Imperial Oil

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June 30, 2011

Innovation Energy Technologies Program
Research and Technology Branch
9th Floor, North Petroleum Plaza
9945 - 108th Street
Edmonton, Alberta T5K 2G6

Attention: Christopher Holly, Branch Head
Research and Technology

Dear Mr. Holly:

Re: Imperial Oil SA-SAGD IETP Annual Project Technical Report

Attached is Imperial Oil's 2010 Annual Project Report for the SA-SAGD pilot as required under IETP application 03-047.

Please contact Ali Jaafar at (403) 284-7538 or ali.e.jaafar@esso.ca with any questions or concerns.

Yours truly,

[Original Signed]

T.J. (Tom) Boone, PhD, P.Eng.
Manager, Oil Sands Recovery Research

TJB/aj
Attachment
cc: Ali Jaafar, IOR
cc: Geoff Pearson, ADOE

*An Alberta limited partnership

IETP Application No. 03-047

Imperial Oil Resources - Cold Lake Solvent Assisted - SAGD Pilot

2010 Annual Project Technical Report

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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 2010. Steam circulation (warm-up) phase that began in 2009 continued until the end of June 2010, at which point downhole pumps were installed on the producer wells. The pad was then restarted under SAGD mode in late July, 2010. Solvent injection commenced on well-pair 2 in late October, 2010, converting it to SA-SAGD mode, while well-pair 1 continued to operate in SAGD mode.

[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 were key members of the SA-SAGD team during 2010:

Tom Boone, PhD, P.Eng. – Manager, Oil Sands Recovery Research
Ali Jaafar, P.Eng. – SA-SAGD Pilot Engineer
Jeff Yerian, PhD – SA-SAGD Pilot Engineer
Darrel Perlau, P.Eng. – Thermal Solvent Research

2.2 Key activities

Key activities undertaken in 2010 include:

December 7, 2009 - January 29, 2010: Pad shut in due to surface facility issues
January 30, 2010: Warm-up phase recommenced
June 30, 2010: Warm-up phase successfully completed, pad shut-in
July 1 - 19, 2010: Service rig work underway to install down hole pumps on producers
July 20, 2010: Pad restarted under SAGD mode
October 20, 2010: Diluent injection commenced into T13-04, converting well-pair 2 to SA-SAGD mode (well-pair 1 continues in SAGD mode)
November 25 – December 22, 2010: Diluent injection shut-in due to surface facility issues (well-pair 2 continued to operate in SAGD mode)

2.3 Production, and material and energy balance flow sheets

Gross balances

Steam:

- Steam for the SA-SAGD pilot was generated at the Mahkeses plant in Cold Lake, which falls outside of the IETP project scope. Summary of injected steam volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	157.6	129.9	0.0	0.0
Feb-10	1,384.4	1,317.1	915.3	896.1
Mar-10	1,483.3	1,452.1	1,765.0	1,497.1
Apr-10	1,153.9	1,161.7	1,168.8	1,116.8
May-10	2,025.7	2,027.2	1,728.2	1,953.8
Jun-10	1,677.8	1,932.0	1,399.1	1,826.0
Jul-10	0.0	1,116.2	0.0	1,145.4
Aug-10	0.0	3,720.7	0.0	4,132.5
Sep-10	0.0	3,633.1	0.0	4,234.7
Oct-10	0.0	4,200.9	0.0	4,152.6
Nov-10	0.0	4,165.8	0.0	4,538.4
Dec-10	0.0	4,451.4	0.0	5,199.9

Produced Materials

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

	T13-01	T13-02	T13-03	T13-04
Jan-10	119.3	189.8	0.0	0.0
Feb-10	990.8	1,010.5	636.7	1,027.6
Mar-10	1,176.7	1,458.7	1,681.2	1,319.6
Apr-10	946.0	1,040.8	1,076.2	849.6
May-10	1,335.3	989.8	1,267.5	993.5
Jun-10	2,067.1	500.9	2,397.9	616.7
Jul-10	441.7	0.0	1,212.5	0.0
Aug-10	3,813.2	0.0	4,516.7	0.0
Sep-10	3,618.4	0.0	4,069.5	0.0
Oct-10	4,123.5	0.0	4,568.7	0.0
Nov-10	3,983.7	0.0	4,747.9	0.0
Dec-10	4,804.9	0.0	5,748.5	0.0

Volume disposed:

- There are no disposal wells included in this IETP project

Produced hydrocarbon liquid (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	28.8	3.9	7.1	0.5
Mar-10	34.4	23.0	8.7	14.6
Apr-10	101.4	32.3	48.3	26.4
May-10	266.2	189.7	298.2	203.2
Jun-10	369.2	109.4	362.8	133.0
Jul-10	140.8	0.0	413.3	0.0
Aug-10	907.0	0.0	1,285.0	0.0
Sep-10	829.2	0.0	1,029.7	0.0
Oct-10	790.7	0.0	1,167.5	0.0
Nov-10	885.9	0.0	1,657.7	0.0
Dec-10	1,067.1	0.0	1,210.7	0.0

- The standard API of Cold Lake oil is 11.
- Volumes in T13-03 in October / November / December include diluent recovered in the oil liquid phase. A breakdown is provided in Section 4.1.

Diluent (purchased, in m^3):

	T13
Jan-10	0.0
Feb-10	0.0
Mar-10	0.0
Apr-10	0.0
May-10	0.0
Jun-10	0.0
Jul-10	0.0
Aug-10	0.0
Sep-10	0.0
Oct-10	418.1
Nov-10	653.1
Dec-10	300.0

- These volumes represent diluent that was purchased and stored on site at T13 (inside the diluent tank). Summary of injected diluent volumes (by well, in m^3):

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	0.0	0.0	0.0	0.0
Mar-10	0.0	0.0	0.0	0.0
Apr-10	0.0	0.0	0.0	0.0
May-10	0.0	0.0	0.0	0.0
Jun-10	0.0	0.0	0.0	0.0
Jul-10	0.0	0.0	0.0	0.0
Aug-10	0.0	0.0	0.0	0.0
Sep-10	0.0	0.0	0.0	0.0
Oct-10	0.0	0.0	0.0	309.5
Nov-10	0.0	0.0	0.0	616.3
Dec-10	0.0	0.0	0.0	281.5

Produced Sand (m^3):

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

Produced gas (E^3m^3):

- Due to metering issues, gas production volumes from August to December 2010 were likely not accurate. As a result, solution gas was estimated using a standard Cold Lake GOR (7.5 m^3/m^3). Diluent recovered in the gas phase is not included in these estimates.

	T13-01	T13-02	T13-03	T13-04
Jan-10	0.0	0.0	0.0	0.0
Feb-10	0.0	0.0	0.0	0.0
Mar-10	0.0	0.0	0.0	0.0
Apr-10	0.7	0.2	0.4	0.1
May-10	2.6	1.6	3.3	1.9
Jun-10	2.8	0.8	2.7	1.2
Jul-10	1.1	0.0	3.1	0.0
Aug-10	6.8	0.0	9.6	0.0
Sep-10	6.2	0.0	7.7	0.0
Oct-10	5.9	0.0	8.8	0.0
Nov-10	6.6	0.0	12.4	0.0
Dec-10	8.0	0.0	9.1	0.0

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

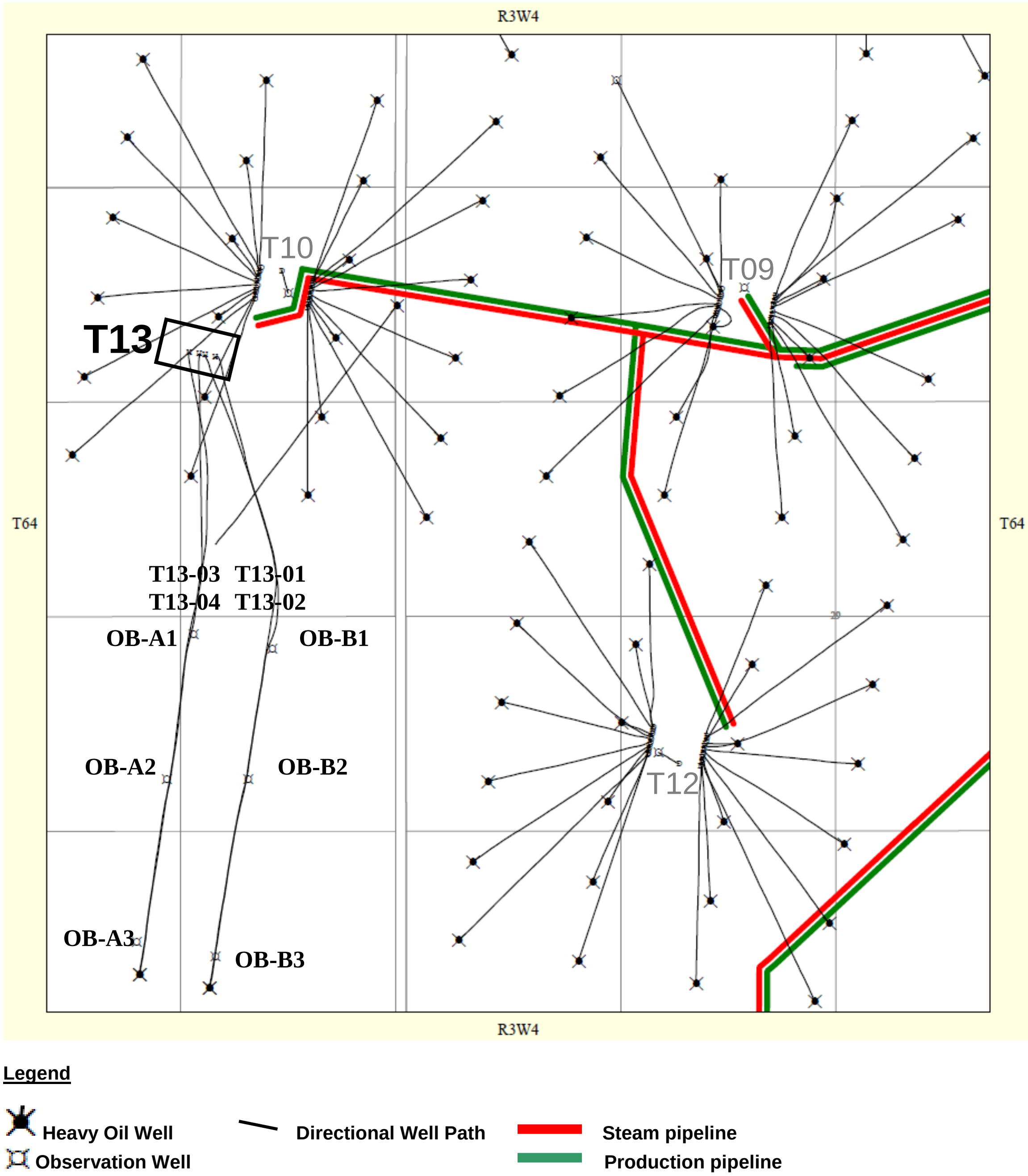


Figure 1: Location of SA-SAGD surface facilities and well trajectories

3.2 2010 drilling, completion, and work-over operations

There is no drilling or completion work to report for 2010. 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.

3.3 Well operation

All four horizontal wells (T13-01, 02, 03, 04) started steam injection on November 17, 2009. The wells continued to operate in warm-up mode until June 30, 2010. On July 20, 2010, SAGD mode was initiated on both well-pairs. On October 20, 2010, solvent injection commenced into well T13-04, thus initiating SA-SAGD operation on the west well pair.

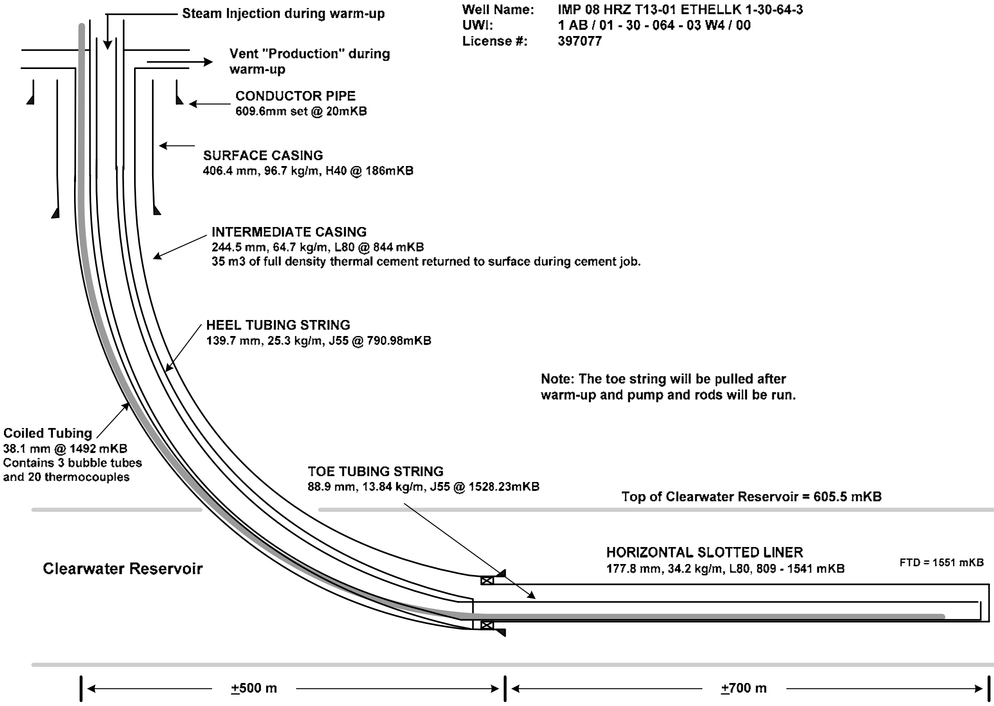
3.4 Well list and status

All wells are currently active. List as follows:

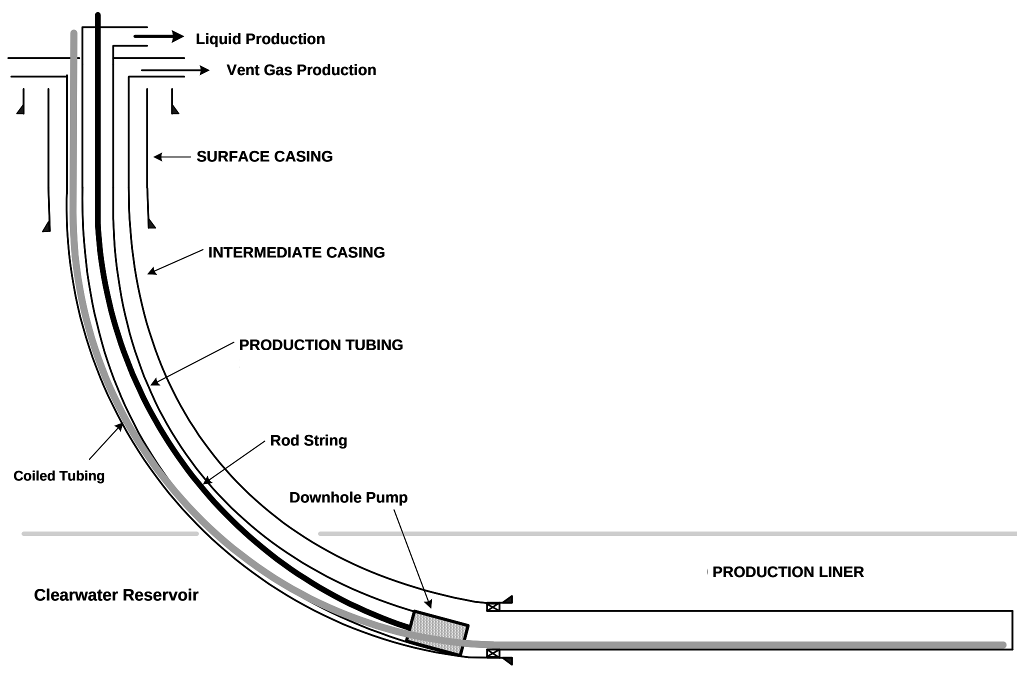
East well pair	1AB/01-30-064-03W4/0 (**T13-01**) producer
	1AC/01-30-064-03W4/0 (**T13-02**) injector
	1AA/08-30-064-03W4/0 (**OB-B1**) observation well
	1AD/08-30-064-03W4/0 (**OB-B2**) observation well
	1AA/01-30-064-03W4/0 (**OB-B3**) observation well
West well pair	1AB/02-30-064-03W4/0 (**T13-03**)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

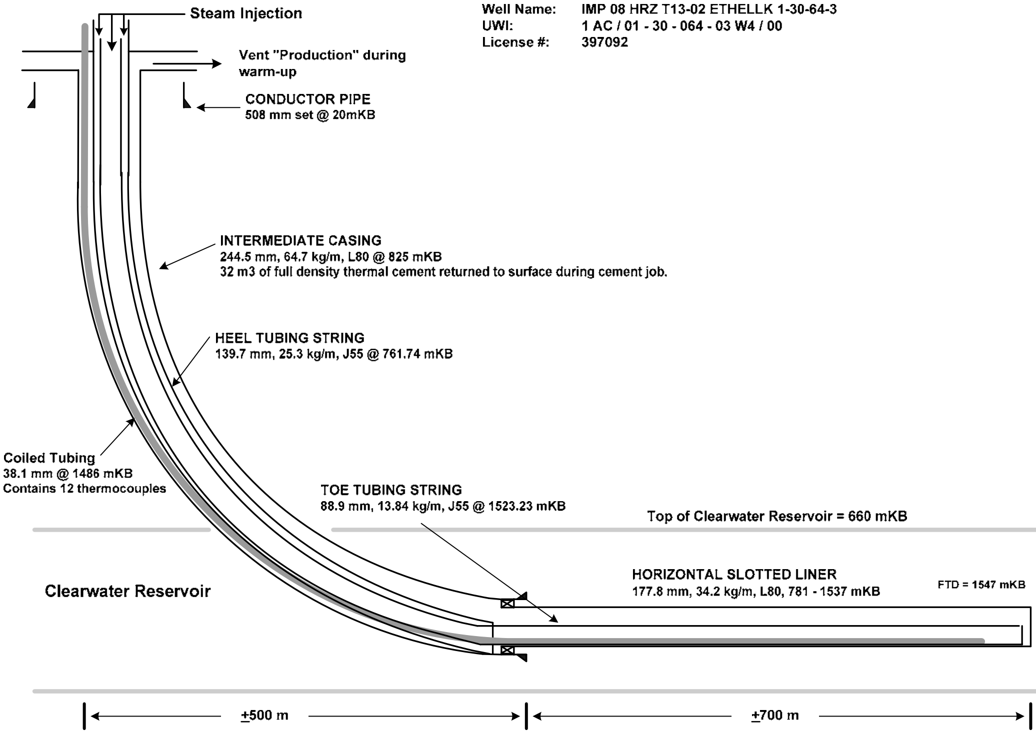
T13-01 (east producer) – warm-up schematic:



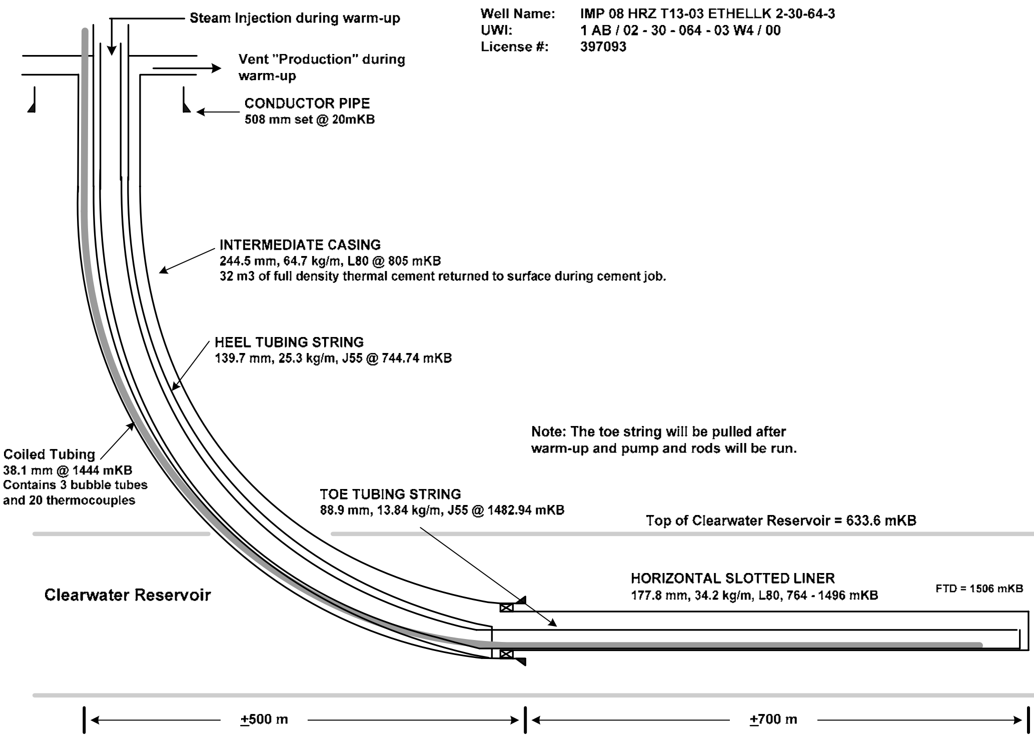
T13-01 (east producer) – SAGD schematic:



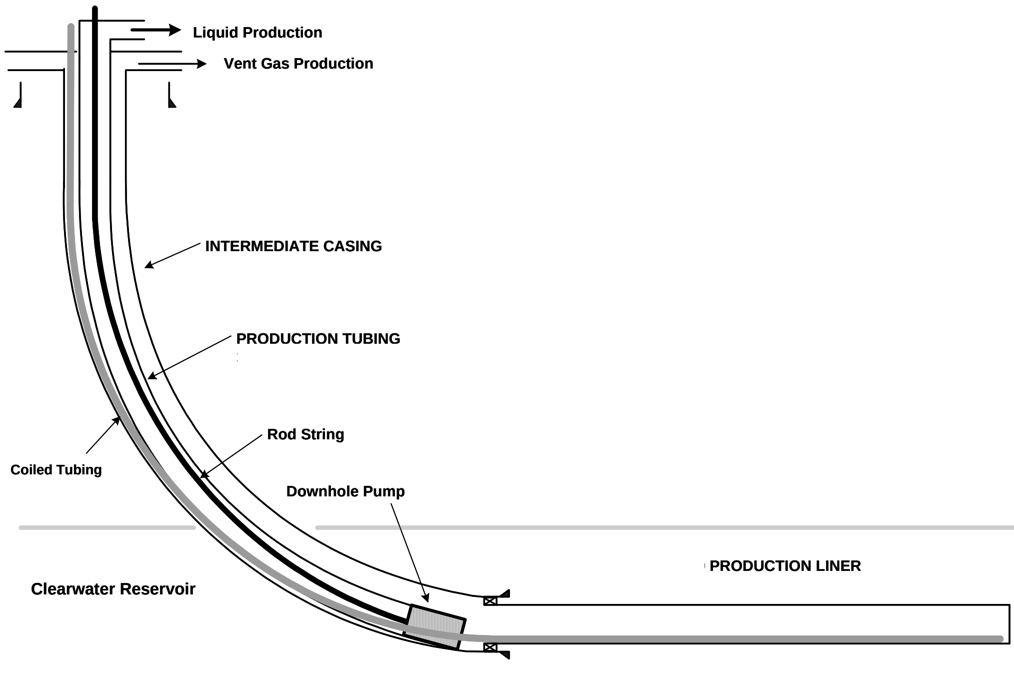
T13-02 (east injector):



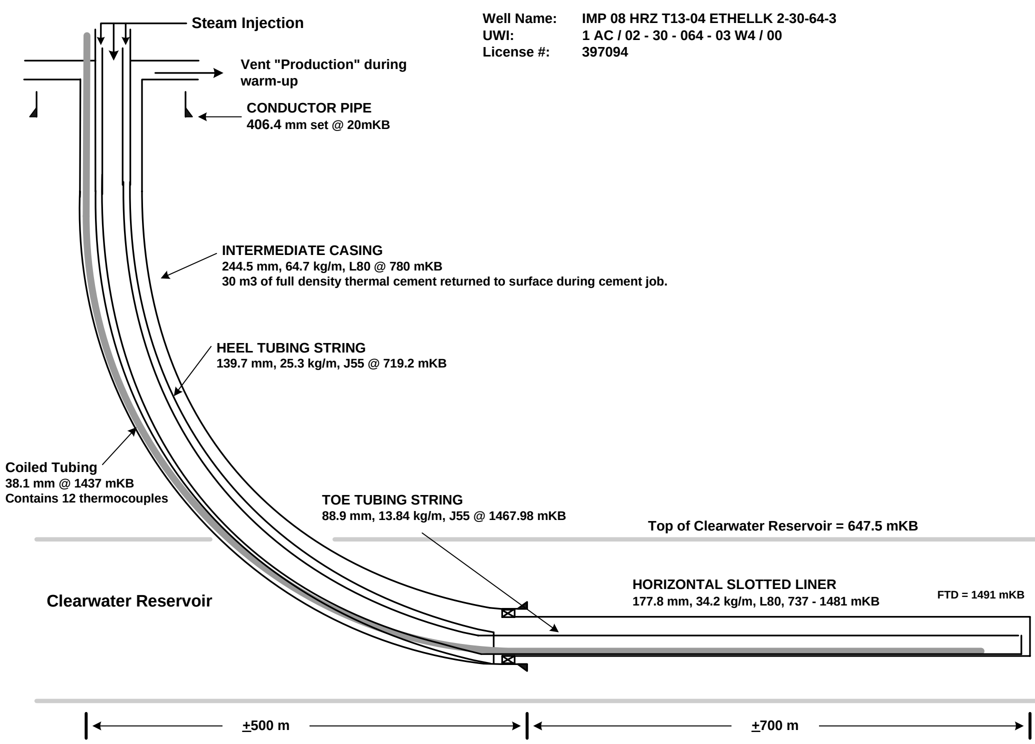
T13-03 (west producer) – warm-up schematic:



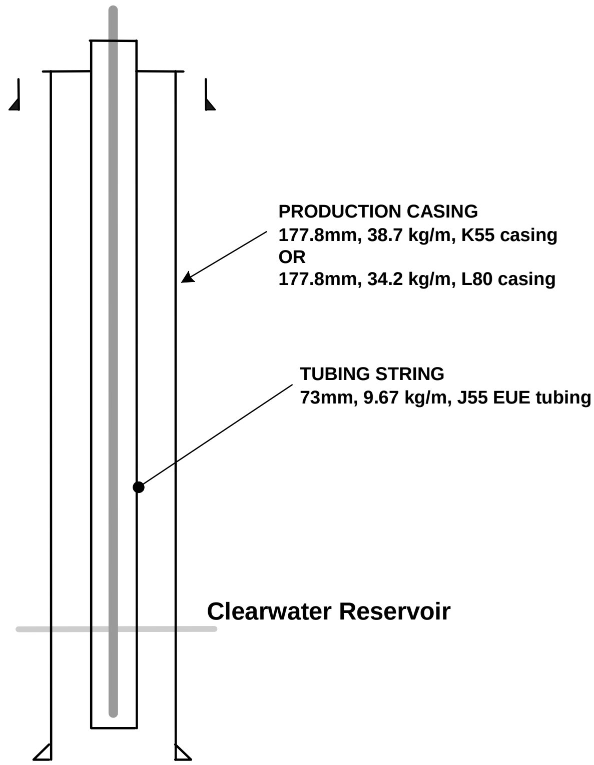
T13-03 (west producer) – SAGD schematic:



T13-04 (west injector):



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



3.6 Spacing and pattern

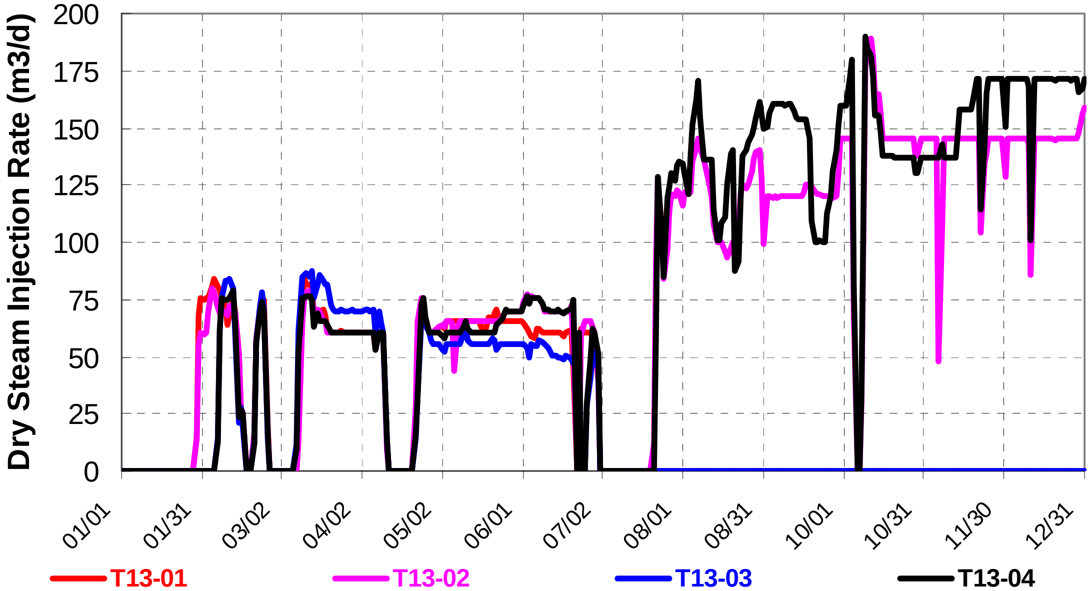
The horizontal well-pairs are spaced approximately 150 m apart, with approximately 650 m of drainage length per well. This translates into a drainage pattern of approximately 97,500 m^2 (150m * 650 m), which is roughly 24 acres per well.

4 Production Performance

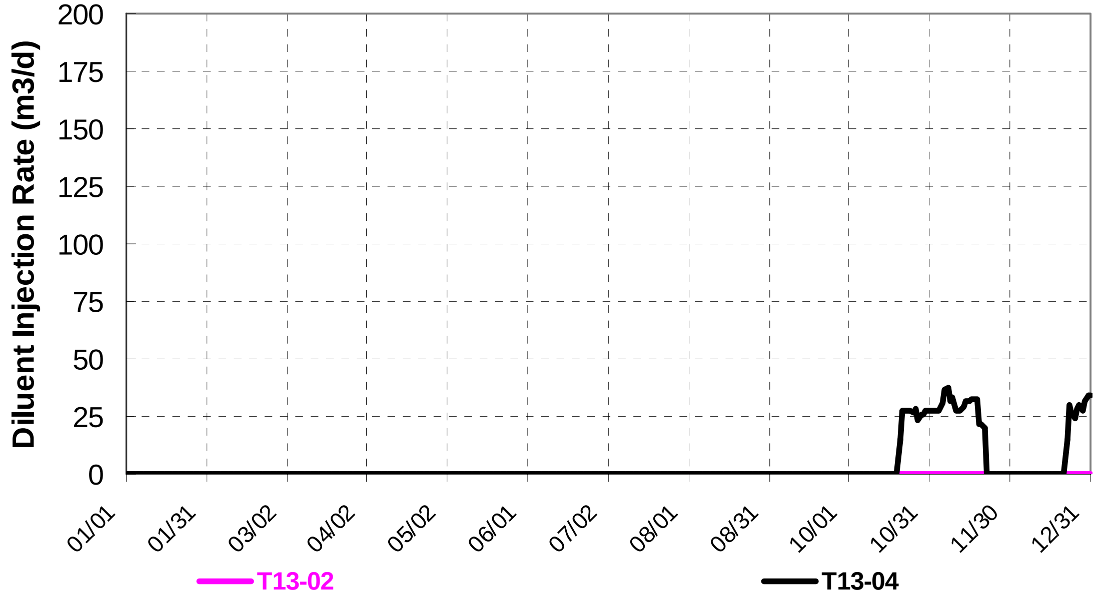
4.1 Injection and production history

Warm-up steam re-commenced on January 30, 2010 and continued until June 30, 2010. Typical daily rates ranged from 50 - 75 m^3/day per well.

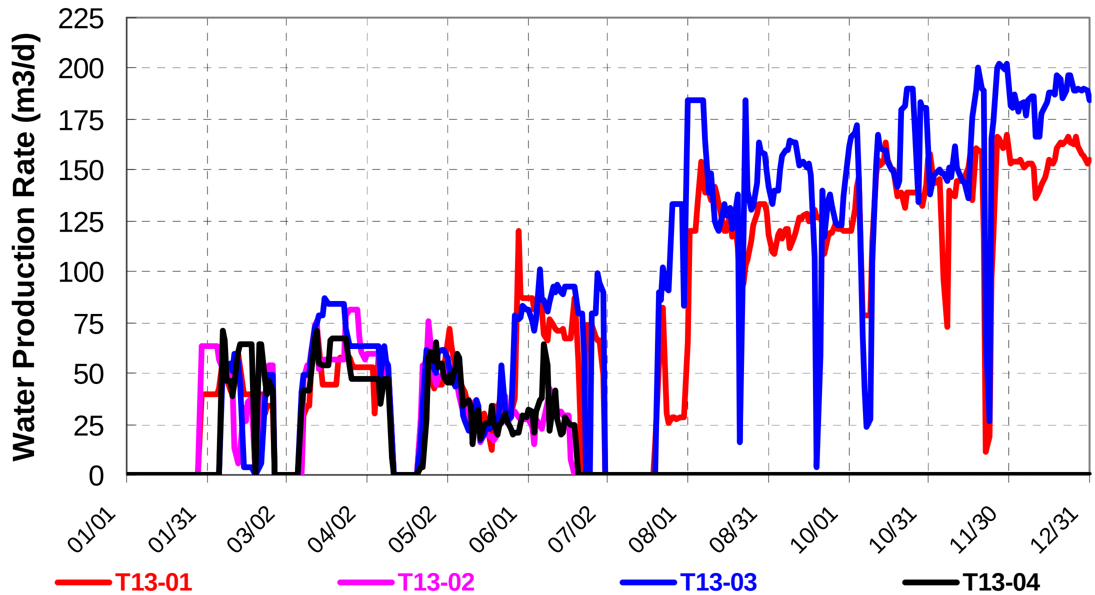
Warm-up was successfully completed on June 30, 2010. SAGD mode commenced on July 20, 2010 with steam injection occurring only on the "injector wells" (T13-02 & T13-04). Typical daily rates ranged from 120 – 170 m^3/day per well. A plot of the daily steam injection rates for each well is shown below.



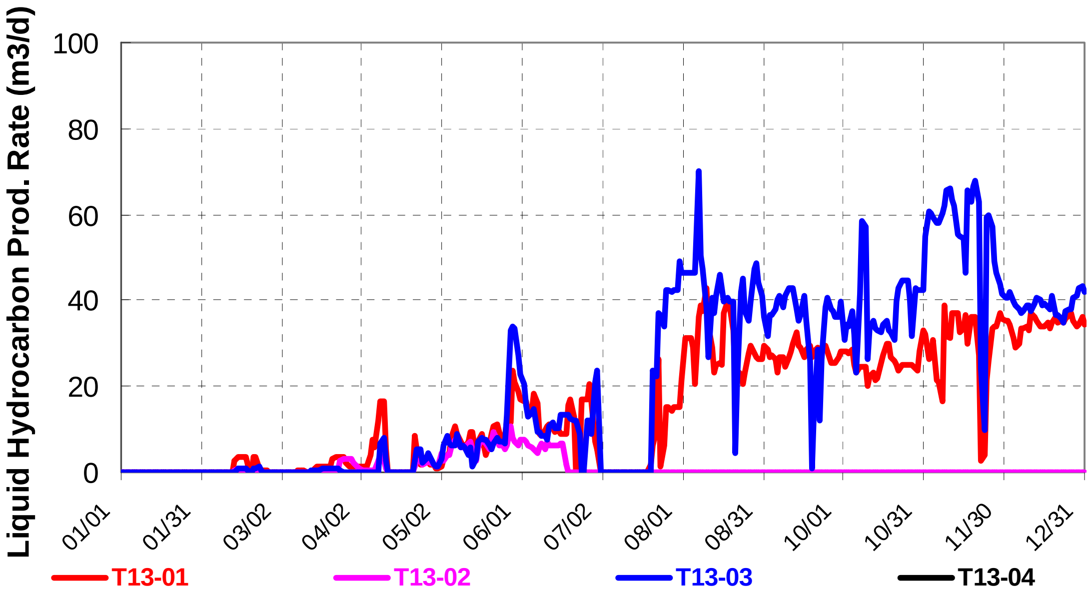
Solvent injection commenced on well T13-04 on October 20, 2010, thus converting well-pair 2 to SA-SAGD operation. Typical daily solvent rates (when diluent was being injected) ranged from 27 – 37 m^3/day for well T13-04. A plot of the daily diluent injection rates for each well is shown below.



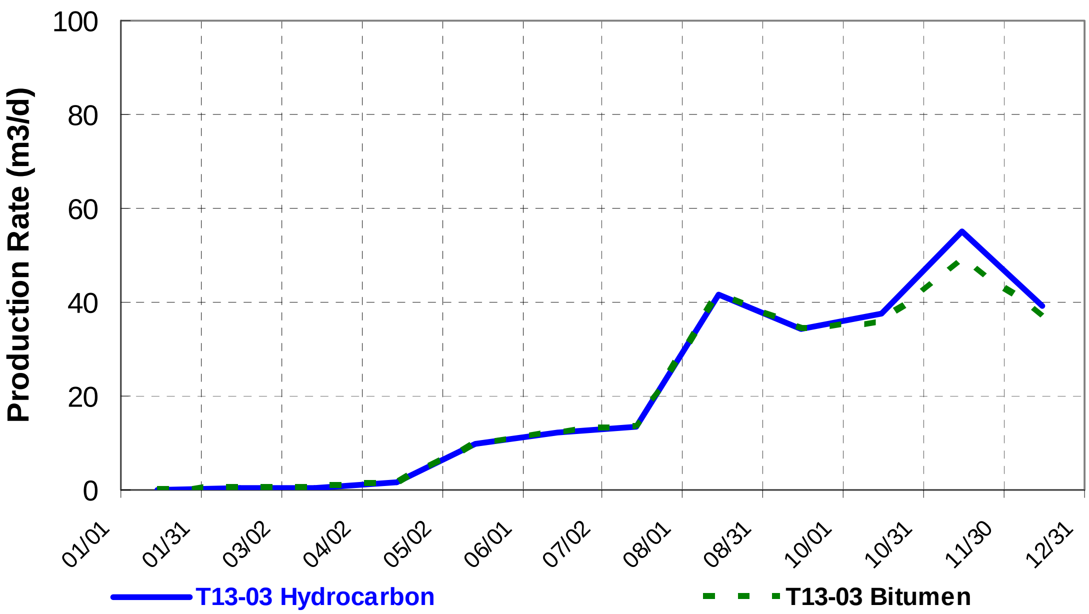
Water production during 2010 consisted of water from the condensing steam. Water production volumes from each well (daily average rates) are shown below.



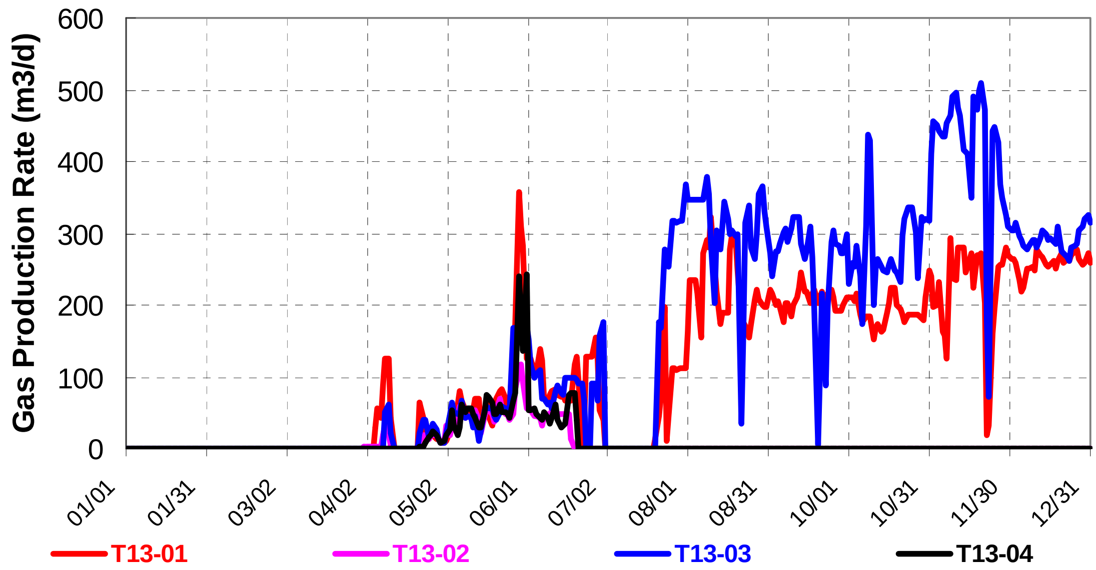
Near the end of the warm-up phase, small volumes of oil were being produced. Liquid hydrocarbon volumes ramped up as SAGD operation commenced. Once SA-SAGD mode commenced on well-pair 2, recovered solvent was observed in the liquid hydrocarbon phase. Liquid hydrocarbon production volumes from each well (daily average rates) are shown below.



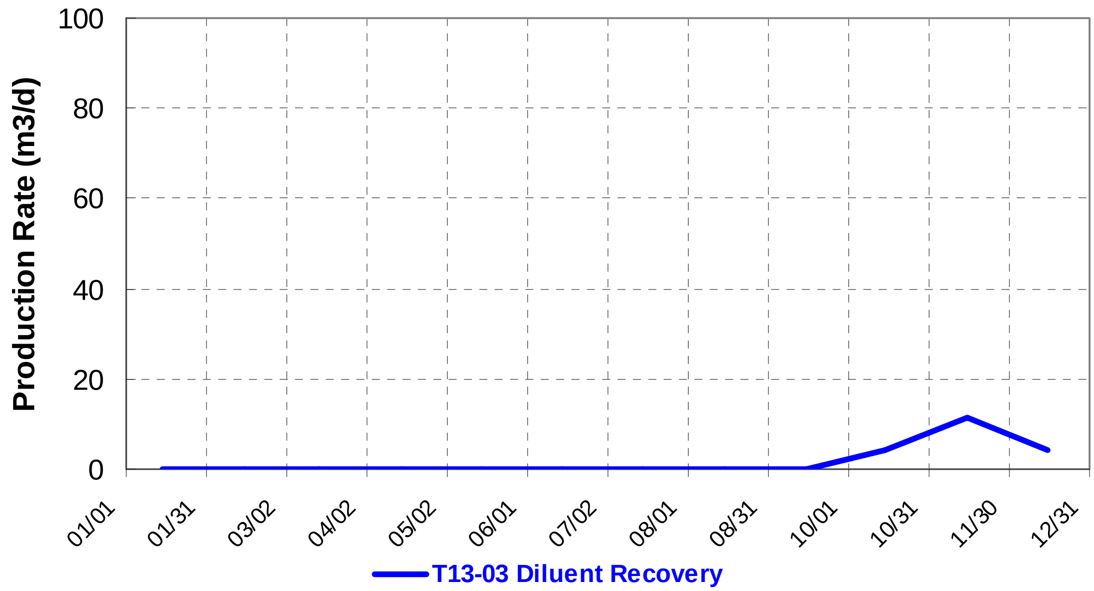
Apart from T13-03, hydrocarbon volumes shown above were all bitumen volumes. From production test samples, it was found that 2 – 6 m^3/day of T13-03 hydrocarbon liquid volumes were recovered diluent. A breakdown of T13-03 hydrocarbon volumes to show bitumen production versus total hydrocarbon volumes (monthly average rates) is shown below.



Gas production during 2010 consisted of solution gas as well as other naturally occurring reservoir gases. Due to metering issues, gas production volumes from August to December 2010 were likely not accurate, and as a result, solution gas was estimated using a standard Cold Lake GOR (7.5 m^3/m^3). Gas production volumes from each well (daily average rates) are shown below.



Diluent recovery was also measured once diluent injection commenced. It was observed that roughly 40 - 50% of injected volumes were being recovered on a monthly basis. It was estimated that roughly half of the recovered diluent was returning in the liquid stream, with the other half in the gas stream. Total diluent recovery volumes (recovered from both the liquid and gas streams) from T13-03 (monthly average rates) are shown below.



4.2 Composition of produced / injected fluids

The composition of the injected fluid consisted of dry steam (both well-pairs) and diluent (well-pair 2 only). Injected diluent for the SA-SAGD well pair is sourced from Provident Midstream from its facility in Redwater, AB. The table below details a typical composition of the diluent.

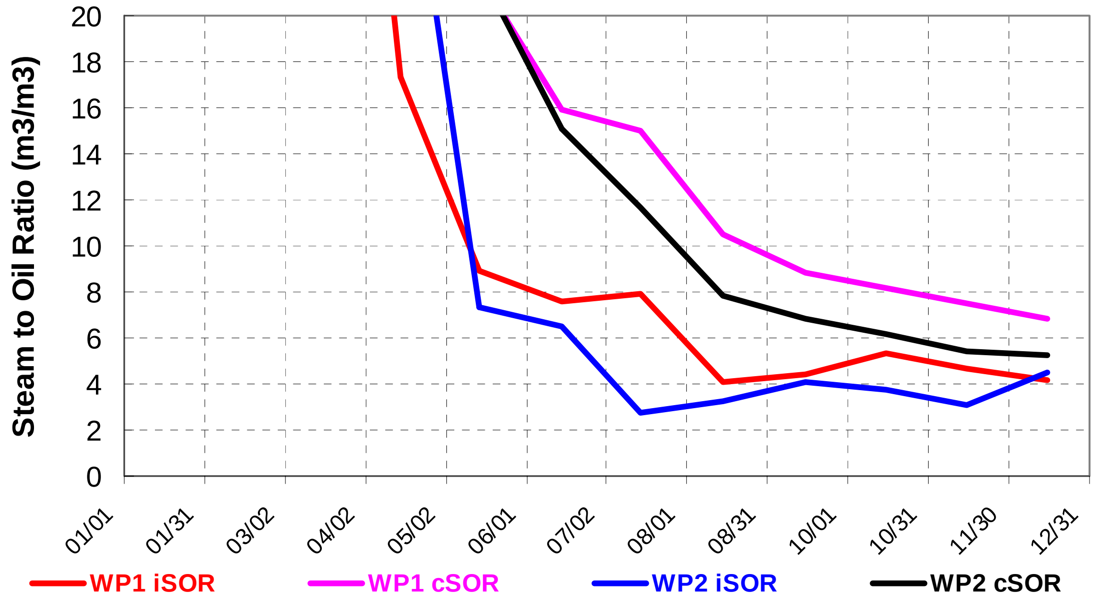
COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0010	0.0005	0.0007
i-Butane	i-C4	0.0039	0.0027	0.0032
n-Butane	n-C4	0.0451	0.0312	0.0361
i-Pentane	i-C5	0.2108	0.1811	0.1961
n-Pentane	n-C5	0.2036	0.1749	0.1876
Hexanes	C6	0.1696	0.1740	0.1773
Heptanes	C7	0.0971	0.1158	0.1139
Octanes	C8	0.0641	0.0872	0.0835
Nonanes	C9	0.0245	0.0374	0.0351
Decanes	C10	0.0061	0.0103	0.0095
Undecanes	C11	0.0006	0.0011	0.0009
Dodecanes	C12	0.0002	0.0004	0.0003
Tridecanes	C13	Trace	Trace	Trace
Tetradecanes	C14	0.0000	0.0000	0.0000
Pentadecanes	C15	0.0000	0.0000	0.0000
Hexadecanes	C16	0.0000	0.0000	0.0000
Heptadecanes	C17	0.0000	0.0000	0.0000
Octadecanes	C18	0.0000	0.0000	0.0000
Nonadecanes	C19	0.0000	0.0000	0.0000
Eicosanes	C20	0.0000	0.0000	0.0000
Heneicosanes	C21	0.0000	0.0000	0.0000
Docosanes	C22	0.0000	0.0000	0.0000
Tricosanes	C23	0.0000	0.0000	0.0000
Tetracosanes	C24	0.0000	0.0000	0.0000
Pentacosanes	C25	0.0000	0.0000	0.0000
Hexacosanes	C26	0.0000	0.0000	0.0000
Heptacosanes	C27	0.0000	0.0000	0.0000
Octacosanes	C28	0.0000	0.0000	0.0000
Nonacosanes	C29	0.0000	0.0000	0.0000
Triacontanes Plus	C30 +	0.0000	0.0000	0.0000
Benzene	C6H6	0.0095	0.0088	0.0068
Toluene	C7H8	0.0150	0.0164	0.0128
Ethylbenzene, p + m-Xylene	C8H10	0.0190	0.0240	0.0187
o-Xylene	C8H10	0.0048	0.0061	0.0046
1, 2, 4 Trimethylbenzene	C9H12	0.0003	0.0004	0.0003
Cyclopentane	C5H10	0.0243	0.0203	0.0183
Methylcyclopentane	C6H12	0.0343	0.0344	0.0309
Cyclohexane	C6H12	0.0267	0.0268	0.0231
Methylcyclohexane	C7H14	0.0395	0.0462	0.0403
TOTAL		**1.0000**	**1.0000**	**1.0000**

Produced fluids consisted of condensed water, bitumen, and recovered solvent. The table below details a typical composition of Cold Lake bitumen.

COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0000	0.0000	0.0000
i-Butane	i-C4	0.0000	0.0000	0.0000
n-Butane	n-C4	0.0000	0.0000	0.0000
i-Pentane	i-C5	0.0000	0.0000	0.0000
n-Pentane	n-C5	0.0000	0.0000	0.0000
Hexanes	C6	0.0000	0.0000	0.0000
Heptanes	C7	0.0000	0.0000	0.0000
Octanes	C8	Trace	Trace	Trace
Nonanes	C9	Trace	Trace	Trace
Decanes	C10	0.0025	0.0006	0.0007
Undecanes	C11	0.0084	0.0022	0.0024
Dodecanes	C12	0.0174	0.0050	0.0054
Tridecanes	C13	0.0290	0.0090	0.0096
Tetradecanes	C14	0.0344	0.0115	0.0122
Pentadecanes	C15	0.0411	0.0147	0.0155
Hexadecanes	C16	0.0425	0.0162	0.0169
Heptadecanes	C17	0.0425	0.0172	0.0179
Octadecanes	C18	0.0404	0.0173	0.0179
Nonadecanes	C19	0.0391	0.0177	0.0182
Eicosanes	C20	0.0368	0.0175	0.0180
Heneicosanes	C21	0.0366	0.0183	0.0187
Docosanes	C22	0.0313	0.0164	0.0167
Tricosanes	C23	0.0296	0.0162	0.0164
Tetracosanes	C24	0.0261	0.0149	0.0150
Pentacosanes	C25	0.0246	0.0146	0.0147
Hexacosanes	C26	0.0243	0.0150	0.0150
Heptacosanes	C27	0.0225	0.0144	0.0144
Octacosanes	C28	0.0217	0.0144	0.0144
Nonacosanes	C29	0.0218	0.0150	0.0149
Triacontanes Plus	C30 +	0.4274	0.7319	0.7251
Benzene	C6H6	0.0000	0.0000	0.0000
Toluene	C7H8	0.0000	0.0000	0.0000
Ethylbenzene, p + m-Xylene	C8H10	0.0000	0.0000	0.0000
o-Xylene	C8H10	0.0000	0.0000	0.0000
1, 2, 4 Trimethylbenzene	C9H12	0.0000	0.0000	0.0000
Cyclopentane	C5H10	0.0000	0.0000	0.0000
Methylcyclopentane	C6H12	0.0000	0.0000	0.0000
Cyclohexane	C6H12	0.0000	0.0000	0.0000
Methylcyclohexane	C7H14	0.0000	0.0000	0.0000
TOTAL		**1.0000**	**1.0000**	**1.0000**

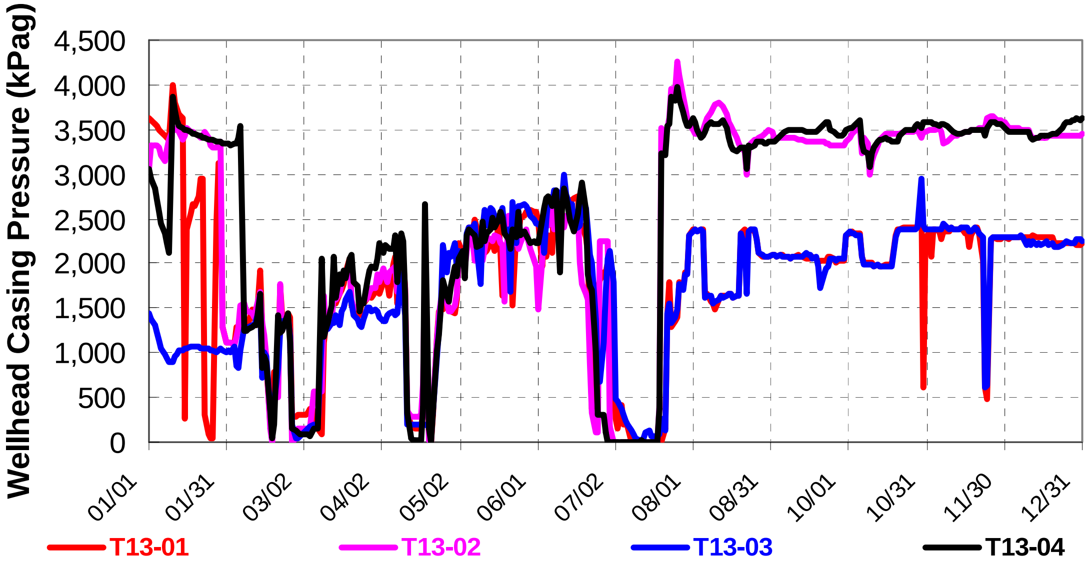
4.3 Predicted vs. actual comparisons

With SAGD being initiated in mid 2010, instantaneous steam to oil ratios (SOR) of 3 – 5 m^3 steam / m^3 oil were observed, with cumulative SORs of 6.9 (well-pair 1) and 5.3 (well-pair 2) at the end of 2010. This is within the expected range of performance. The effect that solvent injection has on the SAGD process has yet to be determined due to the short period of solvent injection in 2010. A plot of instantaneous and cumulative SORs (monthly averages) for each well-pair are shown below.



4.4 Pressures

The wellhead pressure at the casing (circulation return pressure) varied in the 1,500 – 3,000 kPa range during warm-up. During SAGD operation, steam is injected close to reservoir pressure (3,500 kPa) in wells T13-02 and T13-04, with production in the 2,000 – 2,400 kPa range (wells T13-01 and T13-03). Plots of casing wellhead pressures (daily average) for each well are shown below.

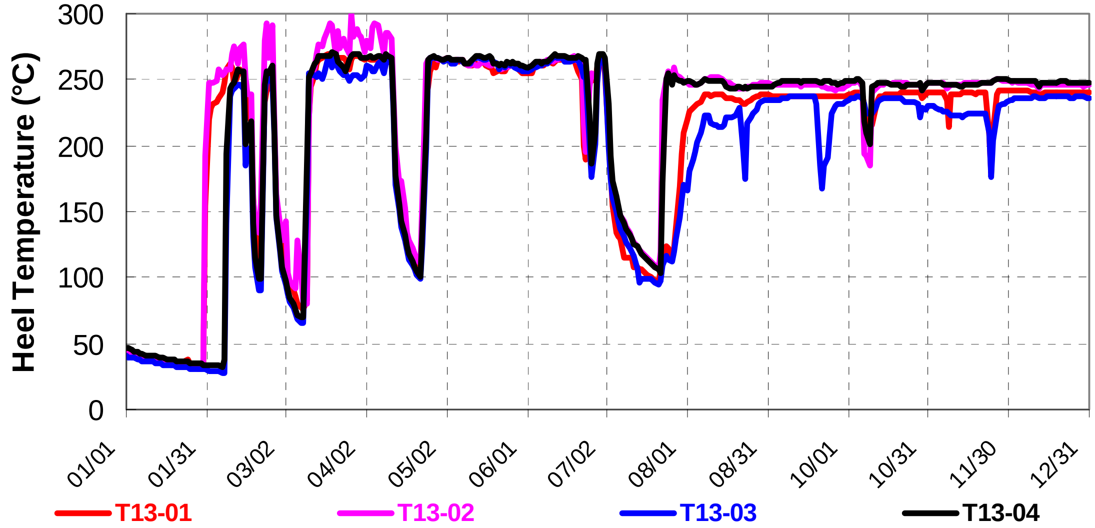


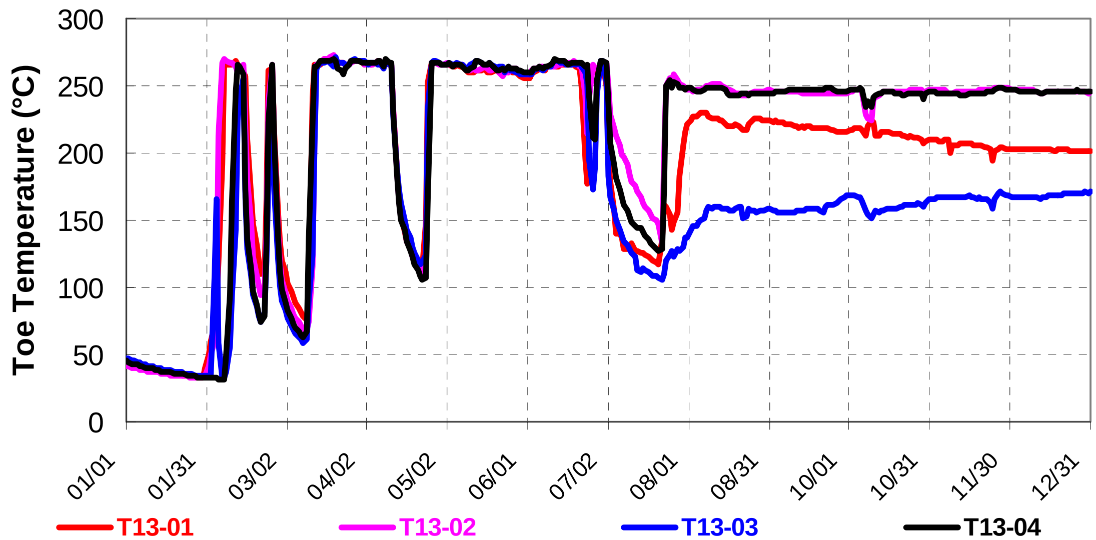
5 Pilot Data

5.1 Additional data

Beyond pressure and production, additional surveillance data collected during this time included temperature in each horizontal well and all six observation wells.

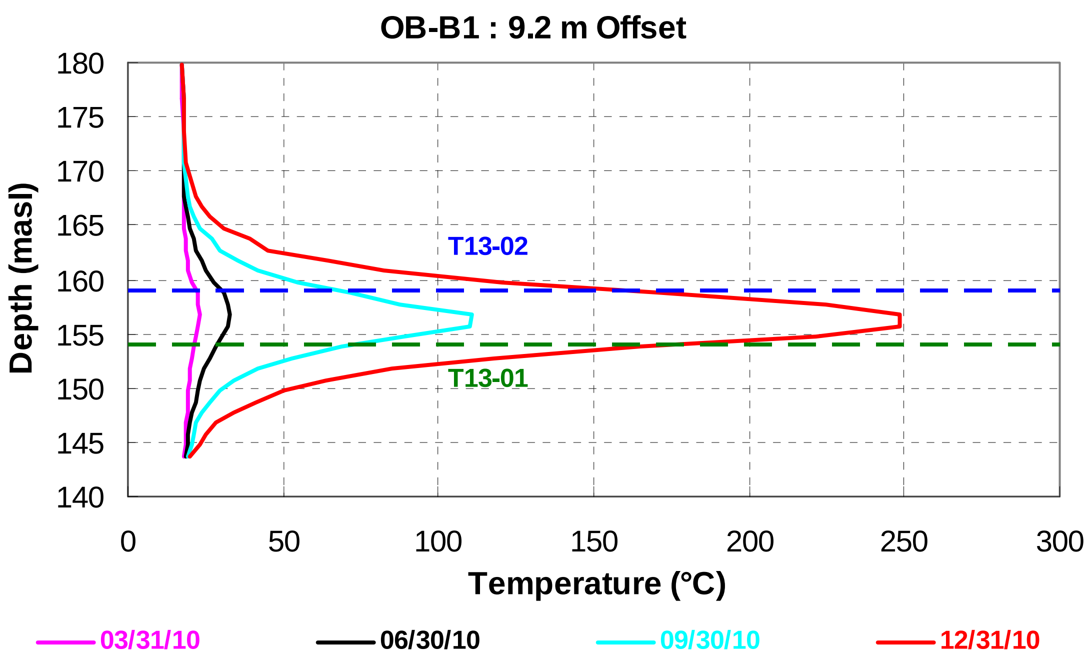
The heel and toe temperatures were generally around saturated steam temperature (265 °C) during warm-up phase. The injector wells continued to be at saturated steam temperature (250 °C due to lower injection pressure) once SAGD operation started. Temperatures on the producer wells varied from 160 – 250 °C along the wells during SAGD operation. Temperatures (daily average) along the horizontal well at the "heel" and "toe" wells are shown below.

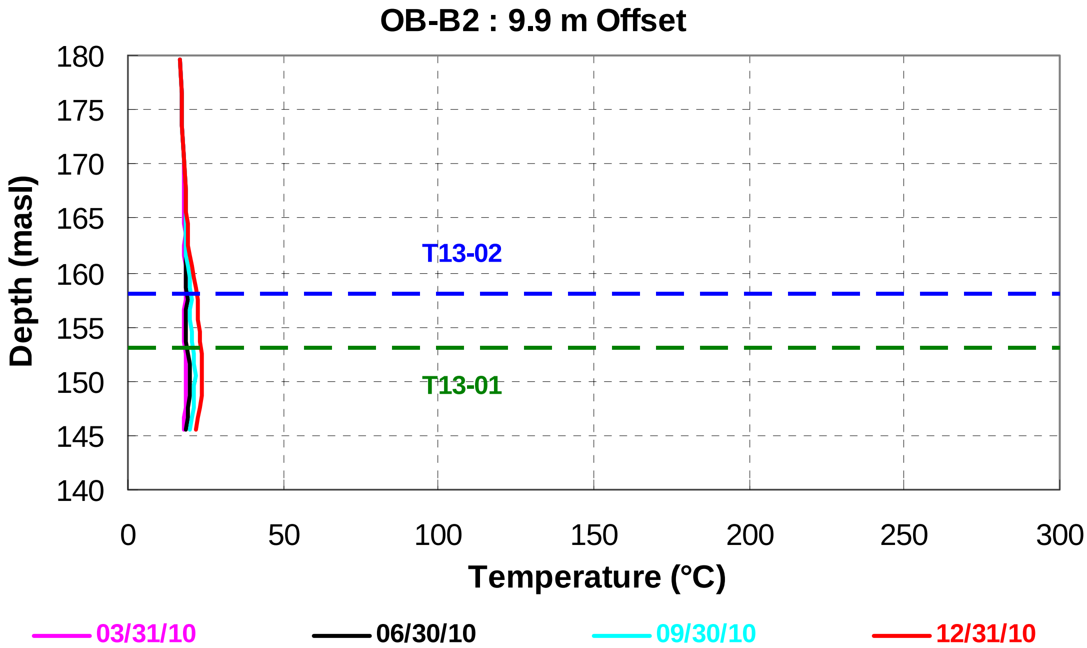


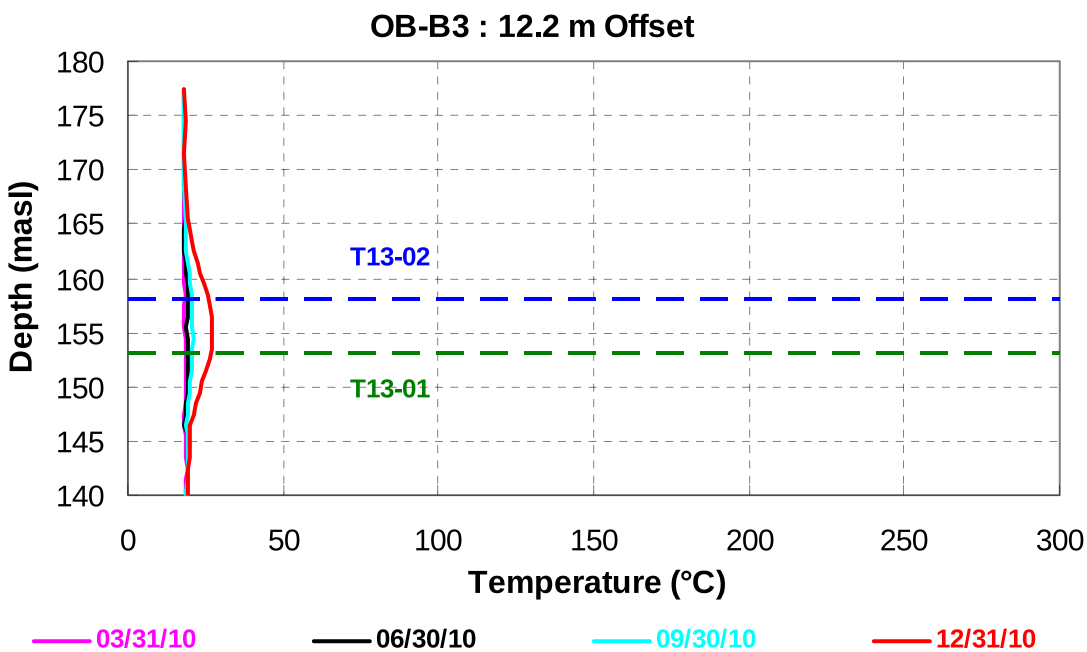


There are six total observation wells, three for each well-pair, that are positioned at the toe, heel, and midpoint of each horizontal well-pair. The offset distance from the horizontal wells varies between 5.7 and 13. 5 m. The temperature at the observation wells provides a measure of the amount of heat transferred to the reservoir.

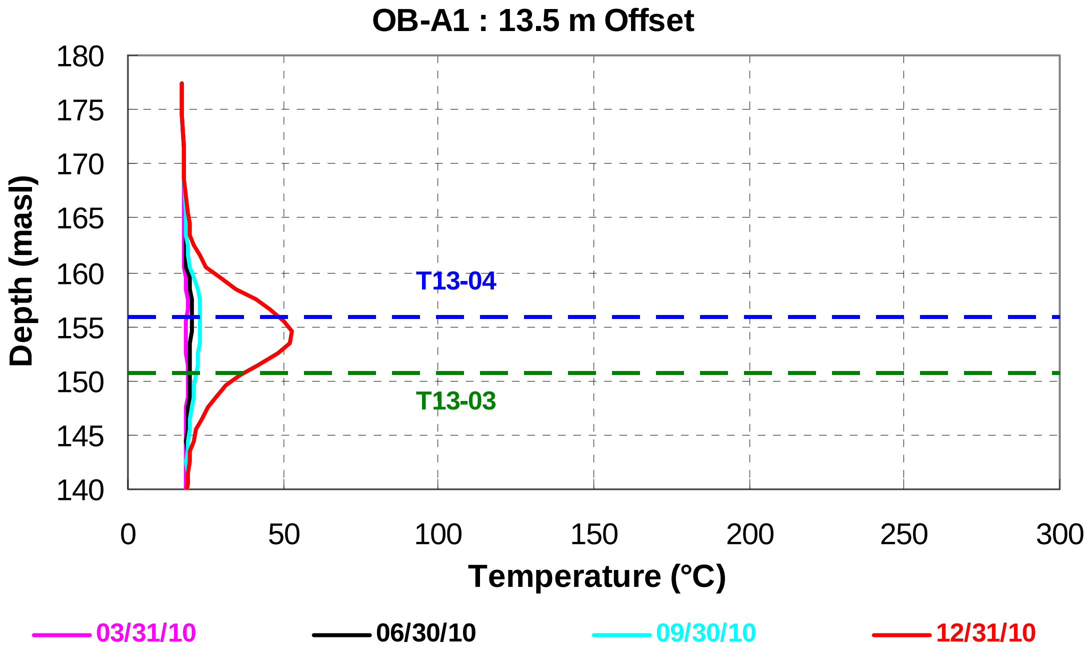
Observation wells OB-B1, B2, and B3 are adjacent to heel, mid, and toe of well-pair 1 (T13-01 & T13-02). Steam temperature was reached on OB-B1 by the end of 2010. Temperature responses of between 5 – 10°C were also observed on B2 & B3. The temperature as a function of depth is shown below for each observation well at three-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).

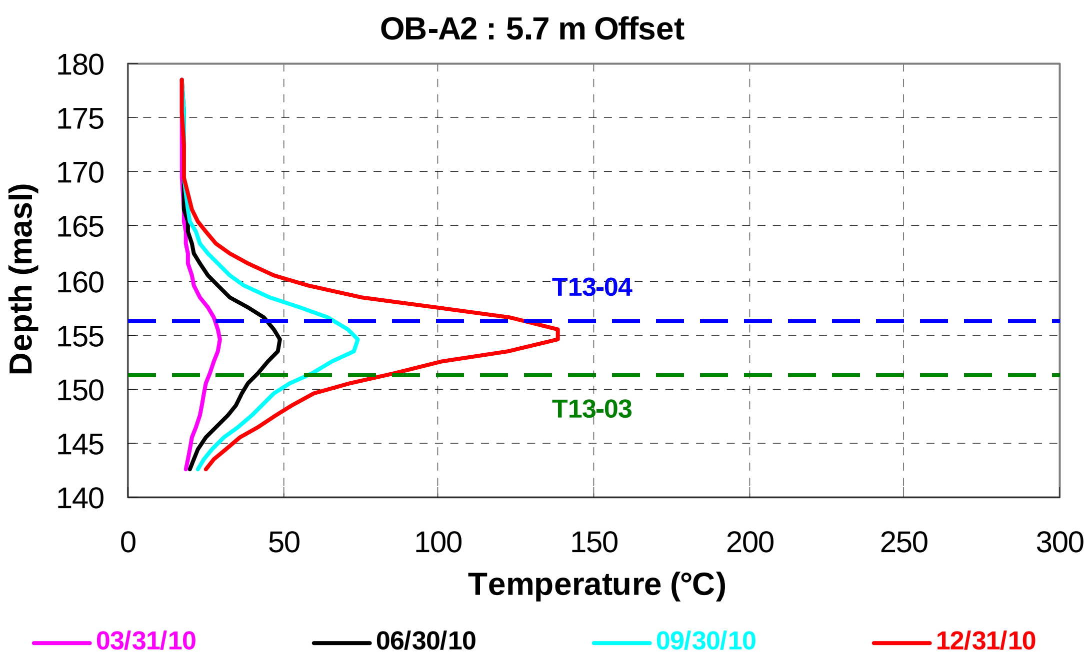


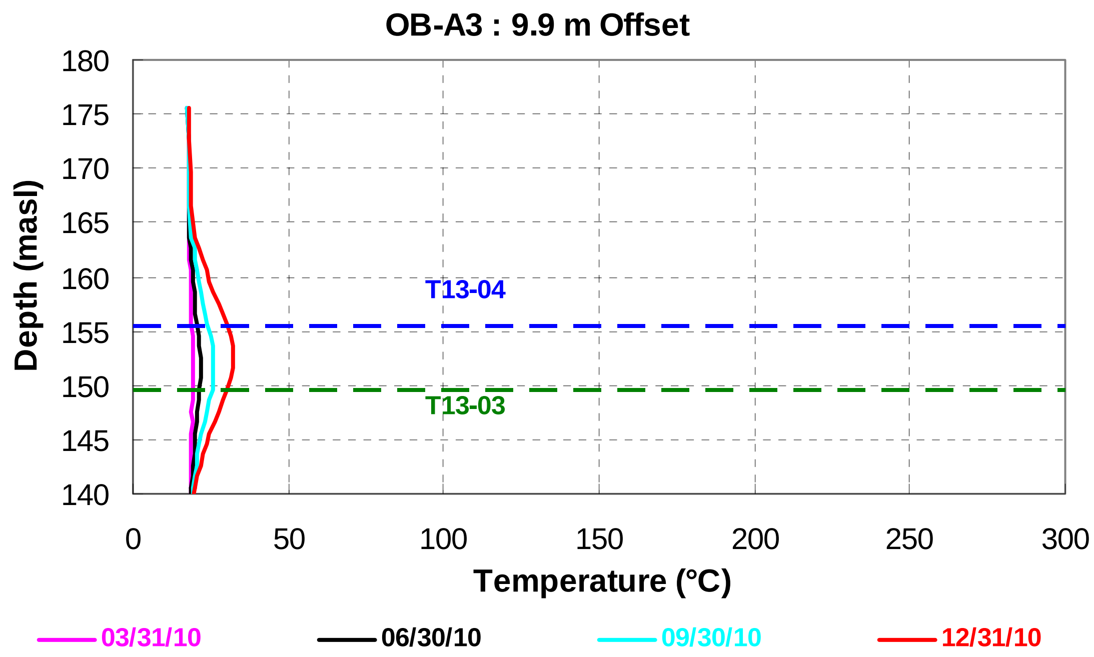

OB-B2 : 9.9 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
0
50
100
150
200
250
300
Temperature (°C)
T13-02
T13-01
03/31/10
06/30/10
09/30/10
12/31/10


OB-B3 : 12.2 m Offset
Depth (masl)
180
175
170
165
160
155
150
145
140
0
50
100
150
200
250
300
Temperature (°C)
T13-02
T13-01
03/31/10
06/30/10
09/30/10
12/31/10

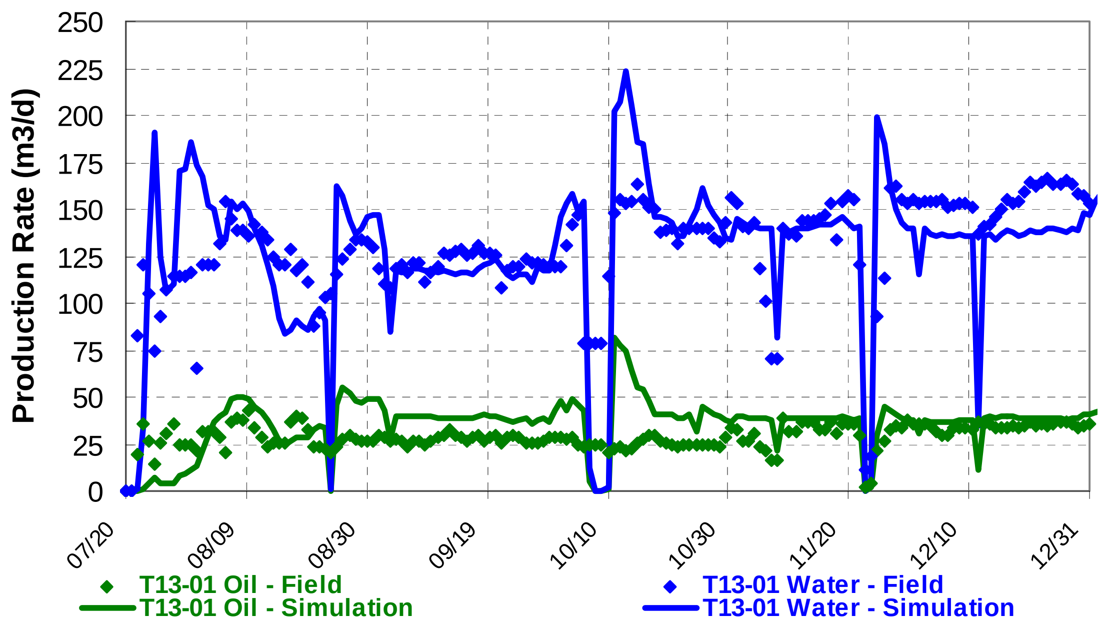
Observation wells OB-A1, A2, and A3 are adjacent to heel, mid, and toe of well-pair 2 (T13-03 & T13-04). Temperature response was seen primarily on OB-A2 which reached approximately 140°C by the end of 2010. Temperature responses were also observed on A1 & A3. The temperature as a function of depth is shown below for each observation well at three-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).



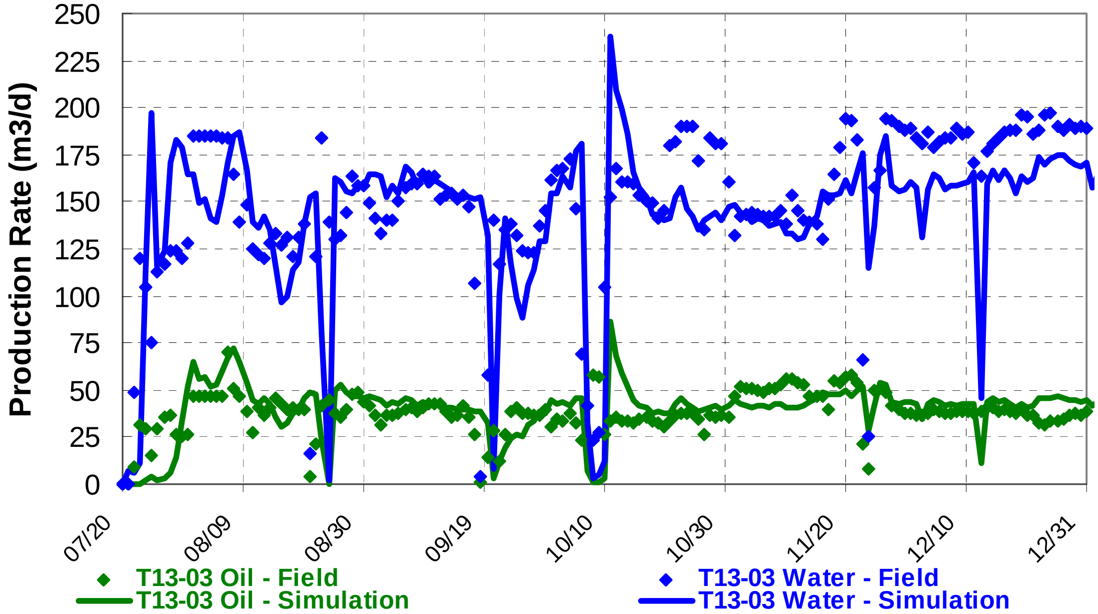




Field data was also used to generate history matched petrel based simulation models for SAGD / SA-SAGD operation, and create go forward predictions. Using steam injection volumes and production pressures as inputted values, oil and water production rates were history matched. A plot showing the history match that was attained for well-pair 1 is shown below.

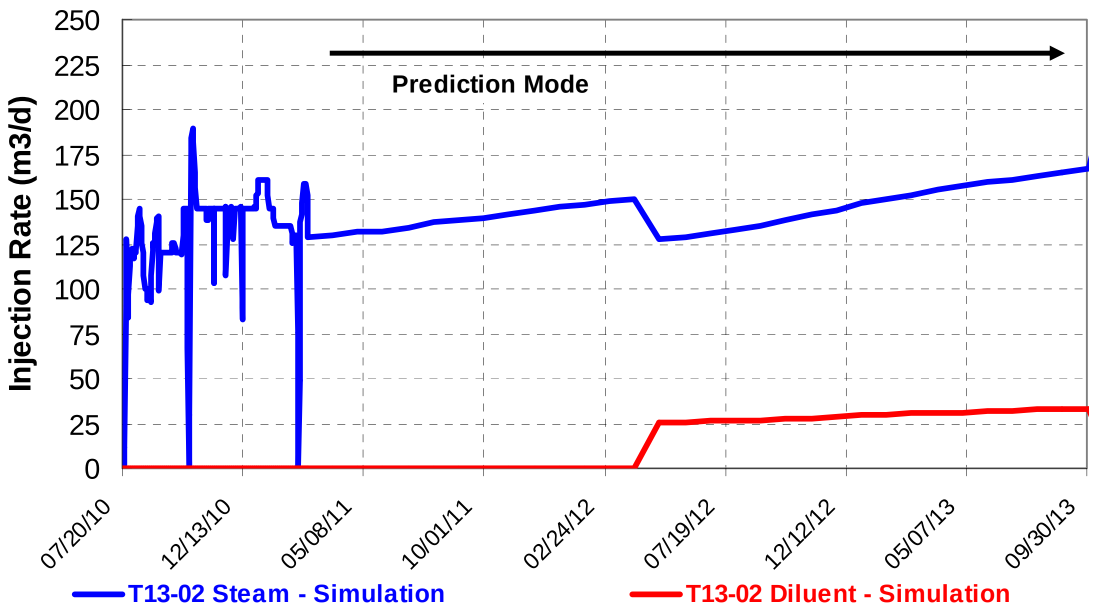


It can be seen that a reasonable water match is attainted, and excluding a slighter higher match in September and October, a reasonable oil match is also attained. A plot showing the history match that was attained for well-pair 2 is shown below.

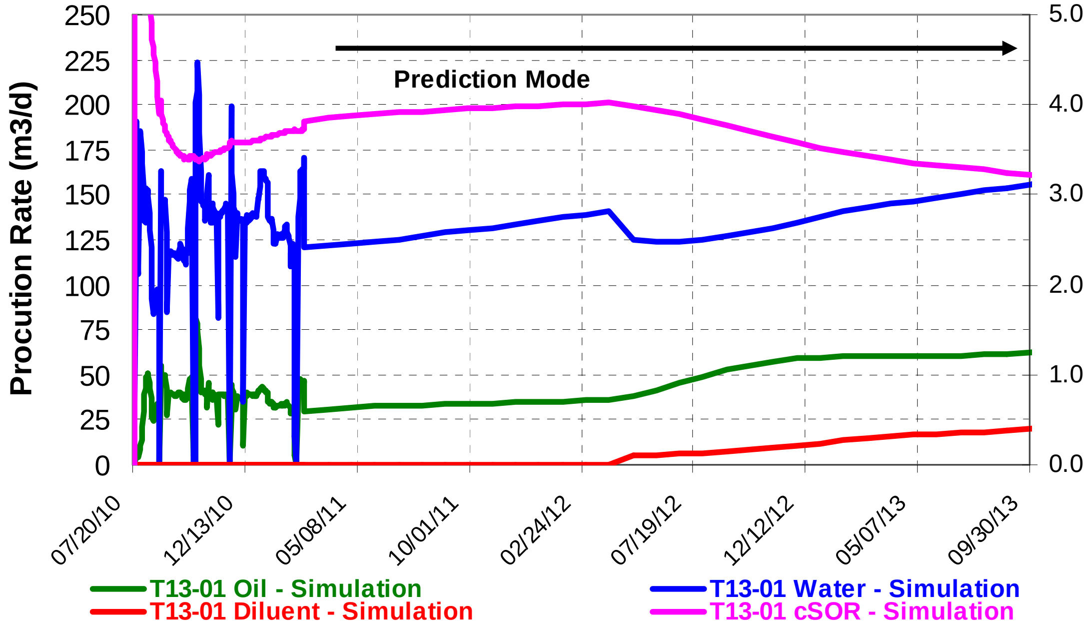


It can be seen that for well-pair 2 a reasonable water and oil match is attainted.

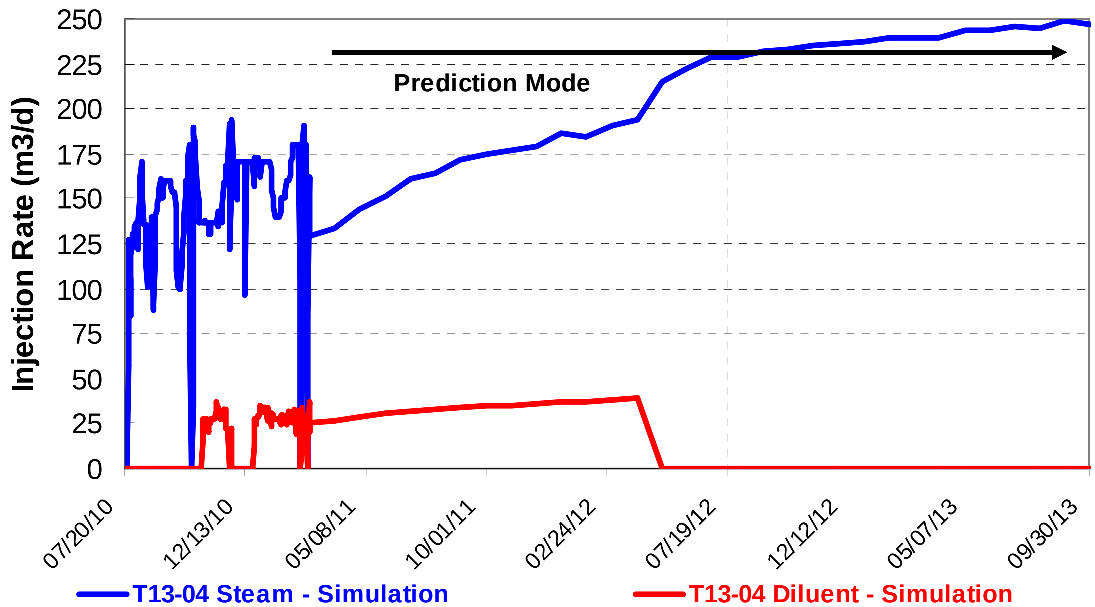
Using these same history matched simulation models, go forward injection and production performance was predicted to the end of pilot period (September 30, 2013). A plot showing the predicted injection profile for well-pair 1 is shown below.



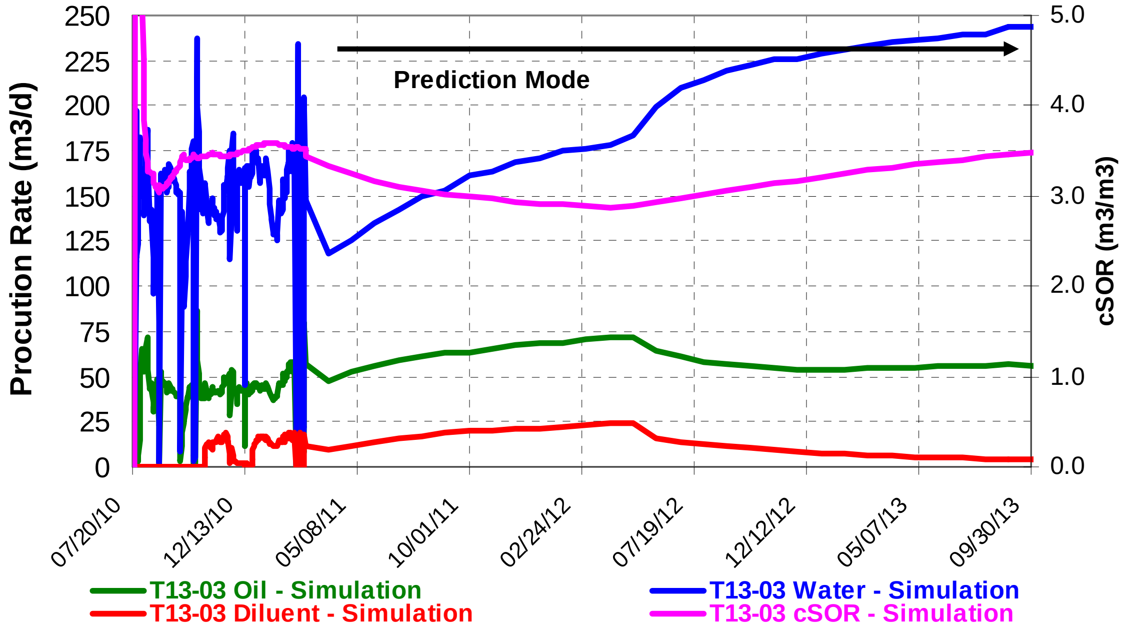
Steam rates are expected to slowly increase with time in order to maintain reservoir pressure as the steam chamber matures. Once the pilot reaches the half-way mark (May 2012), solvent injection will begin on well-pair 1, converting it to a SA-SAGD operation. This well-pair is then expected to continue operating in SA-SAGD mode until the end of the pilot period. A plot showing the predicted production profile for well-pair 1 is shown below.



Oil and water production rates are expected to continue increasing with time as the well-pair progresses in SAGD operation. Once solvent injection commences, an oil uplift is expected to bring rates from 35 m^3/day to 45 m^3/day within two months, and rates are expected to continue increasing to around 60 m^3/day by the end of the pilot, as the steam and solvent chamber continues to mature further. Cumulative SOR is expected to remain around 4 m^3/m^3 during SAGD mode, and begin declining to around 3.2 m3/m3 by the end of the SA-SAGD phase. Overall diluent recovery is expected to be around 40-50% by the end of the pilot period. A plot showing the predicted injection profile for well-pair 2 is shown below.



As with well-pair 1, steam rates are also expected to slowly increase with time in order to maintain reservoir pressure as the steam chamber matures. As this well-pair is currently operating in SA-SAGD mode, solvent injection will end once the pilot reaches the half-way mark (May 2012), thus converting well-pair 2 back to a SAGD operation. At the conversion point, an increase in steam injection is expected as diluent injection has ended, thus a greater steam rate is needed to maintain total injection pressure. This well-pair is then expected to continue operating in SAGD mode until the end of the pilot period. A plot showing the predicted production profile for well-pair 1 is shown below.



Oil and water production rates are expected to continue increasing with time as the well progresses in SA-SAGD operation. Once solvent injection ends, the oil rate is expected to decline from around 70 m^3/day to 55 m^3/day within three months. Cumulative SOR is expected to be around 2.9 m^3/m^3 by the end of SA-SAGD mode, and begin increasing to around 3.5 m3/m3 by the end of the SAGD phase. Overall diluent recovery is expected to be around 70-80% by the end of the pilot period, which is due to the longer recovery time given to this well-pair as compared to well-pair 1.

Other pilot surveillance data, such as saturation logs, 3D seismic, and tracers, were not planned for 2010.

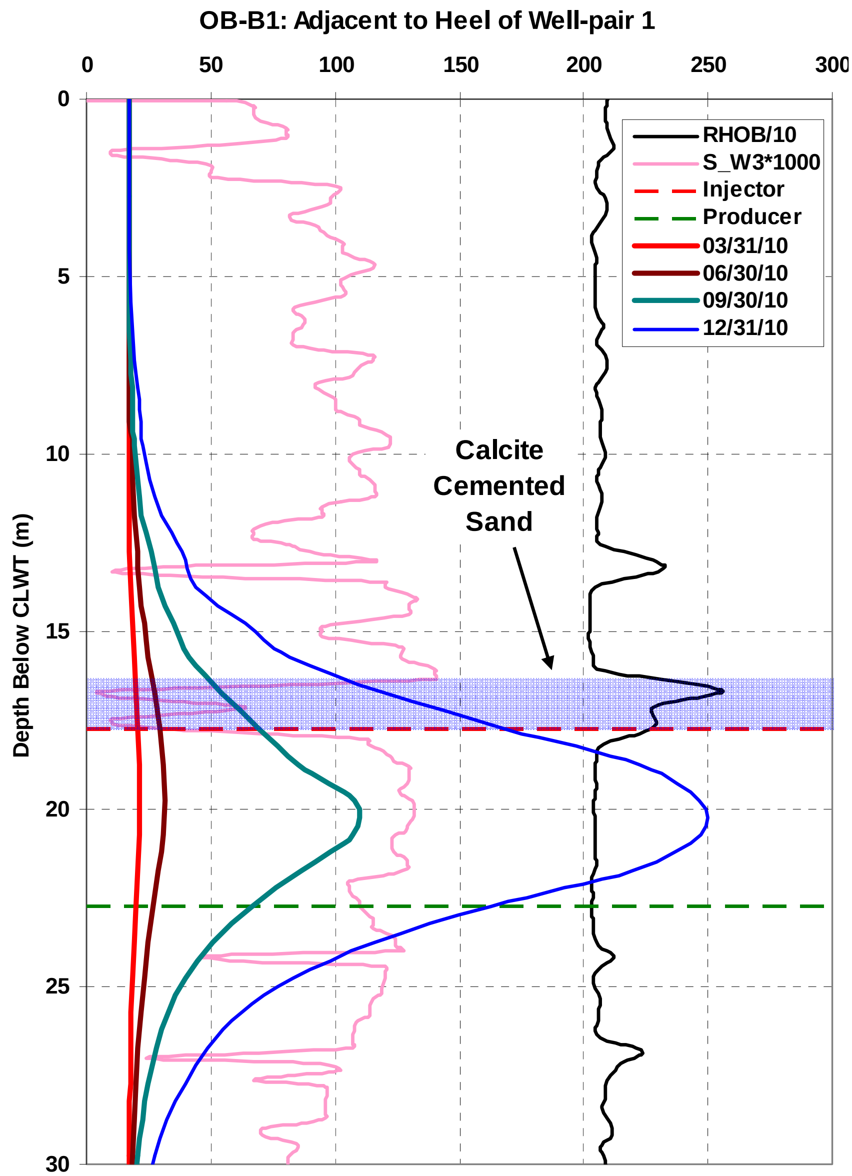
5.2 Interpretation of pilot data

The first half of 2010 consisted of steam circulation warm-up. Near the end of the warm-up phase, circulation from the injector wells was gradually choked off resulting in an increase of fluid production at the corresponding producer wells. This indicated that warm-up was successful at establishing communication between the well-pairs and aided in timing a switch to SAGD operation.

SAGD operation during the second half of the year yielded SORs in the 3 – 5 m^3 steam / m^3 oil which is within the range of expectations for a SAGD process in the Clearwater formation. With solvent injection commencing in late October in well-pair, an uplift in oil volumes was observed.

Due to the short period of solvent injection in 2010, interpretations regarding the effect of solvent addition have yet to be made.

Finally, the extent of reservoir heating can be interpreted from thermocouple data in each of the six observation wells. Well OB-B1 reached steam temperature by the end of 2010 indicating the extent of the steam chamber at the heel of well-pair 1. Temperature responses were also seen in wells OB-A1 and OB-A2, indicating lateral steam chamber growth in well-pair 2. It is also known that calcite cemented sands are present in this region, and may potentially be local barriers that impede vertical steam chamber growth. A plot showing OB well density and saturation for well B1 relative to the Clearwater Top (CLWT), with observation well temperatures superimposed is shown below.



In the plot, it can be observed that a calcite cemented sand (shaded blue region) is present a couple meters above the injector well (exhibits a higher density reading which corresponds to a lower bitumen saturation). While it is too early to conclude what effect this may have on vertical steam chamber growth, it is actively being monitored on this well and other observation wells which display similar geological features.

Overall, pilot performance to date is as expected. SAGD SORs are within the range of expectations for both well-pairs. An uplift in oil volumes in T13-03 was seen at the same time diluent injection commenced in well-pair 2 (SA-SAGD), with early production data being inline with predicted uplift and diluent recovery expectations. However, due to the short period of diluent injection in 2010, it is too early to draw conclusions or interpretations of the effect that solvent addition has to the SAGD process.

6 Pilot Economics

Price data used in this section is a combination of:

- WTI / solvent pricing from the Sproule December 31, 2010 price database
- Bitumen / natural gas pricing based on actual prices from Imperial Oil's 2010 10-K filing

	WTI (Cushing Oklahoma) C$/bbl	Bitumen C$/bbl	Solvent (Edmonton Pentanes Plus) C$/bbl	Natural Gas C$/mcf
2009	70.02	51.81	68.13	4.11
2010	81.79	58.36	84.21	4.04

6.1 Sales volumes of natural gas and by-products

Natural gas volumes produced consisted of solution gas. These gas volumes were sent via a production pipeline to Imperial's Mahkeses plant, and used as fuel gas for steam generation.

Natural gas production was 103,613 m^3 in 2010. Steam injection was 74,861 m^3 in 2010. Based on a 75 m^3 natural gas / m^3 steam ratio to generate steam, it is estimated that 5,614,538 m^3 of natural gas was required to generate steam volumes, thus the net gas volume for 2010 was -5,510,925 m^3 (103,613 m^3 - 5,614,538 m^3).

6.2 Revenue

As the SA-SAGD pilot is part of Imperial Oil's Cold Lake Production Project, injection and production volumes are blended with Mahkeses plant volumes, and thus revenue and net gas costs are not calculated separately.

Gross revenue for the pilot in 2010 is estimated to be C$ 4,898,707. This is based on a bitumen production volume of 13,345 m^3, and a bitumen price of 58.36 C$/bbl (367.07 C$/m^3).

6.3 Capital costs

The following table summarizes capital costs by category, incurred in 2010 (as per 2010 IETP claim form submissions):

Category	Description and Details of Capital Costs	Cost (C$)
Facilities	Drilling	4,520
	Surface Facilities (Steam injection facilities, separator; chemical injection facilities, separator; production facilities, pump jacks, ROV, coolers)	209,348
	Engineering Procurement Construction	272,452
	Trunkline / Laterals	0
	Facilities - Capital Related Expense	370,697
Drilling	Drilling four horizontal wells - 2 well-pairs, each well-pair consist of an injector and producer well.	0
	Completion of horizontal wells	162,317
	Capital Related Expense	9,829
Trunkline	Drilling	0
	Surface Facilities	0
	Engineering Procurement Construction	2,373
	Trunkline / Laterals	78,226
	Capital Related Expense	0
Total Capital Costs (C$)		**1,109,761**

6.4 Direct and indirect operating costs

The following table summarizes operating costs by category, incurred in 2010 (as per 2010 IETP claim form submissions):

Category	Description and Details of Operating Costs	Cost (C$)
Facility Exp.	Drilling observation wells, well heads, completions, reservoir monitoring instrumentation	0
	Completions	0
	Surface Facilities (Facilities portion associated with solvent injection: solvent tank, pump, lines; production and vent gas testing equipment, samples, separators, horizontal well reservoir monitoring instrumentation; EPCM)	317,270
Field Exp.	Field operating costs	902,639
	Surveillance costs	11,904
Total Operating Costs (C$)		**1,231,813**

In addition, as solvent injection commenced in late 2010, solvent injectant costs were incurred. This consisted of both cost of solvent, as well as trucking costs associated with transporting these volumes to site. Solvent costs incurred in 2010 were (as per 2010 IETP claim form submissions):

Total Injectant Costs (C$)	**811,423**

Lastly, as discussed in the 2009 annual report presentation, natural gas for the pilot is generated at Imperial Oil's Cold Lake Mahkeses plant, which falls outside of the IETP project scope. As steam generated for the SA-SAGD pilot is a small fraction of the total plant capacity, it is difficult to include steam generation costs in the IETP claim forms that are accurate and auditable. As a result, estimates have been made (see section 6.1 and 6.6) to aid in cash flow calculations. While these costs have not been included in IETP claim form submissions, Imperial can include them go forward and retroactively, if requested.

6.5 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. As revenue began to be generated in 2010, it is estimated the pilot contributed C$ 395,006 of royalties in 2010.

(C$)	2005	2006	2007	2008	2009	2010	Total ('05-'10)
SA-SAGD Revenue[1]	0	0	0	0	0	5,216,789	**5,216,789**
SA-SAGD CAPEX & OPEX[2]	1,484,356	1,442,184	1,661,186	20,463,138	12,569,963	3,152,997	**40,773,824**
SA-SAGD Gas Expense[3]	0	0	0	0	52,724	786,251	**838,975**
SA-SAGD Cash Flow	(1,484,356)	(1,442,184)	(1,661,186)	(20,463,138)	(12,622,687)	1,277,541	**(36,396,010)**
Cold Lake Royalty Rate	30%	30%	30%	25%	28%	31%	
Cold Lake Royalty Impact	(445,307)	(432,655)	(498,356)	(5,115,785)	(3,510,369)	395,006	**(9,607,466)**
Total Cold Lake Payable Royalties[4]	**157,264,756**	**375,655,398**	**338,663,276**	**574,810,144**	**448,583,045**	**627,504,000**	**2,522,480,618**

[1] Estimated, see section 6.6 for assumptions
[2] Based on IETP claim form submissions, see sections 6.3 and 6.4
[3] Estimated, see section 6.6 for assumptions
[4] Total Cold Lake royalties paid, which include SA-SAGD costs and revenue. IETP credits are not included.

6.6 Cash flow

As the SA-SAGD pilot is part of Imperial Oil's Cold Lake Production Project, injection and production volumes are blended with Mahkeses plant volumes, and thus revenue and net gas costs are not calculated separately. For the purpose of this report, estimates have been made for:

Bitumen revenue in 2010 = C$ 4,898,707 (see section 6.2)
Recovered solvent revenue in 2010 = C$ 318,082 (based on a recovered volume of 600.5 m^3, and a solvent price of 84.21 C$/bbl = 529.7 C$/m^3)
Net natural gas expense in 2010 = C$ 786,251 (see section 6.1 - based on a net gas volumes of -5,510,925 m^3 (-194,616 mcf), and a gas price of 4.04 C$/mcf)

Capital and operating costs are known to be:

Capital costs in 2010 = C$ 1,109,761 (see section 6.3)
Operating costs in 2010 = C$ 2,043,237 (see section 6.4 – includes operating and injectant costs)

2010 cash flow is estimated to be:

Cash Flow = Revenue – Costs – Royalties
= (Bitumen + Solvent Revenue) – (Capital + Net Gas + Operating Costs) – Royalties
= (4,898,707 + 318,082) – (1,109,761 + 786,251 + 2,043,237) – 395,006
= 5,216,789 – 3,939,248 – 395,006
= C$ 882,535

This does not include taxes.

6.7 Cumulative project costs and net revenue

Cumulative project costs to date are:

C$	Up to YE 2009	2010	Total (to YE 2010)
Total Capital Costs	25,024,122	1,109,761	**26,133,883**
Total Operating Costs	12,596,704	1,231,813	**13,828,517**
Total Injectant Costs	0	811,423	**811,423**
Total Net Gas Costs[1]	52,724	786,251	**838,975**
Total Costs	**37,673,550**	**3,939,248**	**41,612,798**

[1] Estimated, see section 6.6 for assumptions

Cumulative project revenue to date is:

C$	Up to YE 2009	2010	Total (to YE 2010)
Bitumen Revenue[2]	0	4,898,707	**4,898,707**
Solvent Revenue[3]	0	318,082	**318,082**
Total Revenue	**0**	**5,216,789**	**5,216,789**

[2] Estimated, see section 6.2 for assumptions
[3] Estimated, see section 6.6 for assumptions

6.8 Deviations from budgeted costs

Changes from actual versus budgeted costs were outlined in the 2009 annual progress report. There have since been no further changes.

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

Diluent injection was shut-in on November 25. This was due to ice forming in the diluent line (as a result of an earlier maintenance shut-in) which caused a flow blockage, thus increasing the line pressure and lifting the diluent pressure safety valve (PSV). Diluent was directed to the pad pop tank, thus no safety or environmental concerns arose. Measures were then put in place to avoid a similar incident from re-occurring, and diluent injection re-commenced on December 22, 2010.

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:

▪ Switch well operation (SA-SAGD on well-pair 1, and SAGD on well-pair 2)	Q2, 2012
▪ 2011 Progress Report	Q2, 2012
▪ 2012 Progress Report	Q2, 2013
▪ Final Report Issued	Q2, 2014

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 overall 2010 performance:

- Circulation (warm-up phase) was successfully completed in late June, 2010
- SAGD mode commenced in late July, 2010
- SA-SAGD mode commenced on well-pair 2 in late October, 2010
- SAGD performance to date is within the expected range
- The effect that solvent injection has on SAGD has yet to be determined due to the short period of solvent injection in 2010.

Difficulties Encountered

Other than a brief shut-in of diluent injection (as discussed in section 7.2), no major difficulties were encountered in 2010.

Technical and Economic Viability

Due to the short solvent injection period in 2010, 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)

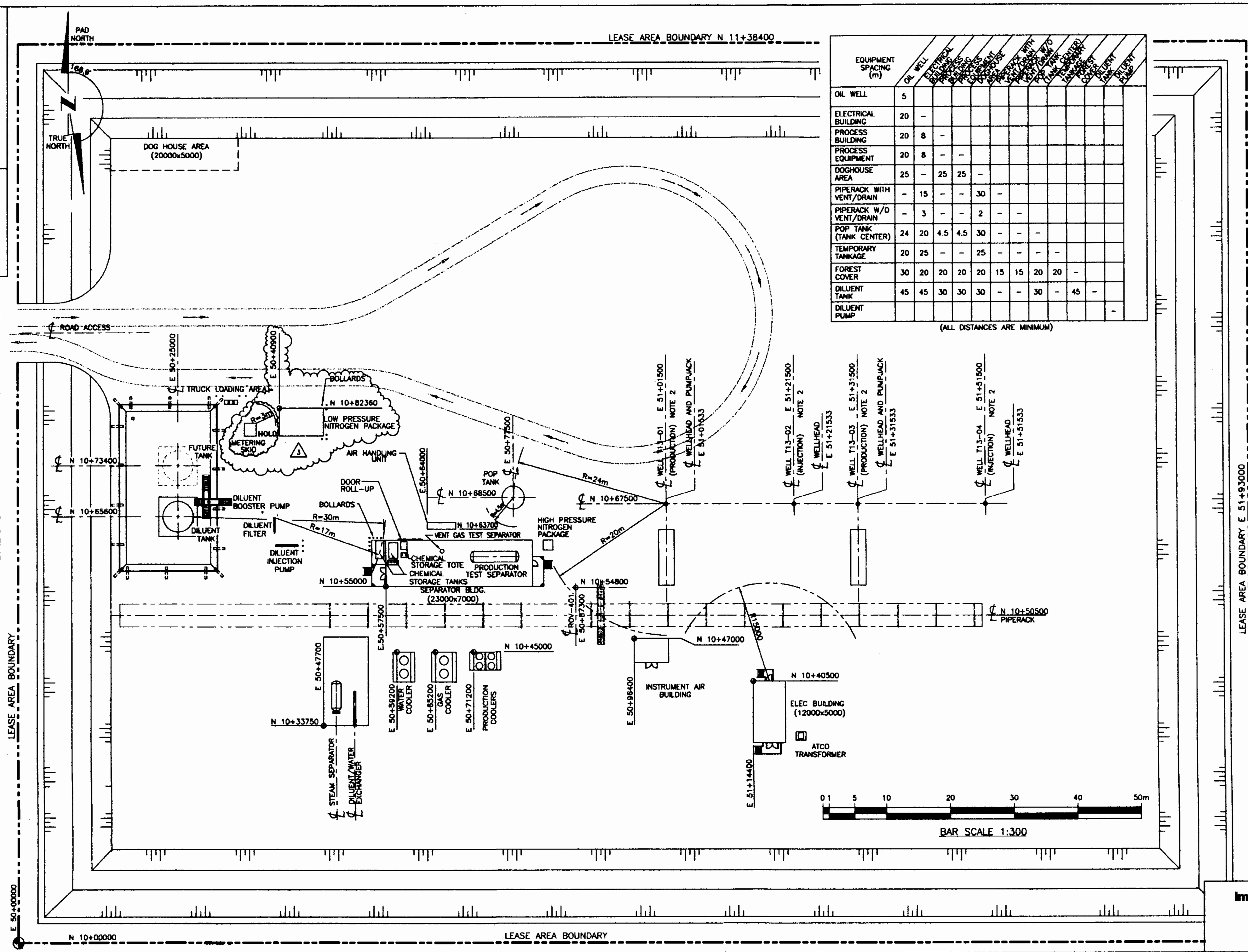
&

Site Maps

073-1151-010-302 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES



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 ZJCEO).
- 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.

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

Version: 4

D-STD

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

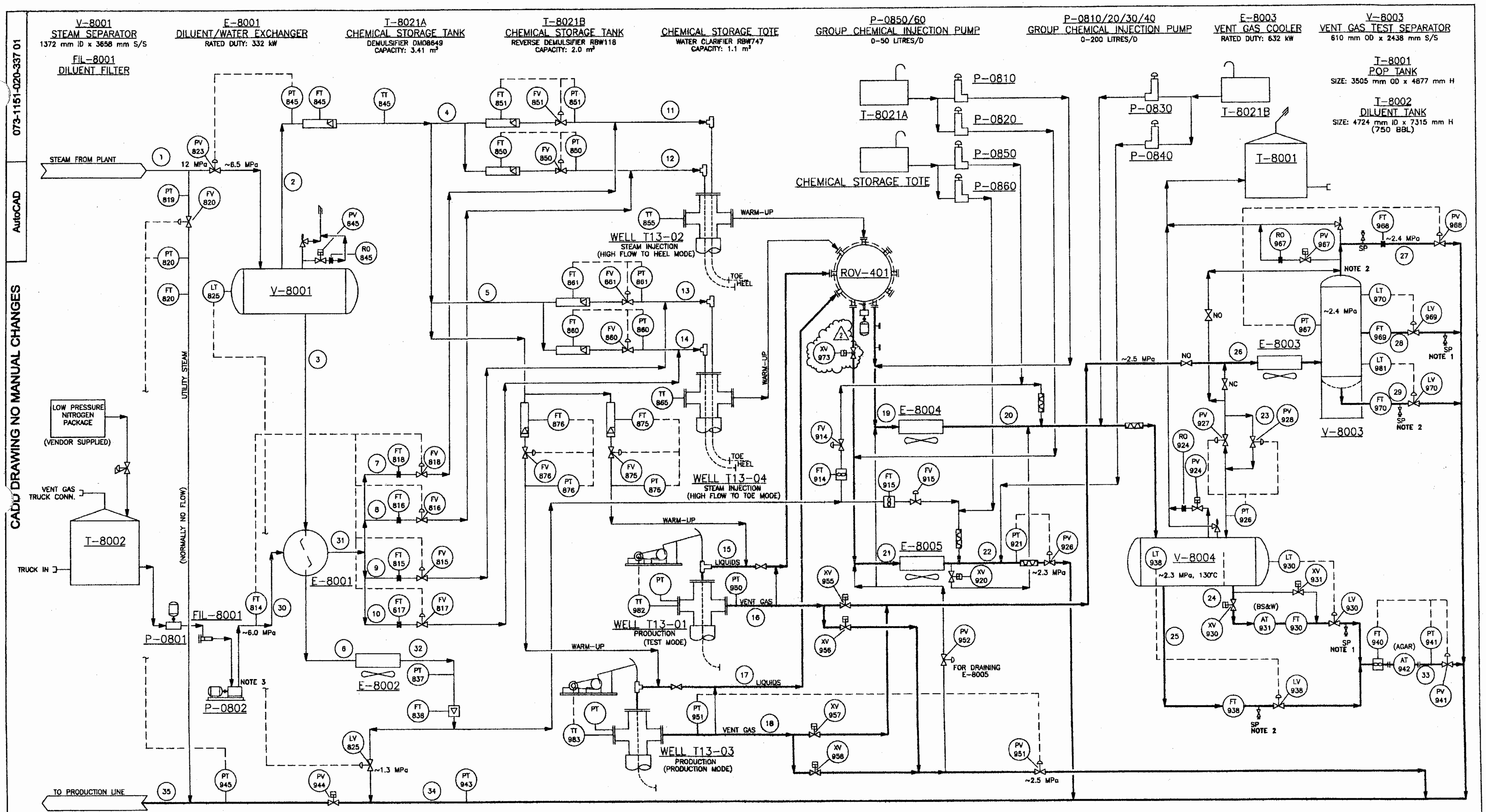
Imperial Oil
Esso

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: YBWANG3   Plot date/time: May 25, 2009 - 10:39am   XREF drawings: 073-1151-XRF-M00013 [073-1151-XRF-M00013.DWG]   IMAGE attachments:



CONSTRUCTION NOTES:

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

P-0801
DILUENT BOOSTER PUMP
66 m³/d

P-0802
DILUENT INJECTION PUMP
66 m³/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

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

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.
2	09 03 18	RE-ISSUED FOR CONSTRUCTION PER MOC C-4481 (XY.2006.28284)	MG	DAP	SAS	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

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

073-1151-020-337 01

AutoCAD

CADD DRAWING NO MANUAL CHANGES

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