2015 Annual Performance Review

Cold Lake Approvals 8558 and 4510

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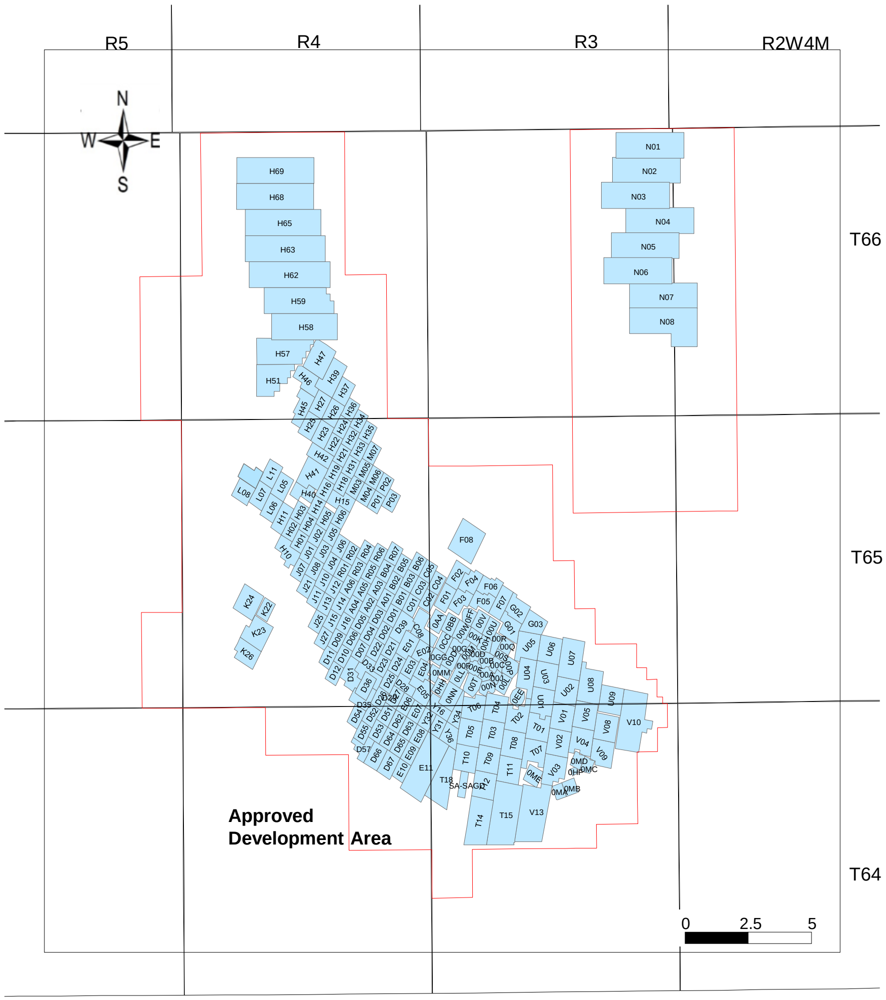
Table of Contents

Note: The following information covers the period from October 1st 2014 to September 30th 2015, unless otherwise stated.

Acronyms	Definitions
BTEX	Benzene Toluene Ethylbenzene Xylenes
BIS	Bitumen In Shale
BHL	Bottom Hole Location
BTC	Buttress Thread Collar
CDWQG	Canadian Drinking Water Quality Guidelines
CW(T)	Clearwater (Top)
CLO	Cold Lake Operations
CS(T)	Colorado Shale (Top)
CEW	Colorado Shale Evaluation Well
CI	Contour Interval or Casing Integrity
(HP) CSS	(High Pressure) Cyclic Steam Stimulation
(O)EBIP	(Original) Effective Bitumen in Place
EUE	External Upset Tubing
FTD	Final Total Depth
FLIR	Forward Looking Infra-red
GM	Gas Migration
(U)/(L)GR	(Upper)/(Lower) Grand Rapids
GEW	Groundwater Evaluation Well
GW	Ground Water
HW	Horizontal Well
HRSG	Heat Recovery System Generator
(H)PSW	(Hybrid) Passive Seismic Well
IOI	Injector Only Infill
LASER	Liquid Addition to Steam for Enhanced Recovery
LTC	Long Thread Collar
MD	Measured Depth
NS-CC	Nippon Steel-Casing Connection
OV	Oilsand Valuation Well
PIMFET	Production Injection Management Fatigue Estimation Toolkit
RFC	Regulated Fill-up Cement
STC	Short Thread Collar
ST	Side Track
(SA)-SAGD	(Solvent Assisted) Steam Assisted Gravity Drainage
SCVF	Surface Casing Vent Flow
TVD	True Vertical Depth
VOF	Volume Over Fill-Up

Background



Development History

60's-70's	Lease acquisition Small scale research pilots
1975	10 kbd commercial pilot
'85-'94	Phase 1-10 > Maskwa > Mahihkan
2002	Phase 11-13 Mahkeses > Cogeneration facility
2004	Approval area expanded > Nabiye, Mahihkan North
2015	Phases 14-16 Nabiye > Cogeneration facility

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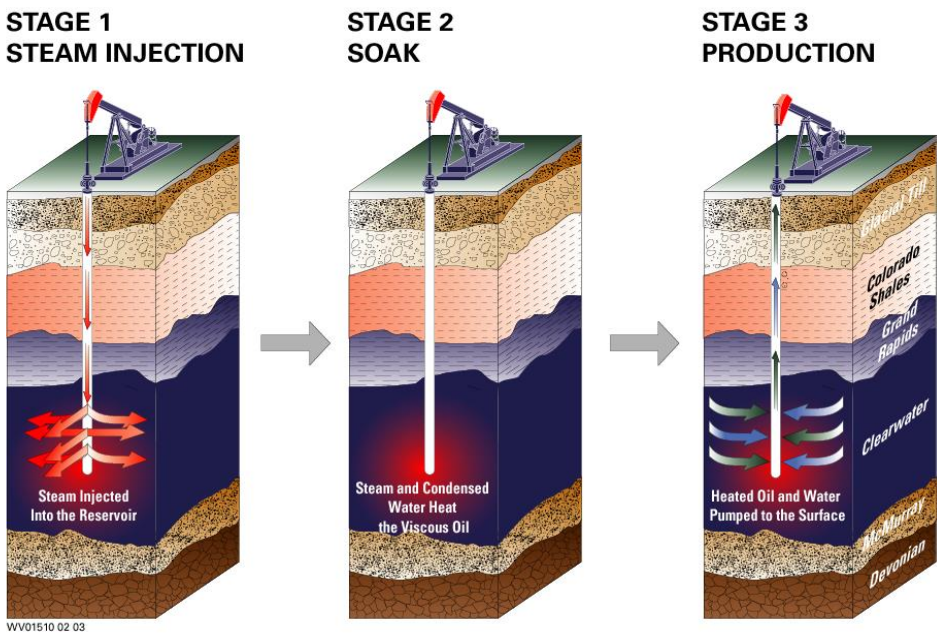
CSS Process Overview



Wells required	One
Well type	Deviated or horizontal
Steam pressure	Above fracture pressure

- High pressure, high rate with multiple recovery mechanisms
  - > compaction drive
  - > solution gas drive
  - > gravity drainage
- Steam heats bitumen to allow flow (4 - 6 weeks)
- Soak (several weeks) allows heat to contact more bitumen
- Production period lengths increase from few months in early cycles to multiple in last cycles
- Full Well life; 8 -17 cycles and up to 50 years including follow-up processes

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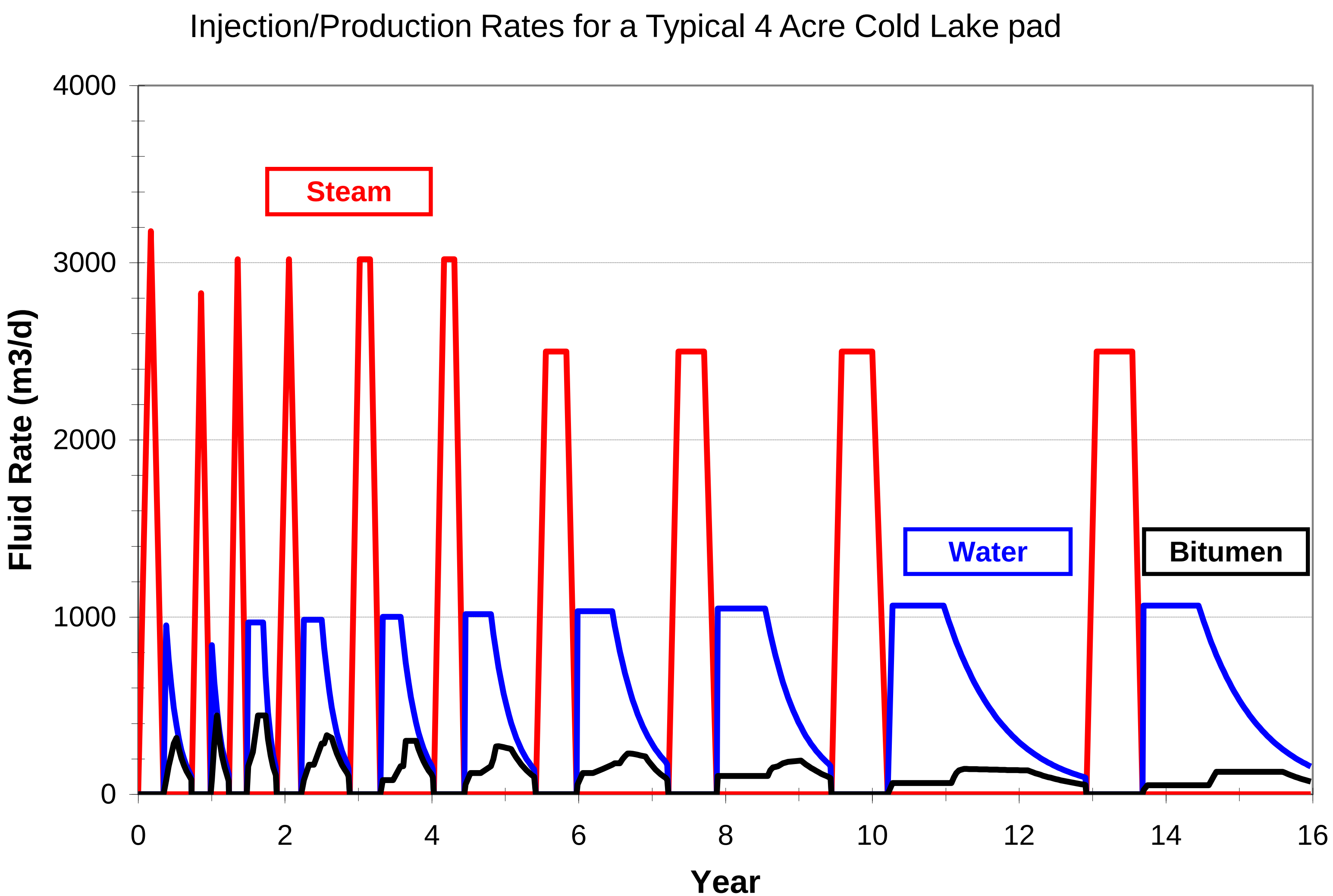
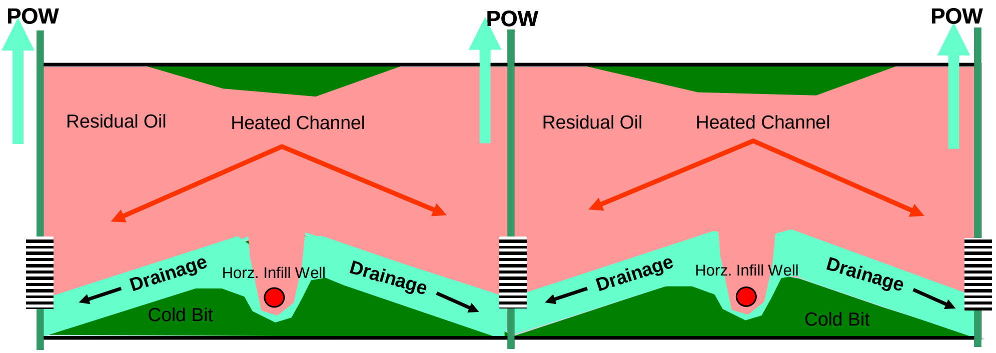
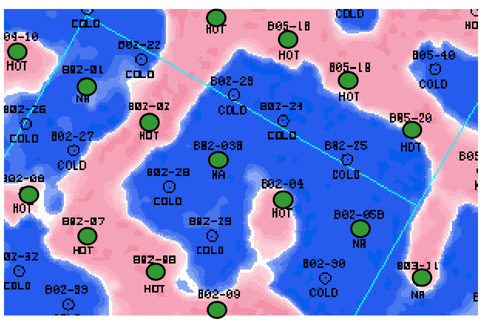
CSS Process Overview



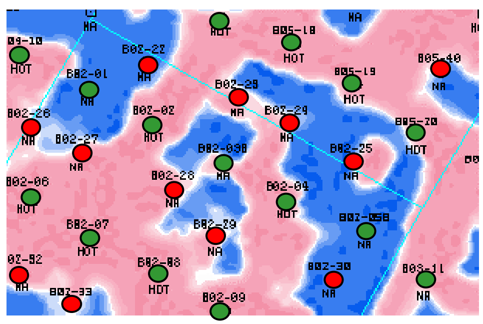
Injector Only Infills (IOI)



- Injector only Infill wells direct cyclic steam to cold bitumen
- Steam distribution in horizontal wells controlled by limited entry perforations (~20 holes/1000 m well)
- Existing deviated wells operate as cyclic producers



Pre-Infill 3D Seismic



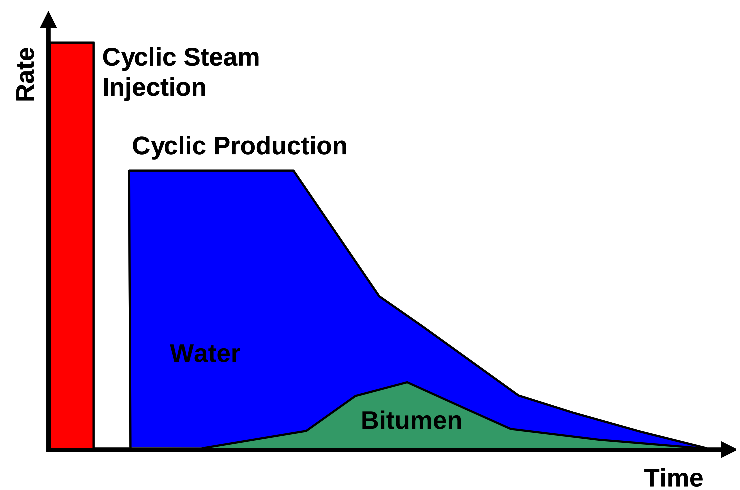
Post-Infill 3D Seismic

Hot reservoir (partially depleted)

Cold reservoir (undepleted)

CSS wells

Infill wells



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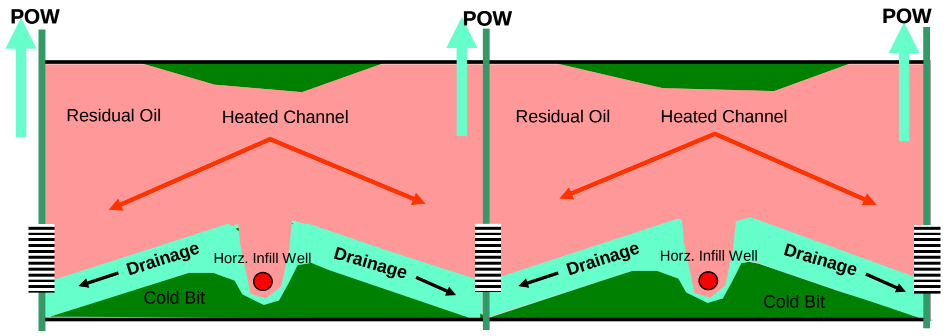
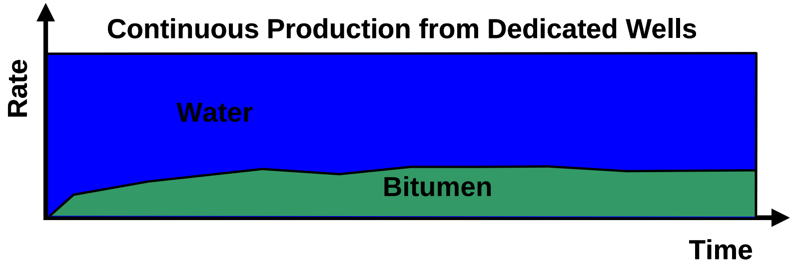
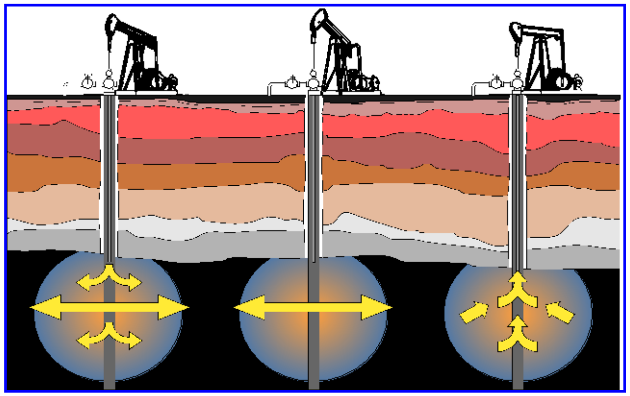
Steamflood Process Overview



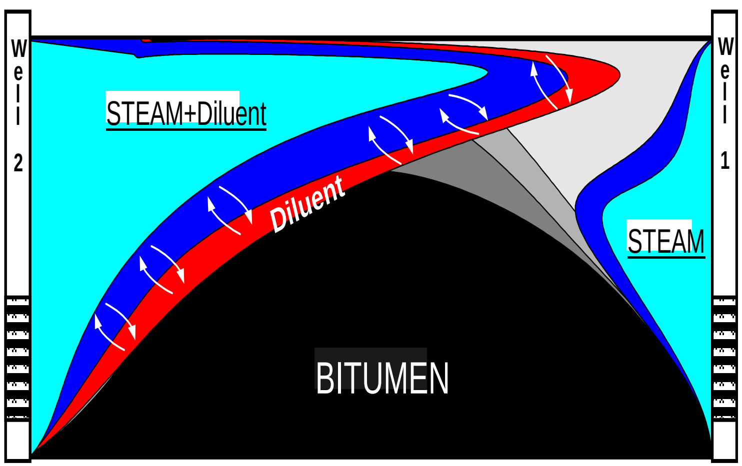


- Continuous steam injection, at low rates has the potential to:
  - > Lower operating costs
  - > Improve well operability
  - > Reduced casing stress
- Target reservoir pressure between 0.5 to 1.5 MPa
- Continuous rather than cyclical steam injection through dedicated injection-only and production-only wells

LASER Process Overview



CSS Thermal Process



Liquid Addition to Steam for Enhancing Recovery

- LASER is a late-life technology
  > Follow-up process for CSS (cyclic steam stimulation)

  > Implemented with 2-3 cyclic cycles remaining

  > Alternative to purely thermal processes

- LASER is a cyclic steam process with the addition of a C5+ condensate to the steam during injection
  > Enhances gravity drainage efficiency by reducing in-situ viscosity beyond thermal limit

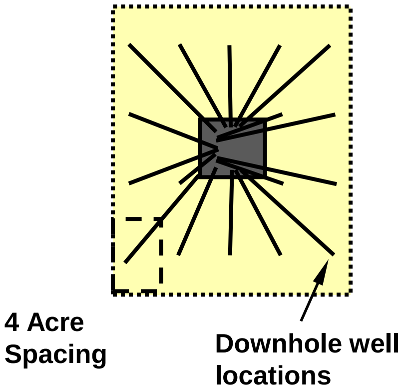
  > Potentially increases the recovery by >5% of EBIP

- Key process performance indicators
  > Incremental OSR over a purely thermal baseline

  > Fractional recovery of injected solvent

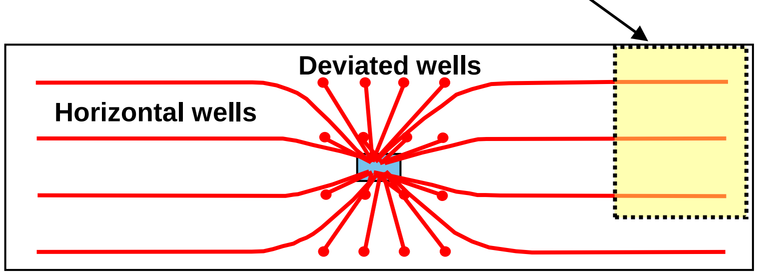
Pad Design

Original Pad Design



Mega Pad

Subsurface area of original Cold Lake Pad design



- Wells drilled directionally from central lease location
  - > Reduced environmental disturbance
  - > Improved development economics
  - > Increased operational efficiencies
- Original pad design 20 wells on 4 acre spacing
- Current pad designs
  - > Up to 35 wells on 4 or 8 acre spacing
  - > Mix of deviated and horizontal wells

Geoscience Overview

Average Reservoir Properties and OBIP

Reservoir and Fluid Properties

Depth	Clearwater @ 400M	
Depositional Facies	Continental scale fluvial-deltaic system	
Sands	Unconsolidated, reactive, clay clasts	
Diagenetic Cements	Mixed-layer clays	
Bitumen API Gravity	10.2	
Bitumen Viscosity	100,000 cp @ 13 C 8 cp @ 200C	
Bitumen Saturation	Average 70%	
	Range	*Average*
Porosity	27 - 35%	32%
Permeability	1 - 4 Darcies	1.5 Darcies
Bitumen Wt %	6 - 14%	10.5%
Total Net Pay	0 - 60m	30m

Original-Bitumen-in-Place (OBIP)

Clearwater Fm	*8 Wt %*		*6 Wt %*	
	(E6m3)	*(MBO)*	*(E6M3)*	*(MBO)*
Entire Approval Area	2,250	14,150	2,609	16,410
Operating Portion[1]	1,888	11,875	2,185	13,740

[1] Volume of main approved development area (i.e. excluding Nabiye)

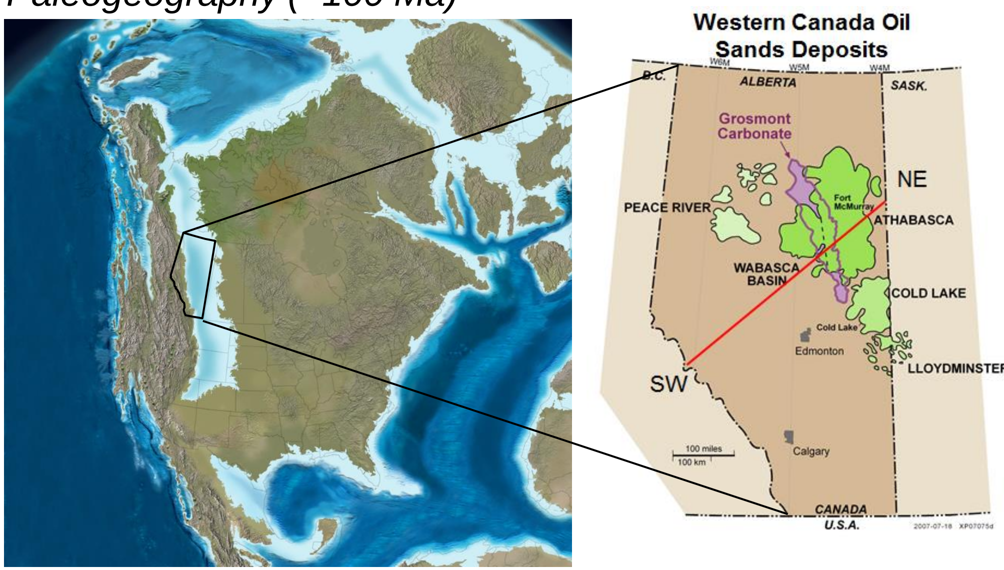
CALCULATION METHOD

OBIP = A * H * V

A = area (m2)
H = Net pay (m)
V = Volumetric Factor = W * (2.64 – (1.64 * P))
W = Saturation (avg Wt %)
P = avg Porosity

Mannville Group: Geologic Setting

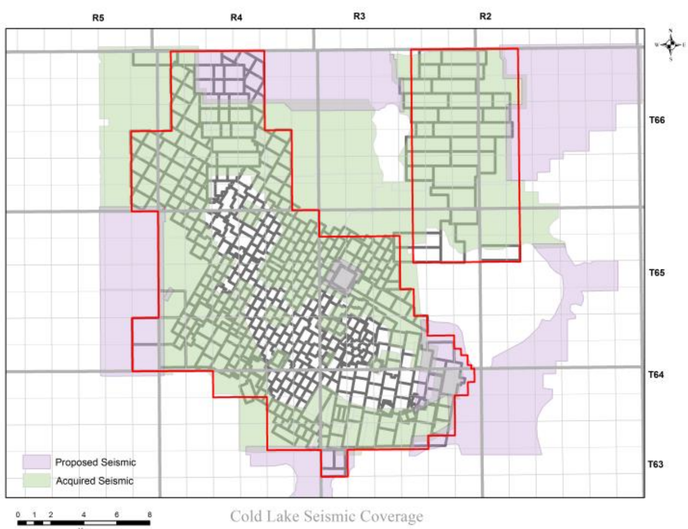
Paleogeography (~100 Ma)



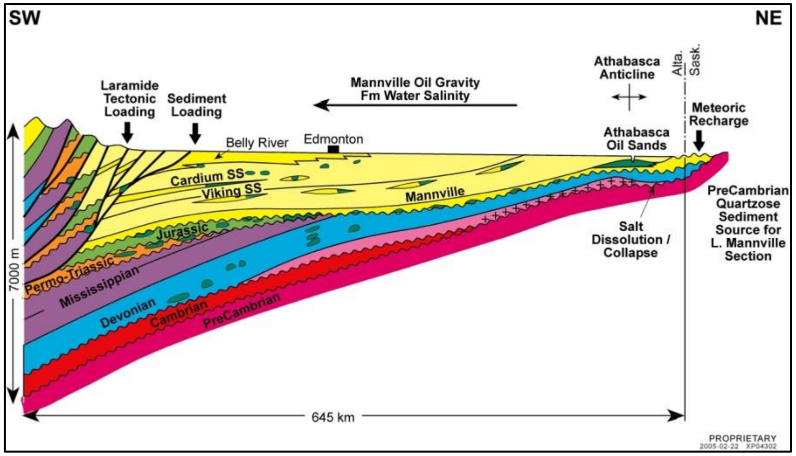
Blakey, www2.nau.edu/rcb7/index.html

Depositional Environment

- Manville group deposited during Barremian to Albian time associated with fluvial drainage to the north toward the boreal sea (Western Interior Seaway)
- Western Canada Basin is a large foreland basin thickening to the west; marine & non-marine deposits
- Sub-divided into two lithostratigraphic units: 1) Lower tidally influenced fluvial (McMurray); and 2) Upper estuarine/shelf dominated (CLW & GR)
- Regional high to the east due to backbulge where salt dissolution and underlying Paleozoics likely controlled subsidence - Athabasca anticline



Cold Lake Seismic Coverage



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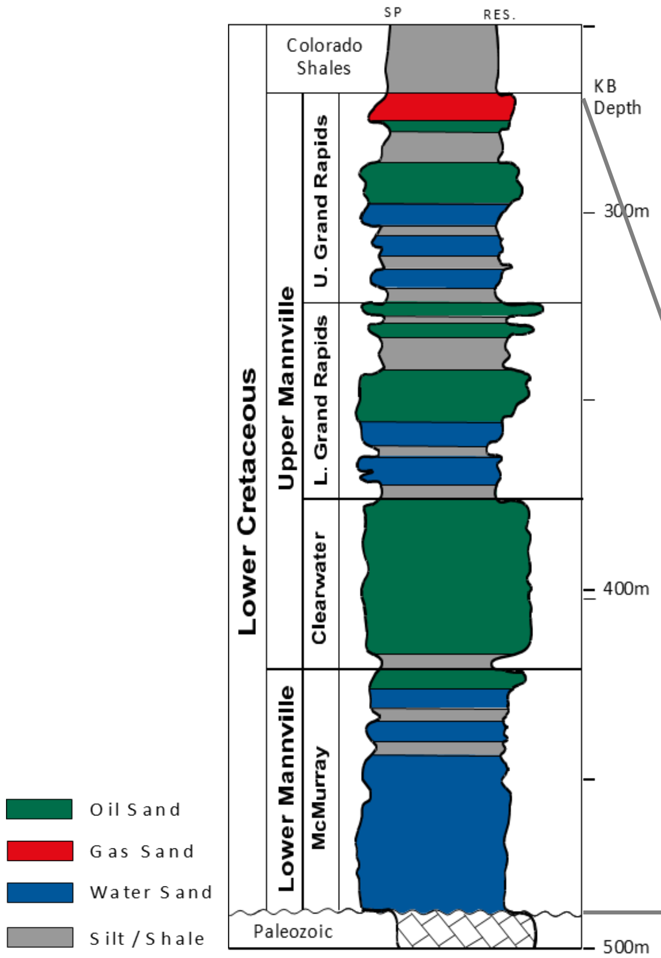
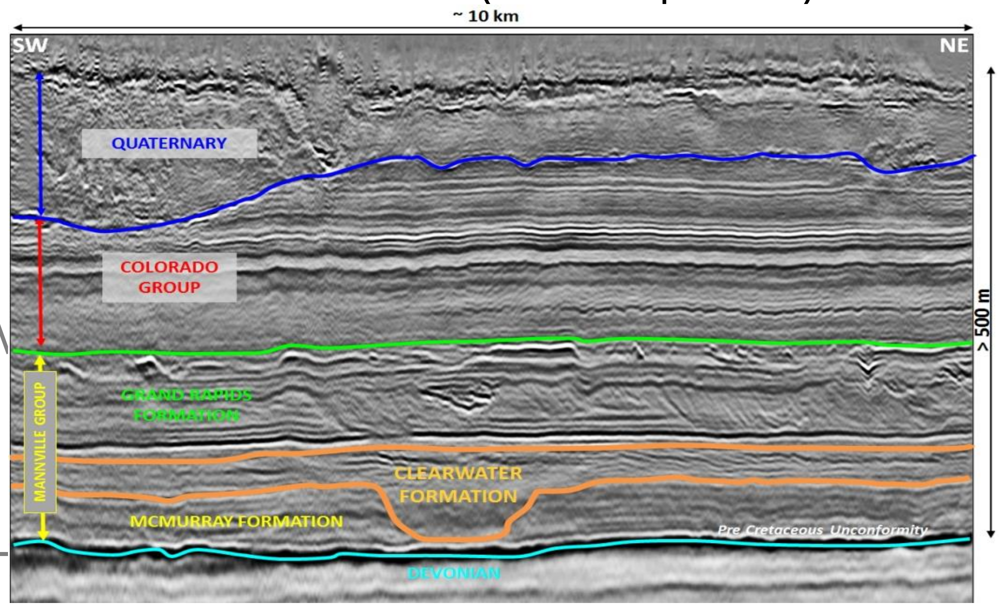
Representative Type Log

Representative Well Log Response – Mannville Group



- Schematic type well log through the Mannville Group, (Albian) of Cold Lake field, Alberta
- Primary reservoir is the Clearwater Formation, secondary targets comprise the Grand Rapids and McMurray formations
- Clearwater Formation is a reservoir with a complex stratigraphic architecture that consists of a succession of deltaic and tidally influenced distributive fluvial systems
- Development to date has focused on the Clearwater in the central axis of the main fluvial valley complex

Seismic Cross Section at Cold Lake (Surface to Top Devonian)



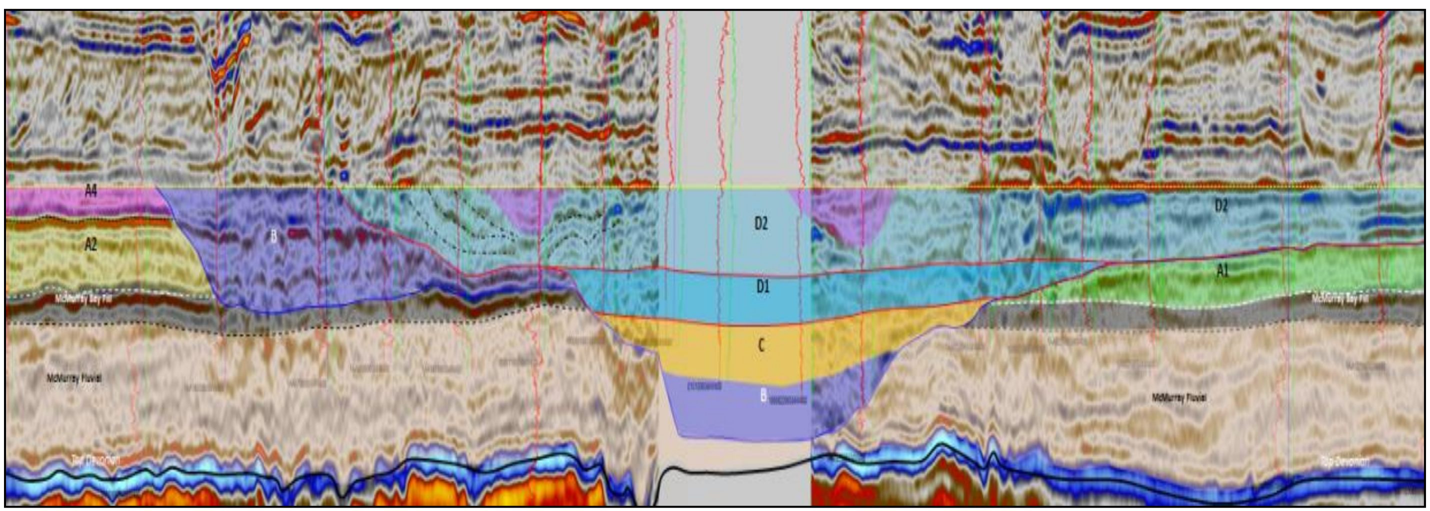
2014 Stratigraphic Framework

History

- Existing Cold Lake Clearwater stratigraphic framework developed in 1998
  - Adequate framework for majority of Cold Lake development projects
- Increasing complexity of recent & future development opportunities requires more predictive framework – depositional and diagenetic controls on RQ
  - Revised framework integrates 370 km^2 of hi-res 3D seismic and 1500 cores/logs
  - Identified four genetic units within the Clearwater that were mappable sub-regionally

Early Implementation

- Improved predictability of EOD distribution and impact on RQ has assisted with understanding production characteristics at Mahihkan North & K26, and has influenced investment decisions (e.g. D40 area)
- Mahihkan North modeling effort provides insights into future developments and technology applications



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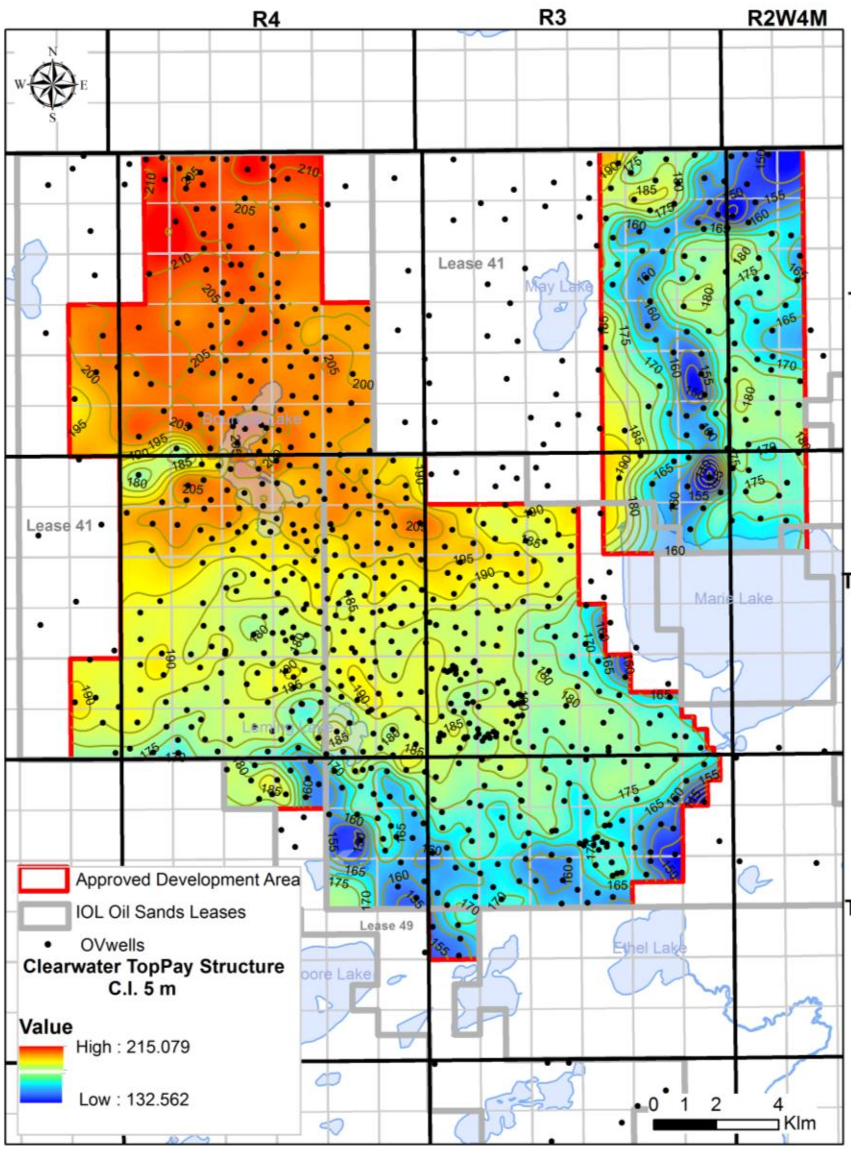
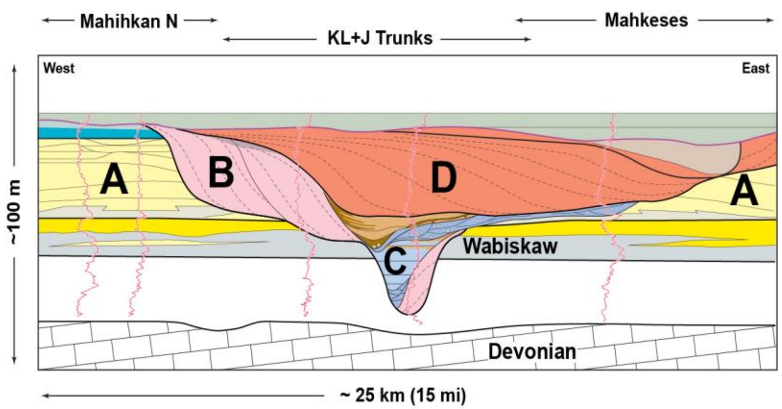
Top Bitumen Pay Structure



- Top of bitumen pay is a smoothly varying surface which gently dips from a high of 220m above sea level (A.S.L.) in the NW to a low of 136m A.S.L. in the SE
- Top of bitumen structure varies more greatly in the Nabiye area
- Mapped surface is either a rock/bitumen or a gas/bitumen contact

Clearwater Formation Stratigraphic Framework



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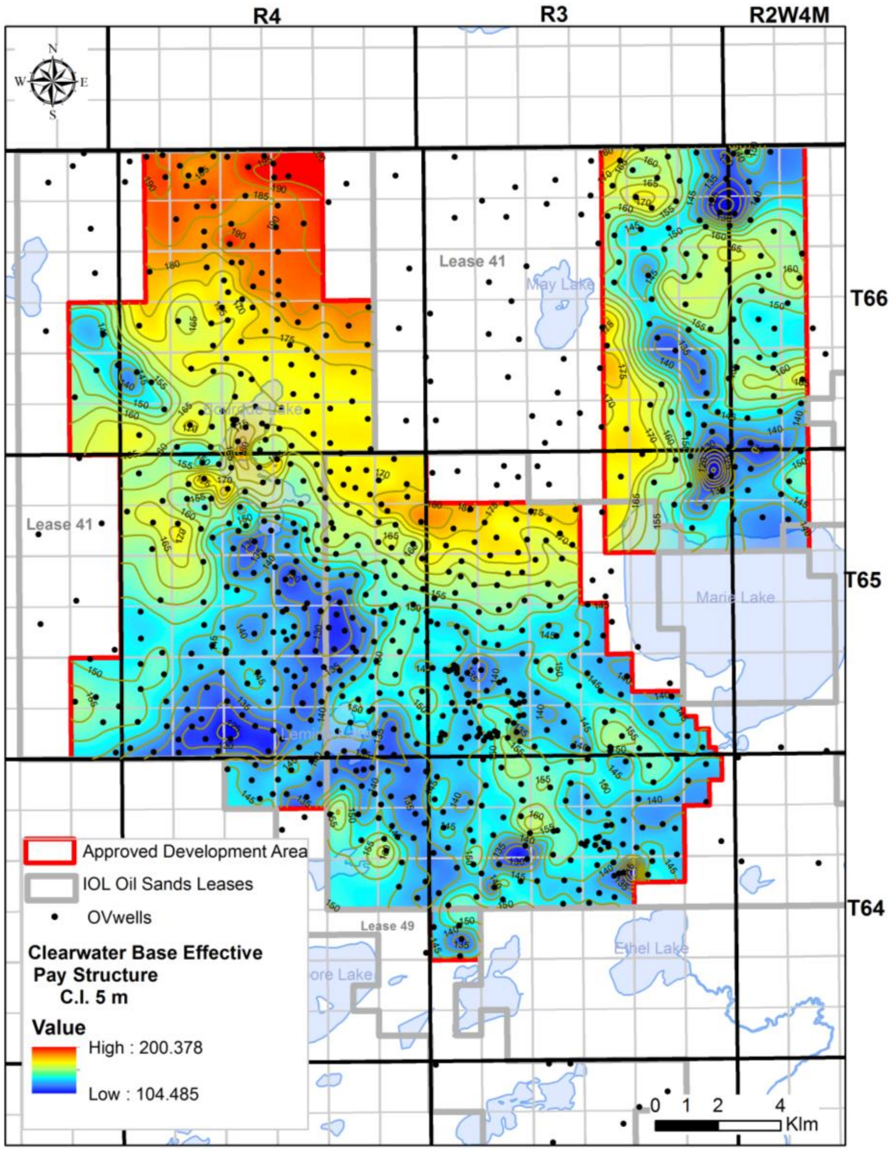
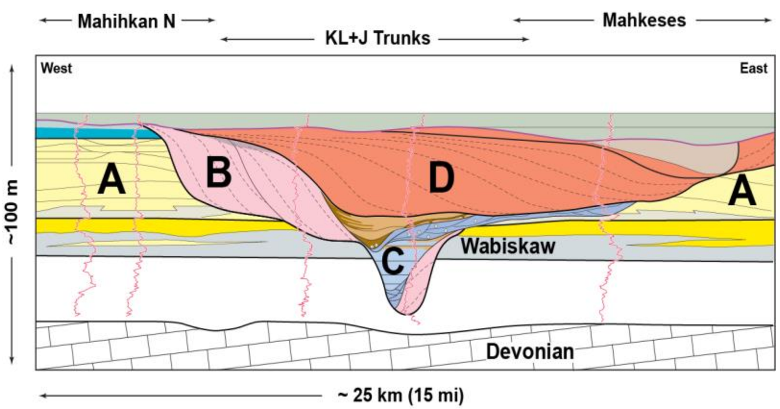
Base Bitumen Pay Structure



- Map represents amalgamated incised valley fills associated with low-stand erosional events
- Different successions, depending on their depositional environment are filled with varying amounts of sand and shale.
- Mapped surface is either a bitumen/rock, a bitumen/water transition zone or a bitumen/water contact

Clearwater Formation Stratigraphic Framework



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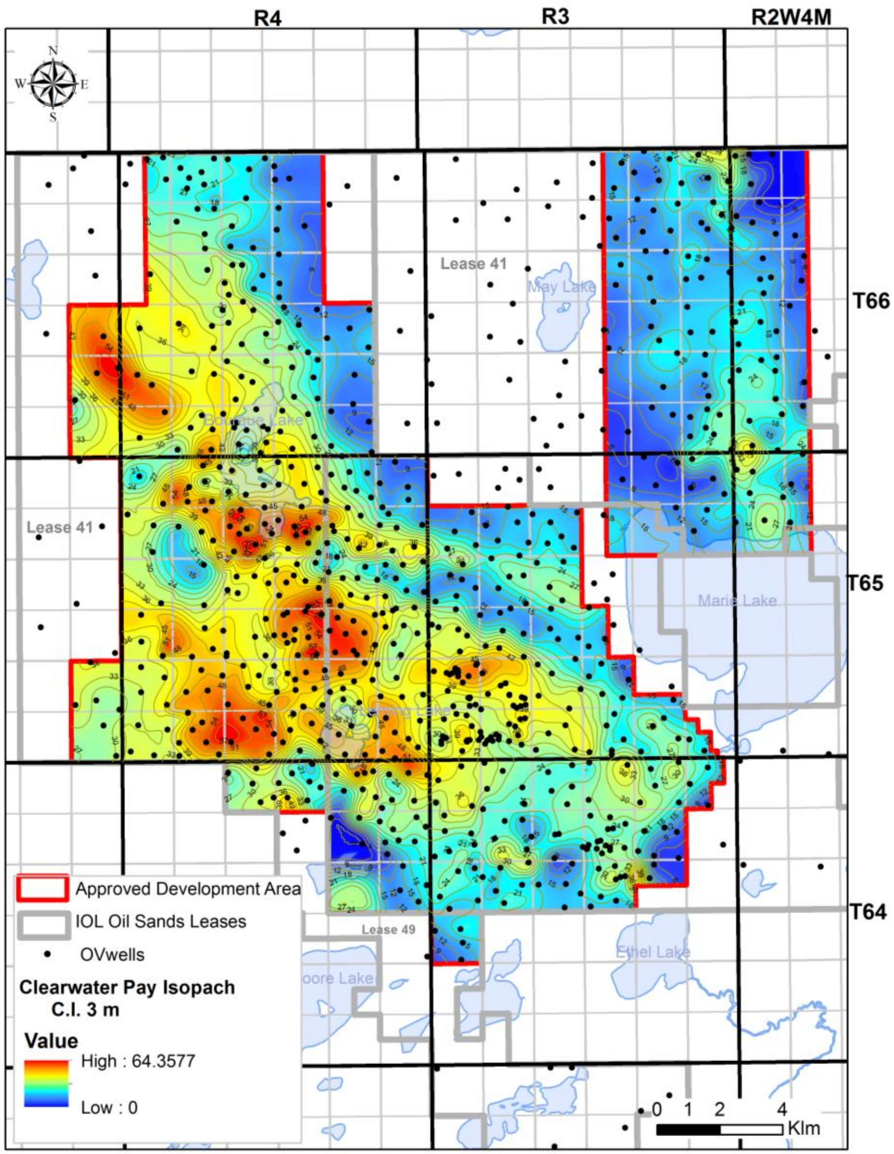
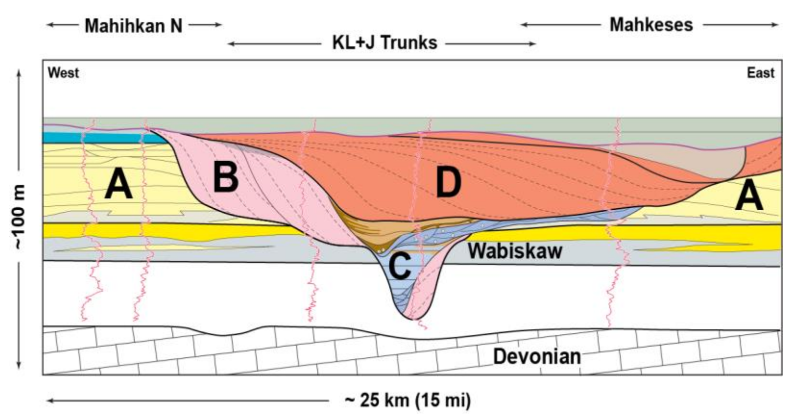
Isopach of Net Bitumen Pay (>8 wt %)



- Map illustrates distribution of pay above 8 wt% saturation cut off
- Thin pay and pay immediately adjacent to water included in isopach calculation
- Thickness trend is consistent with orientation of main valley incision

Clearwater Formation Stratigraphic Framework



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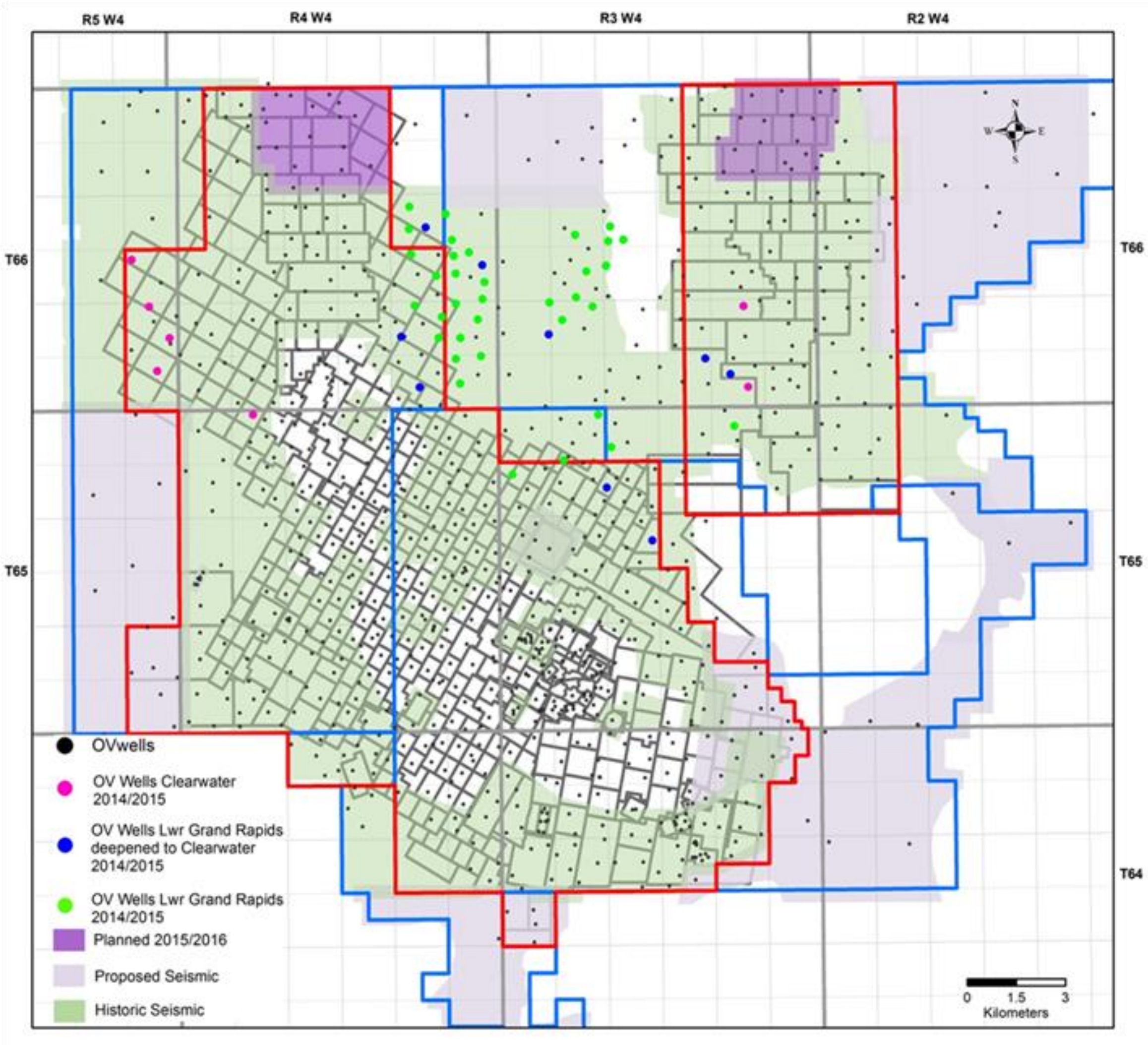
Approved Development Area



Map Illustrates:

- Approved Development Area
- Location and extent of existing development pads
- Distribution of OV core holes
- OV core holes drilled in 2015
- 3D seismic coverage
- 3D seismic planned in 2015/16

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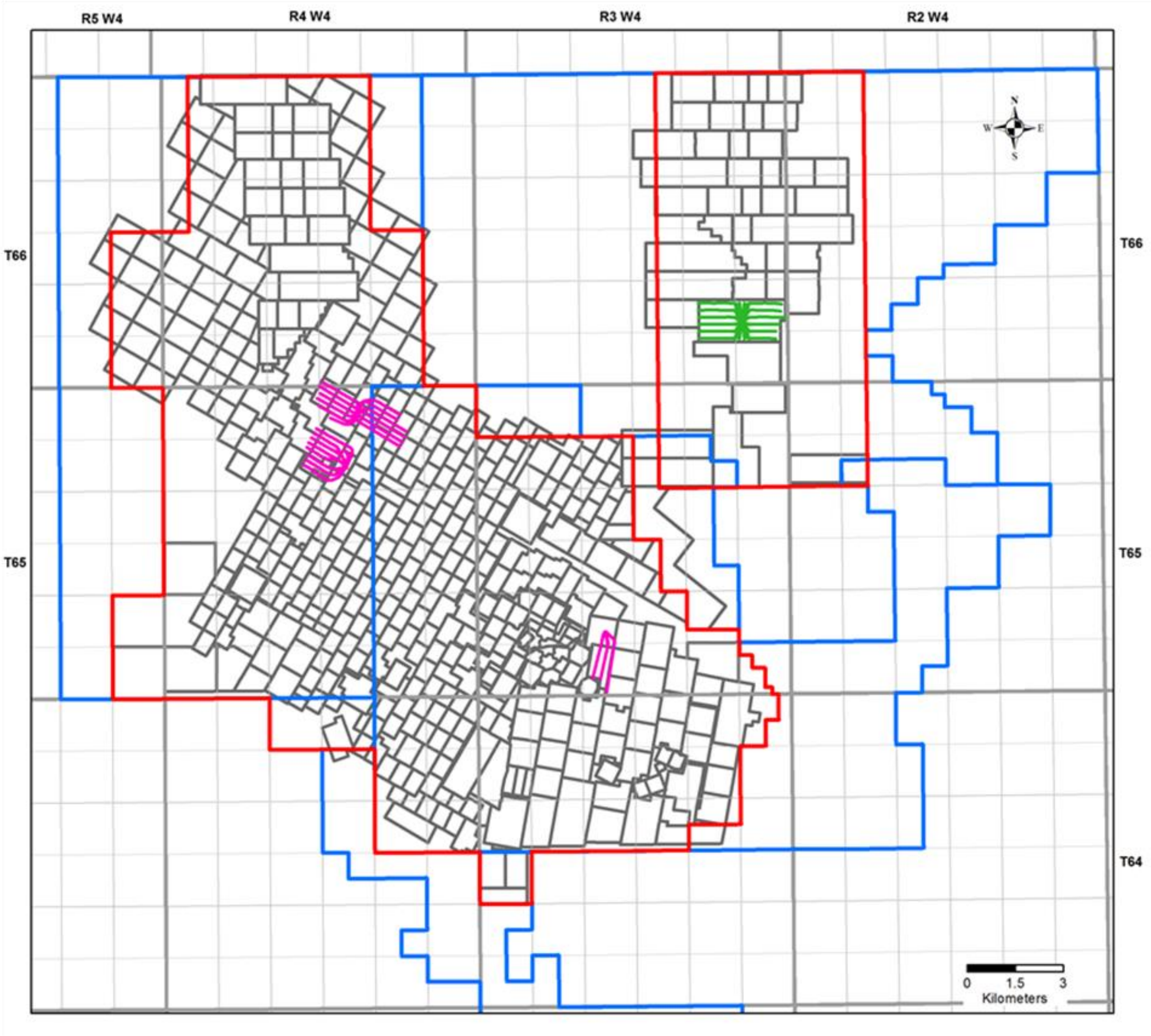
Approved Development Area



Map Illustrates:

- Approved Development Area
- Cold Lake Oilsands Leases
- Location and extent of existing development pads
- Development wells drilled in 2015
  - N09, H17, U05
- Development wells drilled by year end
  - H22

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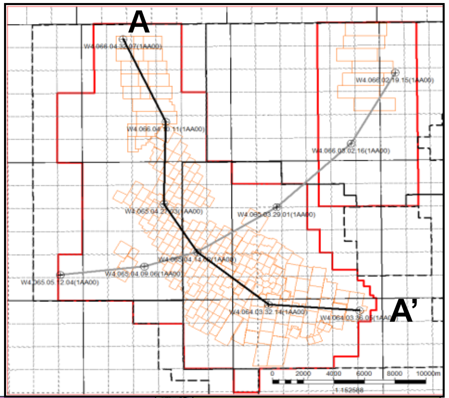
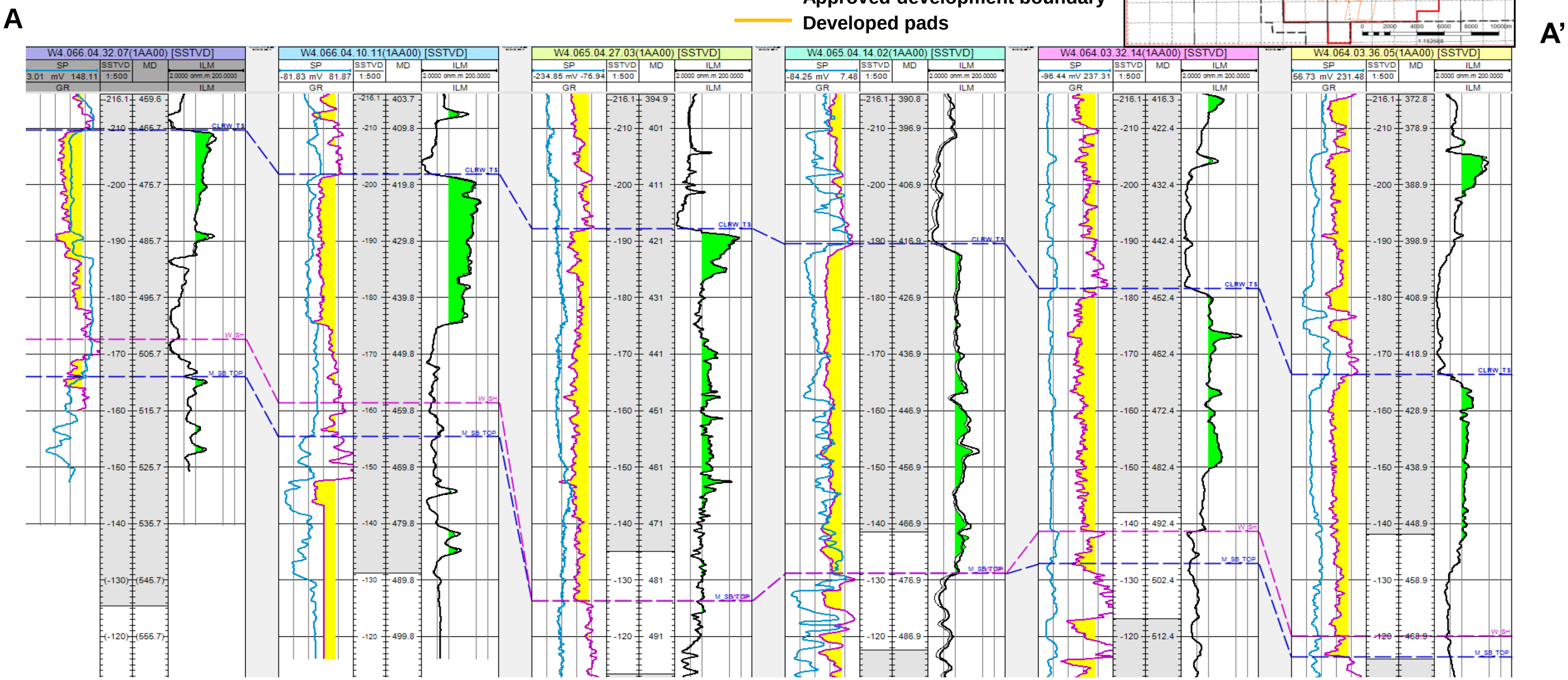
Representative Structural Well Log Cross Section

Cross section represents stratigraphic and structural variability within the Clearwater Formation from northwest to southeast .



Cold Lake Leases
Approved development boundary
Developed pads



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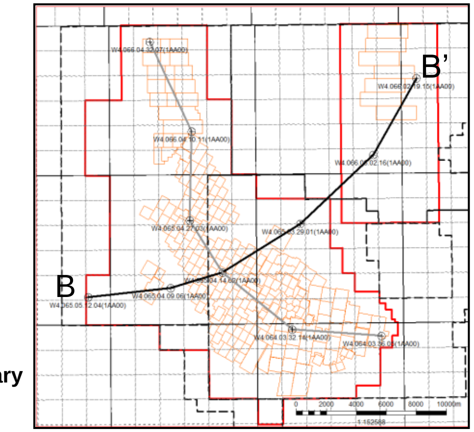
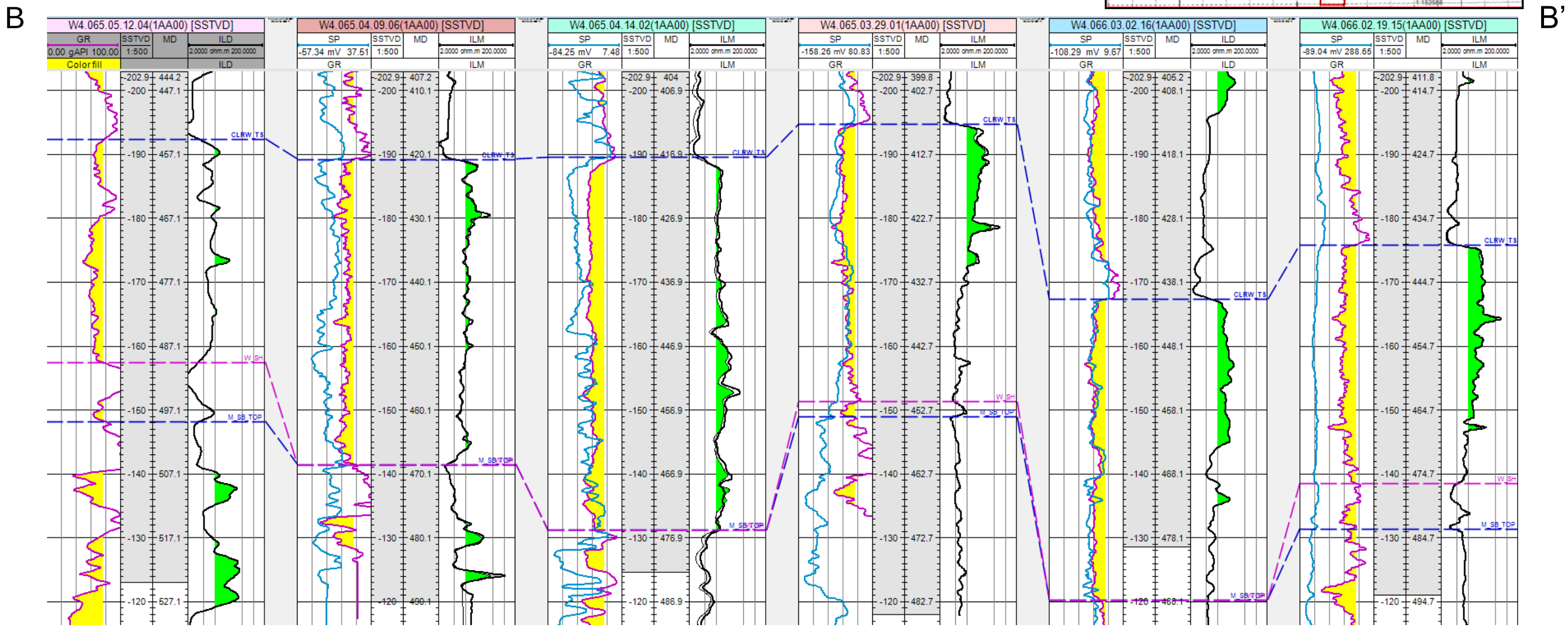
Representative Structural Well Log Cross Section

Cross section represents stratigraphic and structural variability within the Clearwater Formation from southwest to northeast.



Cold Lake Leases
Approved development boundary
Developed pads



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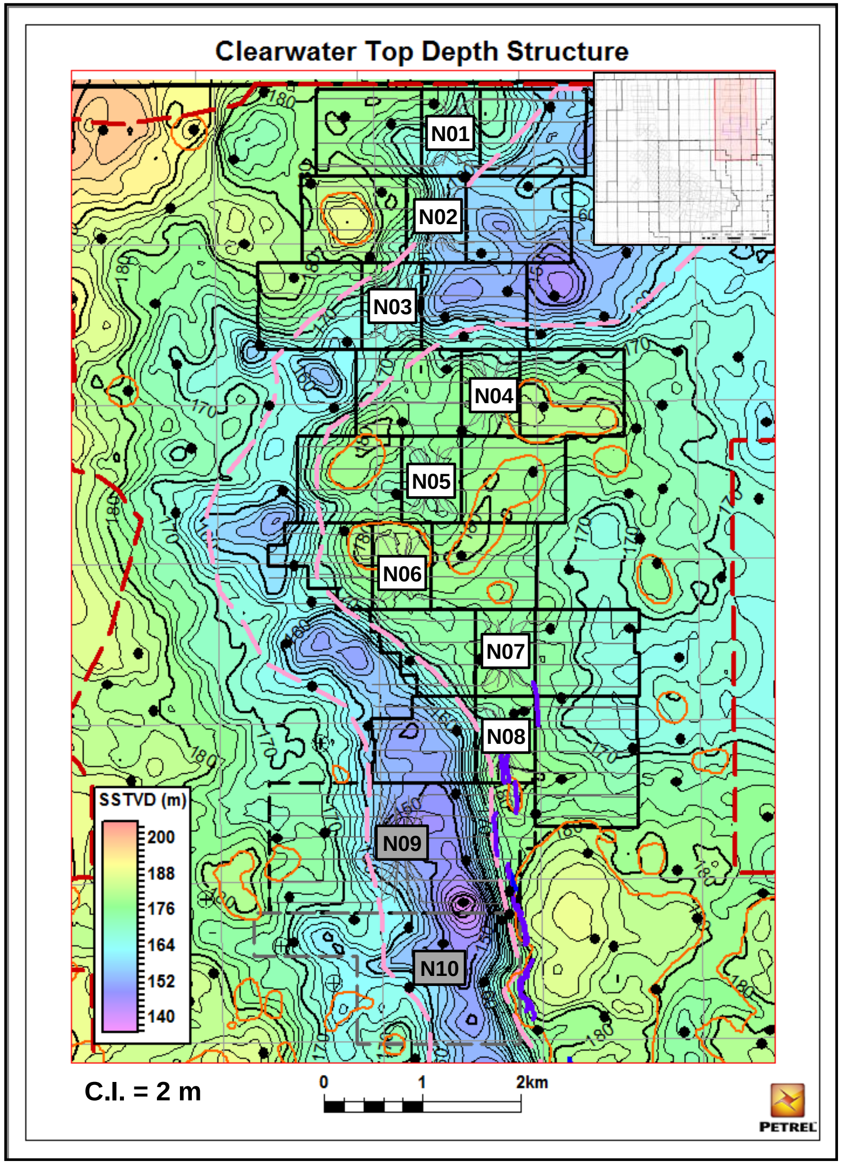
Nabiye Field Geology: Top Clearwater Structure

Map illustrates:

- Depth (Elevation) of the Top Clearwater Formation across the greater Nabiye Development area
  - Clearwater Top structure map integrates 3D seismic surveys and all well data
  - Significant structural change from 200 m asl to 140 m asl due to underlying salt dissolution of Paleozoic evaporites
  - Salt dissolution in the area occurred pre-, syn- and post-deposition of the Mannville Group
  - Structural deformation generated extensional faults within the Clearwater, Grand Rapids, and lower Joli Fou formations along the southeastern edge of the salt-dissolution valley
- Presence of top gas/water areas
- Distribution of the OV wells used in GeoModel
- Current production pads and future development pads

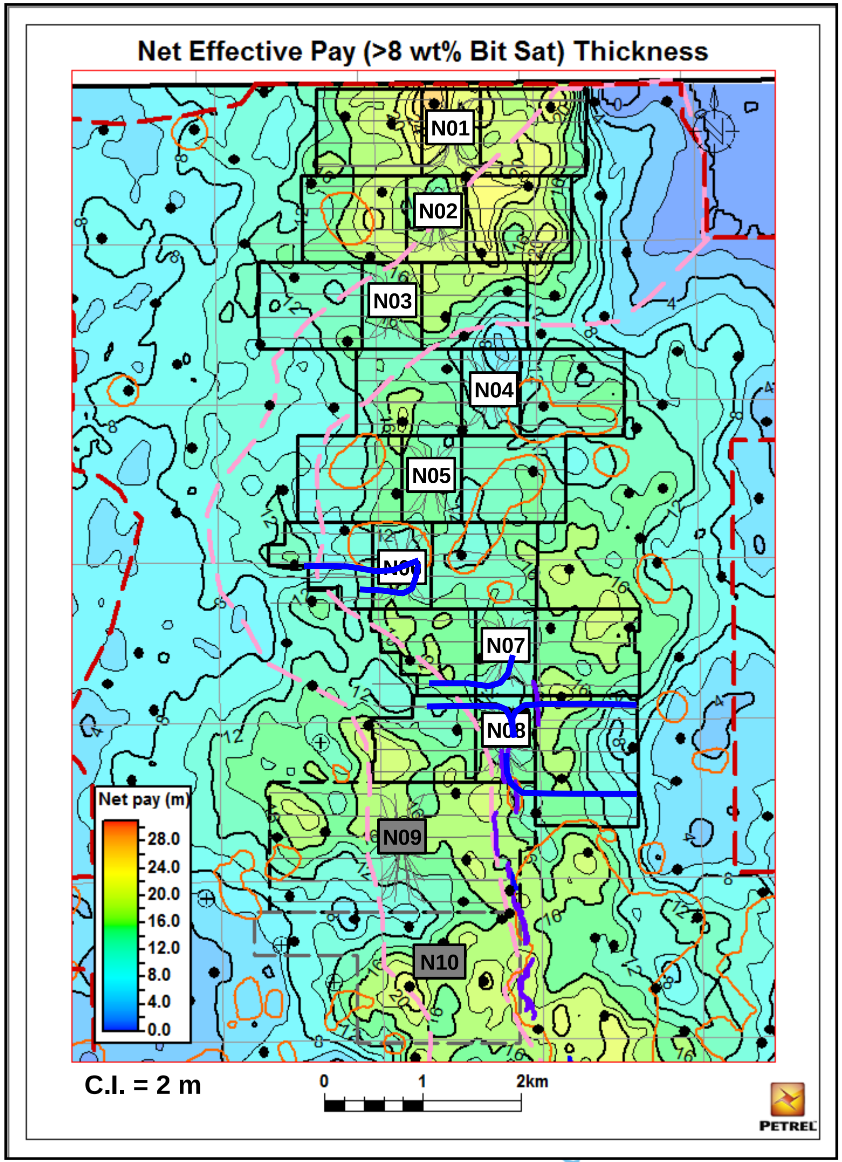
Cored OV Wells used in updated GeoModel
Production Pads: Drilled and Steamed (N01-N08)
Production Pads: Drilled (N09)
Future Development Pads (N10)
Seismic Surveys combined outline (3D)
Top Gas/Water Areas (From Seismic and Wells)
Salt Dissolution
Faults in Clearwater Formation



Isopach of Net Effective Bitumen Pay

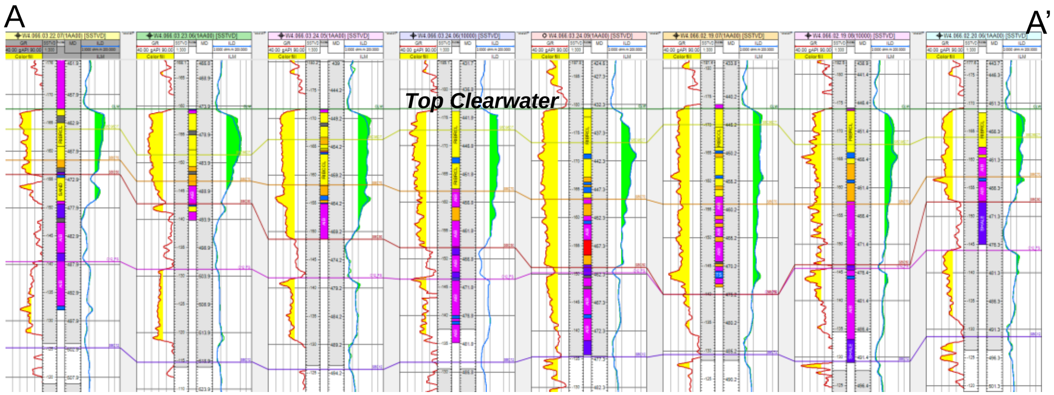
Map illustrates:

- Distribution of Net Effective Pay Thickness across the greater Nabiye Development area
  - Calculated from well top picks – top and base effective pay which account for top gas/water and bottom water standoff
  - Effective Pay defined as >8 wt% bitumen saturation; thin pay not included
- Blue well paths illustrate where horizontal production wells encountered free water and required re-drill
  - West side of pads N06, N07 and N08; and east side of pad N08 (wells required standoff)
- Presence of top gas/water areas
- Distribution of the OV wells used in GeoModel



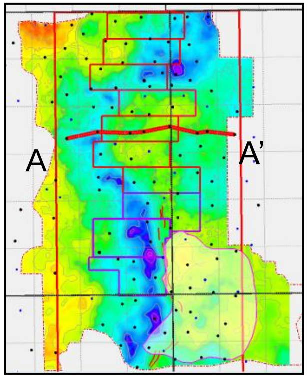
Cored OV Wells used in updated GeoModel
Production Pads: Drilled and Steamed (N01-N08)
Production Pads: Drilled (N09)
Future Development Pads (N10)
Seismic Surveys combined outline (3D)
Top Gas Areas (From Seismic and Wells)
Salt Dissolution
Faults in Clearwater Formation

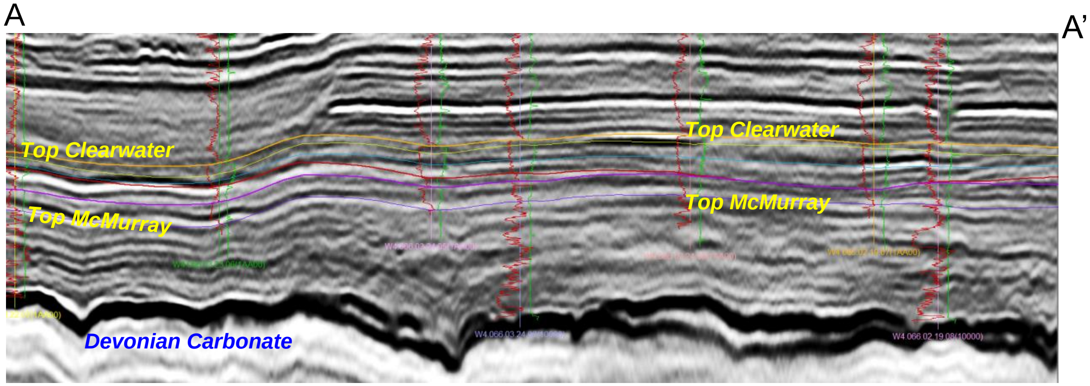
Geologic Cross Section AA' Across Nabiye Field



Well log cross section datumed on Top Clearwater surface displaying the internal stratigraphy across Nabiye field (pad N05 area)

Top Clearwater Structure CI=5m

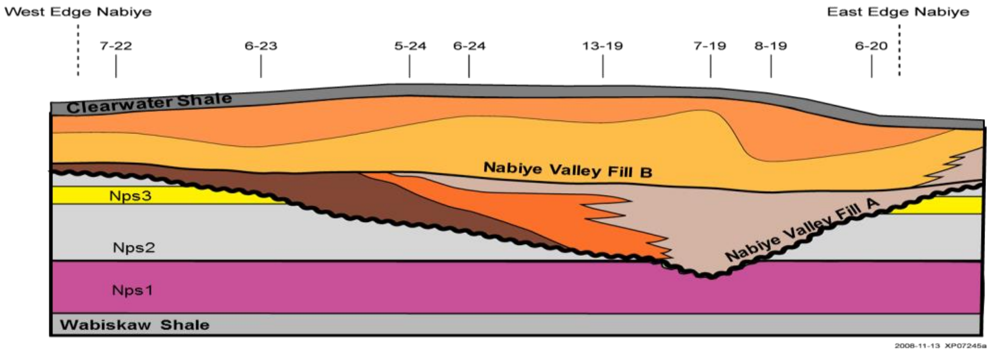




Structural seismic section across Nabiye pad N05 area (depth converted data) displaying internal stratigraphy.

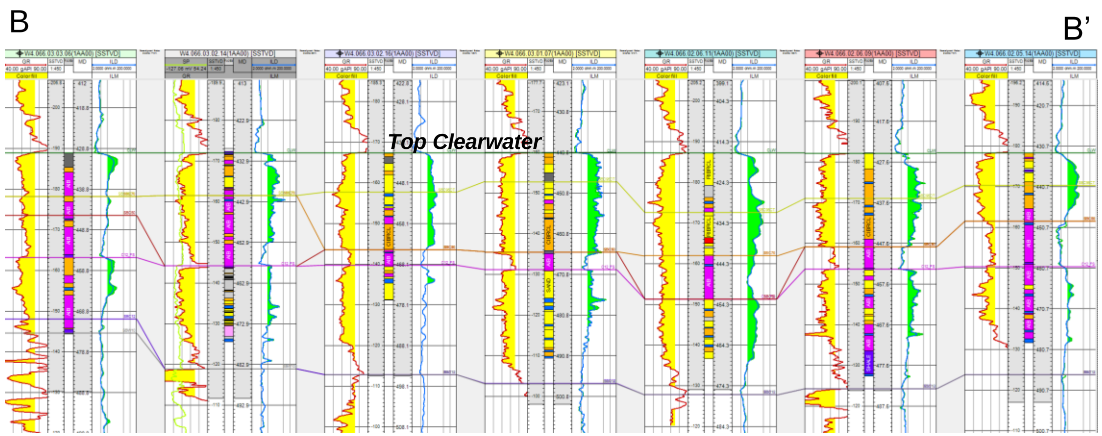
Structural deformation induced by salt dissolution within the underlying Paleozoic succession developed over the west side of pad N05 (see map inset also) where Top Clearwater drops >10 m to the west.

Notice irregular/erosional nature of the Pre-Cretaceous unconformity separating Paleozoic carbonates below from Cretaceous McMurray sandstones above



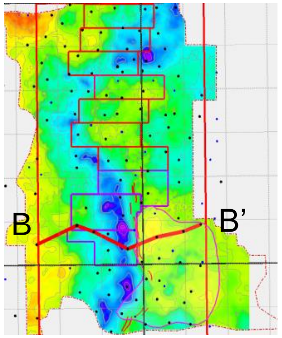
Simplified stratigraphic schematic showing internal stratigraphy and interpreted environments of deposition

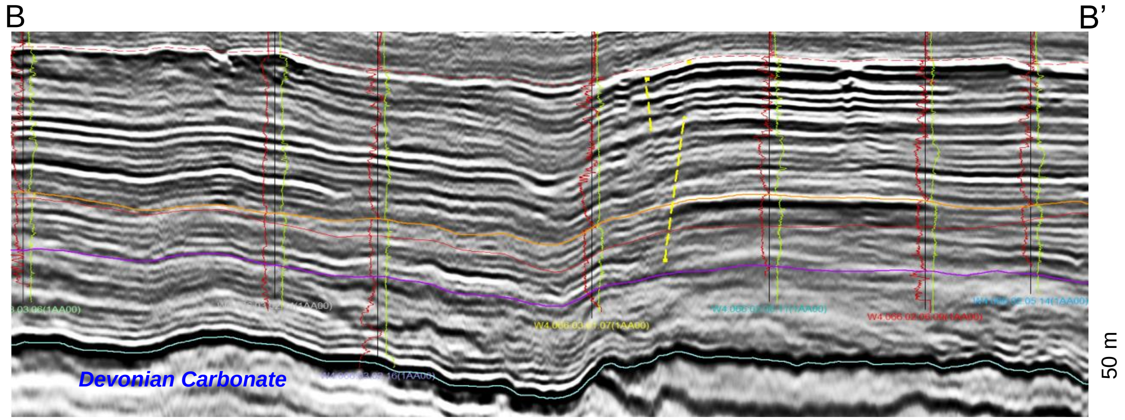
Geologic Cross Section BB' Across Nabiye Field



Top Clearwater Structure CI=5m

Well log cross section datumed on Top Clearwater surface displaying the internal stratigraphy across Nabiye field (pad N09-N10 area)





Full stack seismic depth section across Nabiye pad N09-N10 area displaying main interpreted surfaces with an 8m x 8m bin spacing

Notice the structural deformation induced by salt dissolution over the central part of the cross section (east side of pads N09-N10) .

Notice irregular/erosional nature of the Pre-Cretaceous unconformity separating Paleozoic carbonates below from Cretaceous McMurray sandstones above

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N09 Pad Drilling: Geoscience Learnings

Geologic Framework, Structure & Net Pay

- Ability to make real-time adjustments to Clearwater prognosis and target TD in advance of next well
- Seismic definition required for dissolution valley geometry to influence geosteering
- Optimal positioning of wells above reservoir concretion zone to limit geosteering difficulties
- Additional pay confirmed on west side of N09 pad

Geosteering

- Able to geosteer 1 – 2m above base effective pay (BEP)
- Reduced perched water risk (N09 'water-hunt' well did not encounter perched water) resulted in less restriction on drilling targets – faster drilling
- Drill bit deflections caused 'hard-tags' of basal shale – adjust targets above concretion layer

Logging

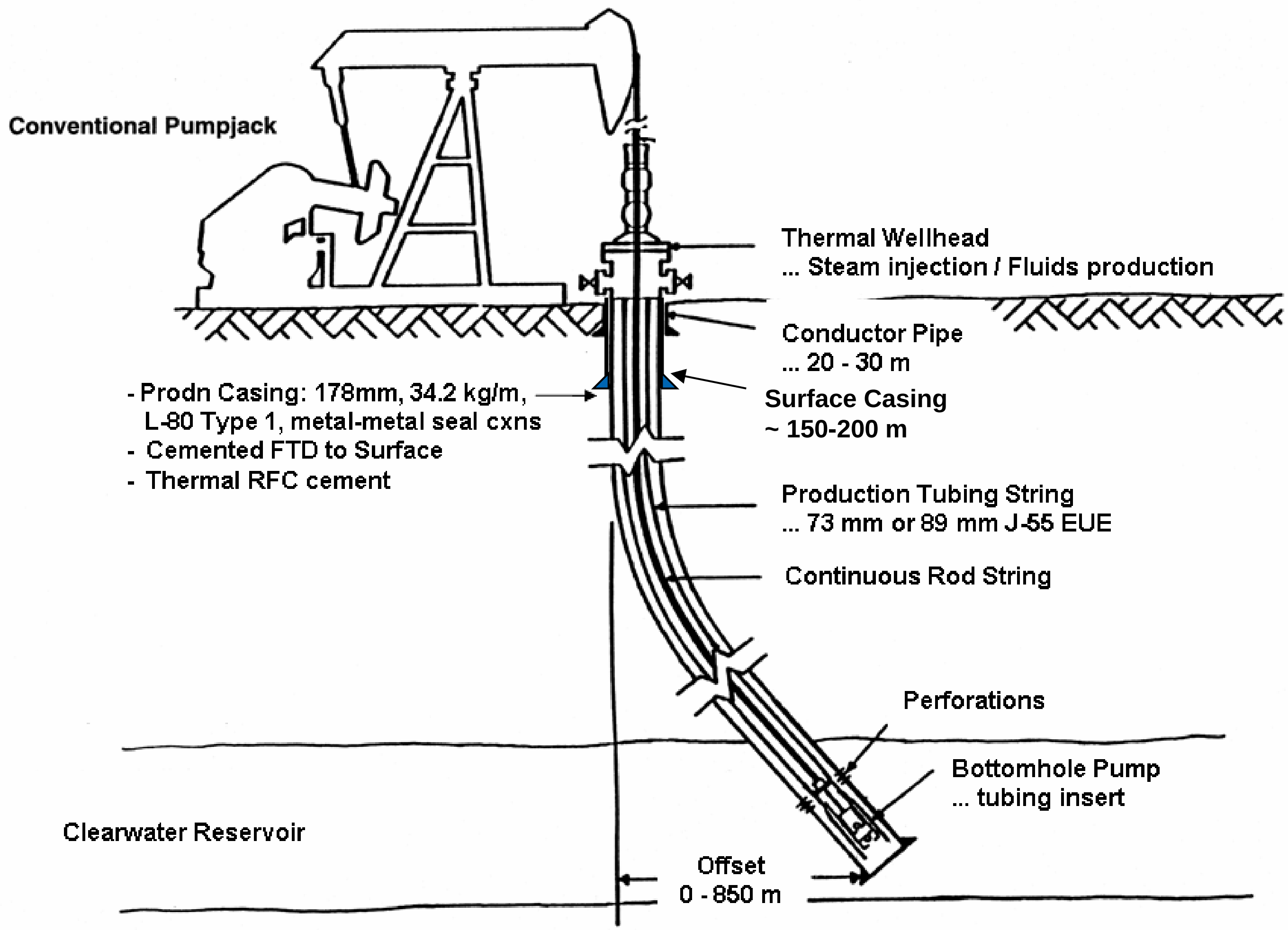
- LWD and ADR tool used in 12 laterals
    - Data transmission acceptable for geosteering with only rare periods of poor transmission
    - Essential for active management of drilling in complex lateral sections
    - BEP mapped along laterals from the ADR logs

Completions & Screen Placements

- Abundant concretions influenced screen placements
- Identification and description required to position screens to avoid concretion intervals

Drilling and Completions

Typical Deviated CSS Well Design



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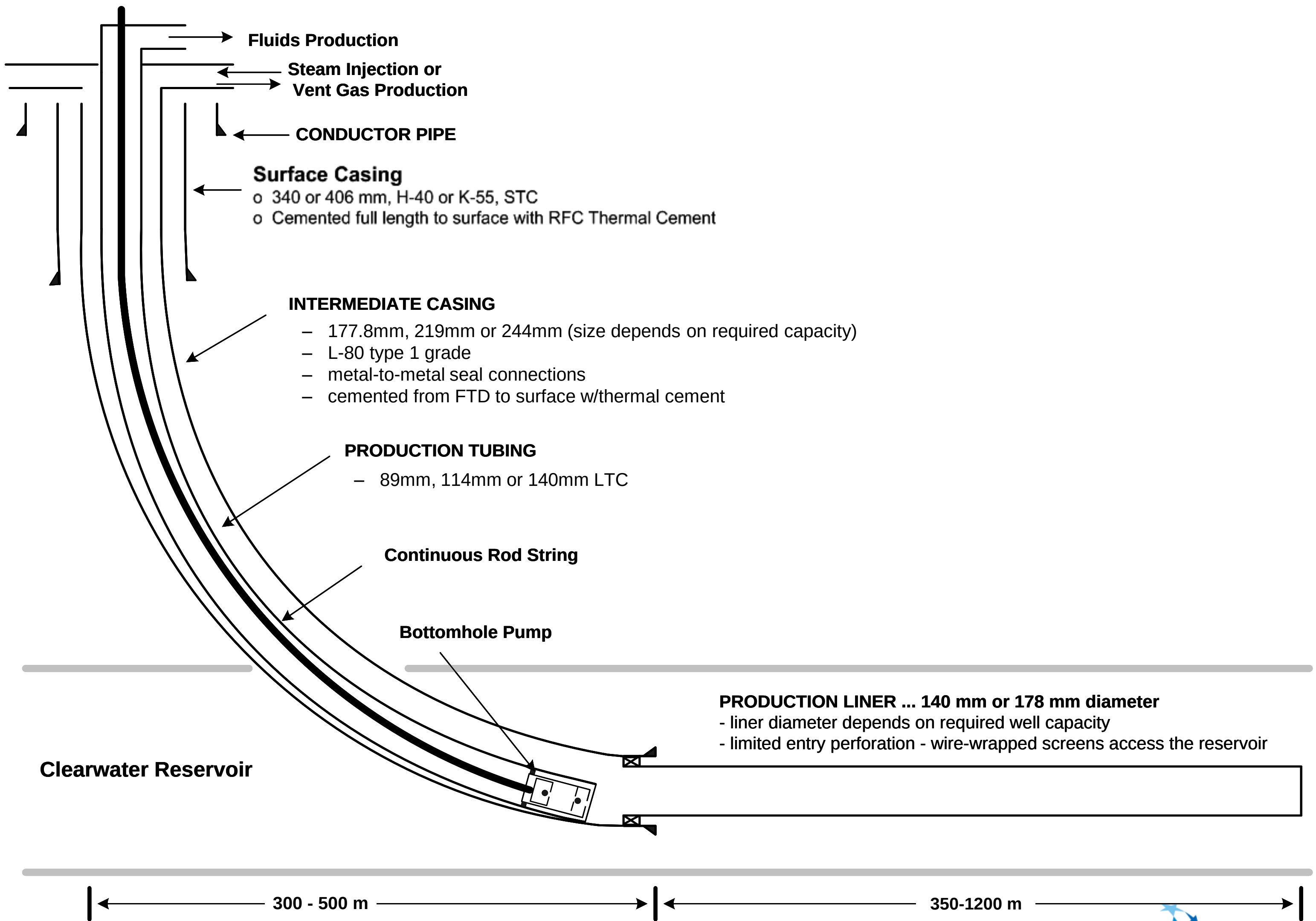
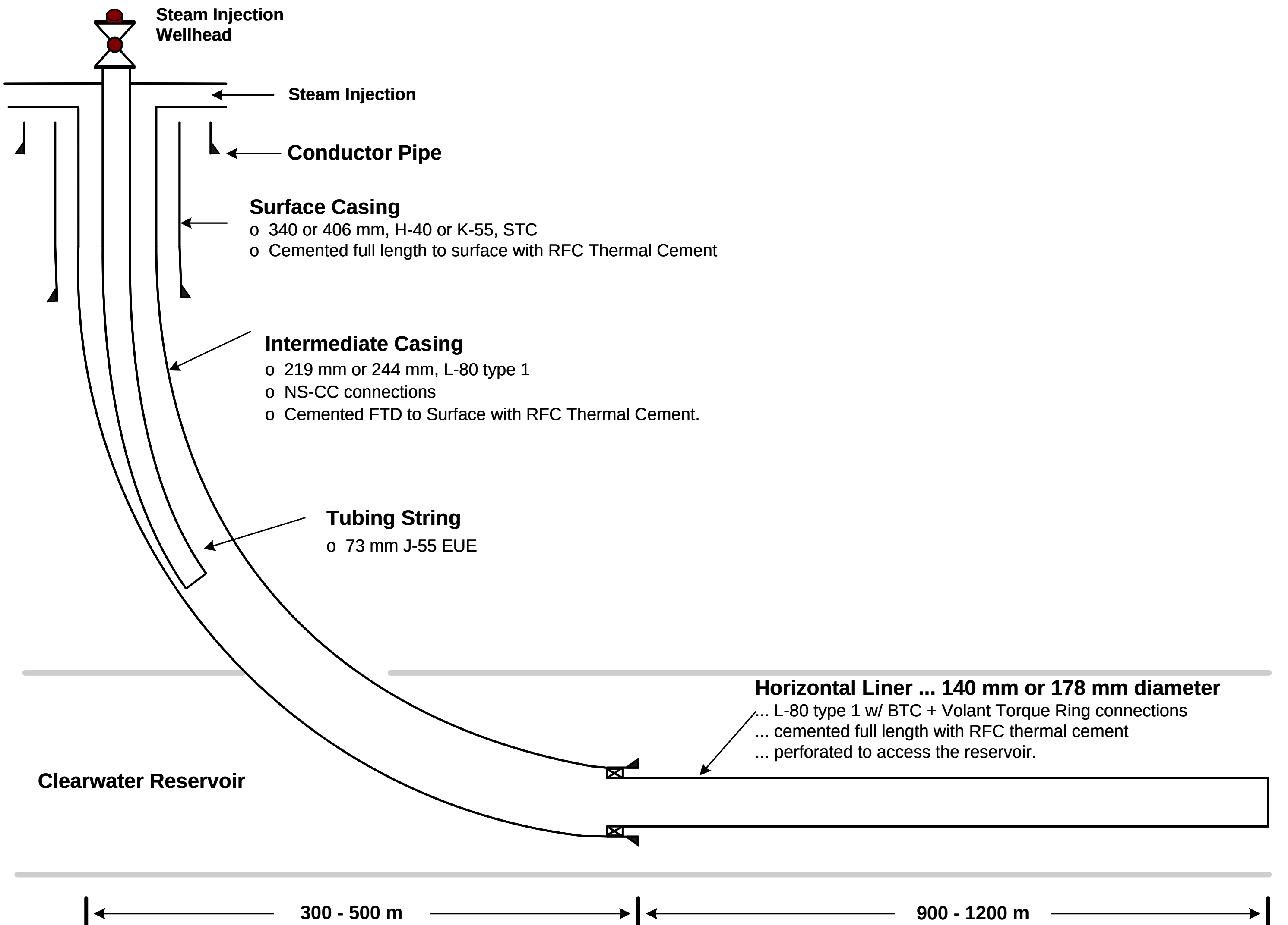
Horizontal CSS or HIP Well Design



Horizontal Steam Injection Well Design



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Artificial Lift

Artificial Lift Performance

Pumpjack	Bottom Hole Pump	Speed	Design Rate
160 - 173 - 86	50.8 mm	7 SPM 11 SPM 16 SPM	38 m3/d 60 m3/d 87 m3/d
228 - 173 - 86 or 320 - 213 - 86	63.5 mm	7 SPM 11 SPM 16 SPM	60 m3/d 93 m3/d 135 m3/d
456 - 213 - 144	63.5 mm (long stroke)	4 SPM 7 SPM 14 SPM	55 m3/d 100 m3/d 200 m3/d
912 - 305 - 192	82.6 mm	4 SPM 7 SPM 11 SPM	130 m3/d 225 m3/d 350 m3/d
1280 - 305 - 240	95.3 mm	4 SPM 7 SPM 10 SPM	210 m3/d 370 m3/d 530 m3/d

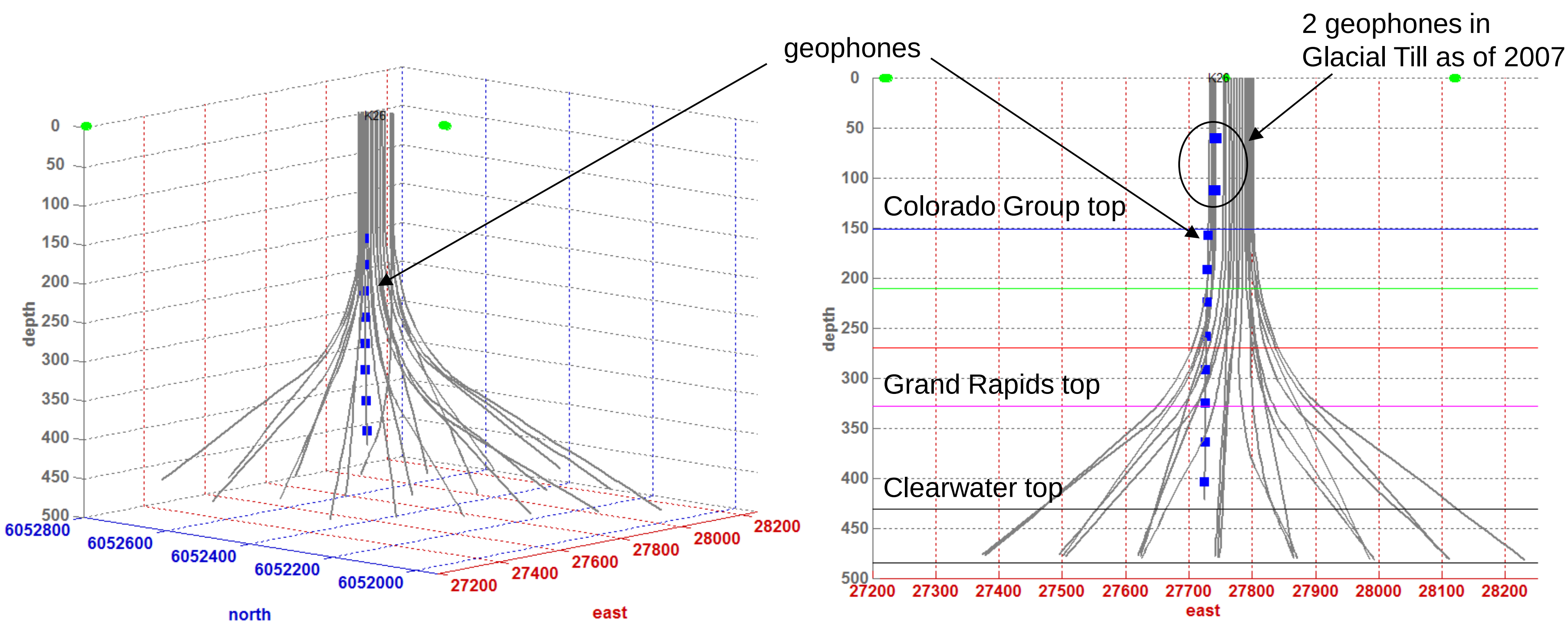
- Insert rod pumps used across field
- Size of lift system depends on:
  - Offset to reservoir target
  - Well deliverability: deviated versus horizontal wells
- Operating Conditions
  - Pumping temperature 75 – 220°C
  - Pump Intake pressure 6 MPa to less than 500 kPa
  - Average run life of rod pumps is between 600-700 days
- Corpac Variable Frequency Drive (VFD) Program ongoing
  - Installing VFD's on all new producing wells and select retrofits on existing producing wells
  - Using VFD controllers for inferred measurement, speed control, pumping unit shutdown and optimization

Instrumentation in Wells

Instrumentation in Wells

- A passive seismic well with permanent omnidirectional geophones is installed at all new high pressure pads at Cold Lake since 1998
- Seismicity is monitored to detect fluid incursion and casing failures in uphole zones

Typical Passive Seismic Configuration



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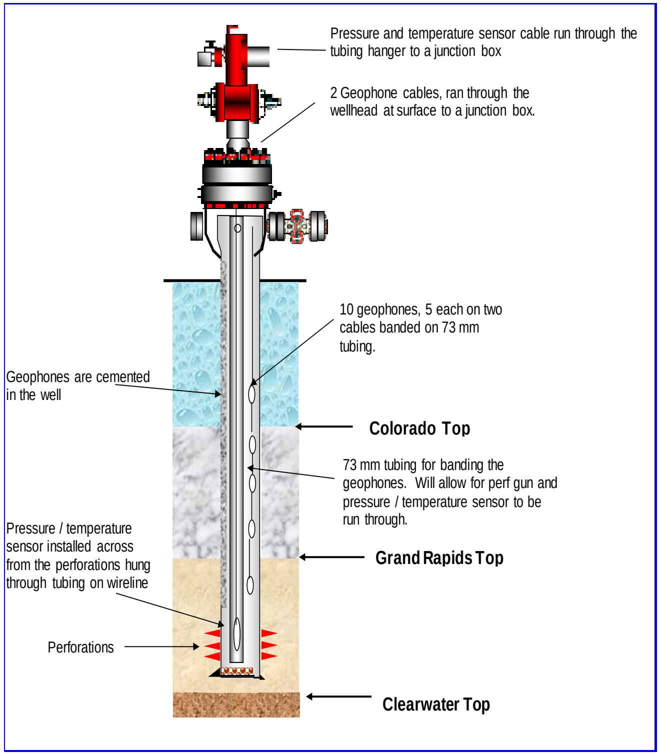
Instrumentation in Wells

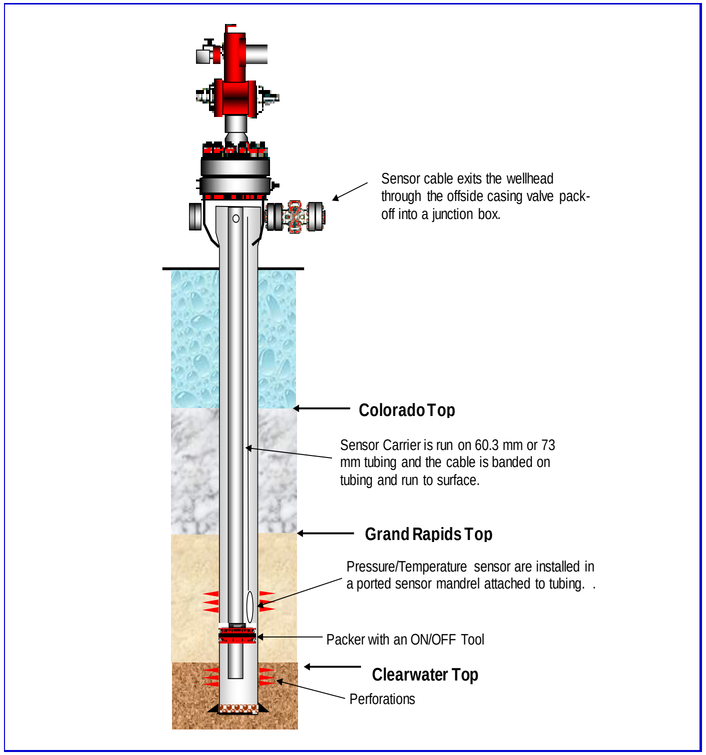
Hybrid Passive Seismic Well

- A hybrid Passive Seismic well design allows pressure monitoring in the Grand Rapids and passive seismic monitoring with cemented geophones in the same well.



Grand Rapids Pressure Monitoring Well

- There are several wells in the field used to monitor Grand Rapids pressure. These wells often monitor more than one interval. The configuration below provides pressure monitoring in one Grand Rapids interval and one Clearwater interval.



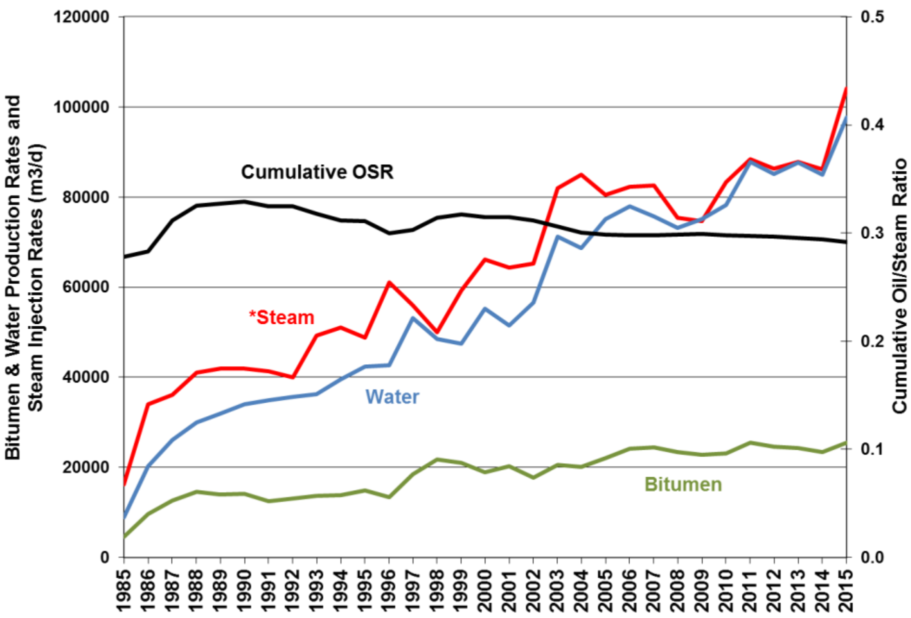
Scheme Performance

Cold Lake Recovery Determination

- Bitumen recovery from the CSS process in the Clearwater zone is a function of effective pay thickness and bitumen saturation
- Effective pay and bitumen saturations are determined from facies based descriptions of logs and cores obtained from the Clearwater zone at an 8 wt% cutoff
  - Shale and clay content are considered in the determination of effective pay
- Recovery predictions are based on performance type curves derived from field performance and reservoir simulation
- Adjustments are made for other factors impacting recovery such as:
  - Bottom water
  - Clearwater gas cap
  - Split pay
  - Adjacent reservoir depletion
  - Well spacing

Cold Lake Production Performance

Cold Lake Approval 8558 Area Production



	Bitumen Production 10^3 m^3/d	Steam Injection 10^3 m^3/d	Cumulative	
			OSR	SOR
2014	23.3	86.1	0.29	3.4
2015 YTD Sep	25.4	104.1	0.29	3.4

- Maximum daily bitumen production under approval 8558 is 40,000 m^3/d
- Development continues to increase production rates
- Development is driven by many factors including technology and economics
- Steam injection volumes increasing in 2015 due to Nabiye plant start-up

* Steam volumes prior to Oct 2004 not adjusted for meter correction

** Production data includes CSP and SA-SAGD pilot projects

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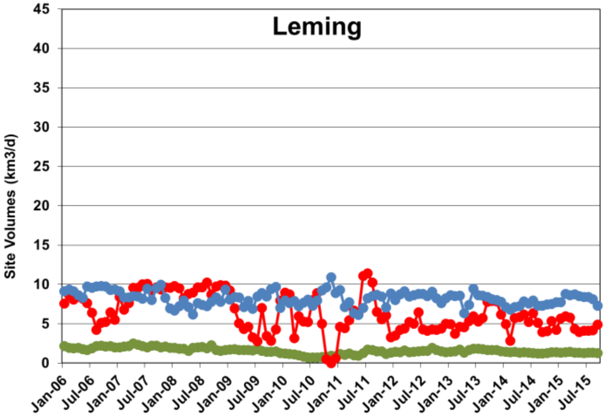
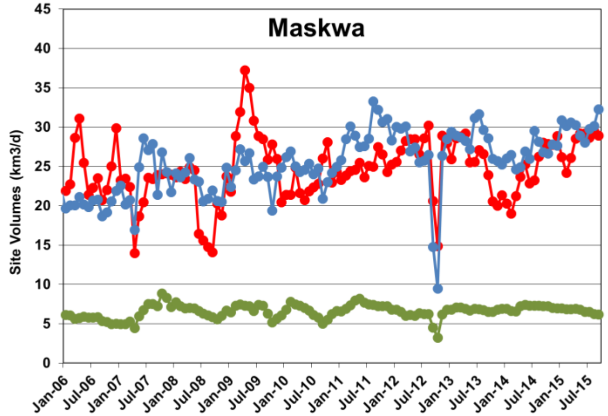
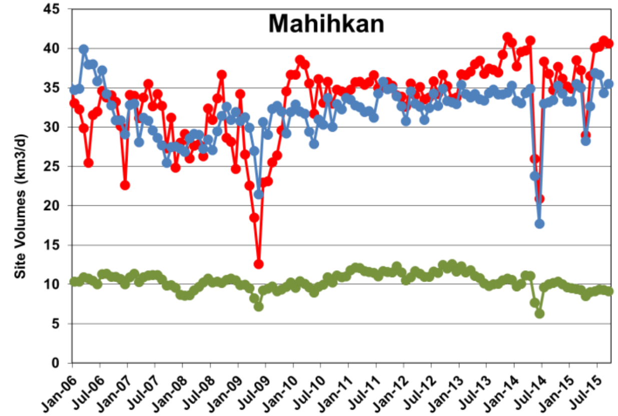
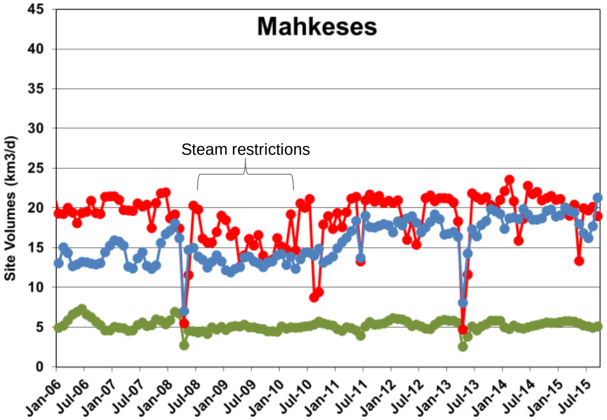
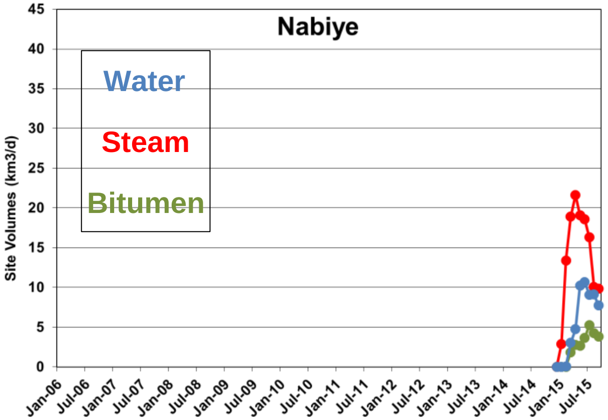
Individual Site Performance











Plant	2015 Average	
	OSR	SOR
Leming	0.16	6.3
Maskwa	0.27	3.7
Mahihkan	0.23	4.3
Mahkeses	0.26	3.8
Nabiye	0.16	6.3

Steam Transfers (10^3 m^3)

Maskwa to Mahihkan:	**361**	**D04 Infills (Oct. 2014 – Sept. 2015)**
Mahihkan to Maskwa:	**42**	**J10 Infills (Oct. 2014 – Feb. 2015)**
Leming to Maskwa:	**1669**	**0FF Infills (Oct. 2014 – Sept. 2015), 00U Infills (Oct. 2014-Sept. 2015)**
Leming to Mahkeses:	**0**	
Mahkeses to Leming:	**567**	**T05 Infills (Oct. 2014 – April 2015, Sept. 2015)**

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Abandonment Outlook

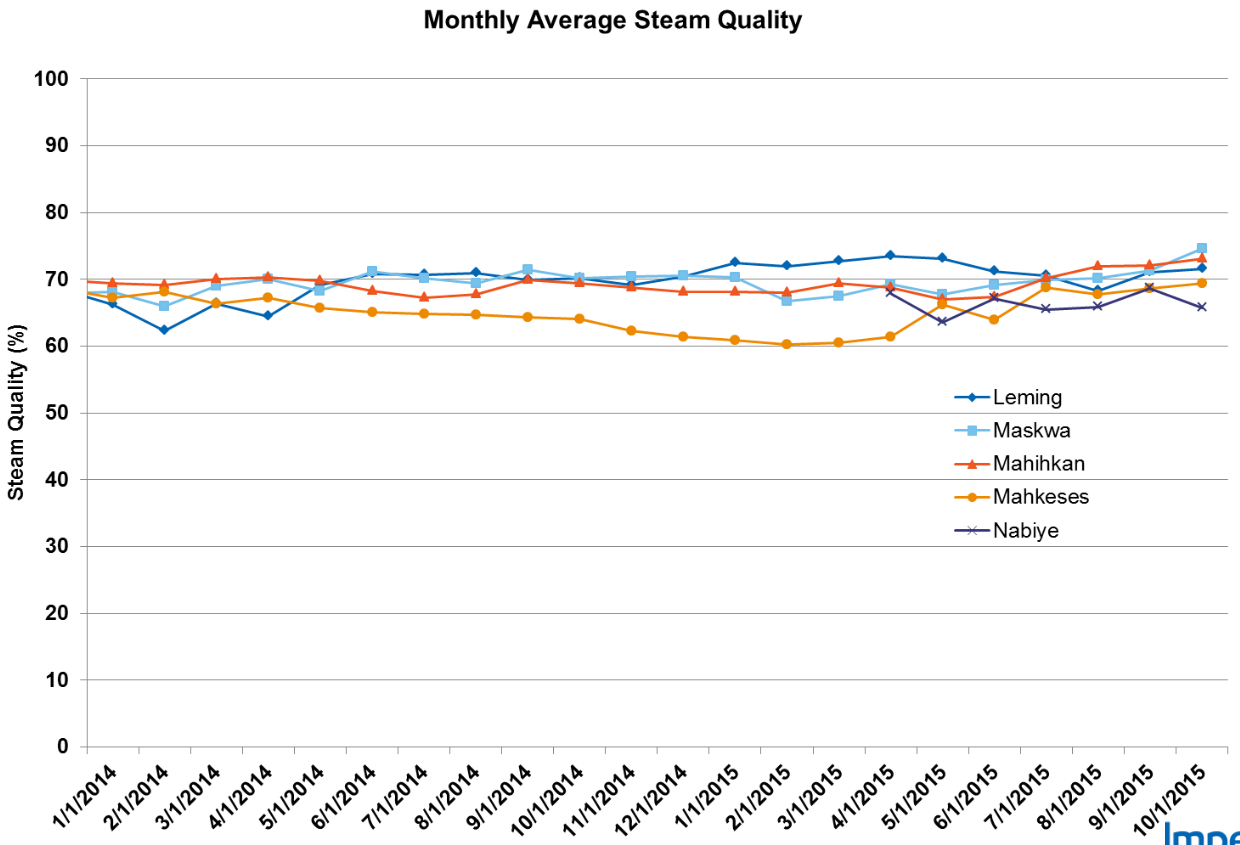
- 5 year outlook for pad abandonment
  - ‘Flow Behind Pipe’ assessment (inc. E07 pad testing) confirms hydraulic isolation behind casing on Cold Lake wells.
  - Assessment also demonstrates that post-steam cement bond logs do not reflect degree of hydraulic isolation behind casing
  - E07 pad wells abandonment almost complete: 2 wells require cement top up, cut & cap wells planned for 2016+
  - CC/DD/GG pad abandonment progressed; 44 wells fully or partially abandoned, remainder will continue 2016+
  - Q and S pad scheme approval in place, abandonments to follow CC, DD & GG
  - 20 Shale monitoring wells will be abandoned in low pressure areas as per AER approval received in January 2014
- Pads with support from adjacent pads will continue operation
- Individual wells that are uneconomic will be zonally abandoned to meet the conditions of Directive 13

Pads not steamed in prior 48 months

Pad	Plans
00N	Operating as water storage pad
00U	Operating with support from adjacent pads
00V	Operating with support from adjacent pads
00Q	All wells zonally abandoned in the CLW
00S	All wells zonally abandoned in the CLW
0AA	Operating with support from adjacent pads
0CC	Abandonment process started
0DD	Abandonment process started
0FF	Operating with support from adjacent pads
0GG	Abandonment process started
0HH	Operating with support from adjacent pads
0LL	Operating with support from adjacent pads
A01	Operating with support from adjacent pads
A03	Operating with support from adjacent pads
A05	Operating with support from adjacent pads
B01	Operating with support from adjacent pads
B02	Operating with support from adjacent pads
B03	Operating with support from adjacent pads
B04	Operating with support from adjacent pads
B05	Operating with support from adjacent pads
B06	Operating with support from adjacent pads
D54	Operating with support from adjacent pads
D55	Operating with support from adjacent pads
C03	Operating with support from adjacent pads
C05	Operating with support from adjacent pads
D26	Operating with support from adjacent pads
D27	Operating with support from adjacent pads
D52	Operating with support from adjacent pads
H24	Operating with support from adjacent pads
H32	Operating with support from adjacent pads
H33	Operating with support from adjacent pads
H34	Operating with support from adjacent pads
H35	Operating with support from adjacent pads
K24	Operating with support from adjacent pads
P01	Operating with support from adjacent pads
P02	Operating with support from adjacent pads
P03	Operating with support from adjacent pads
M03-M07	Operating with support from adjacent pads
J06	Operating with support from adjacent pads
J27	Operating with support from adjacent pads
D57	Abandonment process started, all wells zonally abandoned
D66	Abandonment process started, all wells zonally abandoned

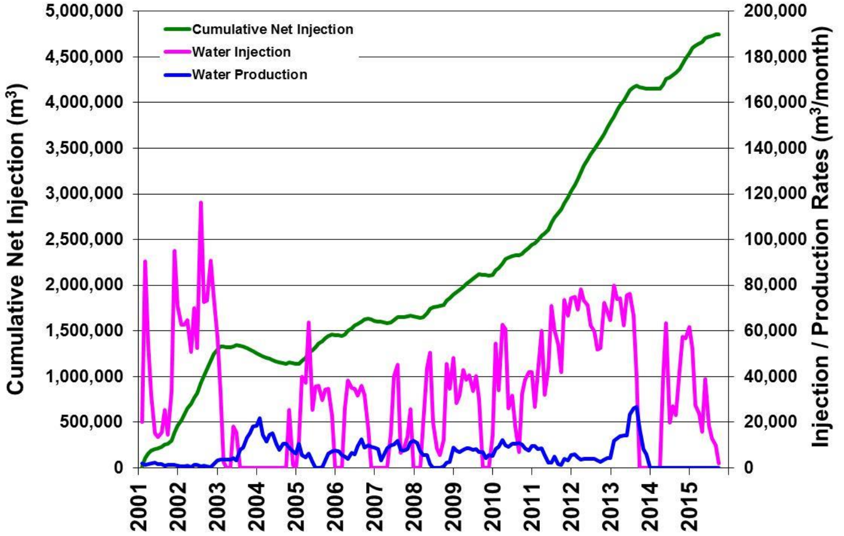
Steam Quality

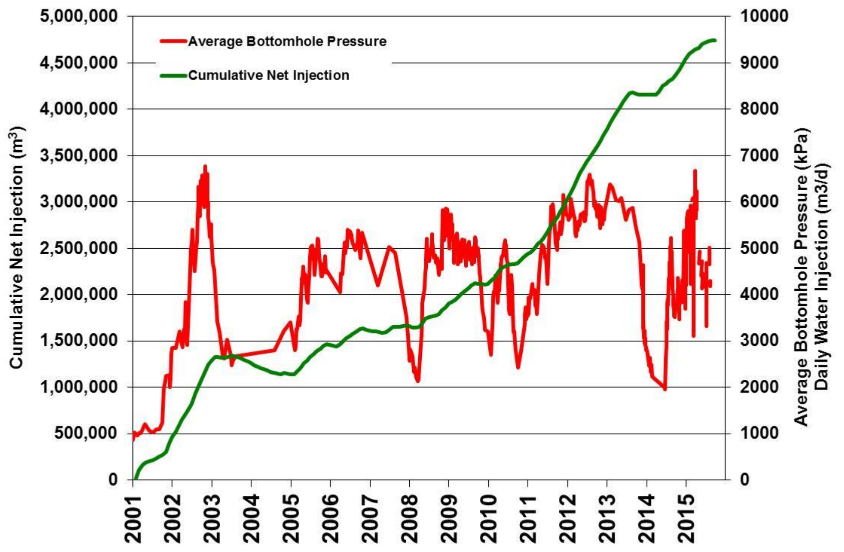
- Mahkeses average steam quality low from March 2014 – June 2015 due to lower water quality and HRSG tube scaling
- Nabiye steam quality tuning ongoing as part of plant commissioning
- Realignment on steam quality to field in July 2015: 75% OTSG & 70% HRSG to improve long term recovery



Cold Lake N-Pad – Approval 4510

- Approval 4510 is for utilization of Leming N-pad as a temporary water storage scheme
- Annual N-Pad Report to be submitted end of November 2015
- Adjacent pad performance indicates connection to N-Pad storage volume
- No N-Pad water production since Dec 2013
- N-Pad water injection declined with Nabiye water startup requirements
- Future N-Pad operating strategy will be to discontinue water injection





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Cold Lake N-Pad – Approval 4510

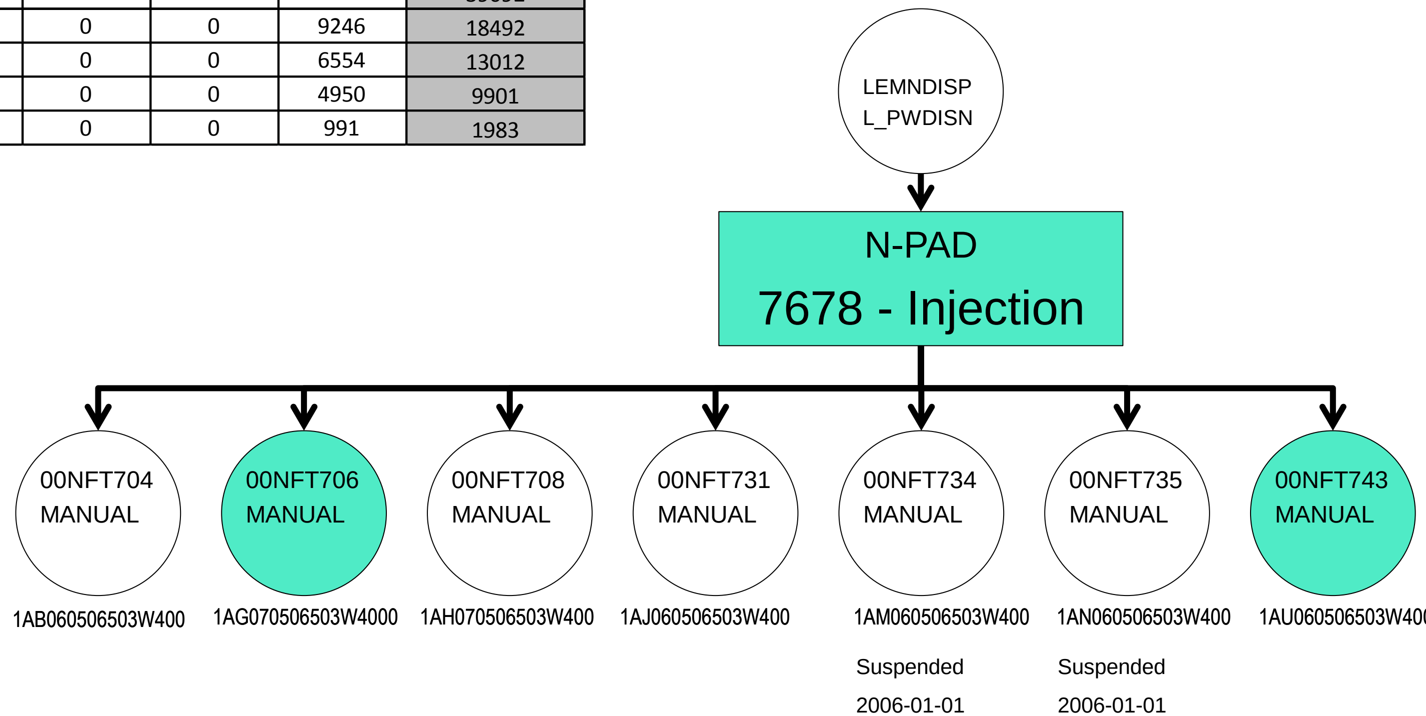
Table 1: N-Pad Water Injection (m3)

Month	N-04	N-06	N-08	N-31	N-43	Monthly Total
Oct-14	0	24779	0	0	32575	57354
Nov-14	0	24333	0	0	32380	56713
Dec-14	0	26195	0	0	35625	61820
Jan-15	0	22295	0	0	29762	52057
Feb-15	0	12966	0	0	14420	27386
Mar-15	0	11863	0	0	11881	23744
Apr-15	0	7859	0	0	7859	15718
May-15	0	19546	0	0	19546	39092
Jun-15	0	9246	0	0	9246	18492
Jul-15	0	6458	0	0	6554	13012
Aug-15	0	4950	0	0	4950	9901
Sep-15	0	991	0	0	991	1983

N-Pad Schematic

ERCB injection system #7678

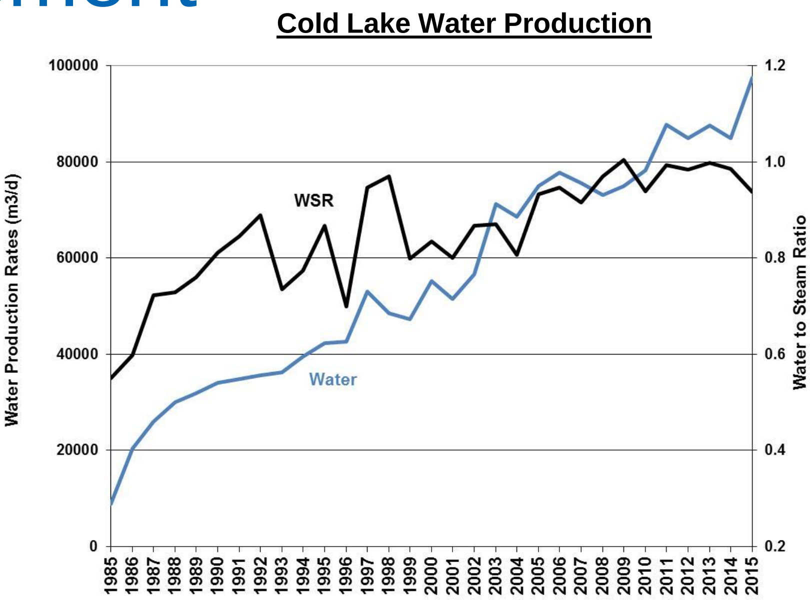
Produced Water From Leming

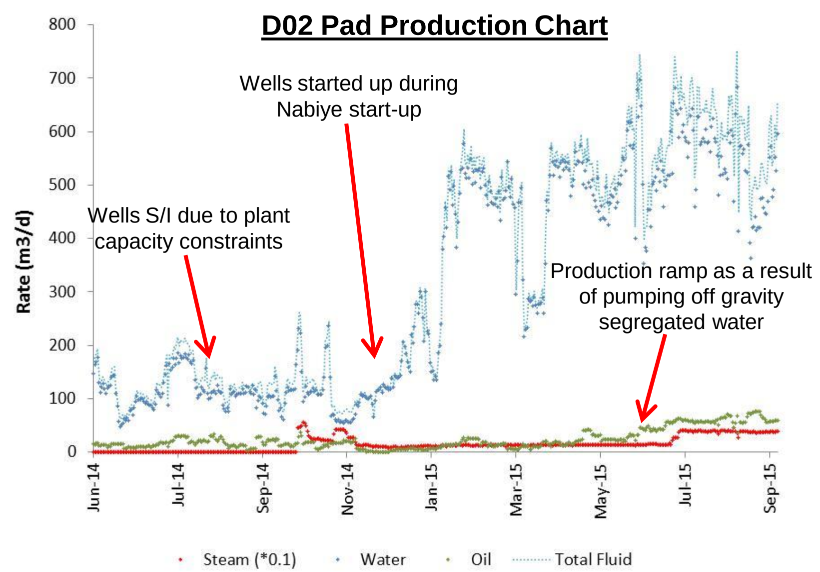


Cold Lake Water Management

- **Cold Lake Water Production**
  - Increasing water production driven by field development
  - Water to steam ratio has increased as pads move into later cycle production (late life CSS / steamflood)
  - Typically field water deliverability is in excess of facility water handling capacity, requiring production shut-in
  - With Nabiye start-up, water handling capacities increased at existing facilities, allowing wells in the base to increase production

- **Operating Strategies**
  - Production shut-ins prioritized based on water to oil ratio to maximize oil production
  - Maximize steam injection quality
  - Minimize bringing water into the system
    - Freshwater and brackish water
  - Utilize out of zone disposal





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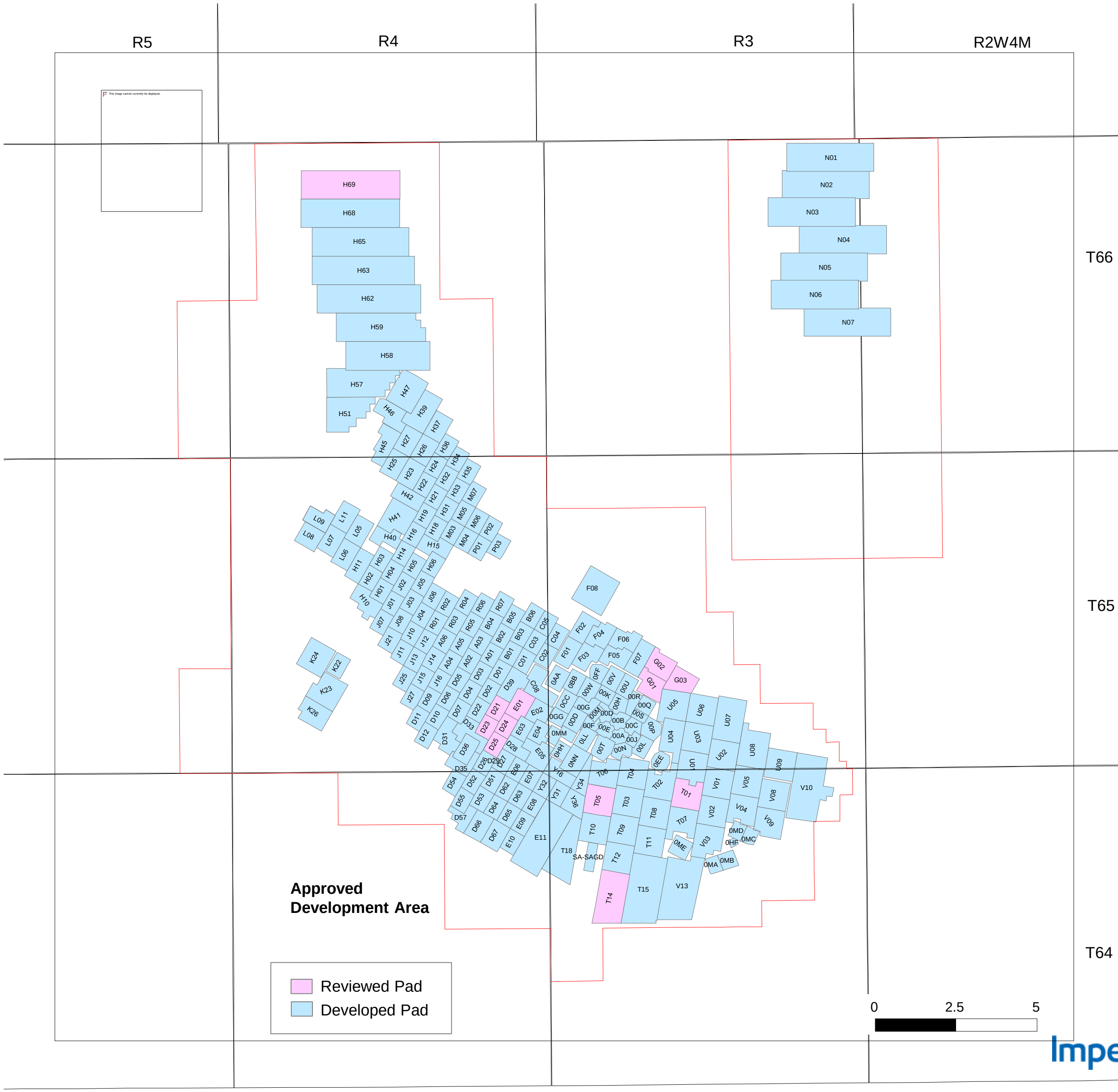
Pad Performance Reviews



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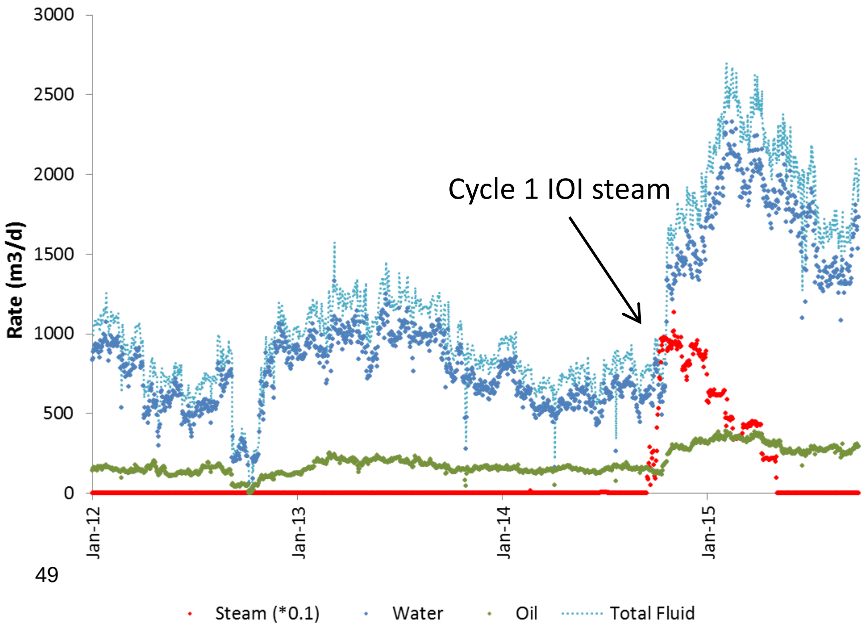
Maskwa D22 Injector Only Infills

- Cycle 1 cyclic IOI, 6 Infill wells, 10 BHL/well
  - Infill steam injection in D21, D23, D24, D25, and E01 pads
  - First steam-in: September 2014
  - Steam strategy: high steam injection rates, ~25,000 m^3 steam per BHL

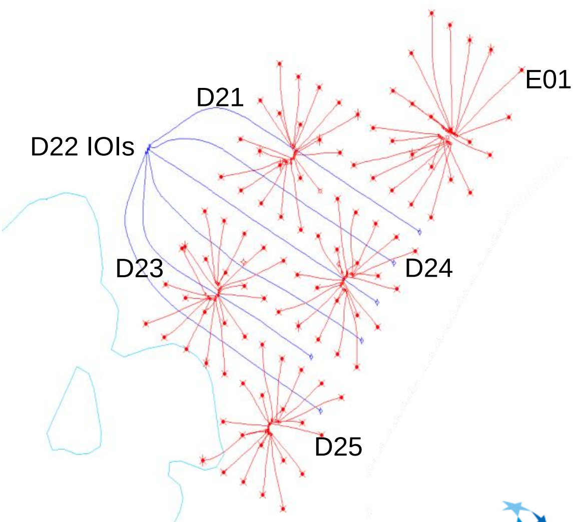
- Infill steam support and production optimization significantly increased production

- Productivity improvement opportunities maximized benefit from IOI steam
  - Reactivation of suspended wells increased wellbore utility
  - Appropriately timed pump speed-ups and maintenance work optimized total fluid lifting capabilities

D22 IOI Area Production



D22 IOI Well Layout



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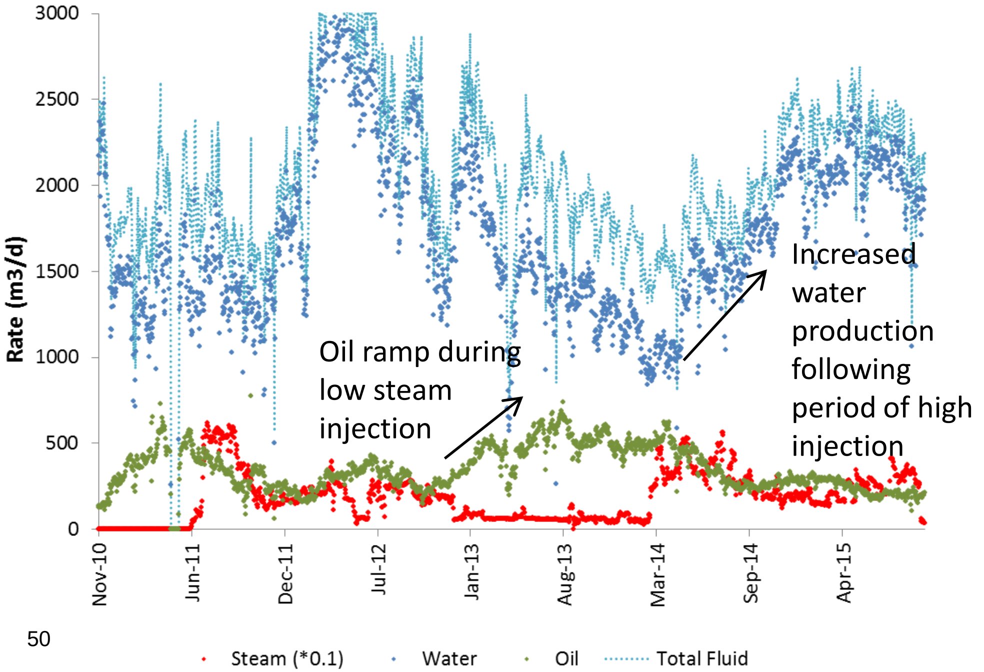
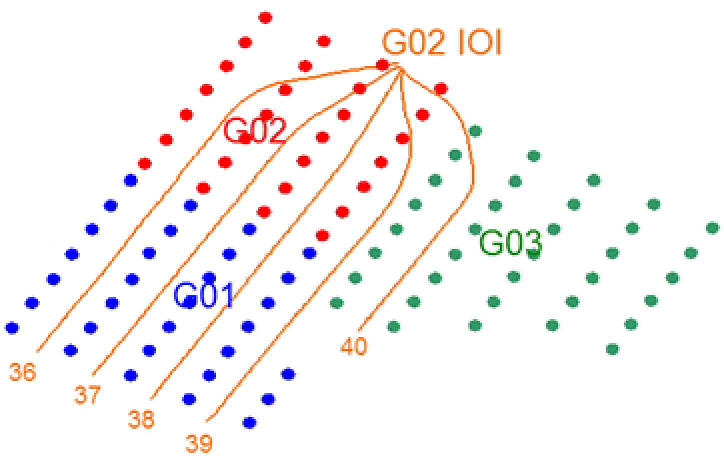
Leming G02 Injector Only Infills

- G02 IOI's are 5 horizontal injector wells infilling G01, G02, G03 pads (64 bottom hole locations)
- Production performance increased in 2013 following period of low steam injection.
- Steam rates increased at G02 in 2014 to improve reservoir fluid balance at other Leming steam flood pads
- Observed a decline in oil rate and an increase in water production after a sustained period of high steam injection
- Steam rates scheduled to be reduced in Q1 2016 to pump off excess water and improve reservoir fluid balance at G02

G02 IOI Area Production



G02 IOI Well Layout



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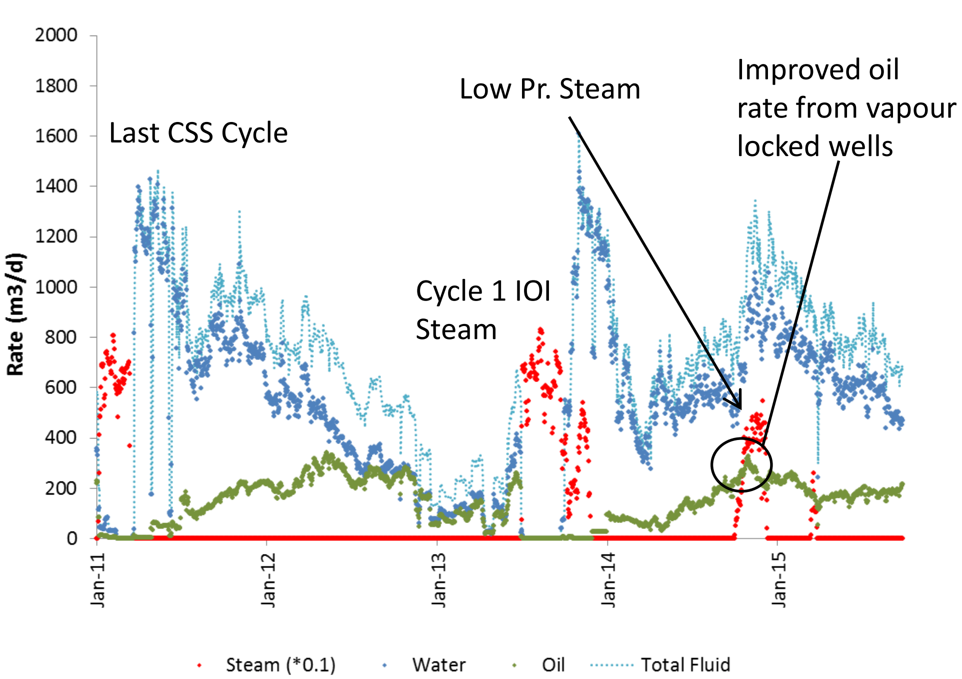
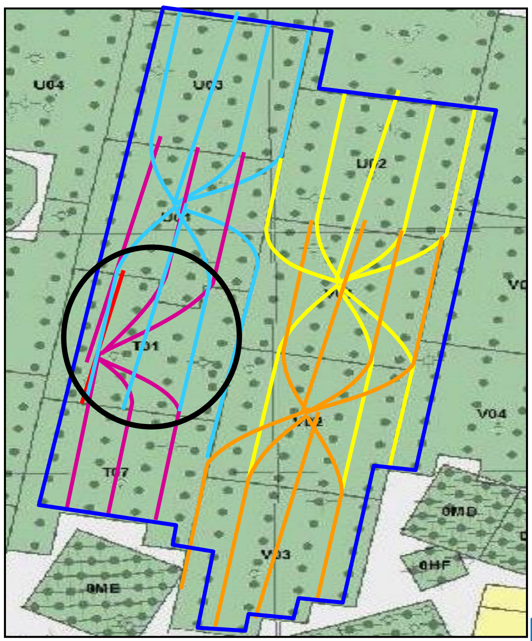
Mahkeses U01 Injector Only Infills

- T01 is an 8 acre 24 well pad infilled by U01 IOIs
- Cycle 1 IOI steamed July – Nov 2013
- Following Cycle 1 steam, low pressure/high temperature wellbore conditions caused vapour locking on select wells.
- Low pressure steam re-introduced to U01 IOI's in Sept 2014 to pressure up T01 producer wells to super-saturated conditions – observed improved oil rates on previously vapour locked wells

T01 Production



U01 IOI Well Layout



Mahkeses T05 Pad

- T05 is an 8-acre, 24 well pad
- 7 wells were repaired to HPCSS prior to cycle 11 to improve wellbore utility
- Repair campaign allowed for increased steam volumes to be injected in Cycle 11

T05 Well Utility and Shear Stress Model

Pad T05

Cycle 10

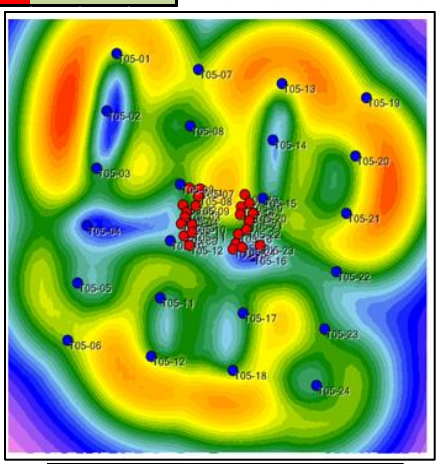
1	7	13	19
2	8	14	20
3	9	15	21
4	10	16	22
5	11	17	23
6	12	18	24

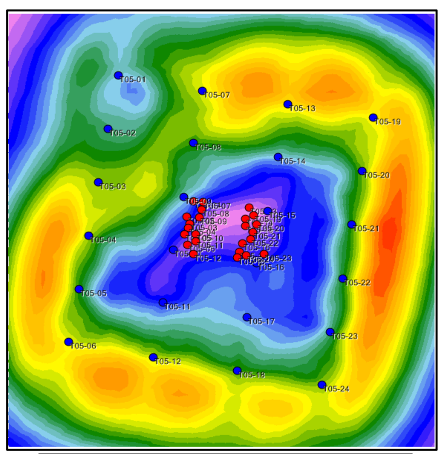
HPCSS
POW
Subfrac
Suspended

Cycle 11

1	7	13	19
2	8	14	20
3	9	15	21
4	10	16	22
5	11	17	23
6	12	18	24

HPCSS
POW
Subfrac
Suspended

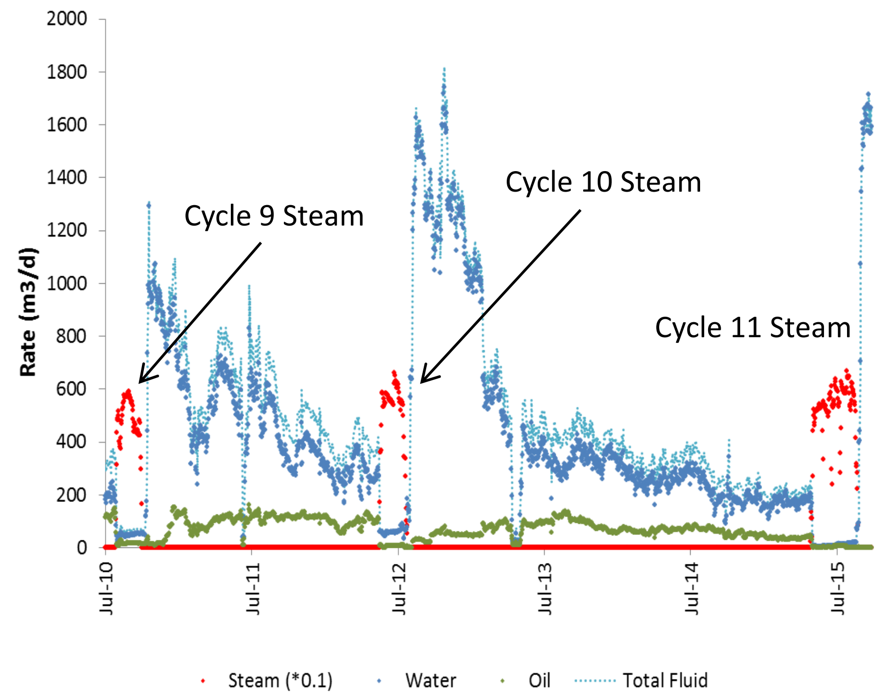




Total Avg VOF:
4,200 m3/BHL
Total Pad Steam:
350,000 m3

Total Avg VOF:
7,700 m3/BHL
Total Pad Steam:
630,000 m3

T05 Production



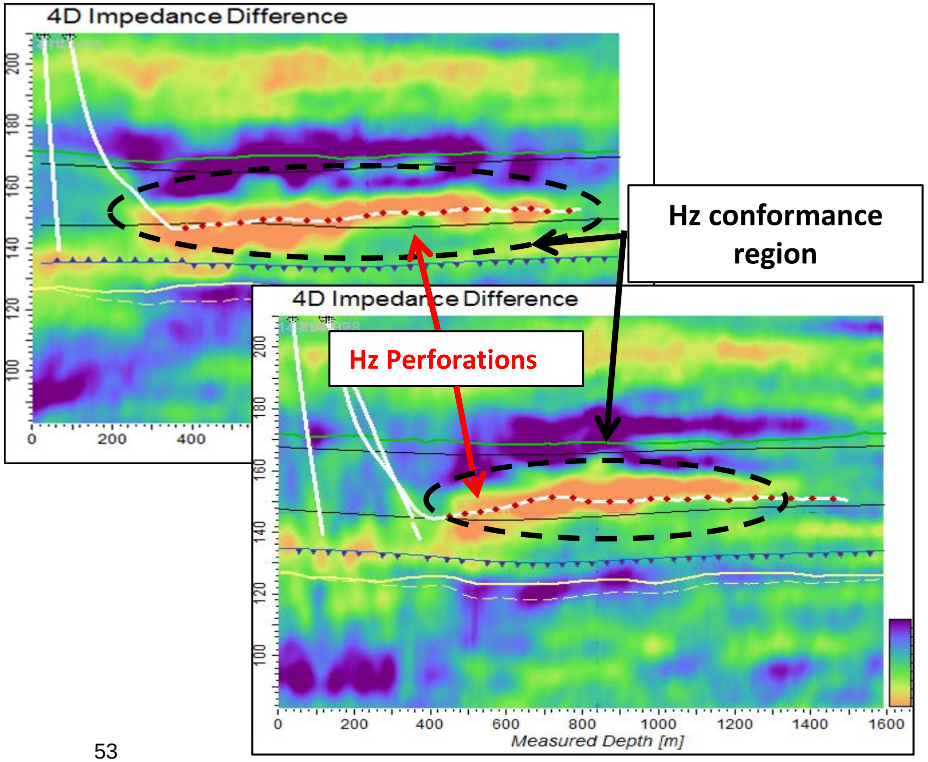
Hot colours = higher shear stress

Cool colours = lower shear stress

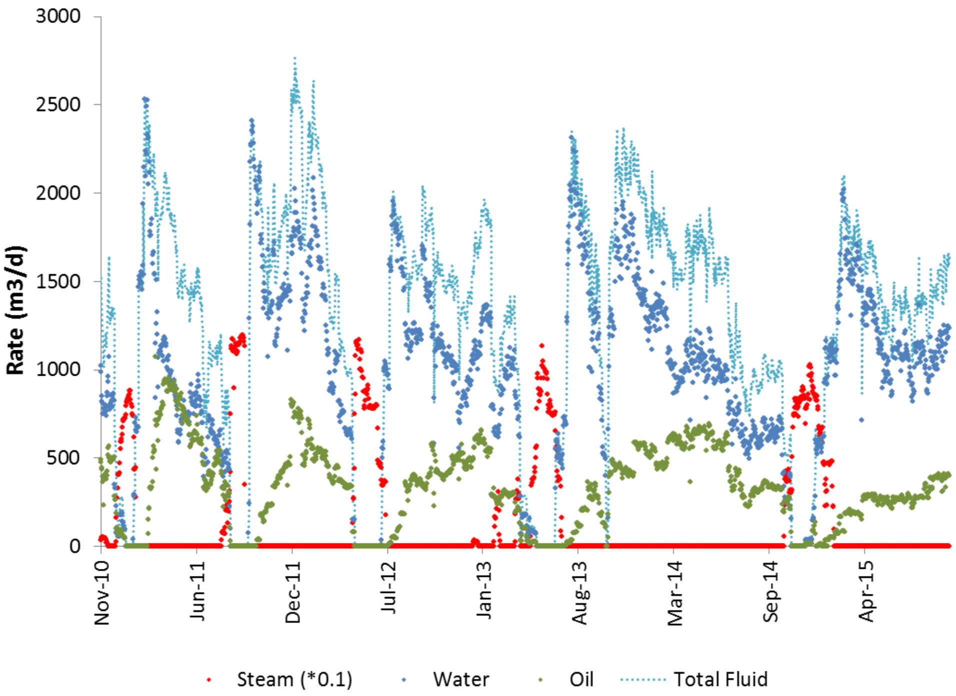
Mahkeses T14 Pad

- Mahkeses T14 is an 8 acre spacing / 20 well pad (includes 5 horizontals and 43 total bottom hole locations)
- 4D Seismic survey taken following Cycle 5 steam in Q4 2013
- Seismic analysis indicated varied steam conformance along the length of horizontal wells
- Results from seismic interpretation are consistent with steam and production data observed on T14

T14 Horizontal Well 4D Seismic



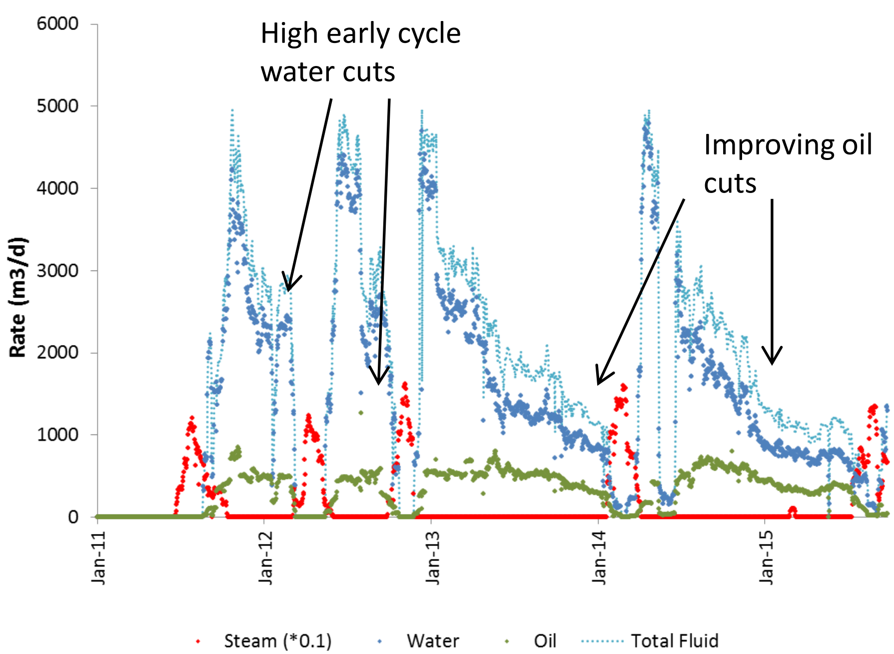
T14 Production



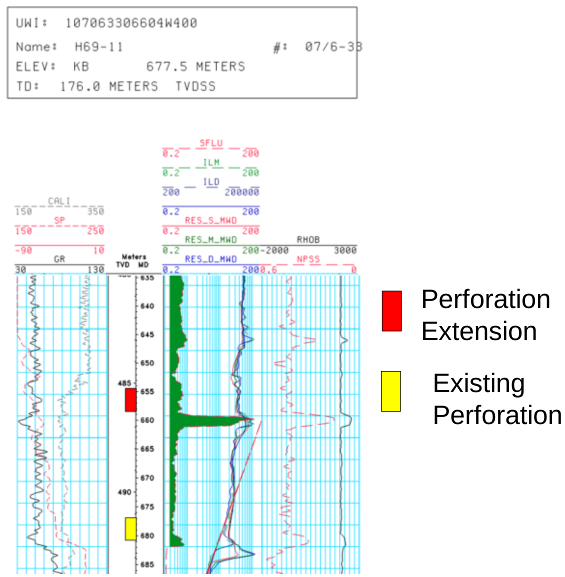
Mahihkan H69 Pad

- Mahihkan H69 is an 8 acre spacing / 24 well (16 vertical, 8 horizontal) pad, currently in cycle 5
- 13 vertical wells recompleted uphole into higher bitumen saturation interval
  - Environment of deposition thought to have influenced early cycle production performance, similar to H68 pad
  - Both perforation extensions and reperforations with plug backs attempted – both were equally successful
  - Recompleted wells were steamed at reduced rates/volumes to increase the likelihood of establishing new conformance regions
- Cycle 6 steam in scheduled for Q2 2017

H69 Production



H69 Analog Recompletion



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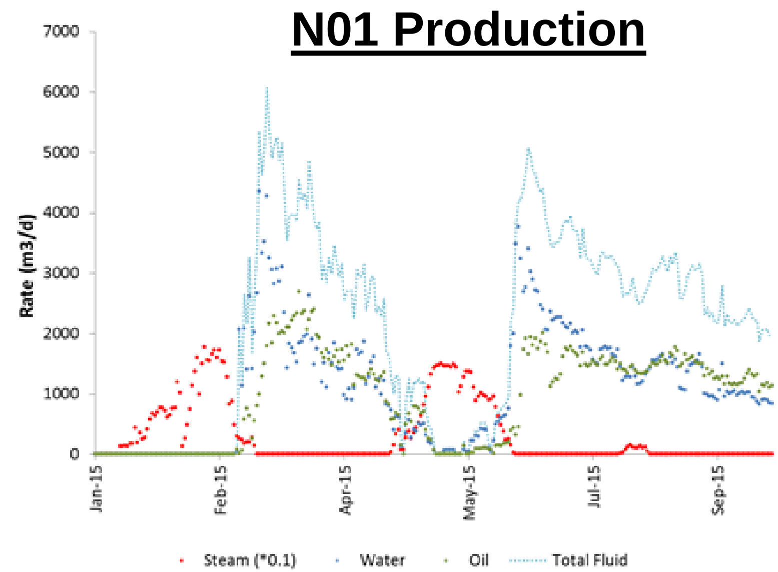
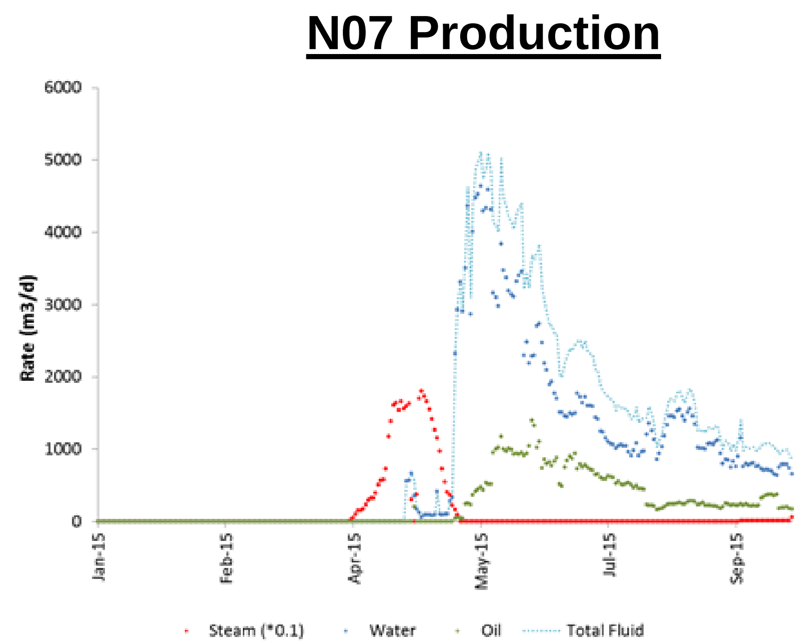
Nabiye Production Performance

- Nabiye first oil achieved Feb 2015
- N01-N03 production performance
  - Steam strategy adjusted to manage out of zone excursion risk
- N04-N07 production performance
  - Environment of deposition thought to be influencing early cycle production similar to analog Mahihkan North pads
  - No evidence of connection to material thief zones
- Future plans
  - N08 and N09 productivity maintenance pads steam in Nov 2015 and Jul 2016 respectively
  - Continue to optimize N01-N03 steam strategy
  - Limited recompletion trial underway at N06-N07 to improve early cycle OSR performance

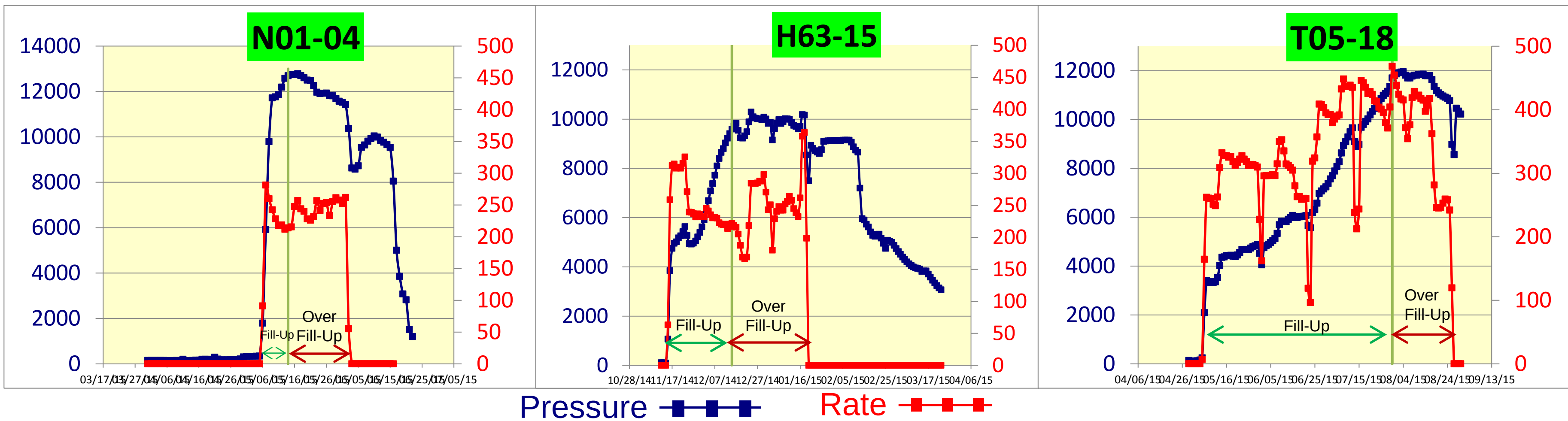




Steam Volume Over Fill-up Methodology

Volume Over Fill-up (VOF)

- Steam volume injected into individual wells above specified fracture pressure is summated as VOF. Specified fracture pressure is estimated using pressure and rate data during the steam cycle. During the steam cycle of the well, pressure will increase until it hits a point of ‘roll-over’ where it will no longer increase in pressure, staying constant. At the point of roll-over is where VOF starts being counted. All volume injected prior to roll-over, is considered fill-up.



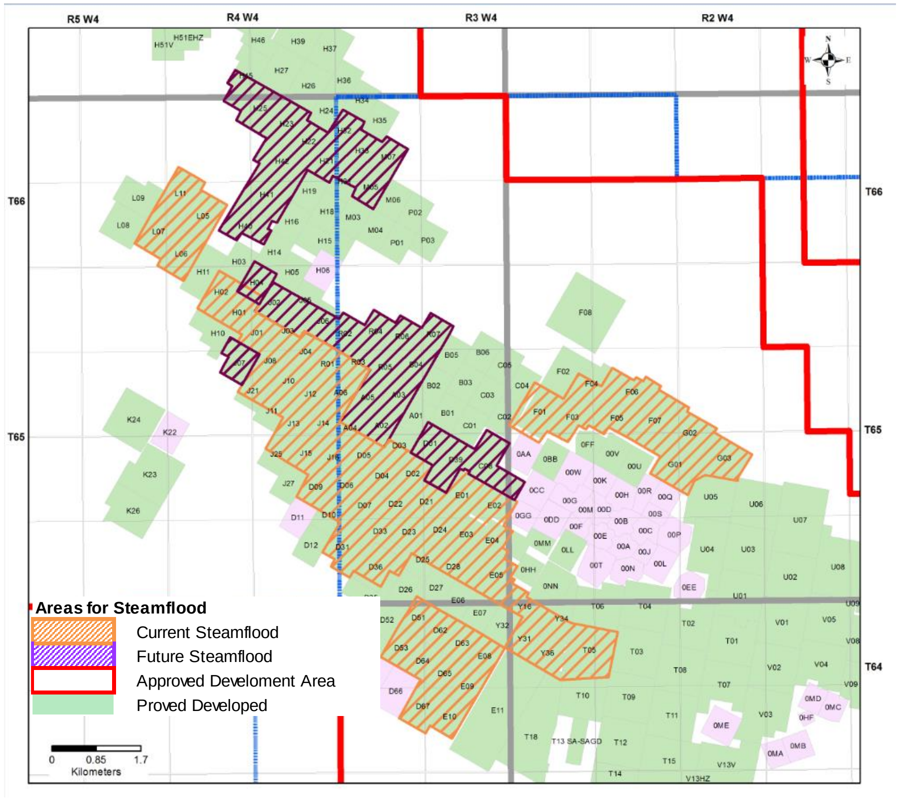
Designation	Well	Cycle	Total Volume (m3)	Volume to Fill-up (m3)	Volume Over Fill-up (m3)
Early Cycle	N01-04	2	6209	1737	4471
Mid Cycle	H63-15	4	15865	7150	8715
Late Cycle	T05-18	11	38066	28085	9981

- Volume over fill-up Best Practices have been implemented to manage reservoir communication and casing integrity.
- All VOF is calculated using wellhead pressure.
- Examples above demonstrate analysis on a per well basis.

Late Life Steamflood Performance

Late Life Steamflood Expansion

- Steamflood Approval received for entire Cold Lake Development Area
- Currently ~100 infills on steamflood into 50 producing pads (~1000 wells)
- Extensive workover program underway to reactivate/improve steamflood wells – 19 wells repaired to date
- Evolving understanding of robustness of steamflood process:
  - Minimal production impact from short periods of non-optimal steaming – area can be over-steamed or under-steamed to satisfy operational constraints without jeopardizing long term production
  - Areas with lower pay quality (clasts/interbeds) demonstrate improved production with cyclic infill steam – however production character more typical of steamflood rather than CSS
  - LEP reconfiguration workovers have been successful at improving steam distribution within the reservoir and increasing production at wells that were previously unsupported



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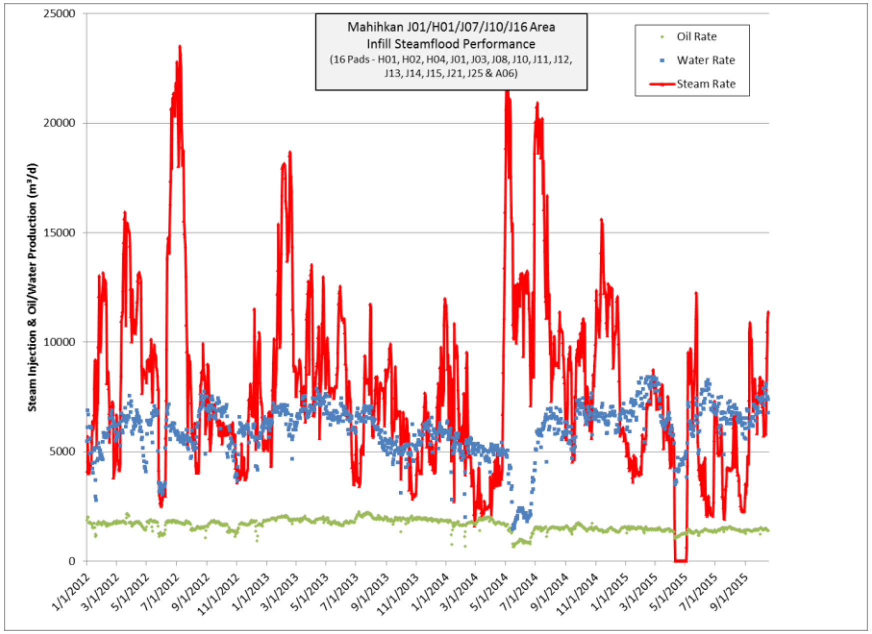
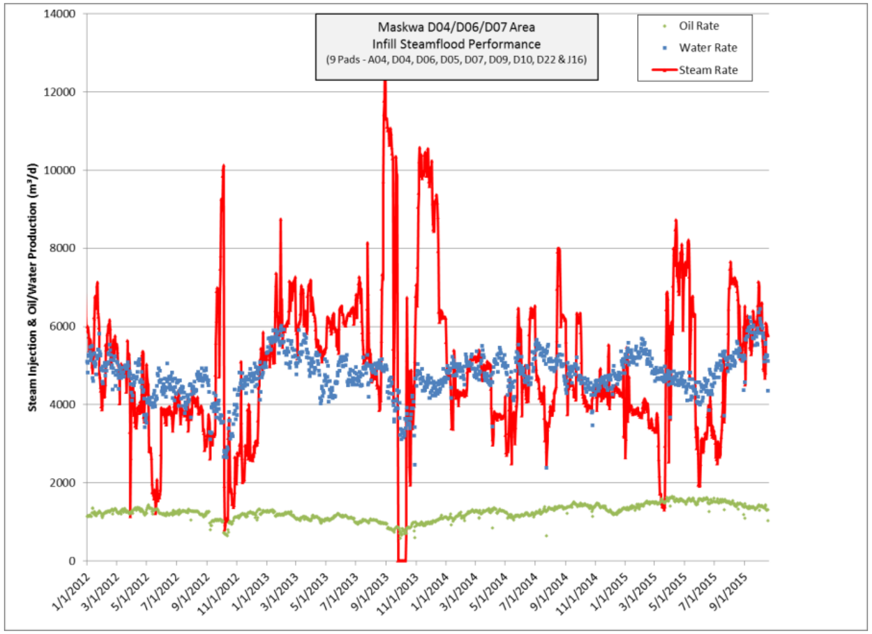
Late Life Steamflood Expansion

- Steamflood expansion into Mahihkan J trunk. Overall performance to date as expected.
- IOI steaming at consistent, target rates has resulted in a stable oil and water production
- Average recovery in this area is 55%

- Steamflood expansion into Maskwa D trunk. Overall performance to date as expected.
- Steamflood injection rates have increased in last year, resulting in increase in oil production
- Average recovery in this area is 53%





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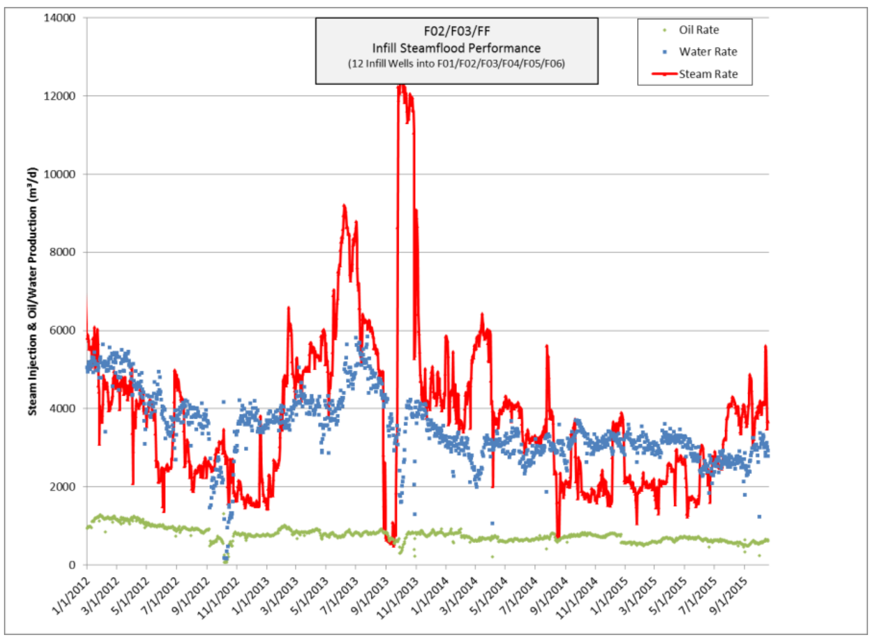
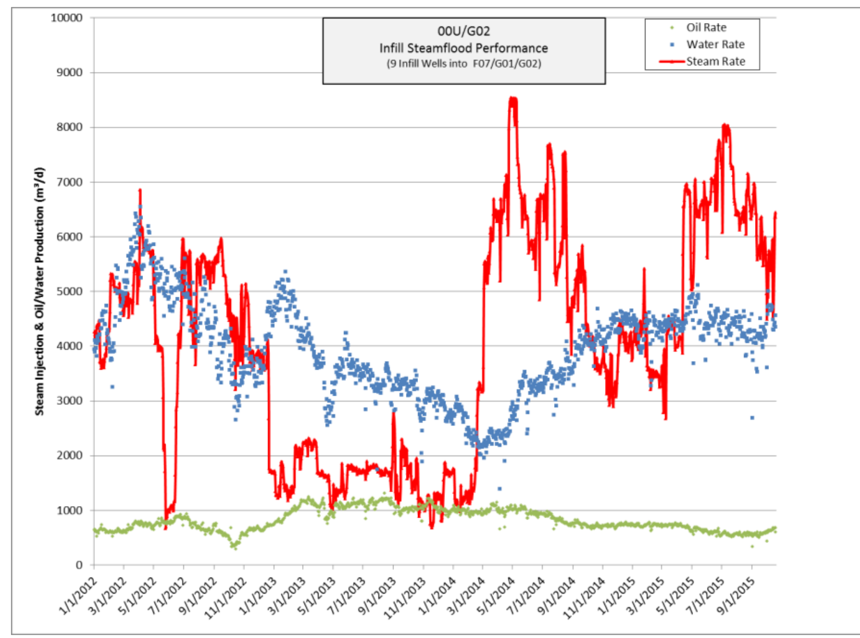
Late Life Steamflood Expansion

- Steamflood expansion into F-Trunk started Q2-Q3 2011. Overall performance to date as expected
- Current strategy for F-trunk is to steamflood
- Current steamflood rates resulting in stable oil and water production
- Average recovery in this area is 44%

- Steamflood expansion into the rest of F-Trunk (F07) and Leming G01 and G02 pad via 00U & G02 IOI's started Q4 2011
- Steamflood rates have increased over past year, resulting in increased water production
- Average recovery in this area is 43%





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LASER Recovery Process

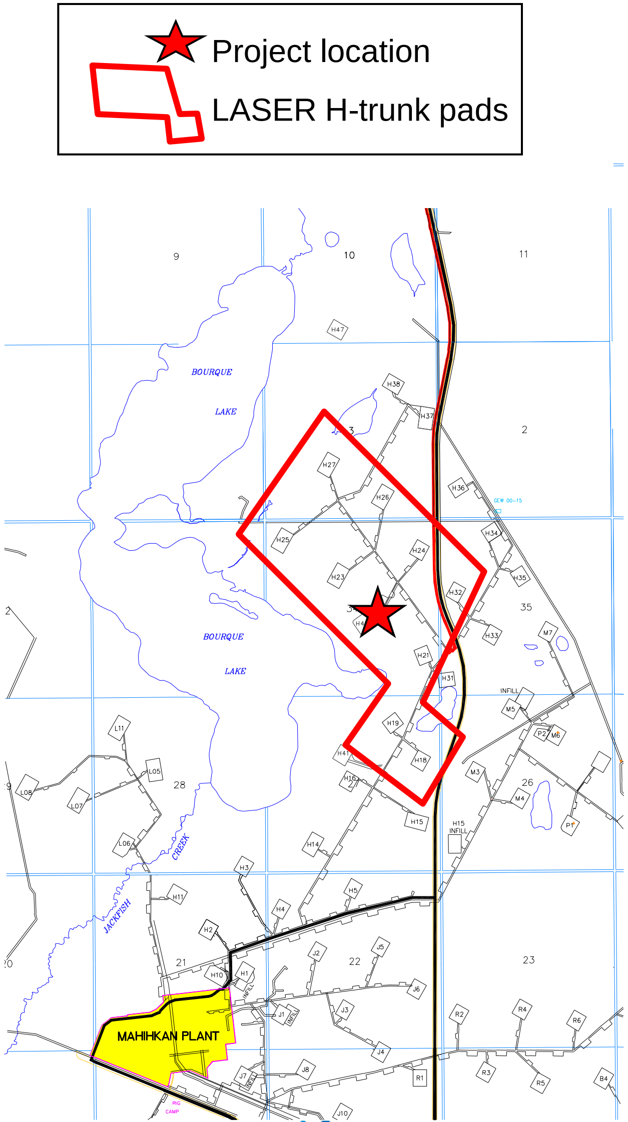
Laser H Trunk Project- Cycle 1 Summary

Background

- 10 pads in Mahihkan H-trunk – diluent injection complete
  - First cycle diluent injection began in Q3 2007 and was completed April 2009
- Diluent management
  - Distributed to pads via dedicated distribution pipeline
  - Produced back to Mahihkan Plant as part of common production stream
    - Produced diluent reduces future blend requirement
- Recovery equipment minimizes burning of flashed diluent in steam generators
  - Started up August 2008

Performance

- Overall first cycle LASER performance is in line with expectations
  - on average a 0.10 OSR uplift was achieved compared to no LASER implementation, due to the 5% v/v diluent injected with the steam in this first LASER cycle. This is approximately a 50% improvement in oil production performance.
  - LASER bitumen production uplift on the 10 H trunk pads ranges from 0.04 to 0.18 OSR uplift
  - the recovery of diluent has reached 58% of the initial injected diluent volume, on average in line with the expectation for diluent recovery for this first LASER cycle
  - LASER diluent production on the 10 H trunk pads ranges from 30% to 90% recovery of the injected diluent
  - there was some fluid migration from the LASER pads, primarily to other pads in the north and east, with the most significant impact being reduced OSR uplift and lower diluent recovery at H26, H27, H24, and H32 pads
  - LASER has been demonstrated to be effective in CSS, IOI, and CSS POW situations
  - implementation of a higher diluent concentration at H23 pad (8.6%) compared to other pads resulted in an increase in incremental bitumen production and OSR uplift for the cycle, but with an apparent lower diluent recovery for LASER. An estimated 0.18 OSR uplift and 49% diluent recovery was achieved at H23 pad, but with uncertainty in the high concentration assessment due to fluid migration between pads.
  - the LASER process has been demonstrated to be successful across a wide range of diluent concentrations at the H trunk project, but identification of an optimal diluent concentration for LASER from the field data is difficult due to the pad-to-pad fluid migration experienced in the cycle
  - the sustainability of the LASER performance uplift has been demonstrated by the third cycle of LASER at H22 pad, with an estimated 0.14 OSR uplift in the cycle



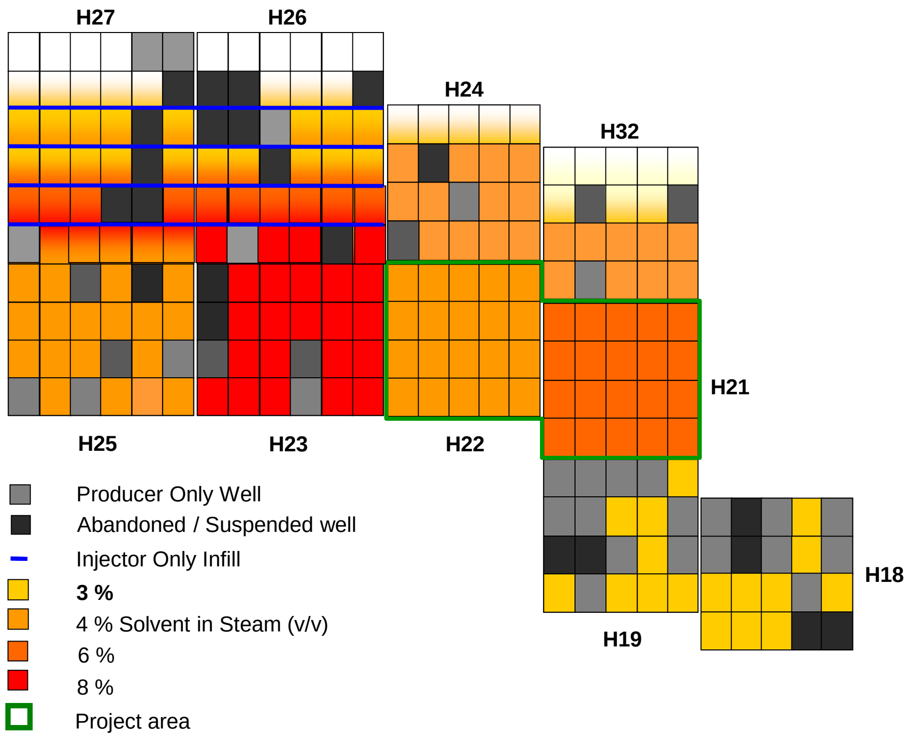
Cycle 1 Laser H Trunk Project- Diluent Injection

Diluent Injection

Complete in all 10 pads

Key Learning Initiative	# of Pads Location	Target (% v/v)	Actual (% v/v)
LASER POW	2		
9 injectors	H18	3%	3.2%
8 injectors	H19	3%	3.0%
LASER CSS	6		
Standard	H21	4%	6.1%
3rd LASER Cycle	H22	4%	4.5%
High Diluent	H23	8%	8.6%
Standard	H25	4%	4.4%
Potential Last Cycle	H24	3.5%	3.9%
Potential Last Cycle	H32	3%	3.9%
LASER IOI	2		
After 1 IOI cycle completed	H26	5%	4.4%
After 1 IOI cycle completed	H27	5%	4.6%

- Original LASER Pilot at H22 pad had 6% v/v of diluent injected in 8 wells (equivalent to ~2.4% v/v across a 20-well pad)
- Based on successful results at H22 Pilot, increased diluent to nominal average of 5% v/v for commercial implementation in 2007
- 8% v/v injected at H23 to test theory of increased benefits with higher concentration
- Remaining pads received diluent concentrations between 3-6% v/v
    - Lower diluent concentrations injected into pads with lower performance expectations



Injection Data for First LASER Cycle (10 pads)

Cumulative (km^3)	to 09/30/2012
Steam Injection	6,246
Diluent Injection	297

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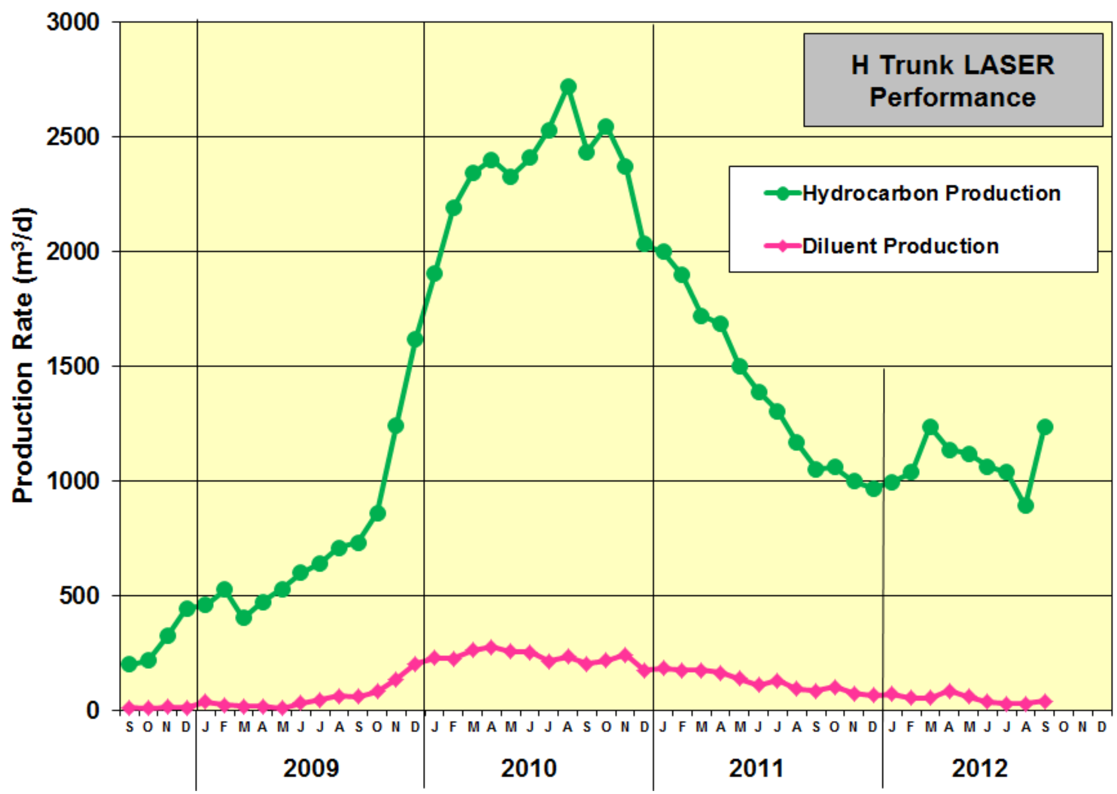
Cycle 1 LASER H Trunk - Production Performance

Production

- Steam injection cycle at the 10 pad H Trunk LASER implementation was completed in early 2009
- Oil production and diluent reproduction increased to peak rates in 2010 as expected
- Production has declined throughout the remainder of the cycle, through 2011 and into 2012
- With the first H Trunk LASER cycle now at an end, the performance is encouraging. The overall incremental oil production and diluent recovery are in line with expectations.

- H18 and H19 began the production cycle in Q2 2008
    - Peak oil production rates were achieved in 2010 and wells on oil decline during 2011 & 2012
- H21, H22, H23, H25 began the production cycle in Q4 2008
    - Peak oil production rates were achieved in 2010 and wells on oil decline during 2011 & 2012
- H24, H26, H27, H32 began the production cycle in Q1 2009
    - Peak oil production rates were achieved in 2010 and wells on oil decline during 2011 & 2012



Production Data for First LASER Cycle (10 pads)

Cumulative (km^3)	to 09/30/2012
Hydrocarbon Production	1,886
Diluent Production	174

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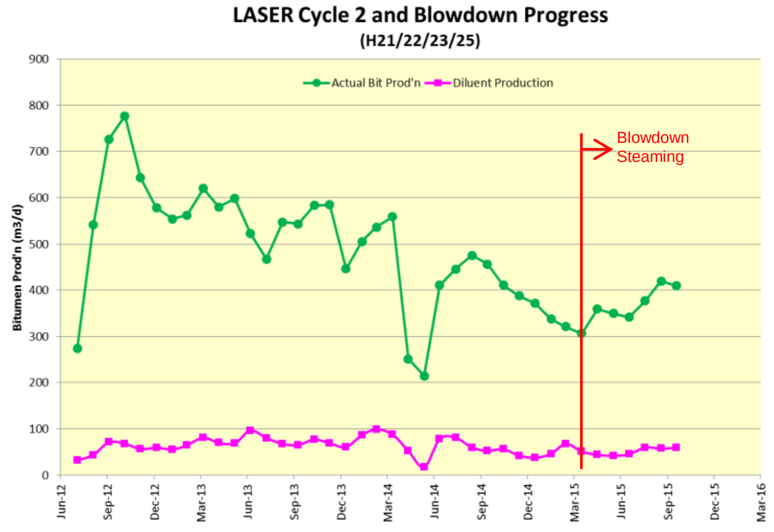
Cycle 2 LASER H Trunk - Production Performance



Background

- H21, H22, H23 and H25 steamed with diluent for cycle 2
- 2nd Cycle injection focus strictly on CSS strategy
- Focus on longer term performance understanding

Injection

- Steamed with diluent from Sept -Dec 2012
- Total steam injection - 1638 km^3
- Total diluent injection – 77 km^3 (4.7% dil. v/v)
- Pressures of ~1.0 - 2.0 MPa achieved
  - Lower reservoir pressures compared to 1st LASER cycle
  - Higher level of depletion and inter-well communication across all pads

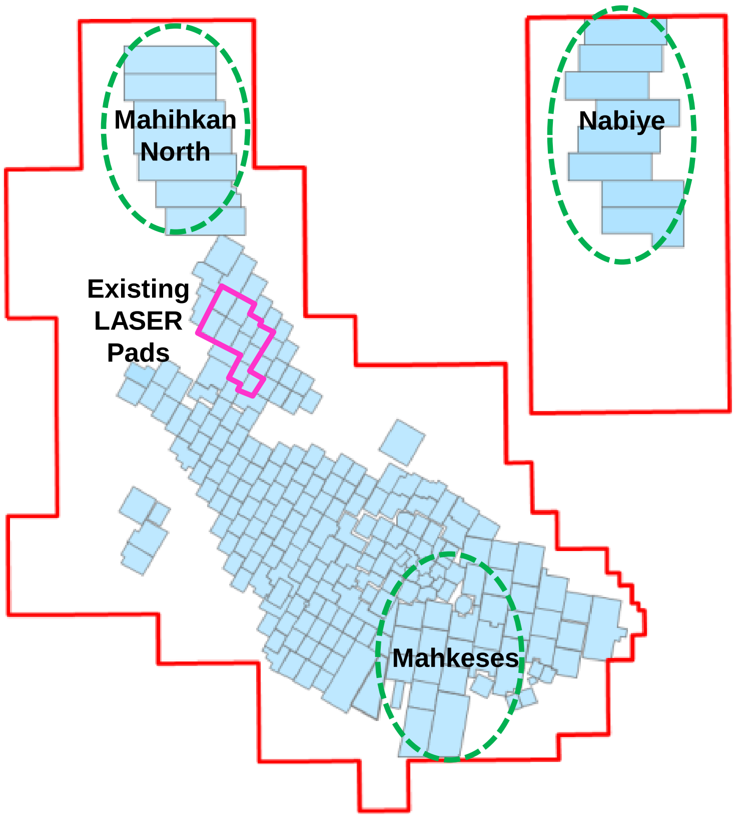
Production Performance

- Oil produced to date: 560 km^3
- Diluent recovery to date for both cycles: 245 km^3
- Cycle 2 production ended in Mar 2015. At the end of the cycle, the four pads averaged OSR increases of 0.12, exceeding the original expectation.
- Diluent production rates peaked in July 2013 and trended as expected, to a cumulative of 62%
- The four pads went into a blowdown cycle in which steam with no diluent was injected. Diluent reproduction continues to be tracked as recovery under blowdown will be a key learning for future LASER projects. The current cumulative recovery is 66%.

Production Data to Date:

Cumulative to 11/01/2015	km^3
Hydrocarbon Production (Cycle 1 + 2)	1,886 + 560
Cumulative Diluent Injection	374
Cumulative Diluent Production	245

LASER - Potential Future Applications



LASER Future Plans

- Following the successes of previous LASER projects, opportunities exist to apply the technology in additional areas of the field
- Potential future applications include:
  - Mahihkan North
  - Nabiye
  - Mahkeses
- Work is underway to evaluate these opportunities
- Details will be communicated as plans become better defined

Factors Impacting Recovery

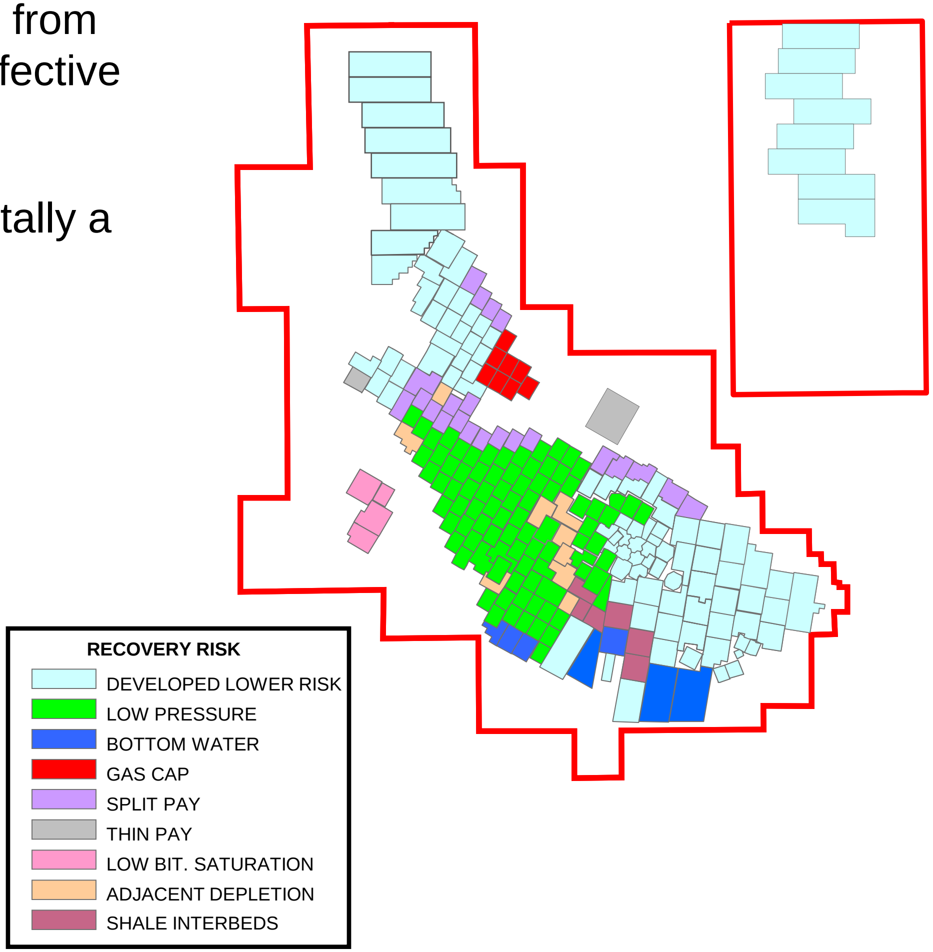
Factors Impacting Recovery

•Individual pad recovery expectations range from less than 10% to over 60% of the original effective bitumen in place.

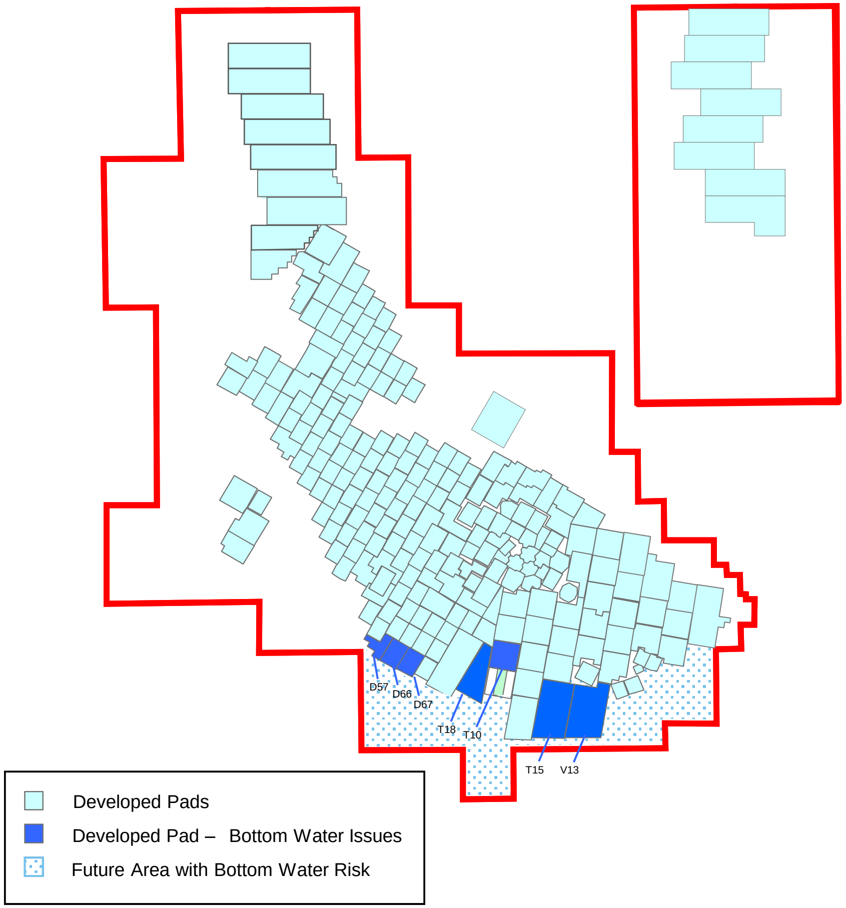
•The variation in recovery level is fundamentally a function of bitumen saturation and shale structure/distribution.

•Additional reservoir challenges include:

- Bottom water
- Clearwater gas cap
- Split pay
- Adjacent reservoir depletion
- Well Spacing

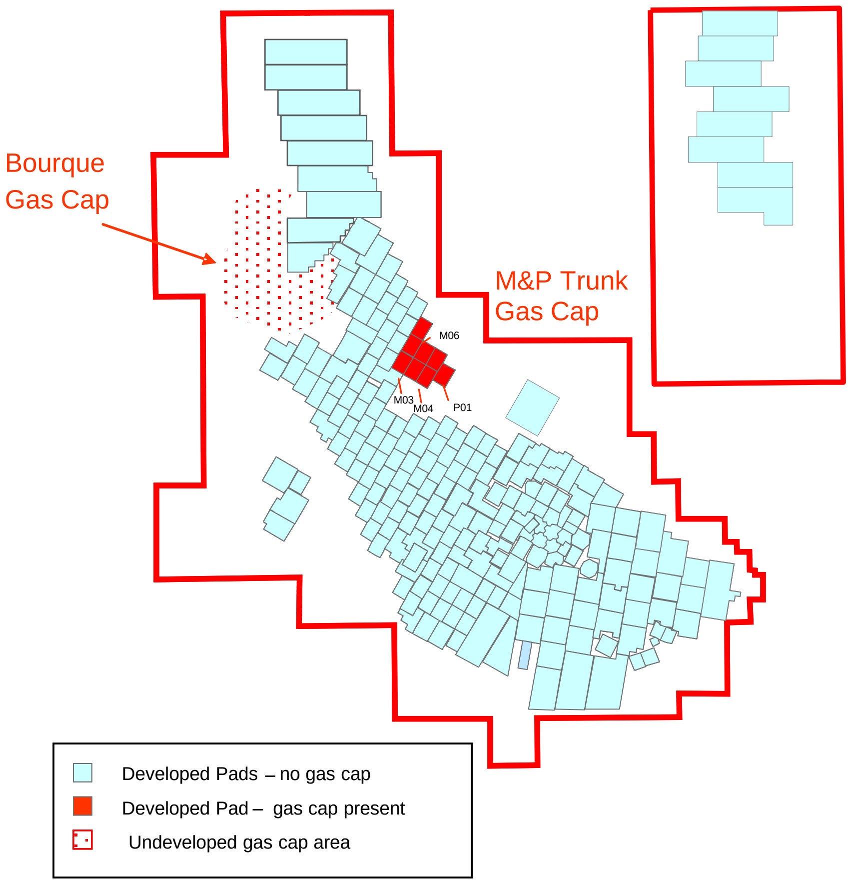


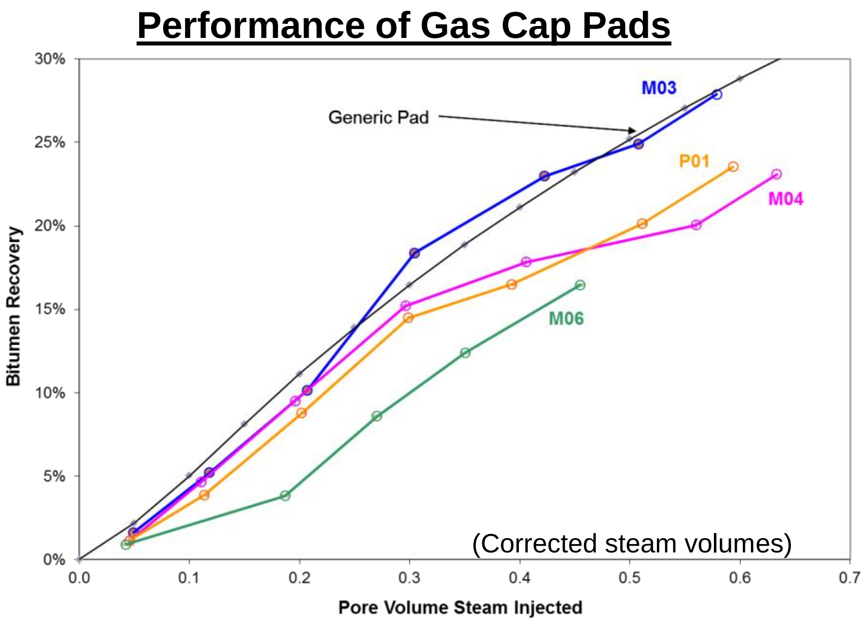
CSS Performance - Bottom Water



- Performance issues:
  - Bottom water is a thief zone for steam injection
  - High mobility water excludes bitumen production
- Mitigation
  - Basal Wabiskaw shale provides seal for much of CLPP 1-13
  - Perforation standoff from transition zone and thin bottom water
  - Additional standoff required for thick bottom water in clean sand
  - Uphole recompletions of wet wells can be effective if sufficient separation is left between old and new perforations

CSS Performance - Gas Cap

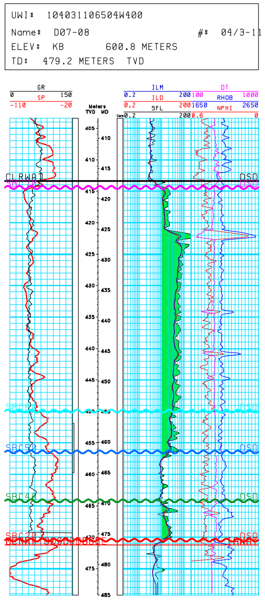




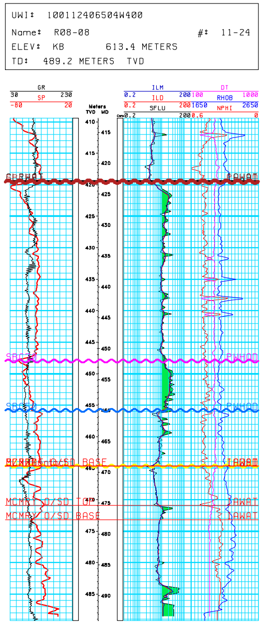
- Two significant Clearwater gas cap areas
  - M&P Trunk – producing
  - Bourque Lake gas cap - undeveloped
- M&P Trunk pads exhibited poorer performance due to pressure losses to the gas cap
- Steaming all pads under a gas cap together reduces steam losses and improves performance
- Recovery expectations at M&P Trunk pads are 30-40% lower due to presence of gas cap

CSS Performance - Split Pay

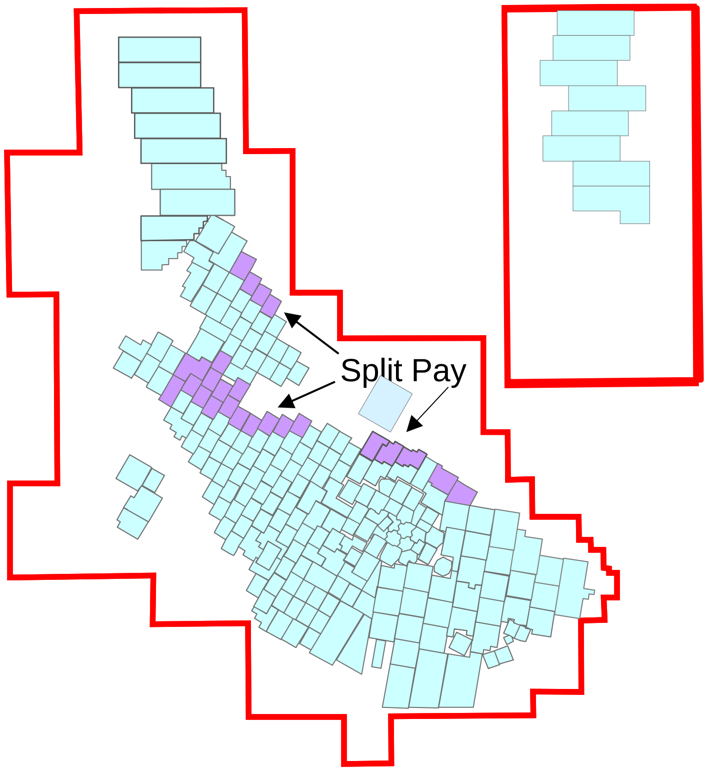
Thick Continuous Pay



Thin Split Pay



Interbedded sequence



- Split pay occurs where an interbedded sequence has cut through lower reservoir sequences
- Interbedded sands and shales act as vertical permeability barrier between lower reservoir sequences and good quality sand in upper sequence

- Upper zone can be accessed through recompletion after lower zone depletion
- Concurrent depletion trials with limited entry perforations resulted in poor inflow performance
- Thin zones have substantially lower recovery due to heat losses to surrounding non-reservoir rock
- Split pay can be used to isolate effects of top fluids

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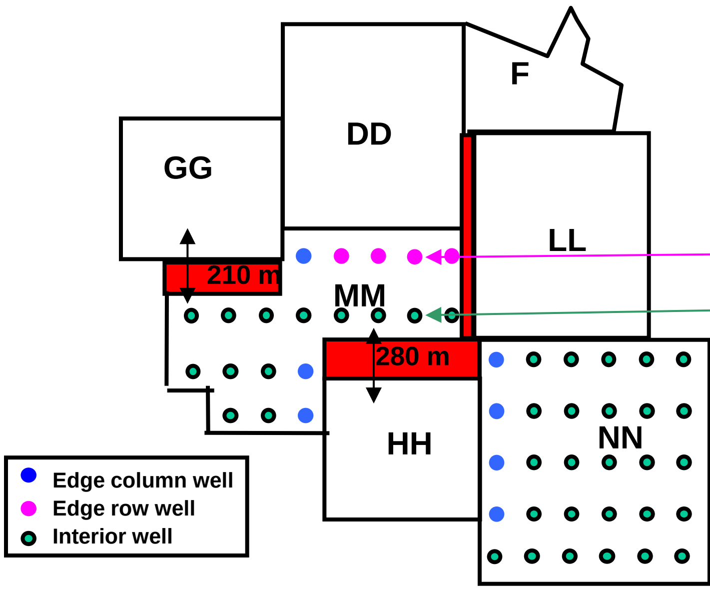
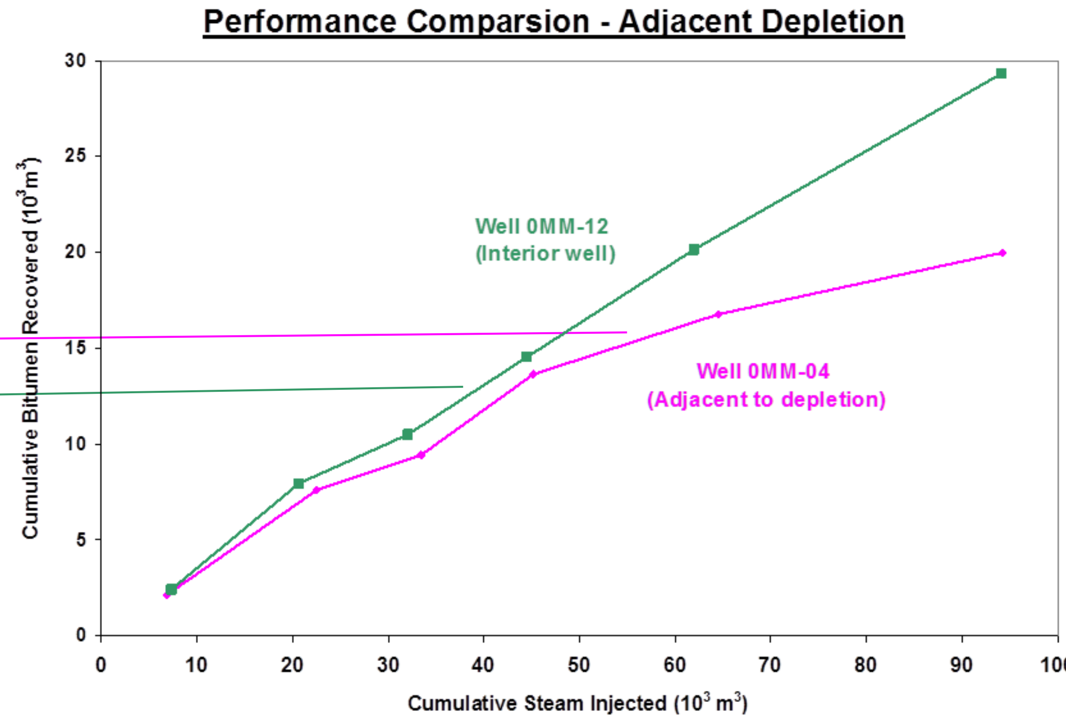
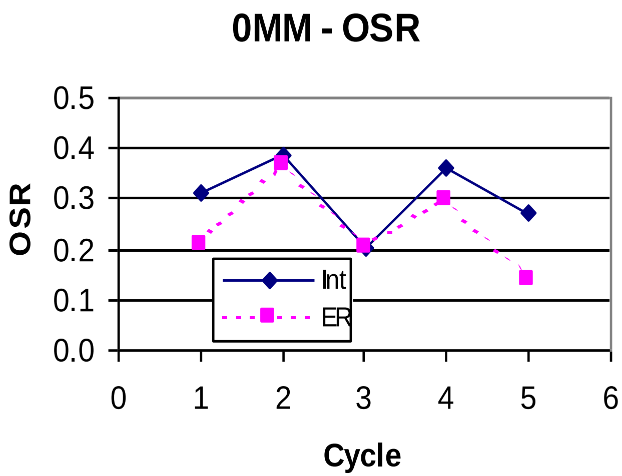
Adjacent to Depletion Example- MM Pad

- MM pad is adjacent to depletion in DD pad which acts as thief zone for steam







- Difficult to achieve high injection pressure after cycle 2 in edge row wells
- Low fluid production in edge row wells

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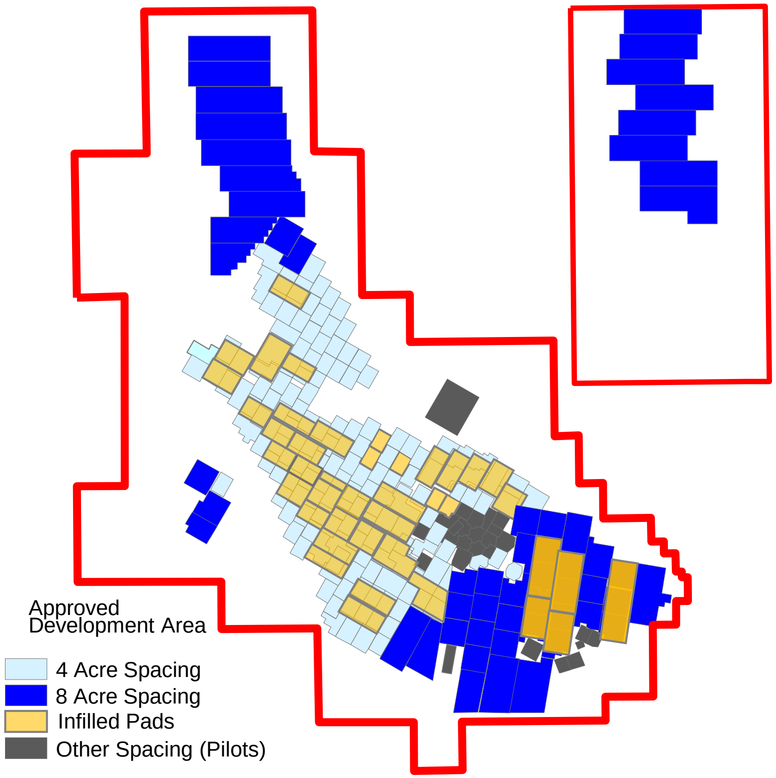
Well Spacing



Infill Drilling

- Where economic, horizontal injector-only-infills are drilled between the rows of wells at mature pads
- Infill steam is directed to bypassed bitumen to increase recovery by 15 to 30% relative to CSS
- Infill steam injection volumes per pad are similar to CSS volumes

- Commercial pads are developed on 4 acre, 8 acre or 11 acre well spacing
  - 4 acre spacing in the thicker central area of the field
  - 8 or 11 acre spacing in thinner resource areas
- Cycle steam injection volumes have been derived primarily from field operating experience with the objectives of:
  - Achieving high levels of reservoir conformance to mobilize cold bitumen
  - Managing inter-well communication
  - Limiting casing damage caused by shear stress
- Current steaming practices employ the same early cycle injection volume strategy for both 4 and 8 acre well spacings:[1]
  - > Cycle 1 8,000 m^3
  - > Cycle 2 7,000 m^3
  - > Cycle 3 8,000 m^3
  - Cycle 2 volumes are reduced because injected fluids are typically not fully reproduced in cycle 1
- Subsequent cycle high pressure steam injection volumes range up to 10,000 m^3 (volumes injected at dilation pressure)
  - Actual injection performance from previous cycles is used to develop the steaming strategy for an individual pad
- Wells drilled on 8 acre spacing are expected to operate through more cycles than those on 4 acre spacing
- Expected recovery from 8 acre spacing is approximately 80% of 4 acre recovery based on reservoir simulation
  - Existing 8 acre pads are not sufficiently mature to demonstrate lower recovery

[1] 11 Acre Spacing steam strategy approved by the ERCB in July 2011 allowing for 12,000 m^3 overfillup per cycle.

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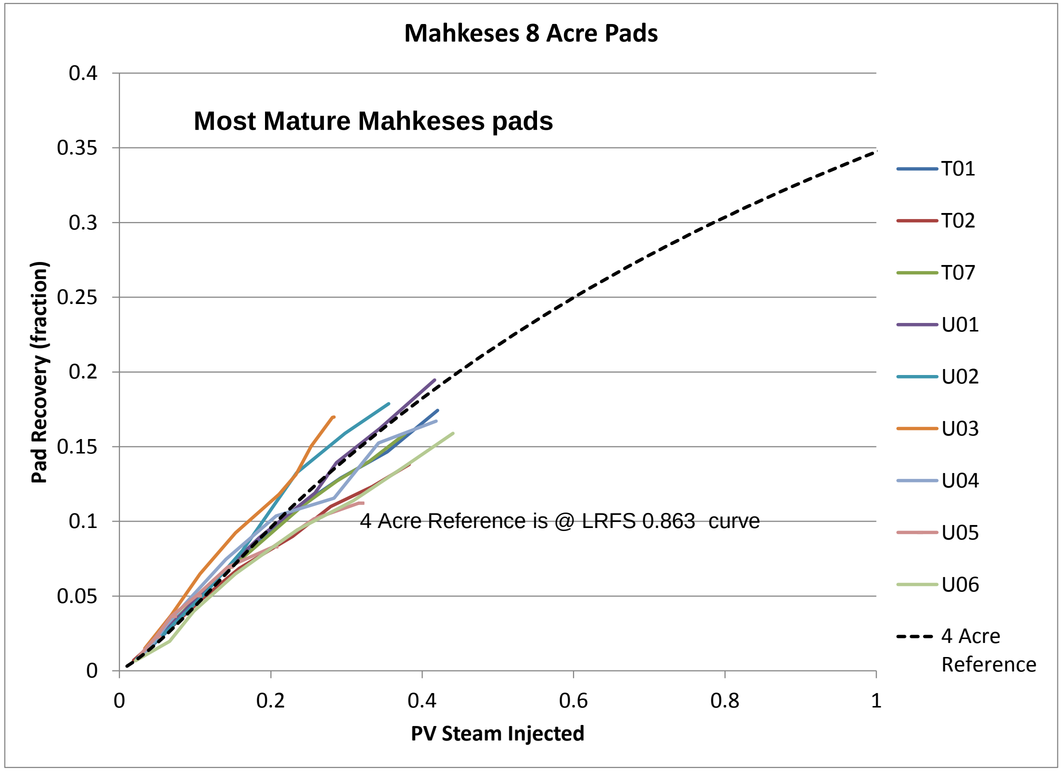
Impact of Well Spacing on Recovery



- 4 acre performance curve shown for equivalent resource to Mahkeses pads
- Most mature Mahkeses pads not sufficiently depleted to validate recovery expectations

Pad Recovery

Pad	Effective OBIP	Recovery to Sept 2013		Ultimate Recovery
	(e3 m3)	(e3 m3)	% EBIP	% EBIP
00A	1184	152	13%	EUR = Recovery to date
00B	1772	126	7%	EUR = Recovery to date
00C	1559	216	14%	EUR = Recovery to date
00D	1236	212	17%	EUR = Recovery to date
00E	1257	150	12%	EUR = Recovery to date
00F	1079	233	22%	EUR = Recovery to date
00G	2097	358	17%	EUR = Recovery to date
00H	2010	291	14%	EUR = Recovery to date
00J	850	249	29%	EUR = Recovery to date
00K	1905	489	26%	EUR = Recovery to date
00L	2019	450	22%	EUR = Recovery to date
00M	982	68	7%	EUR = Recovery to date
00N	1648	490	30%	30% - 35%
00P	2341	714	30%	EUR = Recovery to date
00Q	1988	342	17%	EUR = Recovery to date
00R	1764	116	7%	EUR = Recovery to date
00S	1174	136	12%	EUR = Recovery to date
00T	2644	846	32%	EUR = Recovery to date
00U	2636	990	38%	40% - 45%
00V	2780	728	26%	35% - 40%
00W	2488	1281	52%	50% -55%
0AA	2533	1115	44%	44% - 45%
0BB	2278	1543	68%	68% - 72%
0CC	2369	941	40%	40% - 45%
0DD	2890	884	31%	31% -35%
0EE	1854	575	31%	EUR = Recovery to date
0FF	1976	1017	51%	50% - 55%
0GG	1365	511	37%	37% - 40%
0HF	297	102	34%	EUR = Recovery to date
0HH	1337	617	46%	46% - 50%
0LL	1715	703	41%	50% - 55%
0MA	1454	126	9%	EUR = Recovery to date
0MB	1942	452	23%	EUR = Recovery to date
0MC	1087	496	46%	EUR = Recovery to date
0MD	816	496	61%	EUR = Recovery to date
0ME	2276	533	23%	EUR = Recovery to date
0MM	1879	631	34%	33% - 35%
0NN	2549	910	36%	50% - 55%
A01	2446	954	39%	39% - 45%
A02	2330	1025	44%	45% - 50%
A03	2159	964	45%	45% - 50%
A04	2974	1348	45%	45% - 51%
A05	2024	793	39%	39% - 42%
A06	2615	913	35%	35% - 40%
B01	2070	939	45%	45% - 50%
B02	2131	1017	48%	48% - 50%

- Minor changes in estimated pad recoveries due to revision of breakeven OSR on late life pads
- E07 and D29 pad combined as they are now depleted by one set of horizontal wells
- Injection only infills included expectation for several in Upper H trunk pads

Data shown is from 2013. Updates will be made in 2016.

Pad Recovery

Pad	Effective OBIP	Recovery to Sept 2013		Ultimate Recovery
	(e3 m3)	(e3 m3)	% EBIP	% EBIP
B03	2146	1033	48%	48% - 50%
B04	1938	974	50%	50% - 55%
B05	2110	1461	69%	70% - 75%
B06	1937	1031	53%	53% - 55%
C01	1695	844	50%	50% - 55%
C02	1962	1090	56%	55% - 60%
C03	2304	1542	67%	67% - 70%
C04	2455	893	36%	40% - 48%
C05	2055	795	39%	40% - 45%
C08	4026	774	19%	50% - 60%
D01	2138	921	43%	43% - 50%
D02	2038	718	35%	50% - 55%
D03	3459	1062	31%	35% - 40%
D04	3307	1341	41%	50% - 60%
D05	3075	1406	46%	50% - 60%
D06	3422	2405	70%	75% - 80%
D07	3521	1785	51%	50% - 60%
D09	3331	1964	59%	70% - 80%
D10	4056	1812	45%	50% - 55%
D11	2431	80	3%	EUR = Recovery to date
D12	2883	563	20%	25% - 30%
D21	2132	658	31%	45% - 55%
D22	2664	1133	43%	50% - 60%
D23	2914	1179	40%	55% - 65%
D24	2015	823	41%	45% - 55%
D25	2640	1109	42%	44% - 50%
D26	2990	1508	50%	55% - 65%
D27	2717	928	34%	35% - 40%
D28	2743	474	17%	25% - 35%
D31	5974	1487	25%	63% - 73%
D33	5004	1343	27%	55% - 65%
D35	3616	816	23%	50% - 60 %
D36	3115	1025	33%	65% - 75%
D39	3582	652	18%	45% - 55%
D51	2959	1057	36%	65% - 75%
D52	3082	802	26%	26% - 30%
D53	2704	1176	43%	65% - 75%
D54	1688	646	38%	35% - 45%
D55	1322	656	50%	49% - 55%
D57	728	105	14%	EUR = Recovery to date
D62	2390	1133	47%	60% - 70%
D63	2703	938	35%	45% - 55%
D64	2531	1129	45%	55% - 65%
D65	2319	856	37%	55% - 60%
D66	1498	187	12%	12% - 13%
D67	1546	659	43%	40% -50%
E01	3765	776	21%	50% - 60%

Pad	Effective OBIP	Recovery to Sept 2013		Ultimate Recovery
	(e3 m3)	(e3 m3)	% EBIP	% EBIP
E02	2601	646	25%	45% - 50%
E03	1799	688	38%	50% - 60%
E04	2373	621	26%	45% - 55%
E05	4256	841	20%	45% - 55%
D29/E07	5053	418	8%	20% - 30%
E08	2151	599	28%	30% - 38%
E09	2286	708	31%	35% - 40%
E10	1899	635	33%	35% - 40%
E11	7758	827	11%	40% - 45%
F01	3266	858	26%	40% - 45%
F02	2238	754	34%	35% - 40%
F03	3605	1208	34%	55% - 60%
F04	2091	953	46%	50% - 55%
F05	3406	1272	37%	50% - 60%
F06	2123	785	37%	40% - 45%
F07	3251	1022	31%	55% - 60%
F08	2943	183	6%	25% - 35%
G01	4764	1283	27%	50% - 55%
G02	2664	815	31%	50% - 55%
G03	2365	861	36%	45% - 50%
H01	2583	1797	70%	75% - 80%
H02	1663	1079	65%	65% - 70%
H03	935	437	47%	46% - 50%
H04	973	504	52%	52% - 55%
H05	1402	318	23%	25% - 30%
H06	2310	147	6%	EUR = Recovery to date
H10	2979	507	17%	20% - 25%
H11	2302	1140	50%	70% - 75%
H14	2073	331	16%	20% - 25%
H15	2809	1017	36%	40% - 45%
H16	2000	840	42%	53% - 58%
H18	2422	767	32%	30% - 40%
H19	2034	958	47%	60% - 70%
H21	2719	1028	38%	45% - 50%
H22	2805	1155	41%	40% - 45%
H23	3972	1741	44%	60% - 70%
H24	2213	670	30%	30% - 35%
H25	3716	1514	41%	55% - 60%
H26	3878	1024	26%	30% - 35%
H27	3998	1202	30%	40% - 45%
H31	2276	738	32%	45% - 50%
H32	2244	609	27%	27% - 30%
H33	2170	525	24%	24% - 25%
H34	1423	311	22%	22% - 24%
H35	1570	313	20%	20% - 22%
H36	1629	337	21%	21% - 22%

Data shown is from 2013. Updates will be made in 2016.

Pad Recovery

Pad	Effective OBIP	Recovery to Sept 2013		Ultimate Recovery
	(e3 m3)	(e3 m3)	% EBIP	% EBIP
H37	2139	463	22%	22% - 24%
H39	4853	413	9%	40% - 50%
H40	2484	619	25%	45% - 55%
H41	7842	1419	18%	45% - 55%
H42	3843	1122	29%	35% - 45%
H45	4283	556	13%	30% - 40%
H46	4460	1097	25%	45% - 55%
H47	5407	882	16%	40% - 50%
H51	6675	553	8%	35% - 45%
H57	9705	467	5%	35% - 45%
H58	12793	1514	12%	35% - 45%
H59	10313	1375	13%	30% - 40%
H62	9188	641	7%	25% - 35%
H63	8184	493	6%	25%- 35%
H65	8499	755	9%	35%- 40%
H68	8686	487	6%	30%- 40%
H69	9606	255	3%	30%- 40%
J01	3011	2010	67%	70% - 80%
J02	1874	1192	64%	64% - 70%
J03	2654	1574	59%	70% - 75%
J04	2764	1621	59%	60% - 65%
J05	1355	747	55%	55% - 60%
J06	2500	873	35%	45% - 55%
J07	3043	1582	52%	60% - 70%
J08	3551	2385	67%	80% - 85%
J10	3497	1944	56%	60% - 70%
J11	3378	1222	36%	35% - 40%
J12	3089	1646	53%	60% - 65%
J13	3740	2044	55%	70% - 80%
J14	3438	1440	42%	60% - 70%
J15	4341	2035	47%	65% - 75%
J16	3886	1738	45%	60% - 70%
J21	3638	1237	34%	35% - 40%
J25	3072	643	21%	25% - 30%
J27	2531	352	14%	15% - 25%
K22	1753	513	29%	EUR = Recovery to date
K23	2903	627	22%	25% - 30%
K24	2685	482	18%	20% - 25%
K26	1821	235	13%	14% - 20%
L05	2641	1035	39%	55% - 65%
L06	2161	1350	62%	63% - 70%
L07	2570	1172	46%	65% - 75%
L08	927	435	47%	46% - 50%
L09	2036	0	0%	30% - 35%
L11	4227	1160	27%	40% - 50%
M03	2774	802	29%	29% - 30%

Pad	Effective OBIP	Recovery to Sept 2013		Ultimate Recovery
	(e3 m3)	(e3 m3)	% EBIP	% EBIP
M04	3238	796	25%	25% - 30%
M05	2272	460	20%	20% - 25%
M06	2572	437	17%	17% - 18%
M07	1762	271	15%	15% - 18%
P01	3160	764	24%	24% - 25%
P02	2436	331	14%	15% - 25%
P03	2777	467	17%	17% - 18%
R01	1903	911	48%	50% - 60%
R02	1889	736	39%	50% - 60%
R03	2359	716	30%	35% - 40%
R04	2135	465	22%	25% - 30%
R05	1829	582	32%	40% - 50%
R06	1255	456	36%	40% - 45%
R07	1751	625	36%	40% - 50%
T01	4744	827	17%	40% - 50%
T02	5084	705	14%	40% - 50%
T03	3703	631	17%	30% - 40%
T04	4167	596	14%	30% - 40%
T05	4906	615	13%	30% - 35%
T06	4150	619	15%	40% - 50%
T07	4647	739	16%	40% - 50%
T08	4877	673	14%	35% - 45%
T09	4518	455	10%	35% - 45%
T10	6371	525	8%	30% - 40%
T11	3556	581	16%	30% - 35%
T12	4139	529	13%	25% - 30%
T14	5445	330	6%	30% - 40%
T15	7171	415	6%	30% - 35%
T18	4973	48	1%	30% - 35%
U01	4644	901	19%	40% - 50%
U02	4432	779	18%	45% - 55%
U03	5239	884	17%	45% - 55%
U04	4726	770	16%	40% - 50%
U05	6818	752	11%	35% - 45%
U06	3710	583	16%	25% - 35%
U07	5542	420	8%	30% - 35%
U08	4836	503	10%	30% - 40%
U09	3657	391	11%	35% - 45%
V01	5202	864	17%	40% - 50%
V02	5073	669	13%	25% - 35%
V03	4843	633	13%	25% - 30%
V04	4861	857	18%	40% - 50%
V05	4974	796	16%	40% - 50%
V08	5090	772	15%	40% - 50%
V09	4882	714	15%	40% - 50%
V10	8201	735	9%	30% - 40%
V13	7873	133	2%	25% - 30%
Y16	2362	661	28%	40% - 50%
Y31	2563	554	22%	40% - 50%
Y32	2302	158	7%	40% - 50%
Y34	2818	590	21%	40% - 50%
Y36	3835	690	18%	35% - 40%

Data shown is from 2013. Updates will be made in 2016.

Future Plans

Pad Steaming Priorities

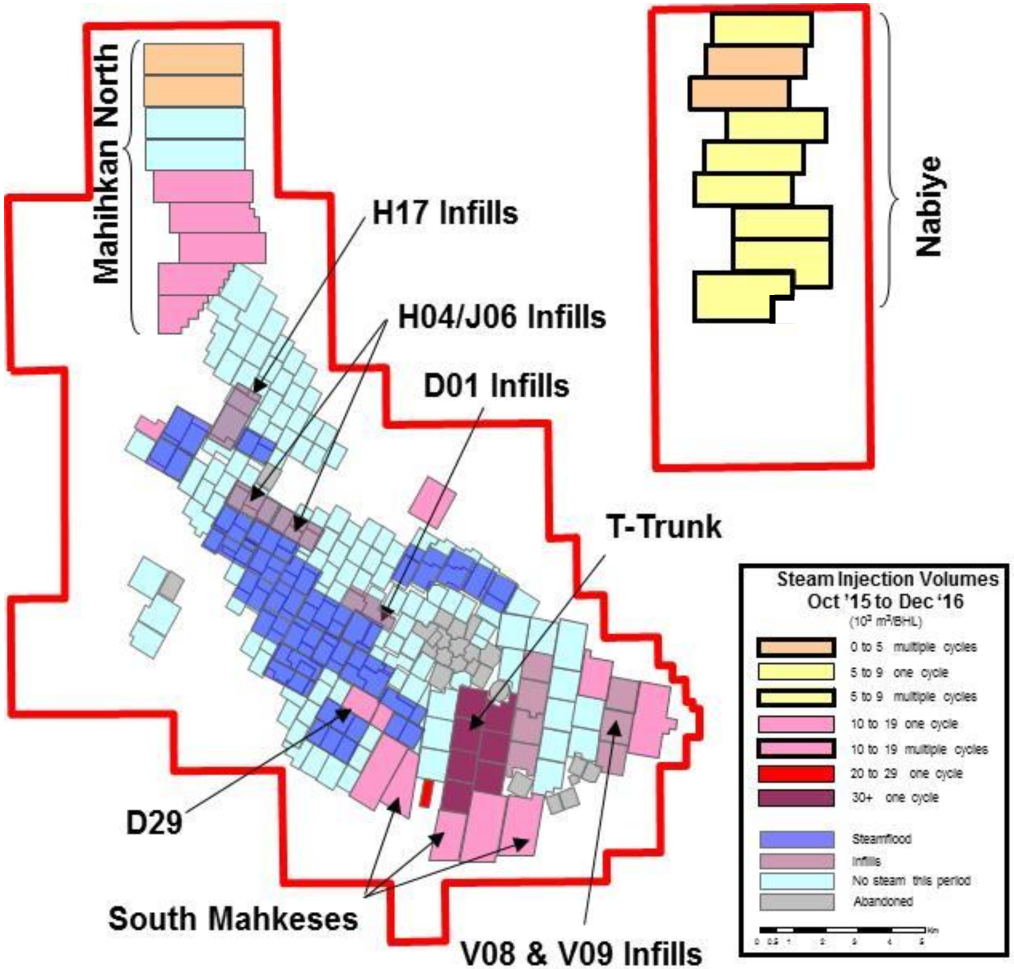
- Long-term steam plans developed annually
  - Targeted cycle timing based on historical performance and optimal cycle length
  - Development plans tied to projected steam demand at each site to fully utilize installed steam capacity

- Earlier cycle pads receive priority during periods of steam demand higher than plant capacity and for scheduling considerations
  - Pads are steamed less frequently as they mature (steam timing is less critical to performance)
  - Individual pad steaming suspended at an economic limit
  - Infill steamflood pads can operate effectively at a range of steaming rates, providing flexibility to steam scheduling

- Mega-row sweep strategy, intended to maximize recovery, dictates relative steam timing of pads within a steaming area

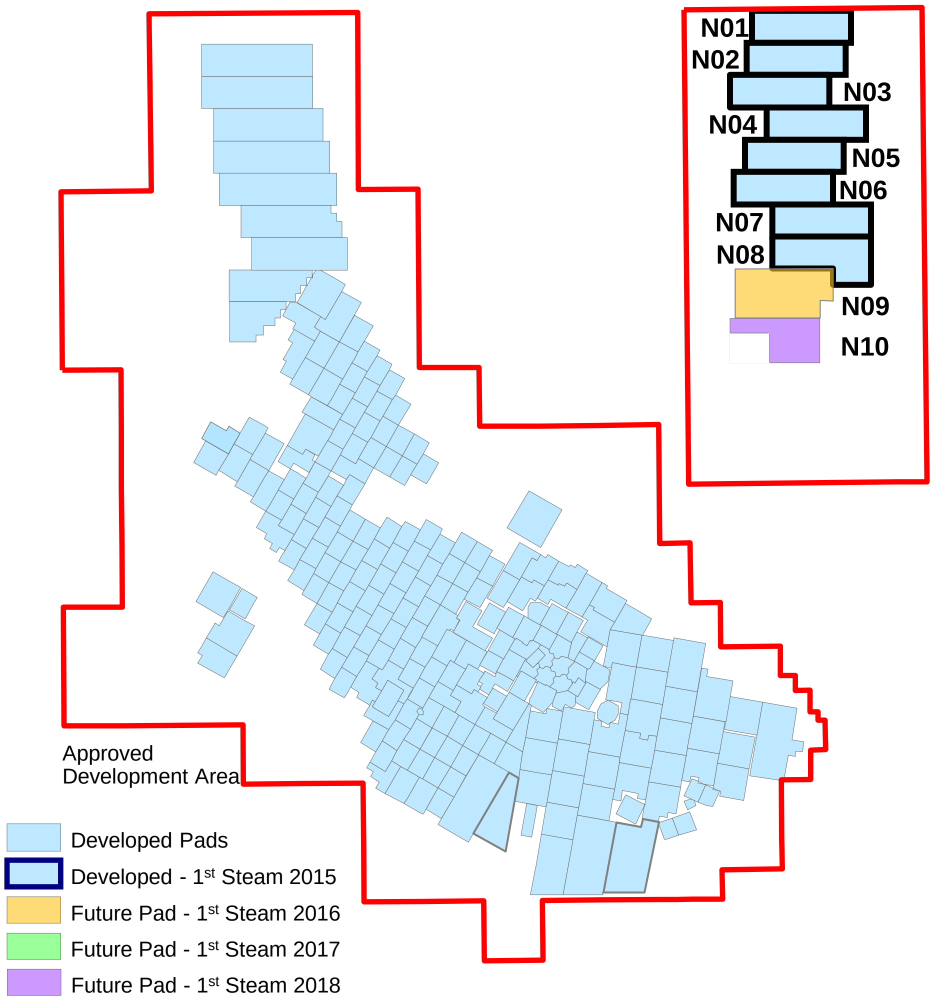
- Additional factors
  - Setback requirements between drilling and steaming operations

Steam Plans to End 2016



- **Mahkeses**
  - South Mahkeses Sweep (T15, T14, T18, V13)
  - T-Trunk Sweep (T03/T04/T02/T08/T11)
  - Infills (T01/T07, V08/V09/U09)
  - T13 SA-SAGD
- **Leming**
  - FF/U/G02 and T05 steamfloods
  - Y32
- **Maskwa**
  - D, E and F-Trunk steamfloods
  - Cycle 1 Infills: D01
  - E11, D29, and F08 CSS cycles
  - Late cycle, low pressure CSS pads
- **Mahihkan**
  - H, J, and L-Trunk steamfloods
  - Mahihkan North sweep (H57/H58/H59/H62)
  - Cycle 1 Infills: H04, J06, H17
  - Late cycle, low pressure CSS pads
- **Nabiye**
  - N01-N07 Cycle 3 and 4 Sweep
  - N08-N09 productivity maintenance pads

Pad Development Program



Drilling and Steaming Schedule

N01	2012	2015
N02	2012	2015
N03	2012	2015
N04	2012	2015
N05	2013	2015
N06	2013	2015
N07	2013	2015
N08	2013	2015
N09	2014	2016
N10	2017	2018

Extensive well repair program and positive steam flood performance has deferred previously planned pad development program

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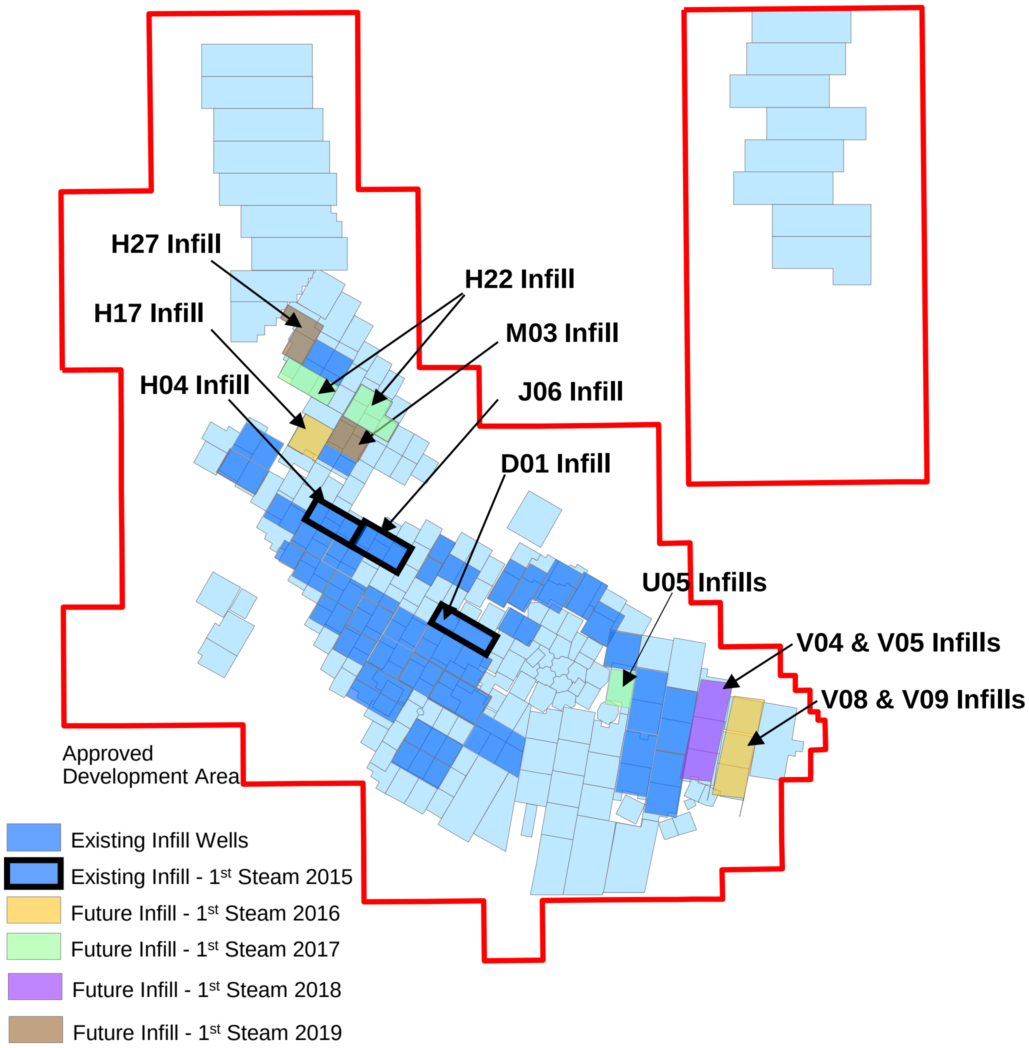
Infill Drilling Program



Drilling and Steaming Schedule

H04	2014	2015
J06	2014	2015
D01	2014	2015
V08	2014	2016
V09	2014	2016
H17	2015	2016
H22	2015	2017
U05	2015	2017
V04	2017	2018
V05	2017	2018
M03	2018	2019
H27	2018	2019

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Cold Lake SA-SAGD Experimental Pilot

Approval #10689D

Agenda

Subsurface

- Background
- Geoscience Overview
- Drilling & Completions (including instrumentation)
- Artificial Lift
- Scheme Performance
- Future Plans

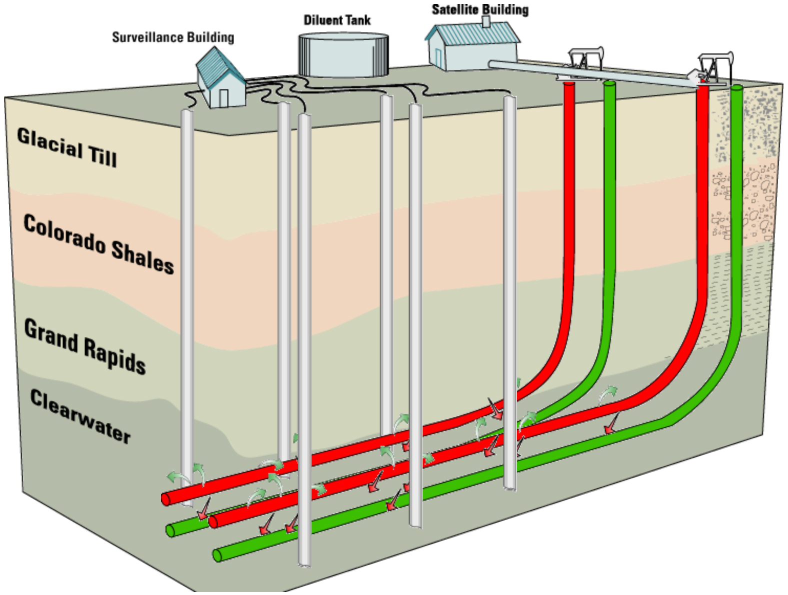
Surface

- Facilities
- Measurement & Reporting
- Environmental Summary / AER Compliance
- Future Plans

Background

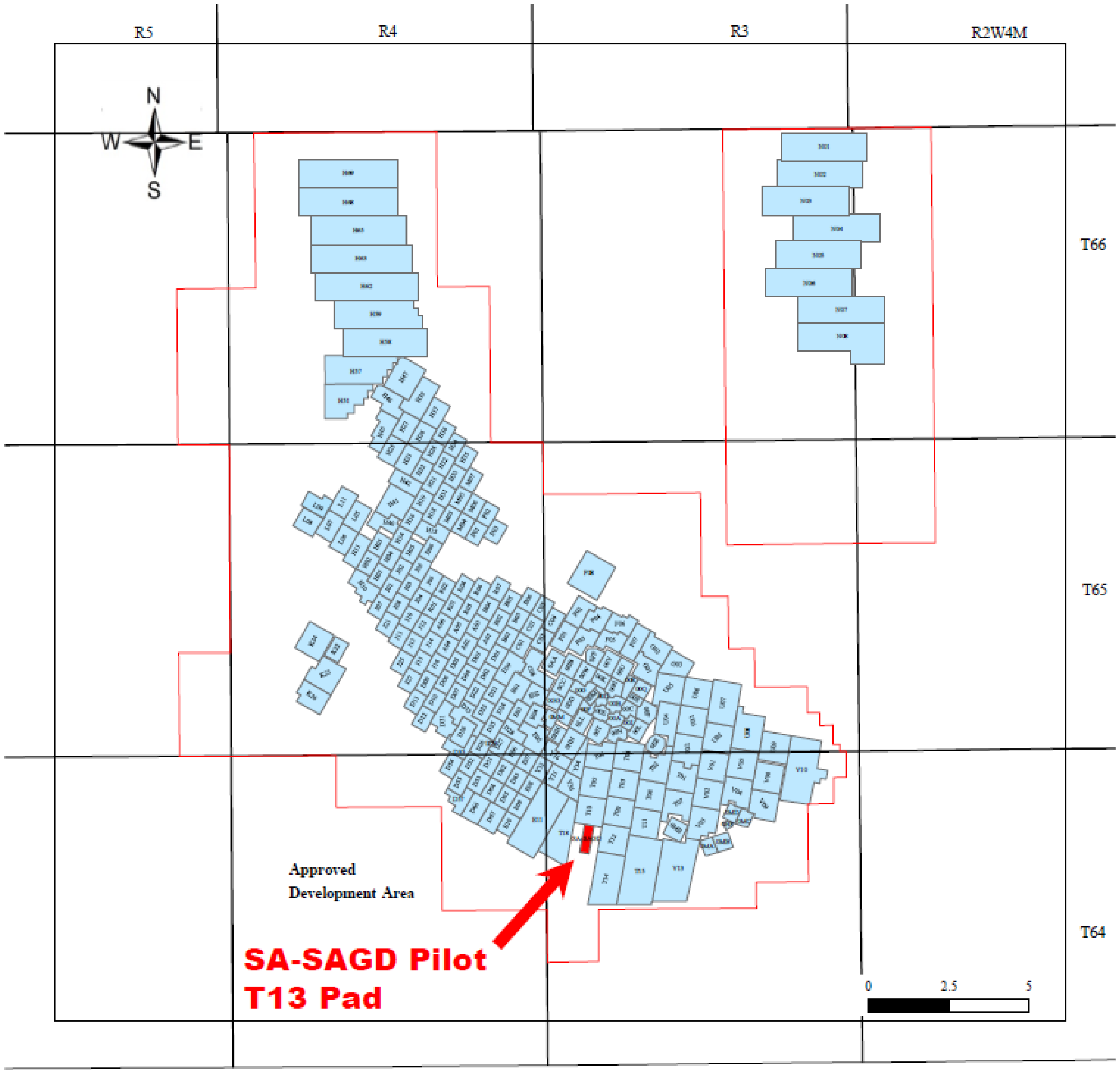
No Update

- Imperial is conducting a Solvent Assisted – Steam Assisted Gravity Drainage (SA-SAGD) pilot in Cold Lake (also known as ES-SAGD)
- 5-20% solvent (diluent) will be added with the injected steam in a dual horizontal well SAGD configuration
  - First well-pair: SA-SAGD → SAGD
  - Second well-pair: SAGD → SA-SAGD
- Pilot includes:
  - Two horizontal well pairs (four wells)
  - Six observation wells (OB wells)
  - Associated steam and diluent injection facilities
  - Artificial lift
  - Production cooling, measurement, and testing facilities
- Pilot will utilize Imperial's existing Mahkeses plant for:
  - Steam generation
  - Water treatment
  - Bitumen separation and processing facilities
  - Existing steam distribution and production gathering systems
- Pilot experimental scheme (non-confidential basis) to December 31, 2016



Location

No Update



Key Operational Events

No Update

- Jul 20, 2010 — SAGD operation commenced on both well-pairs
- Oct 20, 2010 — Diluent injection commenced into T13-04, converting well-pair 2 to SA-SAGD mode (well-pair 1 continues in SAGD mode)
- Nov 25 – Dec 22, 2010 — Diluent injection shut-in due to surface facility issues (well-pair 2 operated in SAGD mode during this period)
- Sep 16 – Oct 19, 2011 — Steam and diluent injection was shut-in for plant maintenance (producer wells remained on production during shut-in period)
- May 24, 2012 — Well-pair 2 was switched from SA-SAGD mode to SAGD mode
- May 29, 2012 — Well-pair 1 was switched from SAGD mode to SA-SAGD mode
- Sep 21 – Oct 1, 2012 — Injection was shut-in for routine maintenance (production was maintained for part of this period)
- Apr 14 – May 8, 2013 — Injection was shut-in for plant maintenance shutdown (production was maintained for well-pair 1 at a lower capacity, and shut-in for well-pair 2)
- Jul 2013 – Oct 2013 — Intermittent diluent injection due to diluent quality issues
- Sep 18 – Sep 29, 2013 — Injection shut-in due to routine maintenance (production was maintained for well-pair 1, and shut-in for most of this period for well-pair 2)
- Apr 2 – May 6, 2014 — Injection was shut-in for plant slowdown (producer wells remained on production during shut-in period)
- Jul – Sep 2014 — No diluent injection into well-pair 1 due to wait on finalized contract with new diluent supplier
- Sep 6 – Sep 13, 2014 — Injection was shut-in for annual metering calibrations (production was also shut-in for both well pairs)
- Oct 10, 2014 — Reduced WP1 diluent injection concentration in steam (v/v) from 20% to 10%

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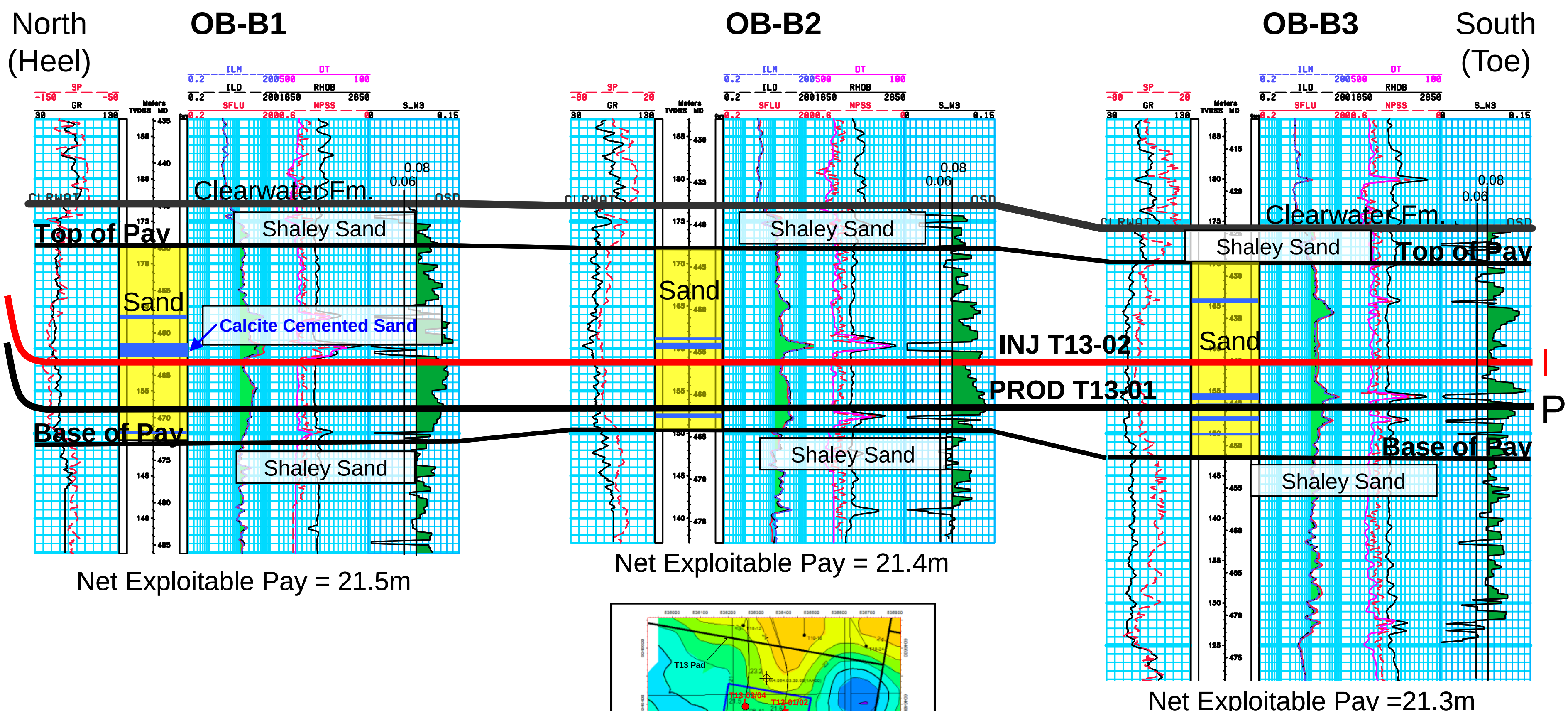
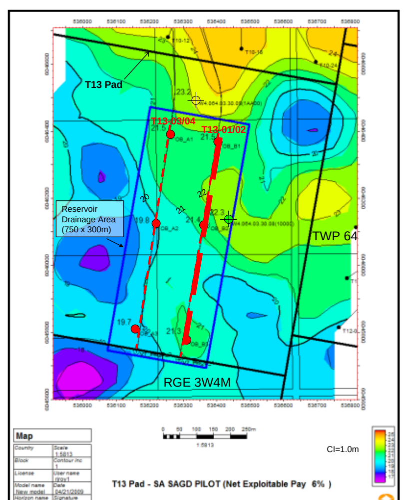
Geoscience Overview

No Update

North-South Structural Cross Section T13-01/02

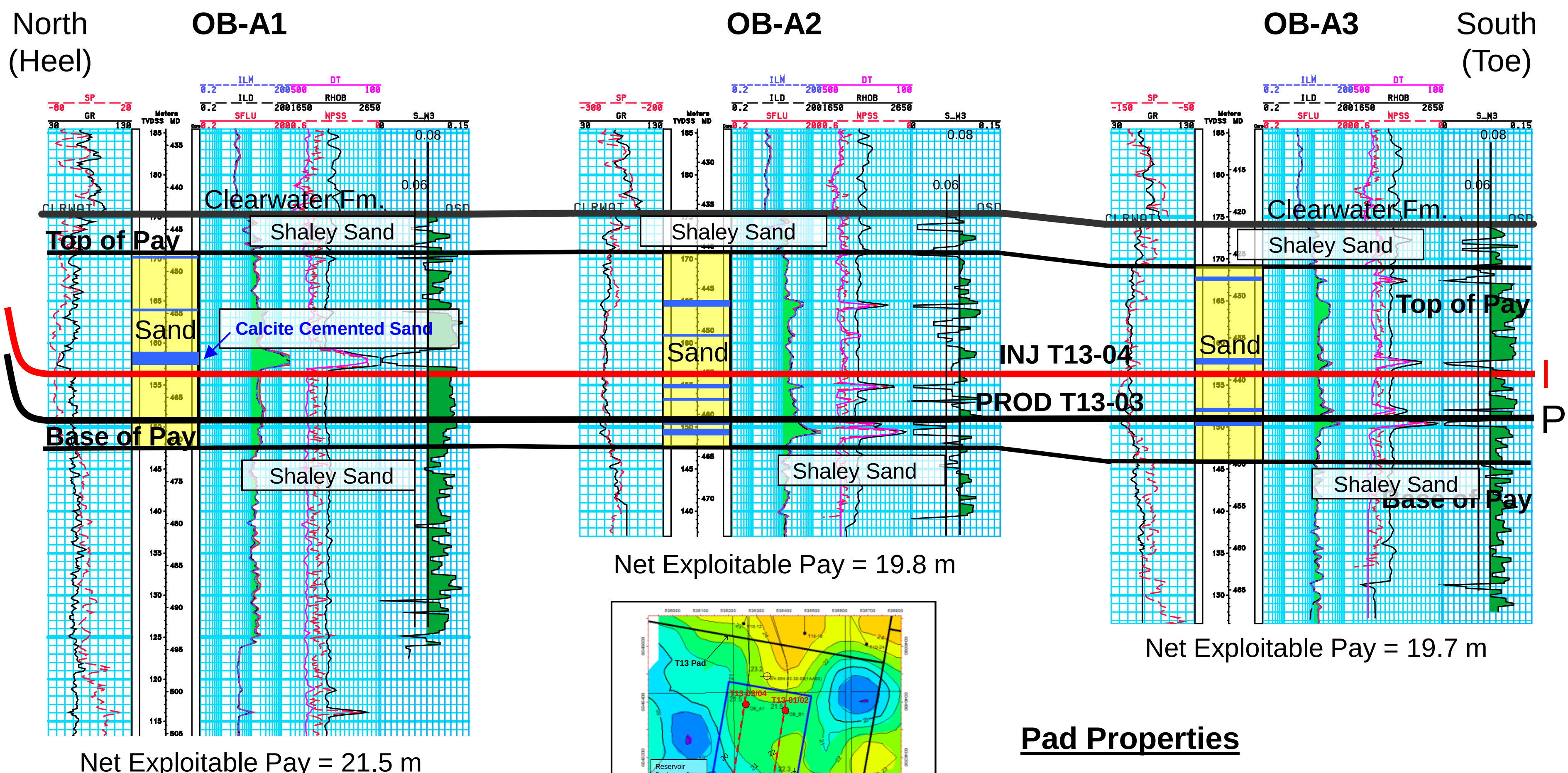


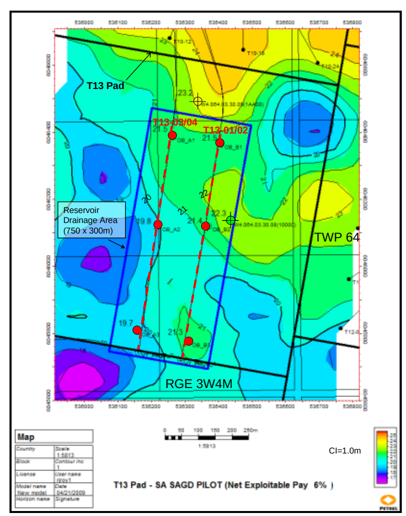


Note: Net Exploitable Pay (6 wt% bitumen cut-off)

No Update

North-South Structural Cross Section T13-03/04





Note: Net Exploitable Pay (6 wt% bitumen cut-off)

Pad Properties

- Effective OBIP for pad = 1062 E^3m^3 (using an 8 wt% cut-off)
- Average bitumen saturation = 70%
- Average porosity = 30%

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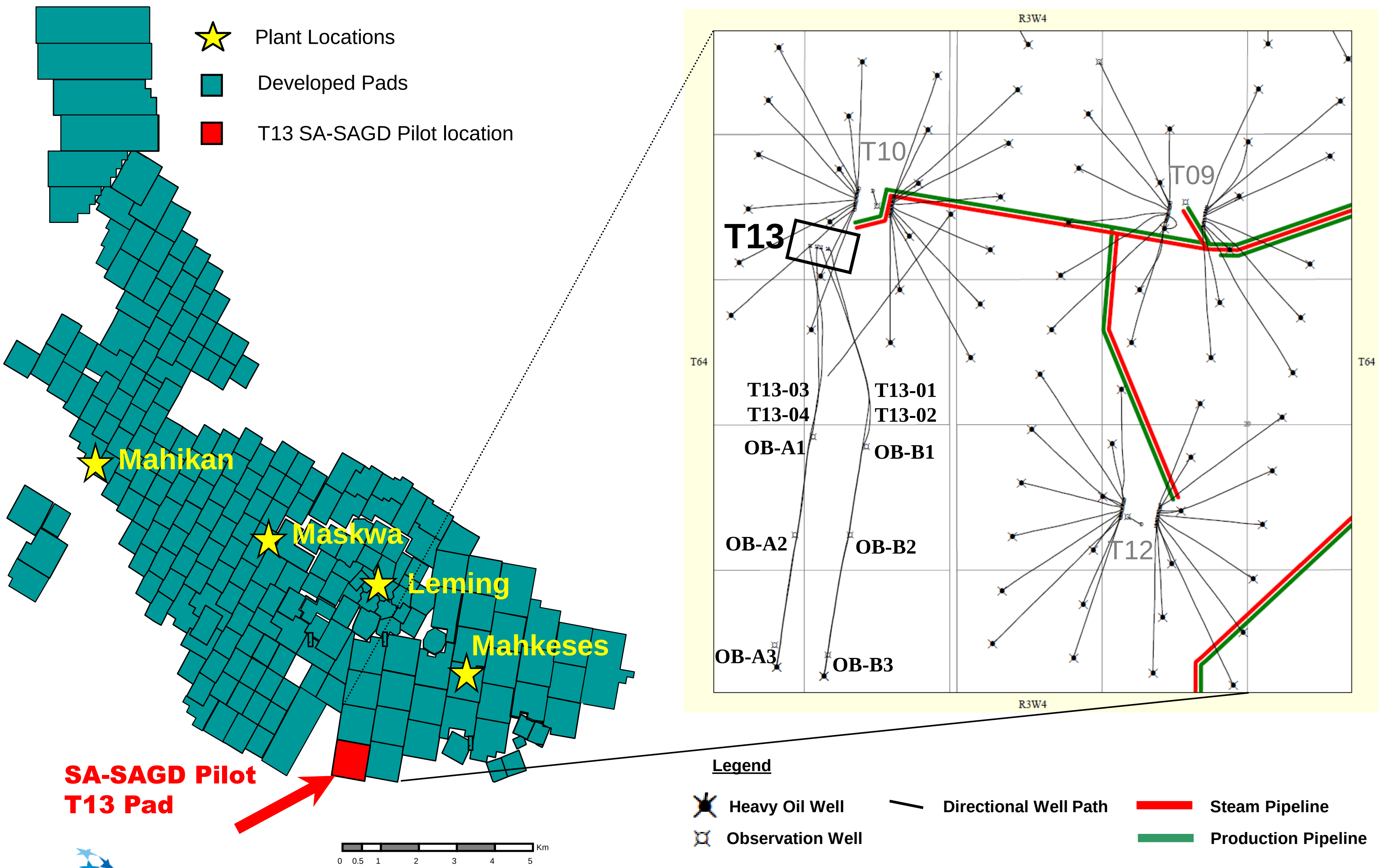
No Update

Drilling & Completions (including instrumentation)

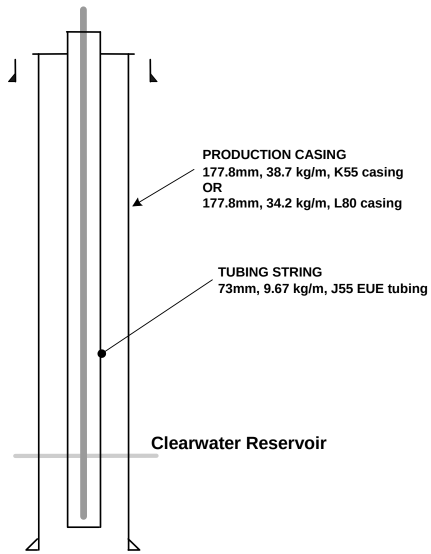
Well Layout

No Update

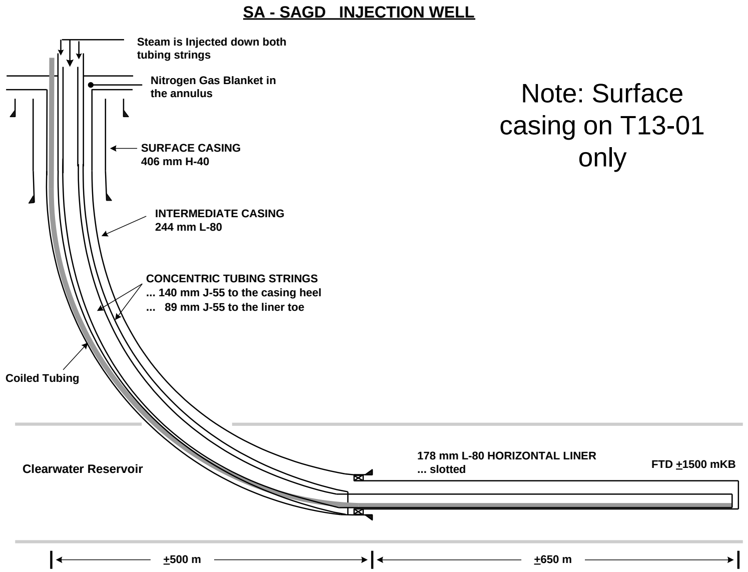


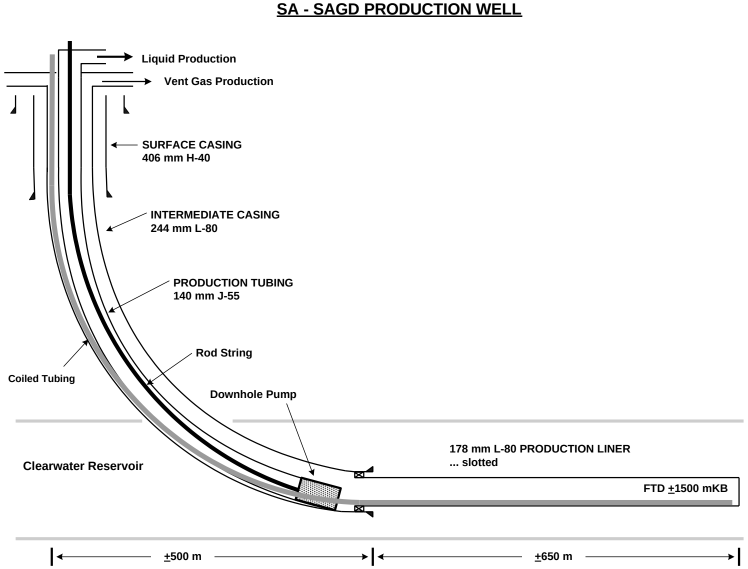
Well Schematics (SAGD / SA-SAGD Mode)

- Injection wells configured with:
  - Horizontal slotted liner
  - Toe / heel tubing string (steam injection)
  - Intermediate casing (filled with N_2)
- Production wells configured with:
  - Horizontal slotted liner
  - Downhole pump at heel of well
  - Production tubing for fluids
  - Intermediate casing for gas production
- Instrumentation in wells include:
  - 3 bubble tubes & 20 thermocouples in producers
  - 12 thermocouples in injectors
  - Between 27 and 34 thermocouples in OB wells



Note: Surface casing on T13-01 only





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Artificial Lift

Artificial Lift

No Update

- Rod pumps utilized on producer wells
- Operating conditions
  - Pumping temperature 75-220 ºC
  - Pump intake pressure 6 MPa to less than 500 kPa
  - Run life of rod pumps is exceeding the expected run life of 300-400 days

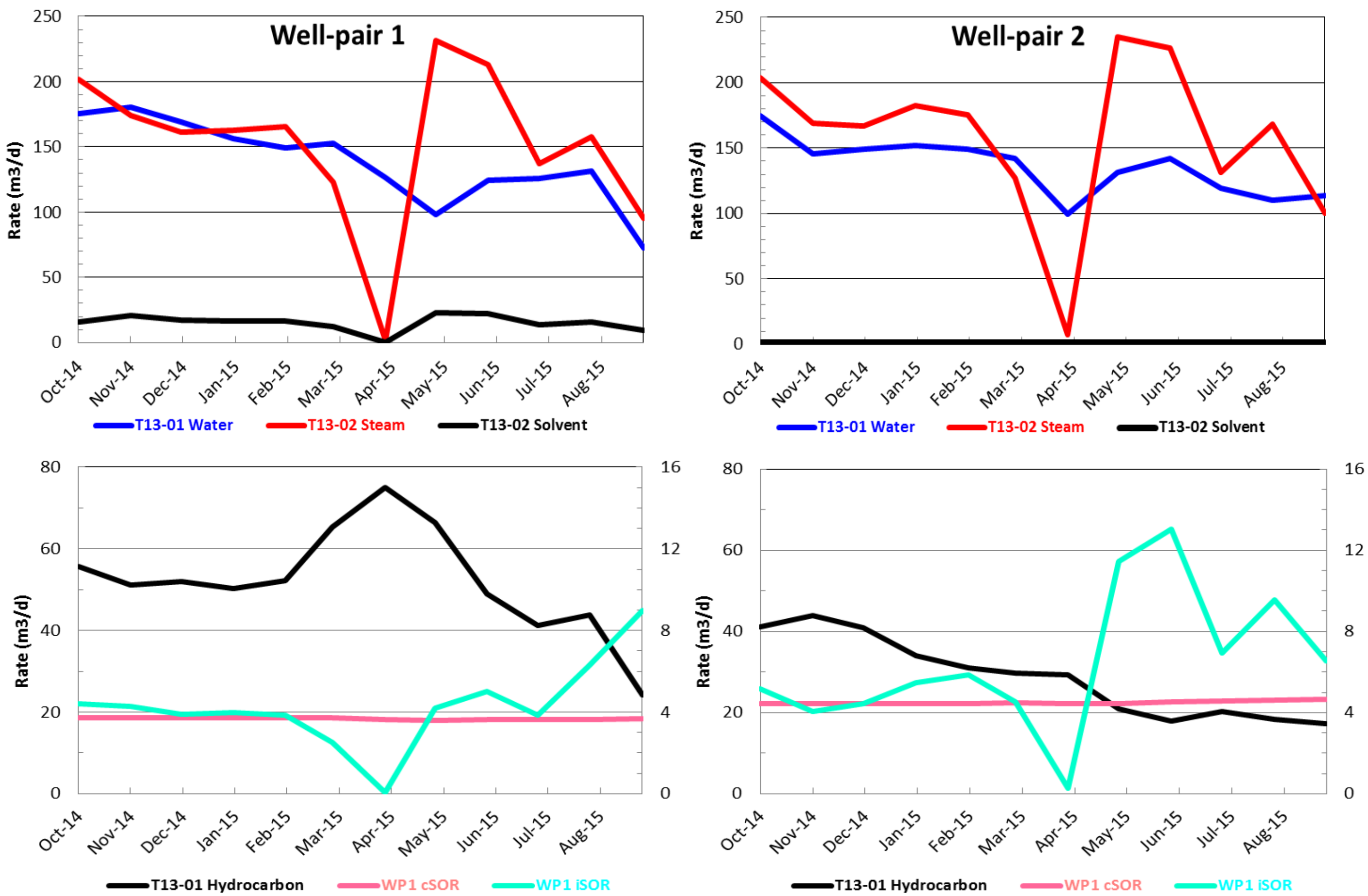
Pumpjack	Bottomhole Pump	Speed	Design Rate
1280	**95.3 mm**	**4 SPM**	**210 m^3/d**
		7 SPM	**370 m^3/d**
		10 SPM	**530 m^3/d**

Scheme Performance

T13 Pilot Events

- Oct 10, 2014 – reduced WP1 diluent injection concentration in steam (v/v) from 20% to 10%
- Oct 29 – 31, 2014 – casing integrity check on both well-pair 1 and well-pair 2
- Mar 8 – 10, 2015 – replaced pump on well-pair 1
- Mar 23 – Apr 29, 2015 - Plant slowdown (no injection), reduced production
- Sep 18 – Sep 30, 2015 – Well perforation work-over at well-pair 1 to remove skin buildup on producer

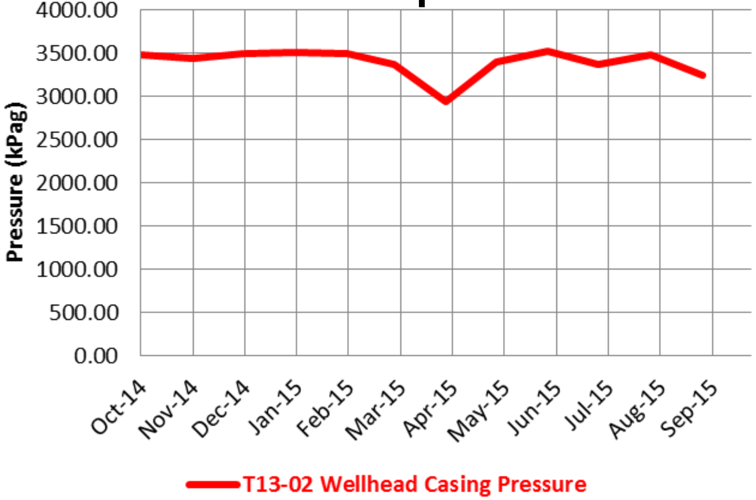
Injection / Production History

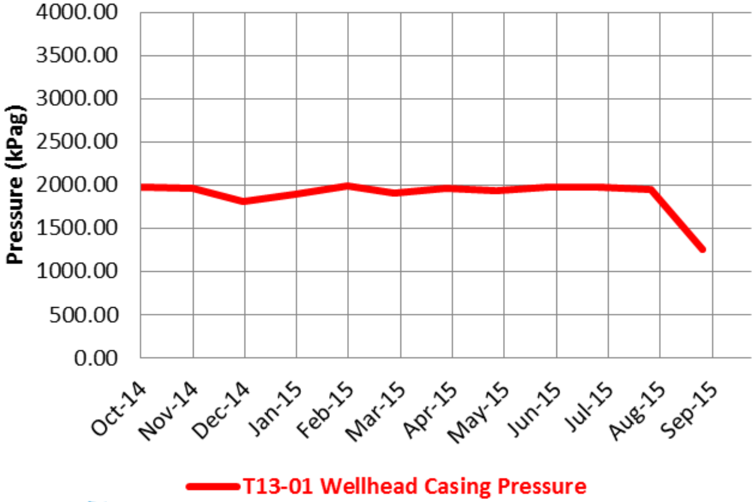


Pressure History

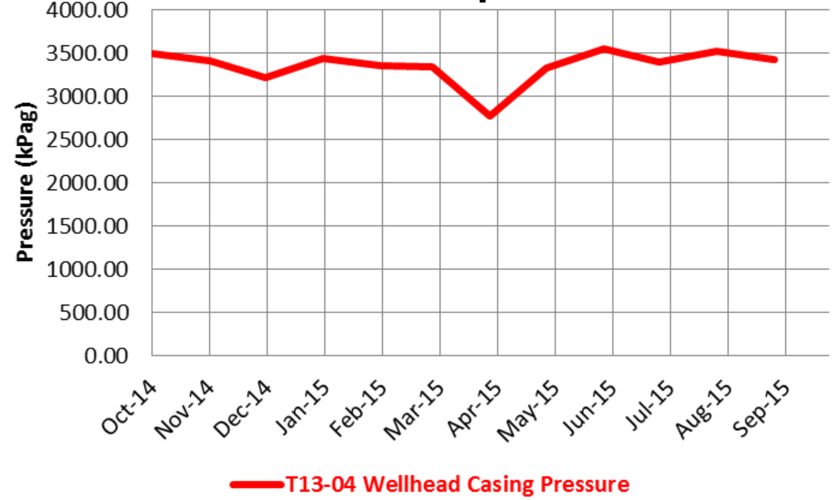
- Injection pressure close to reservoir pressure is being targeted, with corresponding production pressures of roughly 2000 kPag seen on producers (production pressure at T13-01 reduced due to skin in late Q3 2015).

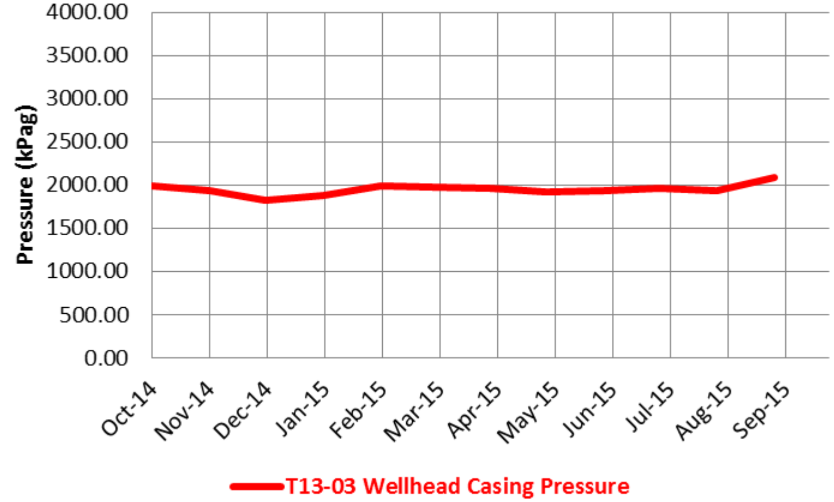
Well-pair 1





Well-pair 2





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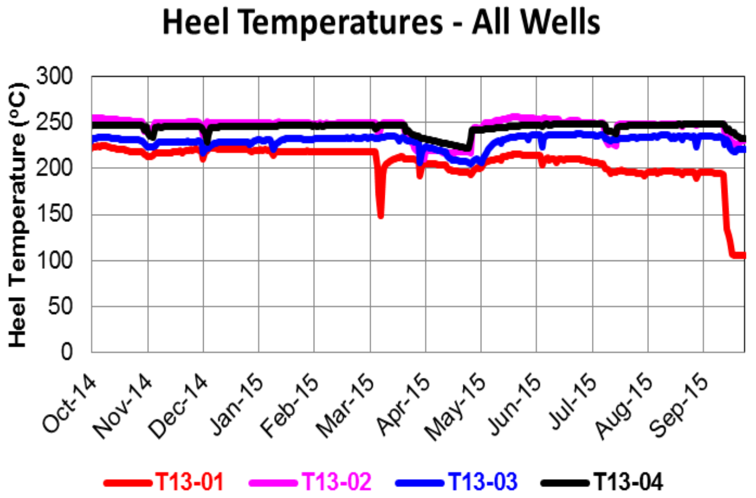
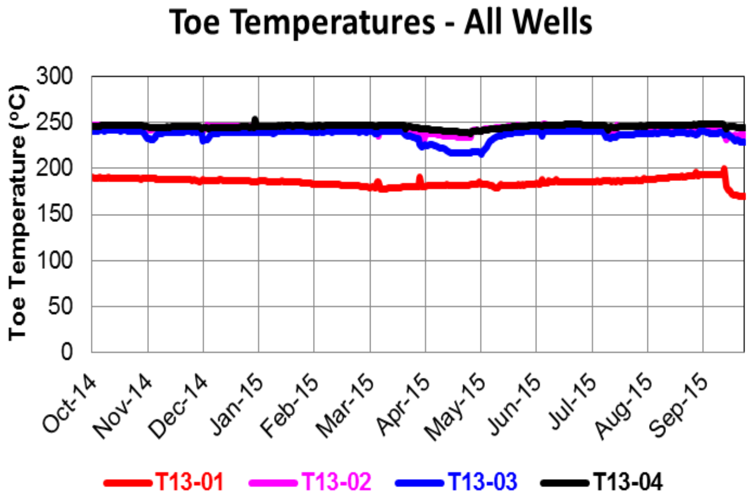
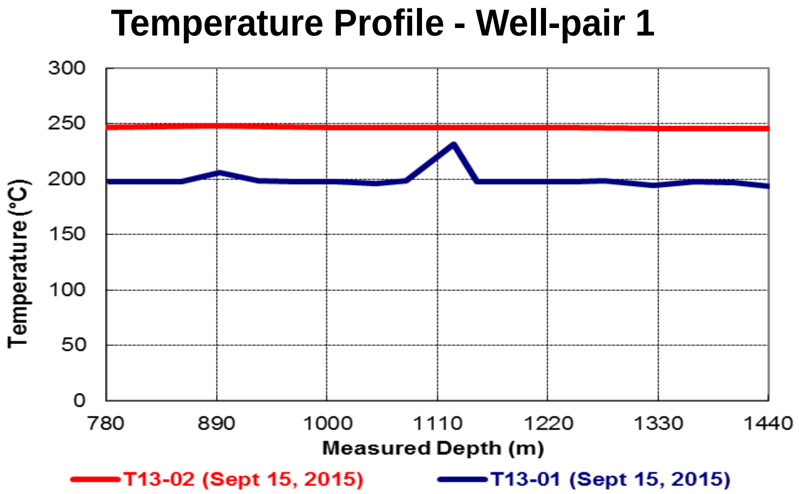
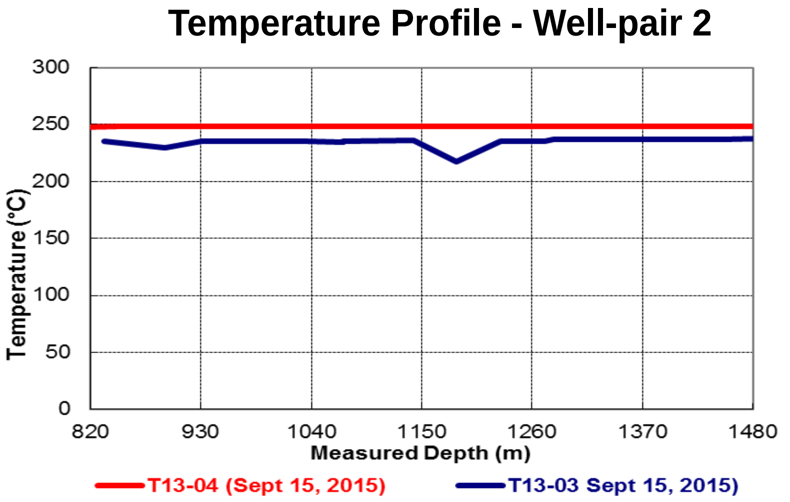
Temperature History

- Steam injected at saturated steam conditions, with steam quality downhole expected to be 90%+









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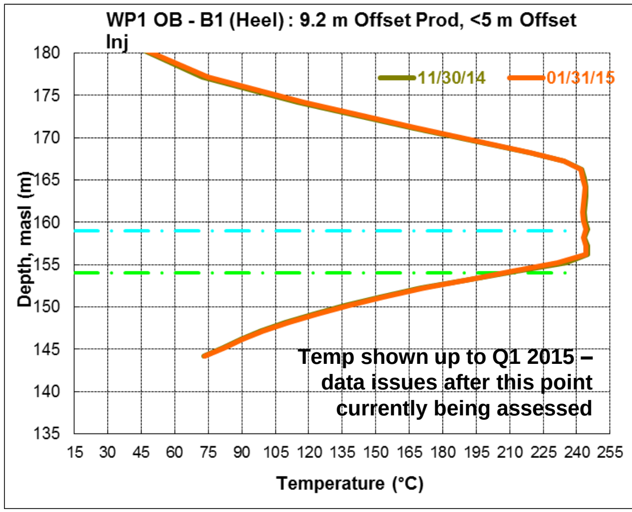
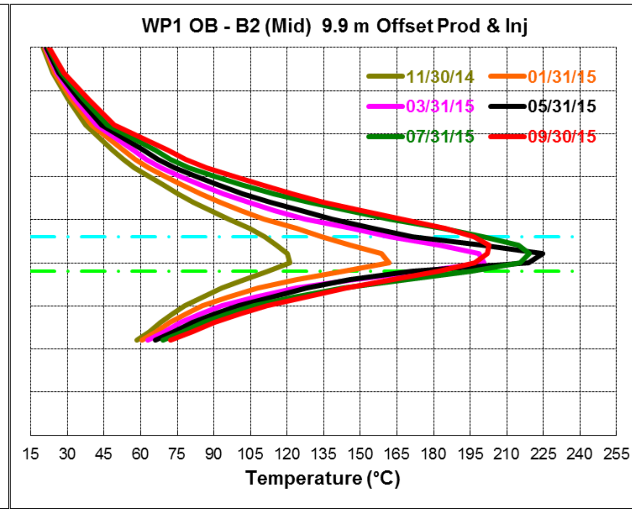
Observation Well Temperatures

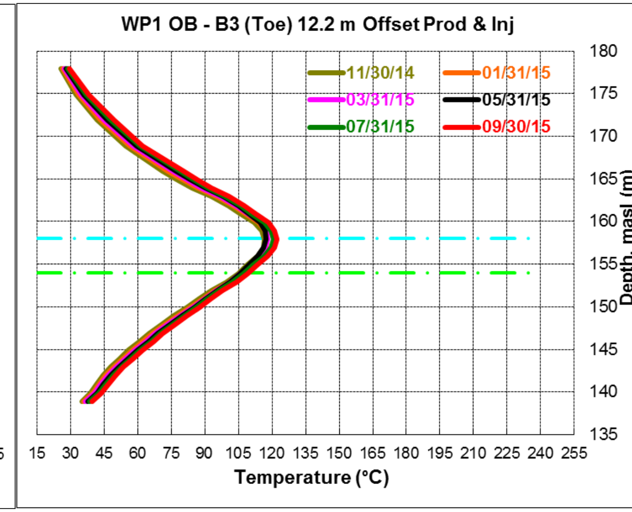
- Temperature at observation (OB) wells provides a measure of amount of heat transferred to reservoir
- All OB wells adjacent to well-pair 2 at steam temperature, as well as OB-B1 (heel, well-pair 1)

Injector
Producer

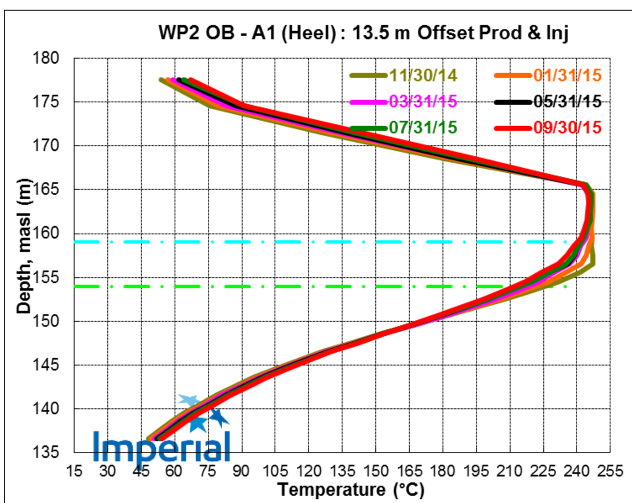
OB Wells Adjacent to WP1

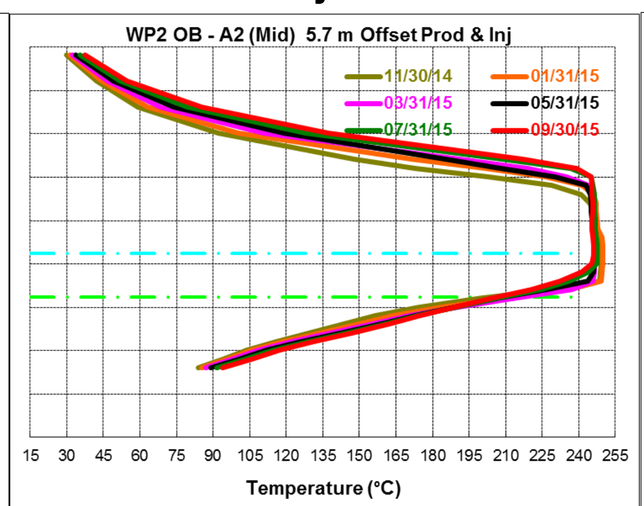


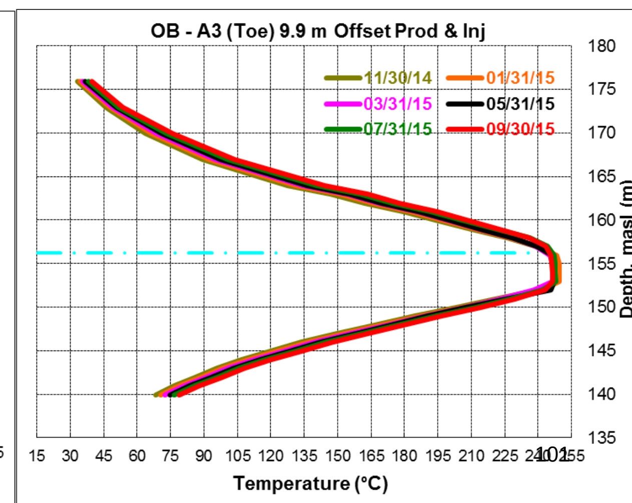




OB Wells Adjacent to WP2







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Cumulative Reservoir Volumes

- Recovery to date:

	Oil Production to Date (km3)	OBIP (km3)	Recovery to Date (%)	Expected Recovery (%)
T13	136	1062	13	40-50

- Solvent recovery: well pair 1 ~ 65%; well pair 2 ~ 86% (+4 % in last year)
- Solvent concentration reduction results in line with expectations

Forward Plans

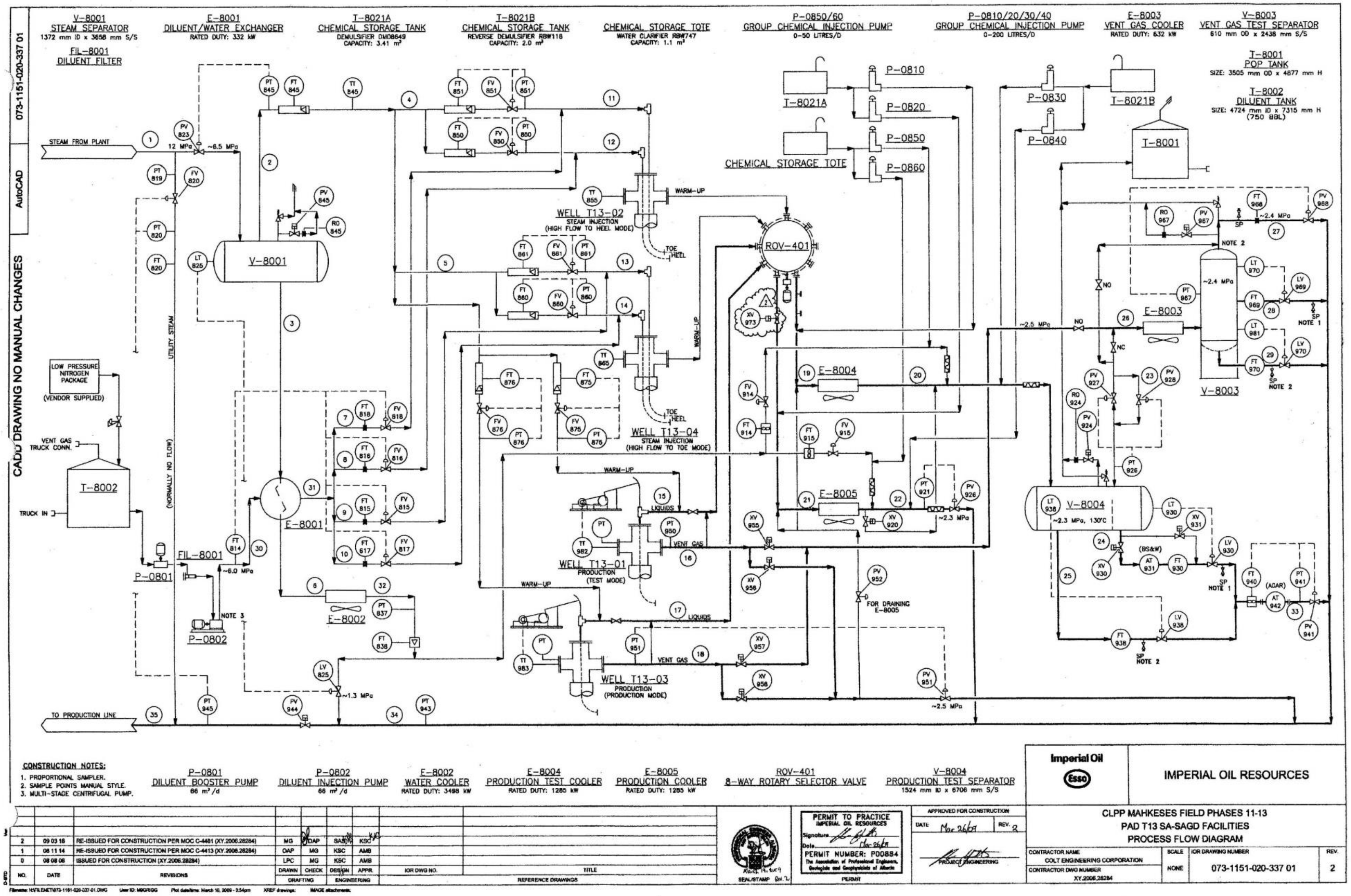
- Complete well-pair 1 perforation job (estimated by end of Oct); resume steady state production on both well-pairs
- Q1 2016 – solvent switch, converting well-pair 1 to SAGD and well-pair 2 to SA-SAGD
- Plan to extend pilot activities in 2017-18 timeframe to continue solvent concentration optimization efforts, as well as to evaluate operating strategy enhancements
  - Current pilot approval expires YE2016

No Update

Facilities

Process Flow Diagram

No Update



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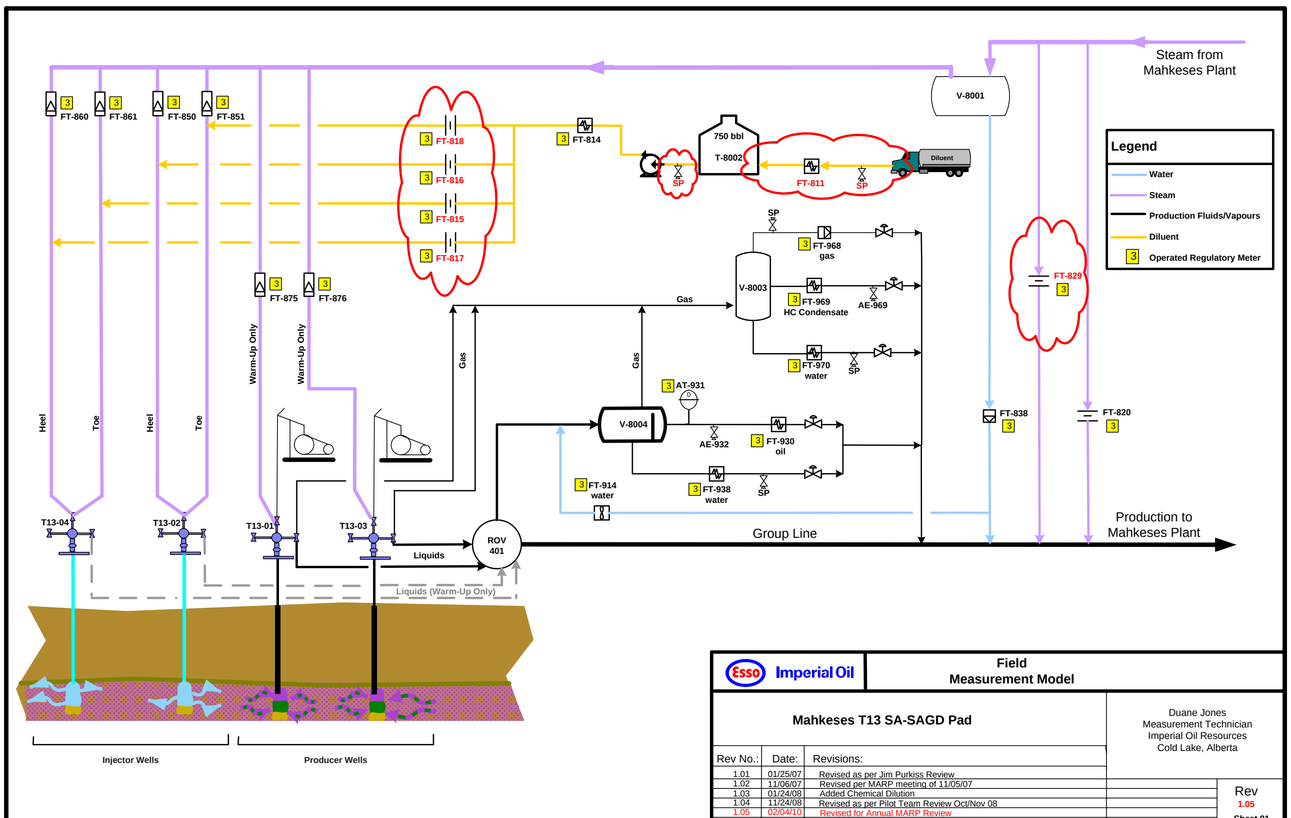
No Update

Measurement & Reporting

Measurement & Reporting

No Update

- Measurement, Accounting, and Reporting Plan (MARP) for the SA-SAGD pilot updated and submitted in February 2015
- No compliance issues to report
  - All metering / tanks have been calibrated according to frequency specified in the MARP
- MARP will be updated on, or prior to, February 28, 2016



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Environmental Summary / AER Compliance / Future Plans

No Update

Environmental Summary / AER Compliance

- No environmental issues in reporting period
- Scheme approval granted (10689D) on September 25, 2013 for continued experimental status (non-confidential basis) until December 31, 2016

Future Plans

- No changes to the pad facility or recovery scheme are planned

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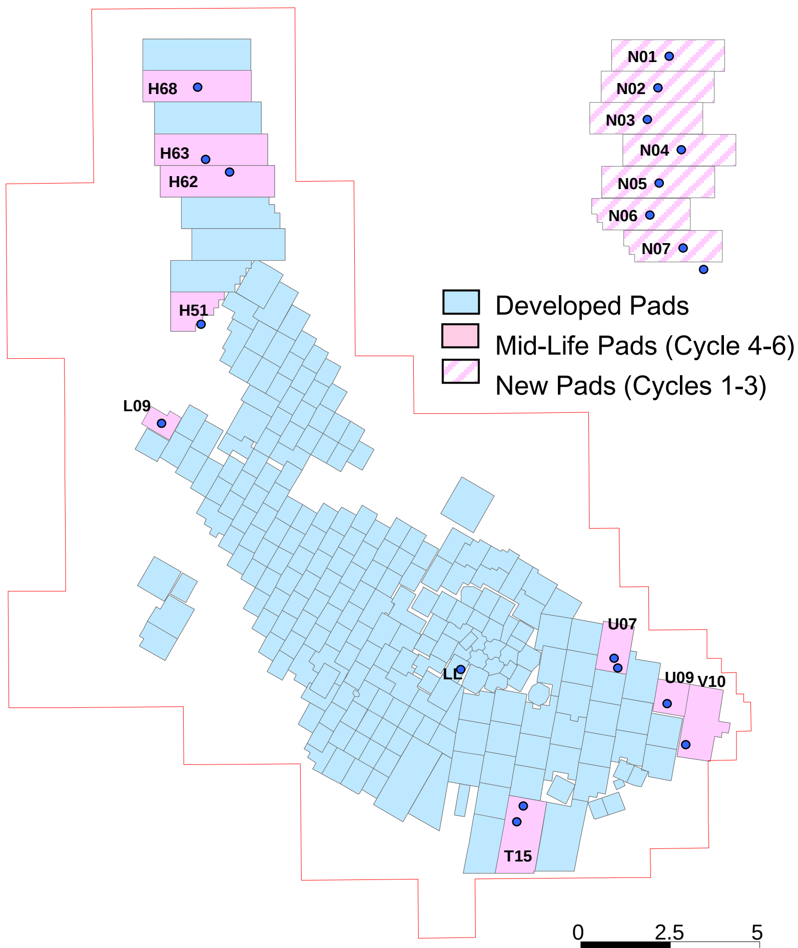
Other Discussion Items

Grand Rapids Monitoring Program

- Investigate interzonal communication between the Grand Rapids and the Clearwater

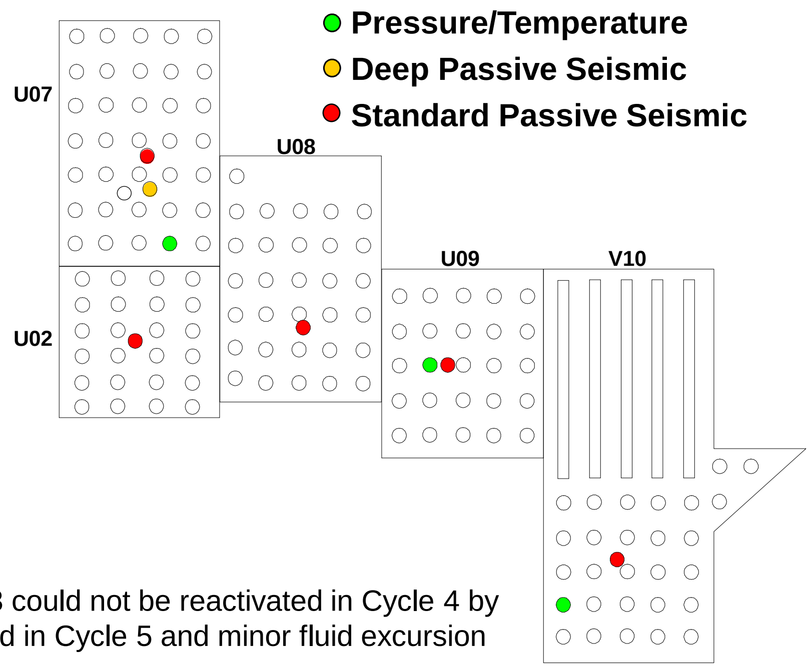


Pad	Basis	Results
U07	Upper Grand Rapids Pressure	Only poro-elastic response observed in Cycle 5 Minor fluid excursion was detected in Cycle 6
U09	Lower Grand Rapids Pressure	Cycle 6 pressure response was diminished from Cycle 5 Minor fluid excursion was detected in Cycle 7
V10	Poor primary cement bond log	Only poro-elastic response observed in Cycle 6
T15	Potential cement channels	Only poro-elastic response observed in Cycle 5
LL	Unsuccessful abandonment of adjacent OV well	No evidence of fluid transfer from CW to LGR
L09	Control pad	Only poro-elastic response observed in all cycles
H51	Possible ghost hole in the Grand Rapids	Only poro-elastic response observed in Cycle 6
H62	Poor primary cement bond log	Only poro-elastic response observed in all cycles
H63	Poor primary cement bond log	Only poro-elastic response observed in all cycles
H68	Control pad	Only poro-elastic response observed in Cycle 4 Only poro-elastic response observed in Cycle 5
N01	Lower & Upper Grand Rapids Pressure	Fluid excursion was detected in Cycle 1 & 2. Technical analysis work underway.
N02	Lower & Upper Grand Rapids Pressure	Fluid excursion was detected in Cycle 1. Technical analysis work underway.
N03	Lower & Upper Grand Rapids Pressure	Fluid excursion was detected in Cycle 1. Technical analysis work underway.
N04	Lower & Upper Grand Rapids Pressure	Fluid excursion was detected in Cycle 1. Technical analysis work underway. No confirmed fluid excursions in Cycle 2
N05	Lower & Upper Grand Rapids Pressure	Only poro-elastic response observed in all cycles
N06	Lower Grand Rapids Pressure	Only poro-elastic response observed in all cycles
N07	Lower & Upper Grand Rapids Pressure	Only poro-elastic response observed in Cycle 1.

U/V Trunk Grand Rapids Monitoring

Objective

- Monitor specific pads on U/V Trunks for potential fluid excursion into Grand Rapids. If excursion exists, identify sources, pathways, volumes, notify AER and take steps to prevent fluid excursion in the next cycle.



Grand Rapids Monitoring Program

- All Pads:
  - Standard Passive Seismic
  - Steam injection rates and pressures
  - Post-steam temperature logs
- U07: One pres/temp monitoring well in LGR and two pres/temp monitoring wells in UGR, and one Deep Passive Seismic to monitor the Grand Rapids
- U09: One pressure/temperature monitoring well in the LGR and Clearwater
- V10: One pressure/temperature monitoring well in the LGR and Clearwater

Observations

- Pressure responses into the LGR and UGR observed at U07 in Cycle 2 and 3 could not be reactivated in Cycle 4 by selective steaming of most likely source wells. Poro-elastic response observed in Cycle 5 and minor fluid excursion observed at well U07-20 in Cycle 6 under Cold Lake steaming best practices.
- Pressure responses in the Grand Rapids at V10 diminished with cycle

Conclusions

- Pathways from the Clearwater to Grand Rapids generally healed after early cycles due to either:
  - Plugging of the conduit with bitumen
  - Stress state changes to favour horizontal fracturing
- High pressures in UGR bitumen zones can be highly localized

Plans

- Steam all pads with high overlap strategy per Cold Lake best practices
- Continue monitoring the pressure response in the Grand Rapids
- Implement CI check on U07-20 prior to Cycle 7 steaming and, if failed at the CW top, steam at sub-frac pressures

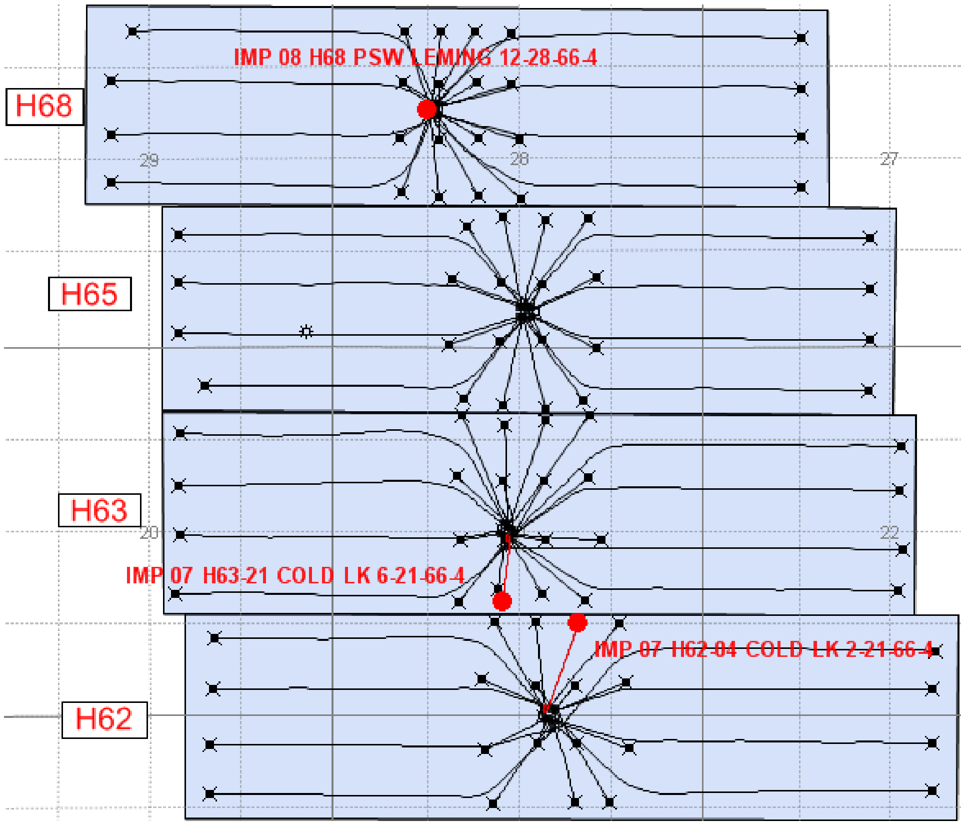
Upper H-Trunk Grand Rapids Monitoring

Objective

- Monitor Grand Rapids pressures for potential uphole fluid excursions (cement channel concerns)

Monitoring Program

- H62-04, H63-12 and H63-21
  - Pads monitored due to cement integrity concerns
  - H62-04: Completed in Lower Grand Rapids and Clearwater
  - H63-H12: Converted back to a CSS well in 2014
  - H63-21: Completed in Lower Grand Rapids
- H68 Hybrid Passive Seismic Well (HPSW)
  - Pad selected as "control" pad, i.e. no prior wellbore integrity issues
  - Installed to provide passive seismic data and Lower Grand Rapids pressures



Observations

- H62 – Only poro-elastic responses observed during steaming
- H63 – Only Poro-elastic responses observed during steaming
- H68 – Only Poro-elastic responses observed during steaming Cycle 5

Conclusions

- Possible excursion identified at H68 in Cycle 3 (2013) – No fluid excursion identified in Cycle 4 or Cycle 5

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Nabiye Grand Rapid Monitoring

Objective

- Monitor Grand Rapids pressures for potential uphole fluid excursions

Monitoring Program

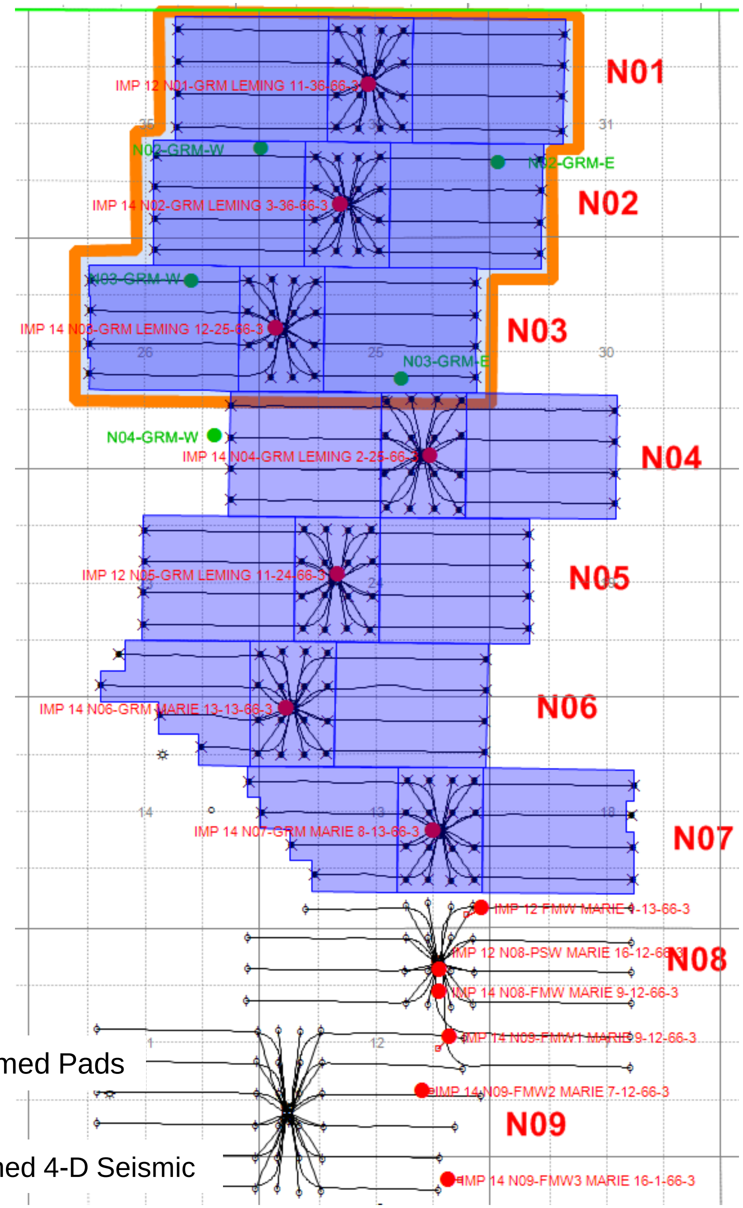
- N01-N07
  - N01-GRM: Completed in Lower and Upper Grand Rapids
  - N02-GRM: Completed in Lower and Upper Grand Rapids
  - N03-GRM: Completed in Lower and Upper Grand Rapids
  - N04-GRM: Completed in Lower and Upper Grand Rapids
  - N05-GRM: Completed in Lower and Upper Grand Rapids
  - N06-GRM: Completed in Lower Grand Rapids
  - N07-GRM: Completed in Lower Grand Rapids
  - N08-HPSW: Completed in Lower Grand Rapids
  - N09-HPSW: Completed in Lower Grand Rapids
  - N02-GRM-W: Planned completion in Lower and Upper Grand Rapids
  - N02-GRM-E: Planned completion in Lower and Upper Grand Rapids
  - N03-GRM-W: Planned completion in Lower and Upper Grand Rapids
  - N03-GRM-E: Planned completion in Lower and Upper Grand Rapids
  - N04-GRM-W: Planned completion in Lower and Upper Grand Rapids
- N07-FMW Hybrid Fault Monitoring Well
  - Well installed to monitor for fault events and pressures in the Grand Rapids
  - Installed to provide passive seismic data and mid Grand Rapids pressures
  - 4 Additional FMWs on Pads N08 and N09: Completed in Lower Grand Rapids

Observations

- N01: Fluid excursion was detected in Cycle 1 & 2. Technical analysis work underway.
- N02: Fluid excursion was detected in Cycle 1. Technical analysis work underway.
- N03: Fluid excursion was detected in Cycle 1. Technical analysis work underway.
- N04: Fluid excursion was detected in Cycle 1. Technical analysis work underway. No confirmed fluid excursions in Cycle 2
- N05: Only poro-elastic response observed in cycles 1 & 2
- N06: Only poro-elastic response observed in cycles 1 & 2
- N07: Only poro-elastic response observed in Cycle 1.

Actions

- Adjusted steam volumes
- Diagnostic steaming
- 4-D Seismic planned
- 5 Additional Grand Rapids monitoring wells planned



Steamed Pads

Planned 4-D Seismic

Planned Monitoring Wells

Investigation of BTEX in Deep Groundwater Monitoring Wells

- Investigation initiated in 2011 to identify cause for levels of benzene, toluene, ethylbenzene, or xylene (BTEX) detected in groundwater evaluation wells that exceed Canadian Drinking Water Guidelines
- BTEX may originate from the Colorado Shales or the Glacial Ill (composed of ground Colorado Shales)

Diagnostic	Purpose	Results
Continuous pressure monitoring in aquifers	Detect high-pressure excursions into the aquifers during steaming	No excursions were detected during steaming Some well failure events recorded at Nabyie without aquifer impact. Heat related anomalies (i.e. E11) under investigation.
Nitrogen soak analyses	Detect any collar leakage or casing integrity issues	No collar leakage or casing integrity issues were detected
Gas Migration and Surface Casing Vent Flow testing	Monitoring continued as per AER approval dated Sept. 17, 2013	No anomalies detected over the last year
Heating experiments of shale & till core samples	Test for presence and generation of BTEX in • shale cores • till cores	BTEX was detected in all core samples from Clearwater and Colorado Shales When heated up to 150C, low levels of naturally present BTEX detected in Colorado Shales samples. When heated to 500C, Colorado Shale and glacial till samples generated BTEX. Testing larger sample volumes at 300°C: Colorado Shale samples generated oil with BTEX content; Glacial till samples generated minor amounts of oil and dissolved BTEX in the water phase

Facilities

Facility Modifications

Nabiye Plant startup 1Q15

- Cogen facility similar in design to Mahkeses Plant
- HRSG's experienced damage due to burner design and controls; repairs completed to allow for full steam throughput 4Q15

Produced Water Cross Exchanger Upgrades at Mahihkan and Leming Plants

- Automatic flow reversal and tube pigging improves service factor of exchangers designed to preheat HLI water
- Improves energy efficiency, accelerates steam to field and reduces GHG intensity

OTSG Economizer Replacements

- Several economizers reaching end of life
- Six economizers replaced from Oct 1/14 – Sep 30/15 with more energy efficient design (0.6% - 3.2% increase in efficiency)

Electrical Distribution Network Upgrades (Collaborative Effort with ATCO)

- Several upgrades designed to improve power reliability across the district and reduce UVL
- Installed additional reclosers, lightning arrestors and bird protection devices
- Upgraded old switches and equipment nearing end of life
- Expanded preventative maintenance and surveillance programs

Facility Performance

Bitumen Treatment and Vapour Recovery

- Bitumen production remained within AER inlet licence limits over reporting period

AER Inlet Licence	Maskwa	Mahihkan	Leming	Mahkeses	Nabiye
Bitumen Licence (m^3/d)	11,000	15,000	5,000	8,000	8,000
Actual Oct/14 – Sep/15 (m^3/d monthly avg)	6,760	9,422	1,349	5,445	2,030

- Issues & Limitations
  - None
- Major Downtime
  - Mahihkan Plant 2 shutdown, 24 days, April-May 2015
  - Mahkeses GTG/HRSG's inspections, 22 days, May-Jun 2015
  - Nabiye GTG inspections/HRSG upgrades – 34 days, Aug-Sep 2015
- Major Equipment Failures
  - None
- Vapour Recovery Performance - Over 99% produced gas recovery Oct/14 to Sept/15
  - Recent activities to improve venting performance:
    - Continued use of Forward Looking Infra-red (FLIR) camera
    - Progressing action items from Stock-Tank Vapour Recovery (STVR) venting study
    - Optimizing tank PVRV settings and increased surveillance

Facility Performance

Water Treatment

- Water production remained within AER inlet licence limits over reporting period

AER Inlet Licence	Maskwa	Mahihkan	Leming	Mahkeses	Nabiye
Water Licence (m^3/d)	38,000	41,000	13,500	28,000	22,665
Actual Oct/14 – Sep/15 (m^3/d monthly avg)	29,414	34,228	8,107	18,868	4,585

- Issues & Limitations
  - Continued focus on improving treated water transfer from Maskwa & Mahkeses to Leming

- Major Downtime
  - Mahihkan Plant 2 turnaround: Apr–May 2015
  - Mahkeses GTG/HRSG inspection May-Jun 2015

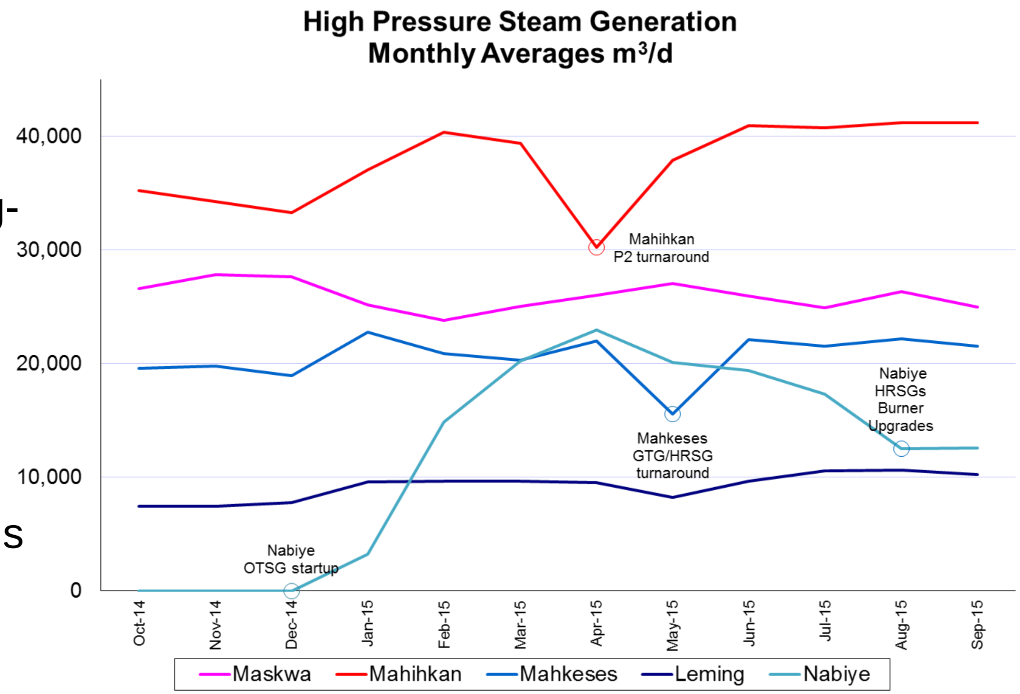
- Major Equipment Failures
  - None

Facility Performance

Steam Generation

Cold Lake District HP Steam Generation (m3/d)						
2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015 YTD**
83,524	88,967	92,132	90,386	93,445	90,361	110,959

- Nabiye steam to field January 2015
- Issues & Limitations
  - Nabiye HRSGs burner upgrades Aug-Oct 2015
- Major Downtime
  - Mahihkan Plant 2 turnaround
    - 24 days: Apr–May 2015
  - Mahkeses HRSG planned inspections
    - 22 days, May-Jun 2015
- Major Equipment Failures
  - None



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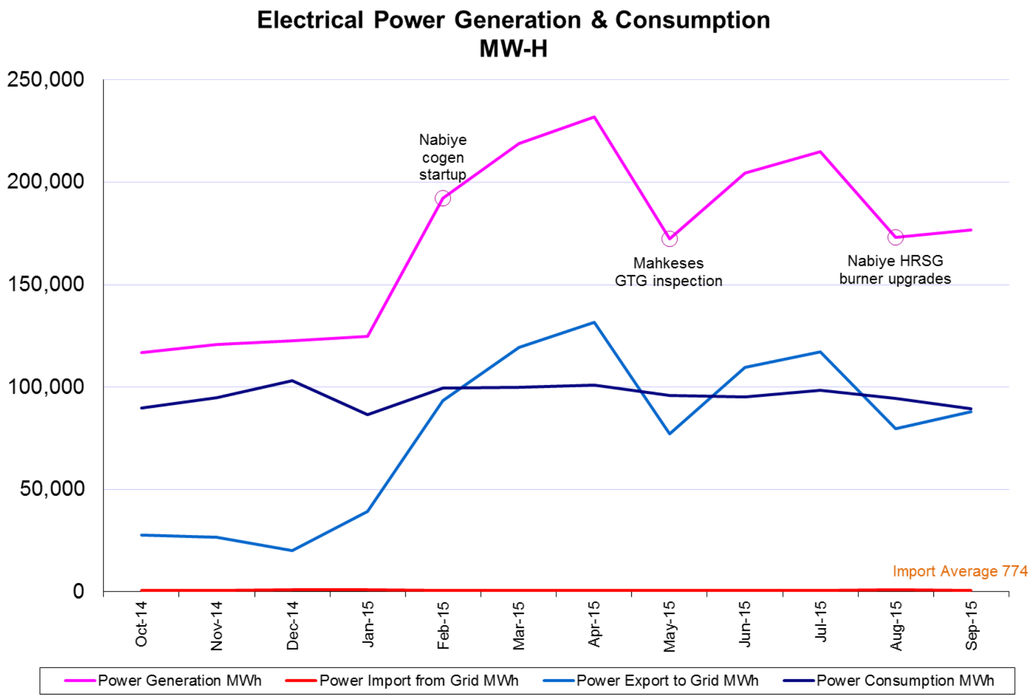
Facility Performance

Electrical Power Generation and Consumption

- Mahkeses & Nabiye Plants each have two gas turbine electrical power generators within a co-generation steam plant that generates power for the district and exports power to the Alberta power grid
- Power is imported when consumption exceeds generation and to Imperial facilities that are outside the district power grid, from the Alberta power grid
- Issues & Limitations
  - Nabiye power distribution curtailment, limiting output to ~95% of rated capacity
- Major Downtime
  - Mahkeses gas turbine generator planned inspections – 22 days, May-Jun 2015
  - Nabiye gas turbine generator, HRSG upgrades – 34 days, Aug-Sep 2015
- Major Equipment Failures
  - None



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Facility Performance

Produced Gas Management

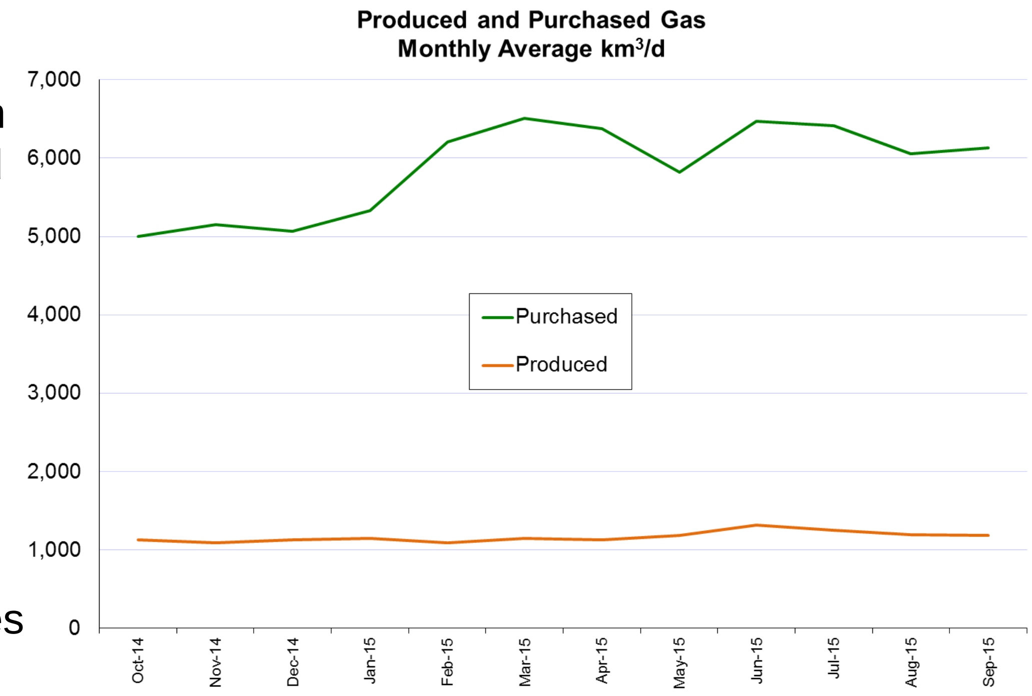
- All recovered produced gas used as fuel for high pressure steam generation

- Purchased sweet gas is used for steam generation (high and low pressure) and heater operation

- Issues and Limitations
  - None

- Major Downtime
  - As per bitumen and water summaries

- Major Equipment Failures
  - None



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Measurement and Reporting

Measurement & Reporting

- There were zero compliance issues with volume reporting for CLO in Q4 2014 & 2015 YTD
- EPAP Compliance Assessment Indicator (CAI) being reviewed in Petrinex monthly by production accounting to ensure compliance to monthly Petrinex reporting.
- Working with AER to ensure Cold Lake's Petrinex reporting aligns with DIR 081 (Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sand Schemes) / Manual 011 (How to Submit Volumetric Data) requirements.
- Currently updating schematics and allocations for Cold Lake MARP. MARP updated to included Nabiye and all follow-ups closed and submitted November 2015
- Began reporting Nabiye Facility in September 2014
- AER Site Measurement Inspection/Audit completed in July 2015 and all follow-ups closed
- Continue working closely with our AER Representatives to identify & clarify compliance to reporting for new processes (CSP).

Proration Factors

Cold Lake 2015 Profac Report

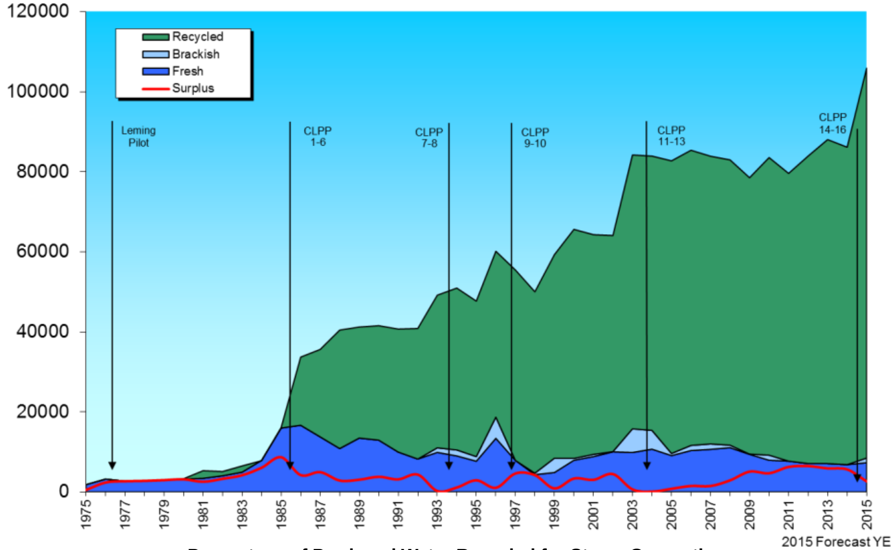
Profacs which are over Deviation Limit			2014			2015									
Battery Code (1330520)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
LEMING	OIL	0.85-1.15%	1.07	1.24	1.21	1.17	1.14	1.19	1.17	1.16	1.05	1.09	1.15	1.17	1.15
	WATER	0.85-1.15%	1.24	1.24	1.30	1.22	1.14	1.17	1.22	1.23	1.20	1.22	1.24	1.23	1.22
	GAS		1.31	1.19	1.22	1.08	0.96	0.90	0.92	0.93	0.83	1.01	1.09	1.03	1.04
			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
Leming Steam Inj IF:0007678	STEAM		1.14	0.98	0.93	0.85	0.78	0.81	0.89	0.94	0.95	0.93	0.98	1.09	1.06
Battery Code (0111783)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MAHKESES	OIL	0.85-1.15%	0.96	1.02	0.98	0.95	0.93	0.79	0.73	0.77	0.75	0.72	0.74	0.81	0.85
	WATER	0.85-1.15%	1.08	1.05	1.01	1.03	1.07	1.12	1.21	1.08	1.04	1.09	1.17	1.17	1.09
	GAS		0.96	0.98	0.99	0.92	0.88	0.76	0.68	0.71	0.73	0.72	0.72	0.80	0.82
Mahkeses Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:0111784	STEAM		1.09	1.08	1.12	1.12	1.04	1.02	0.91	0.98	0.98	0.97	1.02	0.91	1.02
Battery Code (0051211)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MASKWA	OIL	0.85-1.15%	0.99	0.93	0.96	1.02	1.03	1.04	1.04	1.02	1.03	1.05	1.00	0.96	1.01
	WATER	0.85-1.15%	1.04	1.05	1.05	1.18	1.15	1.10	1.07	1.06	1.11	1.19	1.19	1.28	1.12
	GAS		0.77	0.71	0.76	0.72	0.68	0.67	0.64	0.62	0.70	0.69	0.65	0.64	0.69
Maskwa Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:0000797	STEAM		1.00	0.98	1.02	1.04	1.09	1.03	1.02	1.02	1.00	1.04	0.99	0.93	1.01
Battery Code (00051212)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MAHIHKAN	OIL	0.85-1.15%	0.837	0.79	0.81	0.82	0.83	0.85	0.82	0.85	0.86	0.87	0.86	0.84	0.84
	WATER	0.85-1.15%	0.95	0.98	0.97	0.99	1.04	0.97	0.88	0.94	0.97	0.90	0.95	1.03	0.96
	GAS		0.88	0.87	0.94	0.66	0.60	0.63	0.65	0.69	0.73	0.68	0.66	0.64	0.72
Mahihkan Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:0008798	STEAM		1.02	1.02	0.99	0.94	1.01	1.02	1.02	1.05	1.04	1.02	1.03	1.02	1.01
Battery Code (0119087)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
NABIYE	OIL	0.85-1.15%					0.67	1.06	1.05	1.03	0.92	0.90	0.92	0.83	0.92
	WATER	0.85-1.15%					1.01	1.25	1.60	1.06	0.93	0.85	1.04	0.92	1.08
	GAS						1.00	1.54	1.51	2.39	2.48	1.40	1.36	1.42	1.64
Nabiye Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:0119086	STEAM					1.45	1.21	1.09	1.04	1.00	1.02	1.04	1.08	1.02	1.10
Battery Code (0100902)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
SA-SAGD REPORTED	OIL	0.85-1.15%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	WATER	0.85-1.15%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	GAS		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.99	1.00	1.00	1.00
SA-SAGD Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:0100903	STEAM		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
SaltWater Disposal Steam Inj			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
IF:00008036	STEAM		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Facility proration factors reviewed daily at production review meetings with Field, Plant, Well Servicing, Maintenance, Management Representatives. Monthly proration factors documented, reviewed & approved with action plans assigned & stewarded for deviations (Gas & Steam Injection proration factors are used for monitoring & stewardship vs compliance)

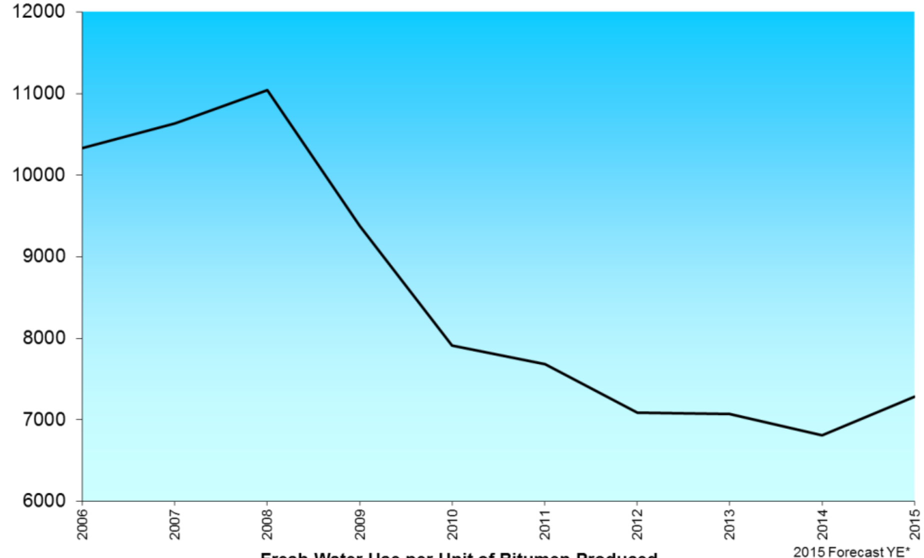
Water Sources and Use

Cold Lake Water Use

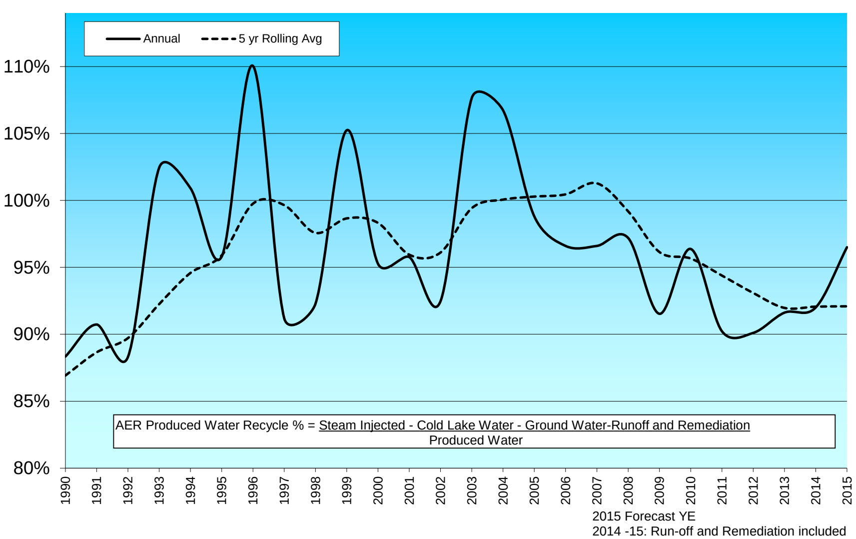
Historical Water Use for Cold Lake Operations
Volume m^3/d



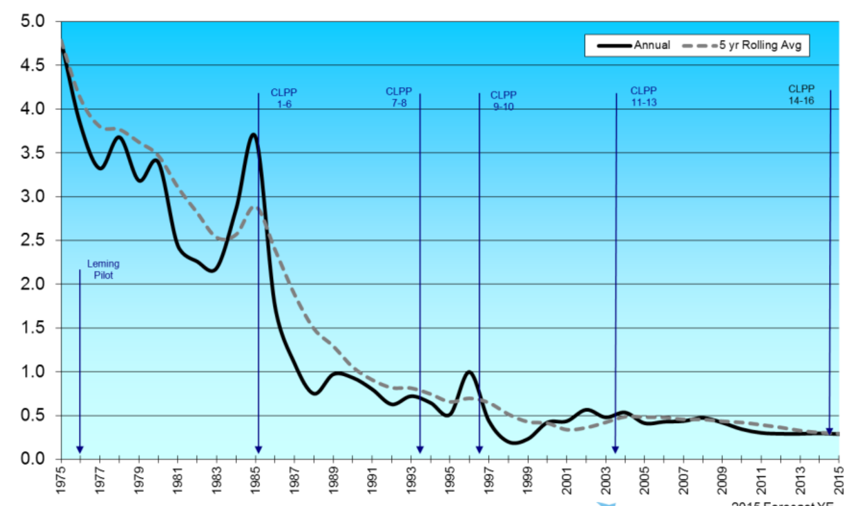
Fresh Water Use for Cold Lake Operations
m^3/d



Percentage of Produced Water Recycled for Steam Generation



Fresh Water Use per Unit of Bitumen Produced
Fresh Water m^3 / Bitumen m^3



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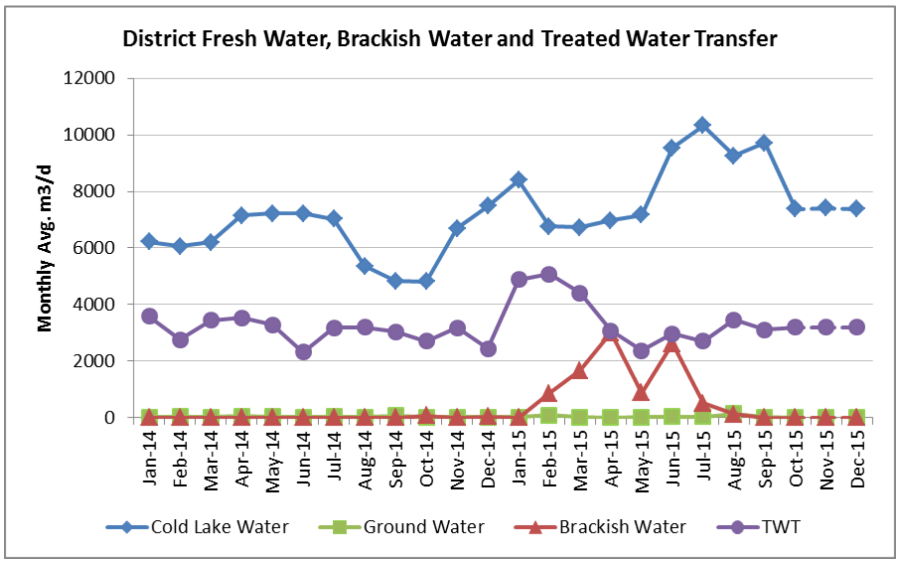
Cold Lake Water Use (cont'd)

Fresh Water Use & Produced Water Recycle

- Higher PW recycle mainly due to use of brackish water and Nabiye startup
- 2014-2015 ground water used only for Cold Lake source water system maintenance
- Increased FW usage in Jun – Aug: Leming ion exchange vessel, Maskwa HLS booster pump maintenance and Mahkeses temporary BFW tank operation
- Produced water recycle improvements:
  - Fresh water reduction initiatives
  - Increased water reuse and steam plant surveillance to improve service factor
  - Nabiye steam startup 2015, consumed excess PW from district



2014 Produced Water Recycle		
	Monthly	Cumulative
Jan	93.1%	93.1%
Feb	91.9%	92.5%
Mar	95.0%	93.4%
Apr	89.8%	92.5%
May	84.4%	90.9%
Jun	87.2%	90.4%
Jul	90.6%	90.4%
Aug	95.2%	91.1%
Sep	94.1%	91.4%
Oct	95.7%	91.9%
Nov	93.0%	92.0%
Dec	92.5%	92.0%
YE		92.0%

2015 Produced Water Recycle		
	Monthly	Cumulative
Jan	90.4%	90.4%
Feb	99.9%	95.0%
Mar	102.9%	97.8%
Apr	105.5%	99.7%
May	96.4%	99.0%
Jun	101.5%	99.4%
Jul	98.5%	99.3%
Aug	96.5%	98.9%
Sep	89.6%	97.8%
Oct*	92.1%	97.3%
Nov*	92.1%	96.9%
Dec*	92.1%	96.5%
YE*		96.5%
*Forecast		

Freshwater Reduction

- Freshwater reduction continues to be key focus area
- 2015 non-saline water consumption ~7300 m3/d (>30% reduction from 2011), continuing strong performance from 2014
- Technical assessments of alternatives ongoing in freshwater utility boilers, inlet cooling, and improved treated water transfer
- Transitioning to disposal limit formula November 2015
  - Updated surveillance tools to ensure compliance
  - Disposal volumes will be low for some time given Nabiye start-up
  - Further decrease in overall freshwater usage intensity given Nabiye low freshwater operations

Water Disposal and Waste Management

Produced Water Disposal to Cambrian – Approval 4510

Monthly Injection Volumes and Average Wellhead Injection Pressures

Monthly Injection Volumes and Average Wellhead Injection Pressures																									
		2014						2015																	
WELL	Disposal	OCTOBER		NOVEMBER		DECEMBER		JANUARY		FEBRUARY		MARCH		APRIL		MAY		JUNE		JULY		AUGUST		SEPTEMBER	
IDENTIFIER	Zone	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)	(KPA)	(m^3)
00 01 19 064 03 4 00 (SWDFT701)	Cambrian	12.5	49397.9	12.6	53,214	12.3	56,977	12.5	51,374	12.6	7,596	11.9	0	12.2	0	12.3	0	12.4	0	10.2	0	12.5	41,432	12.5	49,806
00 01 32 064 03 4 00 (SWDFT702)	Cambrian	13.1	54070.1	13.3	65,275	12.3	70,880	12.7	58,593	12.8	4,324	12.1	0	12.8	0	12.7	0	12.9	0	12.1	0	13.0	31,056	13.0	43,531
02 02 03 064 03 4 00 (SWDFT703)	Cambrian	13.0	32108.9	13.0	37,191	12.7	39,313	12.5	31,516	12.6	3,255	12.0	0	12.5	0	12.5	0	12.7	0	12.9	0	13.0	19,218	12.8	31,263
00 03 04 065 03 4 00 Abandoned	Cambrian																								
00 04 17 065 03 4 00 Abandoned	Cambrian																								
00 08 33 064 03 4 00 Abandoned	Cambrian																								
00 11 07 065 03 4 00 Abandoned	Cambrian																								
00 12 08 065 03 4 00 Abandoned	Cambrian																								
00 07 18 064 03 4 00 (SWDFT705)	Cambrian	0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
00 11 22 064 03 4 00 Abandoned	Cambrian																								
TOTAL DISPOSAL (m^3)			**135577**		**155,679**		**167,170**		**141,483**		**15,174**		**0**		**0**		**0**		**0**		**0**		**91,706**		**124,599**
DAILY AVERAGE (m^3)			**4373**		**5,189**		**5,393**		**4,564**		**542**		**0**		**0**		**0**		**0**		**0**		**2,958**		**4,153**

- Water disposal required due to high field produced water levels (high water to steam ratios)
- Efforts to improve water recycle include reduced fresh water usage, improved steam generation and water reuse service factors, and improved water inter-plant transfer capability
- 2014 disposal volume = 1.65M m^3; 2015 disposal volume = 0.44M m^3
  - Note: 2015 disposal low due to Nabiye start up

Cold Lake Waste Management

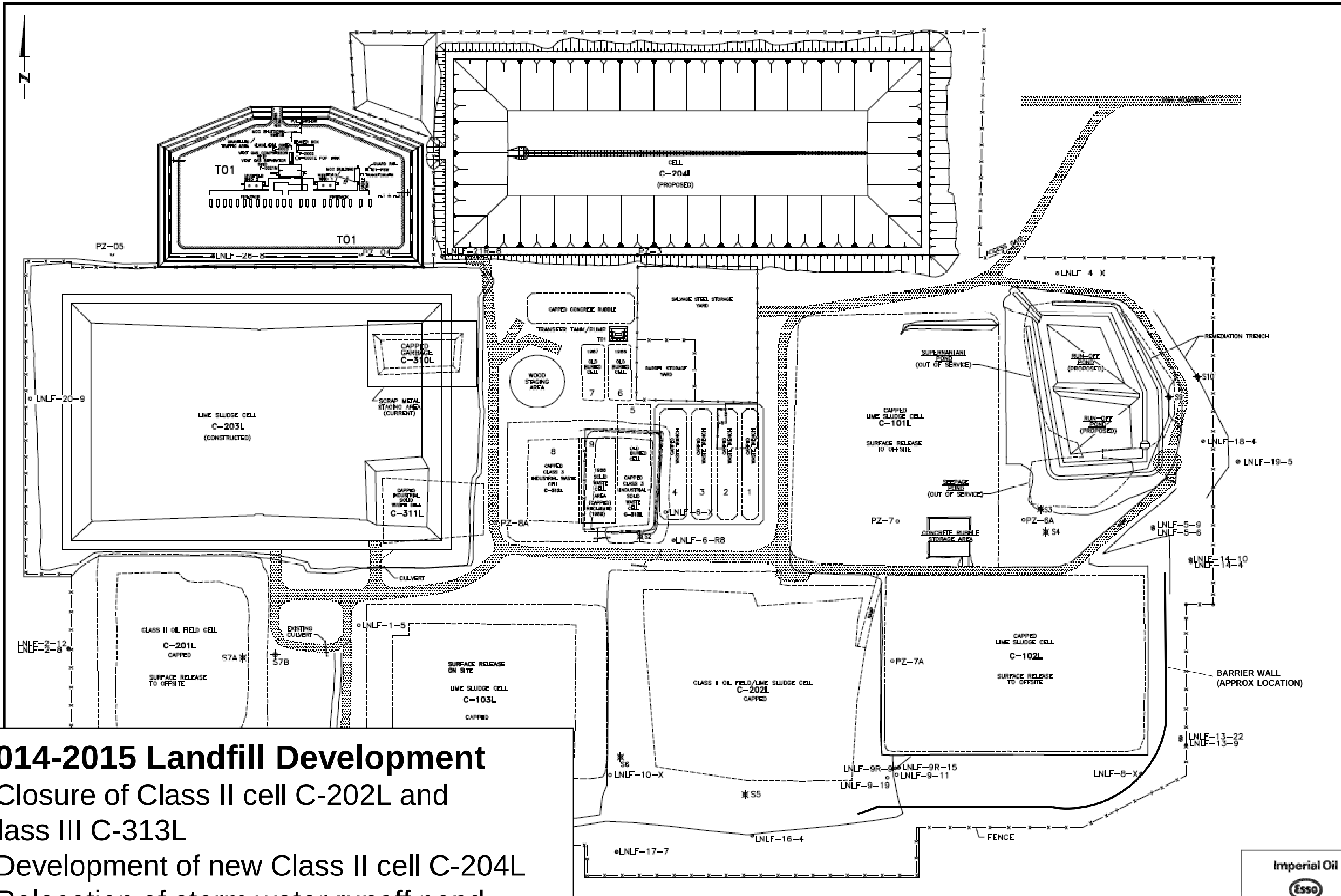
On-Site Disposal	Volumes (m^3) 2014
Class III Waste Volumes (industrial garbage)	8,970
Class II Lime Sludge	43,380*
Class II Oily Wastes (non-DOW)	23,611**
Landfill Leachate Collection and Recycle at Mahkeses Plant	27,950

** Annual volume of lime sludge disposed depends on timing of pond cleaning. Lime sludge generation does not significantly differ from year to year.*
*** Oily waste generation is dependent on amount of abandonment, reclamation, and drilling work undertaken each year*

Off-Site Disposal	2014
Solid Wastes (asbestos, batteries, oily rags, soils)	1813 m^3
Liquid Wastes (lube-oil, paint, etc.)	1775 m^3
Recycled steel	471 t

Note: Off-site disposal wastes manifested as per Directive 58 requirements

Cold Lake Waste Management



2014-2015 Landfill Development

- Closure of Class II cell C-202L and Class III C-313L
- Development of new Class II cell C-204L
- Relocation of storm water runoff pond
- Installation of bentonite barrier wall

Environmental Summary

Approval Renewals and Amendments

Approvals under the Environmental Protection and Enhancement Act (EPEA)

- Received EPEA Renewal in March 2011 (Approval No. 73534-01-00)
- Existing EPEA Approval 73534-00-04 (as amended) is cancelled
- Received EPEA amendment in May 2013 (Approval No. 73534-01-01)
- Approved EPEA amendment included the addition of a line heater, portable sulphur skids, and the condition around the operation of the SRU at Makheses, Mahihkan and Nabiye

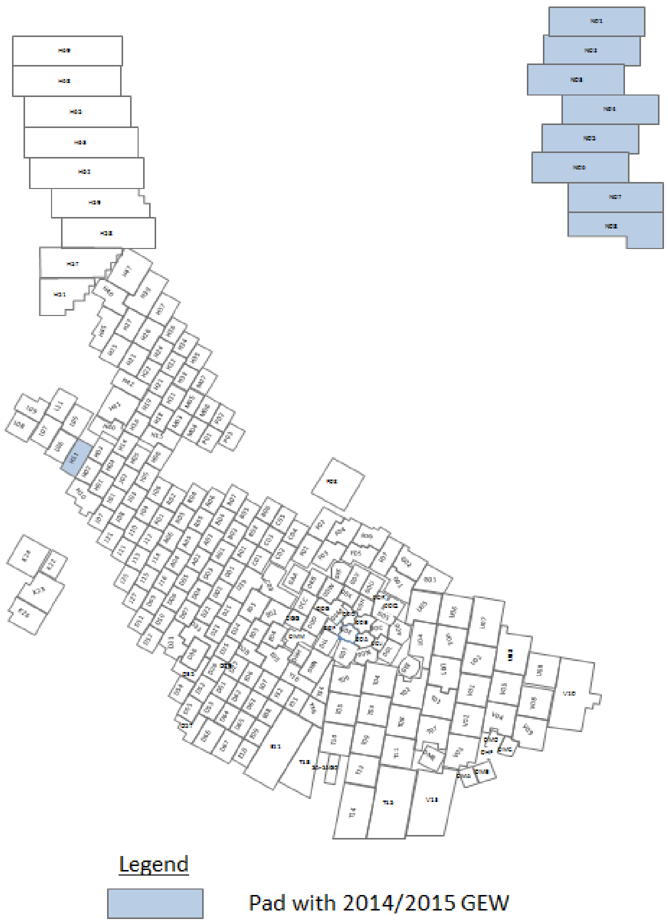
Approvals under the Water Act

- Received Cold Lake Water Act license renewal for surface water diversion in October 2011 (Approval No. 79923-01-00), expires October 2016
- Received license amendment in June 2013 which included additional details around the planned water intake
- Received Water Act license renewal for back-up groundwater wells in October 2011 (Approval No. 148301-01-00), expires October 2016

Monitoring Programs – Wildlife

- Relevant data are submitted electronically to the Fisheries and Wildlife Information System (FWMIS) and supplement existing provincial records
- Wildlife Monitoring and Mitigation Plan has been approved by the AESRD
- Caribou Mitigation and Monitoring Plan has been authorized by AESRD
- Cold Lake Operations made a financial contribution to JOSM (Joint Oil Sands Monitoring) to support a regional approach to monitoring.
- The Wildlife Habitat Council (WHC) created in 1988, is a nonprofit group of corporations, conservation organizations and individuals dedicated to enhancing and restoring wildlife habitat. WHC helps large landowners, like Imperial, manage their unused lands in an ecologically sensitive manner for the benefit of wildlife.
- In 2010, Imperial Cold Lake Operations received the Wildlife at Work Certification from the Wildlife Habitat Council for the successful implementation of a comprehensive wildlife habitat management program. Imperial achieved recertification in 2015.

Monitoring Programs – Groundwater



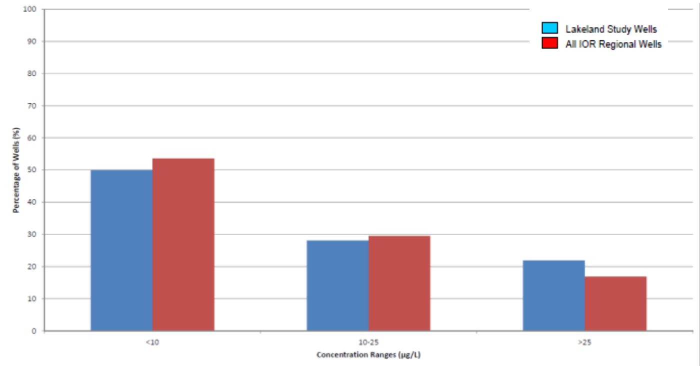
- Monitoring > 400 deep groundwater wells (incl.17 domestic) and > 220 shallow wells
- Monitoring includes chemistry & water levels

- Drilling activity in 2014/2015
  - > Productivity maintenance groundwater evaluation wells (GEW)
  - > N01-N07, N08 Planned
  - > Regional groundwater evaluation wells (REG)
  - > Nabiye Nests
  - > H11 well for VIT trial

Monitoring Programs – Thermal Mobilization

Key Regulatory Review and Stakeholder Communication Dates

Formed COSIA Thermal Mobilization Working Group	May, 2014
COSIA Thermal Mobilization Workshop	June 17, 2014
Cold Lake Operations Neighbor Night	Nov 5, 2014
Annual Performance Review with AER	Nov 25-26, 2014
Submitted 2015 AEPEA Regional Arsenic Report	Mar 31, 2015
Submitted 2015 AEPEA Technical Update Report	Mar 31, 2015
Annual Performance Review with AER	Nov 25-26, 2015



A comparison of arsenic concentrations in wells tested by Alberta Health and Wellness (Lakeland Study Wells - 2000) and wells in Imperial's Regional Groundwater Monitoring Network (IOR Regional Wells - 2015)

Technical Update

- In 2006, Health Canada lowered the maximum acceptable concentration for arsenic in drinking water from 25 µg/L to 10 µg/L.
- Using this standard, 50% of domestic wells in the Lakeland area have naturally high arsenic concentrations above guidelines. (Alberta Health and Wellness Data: Arsenic in Groundwater from Domestic Wells in Three Areas of Northern Alberta, October, 2000).
- In 2015, Imperial conducted a review of arsenic in its regional groundwater wells and reconfirmed that arsenic concentrations are similar to the AHW (2000) study and do not display increasing trends over time. Imperial completed this study as part of its 2015 Deep Groundwater Report to AER.
- Imperial continues to monitor thermally mobilized arsenic at D55, D57, and L08 pads.
- Field observations confirm that heat convection cells play a significant role in the release and transport of arsenic when the GW velocity is low.
- Laboratory experiments indicate that arsenic released by conductive heating is re-adsorbed when the GW is exposed to unheated sediments.
- Field study results to date indicate that peak arsenic concentrations and arsenic mass at D55 and D57 pads have declined as the arsenic plumes migrate down gradient. The average velocity of the dissolved arsenic is retarded relative to GW flow velocity. These observations are an indication that arsenic attenuates as it moves downgradient.
- Additional downgradient monitoring wells are positioned to measure the rate and extent of attenuation. These are key objectives of ongoing work.
- Imperial submitted a 2015 technical update to AER and has an AEPEA requirement to complete an additional technical update report in 2020.
- Imperial has an extensive groundwater monitoring program to aid in the detection of mobilized arsenic. Based on groundwater monitoring to date, there is no evidence that any released arsenic has impacted domestic or livestock groundwater wells.

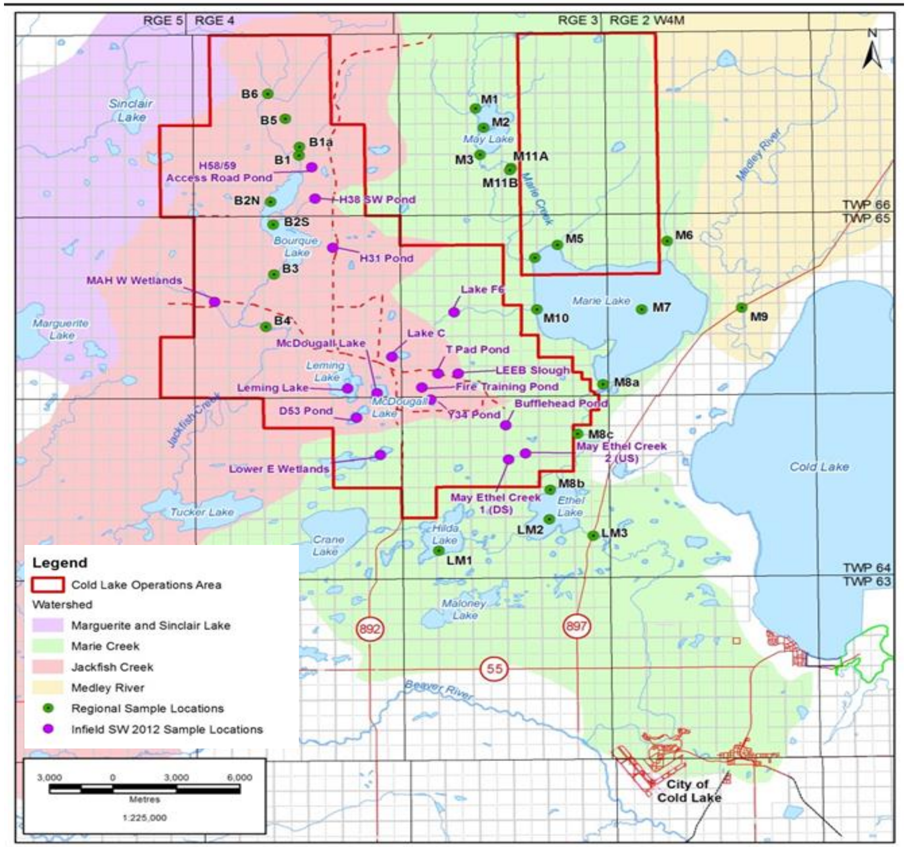
Monitoring Programs – Surface Water

Comprises the following components:

- Surface Water Quality Sampling (Regional, Infield, Wetlands)
- Annual Drainage Assessment
- Level Monitoring (Lake, creeks, wetland piezometers)
- Long-term Wetland Monitoring Plots

Monitoring Programs – Surface Water

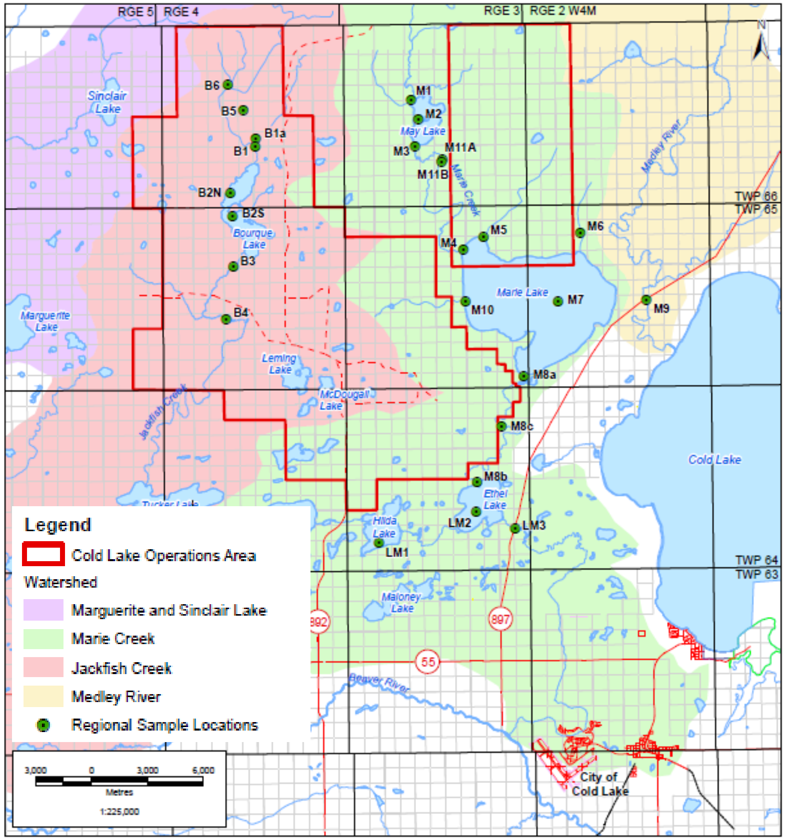
- Spring and fall sampling of water bodies (routine water quality parameters (pH, alkalinity, hardness, etc), major cations and anions, forms of nitrogen, phosphorous, hydrocarbons, and trace elements)
- Flow measurements at selected creek sites
- Depth composite samples from canoe for both regional and infield lakes where depths are greater than 2 meters



Monitoring Programs - Surface Water Regional

- Regional program included spring and fall sampling at 25 sites.
- Data from this program is shared with Beaver River Watershed Association (BRWA), Alberta Lake Management Society (ALMS), Marie Lake Air and Watershed Society (MLAWS), as well as some landowners.
- Includes sites within the Jackfish Creek, Marie Creek, & Medley River Watersheds.

Regional Program		
B1	Unnamed Creek upstream of Bourque Lake	Stream
B1a	Unnamed Creek upsteam of B1	Stream
B2-N	Bourque Lake (North Basin)	Lake
B2-S	Bourque Lake (South Basin)	Lake
B3	Jackfish Creek downstream of Bourque Lake	Stream
B4	Jackfish Creek downstream of Mahihkan Plant	Stream
B5	Unnamed Tributary #4	Stream
B6	Unnamed Tributary #5	Stream
LM1	Hilda Lake	Lake
LM2	Ethel Lake	Lake
LM3	Marie Creek downstream at Hwy 897	Stream
M1	Marie Creek inlet to May Lake	Stream
M2	May Lake	Lake
M3	Marie Creek outlet of May Lake	Stream
M4	Marie Creek inlet to Marie Lake	Stream
M5	Unnamed Tributary #1	Stream
M6	Unnamed Tributary #2	Stream
M7	Marie Lake	Lake
M8a	Marie Creek outlet of Marie Lake	Stream
M8b	Marie Creek inlet to Ethel Lake	Stream
M8c	Marie Creek near Nabiye field	Stream
M9	Medley River	Stream
M10	Unnamed Tributary #3	Stream
M11A	Upstream of Marie Creek Bridge	Stream
M11B	Downstream of Marie Creek Bridge	Stream



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Monitoring Programs – Surface Water Regional Cont'd

Chemistry Observed in the Regional Program:

- Generally, pH, turbidity, DO, phenols, iron & manganese (total) fell outside of the guideline values (normal for area).
- Concentrations of dissolved metals (bioavailable form) are typically low at monitoring sites.

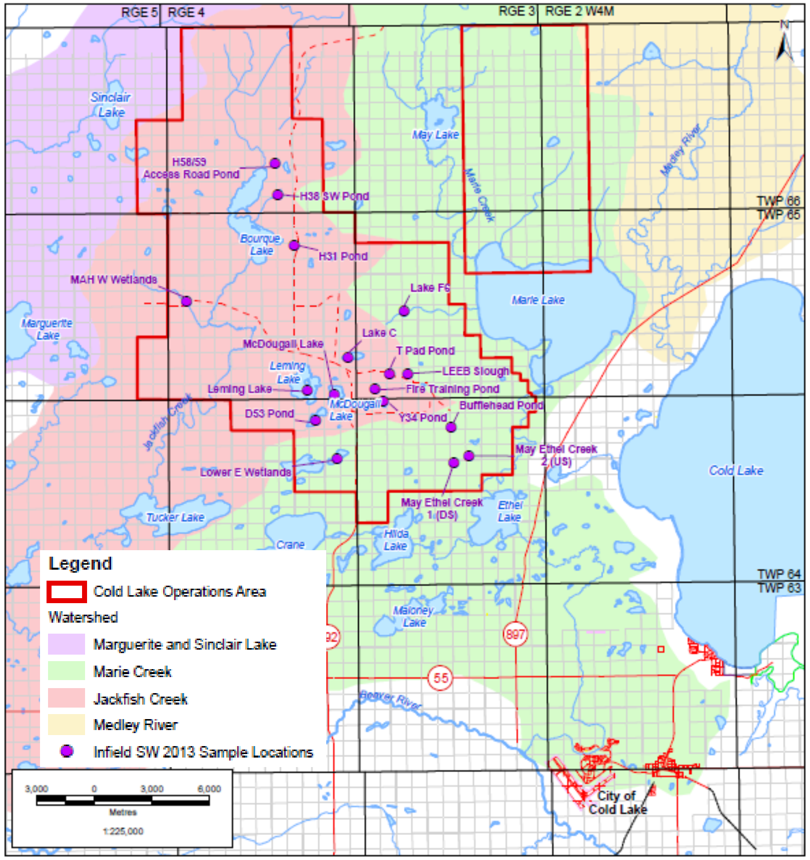
Conclusions:

- Data and observations support the absence of effects directly or indirectly associated with Cold Lake operations

Monitoring Programs – Surface Water Infield

- 18 Sites sampled bi-annually for field and routine parameters, total and dissolved metals, nutrients, and hydrocarbons
- Generally, water parameters did not exceed the water quality guidelines

Infield Program	
Bufflehead Pond	Pond
D53 Pond	Pond
Fire Training Pond	Pond
H31 Pond	Pond
H38 SW Pond	Pond
H58/59 Access Road Pond	Pond
Lake C	Lake
Lake F6	Lake
LEEB Slough	Slough
Leming Lake	Lake
Lower E Wetlands	Wetland
MAH W Wetlands	Wetland
May Ethel Creek 1 (DS)	Creek
May Ethel Creek 2 (US)	Creek
McDougall Lake	Lake
T Pad Pond	Pond
Y34 Pond	Pond



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Monitoring Programs – Surface Water Drainage

Drainage Assessment:

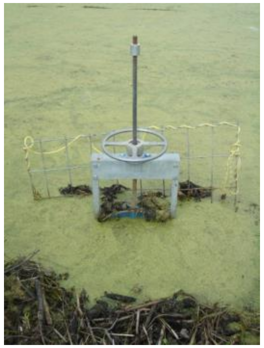
- Completed on an annual basis since 2002
- Include qualitative examination of drainage impediments, vegetation stress, rutting, erosion and/or sedimentation
- 37 sites (in Mahkeses/Leming Field) assessed in 2015
- Sites ranked as high, medium/high, medium, low and for information only. Sites continue to be monitored to assess improvements.
- High and medium/high sites are addressed to prevent impacts
- Mahihkan Field proposed for 2016 assessment

Culvert Assessment:

Completed on an annual basis since 2006

- 112 culverts assessed in 2015
- Assess fish passage, culvert integrity and erosion
- All dyke drains were capped in fall 2009 with complete removal started in 2010 and completed in 2013
- Mahihkan Field proposed for 2016 assessment

Example of culvert assessment study site



Examples of drainage assessment study sites

Monitoring Programs – Surface Water Wetland Level Monitoring

Program Status:

- In 2014/2015, piezometers were monitored for levels using transducers.
- 9 Pairs of staff gauges were installed along the Nabiye road in 2014.

Conclusions:

- Shallow groundwater levels at most wetlands have been relatively stable over time with less than 1 m of variation.

Monitoring Programs – Surface Water Long-term Wetland Monitoring Plots

- Established in August 2006, as per EPEA 73534-00-04 Section 4.9.2a
- Purpose: Monitor long-term effects of groundwater withdrawals on wetland health, extent and distribution
  - Establishment of 11 plots
  - Baseline data collection
- Ongoing monitoring program
  - Conducted every 5 years (last completed in 2015, next survey will be completed in 2020)
- 2015 program
  - Plots established in 2006 and 2010 were assessed
  - Vegetative stress was not identified in any plots in the field level assessment. Analysis of plot data is currently being undertaken.
  - Ongoing evaluation of additional piezometers associated with each wetland monitoring plot

Monitoring Programs – Vegetation

Overview:

- In 2006 a long-term vegetation monitoring program was established, per the commitments made in Section 9, Subject 10 of the IOR Nabiye and Mahihkan North EIA
- The monitoring program was revised and improved in 2009
- The extent of the program is expected to increase as monitoring plots are identified and established in the Nabiye Operating Area

Monitoring Results:

- Monitoring consisted of both edge effects and rare plants monitoring in 2015
- Consultant (AMEC) Conclusion:
  - Edge effects at the transects have been variable.
  - Overall, no significant difference between baseline and species richness values during the Rare Plant survey.

Ongoing Monitoring Program:

- Scheduled to consist of rare plants and edge effects monitoring

Pitcher Plant (Sarracenia purpurea)

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Monitoring Programs – Air Leak Detection and Repair

Overview:

- Leak Detection and Repair (LDAR) program is implemented to detect unintentional hydrocarbon emissions (seals, valves, flanges, etc.).
- The LDAR program is focused on components in sweet hydrocarbon service, particularly stock tank vapour recovery systems and vent gas compressors and piping.
- Imperial has purchased a FLIR GasFindIR HSX camera and trained operations and environmental staff in its use. The camera will be utilized to monitor for gas leaks on tanks and equipment in the district.

Year	Area Tested	Approximate # of Sample Points	# of Leaking Points	Leak Ratio
2012	Mahkeses and Leming Plants and sample of field (older and newer pads)	5,000	1	0.02%
2013	Mahihkan Plant and sample of field (older and newer pads)	8,250	8	0.10%
2014	Maskwa Plant and sample of field (older and newer pads)	6,250	11	0.18%

2015 Progress:

- Consultant was on-site with leak finder camera and gas flow sampler in September 2015.
- Tested Mahkeses Plant, Leming Plant, and sample of field pads (older and newer pads).
- Plan to test 1/3 of operations every year. Nabiye and Mahihkan plant and field is scheduled for surveying in 2016.

Monitoring Programs – Air GHG Emissions

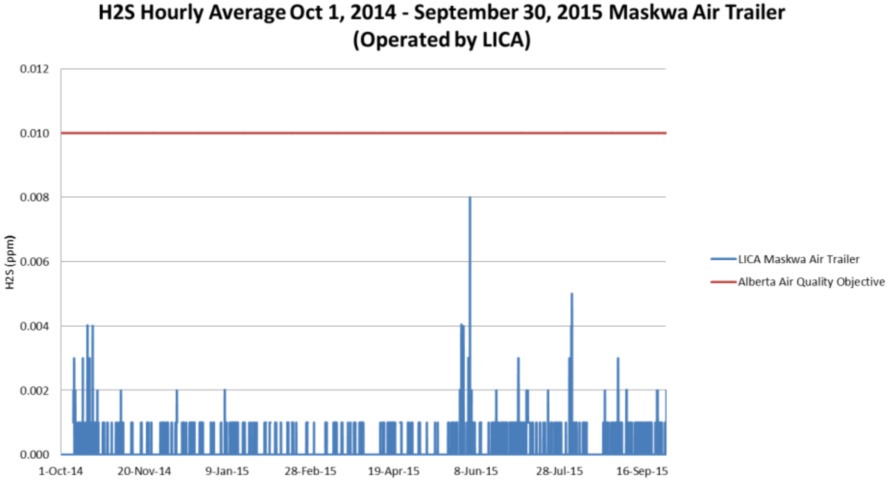
GHG Emissions	2009	2010	2011	2012	2013	**2014**
Carbon Dioxide (CO_2) (tonnes CO_2e)	4,201,016	4,465,633	4,551,849	4,362,031	4,610,458	4,395,476
Methane (CH_4) (tonnes CO_2e)	11,600	11,764	12,777	12,542	18,314	16,659
Nitrous Oxide (N_2O) (tonnes CO_2e)	22,697	23,209	23,564	22,443	23,526	22,331
Total Annual Emissions (tonnes CO_2e) rounded	4,235,313	4,500,607	4,588,190	4,397,015	4,652,297	4,434,467

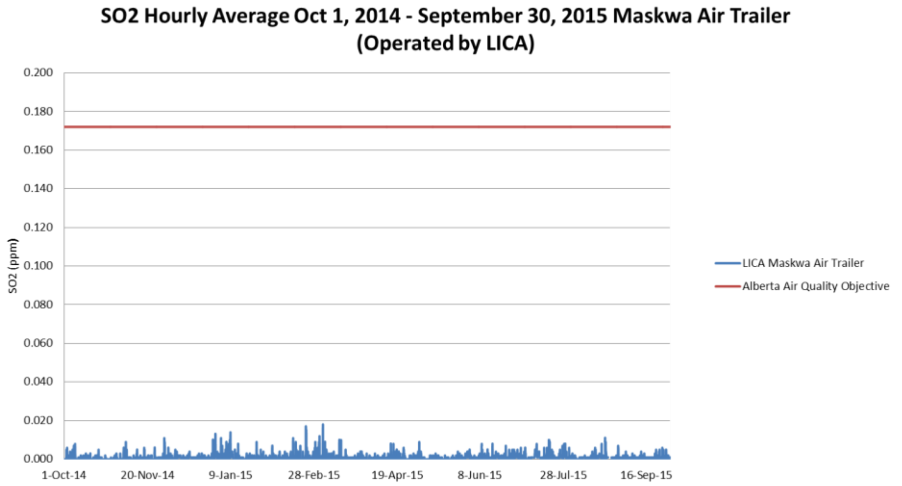
Emissions Intensity	2009	2010	2011	2012	2013	**2014**
Total Annual Emissions (tonnes CO_2e) rounded less Deemed GHG Emissions from Electricity Generation	3,700,235	3,940,533	4,032,204	3,832,184	4,129,165	3,871,899
Total Production (m3)	8,199,284	8,420,509	9,309,664	8,984,787	8,894,400	8,512,771
Emissions Intensity (tonnes CO_2e/m3)	0.4513	0.4680	0.4331	0.4265	0.4642	0.4548

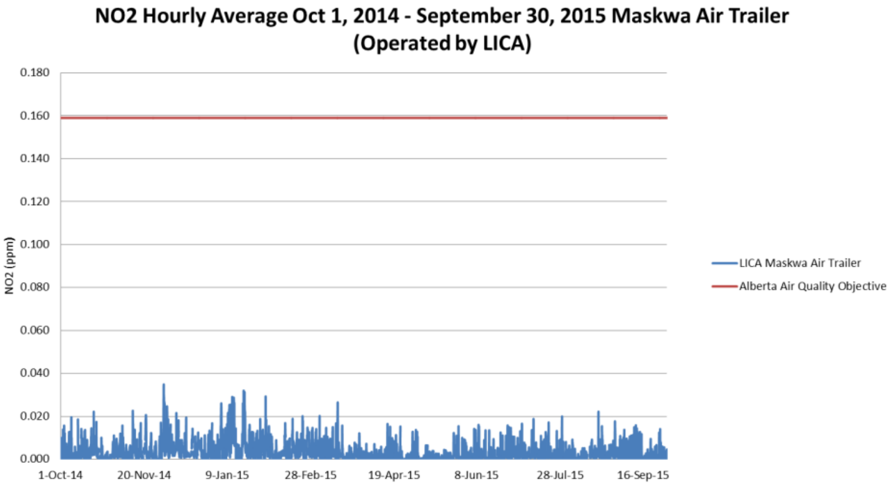
As reported to Alberta Environment under the Specified Gas Emitters Regulation

Monitoring Programs – Air Ambient Monitoring

- Imperial has transitioned "fence line" ambient monitoring network to the LICA Airshed. The Maskwa station is now maintained and operated by LICA.
- Hourly averages of H_2S NO_2 and SO_2 below Alberta Ambient Air Quality Objectives (AAAQO)



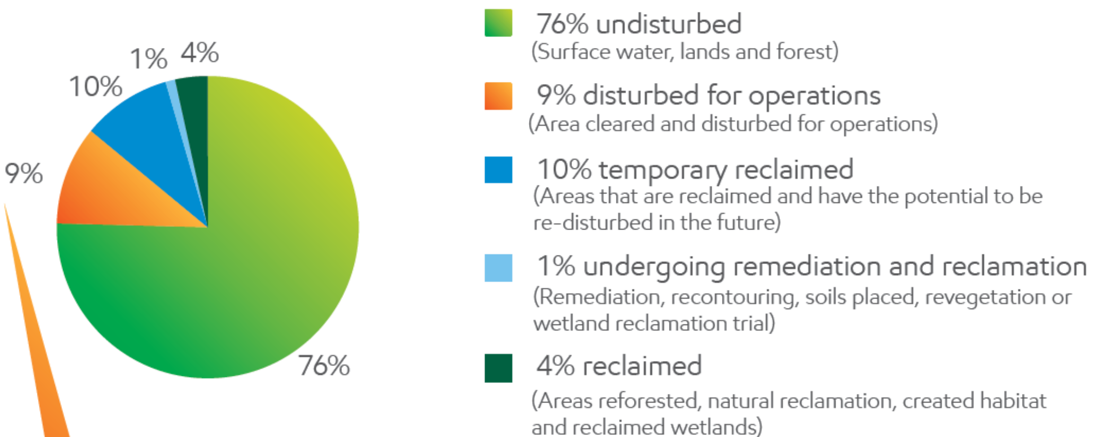




Monitoring – Reclamation

- Since 1999, Imperial's Cold Lake operation has planted over 1.6 million tree and shrub seedlings.   In 2015, ~193,340 tree and 39,540 shrub seedlings were planted

2014 – Cold Lake operations mineral surface lease = 14,222 ha



Year	Total area disturbed (ha)	% Undergoing temporary reclamation, remediation and reclamation	% Reclaimed	Total % undergoing reclamation activity
2012	3,455	43%	14%	57%
2013	3,482	47%	14%	61%
2014	3,482	47%	15%	62%

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Monitoring – Reclamation (cont'd)

Soil and Terrain

- Site stability - annual observations for the first 5 years
- Soil sampling first year following reclamation to demonstrate replacement of soils to an appropriate depth
  > Most sites have adequate topsoil replaced

Revegetation

- Focused on competition, tree seedling survival, agronomic species and weeds
  > Historic practices of establishing native grasses can result in heavy competition with planted trees

Wildlife and Vegetation Stress Monitoring

- Conducted at 5 year intervals
- Wildlife Monitoring completed in 2015
- Vegetation Monitoring to be completed in 2016 .

Environmental Initiatives

- Imperial continues to be involved with LICA (Lakeland Industry and Community Association) as an industry member. Currently Imperial represents industry in the following roles:
  - > Industry Designate on LICA Board of Directors
  - > Industry Alternate on LICA Airshed
  - > Industry Alternate on Beaver River Watershed Alliance (BRWA)
- Imperial continues to engage with Marie Lake Air and Watershed Society (MLAWS) and domestic well owners
- Imperial holds annual Cold Lake Neighbour Night
- Imperial continues to be involved with COSIA (Canada's Oil Sands Innovation Alliance). Hosted Reclamation Tour in September 2014.

Sulphur

Sulphur Removal

Mahihkan Site – Plant Sulphur Removal

- Achieved greater than 69.7% recovery in 4Q14, 1/2Q15 and was continuously below emissions limit
- Over-recovered by 11.1% in previous 3 quarters (4Q14, 1Q15, 2Q15) to account for 68.2% recovery in 3Q15 due to unplanned SRU tower internal repairs; VSD accepted

Mahkeses Site – Plant Sulphur Removal

- Sustained reliability achieved over reporting period:
  - Achieved greater than 69.7% recovery in all quarters of 4Q14, 1/2/3Q15 and was continuously below emissions limit
- Achieved 100% uptime in 4Q14, 1/2/3Q15

Leming Site – No Plant Sulphur Removal

- Leming SO_2 emissions were below limits in all quarters of 4Q14, 1/2/3/Q15 and was continuously below daily emissions limit

Maskwa Site – No Plant Sulphur Removal

- Maskwa SO_2 emissions were below limits in all quarters of 4Q14, 1/2/3/Q15 and was continuously below daily emissions limit

Nabiye Site – Plant Sulphur Removal (not in operation)

- Nabiye sulphur production remains below limits defined in ID 2001-03
- Nabiye SO_2 emissions were below limits in all quarters of 4Q14, 1/2/3/Q15 and was continuously below daily emissions limit

Sulphur Removal, SO_2 Emissions

Calendar Quarter Average Sulphur Emissions By Plant (tonnes/day)																
Calendar Quarter	Leming Plant		Maskwa Plants		Mahihkan Plants			Mahkeses Plant			Nabiye Plant		District	
	Sulphur	SO_2	Sulphur	SO_2	Sulphur	SO_2	Removal	Sulphur	SO_2	Removal	Sulphur	SO_2	Sulphur	SO_2
Q4 2014	0.25	0.51	0.80	1.59	0.23	0.45	72.7%	0.39	0.77	70.1%	0.00	0.00	1.66	3.32
Q1 2015	0.22	0.45	0.85	1.69	0.29	0.59	73.9%	0.37	0.75	70.1%	0.04	0.08	1.78	3.56
Q2 2015	0.21	0.43	0.97	1.94	0.37	0.74	73.6%	0.31	0.63	70.1%	0.20	0.40	2.07	4.14
Q3 2015	0.26	0.52	0.998	1.995	0.41	0.81	68.2%	0.22	0.44	70.1%	0.30	0.60	2.19	4.37

Calendar Quarter Peak Day Sulphur Emissions By Plant (tonnes/day)												
Calendar Quarter	Leming Plant		Maskwa Plants		Mahihkan Plants		Mahkeses Plant		Nabiye Plant		District	
	Sulphur	SO_2	Sulphur	SO_2	Sulphur	SO_2	Sulphur	SO_2	Sulphur	SO_2	Sulphur	SO_2
Q4 2014	0.33	0.66	0.93	1.87	0.55	1.10	0.50	1.00	0.00	0.00	2.15	4.31
Q1 2015	0.28	0.55	1.00	1.99	0.75	1.50	0.50	0.99	0.24	0.49	2.57	5.14
Q2 2015	0.29	0.58	1.10	2.21	0.83	1.66	0.46	0.92	0.52	1.03	2.68	5.36
Q3 2015	0.60	1.19	1.19	2.39	1.26	2.52	0.38	0.77	0.60	1.20	2.88	5.76

*Mahihkan Plant 2 shutdown, 24 days April-May 2015

Compliance

AER Compliance

Incident Investigations

- Facilities failure investigations: none
- Pipeline failure investigations:
  - > AER Incident 20141364
    - Pipeline 20885 Line 176 Failure of pipeline; line was subsequently shut-in; Imperial provided AER with sample results and root cause; AER approved line start-up; Imperial provided supporting rationale for integrity management plan
    - Status: Closed

Inspections

- 8 inspections performed January – September 2015
  - > 7 satisfactory inspections
  - > 0 low risk inspections
  - > 1 high risk inspection (record retention)
- Prior history
  - > 2014: 3 identified low risks
  - > 2013: 0 identified low risks
  - > 2012: 6 identified low risks

Future Plans

Future Plans

- Continue to pursue freshwater reduction opportunities
- Leming Plant Shutdown 2Q2016
- Continue industry sharing and participation

AER Approvals 8558 and 4510

- Imperial is in compliance with all conditions of Approval 8558
- Imperial is in compliance with all conditions of Amendment F to Approval 4510 (details are enclosed in Attachment 2)

Attachments

Imperial

Attachment 1

Approval 8558FF

Compliance Conditions

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2015 Status/Comments
2	The Operator shall notify the AER of any proposed alteration or modification of the scheme or to any equipment proposed for use therein, prior to effecting the alteration or modification.	Susan Stark (CLRE), Hsao-Hsien Chio (CLOT)	8558FF – Mahihkan North LASER approval 8558 dispositions received to allow for the addition of 3 phase test separators to inferred testing system
3	Where, in the opinion of the AER, any alteration or modification of any equipment proposed for use therein a) is not of a minor nature, b) is not compatible with the scheme approved herein, or c) may not result in an improved or more efficient scheme or operation, the alteration or modification shall not be proceeded with or effected without the further authorization of the AER.	Susan Stark (CLRE), Hsao-Hsien Chio (CLOT)	See above
4	Unless otherwise stipulated by the AER, the production from the project area outlined in Appendix A shall not exceed 40 000 cubic metres per day (m3/d) on annual average basis.	Darlene Gates (CLO)	No plan to exceed 40,000 m3
5	The Operator shall conduct all operations to the satisfaction of the AER and in a manner that, under normal operating conditions, will permit a) the recovery of the practical maximum amount of crude bitumen, b) the conservation of the practical maximum volume of produced gas at the well pads and central facilities, c) the practical minimum use of off-site gas for project fuel, d) the practical minimum use of fresh make-up water subject to the Water Act and the practical minimum disposal of water, e) the practical maximum reuse of produced water, with the minimum recycle rate being 95 per cent on an annual basis, unless otherwise stipulated by the AER, and f) the efficient transportation of crude bitumen to market.	Darlene Gates (CLO)	In compliance with all requirements. 2015 YTD produced water recycle exceeds 95%, and is forecasted to remain above 95% for full year 2015.
6.1	The Operator shall measure and record, to the satisfaction of the AER, the volumes and other pertinent characteristics of all fluids injected and produced and other streams as may be required by the AER.	Matt Fuller/Michelle Kelly (CLO)	There were zero compliance issues with volume reporting for CLO in Q4 2014 & 2015 YTD EPAP Compliance Assessment Indicator (CAI) being reviewed in Petrinex monthly by production accounting to ensure compliance to monthly Petrinex reporting. Working with AER to ensure Cold Lake's Petrinex reporting aligns with DIR 081 (Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sand Schemes) / Manual 011 (How to Submit Volumetric Data) requirements. Currently updating schematics and allocations for Cold Lake MARP. Began reporting Nabiye Facility in September 2014. Continue working closely with our AER Representatives to identify & clarify compliance to reporting for new processes (CSP).
6.2	The measurements referred to in paragraph (1) shall be made with sufficient frequency and accuracy as to allow calculation, to the satisfaction of the AER, of mass balances, energy balances and recovery efficiencies for the production processes.	Gord Armbruster (CLO)	There was an issue with Leming produced gas that has been rectified. There are water meters at Maskwa and Mahihkan that are being re-engineered to improve accuracy. In the interim monthly manual rebalance is being done. No other issues or changes for 2015.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2015 Status/Comments
7.1	The Operator shall log all wells from total depth to surface by means of a spontaneous potential - resistivity or gamma ray-resistivity log and such other logs as may be required to ensure sufficient depth and directional control.	Dan Lilly (CLOTG)	One or more wells per pad and all OV wells were logged by LWD, wireline or pipe conveyed methods. Exceptions received for some Passive Seismic wells and the horizontal sections of Injection-Only-Infill wells. AER logging waivers obtained for any wells unable to achieve TD due to mechanical issues.
7.2	The Operator, unless otherwise authorized by the AER, shall take full diameter cores of the entire bitumen bearing section of the Clearwater Formation from not less than four vertical evenly-spaced wells per section, and take fill diameter cores of the remaining bitumen bearing sections of the Mannville Group from at least one vertical well per section, and at the AER's request a) analyze portions of such cores, and b) provide suitable photographs of the clean-cut surface of each core slabbed.	Dan Lilly (CLOTG)	All OV wells cored through the Clearwater Formation. On average four wells per section drilled prior to development. On average, one well per section cored in Grand Rapids in hydrocarbon zones >8m not encumbered by gas.
7.3	Each of the wells referred to in paragraph 2 and one other well per pad shall be logged over the entire Mannville Group by means of a gamma ray-neutron density log.	Dan Lilly (CLOTG)	All OV wells and one well per pad were logged using wireline or pipe conveyed Gamma Ray - Neutron-Density tools.
8	The Operator shall conduct all drilling operations using a water-based mud and not introduce any toxic or potentially toxic additives to any muds or fluids used directly in the drilling of wells associated with the scheme.	Keith Dares (D&C)	Only non-toxic water-based mud systems were used in all drilling activities conducted in 2015
9.1	Prior to the commencement of steam injection operations at all newly-drilled wells, the Operator shall comply with the hydraulic logging requirements of the AER *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements.*	Kelly Wiebe (CLSSE)	Directive 051 approvals received for all newly-drilled wells prior to commencement of steam.
9.2	The Operator shall submit an annual summary report on casing integrity and remedial efforts to the AER by March 31 the following year.	Kelly Wiebe (CLSSE)	Annual casing integrity report submitted March 24, 2015, followed by review on May 12, 2015. No follow-ups.

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Clause	Requirement Summary -	Responsibility	2015 Status/Comments
10	The Operator shall take such steps and effect such measures as may be necessary in the completing and operation of wells to prevent production-casing failures.	Darlene Gates (CLO)	Well construction and casing failure prevention/ detection practices discussed with AER through quarterly drilling/ cementing reviews and annual casing integrity submission.
11.1	The Operator shall conduct additional sampling, testing, and studies to help assess formation integrity and to provide baseline geological and geotechnical information and further knowledge on properties that can influence groundwater flow, water quality, and corrosion of casing and degradation of cement.	John Elliott (OSDR)	Ongoing data collection and analysis in multiple areas: groundwater, passive seismic, gas composition, purge compliance, casing shroud installations, bentonite top ups.
11.2	The Operator shall design and implement monitoring programs to specifically address the potential that its operations may have on liberating or introducing arsenic into the groundwater.	Stuart Lunn (SHE)	Current monitoring is focused on measuring the rate and extent of natural attenuation of arsenic in long term field tests. Field tests have demonstrated that both peak concentrations and mass are declining as the plume migrates downgradient. A technical update was submitted in March 2015. Imperial conducts reviews of arsenic every 2 years to confirm that arsenic concentrations are not increasing over time. This was confirmed in 2015 based on 2014 data. The next analysis will be conducted in 2017 for 2016 data.
12	The Operator shall install surface casing, in a manner satisfactory to the AER, through the glacial drift on all disposal wells.	Keith Dares (D&C)	With the exception of wells that have had an AER approved surface casing depth reduction waiver, surface casing has been installed on all wells consistent with AER Directive 008: Surface Casing Depth Requirements.
13	The Operator, unless given the express written consent of the AER to do otherwise, shall maintain between the location of steamed wells and wells being drilled, a separation adequate to ensure that zones pressured by injected steam are not encountered by wells being drilled.	Matthew McQueen (CLRS)	In full compliance. Drilling program coordinated with steaming schedule to ensure adequate separation.
14	The Operator shall conduct pressure surveys prior to the commencement of steaming and thereafter in any Grand Rapids gas wells that it operates within the expansion area.	Susan Stark (CLRE)	IOR submitted the annual pressure survey to the AER on May 26, 2015
15	The Operator, subject to such terms and conditions as may be described by the AER upon considering an application therefore, shall undertake extensive field investigations of an alternate or follow-up recovery method that the Operator believes may have potential application in the Clearwater Formation.	John Elliott (OSDR)	Multiple field investigations underway: infills, LASER, steamflood, HIPs, SAGD, SA-SAGD, and CSP.

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Clause	Requirement Summary -	Responsibility	2015 Status/Comments
16	The Operator shall conduct recovery tests, satisfactory to the AER, in the McMurray and Grand Rapids Formations in the project area to determine the practicality of recovering bitumen from these formations and provide the results of such tests to the AER.	Susan Stark (CLRE)	Identified candidates for potential Grand Rapids trial. Brought forward an application in Q92 2009 to conduct recovery tests. Based on AER feedback, IOR is going to retest the size and scope of a potential trial.
17.1	Unless otherwise permitted by the AER, cyclic steam stimulation (CSS) operations, having commenced at a well pad, shall continue until the well pad has produced a minimum of 20 per cent of the in-place volume of crude bitumen assigned to that well pad by the AER.	Susan Stark (CLRE)	Nothing new to report
17.2	Where the Operator proposes to cease CSS operations at a well pad that has produced less than 20 per cent of the in-place volume of crude bitumen, and the AER's consent therefore is sought, the Operator shall advise the AER as to the following: a) the reason for proposing to cease CSS operations, b) details of individual well workovers and recompletions attempted, c) details of any infill drilling attempted, d) the effect of ceasing CSS operations on the bitumen recovery ultimately achievable from that part of the reservoir associated with the pad and immediately offsetting pads, e) detailed economics of continuing operations, and f) future plans for the well pad with reference to possible follow-up recovery techniques that could be applied and other zones that could be exploited.	Susan Stark (CLRE)	Nothing new to report
18	The Operator is permitted to implement late life performance optimization using continuous steam injection (steam flooding) in wells at pads A02, A03, A04, A05, A06, B04, D04, D06, D07, D21, D23, D24, D25, D51, D53, D62, D63, D64, D65, D67, E08, E09, E10, F02, F03, F07, G01, G02, G03, H01, H02, H31, H34, H35, H36, J01, J07, J10, J16, M03, M04, M05, M06, M07, 0FF, P01, P02, P03, R01, R02, R03, R04, R05, R06, and R07. Steam injection will be targeted at low rates (150 m3/day/well to 750 m3/day/well) and pressures (700 kPa to 2000 kPa); the Operator is permitted to steam these wells at rates above or below the targeted ranges in order to accommodate steam schedule flexibility as required, but will not exceed peak reservoir pressures of 6 MPa.	Matthew McQueen (CLRS)	The Operator is permitted to implement late life performance optimization using continuous steam injection (steam flooding) throughout the approved Cold Lake development area. Steam injection will be targeted at low rates (150 m3/day/well to 750 m3/day/well) and pressures (700 kPa to 3000 kPa); the Operator is permitted to steam these wells at rates above or below the targeted ranges in order to accommodate steam schedule flexibility as required, but will not exceed peak reservoir pressures of 6 MPa.

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Clause	Requirement Summary -	Responsibility	2015 Status/Comments
19.1	A well shall not be abandoned without prior written AER approval.	Kelly Wiebe (CLSSE)	Well specific non-routine approvals sought prior to abandonment.
19.2	Where the Operator proposes to abandon a well and the AER's consent therefore is sought, the Operator shall advise the AER as to the following: a) the reason for the proposed abandonment, b) the effect of abandoning the well on the bitumen recovery ultimately achievable from that part of the reservoir associated with the well, c) plans for recovering any portion of the remaining bitumen in place, and d) plans for recovering bitumen from other zones penetrated by the well.	Kelly Wiebe (CLSSE)	Pad abandonment approvals are sought prior to commencement of well abandonment on the pad, in accordance with the requirements.
20.1	The Operator shall implement an enhanced regional monitoring network at its existing operation and in the expansion area to monitor groundwater flow directions and groundwater chemistry.	Alana Phelps (SSHE)	Over 125 regional wells and 17 domestic wells sampled in regional groundwater monitoring network. Monitoring is ongoing as required by Schedule VI of ESRD Approval No. 73534-01-01 and Water Diversion License 148301-01-00, as amended.
20.2	The Operator shall set up an enhanced groundwater-monitoring network within its existing operation and in the expansion area to provide information on any water level responses to steam injection.	Alana Phelps (SSHE)	Regularly scheduled water level monitoring is completed on deep groundwater wells. Levels are monitored 3x per week at wells within 2km radius of steaming wells. Monitoring outside the 2km radius is generally done weekly. Except for poroelastic response, steam injection has not been observed to cause water level changes.
21	The Operator shall implement a monitoring program for the Grand Rapids Formation in the Nabiye area, as per Application No. 1703441. This will include, but is not limited to, passive seismic monitoring wells located on each pad, a dual completed Grand Rapids pressure monitoring well on Pad N01 and Pad N05, a hybrid passive seismic and Upper Grand Rapids monitoring well on Pad N07 near the fault.	Susan Stark (CLRE)	Continuous monitoring of the Grand Rapids Formation has been incorporated into our base operational practices.

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Clause	Requirement Summary -	Responsibility	2015 Status/Comments
22	Describe the Operator participation in regional multistakeholders initiatives. Discuss recommendations that have been generated from these regional initiatives and how these recommendations have been incorporated into the project.	Darlene Gates (CLO)	Imperial continues to support and participate in regional monitoring programs and initiatives such as the Lakeland Industry and Community Association (LICA). Currently, Imperial holds the following roles as a participant in LICA: industry designate on the LICA Board of Directors, industry alternate on the LICA Airshed and industry alternate on the Beaver River Watershed Alliance BRWA). The BRWA assists and/ or supports regional water monitoring in the Beaver River watershed (surface water, groundwater, wetlands, and aquatic ecosystem health). Recommendations are incorporated into the regional monitoring programs and/ or carried out by LICA/BRWA. Imperial participates in the monitoring programs as dictated by JOSM. JOSM conducts biodiversity monitoring and data collected is provided to management agencies to help support decision-making with scientific knowledge about provincial biodiversity. Imperial will implement new regulatory requirements that are developed by government as a result of the information gathered through JOSM. Imperial continues to be involved with Canada's Oil Sands Innovation Alliance (COSIA). Cold Lake Operations hosted a multi-stakeholder reclamation tour for COSIA in September 2014.
23	The Operator shall ensure that sulphur recovery will be operational at the Leming, Maskwa, Mahihkan, Mahkeses, and Nabiye sites before total sulphur emissions from flaring and combustion of gas containing hydrogen sulphide (H_2S) reach one tonne/day per site on a calendar quarter-year average basis, unless otherwise stipulated by the AER. The calendar quarter-year sulphur recovery shall not be less than set out in Table 1 of AER *Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* on the basis of the calendar quarter-year daily average sulphur content of produced gas streams flared and used as fuel at each central processing facility.	Darlene Gates (CLO)	Sulfur recovery units are installed and operational at Mahihkan and Mahkeses Plants. A sulfur recovery unit is installed at Nabiye but not operational as sulfur limits are still below the 1 T/day threshold. Maskwa and Leming manage sulfur limits below the 1 T/day threshold. Self disclosure issued to AER for Mahihkan not meeting minimum quarterly recovery of 69.7% for 3Q2015. VSD approved by AER October 19, 2015.
24	The bottomhole location of a scheme well shall not be closer than 100 metres to the offset owner's oil sands lease boundary unless, upon application by the Operator, the drilling and operation of such a closer well is approved by the AER.	Susan Stark (CLRE)	No scheme wells have been drilled within 100m of a lease
25.1	Steam injection into the D29 pad wells must not commence until all E07 pad wells have been properly abandoned. Cement bond logs must be run over the entire intermediate casing interval in all E07 pad wells to confirm hydraulic isolation and determine the need for remediation. A non-routine well abandonment plan must be submitted for all E07 pad wells to the Well Operations Section of the AER's Technical Operations Group for review and approval in accordance with Section 2 of Directive 020: Well Abandonment. The non-routine well abandonment plan must include the interpreted cement bond logs and plans to ensure hydraulic isolation of all primary formation interfaces and across all non-saline aquifers.	Kelly Wiebe (CLSSE)	All E07 wells were initially abandoned to 15 meters above the depth of the oil-in-shale anomaly, allowing D29 to steam. The 'Flow Behind Pipe' assessment was completed, confirming hydraulic isolation behind casing on Cold Lake wells. Final review Sept 17/12. Final E07 non-routine abandonment application submitted Dec 3/13 and approved Jan 31/14 by AER to complete full subsurface abandonment of the E07 wells, excluding E07-14 which remains as an observation well. This abandonment work was completed in Dec/14. This item can be removed from future years updates.

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Clause	Requirement Summary -	Responsibility	2015 Status/Comments
25.2	Any E07 pad wells that are already zonally abandoned only require review below the cement top if the AER identifies issues of concern on those wells not yet zonally abandoned. The Operator must, for any wells zonally abandoned across the Clearwater Formation where plugs have not been placed at the correct depth, drill out the existing plug and abandon the well properly as per *Directive 020*.	Kelly Wiebe (CLSSE)	Wells already zonally abandoned were properly addressed in the applications noted in item 25.1, with abandonments executed as per the non-routine abandonment approval. This work is complete and this item should be removed from future years updates.
26	The Operator is permitted to abandon the Q and S Pads as described in Application No. 1684454. For the abandonment of wells on these pads a non-routine well abandonment plan must be submitted for each well to the Well Operations Section of the AER's Technical Operations Group for review and approval in accordance with Section 2 of *Directive 020: Well Abandonment*. The AER notes many wells on the Q and S Pads have been zonally abandoned; any wells which were previously zonally abandoned across the Clearwater Formation that do not have plugs set at the appropriate depth must be drilled out and reabandoned as per *Directive 020*. Additionally, cement bond logs must be run over the entire intermediate casing interval, to the depth of the zonal abandonment plug in all wells where present, to confirm hydraulic isolation and determine the need for remediation. The nonroutine well abandonment plan must include the interpreted cement bond logs and discussion on how hydraulic isolation of all primary formation interfaces and across all non-saline aquifers will be maintained.	Kelly Wiebe (CLSSE)	Bond logging on Q and S pads complete. Next steps include development and submission of Q and S well specific non-routine abandonment plans for approval.

Attachment 2

Approval 4510

Compliance Conditions

AER Approval 4510

Clause	Requirement Summary	Responsibility	2015 Status/Comments
4510_2	The disposal of fluids...in the wells...which have satisfied Guide 51 requirements, may commence or continue.	Kelly Wiebe (CLSSE)	Injection follows the conditions of the Directive 051 approvals.
4510_3	The reservoir pressure at the observation wells must be monitored on a minimum of an annual basis.	Lyle Robins (CLO)	In compliance. All N Pad injection has ceased as of November 2015
4510_4	If the reservoir pressure increases to 7500 kPa (ga), all of the following disposal wells must be re-logged to ensure there is no migration of the disposal fluid out of the zone via micro-annuli: AB/06-05-065-03W4/0 AU/06-05-065-03W4/0 AJ/06-05-065-03W4/0 AG/07-05-065-03W4/0 AM/06-05-065-03W4/0 AH/07-05-065-03W4/0	Lyle Robins (CLO)	In compliance. All N Pad injection has ceased as of November 2015.
4510	Submit an annual report for Approval 4510	Matthew McQueen (CLRS)	2015 Report to be submitted late November 2015.

Attachment 3

Water Disposal and Storage

Water Disposal and Storage

PW Disposal & Storage
District Summary – Volumes in m^3

System	2014			2015								
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Produced to SWD	137,740.9	160,704.1	172,394.9	144,845.2	15,293.4	0.0	0.0	0.0	0.0	0.0	92,025.2	123,559.7
N Pad Storage	57,353.6	56,713.1	61,820.4	52,056.5	27,385.8	23,743.7	15,718.2	39,092.4	18,491.6	13,012.0	9,900.7	1,982.8
Total Water	195,094.5	217,417.2	234,215.3	196,901.7	42,679.2	23,743.7	15,718.2	39,092.4	18,491.6	13,012.0	101,925.9	125,542.5

Attachment 4

Facility Performance by Plant

Cold Lake Facility Performance

Facility Performance

	1/1/2014	2/1/2014	3/1/2014	4/1/2014	5/1/2014	6/1/2014	7/1/2014	8/1/2014	9/1/2014	10/1/2014	11/1/2014	12/1/2014	1/1/2015	2/1/2015	3/1/2015	4/1/2015	5/1/2015	6/1/2015	7/1/2015	8/1/2015	9/1/2015
	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30
Maskwa Plant																					
Bitumen Production m^3	214821.7	184978.5	203983.4	217152.1	230151.4	218536.9	226379.9	226004.3	217136.8	224244.1	211134.9	216197.2	216201.5	192003.6	212692.2	206959	211393.9	195877	202558.7	193427.6	184892.2
Produced Water m^3	807216.0	741418.4	762707.9	747926.1	833843.3	778221.1	916058.8	872606.2	804535.8	825821.5	834541.3	857426.1	956774.5	843718.3	948256.4	907527.9	896586.2	840656.4	922525.3	933958.2	968375.6
HP Steam Generation m^3	759195.9	696395.9	811365.5	781918.1	826267.1	794014.6	806093.1	831655.5	804351.9	825821.5	834541.3	857426.1	780139.1	666853.9	776831.9	780091.6	838491.2	779796.9	772180	816230.5	750426.2
HP Steam Injection m^3	700233.5	643873.5	748037.9	717571.8	762314.4	732366.9	740787.1	766723.3	743574	793878.4	772494.5	777874.9	723319.2	615061.5	717114.8	722583.2	791523.1	732227.3	724059.9	764499.7	709153.1
Steam Quality %	66.0	68.8	70.3	68.3	70.9	70.3	69.3	71.7	66.0	68.7	70.4	68.4	70.8	70.3	69.3	71.7	69.9	70.4	70.5	70.3	67.4
Produced Gas km^3	12989.2	11470.4	11842.7	11119.1	11483.1	10622.4	10917	11200.5	10295.1	10188	9394.9	9853	10022.4	8645.2	9531.7	8880.3	8791	9207.7	9238.5	8868.1	8671.9
Purchased Gas km^3	36350.3	33493.5	38861.6	37484.3	38986.7	37410.9	38106.5	40293.7	38904.3	42342.8	41820.6	42237.7	38662.4	33387.2	39400	39343.4	42629.6	39248.8	39073.7	41366.3	39636.6
Mahihkan Plant																					
Bitumen Production m^3	302282.3	281683.9	344805.9	332567.6	238933.3	189457.2	298405.5	311175.9	306018.5	322033.6	302146	299020.5	295750.6	263129.1	290169.8	255875.7	279760.7	274989.6	290637.7	290122.1	275240.5
Produced Water m^3	1033505.2	924420.9	1063116.9	1046623.5	737283.0	531090.1	1021943.0	1027874.7	1002924.5	1093701.7	1027805.9	1031467.7	1030276.3	994535.6	1085209.2	846781.1	########	########	1136620.3	1063595.7	1064127.2
HP Steam Generation m^3	1140357.4	1028493.5	1166918	1209001.8	786168.4	536018.6	1158859.9	1181773.6	1097400	1093701.7	1027805.9	1031467.7	1149078.5	1130904.2	1221874.2	907347.6	1175909	1229572	1263125.1	1277509.4	1236156.5
HP Steam Injection m^3	1060147.4	955113.3	1086393	1137321.5	745530.2	511764.3	1099652.9	1103362.1	1018817.1	1144026.6	1058758.3	1058703.8	1056950.8	1042832.4	1133280.4	854694.9	1114213	1183519	1216509.9	1225806.5	1184579
Steam Quality %	69.1	70.0	70.3	70.1	67.9	67.6	67.7	69.8	69.1	70.0	70.4	70.2	67.9	67.8	67.6	69.8	69.5	69.0	68.6	67.7	68.0
Produced Gas km^3	12659.7	11753	13132.6	13097.4	7870.9	4731.4	11893.3	12732.2	12506.2	13173	12837.9	13539.4	13556.2	11104.5	12788.5	11792.6	13264	13732.6	13349.3	13182.3	12265
Purchased Gas km^3	54258.5	48819.2	55107.7	57054.7	36176.4	24302.5	53035.4	52972.1	48688.7	55997.6	51389.1	49910	50964.6	52107.9	56133.5	38912.8	51947	56054.1	58095.2	59766	58657
Mahkeses Plant																					
Bitumen Production m^3	150875.5	129979.8	158256.8	145480.8	148582.3	149633.1	157423.9	159643.4	159252.2	174198.8	165570.3	171122.7	174859.8	161764.4	179182.4	171029.3	170162.1	156412.4	158279.6	152190.9	152551.7
Produced Water m^3	538028.9	523992.7	582465.0	557724.8	615406.0	575092.0	574877.2	574307.0	560425.7	608020.9	593352.8	587116.8	591864.6	561731.1	608646.2	583172.0	557960.8	504795.7	501937.1	549243.1	638891.6
HP Steam Generation m^3	682507.9	611264	689551.6	485678.9	603542.3	690213.8	695831.2	715919.7	683403.6	608020.9	593352.8	587116.8	706673.4	585369.3	629666.1	659255.7	482571.2	664357.2	668202.6	688183.6	646778.2
HP Steam Injection m^3	685863.6	659682.4	645739.5	476491.1	577342.8	684129.8	674425.6	682036.1	628669.2	699832	732501.8	703631	749925.7	650414	693939.5	646140.7	413261.5	598972.2	610071.4	624868.4	610744.1
Steam Quality %	68.1	66.2	67.3	65.8	65.2	64.9	64.6	64.9	68.1	66.1	67.4	65.8	65.2	64.9	64.6	64.9	63.6	62.6	61.7	60.5	60.5
Produced Gas km^3	8376.5	7738.7	8841.1	7770.3	8353.8	8252.5	8747.4	8547	8227.7	8568.1	8161.7	8833.2	9442.7	8534.6	9392.7	8558	8480.7	8473.1	8645.8	8150.5	8285.6
Purchased Gas km^3	50824.1	45885.7	49784.3	32077.3	40327.4	46593	45551.4	46786.4	45324.9	46914.7	48155.8	48884	49330.5	42233.6	42756.3	44982.3	29474.8	44074.8	45518.4	46332.2	44788.4
Leming Plant																					
Bitumen Production m^3	45255.7	38722.6	45064.7	39212.9	43506.9	40338.4	39133.1	37615.1	36800.7	40090.5	41095.9	43611.5	40926.3	38977	44014.8	40429.2	42069.8	38672.3	41545.8	41864.5	39019.4
Produced Water m^3	221735.4	190891.1	221160.8	217318.6	243050.1	227687.2	245976.9	225396.4	219286.3	230745.4	224858.7	240573.5	239202.2	245602.7	267530.9	262401.8	263719.3	252203.3	260476.6	252566.4	219029.9
HP Steam Generation m^3	288352.5	241021	275153.8	306044.2	324981.5	297265.8	303579.6	267605.4	248140.9	230745.4	224858.7	240573.5	297009.2	270915.2	299000.3	285403	256283.2	289833.5	327737	330937.1	306962.7
HP Steam Injection m^3	191799.9	120741.3	233473.4	259133.1	270321.6	225510.7	264554.6	242769.9	237373.1	176949.3	158408.9	225917.5	193121.6	154284.8	186609.4	243663.6	251802.2	286071.5	322110.1	324151.7	299602
Steam Quality %	63.1	66.5	64.5	69.4	70.9	70.9	71.1	70.2	63.1	66.3	64.6	69.5	71.3	70.9	71.2	70.2	70.7	69.9	70.3	71.8	72.3
Produced Gas km^3	3700.4	3431.1	3572.9	2773.3	2647	2498.9	2252.3	2148.3	2416.7	3006.4	2363.9	2657.9	2606.8	2293.9	2321.3	2218.8	2334.2	2112.4	2673.6	2778.6	2412
Purchased Gas km^3	14299.7	12246.2	13738.4	16578	18023	15811.2	15866.5	14281.2	12020.5	9739.4	13203.9	16086.9	16413.2	15033.8	16530.7	15762.6	13536.4	15629.7	17401	16841.4	16255.9
Nabiye																					
Bitumen Production m^3	0	0	0	0	0	0	0	0	0	0	0	0	0	89.4	56908.5	82423.9	81842.6	109409.9	162476.4	132751.4	115153
Produced Water m^3	0	0	0	0	0	0	0	0	0	0	0	0	0	2121.5	94426.6	142437.2	317539.6	320429.3	281439.3	282540	232497.9
HP Steam Generation m^3	0	0	0	0	0	0	0	0	0	0	0	0	101007.3	415576	628866	689730	624092	582779.3	537170.77	388016.25	376892.94
HP Steam Injection m^3	0	0	0	0	0	0	0	0	0	0	0	0	89590.1	375542.8	586189.6	648720.9	591079.5	557507.4	505937.2	312162	295914.1
Steam Quality %															65.0	69.2	63.5	65.0	64.9	68.0	
Produced Gas km^3	0	0	0	0	0	0	0	0	0	0	0	0	0	2.6	1648.6	2369.1	3816.2	5914.2	5038.8	3931.5	3928.9
Purchased Gas km^3	0	0	0	0	0	0	0	0	0	112.8	225.9	146.8	9888.5	31104	46950.6	52284.6	42971.1	39099	38868.4	23342.2	24505.7
SA-SAGD																					
Bitumen Production m^3	3085	3179.7	3085	3179.7	3062.2	1848	1656.5	615.8	2560.2	3688.3	4366.6	3041.7	3012.1	2864.8	2631.8	2358.7	3118.7	2968.4	2894.6	2061.9	1947.8
Produced Water m^3	8214	8821.5	8214	8821.5	8651.9	3598.6	3505.2	2094.9	5874.4	13394.1	13236.4	10824	9453.9	9637.6	9529.7	8327.3	9203.5	6060.9	7071.2	7974.2	7824.8
HP Steam Injection m^3	8723	8442.1	8723	8442.1	9299.6	132	8764.5	6580.4	9720.7	10545.9	10023	12574.2	10090	10131.7	10671.9	9531.4	7160.4	264.2	14457.6	13177.4	8075.7
Produced Gas km^3	8.8	11.6	8.8	11.6	10	9	7.3	4.6	8.1	14.1	31.6	22.2	25.7	23.6	23.3	22.5	29.7	34.1	20.5	8.7	14.5
District																					
Fresh Water m^3	192888.2	170007.9	192578.5	214964.2	224004	216736.2	217913.2	165968	145828.5	149379.1	200841.8	231919.3	247009.7	175002.4	200335.3	192275.5	202984.4	253438.5	276385	243865.8	245986
Brackish Water m^3	0	0	0	0	0	0	0	0	6.1	1788.6	0	751.5	0	23854.6	51601.7	89781.9	26813	78365	15485.7	3426.2	0
Ground Water m^3	469.7	900.5	524.1	1178.8	673.9	81.8	916.3	202.8	1674.9	439.1	291.2	319.7	588.8	2058.1	421.3	46.9	353.6	1042	718.8	4094.6	303.1
Disposal Water m^3	130856.2	123924.6	126967.8	116805.4	143164.6	136591.0	137443.3	140613.8	133215.9	137740.9	160704.1	172394.9	196901.7	42679.2	23743.7	15718.2	39092.4	18491.6	13012.0	101925.9	125542.5
PW Recycle %	93.6	92.4	95.4	92.1	87.7	91.7	92.8	97.0	95.5	96.2	93.7	93.0	90.4	99.9	102.9	105.5	96.4	101.5	98.5	96.5	89.6
Power Generation MWh	127712	118695	125152	81560	101856	111453	107269	109775	110661.129	116826.78	120750.38	122,529	124755	192358	218953	231944	172421	204374	215005	173252	176585.55
Power Import from Grid MWh	504	544	595	21978	8755	1017	2505	989	531	549.638	710.095	1122.546	1129	679	595	690	564	660	878	927	781
Power Export from Grid MWh	29448.768	29651.626	28462.468	9708.842	31235.16	43821.153	23524.128	23204.97	31188.332	27642.255	26588.321	20339.515	39241.731	93482.035	119516.95	131573.46	77032.45	109783.2	117351.33	79746.533	87828.191
Power Consumption MWh	98767	89587	97284	93830	79376	68649	86249	87559	80004	89734	94872	103312	86642	99555	100031	101061	95953	95251	98532	94433	89539
Produced Gas km^3	37734.6	34404.8	37399.3	34769.1	30362.1	26115.9	33818.1	34649.3	33481.8	34957.7	32784.1	34907.1	35651.4	30603.3	35712.5	33861.7	36714	39449.7	39026.4	36952.4	35616.4
Flare Gas km^3	150.7	189.6	233	201.1	152.7	358.2	365.7	109.8	102.8	55.3	53.6	43	88.1	317.5	395.8	273.4	394.7	225.6	334.7	251.4	80.5
Vent Gas km^3	9.5	8.4	14.6	12.6	9.7	20.9	35.7	20.1	20.4	13.9	28	27.1	68.8	67.1	17.9	15.5	39.3	33.9	29.4	65	26.7
Produced Gas Recovery %	99.6	99.4	99.3	99.4	99.5	98.5	98.8	99.6	99.6	99.8	99.8	99.8	99.6	98.7	98.8	99.1	98.8	99.3	99.1	99.1	99.7

Attachment 5

Sulphur Balances by Plant

Cold Lake Plant Sulphur Balances

As per AER approval 8558 clause 24.2, Imperial is required to report monthly sulphur and comply on a calendar quarter year average basis for each plant.

Tonnes/Day	Month	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15
District	Sulphur Inlet	93.5	95.09	102.84	108.41	90.52	114.72	112.48	128.50	109.11	110.80	93.99	123.92
	Sulphur Removed	45.51	45.32	47.72	56.06	45.70	51.88	54.42	59.89	47.29	39.96	34.54	53.10
	Sulphur Emissions	48	49.77	55.12	65.30	55.08	73.20	66.75	79.25	71.10	76.12	65.22	80.14
	SO2 Emissions	95.99	99.55	110.25	130.60	110.16	146.40	133.49	158.49	142.20	152.25	130.43	160.27
	Sulphur Recovery	48.7%	47.7%	46.4%	51.7%	50.5%	45.2%	48.4%	46.6%	43.3%	36.1%	36.7%	42.9%
Leming	Sulphur Inlet	7.35	6.87	9.2	7.19	6.59	6.31	6.71	7.06	5.68	6.35	5.30	12.48
	Sulphur Removed	0	0	0	0	0	0	0	0	0	0	0	0
	Sulphur Emissions	7.35	6.87	9.2	7.19	6.59	6.31	6.71	7.06	5.68	6.35	5.30	12.48
	SO2 Emissions	14.7	13.74	18.4	14.38	13.18	12.61	13.42	14.12	11.36	12.70	10.61	24.97
	Sulphur Recovery	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Maskwa	Sulphur Inlet	23.46	23.92	25.77	25.89	22.66	27.64	28.62	30.88	28.84	31.50	28.97	31.31
	Sulphur Removed	0	0	0	0	0	0	0	0	0	0	0	0
	Sulphur Emissions	23.46	23.92	25.77	25.89	22.66	27.64	28.62	30.88	28.84	31.50	28.97	31.31
	SO2 Emissions	46.9	47.85	51.54	51.78	45.32	55.28	57.24	61.76	57.68	63.01	57.94	62.63
	Sulphur Recovery	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mahihkan	Sulphur Inlet	23.92	23.54	28.3	32.03	26.97	42.43	43.39	48.52	36.60	44.70	32.57	39.96
	Sulphur Removed	18.31	16.75	19.99	25.71	21.66	27.64	34.09	34.95	25.58	27.56	21.07	31.27
	Sulphur Emissions	5.61	6.79	8.31	6.32	5.31	14.80	9.29	13.57	11.02	17.14	11.51	8.69
	SO2 Emissions	11.22	13.59	16.61	12.64	10.62	29.60	18.59	27.14	22.04	34.28	23.01	17.38
	Sulphur Recovery	76.5%	71.1%	70.6%	80.3%	80.3%	65.1%	78.6%	72.0%	69.9%	61.6%	64.7%	78.3%
Mahkeses	Sulphur Inlet	38.78	40.76	39.57	43.31	34.30	34.60	29.00	35.58	30.99	17.70	19.24	31.15
	Sulphur Removed	27.2	28.57	27.72	30.35	24.04	24.24	20.32	24.94	21.71	12.41	13.48	21.83
	Sulphur Emissions	11.58	12.19	11.85	12.95	10.26	10.35	8.68	10.64	9.28	5.29	5.76	9.32
	SO2 Emissions	23.17	24.38	23.70	25.90	20.52	20.71	17.36	21.27	18.55	10.58	11.53	18.64
	Sulphur Recovery	70.1%	70.1%	70.1%	70.1%	70.1%	70.1%	70.1%	70.1%	70.1%	70.1%	70.0%	70.1%
Nabiye	Sulphur Inlet	0	0	0	0	0	3.74	4.77	6.47	7.01	10.55	7.91	9.01
	Sulphur Removed	0	0	0	0	0	0	0	0	0	0	0	0
	Sulphur Emissions	0	0	0	0	0	3.74	4.77	6.47	7.01	10.55	7.91	9.01
	SO2 Emissions	0	0	0	0	0	7.49	9.53	12.93	14.02	21.11	15.82	18.03
	Sulphur Recovery	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Sulphur Measurement & Reporting

Sulphur (H_2S) Sampling Process

- Manual gas samples taken to monitor H_2S concentration
- Additional gas samples may be taken if increased frequency is desired (e.g. approaching licence limits and/or increased variability in samples expected or performance control improvements)

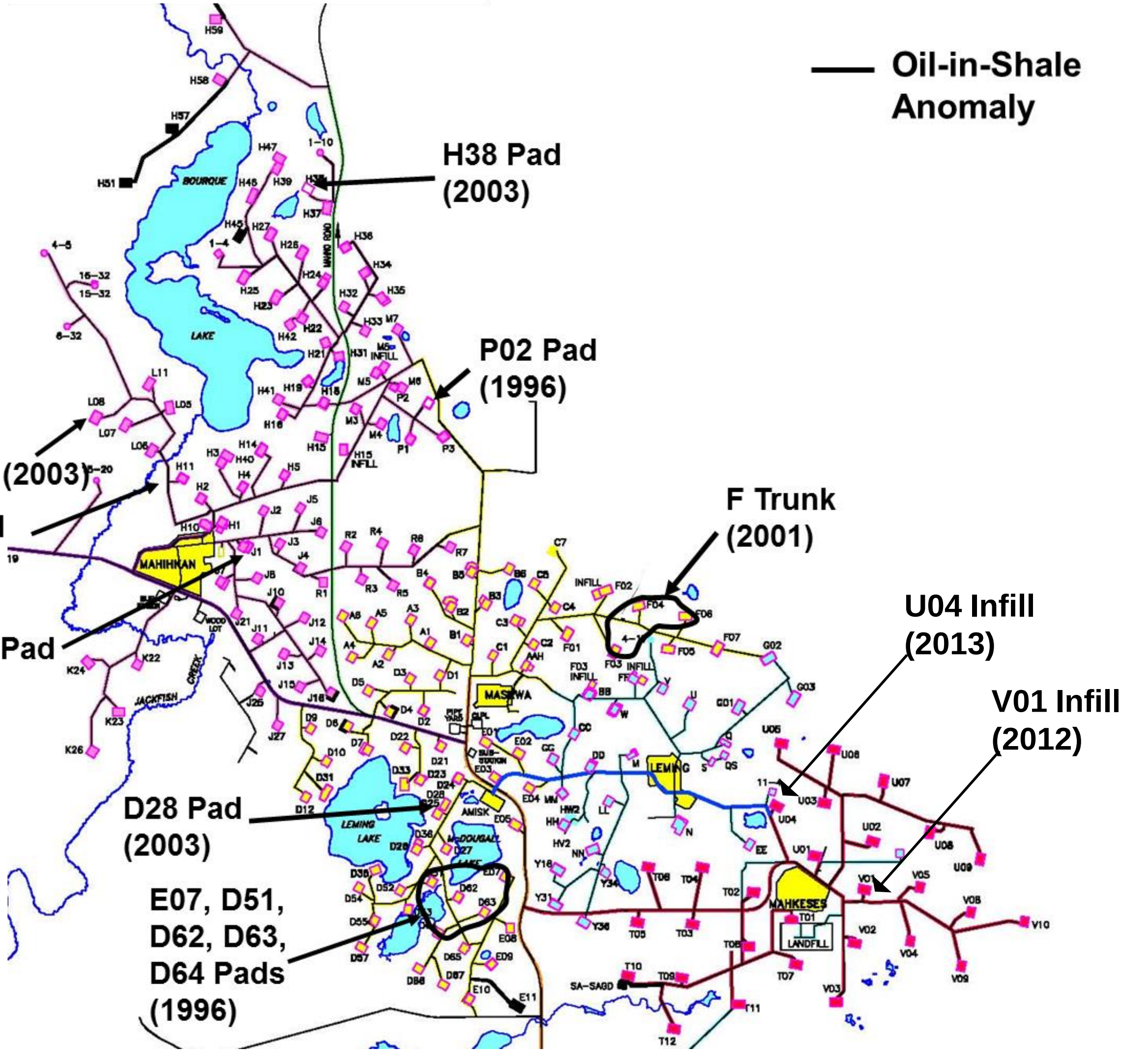
	Gas sample locations	Sampling Frequency
Maskwa Plant	Inlet gas P1 & P3	Weekly
Mahihkan Plant	Inlet gas P2 & P4, P4 SRU inlet and outlet	Weekly (P2) | MWF (P4)
Leming Plant	Inlet gas	Weekly
Mahkeses Plant	Inlet gas, SRU inlet and outlet, combined gas	MTWThF
Nabiye Plant	Inlet gas	TTh

- Sulphur measurement process accuracy is within the requirements of ID 2001-03 for reporting (+/- 0.1 tonnes S and +/- 0.1 km^3 gas)
- Sulphur emissions are documented on a daily basis and monitored against the quarterly limits for each plant

Attachment 6

2015 Bitumen in Shale Report

Oil in Shale Issues Summary



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Oil In Shale Issues Summary

No new oil in shale events to report

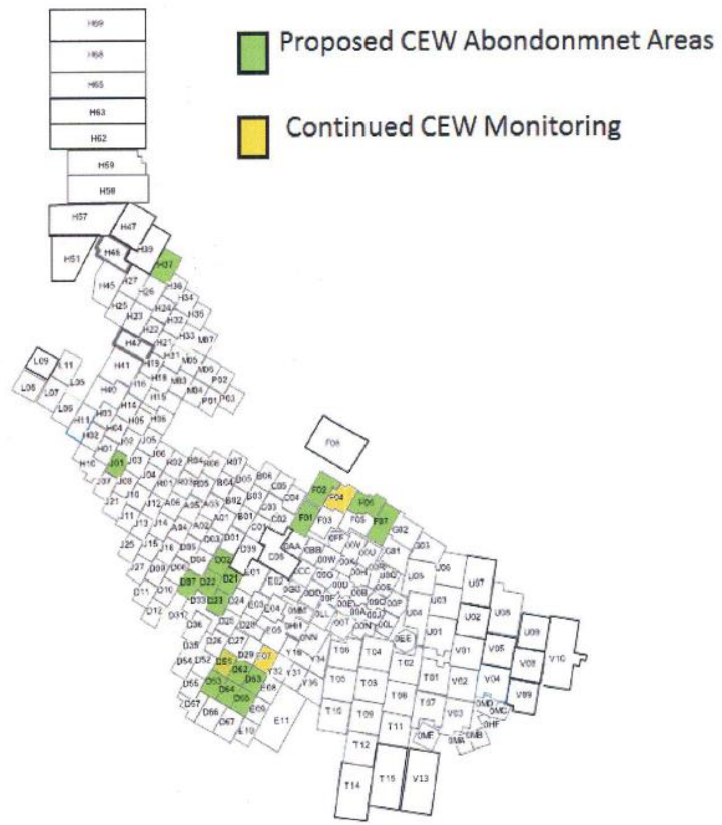
Location	Issue	Date of Discovery	Current Restriction?	Comments/ Commitments/ Results	Next Scheduled Steam Date
E07	Oil in Shale found during drilling at E07 pad	1997	No	E07 wells abandoned. Resource accessed via D29 horizontal wells. Shale pressure monitored while steaming.	Q1 2016 resource steamed via D29
F trunk	Oil in Shale found during re-drill at F03-16A	2001	No	Steaming restrictions lifted Sept 10, 2003. Anomaly area steamed 2006, including new infill wells. Shale pressure monitored and steam pattern adjusted to minimize shear stresses. One GEW shows <1 ppb benzene and below Canadian drinking water quality guidelines (CDWQG).	Steam Flood Ongoing (via infills)
L08	Oil reported during drilling of L08-01 and PS well on pad.	2003	No	Steaming restriction lifted June 13, 2003. Steamed 8 cycles with no abnormal pressures in CEW. Closest GEW well has shown BTEX levels over CDWQG in the past but are now below detection limits	Q1 2017
H38/H39	Oil reported during drilling of H38-12 and H38-22.	2003	No	Steaming restriction lifted Nov 25, 2004. Shale pressure and ground water monitoring wells monitored through 7 cycles. No abnormal pressures observed. In Feb 2011 groundwater had benzene concentrations above CDWQG on H39. Since April 2013, chemistry has been below CDWQG.	Q3 2017
H11	Oil reported during drilling of H11-02 and H11-05	2003	No	No abnormal pressures at CEW during 8 steam cycles. Benzene observed in 2004 and 2005 but was subsequently below detection limit. Benzene was seen in GEW 11-7 in 2012, but has since been below CDWQG.	Q4 2015

Oil In Shale Issues Summary

Location	Issue	Date of Discovery	Current Restriction?	Comments/ Commitments/ Results	Next Scheduled Steam Date
J01 Infills	Oil reported during drilling of J01-H1	2003	No	No abnormal pressures at CEW during infill well steaming cycles. Groundwater shows no abnormal hydrocarbons.	Steam Flood Operations Ongoing
D28	Oil reported during drilling of D28-07 and D28-09.	2003	No	Steaming area via infill wells since 2012 with no anomalous pressure response at the CEW. Groundwater shows no abnormal hydrocarbons.	Steam Flood Ongoing (via infills)
V01	Oil in Shale found during drilling of V01-H28 infill	Nov 2012	No	Deep groundwater monitoring well installed – no impacts were observed	Q4 2017
U04	Oil in Shale found during drilling of U04-H26	Feb 2013	No	No groundwater monitoring drilled as there is no deep continuous aquifer to monitor	Q3 2017

Colorado Shale Monitoring Wells

- AER has approved Imperial's application to discontinue monitoring at 28 Colorado Shale monitoring wells in areas which have converted to low pressure steaming operations
- Of the 28 wells, 20 will be abandoned and eight will be returned to low pressure operation
- In a few areas with either high pressure steaming plans, or high pressure in the Colorado Shale, four monitoring wells will be maintained
- A list of these wells is on the next page



Colorado Shale Monitoring Wells

Table 1 – Monitoring wells proposed for conversion to low-pressure producers

Well	UWI	License #	Comments
D51-05 (Colorado)	102/13-36-64-4W4/0	127833	Retain D51-10 as the pad monitoring well
D51-17 (Colorado)	100/09-35-64-4W4/0	127845	Retain D51-10 as the pad monitoring well
D02-02 (Colorado)	102/09-11-65-4W4/0	114515	
D21-12 (Colorado)	102/01-11-65-4W4/0	114815	
D21-15 (Colorado)	106/04-12-65-4W4/0	114818	
D22-14 (Colorado)	105/02-11-65-4W4/0	115055	
D23-13 (Lloydminster and Colony)	109/16-2-65-4W4/0	116121	
D65-11 (Colony)	105/04-36-64-4W4/0	188547	Run temperature log and take manual pressure reading before conversion

Table 3 – Wells proposed for continued monitoring

Well	UWI	License #	Comments
D51-10	100/16-35-64-4W4/0	127838	Retain D51-10 as the pad monitoring well
E07-PM1	112/15-36-64-4W4/0	218719	Retain E07-PM1 –continued HP steaming from D29 –failed sensor recently repaired
E07-14	108/15-36-64-4W4/0	189068	Retain E07-14 –continued HP steaming from D29
F04 CEW-7	114/09-18-65-3W4/0	265997	Retain F04 CEW-7 to monitor anomaly

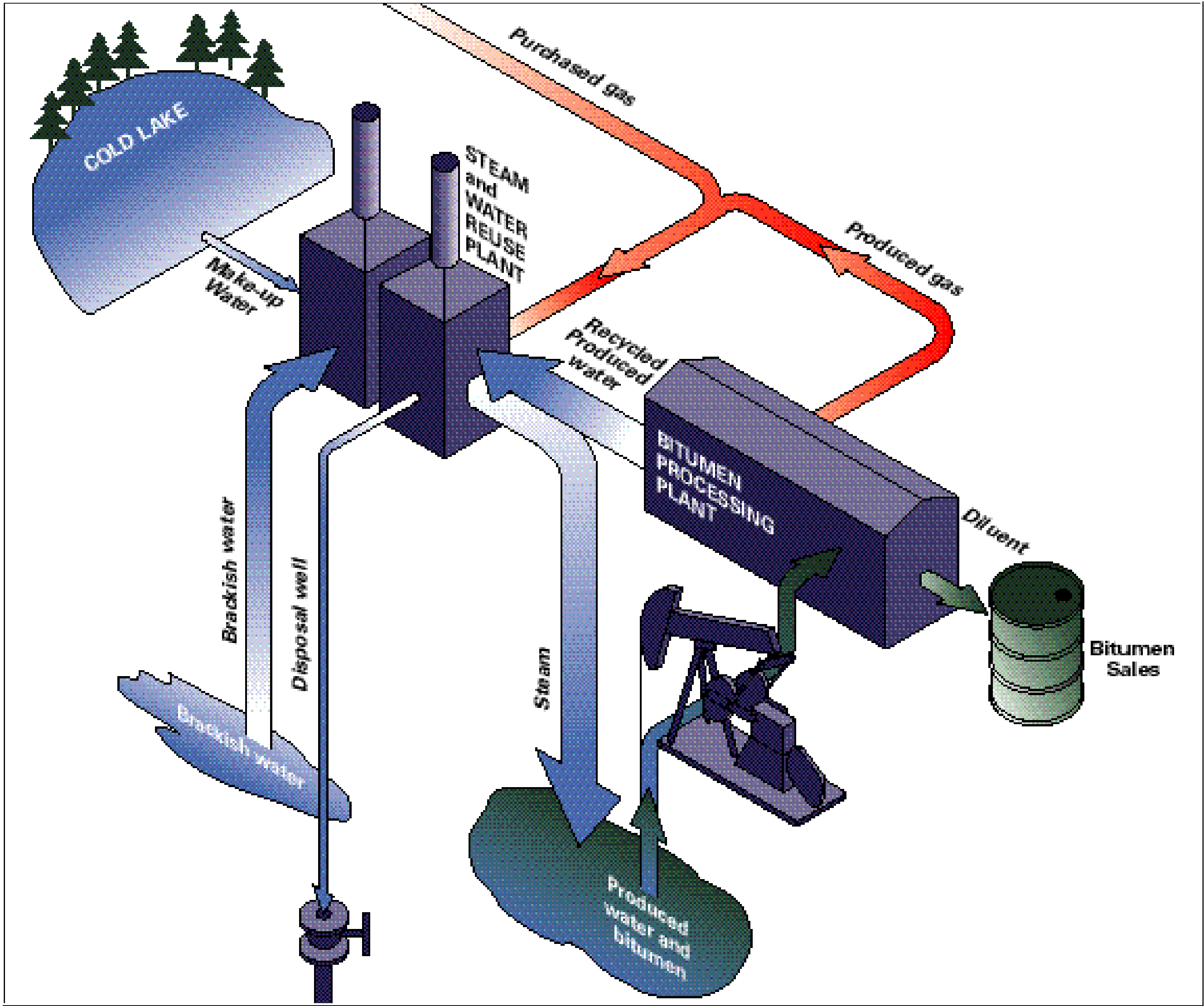
Table 2 – Colorado Evaluation Wells (CEWs) proposed for abandonment

Well	UWI	License #	Comments
D62-OB2	1AB/11-36-64-4W4/0	194968	Run temperature log and take manual pressure reading before abandonment
D63-OB2	112/11-36-64-4W4/0	199930	Run temperature log and take manual pressure reading before abandonment
D64-OB2	1AA/05-36-64-4W4/0	196036	Run temperature log and take manual pressure reading before abandonment
D07-CEW-5	112/03-11-65-4W4/0	265162	Run temperature log and take manual pressure reading before abandonment
F01 CEW-8	110/06-18-65-3W4/0	267431	
F02 CEW-6	112/10-18-65-3W4/0	265998	
F03 CEW-1	115/02-18-65-3W4/0	263666	Previously suspended
F03 CEW-2	111/08-18-65-3W4/0	263374	
F03 CEW-3	112/04-17-65-3W4/0	263493	Previously suspended
F03-16A	110/08-18-65-3W4/0	260559	
F04 CEW-9	103/13-17-65-3W4/0	265997	Previously suspended
F06 CEW-10	112/06-17-65-3W4/0	267585	
F07 CEW-13	112/02-17-65-3W4/0	267537	
14-17 CEW-12	102/14-17-65-3W4/0	268171	Previously suspended
FF CEW4	100/16-7-65-3W4/0	268445	Previously suspended
H37-CEW-18	111/09-3-66-4W4/0	284934	
H38-CEW-24	106/16-3-66-4W4/0	297208	
H38-CEW-26	103/16-3-66-4W4/0	275128	
H38-CEW-27	107/15-3-66-4W4/0	277163	
J01-CEW-21	112/04-22-65-4W4/0	289972	No plans for this pad

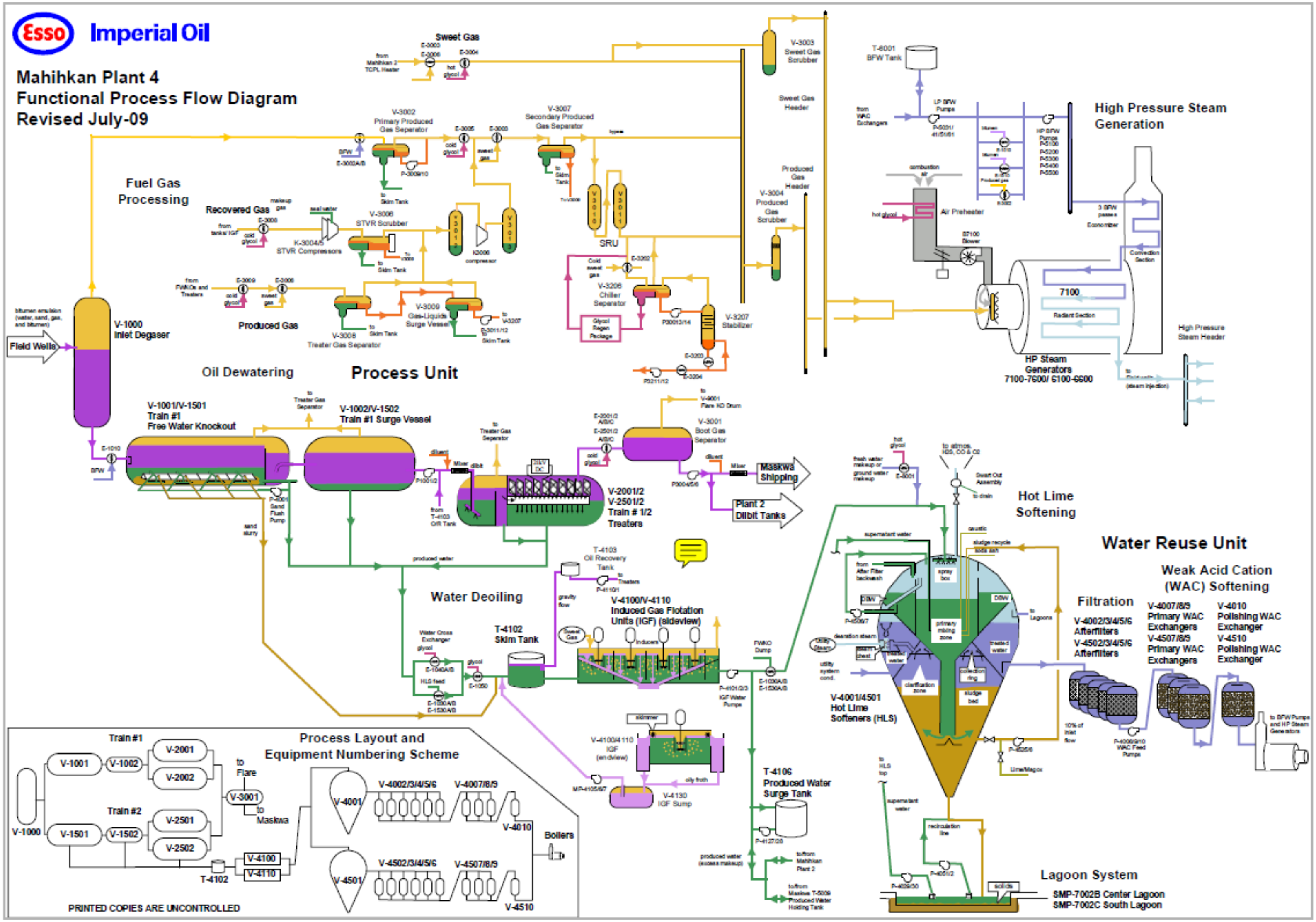
Attachment 7

Process Flow Schematics

Cold Lake Operations Process Overview



Process Flow Schematics



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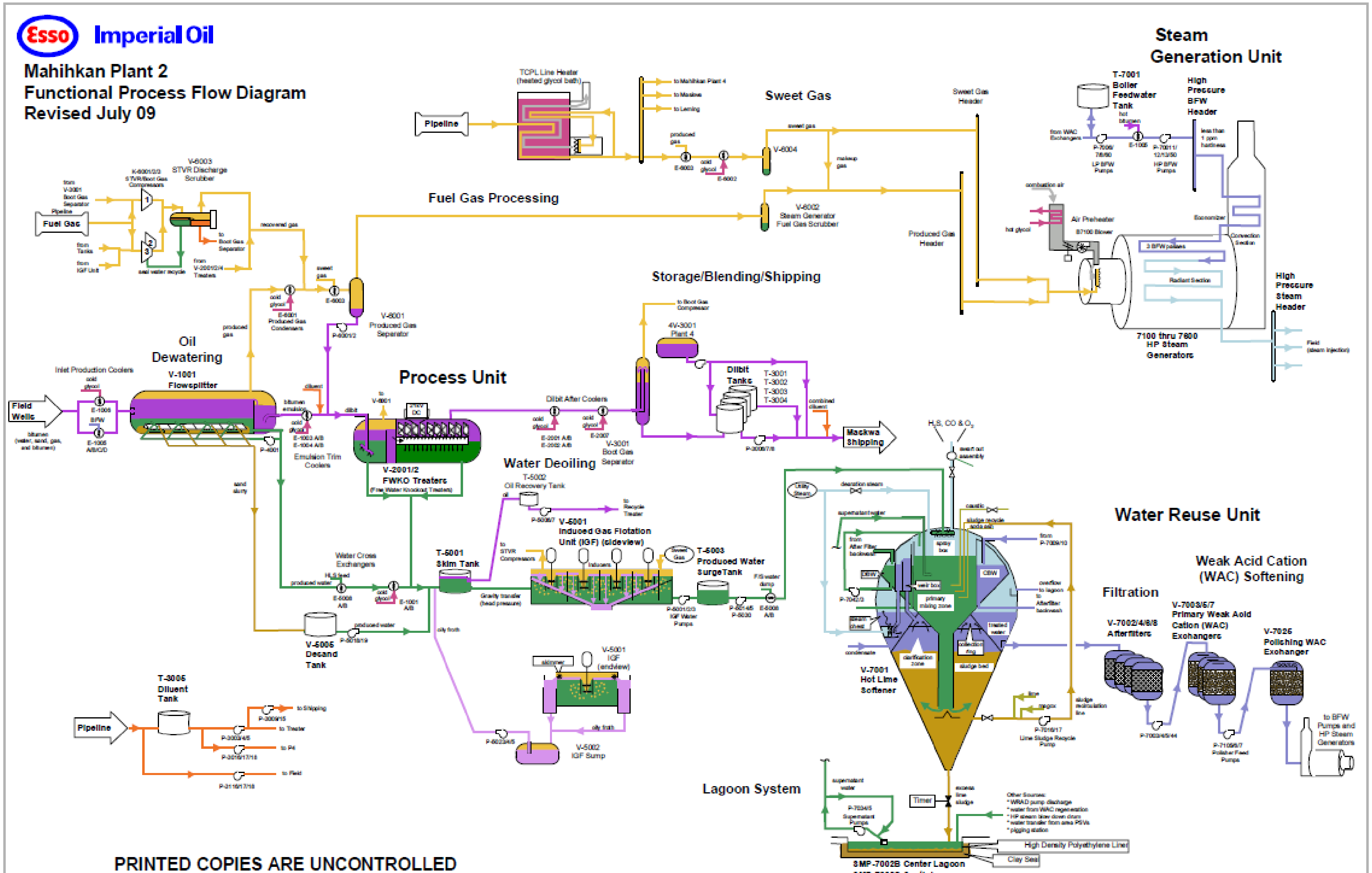
Process Flow Schematics



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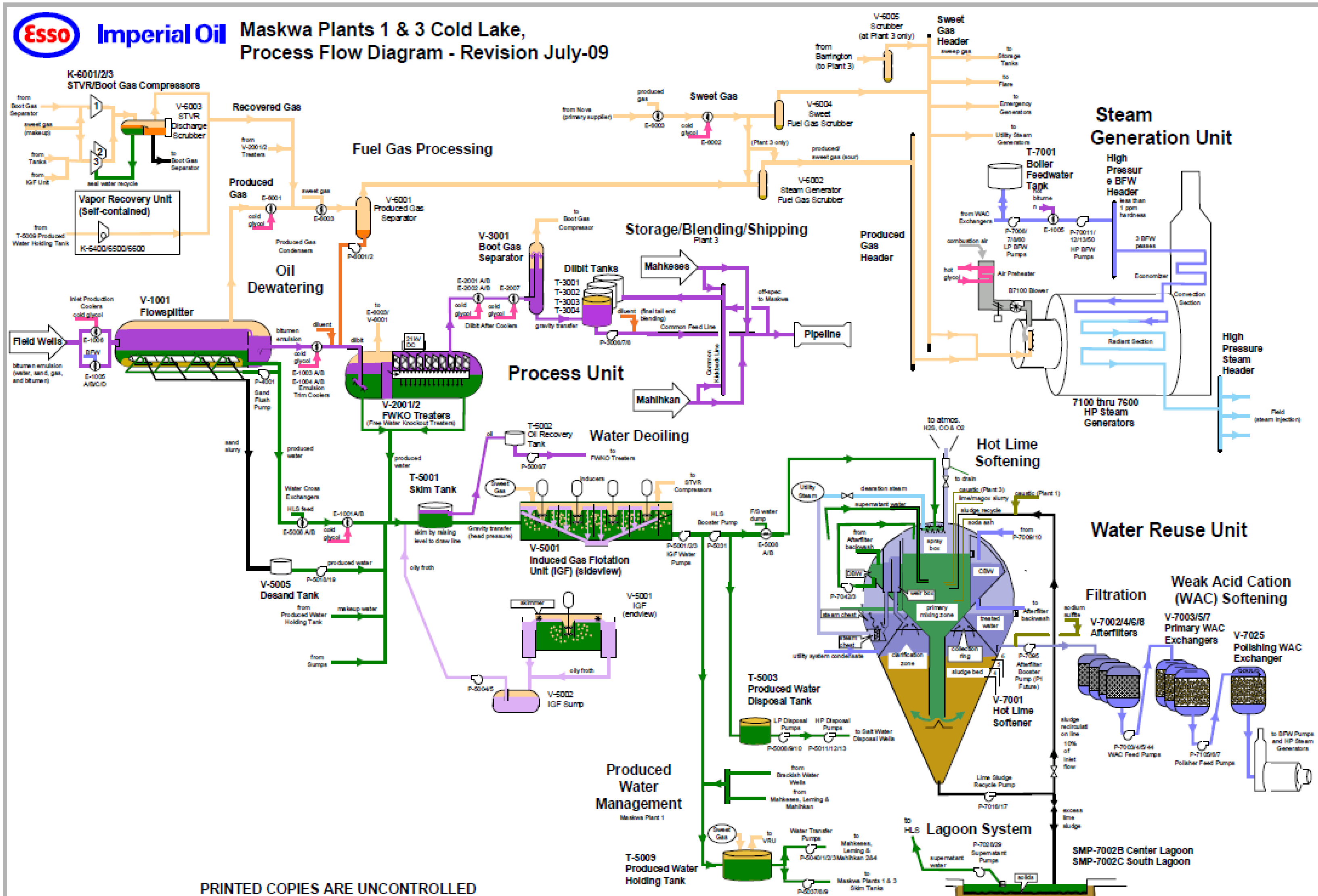
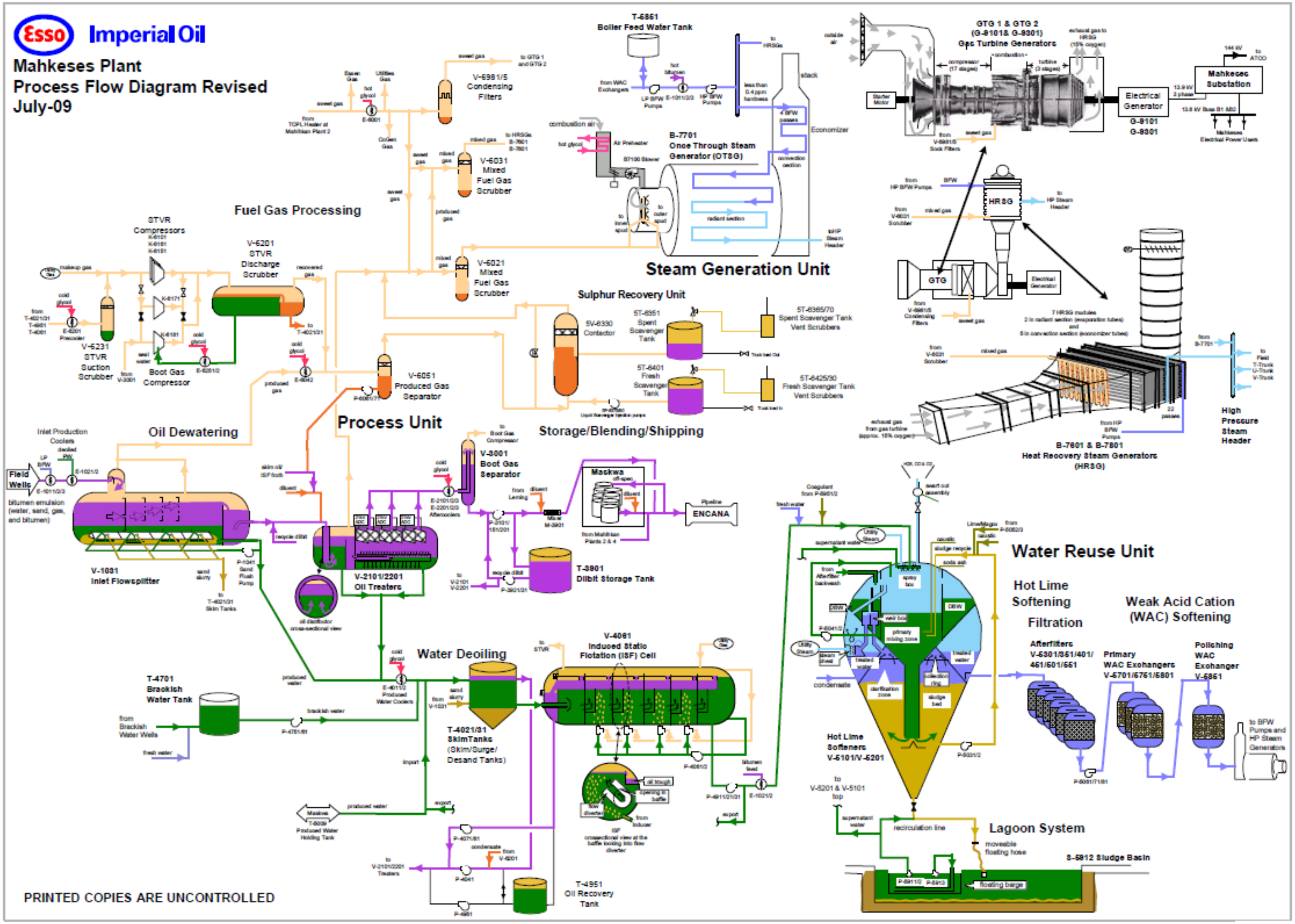
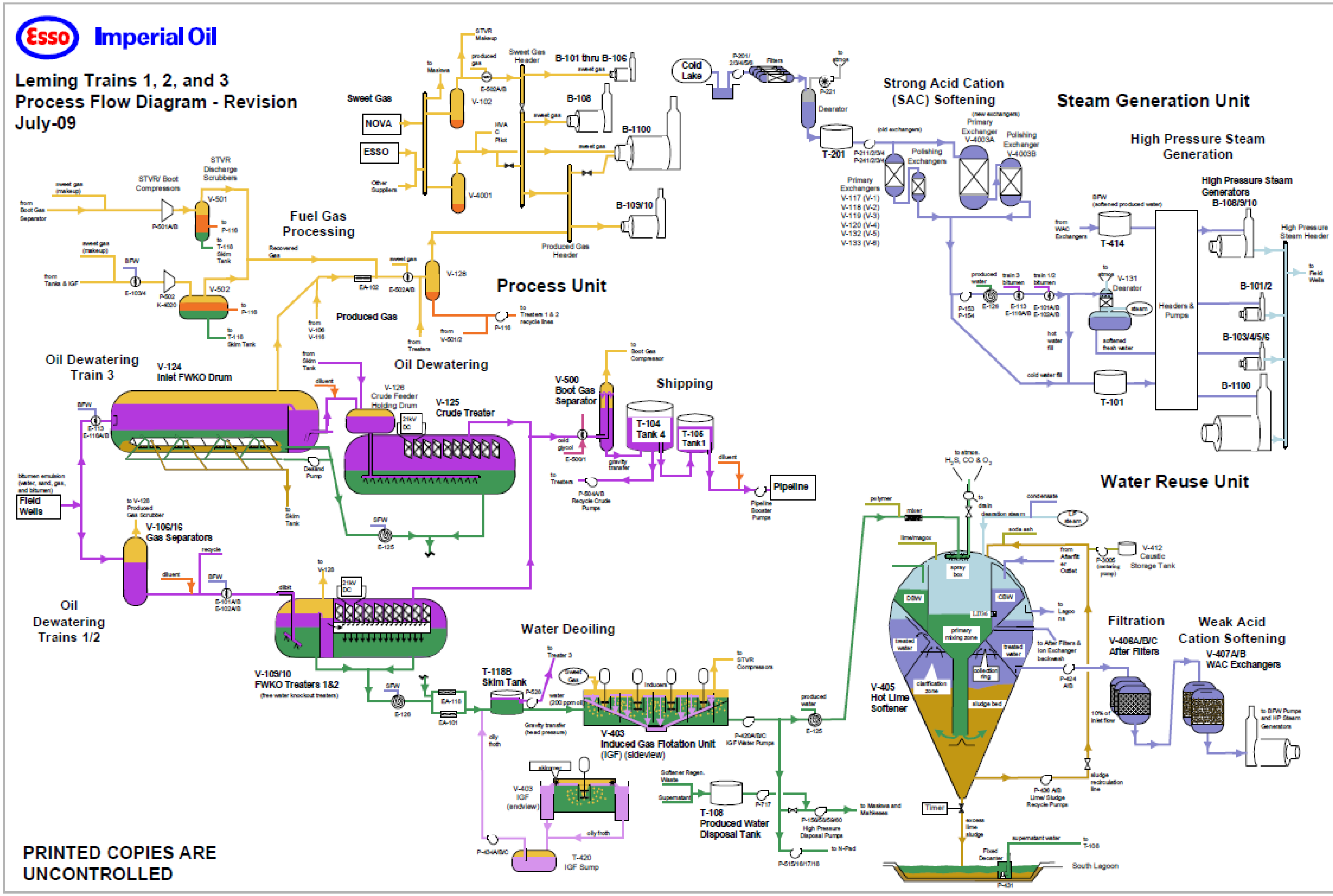
Process Flow Schematics



Process Flow Schematics



Process Flow Schematics



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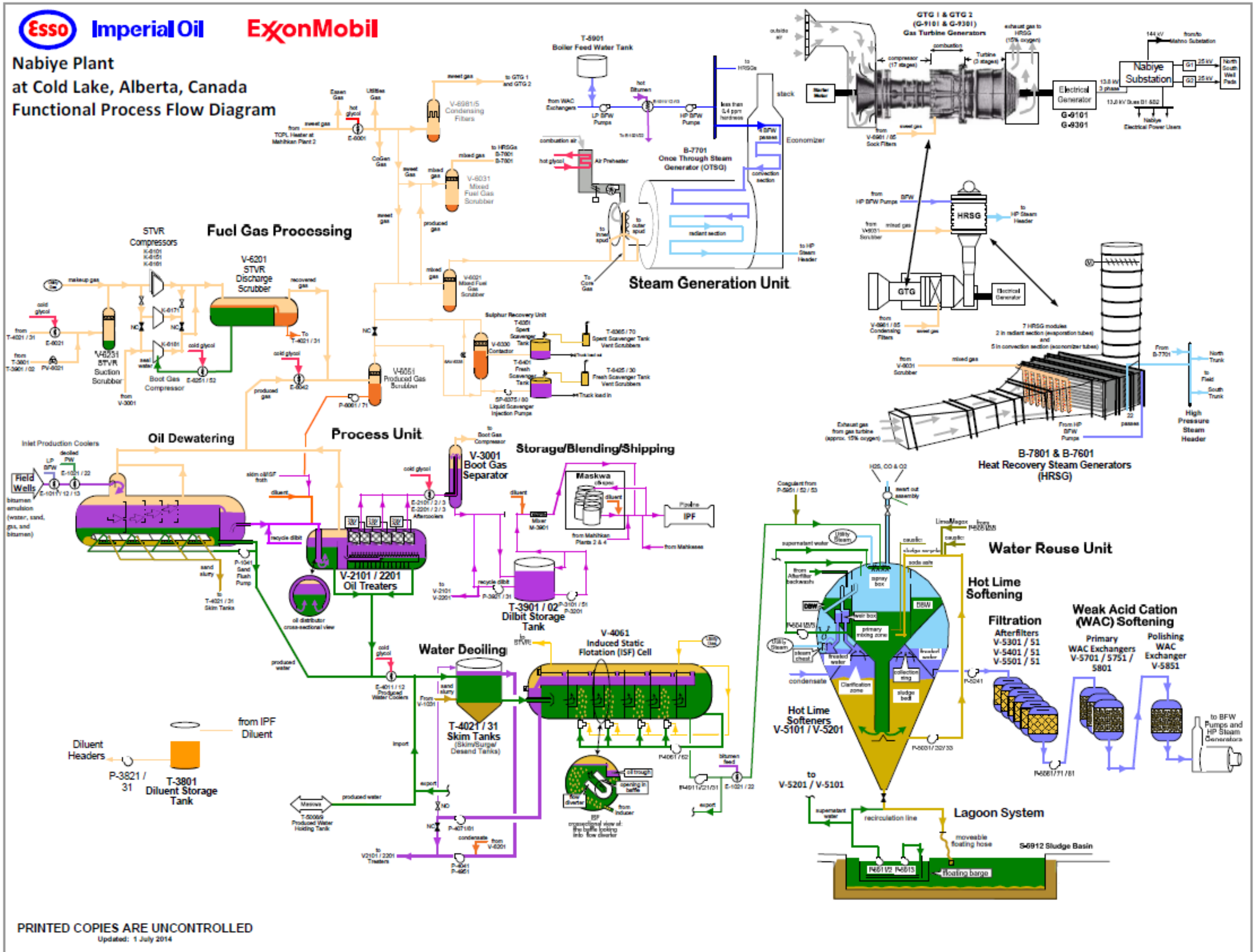
Process Flow Schematics



Attachment 8

Cold Lake Water Use

Cold Lake Water Use (cont'd)

Cold Lake Operations Water Management Strategy

- Maximize produced water recycling
- Minimize the need for non-saline water
- Use the non-saline groundwater withdrawal licence for Cold Lake water system maintenance or as a contingency source in the event of lower water levels in Cold Lake

Cold Lake Fresh Water Uses:

- Leming production inlet cooling and HP steam boiler feed water makeup
- Domestic use, safety showers/eyewashes
- Utility boiler feed water for low-pressure steam
- Utility water; sample cooling, seal flush water for pump seals and compressors
- Field wellhead and rig work activities
- Emergency firewater supply

Water Conservation & Improvements

- Early 90's developed capability to utilize brackish water to supplement produced water
- Inter-site produced water transfer systems reduce make-up water requirements and limit disposal of produced water
- Mahkeses freshwater consumption significantly lower than other plants (<100 m3/d); Nabiye will be similar
- Treated water transferred from Maskwa & Mahkeses to Leming reduces freshwater usage
- Brackish water deliverability not an issue to date
- Inter-site steam transfer provide additional water use flexibility
- Completed fresh water reduction initiatives which will reduce freshwater consumption on site by 30% by 2014 (reduction based on average consumption, 2006-2008)

Cold Lake Water Use (cont'd)

- Produced water and Brackish water both contain TDS (Total Dissolved Solids)
- Produced water contains silica (requires MgO treatment)
- Natural waters do not contain silica, tannin and are higher in magnesium
- Produced water contains tannin (helps mitigate Caustic Stress Corrosion Cracking)
- Produced water pH is a function of dissolved CO_2

Brackish and Fresh water well summary:

Well ID	*UWI*	*Regulatory Name*
Brackish water (1-05-65-02-W4M)		
BRAK1CLD	*1F1010506502W 400*	*BRAKISH WATER WELL #1*
BRAK2CLD	*1F2010506502W 400*	*BRAKISH WATER WELL #2*
BRAK3CLD	*1F3010506502W 400*	*IMP MARIE 3 COLDLK 1-5-65-2*
Groundwater (5-22-65-04-W4M) – Licence 00148301-00-00		
FW1-1 CLD	*1F1052206504W 400*	*ESSO FW E1-1 COLD LAKE WW 5-22-65-4*
FW1-2 CLD	*1F3052206504W 400*	*ESSO FW E1-2 COLD LAKE WW 5-22-65-4*
Cold Lake water (14-02-65-02-W4M) – Licence 00079923-00-00		
LEMFWCLD	*1L1140206502W 400*	*COLD LAKE FRESH WATER SOURCE*

Water properties summary:

Parameter	Produced Water	Brackish Water	Cold Lake Water	Ground Water	Disposal Water
pH	~6 to 7.5	~7.5	~7.5	~8	~6 to 7.5
Ca as CaCO3	150 - 300 ppm	85 ppm	90 ppm	200 ppm	150 - 400 ppm
Mg as CaCO3	5–25 ppm	95 ppm	40 ppm	150 ppm	5–100 ppm
Total Hardness as CaCO3	155–325 ppm	180 ppm	130 ppm	350 ppm	155–500 ppm
Alkalinity "M" Alkalinity "TIC"	450 ppm 300 ppm	1000 ppm 1000 ppm	150 ppm 150 ppm	550 ppm 550 ppm	450 ppm 300 ppm
Silica	150–350 ppm	< 10 ppm	< 5 ppm	< 15 ppm	50–350 ppm
Chloride	5000–8000 ppm	4000 ppm	< 5 ppm	< 20 ppm	2000–10000 ppm
TDS	~12000 ppm	~7000 ppm	~300 ppm	~800 ppm	5000-12000 ppm
Tannin	100–200 ppm	0 ppm	0 ppm	0 ppm	50–200 ppm
Dissolved Gases	CH4, CO2, H2S	CH4, CO2	Dissolved Oxygen	CO2	CH4, CO2, H2S

Attachment 9

Plant Licence Limits

Plant Licence Limits

Cold Lake Operations – Operating Plant Licence Limits

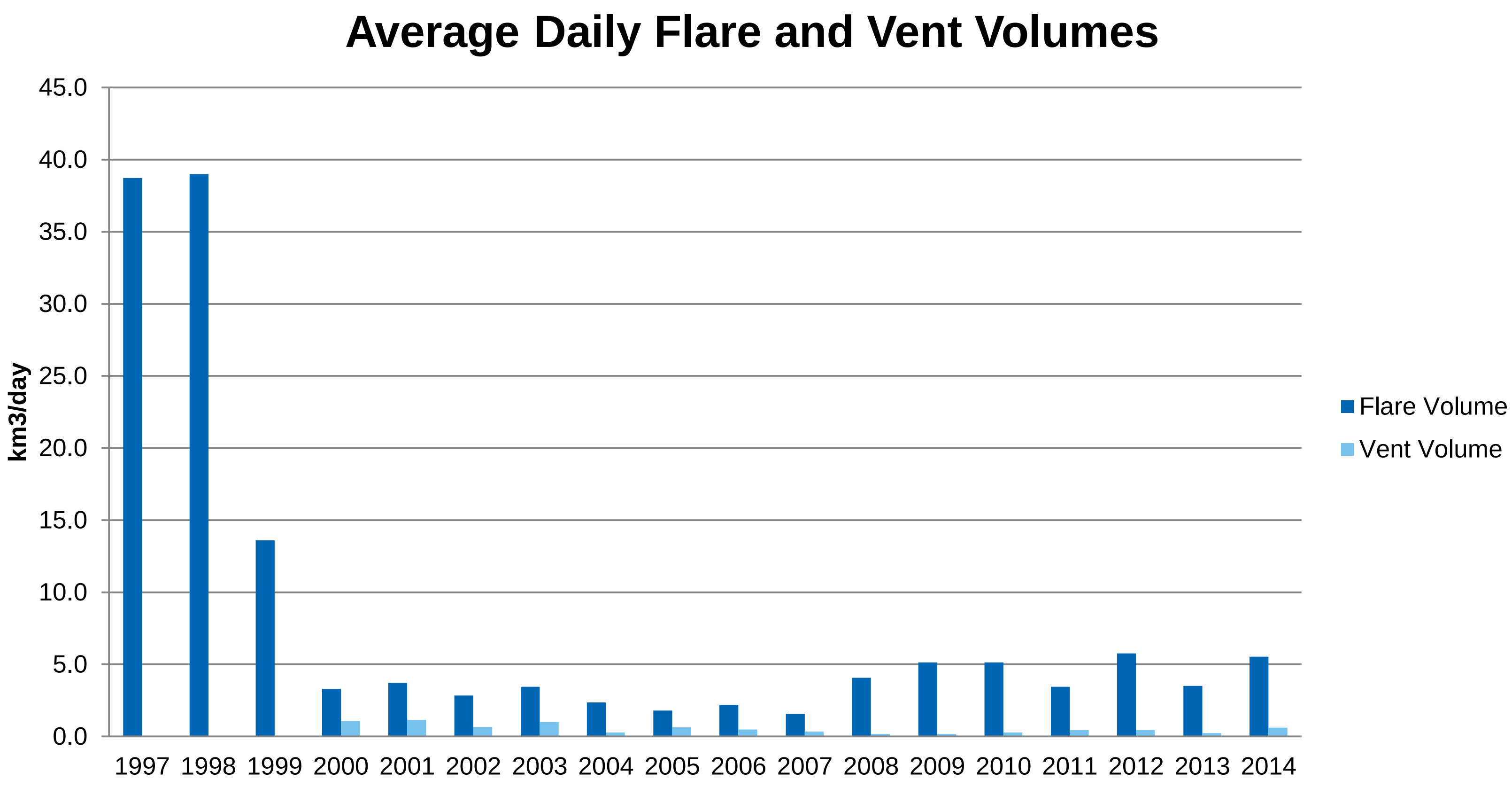
Agency	Maximum Daily Inlet Limits	Units	Maskwa	Mahihkan	Mahkeses	Leming	Nabiye	District
AER	Bitumen Inlet	m^3/d	11,000	15,000	8,000	5,000	8,000	40,000
AER	Gas Inlet	km^3/d	600	600	330	250	280	--
AER	Water Inlet	m^3/d	38,000	41,000	28,000	13,500	22,665	--
AER	H_2S Inlet Composition	mol/kmol	9.99	10.00	9.99	9.99	9.99	--
AER	Sulphur Inlet	t/d	8.13	3.00	4.43	3.39	3.76	--
Agency	**Maximum Daily Emission Limits**	**Units**	**Maskwa**	**Mahihkan**	**Mahkeses**	**Leming**	**Nabiye**	**District**
AER	Sulphur	t/d	2.00	3.00	0.54	1.05	0.99	--
AER	NOx	kg/hr	196.66	167.3	135.00	80.24	135.75	--
AER	CO_2	t/d	4,532.00	4,500.00	3,307.00	1,596.40	4323.00	--
AER	Continuous Flaring	km^3/d	0	0	0	0	0	--
AER	Continuous Venting	km^3/d	0	0	0.02	0	0.16	--
AENV	Sulphur Dioxide (SO_2)	t/d	4.00	--	--	2.10	--	13.15
AENV	NOx	kg/hr	--	--	126.00	--	135.75	--
Agency	**Calendar Quarter-Year Daily AVERAGE Emission Limits**	**Units**	**Maskwa**	**Mahihkan**	**Mahkeses**	**Leming**	**Nabiye**	**District**
AER	Sulphur	t/d	1.00	--	--	1.00	--	--
AER	Inlet Produced Gas Sulphur Recovery	%	--	69.7%	69.7%	--	70.0%	--
AENV	Sulphur Dioxide (SO_2)	t/d	--	1.80	1.08	--	1.08	--

Attachment 10

Monitoring Programs

Air Flare and Vent

Monitoring Programs – Air Flare and Vent



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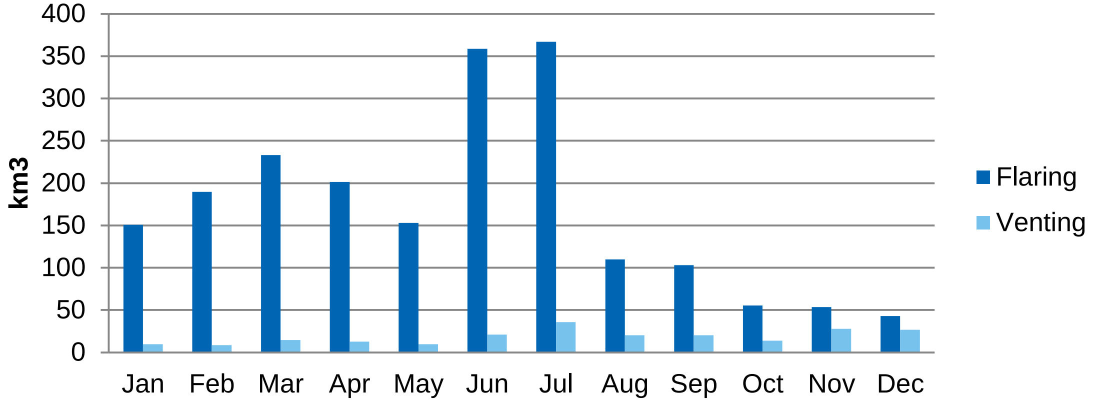
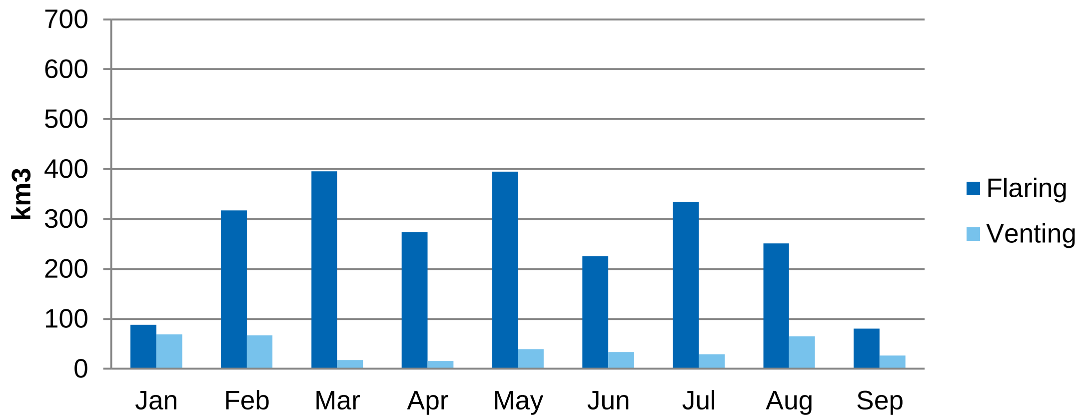
Monitoring Programs – Air Flare and Vent

IOR Cold Lake Flaring and Venting 2014



IOR Cold Lake Flaring and Venting 2015 YTD



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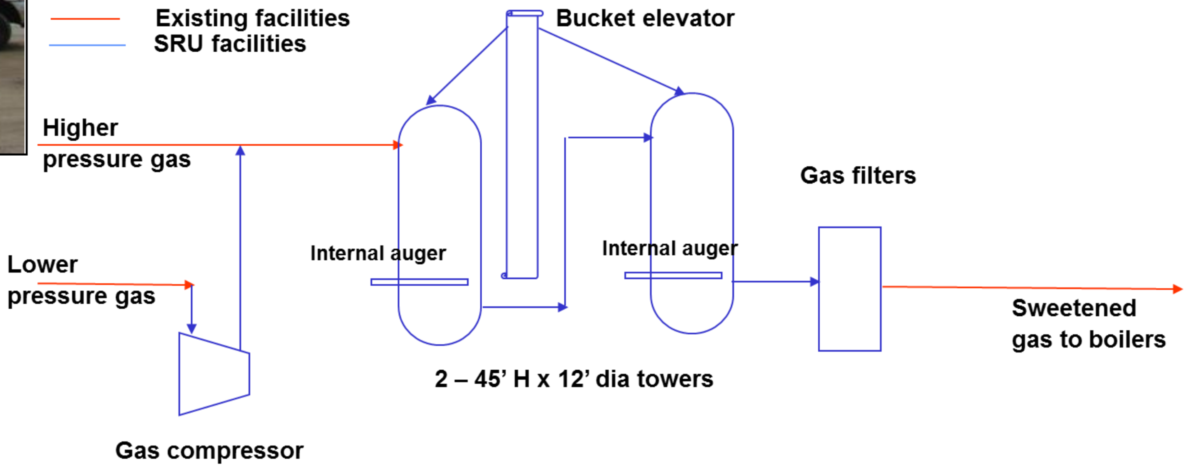
Attachment 11

SRU Description

Mahihkan and Mahkeses

Mahihkan SRU Description

- 2 identical towers for batch operation: 12 ft Diameter by 45 ft Height
- Solid media H2S scavenger Sulphatreat XLP ®
- Piping and switching valves to allow parallel or series (lead/lag) operation. Bypass included for control of gas rate (pressure drop)
- Screw compressor skid to boost low pressure gas streams to SRU
- Media sock filters at outlet of SRU
- External portable auger and bucket elevator for media loading at top of contactor
- Internal auger for tower unloading



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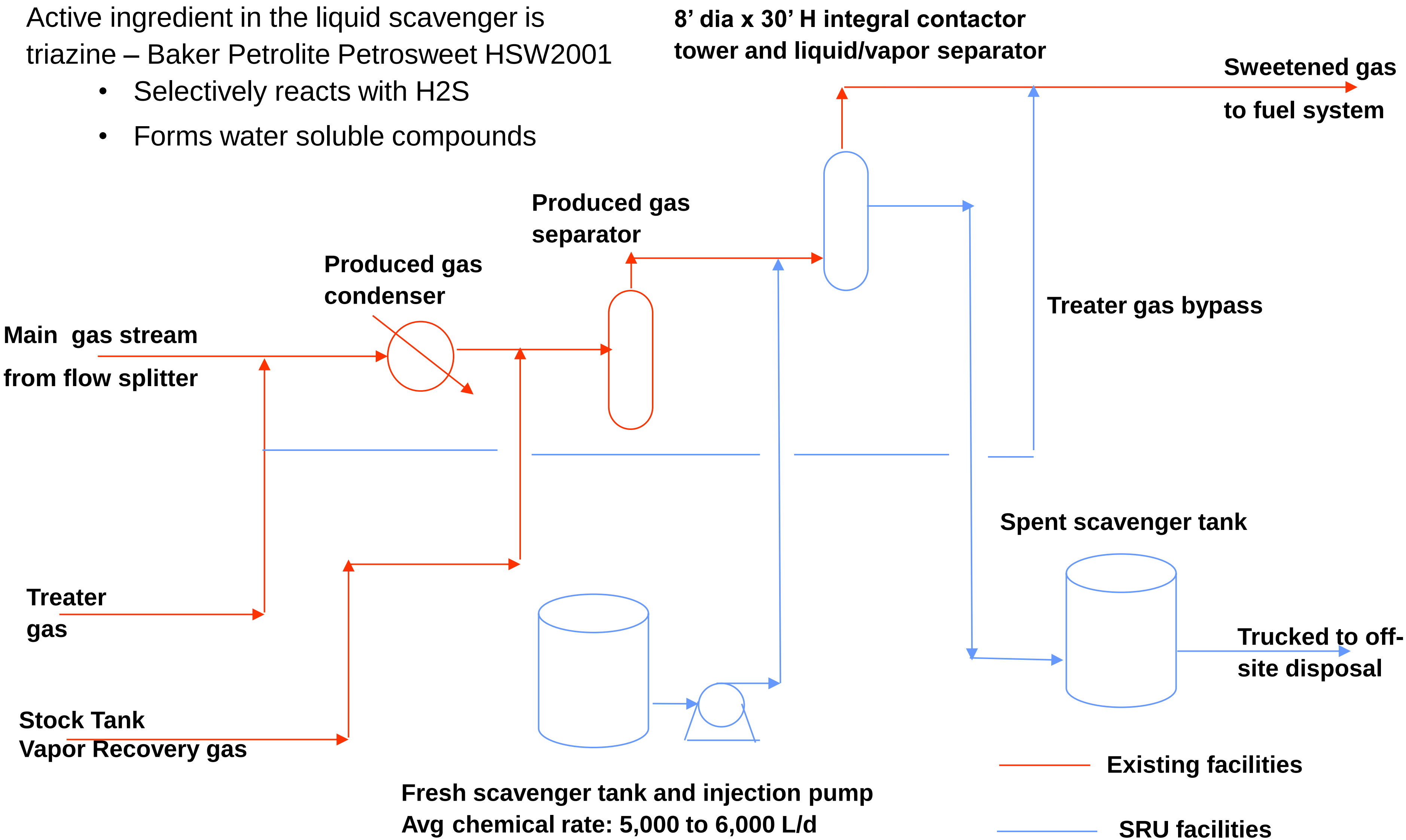
Mahkeses SRU Description

Active ingredient in the liquid scavenger is triazine – Baker Petrolite Petrosweet HSW2001

- Selectively reacts with H2S
- Forms water soluble compounds



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