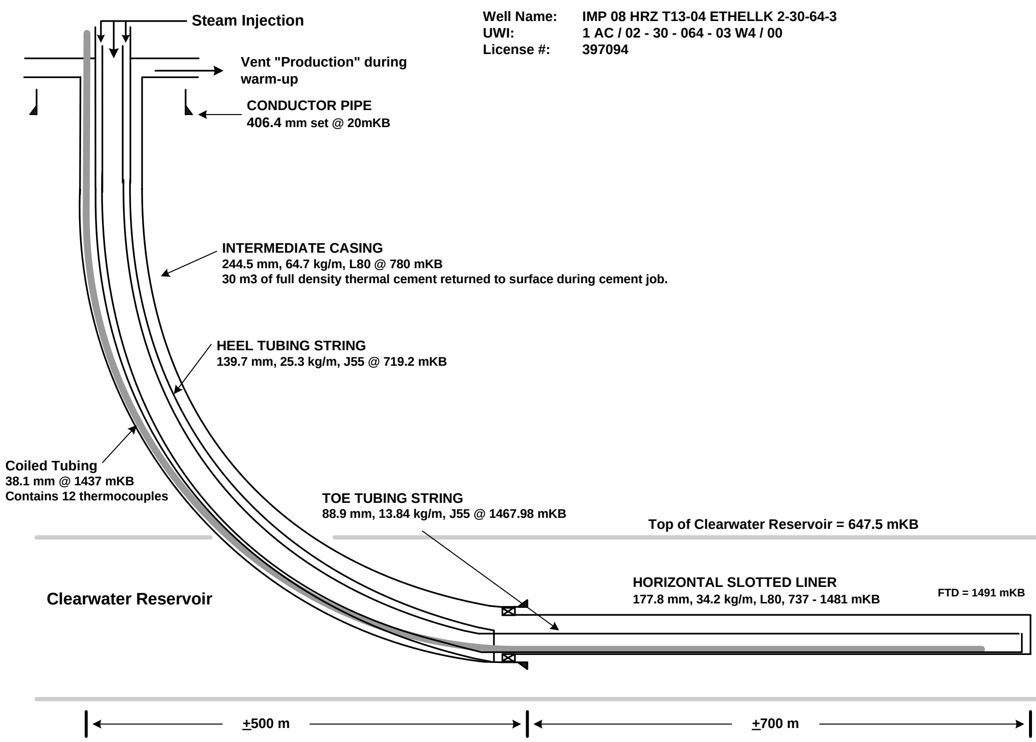
T13-02 (east injector):



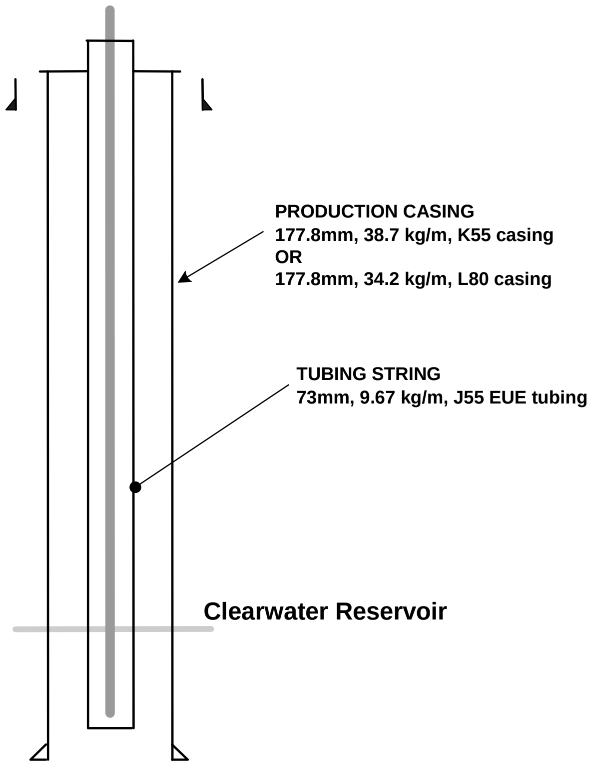
T13-03 (west producer):



T13-04 (west injector):



All six observation wells (fitted with thermocouple bundles installed inside the 73 mm tubing string):



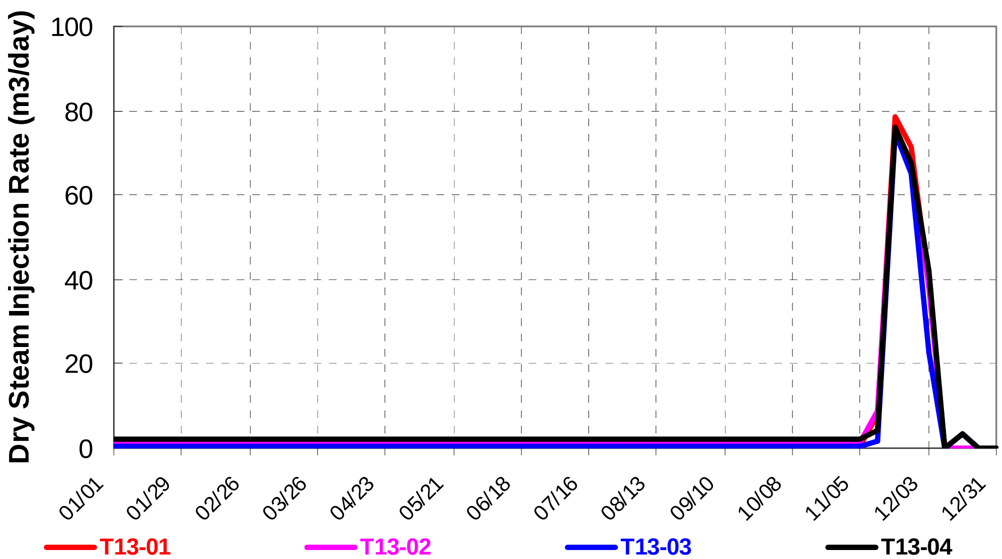
3.6 Spacing and pattern

The horizontal well-pairs are spaced approximately 150 m apart, with approximately 650 m of drainage length per well. This translates into a drainage pattern of approximately 97,500 m^2 (150m * 650 m), which is roughly 24 acres per well.

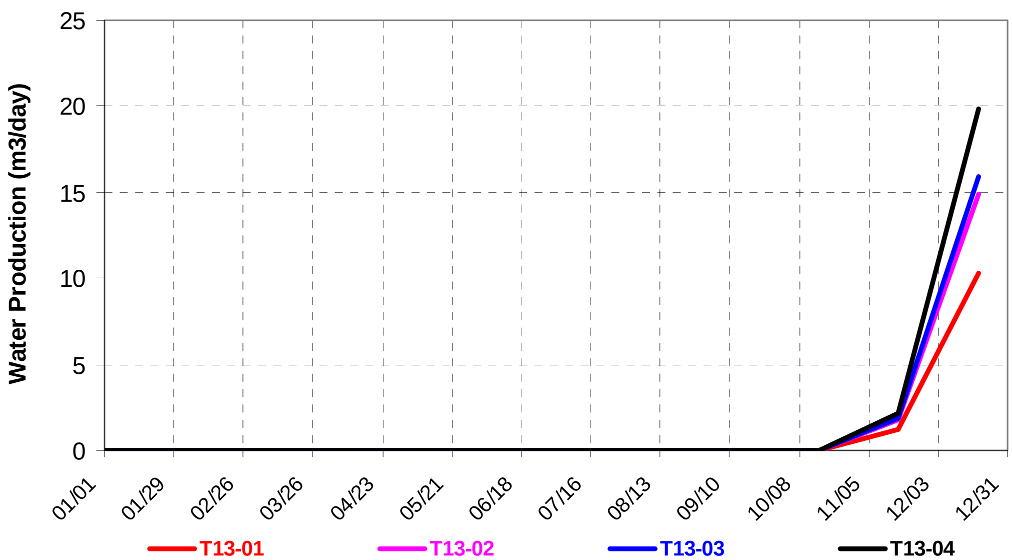
4 Production Performance

4.1 Injection and production history

Steam-in commenced on November 17, 2009. Typical daily rates ranged from 60 - 90 m^3/day per well. Steam injection was stopped on December 7, 2009 due to issues related to the water condensate cooler. Steam injection was re-started into T13-03 and T13-04 on December 17; however, repairs to the cooler were not sufficient. Steam injection was then stopped on December 18 and the pad was shut-in for the rest of 2009. A plot of the weekly average rate for each well is shown below.



Production during 2009 primarily consisted of water from the condensing steam. Metering and visual inspection of the produced fluids indicated no measurable quantities of bitumen. The production estimates from each well (monthly average rates) are shown below.



4.2 Composition of produced / injected fluids

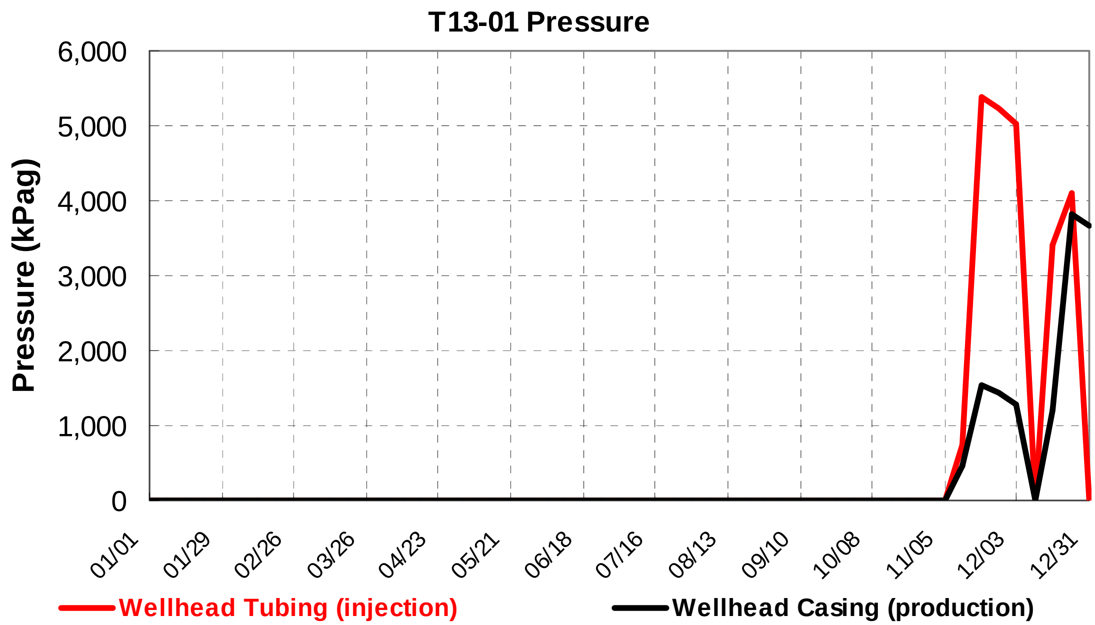
During circulating operations, the composition of the injected fluid consisted only of dry steam. No solvent was injected into any well in 2009. The produced fluids consisted of condensed water.

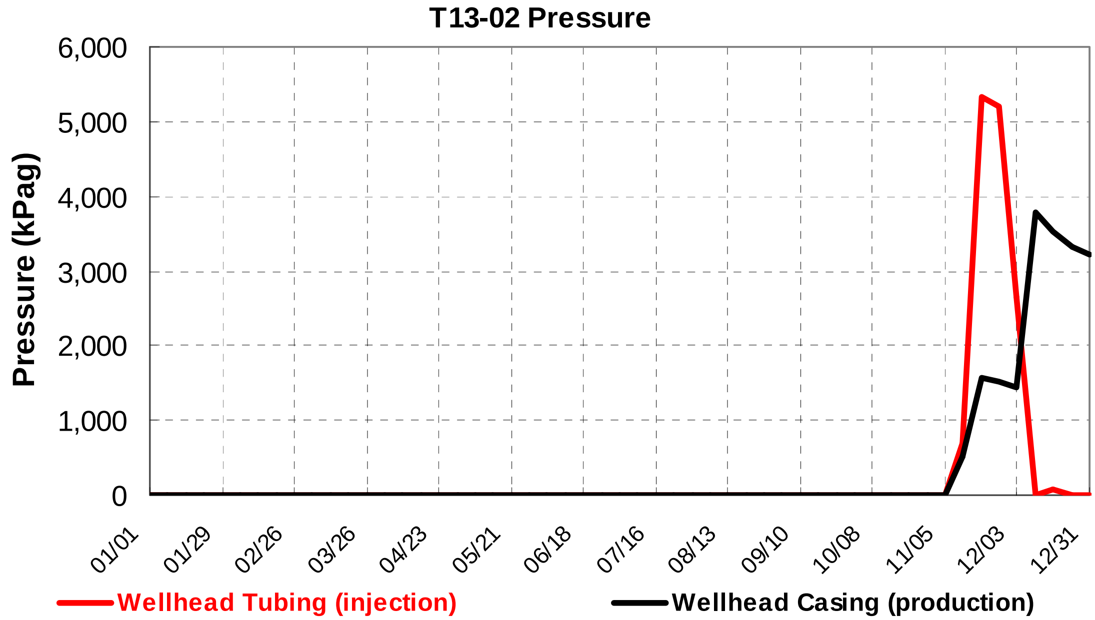
4.3 Predicted vs. actual comparisons

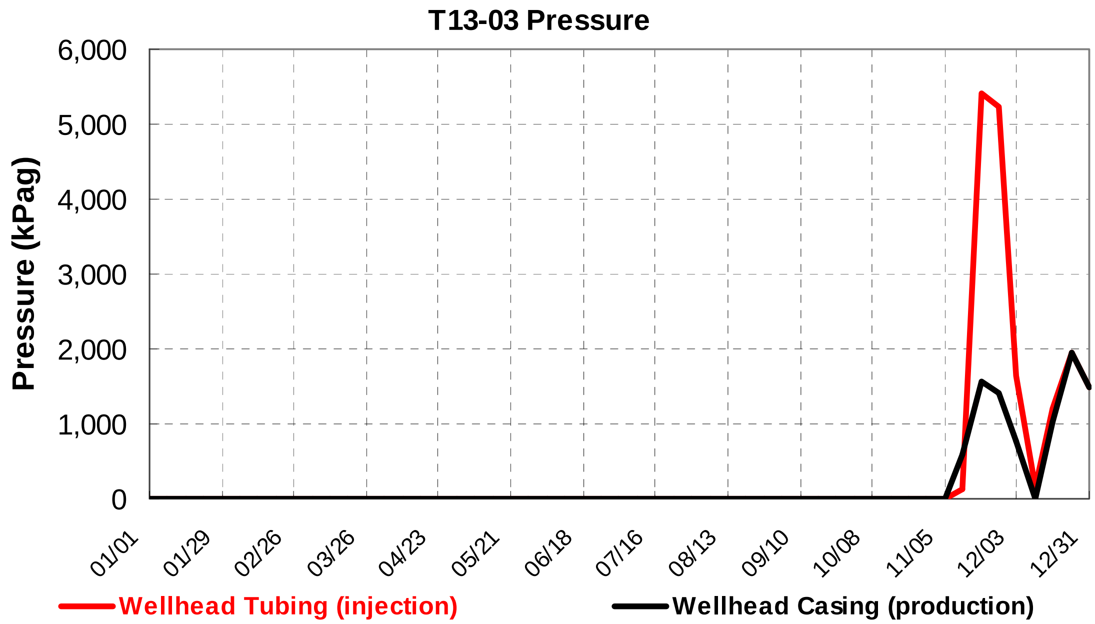
Predicted composition of the produced fluids was consistent with field observations. Initial circulation of steam does not sufficiently warm the nearby reservoir region to mobilize bitumen.

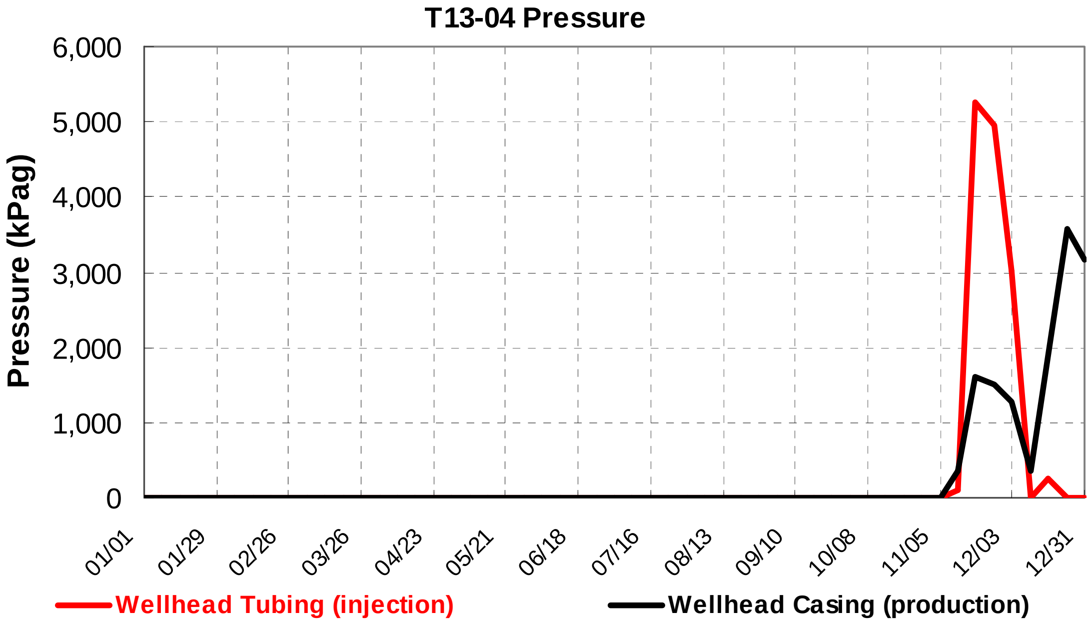
4.4 Pressures

Wellhead injection pressures greater than 5 MPa were required to continuously lift the condensing steam to surface, and into the group production pipeline. The wellhead pressure at the casing (return pressure) was in the 1,200 – 1,500 kPa range during 2009, about 200 kPa greater than group pressure. Plots of the injection and casing wellhead pressure (weekly average) for each well are shown.




T13-02 Pressure
6,000
5,000
4,000
3,000
2,000
1,000
0
Pressure (kPag)
01/01
01/29
02/26
03/26
04/23
05/21
06/18
07/16
08/13
09/10
10/08
11/05
12/03
12/31
Wellhead Tubing (injection)
Wellhead Casing (production)


T13-03 Pressure
6,000
5,000
4,000
3,000
2,000
1,000
0
Pressure (kPag)
01/01
01/29
02/26
03/26
04/23
05/21
06/18
07/16
08/13
09/10
10/08
11/05
12/03
12/31
Wellhead Tubing (injection)
Wellhead Casing (production)

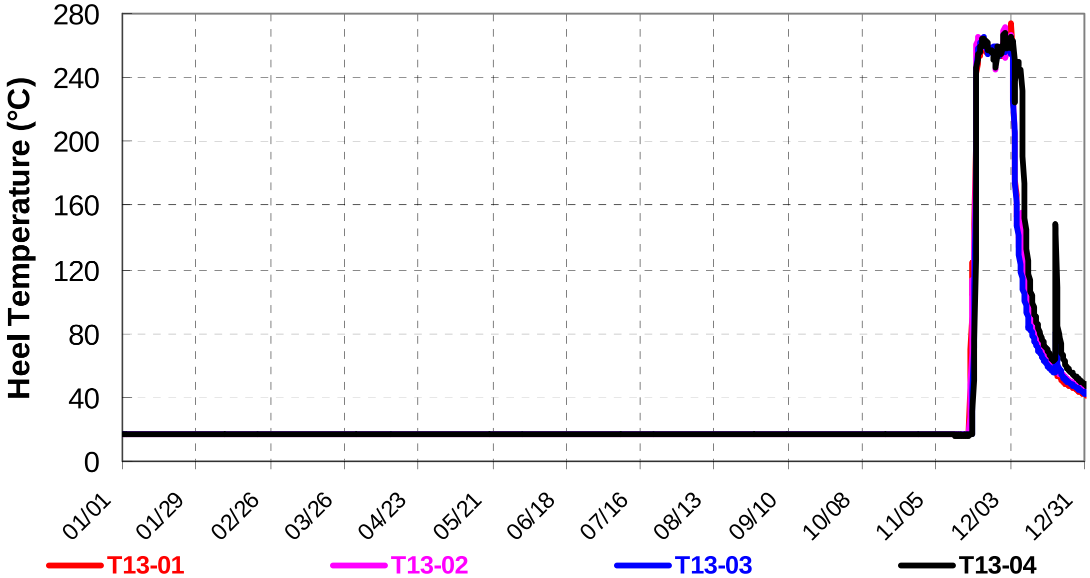

T13-04 Pressure
Pressure (kPag)
6,000
5,000
4,000
3,000
2,000
1,000
0
01/01
01/29
02/26
03/26
04/23
05/21
06/18
07/16
08/13
09/10
10/08
11/05
12/03
12/31
Wellhead Tubing (injection)
Wellhead Casing (production)

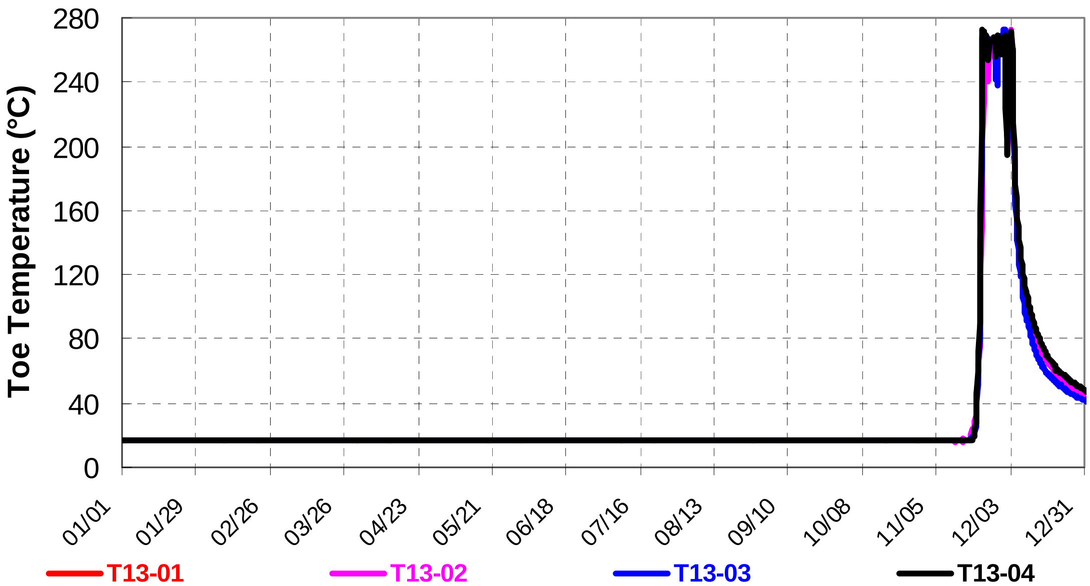
5 Pilot Data

5.1 Additional data

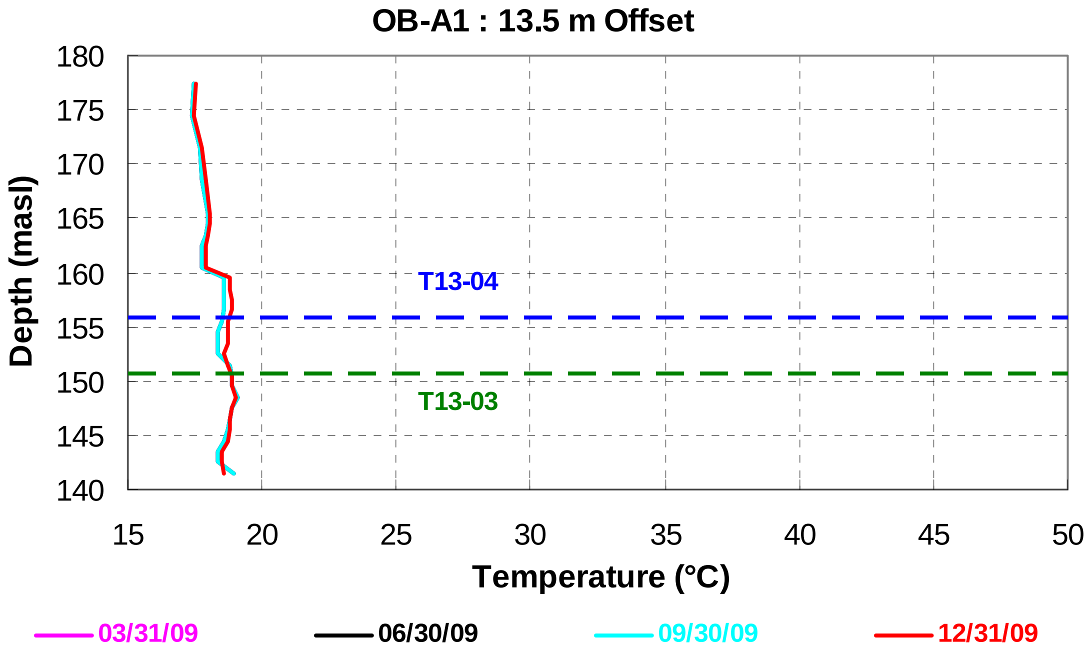
Operations in 2009 focused on warming the reservoir through steam circulation into each wellpair. Beyond pressure and production, additional surveillance data collected during this time included temperature in each horizontal well and all six observation wells.

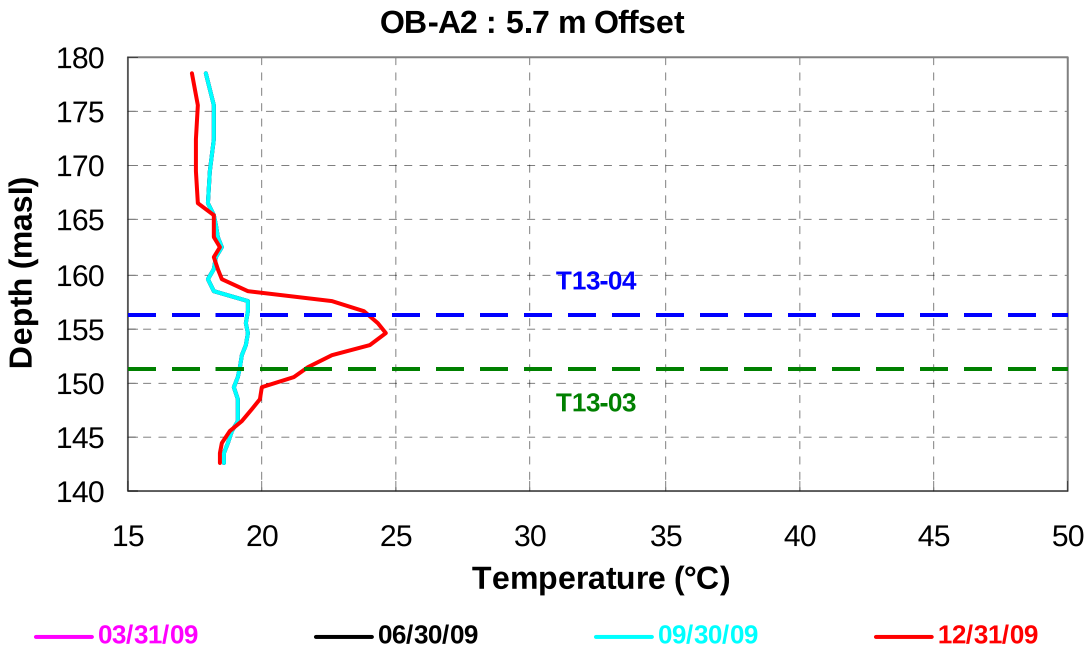
The heel and toe temperature gradually increased as the injected steam pushed through the tubing and up and casing annulus. Steam temperatures at the heel were achieved after 2 days of injection while steam temperatures at toe were achieved after 7 days of injection. The timing of these events was consistent with predictions. Temperatures along the horizontal well at the "heel" and "toe" wells are shown below.

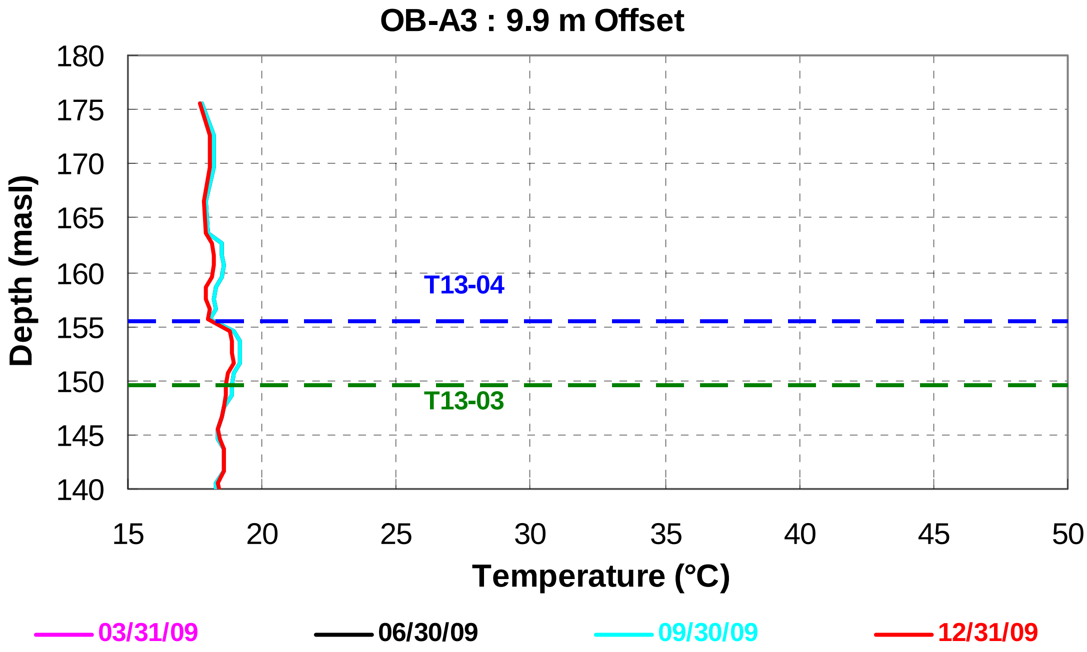


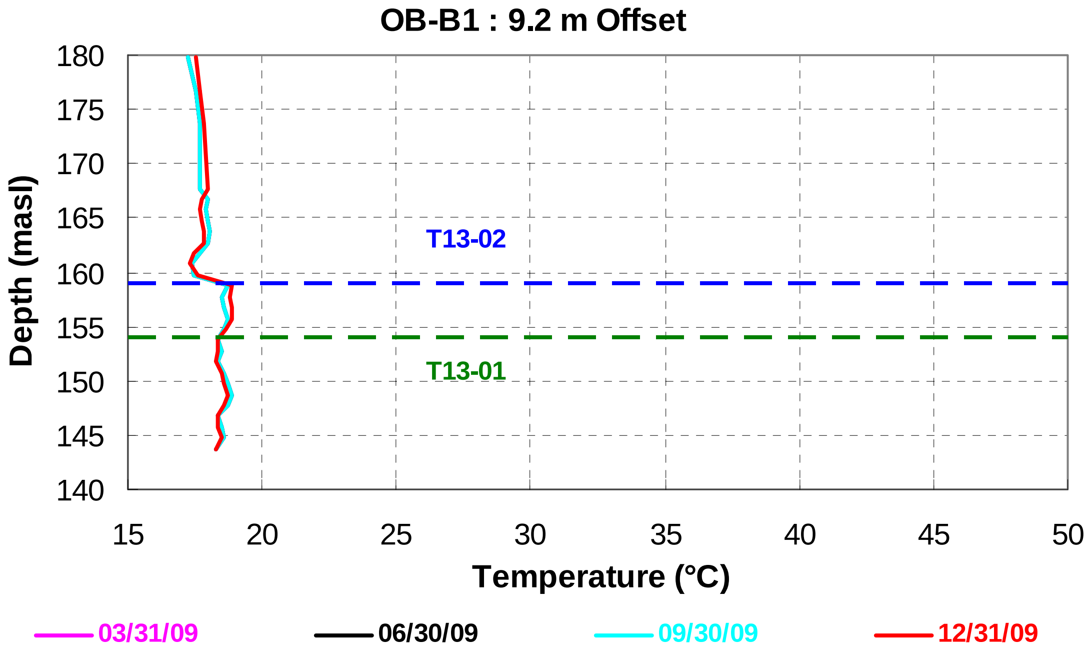


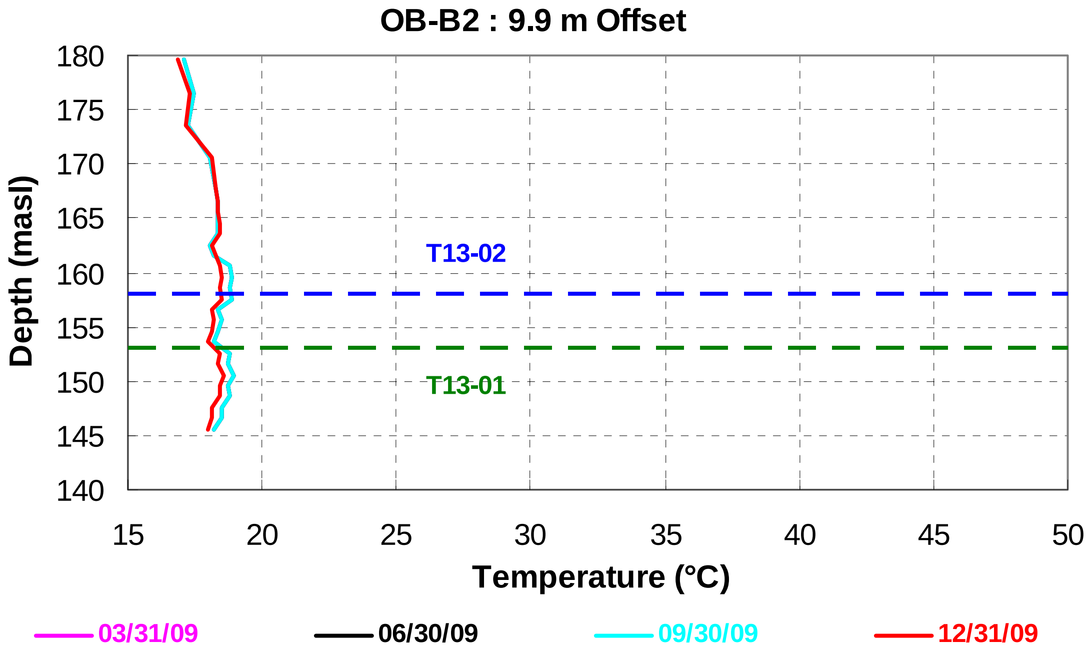
There are six total observation wells, three for each wellpair, that are positioned at the toe, heel, and midpoint of each horizontal wellpair. The offset distance from the horizontal wells varies between 5.7 and 13. 5 m. The temperature at the observation wells provides a measure of the amount of heat transferred to the reservoir. Although steam circulation lasted only 22 days in 2009, there was a significant temperature response seen at OB-A2, the nearest observation well. During steaming, the temperature at OB-A2 remained constant at the initial temperature and then increased to near 25°C after steaming was stopped. This rise in temperature without steam injection into the reservoir demonstrates conductive heating within the reservoir. There was no temperature response observed at any other observation well. The temperature as a function of depth is shown below for each observation well at three-month intervals.

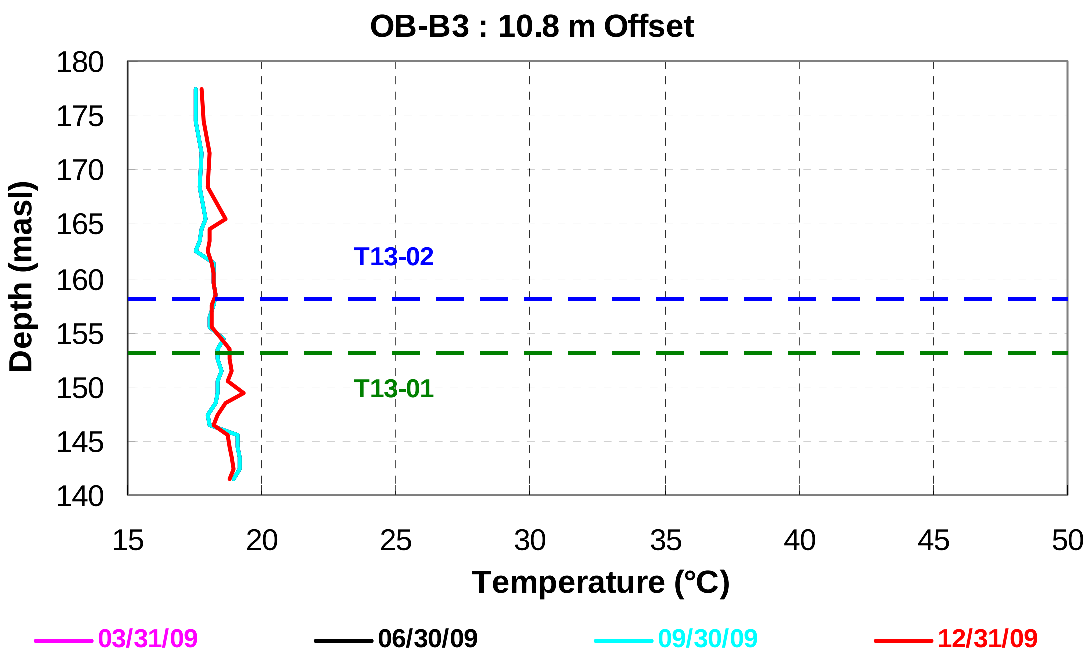





OB-A3 : 9.9 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
15
20
25
30
35
40
45
50
Temperature (°C)
T13-04
T13-03
03/31/09
06/30/09
09/30/09
12/31/09


OB-B1 : 9.2 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
15
20
25
30
35
40
45
50
Temperature (°C)
T13-02
T13-01
03/31/09
06/30/09
09/30/09
12/31/09





Other pilot surveillance data, such as saturation logs, 3D seismic, and tracers, was not planned for 2009.

5.2 Interpretation of pilot data

The extent of reservoir heating can be interpreted from thermocouple data in each horizontal well and six observation wells. After steam circulation is stopped, temperatures within the horizontal wells slowly decline as heat conducts away from the well and into the reservoir. The rate of temperature decline is related to the amount of energy near the wellbore. All four wells show similar decay rates which indicate comparable heating in the reservoir. Temperature increases in the observation wells provides direct indication of reservoir heating. The nearest observation well (OB-A2) is estimated to be 5.7 m from T13-03 and T13-04 and exhibited a temperature increase from 17.5 - 25°C as a result of steam circulation. As noted previously, the temperature increase for OB-A2 occurred while steam injection was stopped, demonstrating conductive heat transfer.

In addition to understanding the heating of the reservoir through steam circulation in the wellbore, pilot data can be used to validate previous estimates. In particular, the modeling of the time required for steam temperature to reach the toe was an important milestone for early operations. Prior to field operation, initial estimates showed that 70 - 90 m^3/day of dry steam circulation was needed to achieve steam-to-toe in 7 - 10 days. Field operations were consistent with these predictions as all four wells achieved steam-to-toe within 7 days. The maximum pressure needed to lift the condensing water for each wellbore was also predicted prior to field operations. Predictions showed that 5.5 - 6.0 MPa were required to lift the water to surface, consistent with field observations.

6 Pilot Economics

6.1 Sales volumes of natural gas and by-products

No natural gas was produced in 2009.

6.2 Revenue

No revenue was incurred in 2009 as the wells were injecting steam and producing only water during the November to December timeframe.

6.3 Capital costs

The following table summarizes capital costs by category, incurred up to year end 2009:

Category	Description and Details of Capital Costs	Cost (C$M)
Facilities	Drilling	0.05
	Surface Facilities (Steam injection facilities, separator; chemical injection facilities, separator; production facilities, pump jacks, ROV, coolers)	9.39
	Engineering Procurement Construction	3.58
	Trunkline / Laterals	0.12
	Facilities - Capital Related Expense	0.79
Drilling	Drilling four horizontal wells - 2 well pairs, each wellpair consist of an injector and producer well.	6.00
	Completion of horizontal wells	2.22
	Capital Related Expense	0.05
Trunkline	Drilling	0.00
	Surface Facilities	0.06
	Engineering Procurement Construction	0.10
	Trunkline / Laterals	2.65
	Capital Related Expense	0.04
Total Capital Costs		**25.02**

6.4 Direct and indirect operating costs

The following table summarizes operating costs by category, incurred up to year end 2009:

Category	Description and Details of Operating Costs	Cost (C$M)
Facility Exp.	Drilling observation wells, well heads, completions, reservoir monitoring instrumentation	2.43
	Completions	0.18
	Surface Facilities (Facilities portion associated with solvent injection: solvent tank, pump, lines; production and vent gas testing equipment, samples, separators, horizontal well reservoir monitoring instrumentation; EPCM)	9.93
Field Exp.	Field operating costs	0.06
	Surveillance costs	0.00
Total Operating Costs		**12.60**

No injectant costs have been incurred as of year end 2009.

6.5 Crown royalties

This pilot is part of Imperial Oil's Cold Lake Production Project, and the capital and operating costs have been used as allowable costs. The royalty benefit created by spending $37.6M of allowed costs (between 2005-2009) equalled C$M 9.99, which brought total Cold Lake payable royalties to $1.89B from $1.9B, as summarized below.

C$M	2005	2006	2007	2008	2009	Total ('05-'09)
Cold Lake Payable Royalties (Without SA-SAGD Costs)	**157.71**	**376.09**	**339.16**	**579.93**	**452.08**	**1,904.96**
SA-SAGD CAPEX & OPEX	1.48	1.44	1.66	20.46	12.57	37.62
Cold Lake Royalty Rate	30%	30%	30%	25%	28%	
Royalty Benefit of SA-SAGD Costs	0.45	0.43	0.50	5.12	3.50	9.99
Cold Lake Payable Royalties (With SA-SAGD Costs)	**157.26**	**375.66**	**338.66**	**574.81**	**448.58**	**1,894.98**

As previously mentioned, there has been no oil production in 2009 for the SA-SAGD pilot, thus royalty revenue from pilot production will start to accumulate in future years.

6.6 Cash flow

As revenue has yet to be incurred, cash flow is simply negative costs to date (see sections 6.3, and 6.4 for costs to date).

6.7 Cumulative project costs and net revenue

Please refer to sections 6.2, 6.3, and 6.4.

6.8 Deviations from budgeted costs

There have been several changes in costs from the original application.

Firstly, Imperial has decided to expense all costs associated with the solvent portion of the pilot. This includes facility related items (solvent tank, pumps, etc, see 6.4), as well as costs associated with the observation wells. This accounting change differs from the original application as these costs were initially submitted as part of capital expenditures. The rationale to expense these items is due to the fact that SA-SAGD is a commercially unproven technology. Imperial continues to capitalize the base SAGD operation, as this technology is commercially viable.

Secondly, consumed energy costs (gas burned to generate steam) were included in the original application. These have yet to be included in any IETP claim forms, and Imperial will work with the ADOE to ensure these costs are included in future claim forms.

Third, facility related costs (both capital and expense) have increased since the original application. A summary of cost changes:

Cost summary, C$M	Original Application	Actual
Drilling and Completions[1]	7.7	8.4
Production Trunkline[2]	0.0	2.9
Facilities[3]	18.7	14.4
Total Facilities Capital	**26.4**	**25.7**
Facilities[3]	0.0	12.9
Total Facilities Expense	**0.0**	**12.9**
Total Drilling & Facility Costs Only	**26.4**	**38.6**

[1] Drilling and completion costs increased by C$M 0.7 due to cost increases versus original estimate

[2] Capacity on the existing production pipeline to the Mahkeses plant was limited and as a result the production line had to be twinned to accommodate this pilot (not part of the original estimate)

[3] Facility costs have been allocated to both capital and expense depending on whether they relate to the base SAGD operation, or the solvent assisted operation (as outlined earlier in this section). Looking at facility costs on a total basis, the actual costs have increased to C$M 27.3 from the original estimate of C$M 18.7 (+ C$M 8.6). Cost increases due to:

- Additional engineering, procurement, construction, and maintenance (EPCM) costs due to scope more technically complex than plan
- Increased labour, equipment and material rates
- Post turnover facility fixing and optimization costs
- Upgrades to heating, venting, and air conditioning (HVAC) system to meet fugitive emission requirements
- Additional metering on solvent streams to meet regulatory requirements
- Additional remediation work on observation wells as per regulatory requirements

7 Facilities

7.1 Major equipment items

Major equipment items include:

Injection side

- Steam separator to separate condensed water from the inlet steam line
- Diluent tank (~83m^3 of useable volume)
- Diluent pump

Production side

- Rotary operated valve to direct production either to test or the group line
- Production cooler
- Production test cooler
- Production test separator
- Gas test separator

7.2 Capacity limitation, operational issues, and equipment integrity

Capacity limitations

- 300 m^3/d (cold water equivalent) of dry steam injected per well pair
- 330 m^3/d water produced per well
- 20% (based on dry steam rate), or 60 m^3/d, maximum solvent injected per day
- 51.6 m^3/d solvent produced per day
- 84 m^3/d bitumen produced per well, without solvent assistance
- 110.4 m^3/d bitumen produced per well, with solvent assistance
- 2,100 m^3/d gas produced per well
- Total liquid from solvent assisted producing well: 492 m^3/d (330 m^3/d + 110.4 m^3/d + 51.6 m^3/d)

Operational Issues

There have been no significant operational issues to date.

Equipment Integrity

One equipment issue has been encountered to date. An aerial cooler, designed to reduce the temperature of the water condensate from the steam separator, started to leak condensate from the endplates of the heat exchange tubes. Mechanical sealing within the tubular heat exchanger was compromised when the condensate flow was stopped and began to freeze. As a result of the leak, the aerial cooler was shutdown for a 3 week period, and all steaming activities were ceased. Repair work for the damaged aerial cooler was carried out in early 2010, and the issue has been resolved.

7.3 Process flow and site diagrams

For detailed PFDs and site diagrams, please refer to Appendix A.

8 Environmental / Regulatory / Compliance

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

8.1 Regulatory Compliance

The project is operating under ERCB scheme approval 10689B. To date, the pilot has been in full compliance, and no regulatory issues have arisen.

8.2 Environmental Considerations

The SA-SAGD 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 those commitments outlined in the subsequent operating approval No. 73534-00-04 (as amended) issued by Alberta Environment (AENV) 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. The system, known as RegFrame, tracks commitments and notifies key personnel of activities for which the company is responsible. RegFrame includes information from numerous sources including directives, approvals, codes of practice, and specific local agreements. All requirements associated with the CLEP EIA and the EPEA are incorporated into applicable phases of the T13 SA-SAGD pilot life-cycle.

8.3 Air Quality

The SA-SAGD 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. As a standard practice, and as per current policies and procedures, Imperial conducts individual site air quality monitoring during a-typical events or upset conditions.

8.4 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 SA-SAGD pilot did not generate an increase in water demand.

The SA-SAGD pilot location does not lie within 100 m of a water body. Imperial constructs its facilities with the objective of maintaining drainage patterns and natural flow and managing surface water runoff. Presently Imperial conducts monitoring of lakes and streams/creeks in the CLO area as part of the Regional Surface Water Monitoring Program (IOR 2005).

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.

8.5 Wildlife

Imperial develops its project schedules in a manner consistent with applicable regulations. EPEA Approval 73534-00-04 (as amended), outlines restricted periods for tree and brush clearing which Imperial adhered to during the SA-SAGD pilot construction. 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 SA-SAGD development was conducted with the objective of minimizing disturbance to wildlife habitat and movement.

During production, Imperial personnel adhere to the Wildlife Management Guide (IOR 2008) 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 Wildlife Monitoring Program which is presently being developed.

8.6 Noise

Imperial has committed to meet the requirements of the Noise Control Directive ID 99-8 (EUB 1999).

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).

8.7 Reclamation

As mentioned, the SA-SAGD pilot is covered under the AEPEA Approval 73534-00-04, as amended, which also covers the decommissioning, remediation, and reclamation phases of the pilot. Specific plans to remediate this pad have yet to be worked.

9 Future Operating Plan

9.1 Project schedule

Key future milestones would be as follows:

▪ Continue warm-up of horizontal wells with steam	Q1-Q2, 2010
▪ Switch over into SAGD operation, initiate controlled plan of solvent injection	Q3, 2010
▪ 2010 Progress Report	Q2, 2011
▪ 2011 Progress Report	Q2, 2012
▪ Final Report Issued	Q2, 2013

Key deliverables from the project team and the pilot operating team would be as follows:

- Project execution plan and commissioning documentation
- Geologic assessment of reservoir quality in pilot area based on log and core data
- Drilling and completions programs
- Pilot start up and operating plan
- Planned solvent injection profile for each horizontal well pair
- Pilot surveillance plan
- Monthly reporting of injection and production volumes (held confidential by the ERCB)
- Annual progress reports (ERCB confidential) would only document operations data and the ongoing analysis of pilot performance including plots of cumulative injection, production, steam-oil ratios and solvent recovery from each well pair; plots of temperature profiles from the observation wells; and data from any surveillance tools such as 3D seismic or cased hole logging
- Final report to include an engineering analysis of pilot performance versus key pilot objectives including output from reservoir simulation tools tuned to history match observed pilot performance

9.2 Changes in pilot operation

Currently, no changes have been implemented to the pilot operation.

9.3 Optimization strategies

Currently, no optimization strategies have been implemented.

9.4 Salvage update

Currently, there are no plans to salvage any of the equipment on site.

10 Interpretations and Conclusions

10.1 Overall performance assessment

To summarize major lessons learned (which have all previously been discussed):

- Ensure temperature sensing devices are properly installed
- Nitrogen is an effective insulator and is useful in achieving steam temperatures at the toe
- Hydraulics of steam circulation are challenging to model / predict

Difficulties Encountered

The major difficulties encountered during 2009 operations were due to surface facility issues. Improperly installed temperature sensing devices contributed to the "freezing" of the water condensate cooler. Although there were no difficulties encountered with respect to steam circulation into each well, drilling activities near wells T13-01 and T13-02 required operation at a bottomhole pressure lower than hydrostatic which was difficult to achieve.

Technical and Economic Viability

No solvent has been injected into the reservoir. Therefore, judgements regarding technical and economic viability of a solvent-assisted SAGD process cannot be made at this time.

Overall Effect on Gas / Bitumen Recovery

This has yet to be determined.

Future expansion or commercial field application

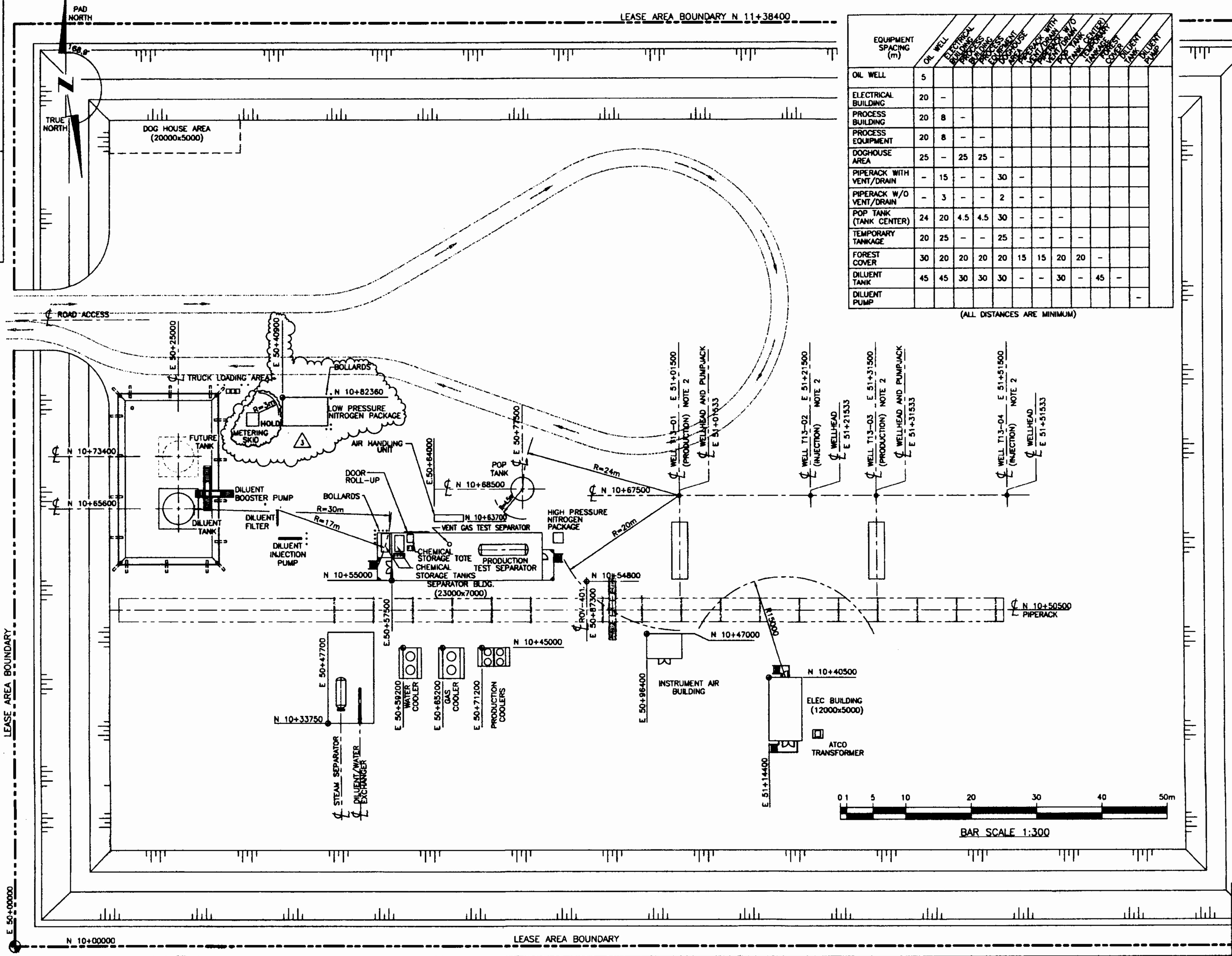
This has yet to be determined.

Appendix A

Process Flow Diagrams (PFDs)

&

Site Maps



EQUIPMENT SPACING (m)	OIL WELL	ELECTRICAL BUILDING	PROCESS BUILDING	PROCESS EQUIPMENT	DOGHOUSE AREA	PIPERACK WITH VENT/DRAIN	PIPERACK W/O VENT/DRAIN	POP TANK (TANK CENTER)	TEMPORARY TANKAGE	FOREST COVER	DILUENT TANK	DILUENT PUMP
OIL WELL	5											
ELECTRICAL BUILDING	20	-										
PROCESS BUILDING	20	8	-									
PROCESS EQUIPMENT	20	8	-	-								
DOGHOUSE AREA	25	-	25	25	-							
PIPERACK WITH VENT/DRAIN	-	15	-	-	30	-						
PIPERACK W/O VENT/DRAIN	-	3	-	-	2	-	-					
POP TANK (TANK CENTER)	24	20	4.5	4.5	30	-	-	-				
TEMPORARY TANKAGE	20	25	-	-	25	-	-	-	-			
FOREST COVER	30	20	20	20	20	15	15	20	20	-		
DILUENT TANK	45	45	30	30	30	-	-	30	-	45	-	
DILUENT PUMP												-

(ALL DISTANCES ARE MINIMUM)

MAJOR EQUIPMENT LIST

TAG No.	DESCRIPTION	LOCATION
E-8001	DILUENT/WATER EXCHANGER	AS SHOWN
E-8002	WATER COOLER	AS SHOWN
E-8003	GAS COOLER	AS SHOWN
E-8004	PRODUCTION TEST COOLER	AS SHOWN
E-8005	PRODUCTION COOLER	AS SHOWN
HTR-8110/1/2/3/4/5	BUILDING HEATERS	SEPARATOR BLDG.
EF-8010/1/2/3	EXHAUST FANS	SEPARATOR BLDG.
HTR-0004/5/6	BUILDING HEATERS	ELEC. BUILDING
EF-0003/4	EXHAUST FANS	ELEC. BUILDING
FIL-8001	DILUENT FILTER	AS SHOWN
K-8021	INSTR. AIR COMP. PACKAGE	INST AIR BLDG.
P-0801	DILUENT BOOSTER PUMP	AS SHOWN
P-0802	DILUENT INJECTION PUMP	AS SHOWN
P-0810/20/30/40/50/60	GROUP CHEM. INJ. PUMP	SEPARATOR BLDG.
T-8001	POP TANK	AS SHOWN
T-8002	DILUENT TANK	AS SHOWN
T-8021A/B	CHEMICAL STORAGE TANK	SEPARATOR BLDG.
CHEMICAL STORAGE TOTE		SEPARATOR BLDG.
V-8001	STEAM SEPARATOR	AS SHOWN
V-8003	VENT GAS SEPARATOR	SEPARATOR BLDG.
V-8004	PRODUCTION TEST	SEPARATOR BLDG.
ROV-401	8-WAY ROTARY SELECTOR VALVE	AS SHOWN
T-13-01/03	PRODUCTION WELLHEADS	LEASE AREA
T-13-02/04	INJECTION WELLHEADS	LEASE AREA
-	LP NITROGEN PACKAGE	AS SHOWN
-	HP NITROGEN PACKAGE	AS SHOWN
MAU-8010	MAKE UP AIR UNIT	SEPARATOR BLDG.
HAH-8010	AIR HANDLING UNIT	AS SHOWN

DESIGN NOTES:

1. LOCATION OF GROUNDWATER EVALUATION WELL (GEW) TO BE SUPPLIED BY FIELD.
2. WELLHEAD AND PUMPJACK IS OFFSET 33mm EAST OF WELL BORE.

GENERAL CONSTRUCTION NOTES:

A. CONSTRUCTION CONTRACTOR SHALL:
- LOCATE AND INSTALL ALL HYDROTEST VENTS AND DRAINS AS PER DRAWING 073-0051-080-044 01.
- PAINT PSV AND CAR SEALED VALVES WITH INTERNATIONAL ORANGE ENAMEL PAINT.
- INSTALL CAR SEALED VALVES WITH THE VALVE STEM IN THE HORIZONTAL (PREFERRED) OR DOWNWARD POSITION UNLESS OTHERWISE NOTED.
- GREASE THE UNDERSIDE OF ALL SLIDING PIPE SHOE BASE PLATES AND ALL DIRECTIONAL ANCHORS WITH HIGH TEMPERATURE GREASE (RATED TO -40°C AND 100°C).
- LOCATE AND INSTALL PERSONNEL PROTECTION ON LINES AS PER EBP 14-1-1, PAR.4.14 AND AS PER PIPING GENERAL ARRANGEMENTS.
- DO NOT PLACE VENTS AND DRAINS ON HYDROCARBON PIPING AND PIPELINES WITHIN 15m OF THE ELECTRICAL BUILDING AND 30m OF THE DOGHOUSE AREA.

B. INSTRUMENTATION CONNECTIONS:
- PRESSURE CONNECTIONS ARE 3/4 NPT UNLESS NOTED OTHERWISE. INSTALL AS PER DETAIL 4 ON DRAWING 073-0051-080-044 01.
- TEMPERATURE CONNECTIONS ARE 1 NPT UNLESS NOTED OTHERWISE.
- ORIFICE TAPS ON HORIZONTAL PIPES TO BE HORIZONTAL IN LIQUID AND STEAM SERVICE AND VERTICAL (UPWARD) IN GAS SERVICE. PROVIDE NIPPLES AND GATE VALVES AS PER LINE SPECIFICATION. UNUSED TAPS TO BE PLUGGED WITH HXHD PLUGS COMPLYING WITH PIPING SPECIFICATIONS AND SEAL WELDED. ROOT PASS ON THE ORIFICE FLANGE/PIPE BUTT WELD TO BE GROUND SMOOTH TO THE INSIDE PIPE WALL.

C. DEVIATION/DECISION RECORD:
- MOC-109 DEVIATION TO EBP 3-18-1, PAR.7.3.1. DO NOT INSTALL GUSSETS ON SMALL BORE (<NPS 2) CONNECTIONS.
- MOC-439 DEVIATION TO EBP 19-1-1, TABLE 3. DO NOT PRIME OR PAINT ANY INSULATED PIPING.
- MOC-442 DEVIATION TO EBP 3-30-3, USE OF PLATED CARBON STEEL COMPRESSION FITTINGS WITH STAINLESS STEEL FERRULES IS ALLOWED IN AIR AND CHEMICAL SERVICE (PIPING CLASS ZJCE0).
- MOC-2185 DECISION RECORD, EQUIPMENT SPACING. SEE EQUIPMENT SPACING TABLE (THIS DRAWING).
- MOC-2574-DEVIATION TO EBP 18-200-1, USE OF CE>0.45<0.53 FOR FORGED BODY VALVES WITH PROCEDURES AS DESCRIBED.

073-1151-010-302 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
3	09 05 25	RE-ISSUED FOR CONSTRUCTION - MOC C-4764 (XY.2006.28284)	MG	DAP	BAF	GME
2	08 11 13	ISSUED FOR CONSTRUCTION - MOC C-4405 (XY.2006.28284)	KJG	GBF	GCS	BAF
1	08 11 14	RE-ISSUED FOR CONSTRUCTION - MOC C-4413 (XY.2006.28284)	YW	MG	BAF	GME
0	08 08 15	ISSUED FOR CONSTRUCTION (XY.2006.28284)	CAR	MG	BAF	GME

DRAFTING | ENGINEERING | IOR DWG NO. | TITLE | REFERENCE DRAWINGS

SEAL/STAMP

PERMIT TO PRACTICE
IMPERIAL OIL RESOURCES
Signature
Date MAY 27. 2009
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
PERMIT

APPROVED FOR CONSTRUCTION
DATE 27-MAY-09 REV. 3
PROJECT ENGINEERING

Imperial Oil
Esso

IMPERIAL OIL RESOURCES

CLPP MAHKESES FIELD PHASES 11 - 13
PAD T13 SA-SAGD FACILITIES
PLOT PLAN

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
COLT ENGINEERING CORPORATION	1:300	073-1151-010-302 01	3
CONTRACTOR DWG NUMBER: XY.2006.28284			

Filename: H:\FILENET\073-1151-010-302-01.DWG User ID: YWANG3 Plot date/time: May 25, 2009 - 10:39am XREF drawings: 073-1151-XRF-M00013 [073-1151-XRF-M00013.DWG] IMAGE attachments:

CADD DRAWING NO MANUAL CHANGES

AutoCAD

073-1151-020-337 01

V-8001 STEAM SEPARATOR 1372 mm ID x 3658 mm S/S

FIL-8001 DILUENT FILTER

E-8001 DILUENT/WATER EXCHANGER RATED DUTY: 332 kW

T-8021A CHEMICAL STORAGE TANK DEMULSIFIER DMO8649 CAPACITY: 3.41 m^3

T-8021B CHEMICAL STORAGE TANK REVERSE DEMULSIFIER RBW118 CAPACITY: 2.0 m^3

CHEMICAL STORAGE TOTE WATER CLARIFIER RBW747 CAPACITY: 1.1 m^3

P-0850/60 GROUP CHEMICAL INJECTION PUMP 0-50 LITRES/D

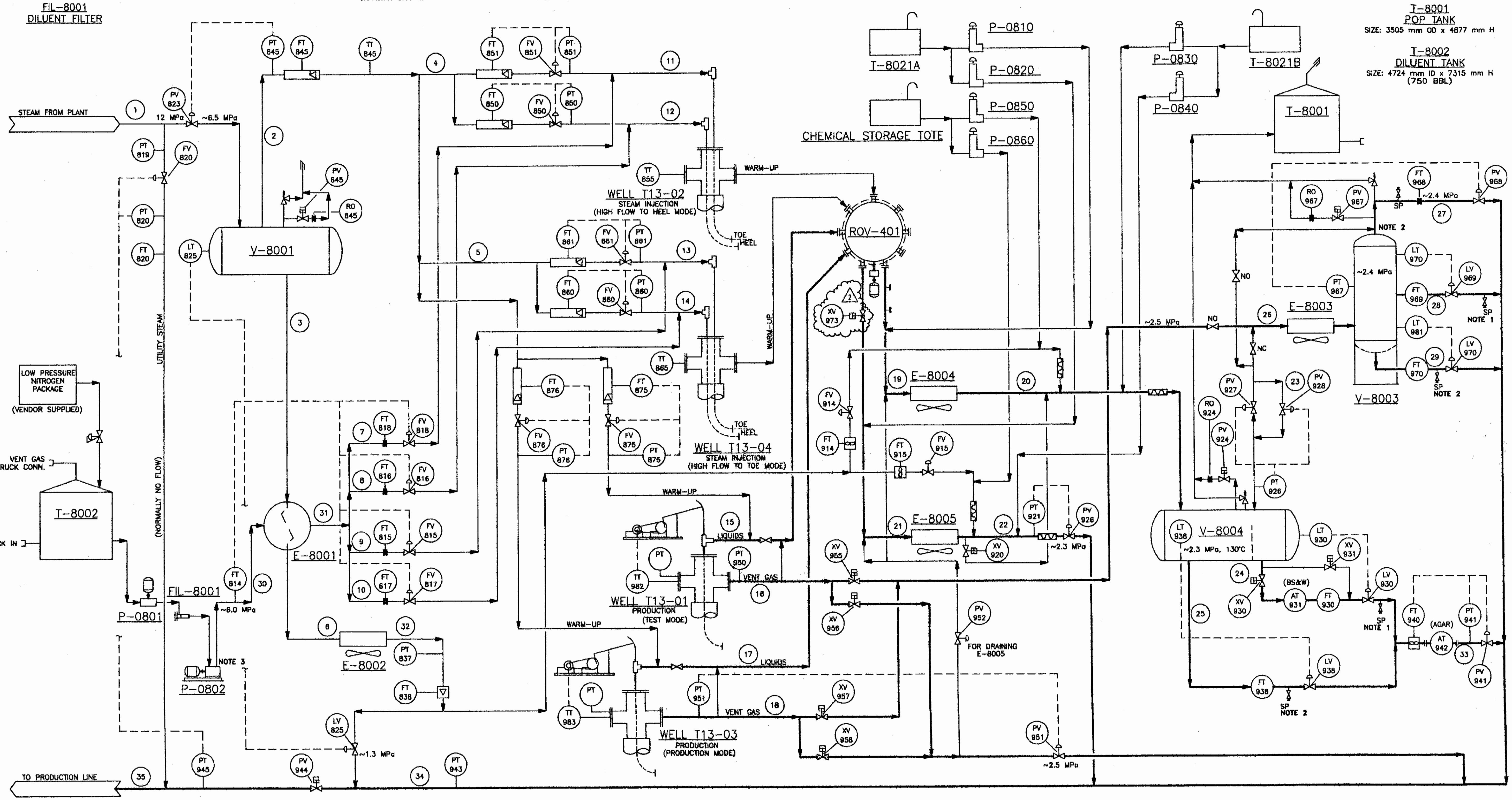
P-0810/20/30/40 GROUP CHEMICAL INJECTION PUMP 0-200 LITRES/D

E-8003 VENT GAS COOLER RATED DUTY: 632 kW

V-8003 VENT GAS TEST SEPARATOR 610 mm OD x 2438 mm S/S

T-8001 POP TANK SIZE: 3505 mm OD x 4877 mm H

T-8002 DILUENT TANK SIZE: 4724 mm ID x 7315 mm H (750 BBL)



CONSTRUCTION NOTES:

1. PROPORTIONAL SAMPLER.
2. SAMPLE POINTS MANUAL STYLE.
3. MULTI-STAGE CENTRIFUGAL PUMP.

P-0801 DILUENT BOOSTER PUMP 66 m^3/d

P-0802 DILUENT INJECTION PUMP 66 m^3/d

E-8002 WATER COOLER RATED DUTY: 3498 kW

E-8004 PRODUCTION TEST COOLER RATED DUTY: 1285 kW

E-8005 PRODUCTION COOLER RATED DUTY: 1285 kW

ROV-401 8-WAY ROTARY SELECTOR VALVE

V-8004 PRODUCTION TEST SEPARATOR 1524 mm ID x 6706 mm S/S

Imperial Oil

Esso

IMPERIAL OIL RESOURCES

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
2	09 03 18	RE-ISSUED FOR CONSTRUCTION PER MOC C-4481 (XY.2006.28284)	MG	DAP	SAB	KSC
1	08 11 14	RE-ISSUED FOR CONSTRUCTION PER MOC C-4413 (XY.2006.28284)	DAP	MG	KSC	AMB
0	08 08 08	ISSUED FOR CONSTRUCTION (XY.2006.28284)	LPC	MG	KSC	AMB

DRAFTING / ENGINEERING

IOR DWG NO. — TITLE — REFERENCE DRAWINGS

SEAL/STAMP

PERMIT TO PRACTICE IMPERIAL OIL RESOURCES
Signature
Date Mar 26/09
PERMIT NUMBER: P00884
The Association of Professional Engineers, Geologists and Geophysicists of Alberta
PERMIT

APPROVED FOR CONSTRUCTION
DATE Mar 26/09 REV. 2
PROJECT ENGINEERING

CLPP MAHKESES FIELD PHASES 11-13
PAD T13 SA-SAGD FACILITIES
PROCESS FLOW DIAGRAM

CONTRACTOR NAME	SCALE	IOR DRAWING NUMBER	REV.
COLT ENGINEERING CORPORATION	NONE	073-1151-020-337 01	2
CONTRACTOR DWG NUMBER XY.2006.28284			

Filename: H:\FILENET\073-1151-020-337-01.DWG User ID: MBGRIGG Plot date/time: March 18, 2009 - 3:54pm XREF drawings: IMAGE attachments: