

Imperial Oil Resources*
237 – 4th Avenue S.W.
Calgary, Alberta
Canada T2P 0H6

E.L. (Eddie) Lui, P.Eng
Vice-President, Oil Sands
Development and Research

Phone: (403) 237-4065
Fax: (403) 237-4011

June 19, 2012

Innovative 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 2011 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]

J.F. (John) Elliott, P.Eng.
Manager, Oil Sands Recovery Research

Attachment
cc: Ali Jaafar, IOR
cc: Geoff Pearson, ADOE

IETP Application No. 03-047

Imperial Oil Resources - Cold Lake Solvent Assisted - SAGD Pilot

2011 Annual Project Technical Report

Confidential under IETP Agreement

Table of Contents

TABLE OF CONTENTS	3
LIST OF APPENDICES	4
1 ABSTRACT	5
2 SUMMARY PROJECT STATUS REPORT	6
2.1 MEMBERS OF THE PROJECT TEAM.....	6
2.2 KEY ACTIVITIES.....	6
2.3 PRODUCTION, AND MATERIAL AND ENERGY BALANCE FLOW SHEETS.....	6
2.4 RESERVES.....	9
3 WELL INFORMATION	10
3.1 WELL LAYOUT MAP.....	10
3.2 2011 DRILLING, COMPLETION, AND WORK-OVER OPERATIONS.....	11
3.3 WELL OPERATION.....	11
3.4 WELL LIST AND STATUS.....	11
3.5 WELLBORE SCHEMATICS.....	12
3.6 SPACING AND PATTERN.....	14
4 PRODUCTION PERFORMANCE	15
4.1 INJECTION AND PRODUCTION HISTORY.....	15
4.2 COMPOSITION OF PRODUCED / INJECTED FLUIDS.....	19
4.3 PREDICTED VS. ACTUAL COMPARISONS.....	21
4.4 PRESSURES.....	22
5 PILOT DATA	23
5.1 ADDITIONAL DATA.....	23
5.2 INTERPRETATION OF PILOT DATA.....	31
6 PILOT ECONOMICS	33
6.1 SALES VOLUMES OF NATURAL GAS AND BY-PRODUCTS.....	33
6.2 REVENUE.....	33
6.3 CAPITAL COSTS.....	34
6.4 DIRECT AND INDIRECT OPERATING COSTS.....	35
6.5 CROWN ROYALTIES.....	36
6.6 CASH FLOW.....	36
6.7 CUMULATIVE PROJECT COSTS AND NET REVENUE.....	37
6.8 DEVIATIONS FROM BUDGETED COSTS.....	37
7 FACILITIES	38
7.1 MAJOR EQUIPMENT ITEMS.....	38
7.2 CAPACITY LIMITATION, OPERATIONAL ISSUES, AND EQUIPMENT INTEGRITY.....	38
7.3 PROCESS FLOW AND SITE DIAGRAMS.....	38
8 ENVIRONMENTAL/REGULATORY/COMPLIANCE	39
8.1 REGULATORY COMPLIANCE.....	39
8.2 ENVIRONMENTAL CONSIDERATIONS.....	39
8.3 AIR QUALITY.....	39
8.4 AQUATIC RESOURCES.....	39

8.5	WILDLIFE	40
8.6	NOISE	40
8.7	RECLAMATION.....	40
9	FUTURE OPERATING PLAN.....	41
9.1	PROJECT SCHEDULE	41
9.2	CHANGES IN PILOT OPERATION.....	41
9.3	OPTIMIZATION STRATEGIES.....	41
9.4	SALVAGE UPDATE	41
10	INTERPRETATIONS AND CONCLUSIONS	42
10.1	OVERALL PERFORMANCE ASSESSMENT	42

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 2011. Pilot operations continued with well-pair 1 operating in SAGD mode, while the adjacent well-pair 2 operated in SA-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 2011:

John Elliott, P.Eng. – Manager, Oil Sands Recovery Research (effective October 1, 2011)
Tom Boone, PhD, P.Eng. – Manager, Oil Sands Recovery Research (up to September 30, 2011)
Ali Jaafar, P.Eng. – SA-SAGD Pilot Engineer
Jeff Yerian, PhD – SA-SAGD Pilot Engineer

2.2 Key activities

The pad continued to operate in SAGD mode (well-pair 1: T13-01 & T13-02) and SA-SAGD mode (well-pair 2: T13-03 & T13-04).

Injection was shut in on September 17, 2011 due to maintenance work on main steam line from Mahkeses plant. Both well-pairs continued to produce during this shut in, with injection resuming on October 18, 2011.

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 m³):

	T13-01	T13-02	T13-03	T13-04
Jan-11	0.0	4,516.2	0.0	4,830.3
Feb-11	0.0	3,613.4	0.0	4,214.0
Mar-11	0.0	4,133.7	0.0	4,510.2
Apr-11	0.0	3,993.4	0.0	4,374.0
May-11	0.0	4,230.6	0.0	4,925.8
Jun-11	0.0	4,008.4	0.0	4,686.1
Jul-11	0.0	3,821.9	0.0	4,263.7
Aug-11	0.0	4,850.0	0.0	5,327.7
Sep-11	0.0	2,139.4	0.0	2,447.3
Oct-11	0.0	2,860.8	0.0	2,871.2
Nov-11	0.0	7,066.3	0.0	8,152.3
Dec-11	0.0	5,299.9	0.0	6,388.8

Produced Materials

Produced water (by well, in m³):

	T13-01	T13-02	T13-03	T13-04
Jan-11	4,665.0	0.0	5,307.6	0.0
Feb-11	3,091.0	0.0	3,802.5	0.0
Mar-11	3,701.1	0.0	4,077.2	0.0
Apr-11	3,577.5	0.0	4,139.4	0.0
May-11	3,803.0	0.0	4,797.2	0.0
Jun-11	3,655.6	0.0	4,633.8	0.0
Jul-11	3,829.6	0.0	4,094.5	0.0
Aug-11	4,403.2	0.0	5,120.0	0.0
Sep-11	3,505.0	0.0	4,014.4	0.0
Oct-11	1,717.8	0.0	1,819.4	0.0
Nov-11	5,300.0	0.0	6,000.0	0.0
Dec-11	5,396.5	0.0	6,589.6	0.0

Volume disposed:

- There are no disposal wells included in this IETP project

Produced hydrocarbon liquid (by well, in m³):

	T13-01	T13-02	T13-03	T13-04
Jan-11	1,034.4	0.0	1,681.0	0.0
Feb-11	954.2	0.0	1,466.5	0.0
Mar-11	1,147.4	0.0	1,759.9	0.0
Apr-11	1,134.5	0.0	1,827.4	0.0
May-11	1,051.4	0.0	1,712.1	0.0
Jun-11	1,127.6	0.0	1,550.1	0.0
Jul-11	1,009.4	0.0	1,856.6	0.0
Aug-11	1,029.4	0.0	2,095.6	0.0
Sep-11	1,262.5	0.0	1,938.8	0.0
Oct-11	2,083.7	0.0	2,258.6	0.0
Nov-11	894.2	0.0	997.7	0.0
Dec-11	1,056.5	0.0	1,905.6	0.0

- The standard API of Cold Lake oil is 11.
- Produced hydrocarbon liquid volumes include liquid hydrocarbon from both the liquid and vent gas separators.
- Volumes in T13-03 include diluent recovered in the oil liquid phase. A breakdown is provided in Section 4.1.

Diluent (purchased, in m³):

	T13
Jan-11	865.8
Feb-11	694.4
Mar-11	964.3
Apr-11	826.7
May-11	783.6
Jun-11	663.4
Jul-11	713.3
Aug-11	777.4
Sep-11	422.7
Oct-11	0.0
Nov-11	420.5
Dec-11	973.2

- 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 m³):

	T13-01	T13-02	T13-03	T13-04
Jan-11	0	0	0	916.1
Feb-11	0	0	0	702.3
Mar-11	0	0	0	895.9
Apr-11	0	0	0	881.8
May-11	0	0	0	686.8
Jun-11	0	0	0	678.8
Jul-11	0	0	0	683.5
Aug-11	0	0	0	778.3
Sep-11	0	0	0	427.7
Oct-11	0	0	0	0
Nov-11	0	0	0	438.8
Dec-11	0	0	0	883.9

Produced Sand (m³):

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

Produced gas (E³m³):

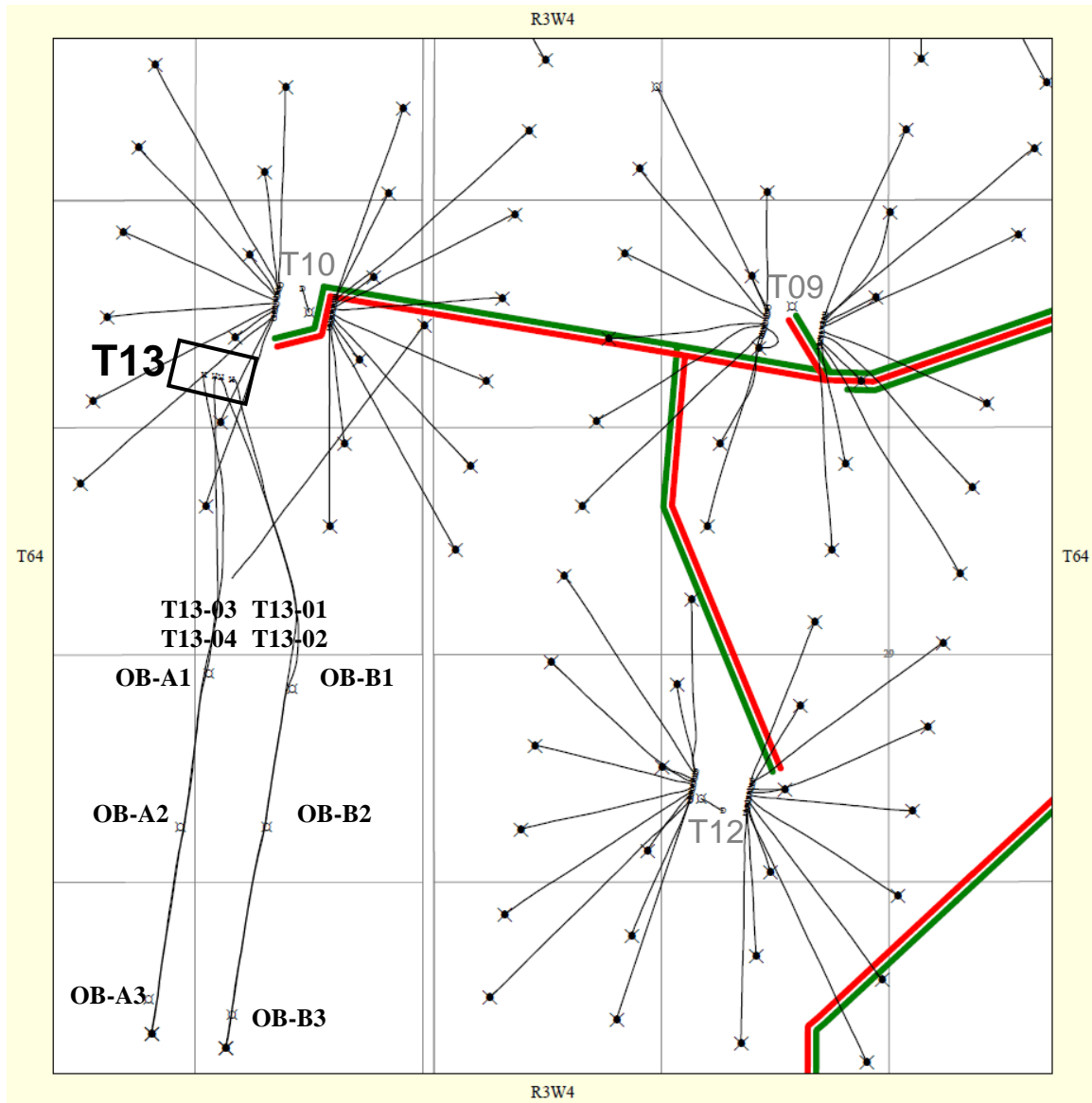
	T13-01	T13-02	T13-03	T13-04
Jan-11	12.1	0	53.5	0
Feb-11	7.1	0	45.8	0
Mar-11	5.2	0	42.9	0
Apr-11	5.4	0	35	0
May-11	5.5	0	41.7	0
Jun-11	7	0	25	0
Jul-11	7.1	0	2.8	0
Aug-11	4.4	0	2.2	0
Sep-11	8	0	8	0
Oct-11	85.3	0	84.4	0
Nov-11	2.8	0	2.8	0
Dec-11	5.4	0	3.3	0

2.4 Reserves

Industry data and simulation of Petrel-based geologic models supported an ultimate reserves recovery of 445 km³ (before royalty) from both well pairs. Reserves for T13 will be reviewed after the pilot life.

3 Well Information

3.1 Well Layout Map



Legend

- Heavy Oil Well
- Observation Well
- Directional Well Path
- Steam pipeline
- Production pipeline

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

3.2 2011 drilling, completion, and work-over operations

There is no drilling or completion work to report for 2011. 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 (well-pair 2).

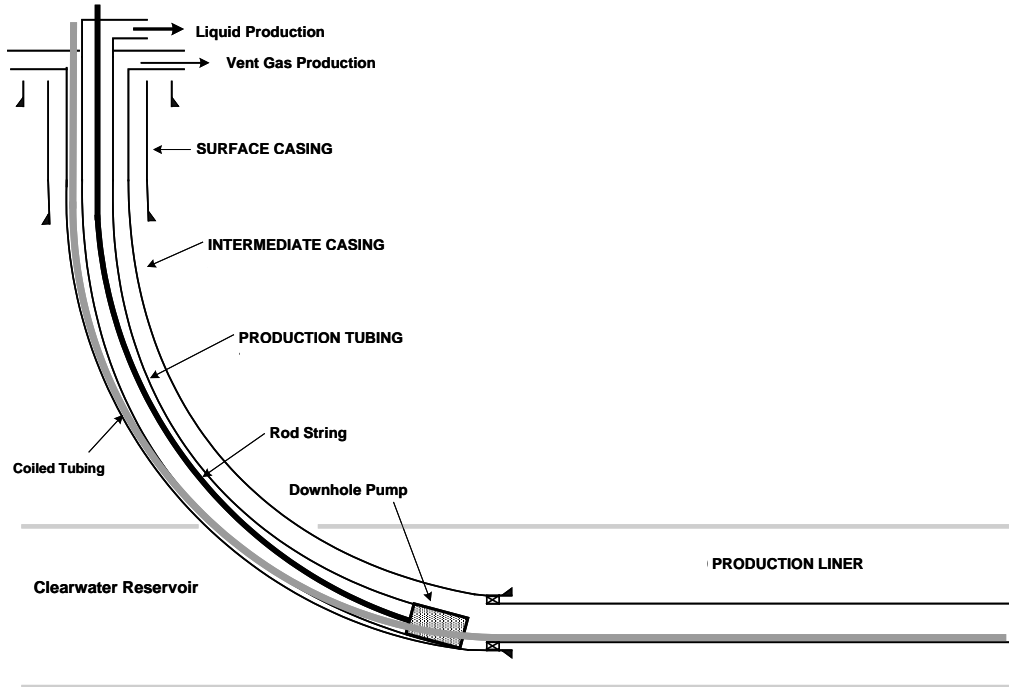
3.4 Well list and status

All wells are currently active. List as follows:

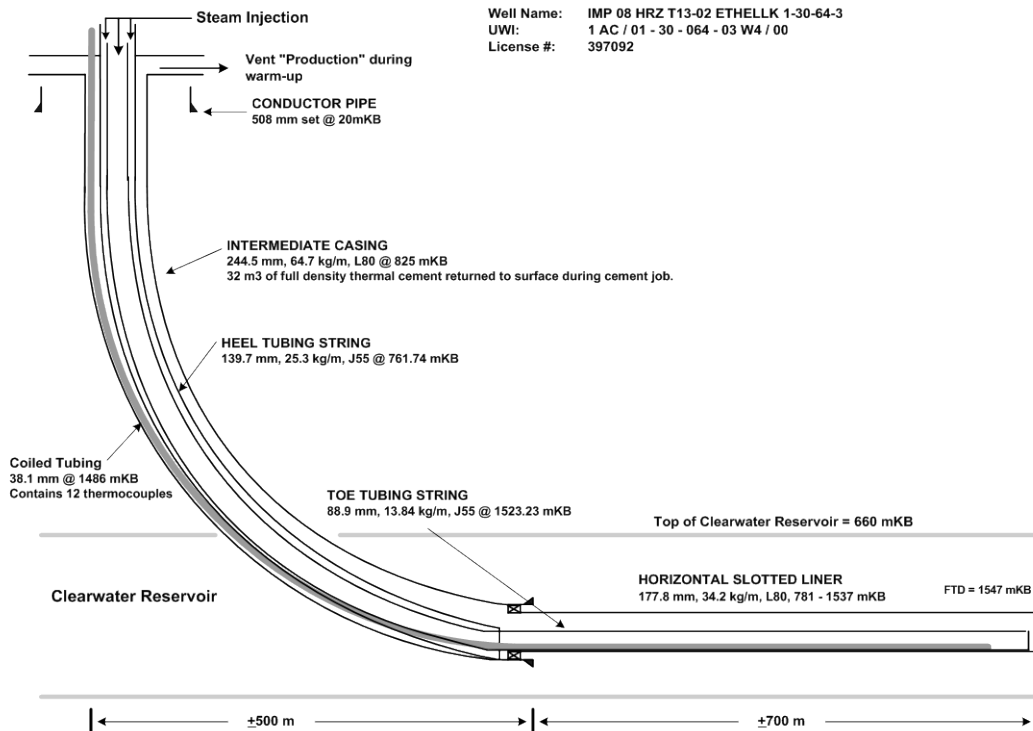
East well pair	1AB/01-30-064-03W4/0 (T13-01) producer
	1AC/01-30-064-03W4/0 (T13-02) injector
	1AA/08-30-064-03W4/0 (OB-B1) observation well
	1AD/08-30-064-03W4/0 (OB-B2) observation well
	1AA/01-30-064-03W4/0 (OB-B3) observation well
West well pair	1AB/02-30-064-03W4/0 (T13-03) producer
	1AC/02-30-064-03W4/0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

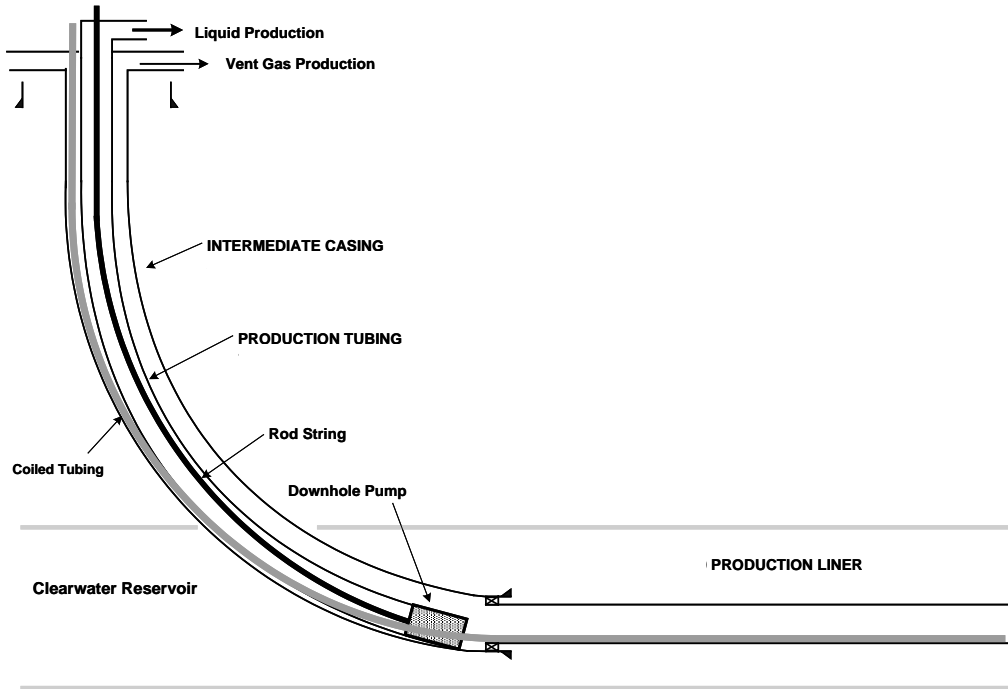
T13-01 (east producer) – SAGD schematic:



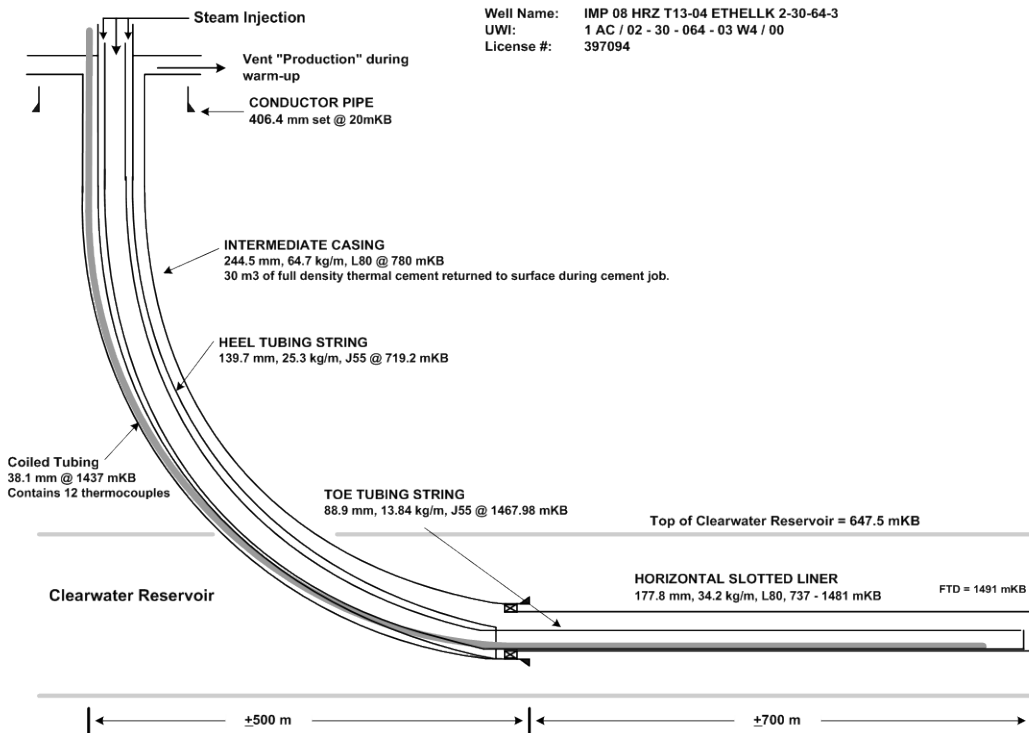
T13-02 (east injector):



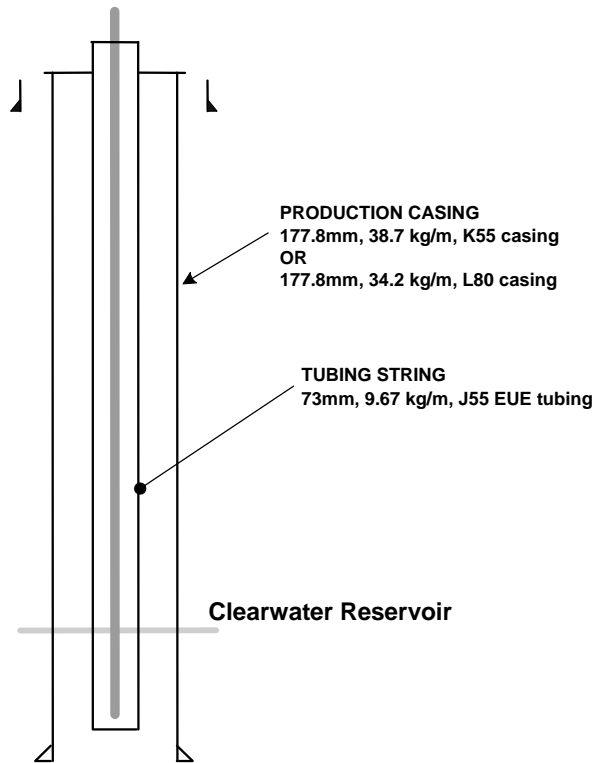
T13-03 (west producer) – SAGD schematic:



T13-04 (west injector):



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



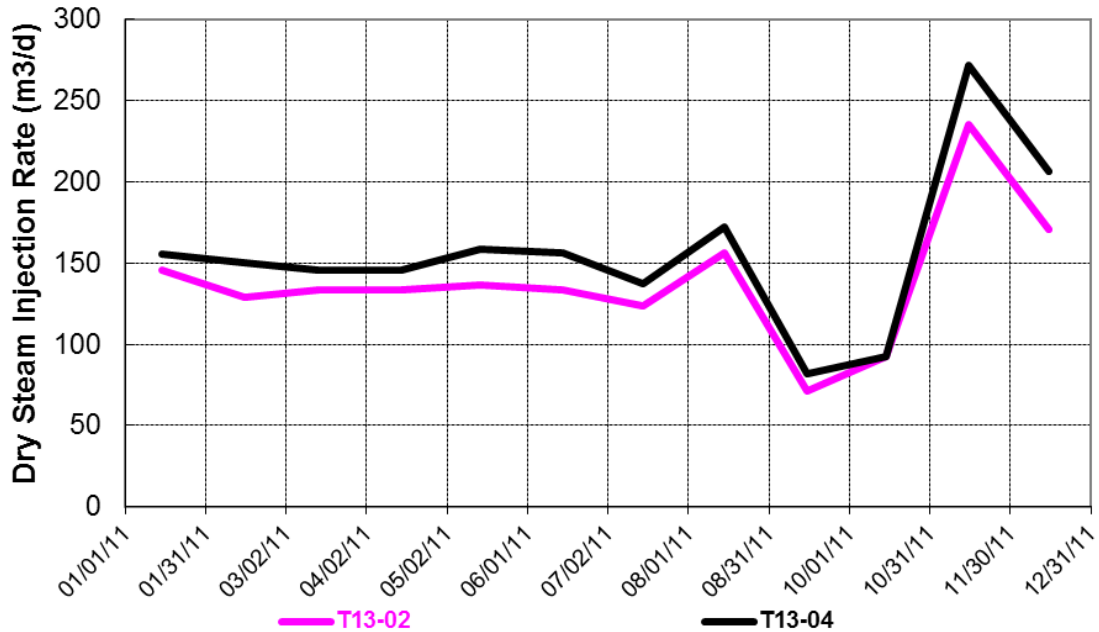
3.6 Spacing and pattern

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 m² (150m * 650 m), which is roughly 24 acres per well.

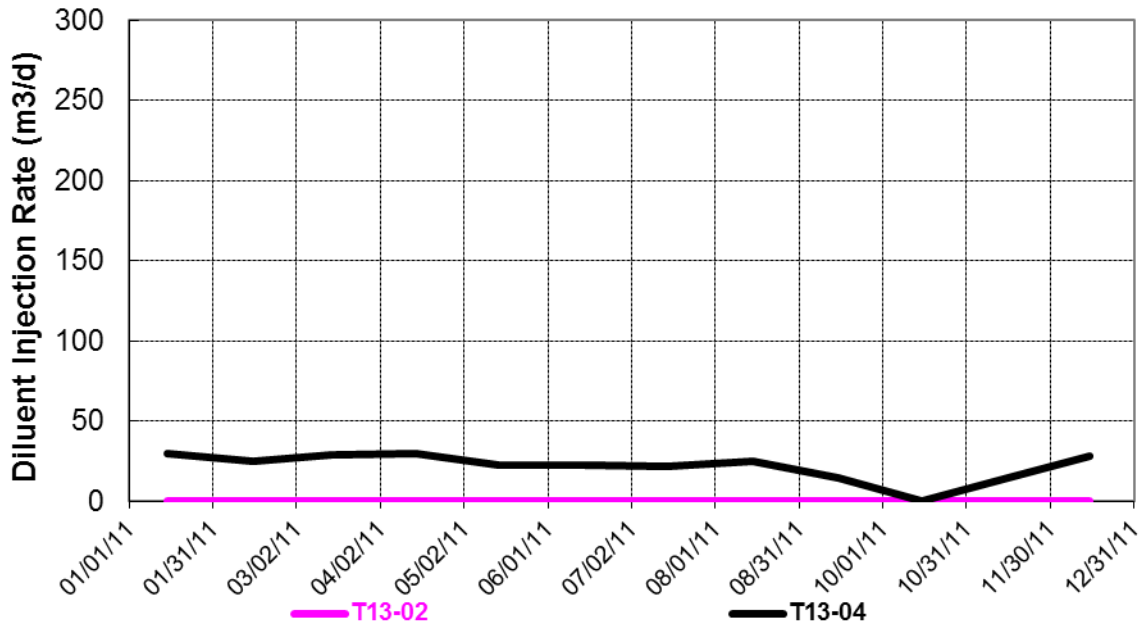
4 Production Performance

4.1 Injection and production history

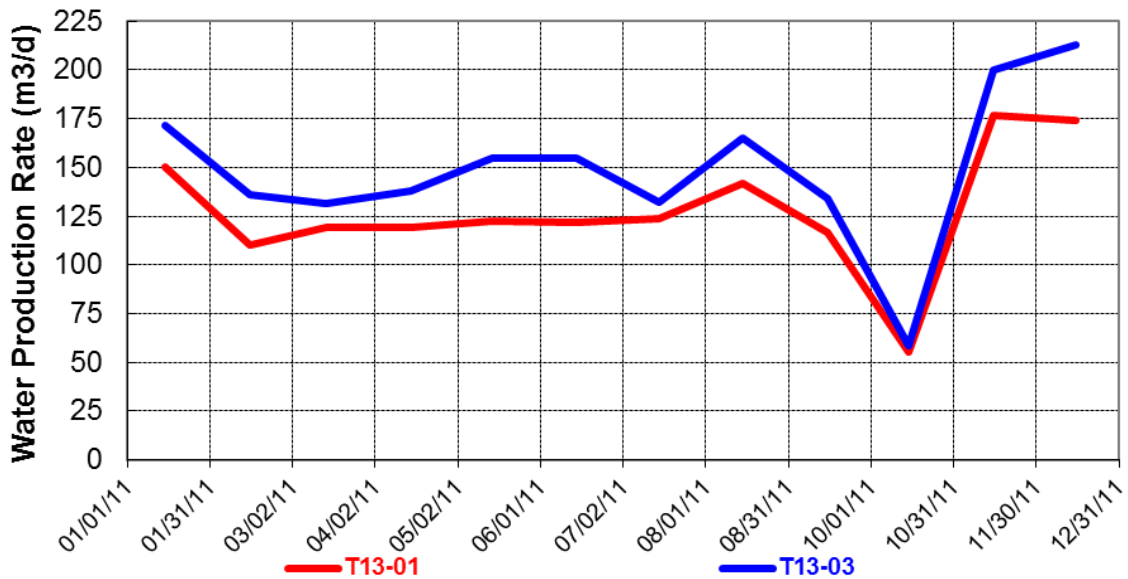
During SAGD / SA-SAGD operation, injection rates are dictated by an operational strategy to maintain injection pressure close to initial reservoir pressure (see section 4.4). Typical rates varied to achieve this, with durations of higher than average injection rates that followed periods of injection shut in (allowing pressure target to be reached in a timelier manner). A plot of the monthly average steam injection rates for each well is shown below.



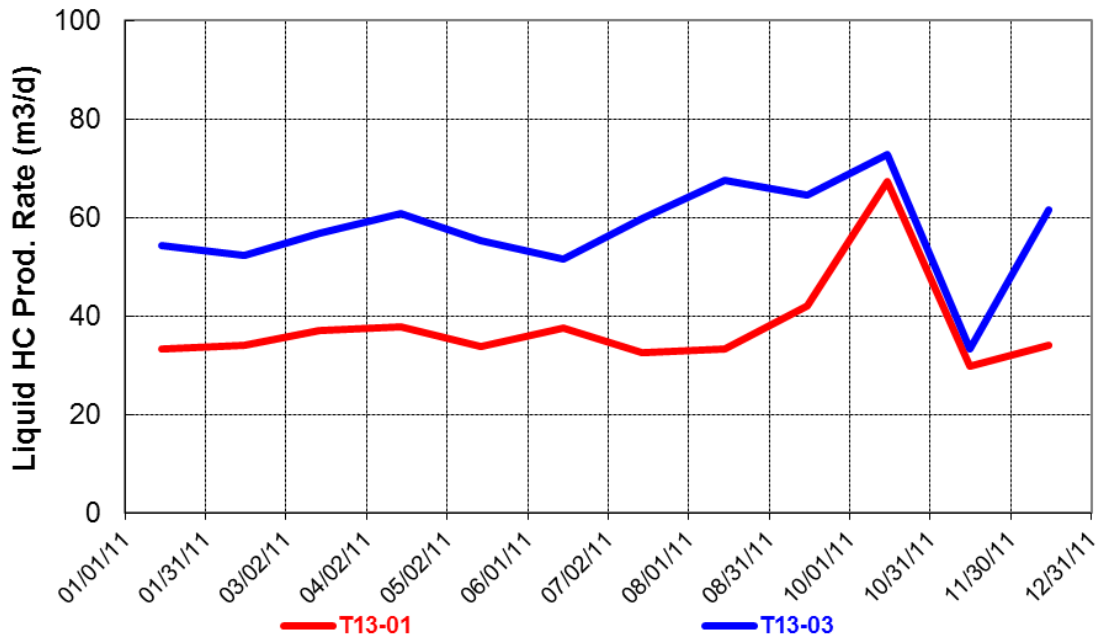
Well-pair 2 continued to operate in SA-SAGD mode during 2011. Rates were dictated by a target diluent volume of 20% volume diluent / volume steam. A plot of the monthly average diluent injection rates for each well is shown below.



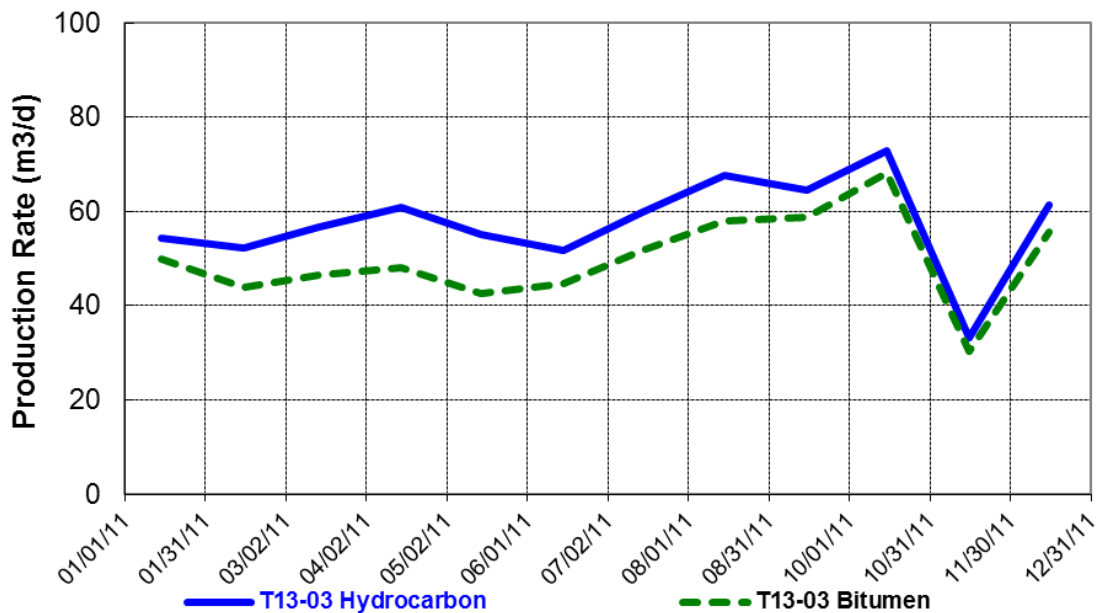
Water production during 2011 consisted of water from the condensing steam. Water production volumes from each well (monthly average rates) are shown below.



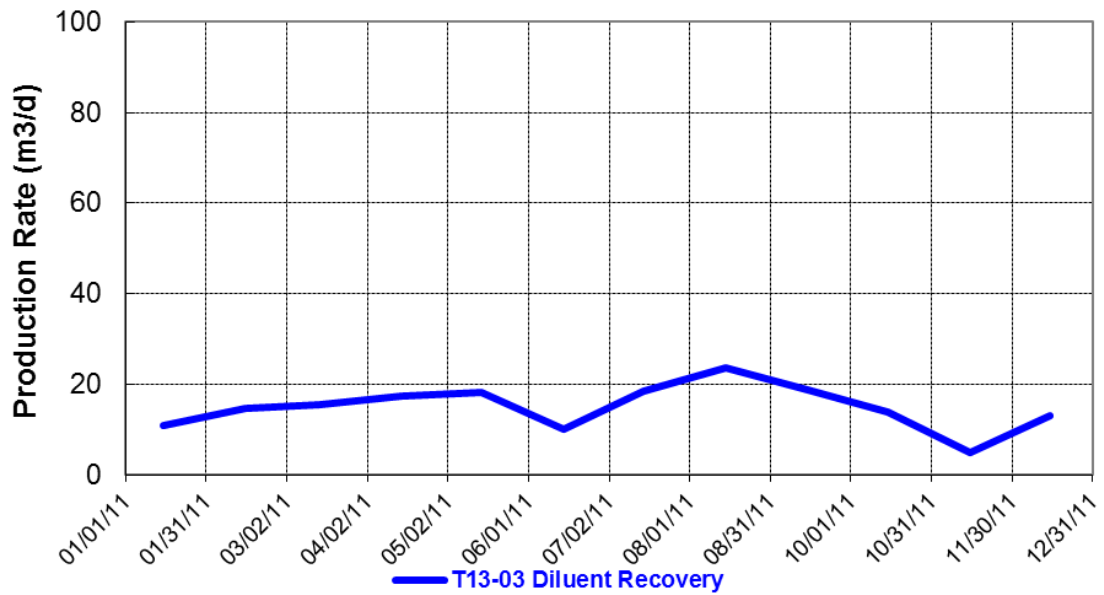
Liquid hydrocarbon volumes consisted of bitumen for the SAGD well-pair (well T13-01) and a bitumen plus recovered diluent mix for the SA-SAGD well-pair (well T13-03). Liquid hydrocarbon production volumes from each well (monthly average rates) are shown below (include liquid hydrocarbon from both the liquid and vent gas separators).



From production test samples, it was found that 3 – 13 m³/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.



Diluent recovery was also measured once diluent injection commenced. It was observed that roughly 40 - 70% of injected volumes were being recovered on a monthly basis. 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
Triacontan 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.

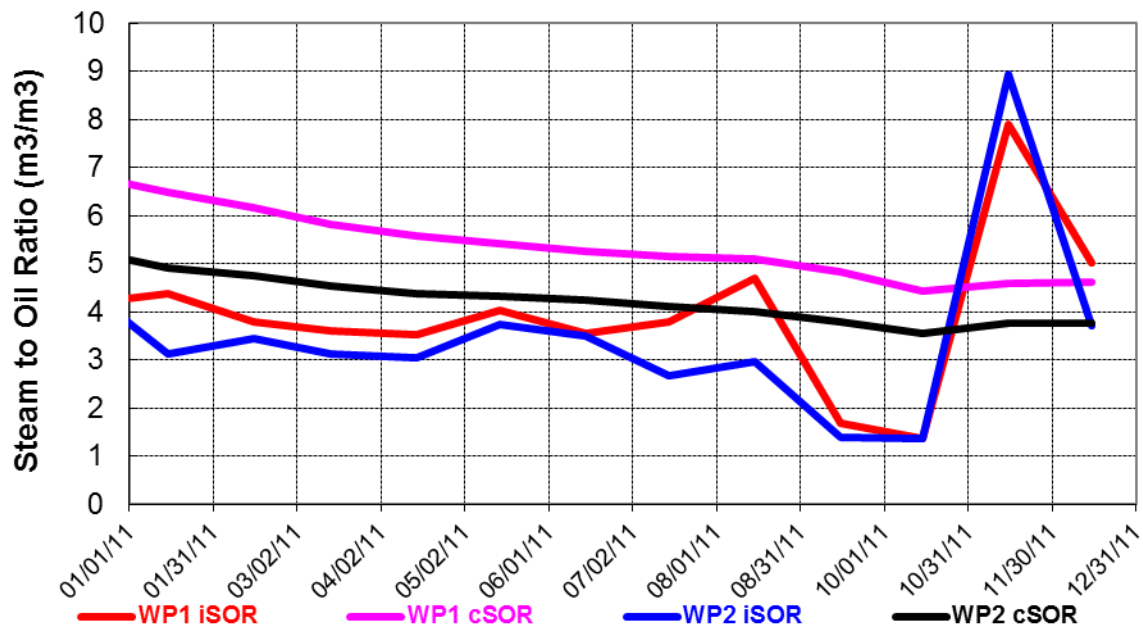
COMPONENT	CARBON NUMBER	MOLE FRACTION	MASS FRACTION	LIQUID VOL FRACTION
Methane	C1	0.0000	0.0000	0.0000
Ethane	C2	0.0000	0.0000	0.0000
Propane	C3	0.0000	0.0000	0.0000
i-Butane	i-C4	0.0000	0.0000	0.0000
n-Butane	n-C4	0.0000	0.0000	0.0000
i-Pentane	i-C5	0.0000	0.0000	0.0000
n-Pentane	n-C5	0.0000	0.0000	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 continuing in 2011 on well-pair 1, instantaneous steam to oil ratios (SOR) of 3.5 – 4.7 m³ steam / m³ oil were observed, with a cumulative SOR (including warm-up volumes) of 4.6 observed by the end of 2011. SA-SAGD operation on well-pair 2 during the year saw instantaneous steam to oil ratios (SOR) of 2.7 – 3.7 m³ steam / m³ oil, with a cumulative SOR (including warm-up volumes) of 3.8 observed by the end of 2011.

Lower SORs were observed in September and October due to injection shut-in while production continued, with higher SORs observed in the following two months due to utilization of high injection rates in order to return to target reservoir pressure in a timely manner.

SORs seen to date are within the expected performance range. Plots of instantaneous and cumulative SORs (monthly averages) for each well-pair are shown below.



4.4 Pressures

During SAGD operation, steam is injected close to reservoir pressure (wellhead pressure of 3,500 kPa) in wells T13-02 and T13-04, with wellhead production in the 2,000 – 2,500 kPa range (wells T13-01 and T13-03). During the September/October injection shut in, wellhead pressure in the injection wells declined to approximately 2,300 kPa. Plots of casing wellhead pressures (monthly average) for each well are shown below.

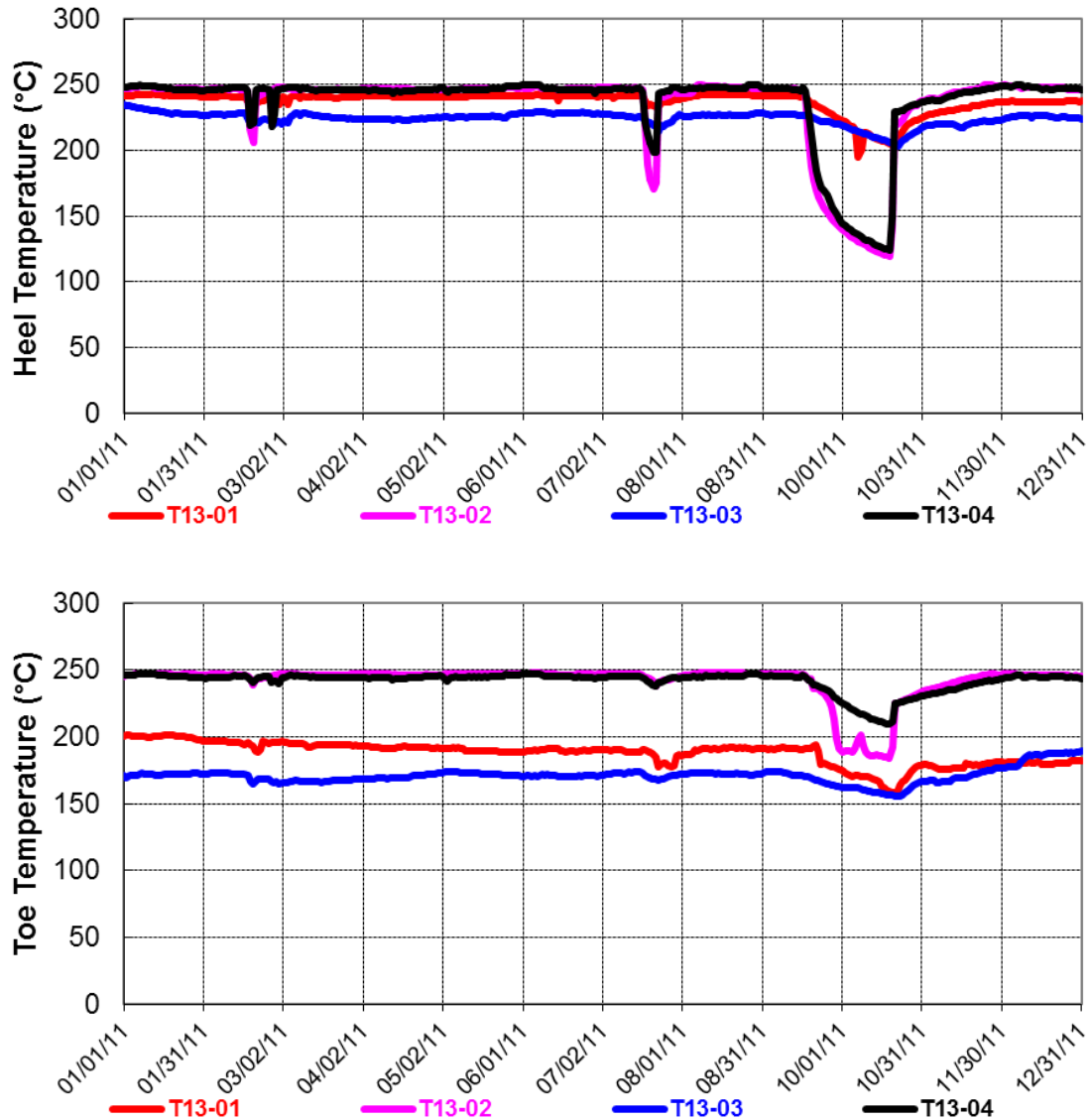


5 Pilot Data

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.

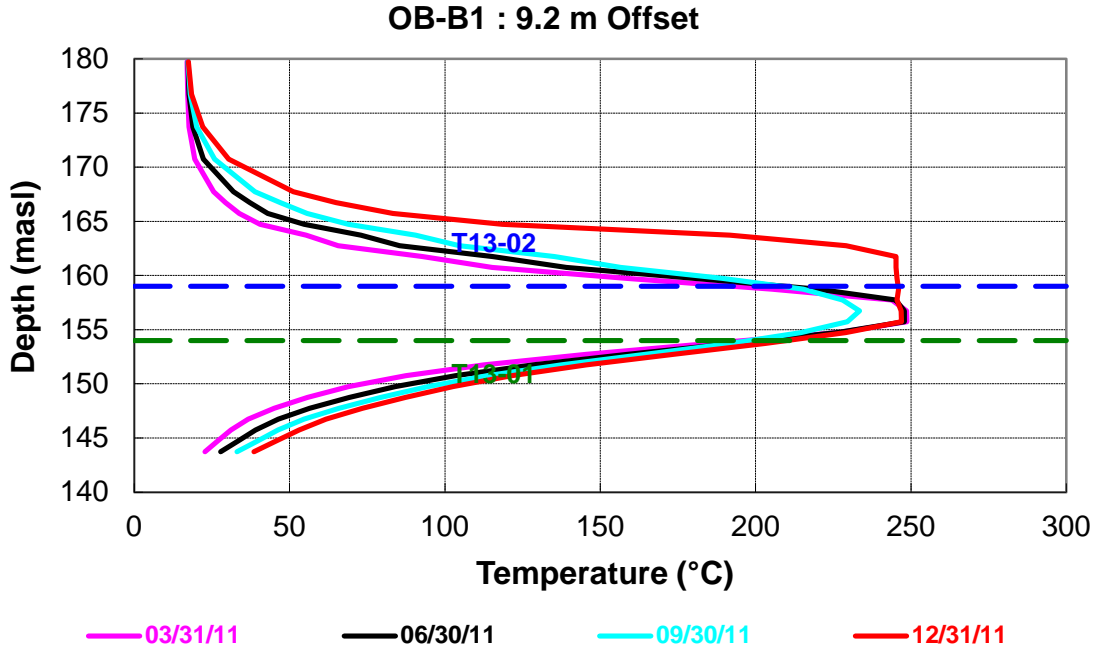
Injector well temperatures were approximately 245°C during SAGD operation (heel and toe of T13-02 & T13-04). Temperatures on the producer wells (T13-01 & T13-03) varied from 150 – 240 °C along the wells during SAGD operation. Temperatures (daily average) along the horizontal well at the heel and toe wells are shown below.



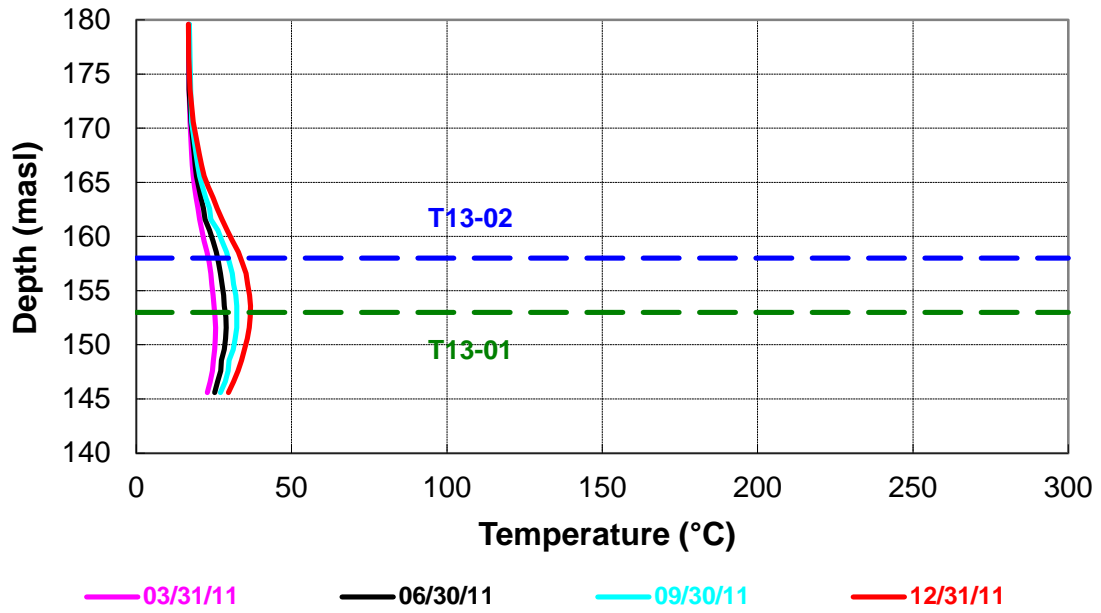
There are six total observation wells, three for each well-pair, that are positioned at the toe, heel, and midpoint of each horizontal well-pair. The offset distance from the horizontal wells varies

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.

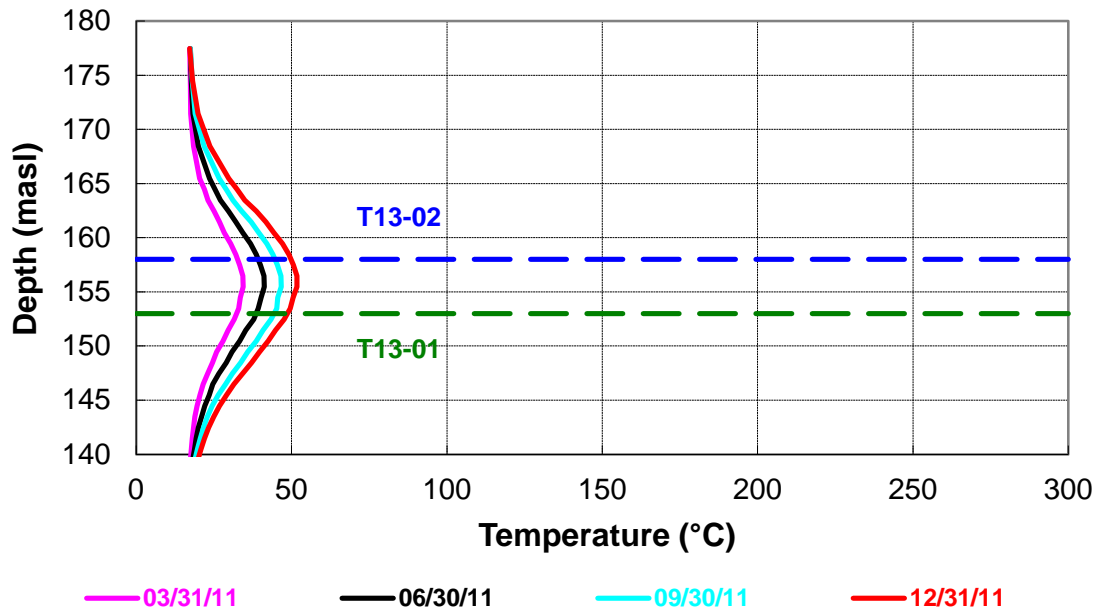
Observation wells OB-B1, B2, and B3 are adjacent to heel, mid, and toe of well-pair 1 (T13-01 & T13-02). Steam temperature was reached on OB-B1 in 2010, with continued vertical growth observed in 2011. Temperature responses of between 35 – 55°C were also observed on B2 & B3 by the end of 2011. The temperature 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).



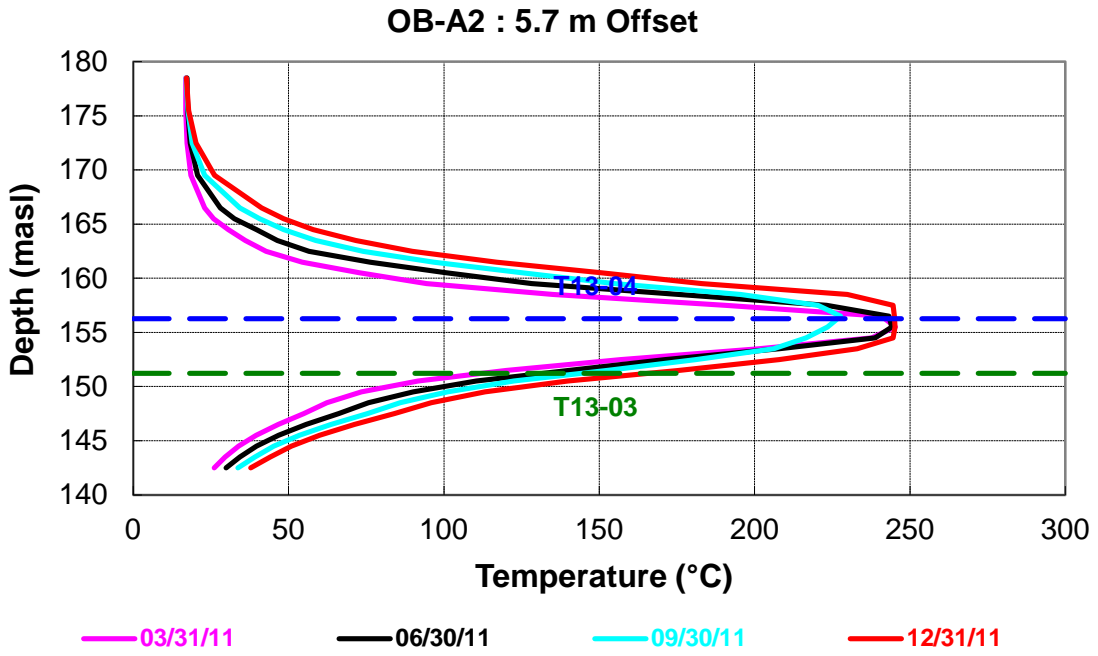
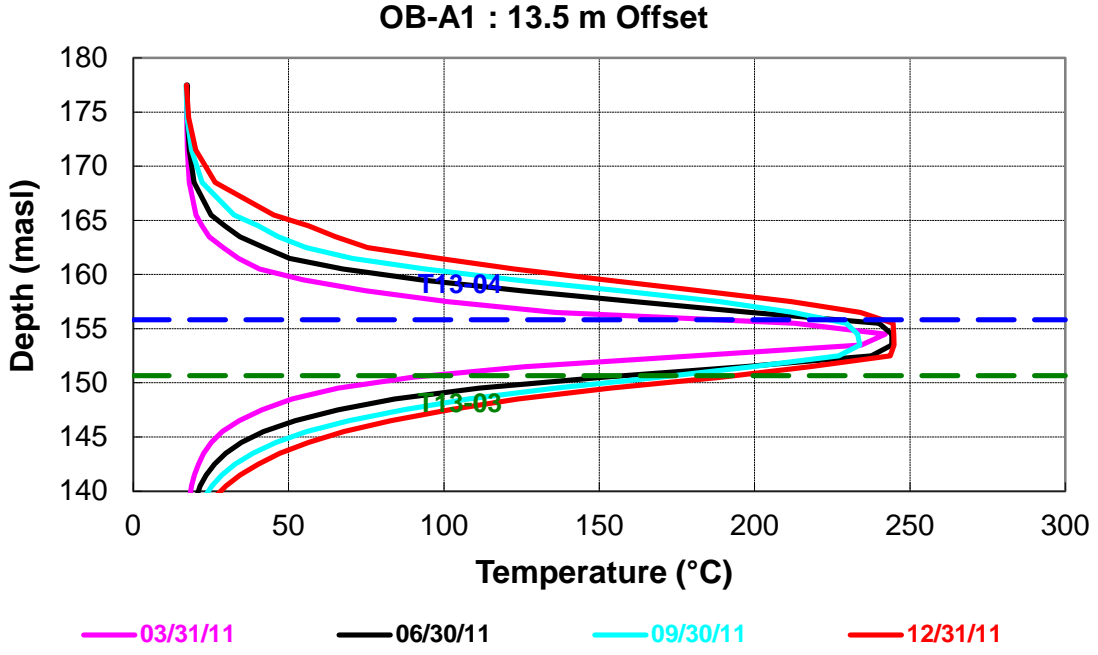
OB-B2 : 9.9 m Offset

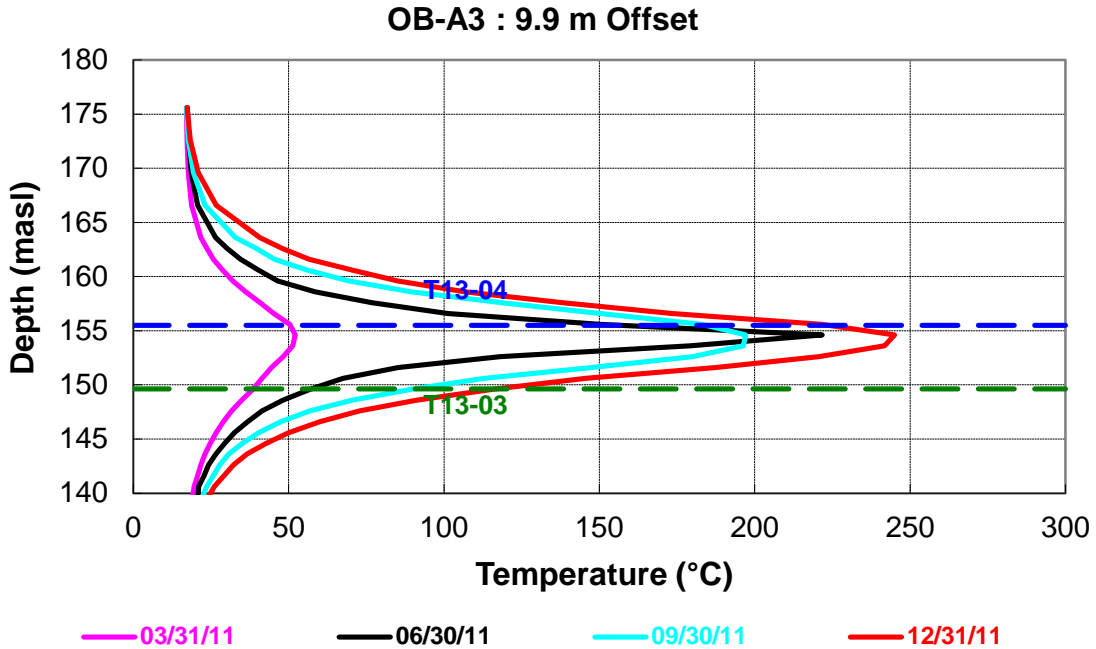


OB-B3 : 12.2 m Offset



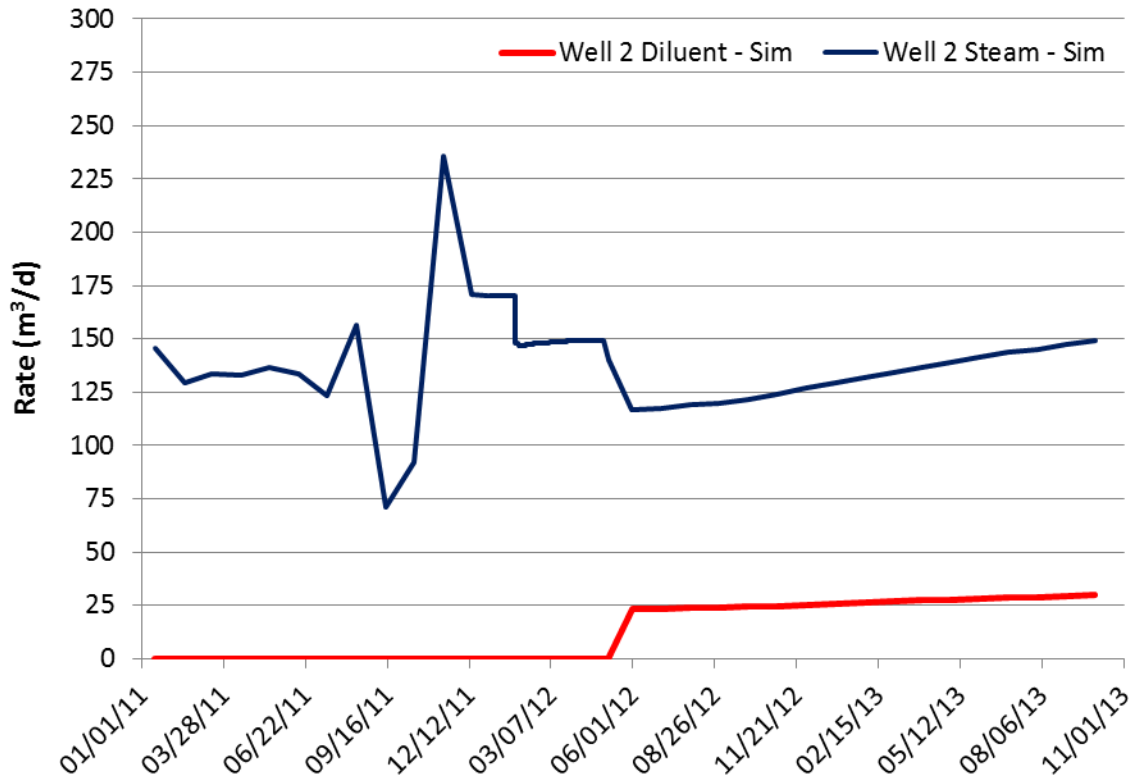
Observation wells OB-A1, A2, and A3 are adjacent to heel, mid, and toe of well-pair 2 (T13-03 & T13-04). All three wells reached steam temperature in 2011. The temperature as a function of depth is shown below for each observation well at three-month intervals (dashed lines represent approximate depths of both the injector and producer wells from the adjacent well-pair).





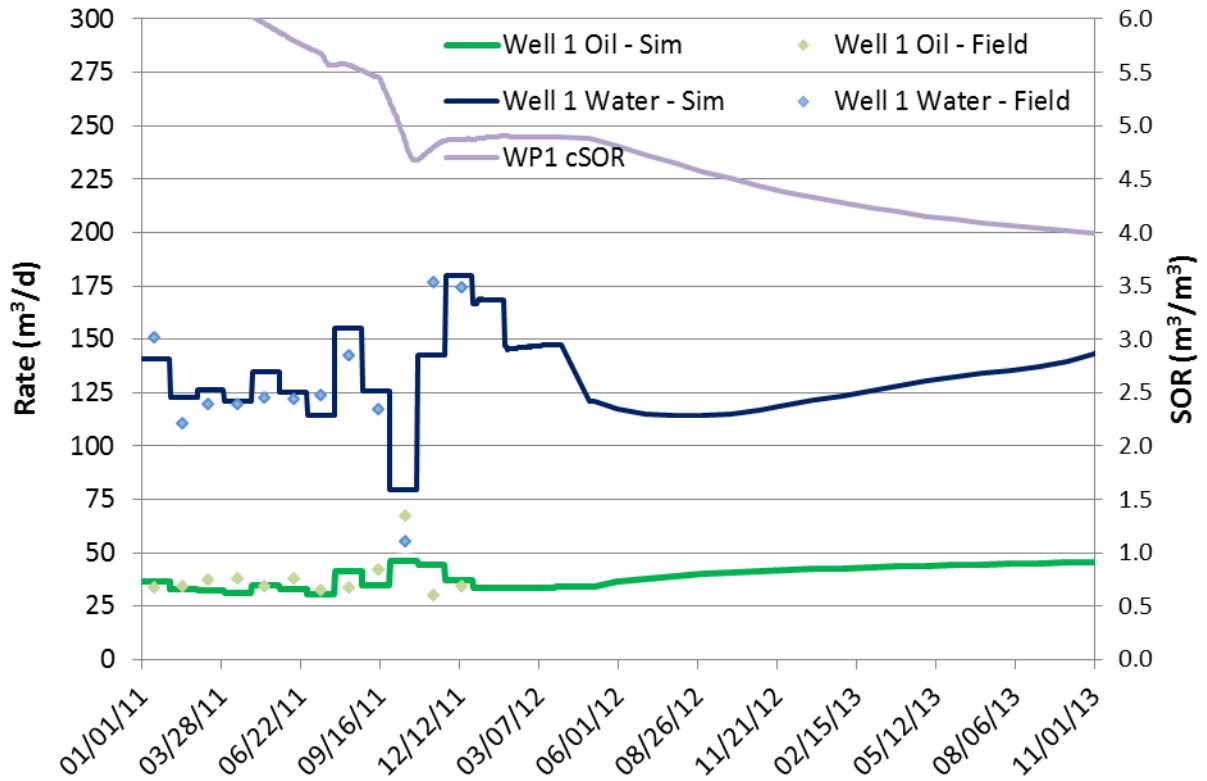
Field data was also used to generate history matched geologic-model based simulation models for SAGD / SA-SAGD operation, and create go forward predictions. Using steam injection volumes and production pressures as inputted values, oil and water production rates were history matched.

A plot showing the historic and predicted injection profile for well-pair 1 is shown below.



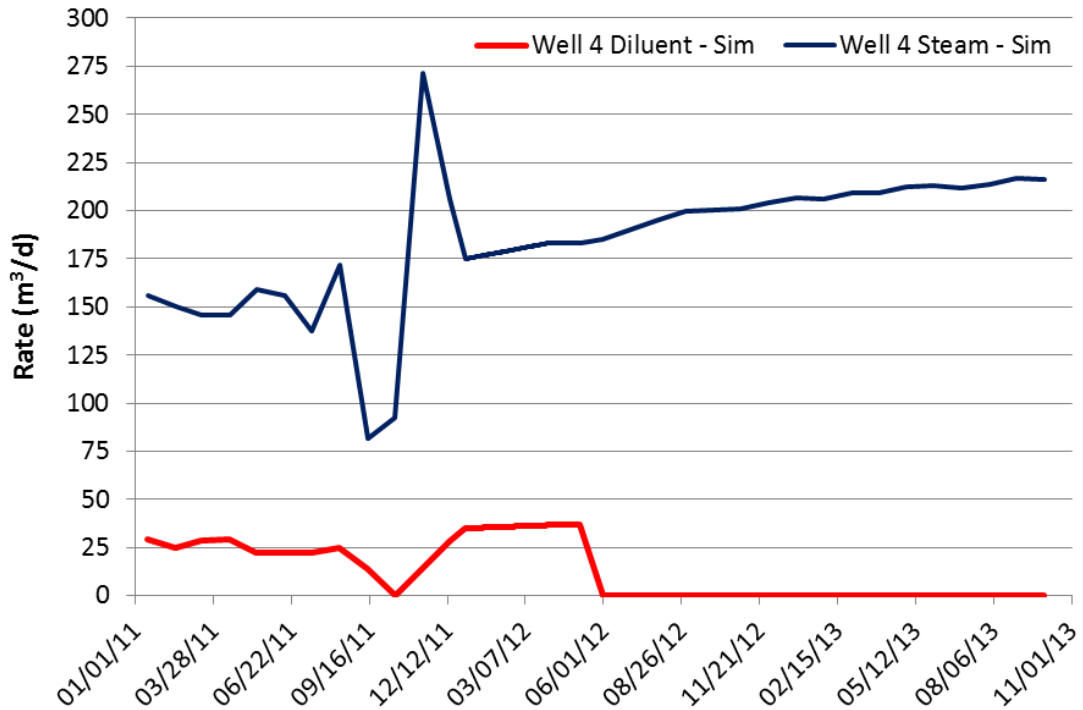
Steam is expected to continue being injected at approximately 150 m³/d in order to maintain target reservoir pressure. Once the pilot reaches the half-way mark (June 2012), solvent injection will begin on well-pair 1, converting it to a SA-SAGD operation. This well-pair is then expected to continue operating in SA-SAGD mode until the end of the pilot period.

Oil and water rates were history matched and a go forward production performance was predicted to the end of pilot period. A plot showing the history matched and predicted production profile for well-pair 1 is shown below.



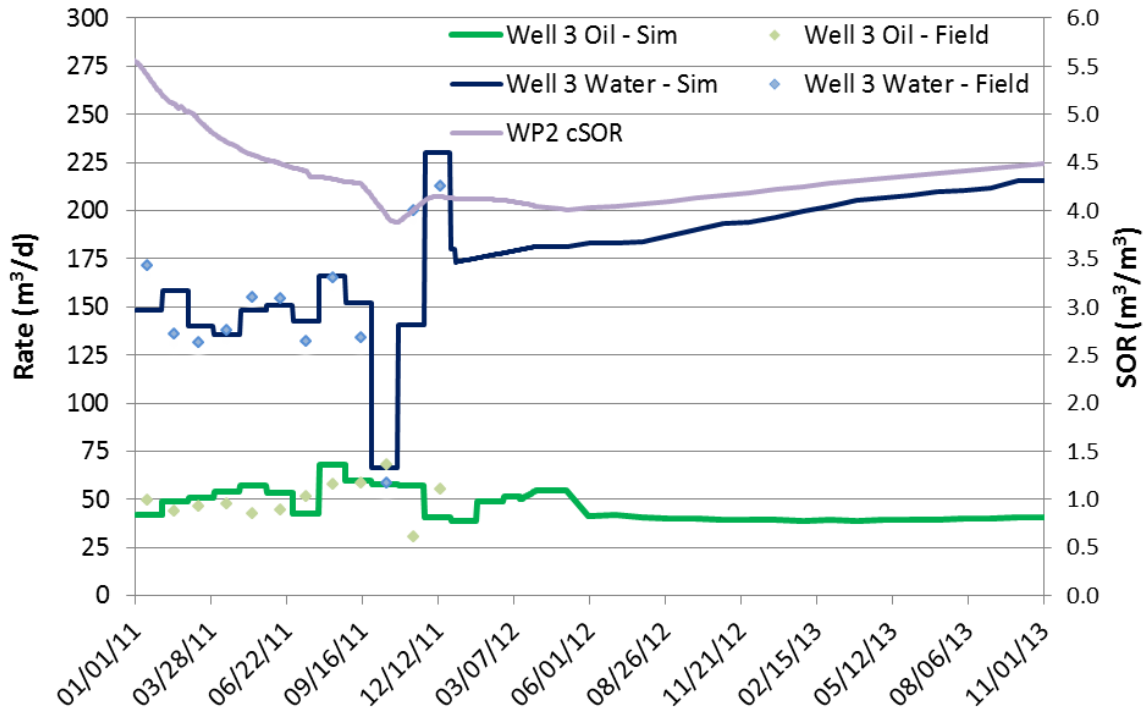
Oil and water production rates are expected to maintain current levels as SAGD operation continues in 2012. Once solvent injection commences, an oil uplift is expected to increase rates within a few months, and rates are expected to continue increasing to around 45 m³/day by the end of the pilot, as the steam and solvent chamber continues to mature further. Cumulative SOR is expected to decline to around 4.0 m³/m³ by the end of the SA-SAGD phase.

A plot showing the historic and predicted injection profile for well-pair 2 is shown below.



Steam and solvent are expected to continue being injected at the same rate in order to maintain target reservoir pressure. Once the pilot reaches the half-way mark (June 2012), solvent injection will end on well-pair 2, returning it back to SAGD operation. Steam rates are expected to increase once the well-pair returns to SAGD operate so as to maintain target reservoir pressure. This well-pair is then expected to continue operating in SAGD mode until the end of the pilot period.

Oil and water rates were history matched and a go forward production performance was predicted to the end of pilot period. A plot showing the history matched and predicted production profile for well-pair 2 is shown below.



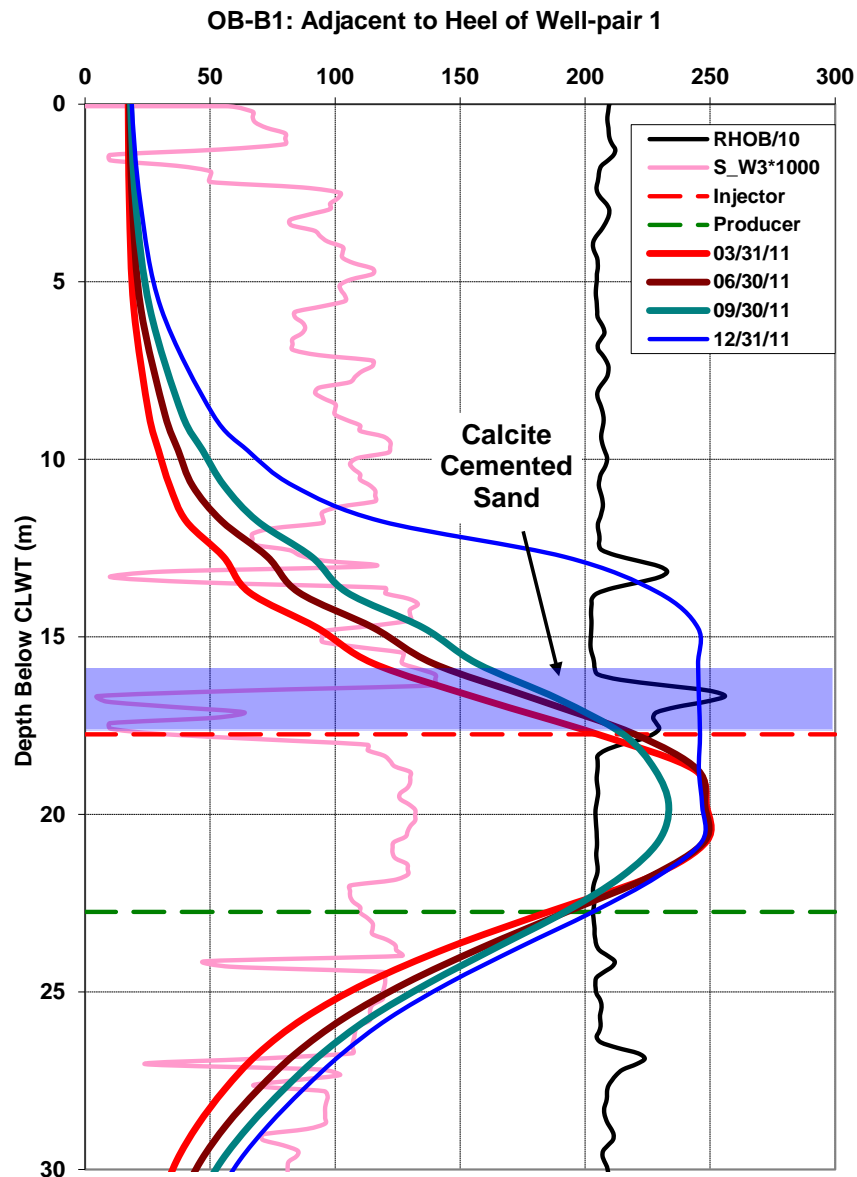
Oil and water production rates are expected to return to pre-shut down levels as the well continues in SA-SAGD operation. Once solvent injection ends, the oil rate is expected to decline within a few months. Cumulative SOR is expected to be around 4.5 m³/m³ by the end of the pilot phase.

Other pilot surveillance data, such as saturation logs, 3D seismic, and tracers, were not planned for 2011.

5.2 Interpretation of pilot data

SAGD operation on well-pair 1 continued in 2011, yielding SORs in the 3 – 5 m³ steam / m³ oil which is within the range of expectations for a SAGD process in the Clearwater formation. While solvent injection continued in well-pair 2 in 2011, interpretations regarding the effect of solvent addition have yet to be made. These interpretations will more accurately be assessed when the well-pair returns to SAGD operation, providing a sufficient baseline on well-pair 2 to provide fair and reasonable comparison.

As mentioned in the 2010 progress report, it is 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). This geological feature caused vertical temperature growth to pause for the majority of 2011, but as seen from the December 31 temperature profile, vertical steam chamber has continued to expand beyond it, thus confirming they act as barriers to delay not prevent steam chamber growth. Other observation wells display similar geological features, and are actively being monitored with the expectation that similar results will be observed.

6 Pilot Economics

Price data used in this section is a combination of:

- Bitumen / natural gas pricing based on actual prices from Imperial Oil's 2011 10-K filing
- Solvent pricing from the Sproule December 31, 2011 price database

	Bitumen C\$/bbl	Solvent (Edmonton Pentanes Plus) C\$/bbl	Natural Gas C\$/mcf
2009	51.81	68.13	4.11
2010	58.36	84.21	4.04
2011	63.95	104.12	3.59

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 **502,640 m³** in 2011.

Steam injection was 107,525.4 m³ in 2010. Based on a 75 m³ natural gas / m³ steam ratio to generate steam, it is estimated that **8,064,405 m³** of natural gas was required to generate steam volumes

Thus, the net gas volume for 2011 was **-7,561,765 m³** (502,640 m³ – 8,064,405 m³).

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 2011 is estimated to be **C\$ 12,877,231**. This is based on a bitumen production volume of 32,014 m³, and a bitumen price of 63.95 C\$/bbl (402.23 C\$/m³).

6.3 Capital costs

The following table summarizes capital costs by category, incurred in 2011 (as per 2011 IETP claim form submissions):

Category	Description and Details of Capital Costs	Cost (C\$)
Facilities	Drilling	0.00
	Surface Facilities (Steam injection facilities, separator; chemical injection facilities, separator; production facilities, pump jacks, ROV, coolers)	27,411.97
	Engineering Procurement Construction	12,302.42
	Trunkline / Laterals	0.00
	Facilities - Capital Related Expense	38,497.75
Drilling	Drilling four horizontal wells - 2 well pairs, each wellpair consist of an injector and producer well.	0.00
	Completion of horizontal wells	0.00
	Capital Related Expense	0.00
Trunkline	Drilling	0.00
	Surface Facilities	0.00
	Engineering Procurement Construction	0.00
	Trunkline / Laterals	0.00
	Capital Related Expense	0.00
Total Capital Costs (C\$)		78,212.14

6.4 Direct and indirect operating costs

The following table summarizes operating costs by category, incurred in 2011 (as per 2011 IETP claim form submissions):

Category	Description and Details of Operating Costs	Cost (C\$)
Facility Exp.	Drilling observation wells, well heads, completions, reservoir monitoring instrumentation	0.00
	Completions	0.00
	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)	12,740.58
Field Exp.	Field operating costs	912,675.00
	Surveillance costs	123,413.04
Total Operating Costs (C\$)		1,048,828.62

In addition, solvent injectant costs were incurred. These consisted of both cost of solvent, as well as trucking costs associated with transporting these volumes to site. Solvent costs incurred in 2011 were (as per 2011 IETP claim form submissions):

Total Injectant Costs (C\$)	5,686,658.89
------------------------------------	---------------------

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.

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. Revenue began to be generated in 2010, with the pilot contributing to total Cold Lake payable royalties over the last two years.

(C\$)	2005	2006	2007	2008	2009	2010	2011	Total ('05-'11)
SA-SAGD Revenue ¹	0	0	0	0	0	5,216,789	16,450,837	21,667,626
SA-SAGD CAPEX & OPEX ²	1,484,356	1,442,184	1,661,186	20,463,138	12,569,963	3,152,997	6,813,700	47,587,524
SA-SAGD Gas Expense ³	0	0	0	0	52,724	786,251	958,678	1,797,653
SA-SAGD Cash Flow	(1,484,356)	(1,442,184)	(1,661,186)	(20,463,138)	(12,622,687)	1,277,541	8,678,460	(27,717,550)
Cold Lake Royalty Rate	30%	30%	30%	25%	28%	31%	34%	
Cold Lake Royalty Impact	(445,307)	(432,655)	(498,356)	(5,115,785)	(3,510,369)	395,006	2,936,257	(6,671,209)
Total Cold Lake Payable Royalties⁴	157,264,756	375,655,398	338,663,276	574,810,144	438,228,250⁵	628,964,325⁵	930,374,295	3,443,960,444

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.

⁵ Amendments to prior years 2009 & 2010 were processed, therefore the royalties for these years has been revised since the 2010 annual IETP progress report

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. Recovered solvent from the pilot will ultimately reduce diluent purchases made at the Mahkeses plant which are required for blending & shipping, but for the purposes of this report, solvent recovery is shown as a theoretical revenue stream. Estimates have been made for:

Bitumen revenue in 2011 = C\$ 12,877,231 (see section 6.2)

Recovered solvent revenue in 2011 = C\$ 3,573,606 (based on a recovered volume of 5,456.8 m³, and a solvent price of 104.12 C\$/bbl = 654.9 C\$/m³)

Net natural gas expense in 2011 = C\$ 958,678 (see section 6.1 - based on a net gas volumes of -7,561,765 m³ (-267,041 mcf), and a gas price of 3.59 C\$/mcf)

Capital and operating costs are known to be:

Capital costs in 2011 = C\$ 78,212 (see section 6.3)

Operating costs in 2011 = C\$ 6,735,488 (see section 6.4 – includes operating and injectant costs)

2011 cash flow is estimated to be:

$$\begin{aligned}
 \text{Cash Flow} &= \text{Revenue} - \text{Costs} - \text{Royalties} \\
 &= (\text{Bitumen} + \text{Solvent Revenue}) - (\text{Capital} + \text{Net Gas} + \text{Operating Costs}) - \text{Royalties} \\
 &= (12,877,231 + 3,573,606) - (78,212 + 958,678 + 6,735,488) - 2,936,257 \\
 &= \mathbf{C\$ 5,742,202}
 \end{aligned}$$

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	2011	Total (to YE 2011)
Total Capital Costs	25,024,122	1,109,761	78,212	26,212,095
Total Operating Costs	12,596,704	1,231,813	1,048,829	14,877,346
Total Injectant Costs	0	811,423	5,686,659	6,498,082
Total Net Gas Costs ¹	52,724	786,251	958,678	1,797,652
Total Costs	37,673,550	3,939,248	7,772,378	49,385,175

¹ Estimated, see section 6.6 for assumptions

Cumulative project revenue to date is:

C\$	Up to YE 2009	2010	2011	Total (to YE 2011)
Bitumen Revenue ²	0	4,898,707	12,877,231	17,775,938
Solvent Revenue ³	0	318,082	3,573,606	3,891,688
Total Revenue	0	5,216,789	16,450,837	21,667,626

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 (~83m³ 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 m³/d (cold water equivalent) of dry steam injected per well pair
- 330 m³/d water produced per well
- 20% (based on dry steam rate), or 60 m³/d, maximum solvent injected per day
- 51.6 m³/d solvent produced per day
- 84 m³/d bitumen produced per well, without solvent assistance
- 110.4 m³/d bitumen produced per well, with solvent assistance
- 2,100 m³/d gas produced per well
- Total liquid from solvent assisted producing well: 492 m³/d (330 m³/d + 110.4 m³/d + 51.6 m³/d)

Operational Issues

No significant operational issues were encountered in 2011.

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 H₂S and SO₂ 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 atypical 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:

- Monthly reporting of injection and production volumes to ERCB (held confidential until end of pilot period)
- 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 2011 performance:

- Continued successful pilot operations in 2011
- SAGD (well-pair 1) and SA-SAGD (well-pair 2) performance to date is within the expected range

Difficulties Encountered

No major difficulties were encountered in 2011.

Technical and Economic Viability

Judgements regarding technical and economic viability of a solvent-assisted SAGD process have yet to be made at this time.

Overall Effect on Gas / Bitumen Recovery

This has yet to be determined.

Future expansion or commercial field application

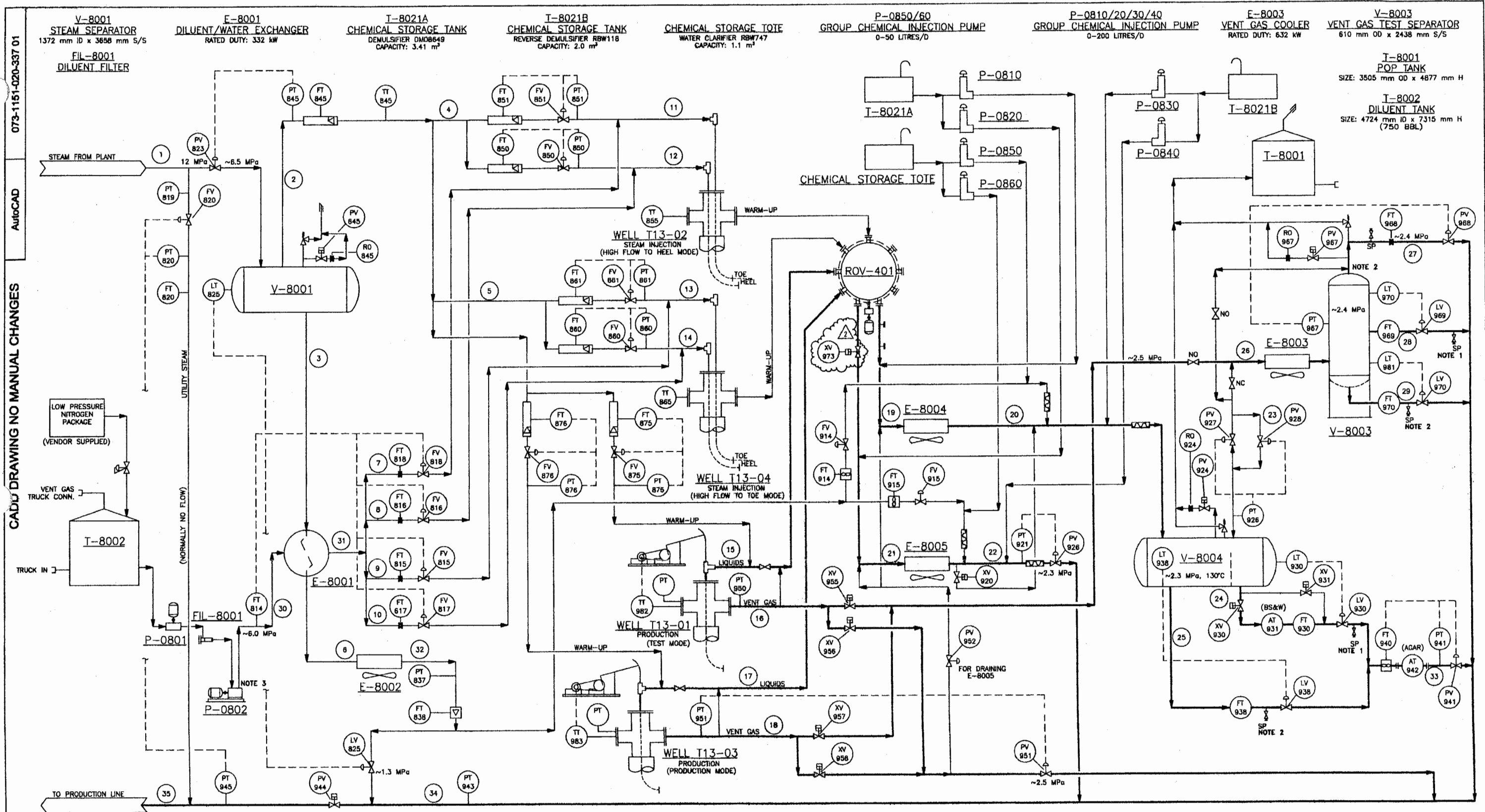
This has yet to be determined.

Appendix A

Process Flow Diagrams (PFDs)

&

Site Maps



073-1151-020-337 01
 AutoCAD
 CAD/DRAWING NO MANUAL CHANGES

- 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

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.	IOR DWG NO.	TITLE
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	CHECK	DESIGN	APPR.		REFERENCE DRAWINGS

Imperial Oil
Esso

IMPERIAL OIL RESOURCES

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

CONTRACTOR NAME
COLT ENGINEERING CORPORATION

CONTRACTOR DWG NUMBER
XY.2006.28284

SCALE
NONE

IOR DRAWING NUMBER
073-1151-020-337 01

REV.
2

073-1151-010-302 01

AutoCAD

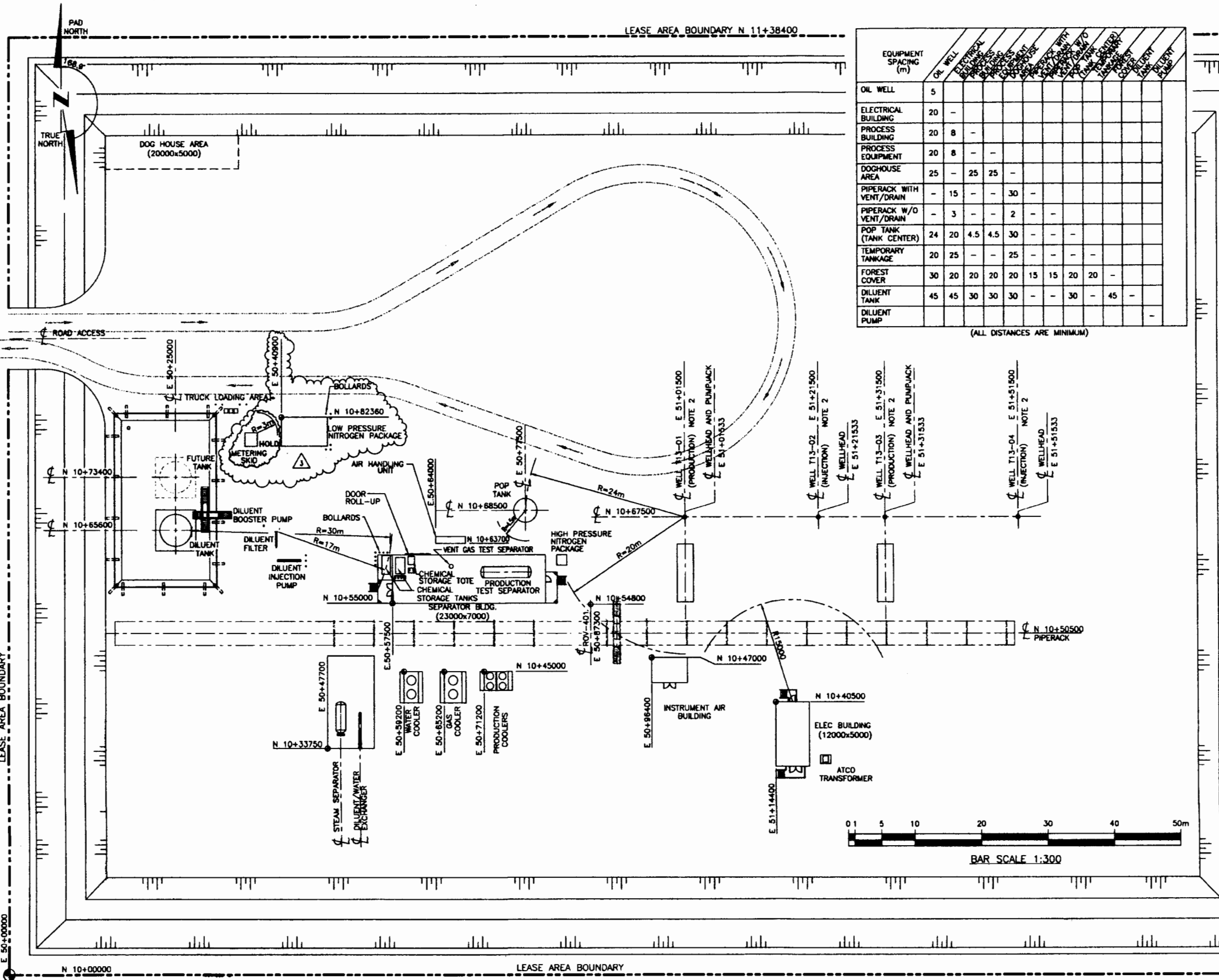
CADD DRAWING NO MANUAL CHANGES

LEASE AREA BOUNDARY

LEASE AREA BOUNDARY

DATE

LEASE AREA BOUNDARY N 11+38400



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

(ALL DISTANCES ARE MINIMUM)

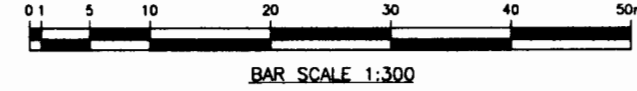
IAG No.	DESCRIPTION	LOCATION
E-8001	DILUENT/WATER EXCHANGER	AS SHOWN
E-8002	WATER COOLER	AS SHOWN
E-8003	GAS COOLER	AS SHOWN
E-8004	PRODUCTION TEST COOLER	AS SHOWN
E-8005	PRODUCTION COOLER	AS SHOWN
HTR-8110/1/2/3/4/5	BUILDING HEATERS	SEPARATOR BLDG.
EF-8010/1/2/3	EXHAUST FANS	SEPARATOR BLDG.
HTR-0004/5/6	BUILDING HEATERS	ELEC. BUILDING
EF-0003/4	EXHAUST FANS	ELEC. BUILDING
FL-8001	DILUENT FILTER	AS SHOWN
K-8021	INST. 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.
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.
HAU-8010	AIR HANDLING UNIT	AS SHOWN

DESIGN NOTES:

- LOCATION OF GROUNDWATER EVALUATION WELL (GEW) TO BE SUPPLIED BY FIELD.
- 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.



IMPERIAL OIL RESOURCES CLPP MAHKESES FIELD PHASES 11 - 13 PAD T13 SA-SAGD FACILITIES PLOT PLAN		CONTRACTOR NAME	SCALE	OR DRAWING NUMBER	REV.
		COLT ENGINEERING CORPORATION	1:300	073-1151-010-302 01	3
CONTRACTOR DWG NUMBER		XY.2008.28284			

NO.	DATE	REVISIONS	DRAWN	CHECK	DESIGN	APPR.	IDR DWG NO.	TITLE
3	06 05 25	RE-ISSUED FOR CONSTRUCTION - MOC C-4784 (XY.2008.28284)	MG	DAF	BAF	GME		
2	06 11 13	ISSUED FOR CONSTRUCTION - MOC C-4405 (XY.2008.28284)	KJO	GBF	GCS	BAF		
1	06 11 14	RE-ISSUED FOR CONSTRUCTION - MOC C-4413 (XY.2008.28284)	YW	MG	BAF	GME		
0	06 06 15	ISSUED FOR CONSTRUCTION (XY.2008.28284)	CAR	MG	BAF	GME		

APPROVED FOR CONSTRUCTION

DATE: 27 MAY 09 REV: 3

Signature: [Signature]

Permit to Practice
 IMPERIAL OIL RESOURCES
 Signature: [Signature]
 Date: MAY 27, 2009
 PERMIT NUMBER: P00884
 The Association of Professional Engineers, Geologists and Geophysicists of Alberta

PROJECT ENGINEERING